



Carolina Power & Light Company

September 3, 1981



FILE: NG-3514(B)

SERIAL No.: NO-81-1413

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
United States Nuclear Regulatory Commission
Washington, D.C. 20555

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
DOCKET NOS. 50-325 AND 50-324
LICENSE NOS. DPR-71 AND DPR-62
REQUEST FOR LICENSE AMENDMENTS
ADDITION OF CO-OWNER

Dear Mr. Denton:

In accordance with the Code of Federal Regulations, Title 10, Section 50.90 and Section 2.101, Carolina Power & Light Company (CP&L) hereby requests revisions to the Operating Licenses for its Brunswick Steam Electric Plant, Unit Nos. 1 and 2. These changes reflect the addition of North Carolina Municipal Power Agency Number 3 (Power Agency) as a co-owner of the Brunswick facilities. The "Application for Amendment of Operating License Nos. DPR-71 and DPR-62 Adding Co-Owner" is attached; in accordance with 10CFR50.33 and 50.33a, it contains the applicable information necessary to determine financial qualification and to conduct the appropriate antitrust reviews. A suggested revision to Paragraph 2.A of each Operating License is also attached.

Power Agency is purchasing undivided ownership interests from CP&L in three fossil units (Roxboro 4, Mayo 1, and Mayo 2), Brunswick 1 & 2, and the four units of the Shearon Harris Nuclear Power Plant (SHNPP). Applications to amend the SHNPP Construction Permits and the SHNPP Application for Operating Licenses are being filed concurrently with this submittal.

In addition, due to their volume, Exhibits A, B.1, B.2, C, D, E, F, G, and H are being submitted under separate cover (Serial No.: NO-81-1414). These exhibits are referenced in the attached application.

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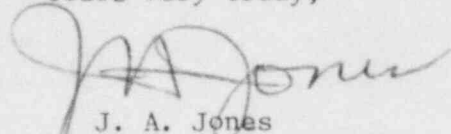
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We have determined that the requested changes constitute one Class II amendment and one Class I amendment in accordance with 10CFR170.22. Accordingly, our check for \$1,600.00 is enclosed.

The agreements which CP&L and Power Agency have executed relating to the sale of generating capacity are conditioned upon necessary regulatory reviews and approvals. It is requested, therefore, that review of this application be expedited.

Please contact our staff should you have any questions regarding this matter.


Yours very truly,


J. A. Jones
Vice Chairman

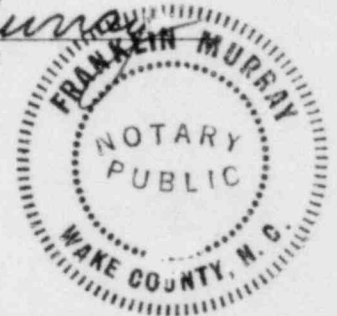
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Attachments

cc: Mr. D. G. Eisenhut (letter only)
Mr. T. A. Ippolito (letter only)
Mr. J. Van Vliet (letter only)

Sworn to and subscribed before me this 3rd day of September, 1981.


Notary Public

My Commission Expires: Oct. 4, 1981



OPERATING LICENSE AMENDMENTS

The following is a proposed revision to Paragraph 2.A of Brunswick Unit No. 1 Operating License No. DPR-71 to reflect North Carolina Municipal Power Agency Number 3 as a co-owner of the facility:

- 2.A This license applies to the Brunswick Steam Electric Plant, Unit 1, a boiling water reactor and associated equipment (the facility), owned by the Carolina Power & Light Company and North Carolina Municipal Power Agency Number 3. The facility is located on the Cape Fear River, near Southport in Brunswick County, North Carolina, and is described in the "Final Safety Analysis Report" as supplemented and amended (Amendments 1 through 31) and the "Environmental Report" as supplemented and amended.

The following is a proposed revision to Paragraph 2.A of Brunswick Unit No. 2 Operating License No. DPR-62 to reflect North Carolina Municipal Power Agency Number 3 as a co-owner of the facility:

- 2.A This license applies to the Brunswick Steam Electric Plant, Unit 2, a boiling water reactor and associated equipment (the facility), owned by the Carolina Power & Light Company and North Carolina Municipal Power Agency Number 3. The facility is located on the Cape Fear River, near Southport in Brunswick County, North Carolina, and is described in the "Final Safety Analysis Report" as supplemented and amended (Amendments 1 through 29) and the "Environmental Report" as supplemented and amended (Supplements 1 through 7).

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of)	
)	
CAROLINA POWER & LIGHT COMPANY)	Docket Nos. 50-325
)	50-324
(Brunswick Steam Electric Plant,)	
Units 1 and 2))	

APPLICATION FOR AMENDMENT OF OPERATING LICENSE
NOS. DPR-71 AND DPR-62 ADDING CO-OWNER

Carolina Power & Light Company ("CP&L") is presently the holder of Nuclear Regulatory Commission ("NRC" or "the Commission") Operating License Nos. DPR-71 and DPR-62 for Units 1 and 2 of the Brunswick Steam Electric Plant. By this application, CP&L and the North Carolina Municipal Power Agency Number 3 ("Power Agency") respectfully request that the Commission amend these Operating Licenses to include Power Agency as a co-owner of Brunswick Units Nos. 1 and 2, consistent with the agreements between CP&L and Power Agency as hereinafter described. CP&L will retain exclusive responsibility for the operation and maintenance and the construction of capital additions to Brunswick Units Nos. 1 and 2.

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1. General Information

a. Name and Address of Proposed Co-Owner

North Carolina Municipal Power Agency Number 3
Post Office Box 95162
Raleigh, North Carolina 27625

b. Description of Business of Proposed Co-Owner

Power Agency is a public body corporate and politic and an instrumentality of the State of North Carolina, incorporated under North Carolina statutes in December, 1976. Power Agency was created to plan, develop, construct, and operate generation and transmission facilities. Power Agency has been granted all of the powers necessary or convenient to carry out such purposes. Power Agency has proposed to enter into contracts with thirty-six political subdivisions, listed in Apperdix A, under which Power Agency is to be the sole and exclusive bulk power supplier for each such political subdivision in excess of any allotment of federal power from Southeastern Power Administration or of the output of any resource such political subdivision may develop and install pursuant to provisions of the Supplemental Power Sales Agreement in effect between Power Agency and such political subdivision. Each such political subdivision is obligated to take or pay for its entitlement share of power from any owned project, such as the Brunswick and Harris Units. The terms of said contracts are for the life of the project or so long as any of Power Agency's bonds issued to finance the project are outstanding, but not exceeding 50 years.

c. Corporate Date Relating to Proposed Co-Owner

Power Agency is a body corporate and politic and an

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instrumentality of the State of North Carolina created pursuant to the Joint Municipal Electric Power and Energy Act, Chapter 159B of the General Statutes of North Carolina. Power Agency is not owned, controlled or dominated by an alien, a foreign corporation or foreign government. Power Agency's office is located at Cypress Building, Highwoods Office Center, Post Office Box 95162, Raleigh, North Carolina 27625. The names and business addresses of Power Agency's Board of Commissioners, all of whom are citizens of the United States, are as follows:

The Honorable Simon C. Sitterson, Jr.*, Chairman
Kinston

Mr. Peter Vandenberg,* Vice Chairman
Laurinburg

Mr. David R. Taylor,* Secretary-Treasurer
Tarboro

Mr. Ralph W. Shaw, General Manager

Mr. Lamar Hales
Town of Apex

Hon. Ralph M. Wallace
Town of Belhaven

Mr. Charles Stewart
Town of Clayton

Mr. Tommy M. Combs
City of Elizabeth City

Mr. J. A. Wooten, Jr.*
Town of Farmville

Mr. Charles O'H. Horne, Jr.*
City of Greenville

Hon. W. D. Cox
Town of Hertford

Hon. Harry S. Taylor, Jr.
Town of Hookerton

Mr. Edward B. Walters
Town of LaGrange

Mr. Mark A. Suggs
Town of Ayden

Mr. Robie G. Dunn
Town of Benson

Mr. James P. Ricks, Jr.
Town of Edenton

Hon. B. D. Kimball
Town of Enfield

Mr. Devone Jones
Town of Fremont

Mr. W. P. Riley
Town of Hamilton

Hon. R. G. Anthony
Town of Hobgood

Hon. Simon C. Sitterson, Jr.*
City of Kinston

Mr. Peter Vandenberg*
City of Laurinburg

Ms. Lois Brown Wheless
Town of Louisburg

Mr. Russ Conner
City of New Bern

Mr. John McNeill
Town of Red Springs

Hon. Frederick E. Turnage*
City of Rocky Mount

Hon. Ferd L. Harrison
Town of Scotland Neck

Mr. Jonathan Hankins
City of Southport

Mr. Guy C. Hill
Town of Wake Forest

Mr. William L. Ross
Town of Waynesville

Mr. T. R. Shaw, Jr.
City of Windsor

Hon. Furman K. Biggs, Jr.
City of Lumberton

Mr. Raymond Glover
Town of Pikeville

Mr. Ralph Mobley
Town of Robersonville

Mr. W. Everette Prince
Town of Selma

Mr. Earl Langley
Town of Smithfield

Mr. David R. Taylor*
Town of Tarboro

Mr. D. R. Jones
City of Washington

Mr. T. Bruce Boyette
City of Wilson

Mr. E. C. Hines
Town of Winterville

*Executive Committee Member

2. RESPONSES TO INFORMATION REQUESTS OF NUCLEAR
REGULATORY COMMISSION STAFF CONCERNING
FINANCIAL QUALIFICATIONS OF MUNICIPAL APPLICANT

NORTH CAROLINA MUNICIPAL POWER AGENCY NUMBER 3

Question 1

Provide a detailed statement of the projected source of funds for each municipal applicant's capital contribution to the subject project reflecting assumptions and detailed explanation.

Response to Question 1

Power Agency's ownership interest in the project will be financed through issuance of tax-exempt revenue bonds. The estimated capital costs, principal amount of bonds required, and assumptions used in developing such estimates are included in Exhibit A.

Question 2

If the applicant is to finance its ownership share with bonds, indicate the source of funds for payment of interest charges and principal.

Response to Question 2

Power Agency will execute Project Power Sales Agreements with its Participants for the Initial Project which in the aggregate provide for the payment of principal and interest (to the extent not capitalized and paid from bond proceeds). Each Participant will pay its Participant's Share of the Monthly Project Power Costs which, as defined, include provisions for such principal and interest charges.

The obligations of the Participant to make payments to Power Agency under the Project Power Sales Agreement will be an expense of its Electric System, and the Participant will not be required to make payments to Power Agency except from revenues of its Electric System. Each Participant will covenant in the Project Power Sales Agreement that it will fix and charge rates for electric service supplied from its Electric System sufficient to meet all of its obligations under the Project Power Sales Agreement and to pay any and all other amounts payable from such revenues including cost of operation and of any general obligation bonds issued by the Participant to finance its electric system.

Exhibit B.1 is a copy of the North Carolina Municipal Power Agency Number 3, Project Power Sales Agreement, Initial Project, dated July 30, 1981. Section 1(t) therein defines Monthly Project Power Costs. Additionally, Sections 4 and 6 therein respectively provide for sale and source of and obligation of payments. Exhibit B.2 is a copy of the Supplemental Power Sales Agreement dated July 30, 1981 to be executed by Power Agency and each Participant.

Question 3

Describe the nature, amount, rating and success of the applicant's most recent revenue and general obligation bond sales. Indicate the current total outstanding indebtedness in each category for each entity.

Response to Question 3

Power Agency has not heretofore issued any such bonds.

Question 4

Provide copies of the official statements for the most recent bond issue.

Response to Question 4

See response to question 3.

Question 5

Provide copies of the most recent annual financial report (June, 1980).

Response to Question 5

Submitted herewith as Exhibit C is the report entitled "Audited Financial Statements and Other Financial Information" for North Carolina Municipal Power Agency Number 3, dated June 30, 1980. Applicants will submit the 1981 financial statement for Power Agency as soon as it becomes available. In addition, applicants can make available to the Commission copies of the most recent annual financial statements of the municipalities which may become Participants in the project.

Question 6

Is each Participant's percentage ownership share in the facility equal to its percentage entitlement in the electrical capacity and output of the plant.

Response to Question 6

Yes, they are equal.

Question 7

Describe the rate-setting authority of each municipal applicant and how that authority may be used to ensure the satisfaction of financial obligations related to both capital and operating costs of the facility.

Response to Question 7

The authority of Power Agency is set forth in Chapter 159B (Joint Municipal Electric Power and Energy Act) of the General Statutes of North Carolina and in Article V, Section 10 of the Constitution of North Carolina. In particular, N.C.G.S. 159B-11(14) authorizes joint agencies "To fix, charge and collect rents, rates, fees and charges for electric power or energy and other services, facilities and commodities sold, furnished or supplied through any project." Under the Power Coordination Agreement and the Operating and Fuel Agreement between Power Agency and Carolina Power & Light Company (Exhibits D and E), Power Agency covenants to set rates adequate to cover all its costs [Power Coordination Agreement, Section 26.1(A); Operating Agreement, Section 19.1(B)]. These obligations are embodied in the agreements between Power Agency and its Participants (Project Power Sales Agreement, Section 6; Supplemental Power Sales Agreement, Section 5). No regulatory approvals are required by Power Agency in setting rates to its Participants. The Participants, as municipalities of the State of North Carolina, have authority to establish their own retail rates for service to their customers. In N.C.G.S. 159B-22, the State of North Carolina covenants and agrees that so long as any bonds of Power Agency are outstanding and unpaid, the State will not limit or alter the rights of any participant or of Power Agency to establish, maintain, revise, charge and collect electric rates to fulfill the terms of any agreement for the project.

Question 8

What is the estimated dollar amount that will be payable by the applicant at the date of closing of the sale, and after closing through the completion of the units.

Response to Question 8

Table 5 of Exhibit A reflects the estimated dollar amounts payable by the applicant for the closings and after closing through the completion of the units (see line 12-- columns (b)+(c)+(d) = closing costs; column (p) minus the sum of (b)+(c)+(d) = amounts to be paid after closing until the units are complete.

Question 9

Provide copies of the joint ownership agreements.

Response to Question 9

Copies of the joint ownership agreements are being filed as a part of this Application.

Question 10

If a membership organization is participating in the joint ownership, explain the contractual arrangement among the members that assures that funds will be available to meet the entity's obligations to the project.

Response to Question 10

The member participants will enter into various agreements with the applicant whereby the participant covenants to charge rates sufficient to cover all costs for facilities acquired and services rendered under the agreements. Please reference to "Response to Question 2", to Exhibit B.1, Section 5(e),

Section 6(b), and Sections 12(c) and (d); and to Exhibit B.2, Section 7(c).

Question 11

Explain the procedure to be used by the lead applicant for billing the municipalities for construction progress payments subsequent to closing the sale.

Response to Question 11

Pursuant to Section 6.2 of the Purchase, Construction and Ownership Agreement ("Sales Agreement" Exhibit F), CP&L will furnish to Power Agency on an annual basis estimates of construction costs for the project and Power Agency's share thereof. Pursuant to Section 6.3 of the Sales Agreement, on the first day of each month after the first closing CP&L will submit to Power Agency a statement showing the amount due from Power Agency for construction expenditures expected to be incurred in the month next following. Power Agency's payment will be due on the first of the month following the month of each such statement. When the costs actually incurred in that month become known, CP&L will make an adjustment on the next monthly statement submitted to Power Agency to correct any differences between Power Agency's progress payment and its share of the costs actually incurred.

The procedures relating to monthly construction progress payments are fully set forth in Sections 6.2 and 6.3 of the Sales Agreement.

Question 12

Describe the applicant's plan for financing its share

of the cost of eventual shut-down of the facility and maintenance in a safe shut-down condition.

Response to Question 12

Provisions for the creation of a Decommissioning Fund have been provided in the draft Bond Resolution (Exhibit G) which is to be adopted by the applicant's Board of Commissioners. In addition, costs of decommissioning the Brunswick and Harris Units have been included in the Preliminary Engineering Report of R. W. Beck and Associates as a portion of the project's overall feasibility.

3. Information Requested by the
Attorney General for Antitrust Review

Carolina Power & Light Company ("CP&L") and North Carolina Municipal Power Agency Number 3 ("Power Agency") are applicants for an amendment to the Operating Licenses for Brunswick Steam Electric Plant Unit Nos. 1 and 2 ("Brunswick Units"), DPR-71 (Brunswick Unit No. 1, issued September 8, 1976) and DPR-62 (Brunswick Unit No. 2, issued December 27, 1974) and the Construction Permits for Shearon Harris Nuclear Power Plant Unit Nos. 1, 2, 3 and 4 ("Harris Units"), CPPR-158, CPPR-159, CPPR-160 and CPPR-161, especially (issued January 27, 1978). Applicants seek to have the Operating Licenses for the Brunswick Units, the Construction Permits for the Harris Units and the application for Operating Licenses for the Harris Units amended to include Power Agency as co-owner of the Brunswick Units and the Harris Units.

This request is submitted by CP&L on behalf of Power Agency in support of their applications for amendments to the Nuclear Regulatory Commission and in response to the information requested by the Attorney General for antitrust review pursuant to Title 10, Code of Federal Regulations, Part 50, Appendix L. 1/, 2/

1/ Because Power Agency does not presently own or operate any generating capacity and because the capacity which will be available to Power Agency through the subject project is less than 1400 MW(e), Power Agency is not required to submit

(Footnote continued on page following.)

INTRODUCTION

A. General Background

There are 72 municipalities in North Carolina which own and operate their own electric distribution systems. Thirty-one of these systems are in Carolina Power & Light Company's service area; sixteen are in Virginia Electric and Power Company's service area in northeastern North Carolina; and twenty-three of these systems are in Duke Power Company's service area. The Town of Murphy is served by the Tennessee Valley Authority and the Town of Highlands is served by Nantahala Power & Light Company.

In May, 1975, the General Assembly of North Carolina enacted the Joint Municipal Electric Power and Energy Act, a new Chapter 159B of the General Statutes of North Carolina. This Act provides that municipal electric systems in the State of North Carolina may jointly plan, develop, construct, and operate generation and transmission facilities. The new law provided that municipalities owning

(Footnote continued from previous page.)

the information requested by the Attorney General described in 10 C.F.R. Part 50, Appendix L other than the information described in Section II, paragraph 9 of Appendix L. See, 18 C.F.R. §50.33(a)(1), (2). CP&L and Power Agency are, however, hereby furnishing information concerning Power Agency in response to each of the requests set forth in Appendix L for the use of the Attorney General in reviewing this Application.

2/ Certain terms which are used in the narrative text are capitalized to signify that such terms are defined terms having specified meanings in the project agreements between Power Agency and CP&L, in the agreements between Power Agency and Virginia Electric and Power Company, or in the proposed bond resolution to be adopted by Power Agency's Board of Commissioners.

electric distribution systems may create joint power agencies with the authority to issue electric revenue bonds for any projects that they may undertake. Such agencies are bodies corporate and politic and instrumentalities of the State of North Carolina. Each municipality joining such an agency appoints a commissioner to serve on a governing Board of Commissioners of Power Agency. Further, a 1977 amendment to the Constitution of North Carolina permits joint power agencies to participate as joint owners in generating or transmission projects with private utilities and rural electric cooperatives.

Since passage of Chapter 159B, municipal electric systems in North Carolina have formed three joint agencies in order to pursue potential power supply projects. These three agencies, North Carolina Municipal Power Agencies Numbers 1, 2, and 3, are organized and have memberships of the majority of the municipally owned distribution systems in the state. Power Agency Number 1 is composed of twenty municipalities which now purchase their wholesale power supply from Duke Power Company. In March, 1978, Power Agency Number 1 contracted with Duke Power Company for the purchase of a 75% ownership interest in Duke's Catawba Nuclear Unit No. 2 and a 37.5% ownership interest in the support facilities at the Catawba Nuclear Station. Power Agency Number 1 closed on these ownership interests in November, 1978. Power Agency Number 2 is composed of 15 municipalities that purchase their wholesale power supply directly or indirectly from Virginia

Electric and Power Company ("VEPCO"). In the spring of 1980, members of Power Agency Number 2 began applying for membership in Power Agency Number 3 in anticipation of successful completion of the negotiations with CP&L for purchase by Power Agency Number 3 of the project and related power supply services. Late in 1980, Power Agency Number 3 acted to include the 14 members of Power Agency Number 2 which sought such inclusion. 1/ At this time, Power Agency Number 2 remains a corporate entity, but its members presently have no plans to pursue projects other than joint ownership of the Joint Units. Today, Power Agency Number 3 is composed of 22 municipalities that purchase their wholesale power supply from CP&L and the 14 members that purchase power either directly or indirectly from VEPCO.

Under North Carolina law, Power Agency may be composed only of North Carolina municipalities. Power Agency Number 3 was incorporated in December, 1976 after its formation by twenty-six North Carolina municipal systems in the CP&L service area. Since that time, eight municipal systems that are served at wholesale through other Power Agency Number 3 members have withdrawn from Power Agency Number 3 and are expected to continue as wholesale customers of the Power Agency Number 3 members that now serve their

1/ One member of Power Agency Number 2, which is served at wholesale by an electric membership corporation, did not apply for membership in Power Agency Number 3.

power supply requirements. Also, four other municipal systems served directly by CP&L have joined Power Agency Number 3. Power Agency Number 3 currently has as members twenty-two of the twenty-three municipal electric systems that are direct wholesale customers of CP&L in North Carolina, all thirteen direct wholesale customers of VEPCO in North Carolina, and one wholesale customer of a member of Power Agency served by VEPCO. The thirty-six members of Power Agency Number 3, including the members which receive service either directly or indirectly from VEPCO, will be referred to collectively as "Power Agency". 1/ The municipal electric system served directly by CP&L that is not a member of Power Agency, the Fayetteville Public Works Commission, was invited to join Power Agency in 1976 but elected not to join. Under North Carolina law, the Fayetteville Public Works Commission, which is the largest municipal electric system in North Carolina, could finance an ownership interest in CP&L generating facilities apart from Power Agency.

B. The Project and Related Power Supply Program

The project, in conjunction with coordinated power supply arrangements, will provide for a long term, all requirements bulk power supply program to meet the power and energy needs of those members of Power Agency which become participants in the project ("Participants"). This long range power supply arrangement includes: (i) acquisition of

1/ See Appendix A for list of members of Power Agency.

undivided ownership interests in three coal-fired generating units and six nuclear generating units currently owned and in operation or under construction by CP&L (the "Joint Units") for the purpose of providing base load generating resources pursuant to a Purchase, Construction and Ownership Agreement and an Operating and Fuel Agreement; and (ii) the provision of all necessary backstand services for such resources plus supplemental power supply and transmission services pursuant to a Power Coordination Agreement with CP&L and agreements with VEPCO. Also, through the operation of the Purchased Capacity arrangement described infra at pp. 21-22 Power Agency will sell to CP&L capacity from Power Agency's ownership interests in specific generating units in declining amounts over a 15 year period; Power Agency thereby retains increasing amounts of base load generation in each year during the term of the Purchased Capacity arrangement. The overall result of these arrangements is that Power Agency will have available assured power supply and transmission resources to provide the total all requirements bulk power supply needs of all Power Agency members through the year 2032 or until the last Joint Unit is retired or decommissioned, whichever is later.

The Joint Units include the 650 MW coal-fired Roxboro Unit No. 4, which is part of CP&L's Roxboro Steam Electric Plant, in operation near Roxboro, North Carolina; the two 790 MW nuclear-fueled units at the Brunswick Steam Electric Plant, in operation near Southport, North Carolina;

the two 720 MW coal-fired units at the Mayo Electric Generating Plant, under construction in Person County, North Carolina; and the four 900 MW nuclear-fueled units at the Shearon Harris Nuclear Power Plant, under construction near New Hill, North Carolina. Power Agency's acquisition of undivided ownership interests in the Joint Units is discussed infra, at pp. 20-21.

C. The Project Agreements

The acquisition and use of the project and other power resources, together with delivery of these resources over CP&L's transmission system for Power Agency and its Participants, would be provided for under three agreements between Power Agency and CP&L, copies of which are submitted with this Application as Exhibits E, F, and G. In addition, agreements have been entered into between VEPCO and Power Agency (Exhibit H hereto) providing for partial requirements service during a Transition Period (extending from December, 1981 through December 30, 1983), and for transmission and emergency services on a long-term basis. The various agreements are:

1. The Purchase, Construction and Ownership Agreement (the "Sales Agreement"). This Agreement provides for: (a) the purchase by Power Agency and conveyance by CP&L of undivided ownership interests in the Joint Units; (b) employment of CP&L as Power Agency's project manager for the Construction, Initial Fueling, and placing into Commercial Operation of those of the Joint Units currently under construction; and (c) monthly payment to CP&L by Power Agency of its share of the Costs of Construction and Initial Fueling of the Joint Units including fees to CP&L as project manager.

2. The Operating and Fuel Agreement (the "Operating Agreement"). This Agreement provides for: (a) operation, maintenance, and fueling of the Joint Units by CP&L; (b) CP&L's making of renewals, replacements and capital additions to the Joint Units; and (c) the ultimate retirement or decommissioning, by CP&L or a qualified contractor, of each of the Joint Units included in the project at the end of its useful life.
3. The Power Coordination Agreement. This Agreement provides for: (a) interconnection between the CP&L system and the project; (b) backstand provisions, including Reserve Capacity and Deficiency Energy; (c) Retained Capacity from the proposed project; (d) Purchased Capacity and Energy sales to CP&L from Power Agency's entitlement to the output of the Mayo and Harris Units; (e) surplus energy sales to CP&L or others from Power Agency's entitlements to the output of the Joint Units; (f) the purchase of Supplemental Capacity and Energy; (g) the purchase of Interim Capacity under certain conditions if the completion of a Joint Unit is postponed beyond certain Trigger Dates; (h) transmission service; and (i) purchase, lease or construction of delivery facilities. This Agreement includes provisions relating to accounting, verification, costing, use of the project by Power Agency, and additional power supply resources that may be constructed or acquired for the benefit of the Participants of Power Agency.
4. Agreements with VEPCO. Power Agency and VEPCO have reached an agreement (the "Settlement Agreement") relating to the transfer of all-requirements service from VEPCO to Power Agency for those members of Power Agency which are currently served by VEPCO and which decide to become Participants in the project. The Settlement Agreement provides that Power Agency will supply the full requirements of such Participants during a Transition Period through a combination of capacity from the project, partial requirements purchases from VEPCO at VEPCO's Schedule RS-A rates, and transmission service over the VEPCO system. The Transition Period will extend from

December, 1981 through December, 1983. ^{1/} After the Transition Period, Power Agency will provide all requirements bulk power supply to such Participants through a combination of Retained Capacity from the project and purchases of Supplemental Capacity and Energy from CP&L pursuant to the Power Coordination Agreement in the same manner as it would supply Participants presently served by CP&L plus additional transmission services over the VEPCO system. Such additional transmission services pursuant to the transmission use agreement included in the Settlement Agreement will be provided for delivery of power over the VEPCO system during and after the Transition Period.

Pursuant to Article 2 of the Sales Agreement, Power Agency will purchase and CP&L will convey undivided ownership interests in the Joint Units in increments through separate closings. The aggregate of the undivided ownership interests in each of the Joint Units which Power Agency will purchase and CP&L will convey ("Ultimate Ownership Interest") is to be determined by multiplying (i) the ownership interest in each Joint Unit which CP&L has offered for purchase by Power Agency ("Ownership Offering") times (ii) the ratio of the projected 1982 Annual Peak Resource Demand contribution of the members of Power Agency which become Participants in the

^{1/} In order for Power Agency to begin service in December 1981 to those Participants now served by VEPCO in the event there is no first closing with CP&L by the end of that month, Power Agency has agreed with VEPCO and with CP&L with respect to an Interim Period from December, 1981 through the date of the first closing with CP&L. Under those agreements, the Transition Period arrangement with VEPCO would begin as scheduled and CP&L would sell Power Agency capacity and energy from the CP&L System in amounts essentially equal to those which Power Agency would have received from the project had Power Agency closed on 69% of its Ultimate Ownership Interests in the Brunswick Units and Roxboro Unit No. 4 in December, 1981.

project to the projected 1982 Annual Peak Resource Demand contribution of all of the members of Power Agency (the "Commitment Ratio"). The Ownership Offerings in the Joint Units are: (i) 19.7% for the Brunswick Units, (ii) 16.5% for the Harris Units and the Mayo Units, and (iii) 13.2% for Roxboro Unit No. 4. Members of Power Agency may become Participants in the project through the execution of Project Power Sales Agreements and Supplemental Power Sales Agreements with Power Agency, which agreements will be substantially in the form of the draft agreements submitted herewith as Exhibits B.1 and B.2. To the extent that any members of Power Agency elect not to become Participants in the project, application of the Commitment Ratio will result in a proportionate reduction of Power Agency's Ultimate Ownership Interest in each of the Joint Units. Also, in the event that any Mayo Unit or Harris Unit is cancelled or decommissioned by CP&L prior to its date of commercial operation, Power Agency's Ultimate Ownership Interest in the cancelled or decommissioned unit and all payment obligations related solely thereto will be reduced by 20%.

Because the aggregate of Power Agency's ownership interests in the Joint Units is in excess of its base load requirements in the initial years of operation of the Mayo and Harris Units, the Power Coordination Agreement provides for the sale to CP&L of capacity and energy from Power Agency's ownership interest in each Mayo Unit and Harris Unit

("Purchased Capacity" and "Purchased Energy"). The sale to CP&L of Purchased Capacity will be on a "take or pay" basis and will be in declining quantities over a fifteen year schedule which will commence on the date of commercial operation of each of the Mayo and Harris Units. The capacity associated with Power Agency's ownership interests in the Joint Units which is not sold to CP&L as Purchased Capacity, and which may therefore be used to meet the Participants' load requirements, is Power Agency's Retained Capacity. Power Agency's Scheduled Retained Capacity Percentage applicable to each Mayo Unit and Harris Unit, and CP&L's Scheduled Purchased Capacity Percentage applicable to each such unit, are set forth in Section 5.3 of the Power Coordination Agreement. The Mayo and Harris Units, including Power Agency's ownership interests in such units, will be dispatched by CP&L as resources available to assist in meeting the combined CP&L-Power Agency territorial load requirements; therefore, the distinction between Retained Capacity and Purchased Capacity will not affect the operation of those units.

The balance of Power Agency's requirements not met by Retained Capacity from the project (or other generating projects which Power Agency may acquire or construct) together with the backstand thereof, will be purchased by Power Agency from CP&L as Supplemental Capacity 1/ and will

1/ Also, during the Transition Period, there would be certain purchases of partial requirements power from VEPCO.

be equal to the Annual Peak Resource Demand (100% peak load) of the Participants less Retained Capacity. When Retained Capacity is operating at less than total capability, Reserve Capacity and associated energy purchased from CP&L would be used to meet the shortage. If shortage still exists, energy associated with Unused Supplemental Capacity purchased from CP&L would be utilized. If the Resource Demand at any time still exceeds that capability being supplied from the available output from Retained Capacity, Reserve Capacity, and Unused Supplemental Capacity, then Deficiency Energy would be additionally purchased from CP&L and, in some circumstances, emergency power would be purchased by Power Agency from VEPCO.

D. Power Agency - Municipal Participants Agreements.

Currently, Power Agency's members individually contract with CP&L or VEPCO for the provision by such utility of wholesale power services. Upon the commencement of the provision of services under the Power Coordination Agreement, this relationship between the Participants and CP&L or VEPCO will terminate, and a new contractual arrangement will be effectuated between each Participant and Power Agency for the supply by Power Agency of essentially all of the Participant's power needs.

This arrangement will be structured through two power sales contracts: the Project Power Sales Agreement and the Supplemental Power Sales Agreement (collectively, the

"Power Sales Agreements"). Under the Power Sales Agreements, Power Agency will be obligated to provide all of the bulk power supply requirements of the Participants. This all requirements bulk power power supply will be in excess of any allotment of power which a Participant may receive from the Southeastern Power Administration ("SEPA") or certain resources which a Participant may install pursuant to the Supplemental Power Sales Agreement. The Power Sales Agreements obligate Power Agency to provide two basic types of bulk power supply to the Participants: project power and supplemental power. Pursuant to the Project Power Sales Agreement, project power is furnished to the Participants on a "take or pay" basis.

Each Participant covenants in the Power Sales Agreements that it will fix and charge rates for electric service supplied from its electric system sufficient to meet all of its obligations under both Power Sales Agreements and to pay any and all other amounts payable from such revenues, including its costs of operation and its obligation to pay principal and interest on any bonds, notes or evidences of indebtedness heretofore or hereafter issued by the Participant to finance its electric system.

RESPONSES TO SPECIFIC INFORMATION REQUESTS

Question 1

State separately for hydroelectric and thermal generating resources applicant's most recent peak load and dependable capacity for the same time period. State applicant's dependable capacity at time of system peak for each of the next 10 years for which information is available. Identify each new unit or resource. For hydroelectric generating capacity, indicate the number of kilowatt hours of use associated with each kilowatt of capacity during the "adverse water year" upon which dependable capacity is based. Indicate average annual kilowatt-hour loads per kilowatt, associated with each system peak shown (exclusive of interchange arrangements).

RESPONSE

At this time Power Agency does not own any generation (either hydroelectric or thermal) resources. Member municipalities of Power Agency currently purchase all of their power supply at wholesale (directly or indirectly) from CP&L or VEPCO except for a small allocation of hydroelectric power received by one member municipality (the Town of Louisburg) from SEPA.

Power Agency does not have any present plans for adding generating capacity other than its Ultimate Ownership Interests in the Joint Units.

Estimated system peak loads, energy requirements, annual load factor and total Retained Capacity for the period 1982-2000 are shown in the table on the page next following. Also included as a part of this response is a table presented in the Preliminary Engineering Report for the

project which shows Power Agency's Retained Capacity in each of the Joint Units for the period 1982-2009 (i.e., through the end of the period in which Power Agency will be selling Purchased Capacity to CP&L based on presently scheduled dates of commercial operation for the Mayo Units and the Harris Units).

TOTAL POWER AGENCY POWER AND ENERGY
REQUIREMENTS (AT GENERATION LEVEL) (1/)

Year	Peak Demand (KW)	Total Annual Energy Requirements (MWH)	Annual Load Factor (%)	Retained Capacity (MW) <u>2/</u>
1982	1,010,528	4,754,648	53.71	381.3
1983	1,054,557	4,961,812	53.71	440.7
1984	1,098,585	5,168,976	53.71	444.7
1985	1,142,613	5,376,140	53.71	522.9
1986	1,186,641	5,583,304	53.71	526.9
1987	1,230,669	5,790,468	53.71	535.7
1988	1,274,697	5,997,632	53.71	619.0
1989	1,318,726	6,204,796	53.71	632.8
1990	1,362,754	6,411,960	53.71	706.1
1991	1,406,782	6,619,124	53.71	723.9
1992	1,450,810	6,826,288	53.71	816.0
1993	1,494,838	7,033,452	53.71	838.7
1994	1,538,867	7,240,616	53.71	935.9
1995	1,582,895	7,447,780	53.71	963.4
1996	1,626,923	7,654,944	53.71	991.4
1997	1,670,951	7,862,107	53.71	1,018.8
1998	1,714,979	8,069,271	53.71	1,046.8
1999	1,759,007	8,276,435	53.71	1,070.3
2000	1,803,036	8,483,599	53.71	1,095.2

1/ Values presented in this table are based on the assumption that all members of Power Agency become Participants in the project.

2/ Retained Capacity values reflect the following considerations and assumptions:

(a) Currently scheduled dates of commercial operation of the Mayo and Harris Units are reflected;

(b) Reflects current maximum net dependable capability (MNDC) of Roxboro Unit No. 4 of 650 MW;

(c) Reflects Scheduled Retained Capacity Percentages applicable to the Mayo and Harris Units pursuant to Section 5.3 of the Power Coordination Agreement; and

(d) Resultant MW of Retained Capacity in the Mayo and Harris Units = Ownership Interest x Scheduled Retained Capacity Percentage x MNDC.

TABLE IX-1
POWER AGENCY RETAINED CAPACITY [1]

Year (a)	Brunswick Plant MW (b)	Rosboro Unit No. 4 MW (c)	Mayo Unit No. 1			Harris Unit No. 1			Harris Unit No. 2			Mayo Unit No. 2			Harris Unit No. 4			Harris Unit No. 3			Total Retained Capacity (MW) (v)	
			Sched. Year (d)	X(4) (e)	MW(5) (f)	Sched. Year (g)	X(4) (h)	MW(5) (i)	Sched. Year (j)	X(4) (k)	MW(5) (l)	Sched. Year (m)	X(4) (n)	MW(5) (o)	Sched. Year (p)	X(4) (q)	MW(5) (r)	Sched. Year (s)	X(4) (t)	MW(5) (u)		
1982	295.5	85.8	1	50.0	59.4																381.3	
1983	295.5	85.8	2	53.3	63.4																440.7	
1984	295.5	85.8	3	56.7	67.3																444.7	
1985	295.5	85.8	4	60.0	71.3	1	50.0	74.3													522.9	
1986	295.5	85.8	5	63.3	75.2	2	53.3	79.2													526.9	
1987	295.5	85.8	6	66.7	79.2	3	56.7	84.2													533.7	
1988	295.5	85.8	7	70.0	83.2	4	60.0	89.1	1	50.0	74.3										612.2	
1989	295.5	85.8	8	73.3	87.1	5	63.3	94.1	2	53.3	79.2										706.1	
1990	295.5	85.8	9	76.7	91.1	6	66.7	99.0	3	56.7	84.2										723.9	
1991	295.5	85.8	10	80.0	95.0	7	70.0	104.0	4	60.0	89.1										816.0	
1992	295.5	85.8	11	83.3	99.0	8	73.3	108.9	5	63.3	94.1										918.7	
1993	295.5	85.8	12	86.7	103.0	9	76.7	113.9	6	66.7	99.0										935.9	
1994	295.5	85.8	13	90.0	106.9	10	80.0	118.8	7	70.0	104.0										963.4	
1995	295.5	85.8	14	93.3	110.9	11	83.3	123.8	8	73.3	108.9										991.4	
1996	295.5	85.8	15	96.7	114.8	12	86.7	128.7	9	76.7	113.9										1,018.8	
1997	295.5	85.8	16	100.0	118.8	13	90.0	133.7	10	80.0	118.8										1,046.8	
1998	295.5	85.8	17	100.0	118.8	14	93.3	138.6	11	83.3	123.8										1,070.3	
1999	295.5	85.8	18	100.0	118.8	15	96.7	143.6	12	86.7	128.7										1,093.2	
2000	295.5	85.8	19	100.0	118.8	16	100.0	148.5	13	90.0	133.7										1,117.9	
2001	295.5	85.8	20	100.0	118.8	17	100.0	148.5	14	93.3	138.6										1,136.8	
2002	295.5	85.8	21	100.0	118.8	18	100.0	148.5	15	96.7	143.6										1,155.5	
2003	295.5	85.8	22	100.0	118.8	19	100.0	148.5	16	100.0	148.5										1,169.4	
2004	295.5	85.8	23	100.0	118.8	20	100.0	148.5	17	100.0	148.5										1,183.2	
2005	295.5	85.8	24	100.0	118.8	21	100.0	148.5	18	100.0	148.5										1,197.2	
2006	295.5	85.8	25	100.0	118.8	22	100.0	148.5	19	100.0	148.5										1,211.9	
2007	295.5	85.8	26	100.0	118.8	23	100.0	148.5	20	100.0	148.5										1,203.0	
2008	295.5	85.8	27	100.0	118.8	24	100.0	148.5	21	100.0	148.5										1,208.0	
2009	295.5	85.8							22	100.0	148.5											1,212.9
and subsequent years																						

[1] Based on a final closing date of December 1, 1982, and the currently scheduled commercial operation dates for the Harris and Mayo Units.
Values are reported as of the end of the calendar year.
[2] Based on current MWD of 650 MW for Rosboro Unit No. 4 and 790 MW for each Brunswick Unit.
[3] Schedule year 1 begins on the date of commercial operation and extends through December 31 of such year if commercial operation is prior to July 1. If commercial operation is later than July 1, schedule year 1 will extend to December 31 of the next calendar year.
[4] Scheduled Retained Capacity percentage pursuant to Section 5.3 of the Power Coordination Agreement.
[5] Resultant MW of Retained Capacity = Ownership Interest x Retained Capacity % x MWD.

Question 2

State applicant's estimated annual load growth for each of the next 20 years or for the period applicant utilizes in system planning. Indicate growth both in kilowatt requirements and kilowatt hour requirements.

Response:

Power Agency's estimated peak load growth and energy requirements at the generation level are set forth in the response to Question 1. Power Agency's estimated annual peak load growth and energy requirements at the delivery point level 1/ for 1981 through 2000 are as follows:

	<u>Kilowatts x 10³</u>	<u>Kilowatthours x 10⁶</u>
1981	922	4,338
1982	964	4,535
1983	1,006	4,733
1984	1,048	4,930
1985	1,090	5,128
1986	1,132	5,325
1987	1,174	5,523
1988	1,216	5,721
1989	1,258	5,918
1990	1,300	6,116
1991	1,342	6,313
1992	1,384	6,511
1993	1,426	6,708
1994	1,468	6,906
1995	1,510	7,104
1996	1,552	7,301
1997	1,594	7,499
1998	1,636	7,696
1999	1,678	7,894
2000	1,720	8,091
Average Annual Growth		
Rate (%): 1981-2000	3.33%	3.34%

1/ Total delivery point requirements of Power Agency members currently served by CP&L and Power Agency members currently served directly or indirectly by VEPCO.

Question 3

State estimated annual load growth in kilowatts and kilowatt hours of companies or pools upon which the economic justification of the subject unit is based for each of the next 20 years or for the period applicant utilized in system planning. Identify each company or pool member.

Response:

Economic justification for the subject project is based solely on the growth in native loads on the Participants' systems and Purchased Capacity and Purchased Energy sales to CP&L in the initial years of operation of each of the Mayo and Harris Units

Question 4

For the year the subject unit would first come on line, state estimated annual load growth in kilowatts and kilowatt hours of any coordinating group or pool of which the applicant is a member (other than the coordinating group or pool referred to in the applicant's response to Item 3) which has generating and/or transmission planning functions. Identify each company or pool member whose loads are indicated in the response thereto.

Response:

On July 30, 1981, Power Agency and CP&L executed a Power Coordination Agreement to establish the terms and conditions for provision by CP&L to Power Agency of certain power services and for other matters. This agreement will be submitted to the Federal Energy Regulatory Commission for its approval or acceptance for filing without suspension. CP&L's projected annual peak demands (in MW, including the demands of the members of Power Agency which are served directly by CP&L and including the demands of Power Agency members now served directly or indirectly by VEPCO) for the period 1981 through 1994 are shown in the table on the page following:

<u>Year</u>	<u>CP&L Peak Demand (including demands of Power Agency members now served directly or indirectly by CP&L)</u>	<u>VEPCO Served Members' Peak Demands at the CP&L Generation Level (1/)</u>	<u>Total CP&L Peak Demand (including demands of Power Agency members now served directly or indirectly by VEPCO) (1/)</u>
1982	6,457	95 (8/)	6,552
1983 (2/)	6,713	138 (8/)	6,851
1984	6,982	387	7,369
1985 (3/)	7,273	403	7,676
1986	7,530	419	7,949
1987	7,813	434	8,247
1988 (4/)	8,147	450	8,597
1989	8,469	466	8,935
1990 (5/)	8,727	481	9,208
1991	8,988	497	9,485
1992 (6/)	9,240	513	9,753
1993	9,497	528	10,025
1994 (7/)	9,752	544	10,296

1/ Values are based on the assumption that all members of Power Agency currently served directly or indirectly by VEPCO become Participants in the project.

2/ Estimated year of commercial operation of Mayo Unit No. 1.

3/ Estimated year of commercial operation of Harris Unit No. 1.

4/ Estimated year of commercial operation of Harris Unit No. 2.

5/ Estimated year of commercial operation of Mayo Unit No. 2.

6/ Estimated year of commercial operation of Harris Unit No. 4.

7/ Estimated year of commercial operation of Harris Unit No. 3.

8/ Transition period

The Agreement for Interim Electric Service between Power Agency and VEPCO -- which covers a Transition Period extending from December, 1981 through December 30, 1983 -- provides for the purchase from VEPCO by Power Agency of certain portions of the power requirements of the Participants which are now served directly or indirectly by VEPCO and for the furnishing by VEPCO to Power Agency of emergency and economy energy services. The Agreement for Transmission Use and Other Electric Service between Power Agency and VEPCO provides for transmission service over the VEPCO transmission system and also for emergency energy services to be rendered after the Transition Period. These agreements will be submitted to the Federal Energy Regulatory Commission for its approval or acceptance for filing without suspension. VEPCO's projected annual peak load (expressed in MW, and shown including and excluding the loads of Power Agency's members currently receiving service directly or indirectly from VEPCO) for the years 1981 through 1994 is presented in the table on the page following.

<u>Year</u>	<u>VEPCO Peak Demands (including demands of Power Agency members now served directly or indirectly by VEPCO)</u>	<u>Peak Demands of Power Agency Members Now Served Directly or Indirectly by VEPCO</u>	<u>VEPCO Peak Demands (excluding demands of Power Agency members now served directly or indirectly by VEPCO) (1/)</u>
1982	8323	92 (2/)	8231
1983	8330	134 (2/)	8196
1984	8534	374	8260
1985	8876	390	8486
1986	9133	405	8728
1987	9405	420	8985
1988	9584	435	9149
1989	9715	450	9265
1990	10,020	465	9555
1991	10,315	481	9834
1992	10,621	496	10,125
1993	10,933	511	10,422
1994	11,251	526	10,725

1/ Values are based on the assumption that all Power Agency members currently served directly or indirectly by VEPCO become Participants in the project.

2/ Transition period

Question 5

State applicant's minimum installed reserve criterion (as a percentage of load) for the period when the subject unit will first come on line. If the applicant shares reserves with other systems, identify the other systems and provide minimum installed reserve criterion (as a percentage of load) by contracting parties or pool for the period when the proposed unit will first come on line.

Response:

Pursuant to Section 7.4 of the Power Coordination Agreement, CP&L will sell and Power Agency will purchase in each year Reserve Capacity equal to a percentage of Power Agency's Retained Capacity in that year. The percentage will be based on the percentage reserves maintained by CP&L for the Combined System (CP&L's System plus Power Agency's project) in the previous year. Power Agency will receive energy associated with its Reserve Capacity only as it is needed to backstand Retained Capacity. Power Agency will pay CP&L a monthly Reserve Capacity charge for each kilowatt of Reserve Capacity based upon CP&L's overall average annual production costs and production capability.

A part of the reserves purchased by Power Agency are Spinning Reserves. Spinning Reserves are reserve capability maintained on the CP&L System as capacity immediately available for rapid increases in load and when other resources are unavailable due to forced outages.

Question 6

Describe methods used as a basis to establish, or as a guide in establishing the criteria for applicant's and/or applicant's pool's minimum amount of installed reserves (e.g., (a) single largest unit down, (b) probability methods such as loss of load one day in 20 years, loss of capacity once in 5 years, (c) other methods and/or (d) judgment. List contingencies other than risk of forced outage that enter into the determination).

Response:

As noted in response to Question 5, the level of Reserve Capacity which Power Agency will purchase pursuant to the Power Coordination Agreement is to be based upon the percentage reserves maintained by CP&L in the immediately preceding year for the Combined System.

Question 7

Indicate whether applicant's system interconnections are credited explicitly or implicitly in establishing applicant's installed reserves.

Responses:

Power Agency's system interconnections are credited implicitly in establishing installed reserves.

Question 8

List rights to receive emergency power and obligations to deliver emergency power, rights or obligations to receive or deliver deficiency power or unit power, or other coordinating arrangements, by reference to applicant's Federal Power Commission (FPC) rate schedules (i.e., ABC Power and Light Co., FPC Rate Schedule No. 15 including supplements 1-5), and also by reference to applicant's state commission filings. Where documents are not on file with the FPC, supply copies, or where not reduced to writing, describe arrangements. Identify for each such arrangement the participating parties other than applicant. Provide one line electrical and geographic diagrams of coordinating groups or power pools (with generation or transmission planning functions) of which applicant's generation and transmission facilities constitute a part.

Response:

The Power Coordination Agreement between CP&L and Power Agency contains provisions regarding comprehensive coordination and backstand services sufficient to serve all of Power Agency's needs. The service agreements between VEPCO and Power Agency (the Agreement for Interim Electric Service and the Agreement for Transmission Use and Other Electric Service) provide transmission, emergency and certain other services suitable for Power Agency's needs when combined with the arrangements with CP&L.

The Power Coordination Agreement provides for:

(1) wheeling Power Agency's power and energy from the project; (2) backstanding Power Agency's ownership interest in the project through (a) reserves, and (b) deficiency energy; and (3) supplying Power Agency's requirements for power and energy through Supplemental Capacity and Energy. The backstand arrangements are firm as opposed to an "as available" basis.

Because the aggregate of Power Agency's ownership interests in the Joint Units is in excess of Power Agency's base load requirements in the initial years of commercial operation of each Mayo Unit and Harris Unit, the Power Coordination Agreement provides for the sale to CP&L of capacity and energy from Power Agency's ownership interest in each Mayo and Harris Unit (Purchased Capacity and Purchased Energy). In the first year of Commercial Operation of each Mayo and Harris Unit, Power Agency will sell 50% of its entitlement to CP&L as Purchased Capacity, and Power Agency will also sell the energy associated with Purchased Capacity. The amount of capacity sold to CP&L as Purchased Capacity from each Mayo Unit and Harris Unit will decline over a fifteen year period until, in the sixteenth year of operation of each such unit, Power Agency will retain its entire entitlement in the Joint Unit. Therefore, in any year Power Agency's Retained Capacity in any Mayo Unit or Harris Unit is Power Agency's entitlement less the Purchased Capacity paid for by CP&L. This allows Power Agency to obtain the economic advantages of having available to it increasing amounts of base load capacity from large generating resources for meeting Power Agency's load. Also, because Power Agency's cost of capital and carrying charges are lower than CP&L's, the sale to CP&L of Purchased Capacity provides a margin over Power Agency's costs which contributes to the economic desirability of the project.

In addition, Surplus Energy from Power Agency's Retained Capacity in any Joint Unit may be sold to CP&L or to others pursuant to Article 11 of the Power Coordination Agreement.

In light of CP&L's commitment to provide Supplemental Capacity and Energy and wheeling, the Power Coordination Agreement imposes certain coordinating requirements (including reasonable advance notice) on Power Agency's purchase or construction of electric generating facilities other than the Joint Units.

The service agreements with VEPCO provide Power Agency with full rights to use VEPCO's transmission system upon making appropriate compensation for such transmission use including compensation for the cost of any necessary modifications to such system. In addition, VEPCO will provide emergency service to Power Agency as may be necessary and as would be available. During the Transition Period, VEPCO will provide additional coordination services including, in particular, partial requirements service.

Question 9

List, and provide the mailing address for non-affiliated electric utility systems with peak loads smaller than applicant's which serve either at wholesale or at retail adjacent to areas served by the applicant. Provide a geographic one line diagram of applicant's generating and transmission facilities (including subtransmission) indicating the location of adjacent systems and as to such systems indicate (if available) their load, their annual load growth, their generating capacity, their largest thermal generating unit size, and their minimum reserve criteria.

Response:

At the present time, Power Agency does not generate or sell electric power; therefore, there are no non-affiliated electric utility systems with peak loads smaller than applicant's which serve either at wholesale or at retail adjacent to areas served by applicant.

Power Agency does not have any generating or transmission facilities and therefore the request for a geographic one line diagram of its existing facilities is not applicable.

There are a number of electric membership corporations served by CP&L and VEPCO which neighbor the members of Power Agency. Those served by CP&L are:

Brunswick Electric
Membership Corporation
P.O. Box 826
Shallote, NC 28459

Carteret-Craven Electric
Membership Corporation
P.O. Box 1499
Morehead City, NC 28557

Central Electric
Membership Corporation
P.O. Box 1107
Sanford, NC 27330

Four County Electric
Membership Corporation
P.O. Box 667
Burgaw, NC 28425

French Broad Electric
Membership Corporation
P.O. Box 9
Marshall, NC 28753

Halifax Electric
Membership Corporation
P.O. Box 667
Enfield, NC 27823

Haywood Electric
Membership Corporation
P.O. Drawer 9
Waynesville, NC 28786

Harkers Island Electric
Membership Corporation
P.O. Box 198
Harkers Island, NC 28531

Jones-Onslow Electric
Membership Corporation
259 Western Boulevard
Jacksonville, NC 28540

Lumbee River Electric
Membership Corporation
P.O. Box 830
Red Springs, NC 28377

Pee Dee Electric
Membership Corporation
P.O. Box 859
Wadesboro, NC 28170

Piedmont Electric
Membership Corporation
P.O. Drawer 1179
Hillsborough, NC 27278

Pitt & Greene Electric
Membership Corporation
P.O. Box 249
Farmville, NC 27828

Randolph Electric
Membership Corporation
P.O. Box 40
Asheboro, NC 27203

South River Electric
Membership Corporation
P.O. Drawer 931
Dunn, NC 28334

Tideland Electric
Membership Corporation
P.O. Box 158
Pantego, NC 27860

Tri-County Electric
Membership Corporation
P.O. Box 130
Dudley, NC 28333

Wake Electric
Membership Corporation
P.O. Box 872
Wake Forest, NC 27587

One municipal electric system is a customer of CP&L but is not a member of Power Agency. This system is:

Fayetteville Public Works Commission
508 Person Street
P.O. Drawer 1089
Fayetteville, NC 28302

Also, nine municipal electric systems are wholesale customers of members of Power Agency. They are:

Customers of the City of Wilson

Town of Black Creek
Black Creek Electric Department
P.O. Box 8
Black Creek, NC 27813

Lucama Electric Department
Town of Lucama
P.O. Box 122
Lucama, NC 27851

Town of Macclesfield
P.O. Box 185
Macclesfield, NC 27852

Town of Pinetops
Drawer C
Pinetops, NC 27864

Stantonsburg Municipal Light Department
Town of Stantonsburg
P.O. Box 174
Stantonsburg, NC 27883

Walstonburg Electric Department
Town of Walstonburg
P.O. Box 86
Walstonburg, NC 27888

Customer of the City of Rocky Mount

Sharpsburg Electric Department
Town of Sharpsburg
P.O. Box 305
Sharpsburg, NC 27878

Customer of the Town of Farmville

Fountain Electric Department
Town of Fountain
Box 111
Fountain, NC 27829

Customer of the Town of Tarboro

Town of Princeville
P.O. Box 1527
Tarboro, NC 27886

An additional municipal electric system is a
wholesale customer of Edgecombe-Martin Electric Membership
Corporation:

Town of Oak City
P.O. Box 26
Oak City, NC 27857

The electric membership corporations located in
North Carolina which are served by VEPCO are:

Albemarle Electric
Membership Corporation
P.O. Box 69
Hertford, NC 27944

Cape Hatteras Electric
Membership Corporation
P.O. Box 9
Buxton, NC 27920

Edgecombe-Martin County
Electric Membership Corporation
P.O. Box 188
Tarboro, NC 27886

Halifax Electric
Membership Corporation
P.O. Box 667
Enfield, NC 27823

Roanoke Electric
Membership Corporation
P.O. Box 440
Rich Square, NC 27869

Tideland Electric
Membership Corporation
P.O. Box 158
Pantego, NC 27860

Question 10

List separately those systems in Item 9 which purchase from applicant (a) all bulk power supply and (b) systems which purchase partial bulk power supply requirements. Where information is available to applicant, identify those Item 9 systems purchasing part or all of their bulk power supply requirements from suppliers other than applicant.

Response:

At the present time, Power Agency does not generate or sell electric power; therefore, there are no systems which purchase all or a portion of their bulk power supply requirements from Power Agency.

There are several municipal electric systems which purchase all their bulk power requirements from certain members of Power Agency. These purchasing municipal systems and the relevant municipal suppliers are listed in the response to Question 9.

Question 11

State as to all power generated and sold by applicant the most recent average cost of Bulk power supply experienced by applicant (a) at site of generating facilities, (b) at the delivery points from the primary transmission (backbone) system, (c) at delivery points from the secondary transmission system, and (d) at delivery points from the distribution system, in terms of dollars per kilowatt per year, in mills per kilowatt hour, and in both the kilowatt costs and kilowatt hour costs divided by the kilowatt hours. If wholesale sales are made at varying voltages, indicate average costs at each voltage.

Response:

At the present time, Power Agency does not generate or sell power.

Question 12

State (a) for generating facilities and (b) for transmission sub-divided by voltage classes, the most recent estimated cost of applicant's bulk power supply expansion program of which the subject unit is a part, in terms of dollars per kilowatt per year, in mills per kilowatt hour and in both the kilowatt costs and kilowatt hour costs divided by the kilowatt hours. Also state separately the most recently estimated cost of subject unit(s).

Response:

The Preliminary Engineering Report for the project contains tables providing information responsive to this question. These tables are provided on the pages following.

Direct costs to Power Agency for the acquisition, construction, initial fueling and placing into commercial operation of the Joint Units are shown in attached Tables X-2, X-3, and X-4 (lines 1-5).

Table XI-2, Schedule 1, summarizes project costs by plant including the net effect of credits for Purchased Capacity and Purchased Energy paid by CP&L. Costs are shown in total dollars, \$/kW of capacity, mills/kWh of energy costs, and total cost in mills/kWh. Also shown are the project Retained Capacity, project output, and capacity factors. The credit shown for capacity costs in some years reflects periods where interest is being capitalized rather than paid from revenues; there is substantial interest income from reserve funds and there are sales of Purchased Capacity to CP&L, all

of which exceed Power Agency's fixed costs in those years and contribute to the net savings for those years.

Schedule 2 , which begins on page 7 of Table XI-2, shows the estimated costs of services from CP&L under the Power Coordination Agreement. Charges in \$/kW/yr for Supplemental Capacity and transmission service are shown based on the maximum annual demands for each service occurring in the year.

Schedule 3, which begins on page 10 of Table XI-2, develops the total cost of the project and related power supply services from the costs shown in Schedules 1 and 2 and shows additional Power Agency costs, including special obligations of the Power Agency members now served directly or indirectly by VEPCO. The power and energy requirements of the Power Agency members at the generation level of the CP&L System are also included in Schedule 3.

TABLE X-2

ESTIMATED CLOSING AND INITIAL FUELING COSTS FOR
POWER AGENCY'S OWNERSHIP INTERESTS IN UNITS IN COMMERCIAL OPERATION
THE BRUNSWICK UNITS AND ROXBORO UNIT NO. 4 [1]
(Dollars in Thousands)

Line No.	(a)	Brunswick Units (b)	Roxboro Unit No. 4 (c)
	<u>Estimated Closing Costs</u>		
1	Costs as of December 31, 1979 [2]	\$199,436	\$36,115
	Plant Additions Subsequent to December 31, 1979:[3]		
2	Direct Costs [4]	24,169	2,542
3	Indirect Costs [5]	861	111
4	AFUDC [6]	1,796	1,435
5	Tax Effects [7]	<u>1,221</u>	<u>652</u>
6	Total Estimated Closing Costs	<u>\$227,483</u>	<u>\$40,855</u>
7		\$770/kW [8]	\$476/kW [8]
8	<u>Total Estimated Costs of Initial Fueling</u>	<u>\$ 16,765 [9]</u>	<u>\$ 2,027 [10]</u>
9		\$ 57/kW [8]	\$ 24/kW [8]
10.	Total Estimated Closing Costs and Costs of Initial Fueling	<u>\$244,248</u>	<u>\$42,882</u>
11		\$827/kW [8]	\$500/kW [8]
12	Maximum Net Dependable Capability (MNDC)[11]	295.5 MW	85.8 MW

- [1] Assumes Power Agency closes on 33%, 36%, and 31% of its Ultimate Ownership Interest of 18.7% of the Brunswick Units and 13.2% of Roxboro Unit No. 4 at each of three separate closings occurring January 1, July 1, and December 1, 1982, respectively, and 100% participation in the proposed Project by Power Agency Members.
- [2] Pursuant to Article 4 of the Sales Agreement.
- [3] Power Agency's share of the cost of plant additions currently scheduled at each facility during the period from January 1, 1980, through each closing date as estimated by CP&L.
- [4] Direct costs include materials, labor, and other construction costs.
- [5] Indirect costs include capitalized overheads such as certain taxes and employer benefits.
- [6] Power Agency's share of CP&L's estimated AFUDC on plant additions after December 31, 1979 and AFUDC on the total Roxboro Unit No. 4 from December 31, 1979 to the date of commercial operation of this Unit.
- [7] The estimated net effect on CP&L's federal and state income taxes, including tax on capital gains, associated with payments by Power Agency for CP&L's AFUDC on plant additions as provided in the Sales Agreement.
- [8] Total estimated cost divided by MNDC as shown on line 12.
- [9] Based on CP&L estimates of the net nuclear fuel-in-reactor at Brunswick and reload fuel-in-process for use at Brunswick at the closings, including AFUDC and the estimated net effect on CP&L's federal and state income taxes including tax on capital gains associated with payments by Power Agency for CP&L's AFUDC.
- [10] Represents Power Agency's share of estimated costs at the closings associated with coal and startup fuel.
- [11] Based on assumptions outlined in footnote [1] above and an MNDC of 1580 MW for the Brunswick Units and the present rating of 650 MW for Roxboro Unit No. 4.

TABLE X-3

ESTIMATED CLOSING, CONSTRUCTION, AND INITIAL FUELING COSTS FOR
POWER AGENCY'S OWNERSHIP INTERESTS IN UNITS UNDER CONSTRUCTION
THE MAYO AND HARRIS UNITS [1]

(Dollars in Thousands)

Page 1 of 2

Line No.	(a)	Mayo Units			Harris Units				
		Unit 1 [2] (b)	Unit 2 (c)	Total (d)	Unit 1 [2] (e)	Unit 2 (f)	Unit 3 (g)	Unit 4 (h)	Total (i)
<u>Estimated Closing and Construction Costs:</u>									
<u>Closing Costs: [3]</u>									
1	Direct Costs [4]	\$ 62,590	\$ 1,745	\$ 64,335	\$153,214	\$ 32,074	\$ 7,287	\$ 11,462	\$ 204,037
2	Indirect Costs [5]	1,078	50	1,128	5,282	1,067	173	310	6,832
3	Management Fees [6]	929	25	954	2,299	485	110	172	3,066
4	ASUNC [7]	13,619	539	14,158	46,960	13,574	2,984	5,406	68,924
5	Tax Effects [8]	9,101	336	9,437	29,163	7,930	1,774	3,144	42,016
6	Total Closing Costs	\$ 87,317	\$ 2,695	\$ 90,012	\$236,923	\$ 55,130	\$ 12,328	\$ 20,494	\$ 324,875
<u>Construction Costs Subsequent to Closings: [9]</u>									
7	Direct Costs [4]	\$ 6,010	\$ 91,660	\$ 97,670	\$ 57,427	\$100,097	\$216,707	\$202,379	\$ 576,610
8	Indirect Costs [5]	416	1,492	1,908	7,501	7,657	15,993	13,951	45,102
9	Management Fees [6]	89	1,373	1,462	890	1,530	3,317	3,089	8,826
10	Total Construction Costs Subsequent to Closings	\$ 6,515	\$ 94,525	\$101,040	\$ 65,818	\$109,284	\$236,017	\$219,419	\$ 630,538
11	Total Estimated Closing and Construction Costs	<u>\$ 93,832</u>	<u>\$ 97,220</u>	<u>\$191,052</u>	<u>\$302,741</u>	<u>\$164,414</u>	<u>\$248,345</u>	<u>\$239,913</u>	<u>\$ 955,413</u>
12	\$/KW [10]	\$790	\$818	\$804	\$2,039	\$1,107	\$1,672	\$1,616	\$1,608
<u>Estimated Costs of Initial Fueling:</u>									
13	At Closings [11]	\$ 1,451	\$ -	\$ 1,451	\$ -	\$ -	\$ -	\$ -	\$ -
14	Subsequent to Closings [11]	1,511	6,157	7,668	10,143	13,125	41,950	36,392	101,610
15	Total Estimated Costs of Initial Fueling	<u>\$ 2,962</u>	<u>\$ 6,157</u>	<u>\$ 9,119</u>	<u>\$ 10,143</u>	<u>\$ 13,125</u>	<u>\$ 41,950</u>	<u>\$ 36,392</u>	<u>\$ 101,610</u>
16	\$/kW [10]	\$25	\$52	\$38	\$68	\$88	\$282	\$245	\$171
<u>Total Estimated Costs of Closing, Construction, and Initial Fueling</u>									
17		<u>\$ 96,794</u>	<u>\$103,377</u>	<u>\$200,171</u>	<u>\$312,884</u>	<u>\$177,539</u>	<u>\$290,295</u>	<u>\$276,305</u>	<u>\$1,057,023</u>
18	\$/kW [10]	\$815	\$870	\$842	\$2,10	\$1,196	\$1,955	\$1,861	\$1,779
<u>Expected Maximum Net Dependable Capability (MNDC) in MW [12]</u>									
19		118.8	118.8	237.6	148.5	148.5	148.5	148.5	594.0
20	Scheduled Date of Commercial Operation	4/1/83	4/1/90		10/1/85	4/1/88	4/1/94	4/1/92	

(Footnotes on following page)

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TABLE X-3
Page 2 of 2

ESTIMATED CLOSING, CONSTRUCTION, AND INITIAL FUELING COSTS
FOR POWER AGENCY'S OWNERSHIP INTERESTS IN UNITS UNDER CONSTRUCTION
THE MAYO AND HARRIS UNITS

Footnotes

- [1] Assumes Power Agency closes on 33%, 36%, and 31% of its Ultimate Ownership Interest of 16.5% in each of the Mayo and Harris Units at each of three separate closings occurring January 1, July 1, and December 1, 1982, respectively; 100% participation in the proposed Project by Power Agency Members; and the scheduled dates of Commercial Operation as shown on line 20.
- [2] Amounts for land and common facilities necessary for the operation of each of the Mayo and Harris Units are included in amounts shown for Mayo Unit 1 and Harris Unit 1, respectively.
- [3] Estimated aggregate amounts to be paid to CP&L by Power Agency at the closings outlined in footnote [1] based on cost estimates provided by CP&L.
- [4] Direct costs include materials, labor, and other construction costs.
- [5] Indirect costs include capitalized overheads such as certain taxes and employee benefits.
- [6] The costs of employing CP&L managers and technicians and utilizing CP&L methods and technical expertise in the construction of the Mayo and Harris Units calculated as 1.5% of CP&L's direct and indirect costs of construction less gross investment in land, capitalized property taxes, or CP&L AFUDC.
- [7] Power Agency's share of AFUDC incurred by CP&L prior to the closing dates based on estimates provided by CP&L.
- [8] The estimated net effect on CP&L's federal and state income taxes, including tax on capital gains, associated with payments by Power Agency for CP&L's AFUDC as provided under the Sales Agreement.
- [9] Estimated amounts for Power Agency's share of construction costs subsequent to the closings.
- [10] Total estimated cost divided by MNDC as shown on line 19.
- [11] Estimates of costs associated with the Initial Core at each Harris Unit based on data supplied by CP&L and costs associated with the Initial Coal Stockpile at each Mayo Unit assuming an average ninety-five-day coal supply based on coal prices and expected usage.
- [12] Based on assumptions outlined in footnote [1] above and the expected MNDC of 720 MW and 900 MW for each Mayo and Harris Unit, respectively.

TABLE X-4

TOTAL ESTIMATED PRINCIPAL AMOUNT OF BONDS
ALLOCATED TO JOINT FACILITIES AND WORKING CAPITAL
(Dollars in Thousands)

Line No.		Brunswick Units	Roxboro Unit No. 4	Mayo Units		Harris Units				Working Capital and Power Agency Expenses	Total - Proposed Project
	(a)	(b)	(c)	Unit 1	Unit 2	Unit 1	Unit 2	Unit 3	Unit 4	(j)	(k)
	<u>Closing, Construction, and Fuel Costs</u>										
1	Closing and Construction Costs [1]	\$227,483	\$40,855	\$ 93,832	\$ 97,220	\$302,741	\$164,414	\$248,345	\$239,913	\$116,277 [2]	\$1,531,080
2	Initial Fueling Costs [3]	16,765	2,027	2,962	6,157	10,143	13,125	41,950	36,392	-	129,521
3	Reload Fuel Expense [4]	12,597	-	-	-	6,615	15,445	24,992	20,292	-	79,941
4	Initial Capital Additions [5]	15,378	148	-	-	-	-	-	-	-	15,526
5	Total Direct Costs	\$272,223	\$43,030	\$ 96,794	\$103,377	\$319,499	\$192,984	\$315,287	\$296,597	\$116,277	\$1,756,068
6	Investment Earnings [6]	(3,133)	(6)	(392)	(10,283)	(6,951)	(12,993)	(30,741)	(28,035)	-	(92,534)
7	Net Direct Costs	\$269,090	\$43,024	\$ 96,402	\$ 93,094	\$312,548	\$179,991	\$284,546	\$268,562	\$116,277	\$1,663,534
8	Gross Interest During Construction [7]	\$ 40,326	\$ 6,447	\$ 51,092	\$104,193	\$343,660	\$271,409	\$499,426	\$456,805	\$ -	\$1,773,358
	<u>Financing Requirements</u>										
	Deposits to:										
9	Bond Fund Reserve Account [8]	40,326	6,447	19,223	23,126	81,018	53,952	91,900	85,176	14,138	415,306
10	Reserve and Contingency Fund [9]	4,034	645	1,922	2,313	8,102	5,395	9,190	8,500	1,415	41,533
11	Underwriters' Discount and Financing Costs [10]	12,831	2,052	6,116	8,078	27,033	18,525	32,099	29,709	4,781	141,224
12	<u>Total Estimated Principal Amount of Bonds</u>	<u>\$366,607</u>	<u>\$58,615</u>	<u>\$174,755</u>	<u>\$230,804</u>	<u>\$772,361</u>	<u>\$529,272</u>	<u>\$917,161</u>	<u>\$848,769</u>	<u>\$136,611</u>	<u>\$4,034,955</u>

[1] From Table X-2, line 6, for Brunswick Units and Roxboro Unit No. 4 and from Table X-3, line 11, for Mayo and Harris Units.

[2] Preliminary estimate of Power Agency's working capital requirements as each unit is placed in service as well as administrative expenses associated with units under construction.

[3] From Table X-2, line 8, for Brunswick Plant and Roxboro Unit No. 4 and from Table X-3, line 15, for Mayo and Harris Units.

[4] Power Agency's share of reload fuel payments through approximately twelve months following the closing dates for the Brunswick Units and for twelve months following the currently scheduled commercial operation dates of each Harris Unit, based on estimates provided by CP&L.

[5] Costs subsequent to the closing dates for capital additions under way, authorized, or planned as of such dates as estimated by CP&L.

[6] At 12% in 1982 on unexpended amounts deposited into the Construction Account from Bond proceeds and at 11% thereafter.

[7] At 11% on Bonds issued in 1982 and 10% on all Bonds issued thereafter. Assumes one year's funded interest on the portion of each issue allocable to the Brunswick Units and to Roxboro Unit No. 4 and two years' funded interest after the currently scheduled commercial operation dates of each Mayo and Harris Unit.

[8] Equal to maximum annual interest on all Bonds issued and allocated to each Joint Facility and to working capital and Power Agency expense.

[9] At 10% of the Bond Fund Reserve Account requirement.

[10] Equal to 3.5% of the total estimated principal amount of Bonds.

NORTH CAROLINA MUNICIPAL POWER AGENCY NUMBER 3
PROJECTED OPERATING RESULTS UNDER
PROPOSED ARRANGEMENT WITH C P & L
CASE A

SCHEDULE 1 - SUMMARY OF PROJECT COSTS

DESCRIPTION			1982	1983	1984	1985	1986	1987	1988	1989
<hr/>										
BRUNSWICK										
NET CAPACITY COSTS	\$000	[1]	\$ (1,539)	\$ 21,119	\$ 45,667	\$ 46,285	\$ 46,969	\$ 47,714	\$ 48,536	\$ 49,431
NET ENERGY COSTS	\$000	[2]	3,578	7,838	9,757	11,242	12,342	13,150	15,136	18,070
TOTAL NET COSTS	\$000	[3]	\$ 2,039	\$ 28,956	\$ 55,424	\$ 57,527	\$ 59,312	\$ 60,864	\$ 63,671	\$ 67,501
NET PROJECT CAPACITY	MW	[4]	158.3	295.5	295.5	295.5	295.5	295.5	295.5	295.5
NET PROJECT GENERATION	GWH	[5]	738.1	1,490.5	1,746.1	1,746.1	1,746.1	1,746.1	1,746.1	1,746.1
CAPACITY FACTOR	%	[6]	53.22	57.59	67.46	67.46	67.46	67.46	67.46	67.46
NET PROJECT FIXED COSTS	\$/KW	[7]	(9.72)	71.48	154.56	156.65	158.97	161.49	164.27	167.30
NET PROJECT ENERGY COSTS	MILLS	[8]	4.85	5.26	5.59	6.44	7.07	7.53	8.57	10.35
TOTAL NET PROJECT COSTS	MILLS	[9]	2.76	19.43	31.74	32.95	33.97	34.86	36.46	38.66
<hr/>										
HARRIS										
NET CAPACITY COSTS	\$000	[11]	\$ (6,842)	\$ (17,406)	\$ (21,907)	\$ (42,361)	\$ (62,630)	\$ (45,545)	\$ 10,307	\$ 11,611
NET ENERGY COSTS	\$000	[12]	-	-	-	546	1,800	2,261	4,917	7,090
TOTAL NET COSTS	\$000	[13]	\$ (6,842)	\$ (17,406)	\$ (21,907)	\$ (41,815)	\$ (60,830)	\$ (43,285)	\$ 15,224	\$ 18,701
NET PROJECT CAPACITY	MW	[14]	-	-	-	18.6	74.3	79.2	139.8	168.3
NET PROJECT GENERATION	GWH	[15]	-	-	-	132.8	396.8	468.1	805.9	949.8
CAPACITY FACTOR	%	[16]	-	-	-	81.67	61.00	67.46	65.81	64.42
NET PROJECT FIXED COSTS	\$/KW	[17]	-	-	-	(2,271.29)	(843.50)	(575.07)	73.73	68.99
NET PROJECT ENERGY COSTS	MILLS	[18]	-	-	-	4.11	4.54	4.83	6.10	7.47
TOTAL NET PROJECT COSTS	MILLS	[19]	-	-	-	(313.38)	(153.32)	(92.48)	18.89	19.69
<hr/>										
ROXBORO										
NET CAPACITY COSTS	\$000	[21]	\$ (432)	\$ 3,320	\$ 8,791	\$ 6,871	\$ 6,964	\$ 7,046	\$ 7,164	\$ 7,262
NET ENERGY COSTS	\$000	[22]	4,735	7,754	11,141	9,234	12,991	11,130	16,306	12,464
TOTAL NET COSTS	\$000	[23]	\$ 4,303	\$ 11,084	\$ 17,932	\$ 16,105	\$ 19,955	\$ 18,176	\$ 23,470	\$ 19,726
NET PROJECT CAPACITY	MW	[24]	46.0	85.8	85.8	85.8	85.8	85.8	85.8	85.8
NET PROJECT GENERATION	GWH	[25]	235.2	327.2	437.4	327.2	437.4	327.2	437.4	327.2
CAPACITY FACTOR	%	[26]	58.41	43.53	58.20	43.53	58.20	43.53	58.20	43.53
NET PROJECT FIXED COSTS	\$/KW	[27]	(9.39)	38.69	79.15	80.08	81.19	82.12	83.50	84.64
NET PROJECT ENERGY COSTS	MILLS	[28]	20.13	23.73	25.47	28.22	29.70	34.02	37.28	38.10
TOTAL NET PROJECT COSTS	MILLS	[29]	18.29	33.88	40.99	49.22	45.62	55.55	53.65	60.29

NORTH CAROLINA MUNICIPAL POWER AGENCY NUMBER 2
PROJECTED OPERATING RESULTS UNDER
PROPOSED ARRANGEMENT WITH C P & L
CASE A

SCHEDULE 1 - SUMMARY OF PROJECT COSTS

DESCRIPTION			1982	1983	1984	1985	1986	1987	1988	1989
<hr/>										
MAYO										
<hr/>										
NET CAPACITY COSTS	\$000	[31]	\$ (2,254)	\$ (11,010)	\$ (9,926)	\$ 6,270	\$ 11,798	\$ 11,362	\$ 10,798	\$ 6,522
NET ENERGY COSTS	\$000	[32]	-	4,905	5,139	9,073	8,365	12,319	10,723	17,403
TOTAL NET COSTS	\$000	[33]	\$ (2,254)	\$ (6,105)	\$ (3,787)	\$ 15,342	\$ 20,163	\$ 23,681	\$ 21,521	\$ 23,925
NET PROJECT CAPACITY	MW	[34]	-	44.6	63.4	67.3	71.3	75.2	79.2	83.2
NET PROJECT GENERATION	GWH	[35]	-	228.2	242.5	343.2	272.8	383.6	303.1	424.0
CAPACITY FACTOR	%	[36]	-	58.47	43.69	58.20	43.69	58.20	43.69	58.20
NET PROJECT FIXED COSTS	\$/KW	[37]	-	(247.15)	(156.65)	93.13	165.51	151.01	136.34	70.43
NET PROJECT ENERGY COSTS	MILLS	[38]	-	21.50	25.31	26.43	30.66	32.11	35.38	41.05
TOTAL NET PROJECT COSTS	MILLS	[39]	-	(26.76)	(15.62)	44.70	73.91	61.73	71.00	56.43
<hr/>										
TOTAL PROJECT COSTS										
<hr/>										
NET CAPACITY COSTS	\$000	[101]	\$ (11,067)	\$ (3,978)	\$ 20,725	\$ 17,265	\$ 3,101	\$ 20,577	\$ 76,804	\$ 74,826
NET ENERGY COSTS	\$000	[102]	8,313	20,307	27,037	30,095	35,499	38,859	47,082	55,027
TOTAL NET COSTS	\$000	[103]	\$ (2,754)	\$ 16,329	\$ 47,762	\$ 47,359	\$ 38,600	\$ 59,436	\$ 123,886	\$ 129,853
NET PROJECT CAPACITY	MW	[104]	204.3	425.8	444.6	467.1	526.8	535.7	600.2	632.7
NET PROJECT GENERATION	GWH	[105]	973.3	2,045.8	2,426.0	2,549.3	2,853.1	2,924.9	3,292.6	3,447.0
CAPACITY FACTOR	%	[106]	54.39	54.85	62.29	62.30	61.83	62.33	62.62	62.19
NET PROJECT FIXED COSTS	\$/KW	[107]	(54.17)	(9.34)	46.61	35.96	5.89	38.41	107.95	118.26
NET PROJECT ENERGY COSTS	MILLS	[108]	8.54	10.02	11.14	11.81	12.44	13.29	15.30	15.96
TOTAL NET PROJECT COSTS	MILLS	[109]	(2.83)	8.08	19.69	18.58	13.53	20.32	37.63	37.67

NORTH CAROLINA MUNICIPAL POWER AGENCY NUMBER 3
PROJECTED OPERATING RESULTS UNDER
PROPOSED ARRANGEMENT WITH C P & L
CASE A

SCHEDULE 1 - SUMMARY OF PROJECT COSTS

DESCRIPTION			1990	1991	1992	1993	1994	1995	1996	1997
BRUNSWICK										
NET CAPACITY COSTS	\$000	[1]	\$ 50,419	\$ 51,508	\$ 52,695	\$ 53,998	\$ 55,435	\$ 57,000	\$ 58,729	\$ 60,625
NET ENERGY COSTS	\$000	[2]	21,731	27,029	33,830	36,247	39,895	43,466	47,539	51,983
TOTAL NET COSTS	\$000	[3]	\$ 72,150	\$ 78,537	\$ 86,526	\$ 90,245	\$ 95,330	\$100,467	\$106,268	\$112,608
NET PROJECT CAPACITY	MW	[4]	295.5	295.5	295.5	295.5	295.5	295.5	295.5	295.5
NET PROJECT GENERATION	GWH	[5]	1,746.1	1,746.1	1,746.1	1,746.1	1,746.1	1,746.1	1,746.1	1,746.1
CAPACITY FACTOR	%	[6]	67.46	67.46	67.46	67.46	67.46	67.46	67.46	67.46
NET PROJECT FIXED COSTS	\$/KW	[7]	170.65	174.33	178.35	182.76	187.62	192.92	198.77	205.19
NET PROJECT ENERGY COSTS	MILLS	[8]	12.45	15.48	19.40	20.76	22.85	24.89	27.23	29.77
TOTAL NET PROJECT COSTS	MILLS	[9]	41.32	44.98	49.58	51.66	54.60	57.54	60.86	64.49
HARRIS										
NET CAPACITY COSTS	\$000	[11]	\$ 55,930	\$ 56,313	\$ 40,039	\$ 30,283	\$ 89,238	\$123,856	\$215,884	\$250,605
NET ENERGY COSTS	\$000	[12]	9,686	13,728	23,380	28,350	39,416	47,924	57,299	67,045
TOTAL NET COSTS	\$000	[13]	\$ 65,616	\$ 70,041	\$ 63,419	\$ 58,632	\$128,655	\$171,779	\$273,183	\$317,651
NET PROJECT CAPACITY	MW	[14]	178.1	188.1	253.6	287.1	357.6	396.0	415.7	435.6
NET PROJECT GENERATION	GWH	[15]	1,052.8	1,111.6	1,478.7	1,651.9	2,093.0	2,295.4	2,457.0	2,574.3
CAPACITY FACTOR	%	[16]	67.46	67.46	66.55	65.68	66.82	66.17	67.46	67.46
NET PROJECT FIXED COSTS	\$/KW	[17]	313.95	299.38	157.86	105.48	249.56	312.77	519.26	575.31
NET PROJECT ENERGY COSTS	MILLS	[18]	9.20	12.35	15.81	17.16	18.83	20.88	23.32	26.04
TOTAL NET PROJECT COSTS	MILLS	[19]	62.32	63.01	42.89	35.49	61.47	74.84	111.19	123.39
POXBORO										
NET CAPACITY COSTS	\$000	[21]	\$ 7,396	\$ 7,515	\$ 7,683	\$ 7,825	\$ 8,018	\$ 8,191	\$ 8,424	\$ 8,626
NET ENERGY COSTS	\$000	[22]	10,013	14,650	22,570	18,235	24,903	21,404	31,138	25,440
TOTAL NET COSTS	\$000	[23]	\$ 25,409	\$ 22,165	\$ 30,253	\$ 26,060	\$ 32,923	\$ 29,595	\$ 39,623	\$ 34,066
NET PROJECT CAPACITY	MW	[24]	85.8	85.8	85.8	85.8	85.8	85.8	85.8	85.8
NET PROJECT GENERATION	GWH	[25]	437.4	327.2	437.4	327.2	437.4	327.2	437.4	327.2
CAPACITY FACTOR	%	[26]	58.20	43.53	58.20	43.53	58.20	43.53	58.20	43.53
NET PROJECT FIXED COSTS	\$/KW	[27]	86.20	87.58	89.55	91.20	93.45	95.47	98.18	100.53
NET PROJECT ENERGY COSTS	MILLS	[28]	41.18	44.78	51.60	35.74	56.93	65.42	71.32	77.76
TOTAL NET PROJECT COSTS	MILLS	[29]	58.09	67.75	69.16	79.65	75.26	90.46	90.58	104.12

NORTH CAROLINA MUNICIPAL POWER AGENCY NUMBER 3
PROJECTED OPERATING RESULTS UNDER
PROPOSED ARRANGEMENT WITH C P & L
CASE A

SCHEDULE 1 - SUMMARY OF PROJECT COSTS

DESCRIPTION			1990	1991	1992	1993	1994	1995	1996	1997
<hr/>										
MAYO										
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NET CAPACITY COSTS	#000	[31]	\$ 1,519	\$ 3,344	\$ 24,062	\$ 32,843	\$ 34,495	\$ 36,211	\$ 38,030	\$ 39,990
NET ENERGY COSTS	#000	[32]	25,215	34,236	35,757	42,182	47,143	56,157	61,370	72,684
TOTAL NET COSTS	#000	[33]	\$ 26,734	\$ 37,580	\$ 59,819	\$ 75,025	\$ 81,639	\$ 92,368	\$ 99,400	\$ 112,674
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NET PROJECT CAPACITY	MW	[34]	131.7	154.4	162.4	170.3	178.2	186.1	194.0	202.3
NET PROJECT GENERATION	GWH	[35]	561.6	706.0	707.0	774.5	777.7	847.1	848.3	919.4
CAPACITY FACTOR	%	[36]	48.69	52.18	49.71	52.08	49.82	51.96	49.91	51.88
NET PROJECT FIXED COSTS	\$/KW	[37]	11.54	21.65	148.20	192.88	193.58	194.56	195.99	197.69
NET PROJECT ENERGY COSTS	MILLS	[38]	44.90	48.49	50.58	54.32	60.62	66.29	72.34	79.05
TOTAL NET PROJECT COSTS	MILLS	[39]	47.60	53.23	84.61	96.61	104.98	109.04	117.17	122.55
<hr/>										
TOTAL PROJECT COSTS										
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NET CAPACITY COSTS	#000	[101]	\$115,265	\$118,680	\$124,480	\$124,949	\$187,187	\$225,256	\$321,068	\$359,846
NET ENERGY COSTS	#000	[102]	74,645	89,642	115,587	125,013	151,360	168,951	197,406	217,153
TOTAL NET COSTS	#000	[103]	\$189,910	\$208,322	\$240,067	\$249,963	\$338,547	\$394,209	\$518,474	\$576,999
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NET PROJECT CAPACITY	MW	[104]	691.1	723.8	7.3	838.6	917.0	963.4	991.1	1,019.2
NET PROJECT GENERATION	GWH	[105]	3,798.0	3,890.9	469.2	4,501.7	5,054.2	5,215.8	5,488.9	5,567.0
CAPACITY FACTOR	%	[106]	62.74	61.37	62.56	61.28	62.92	61.80	63.22	62.36
NET PROJECT FIXED COSTS	\$/KW	[107]	166.79	163.97	156.13	148.99	204.12	233.82	323.97	353.08
NET PROJECT ENERGY COSTS	MILLS	[108]	19.65	23.04	26.45	27.77	29.95	32.39	35.96	39.01
TOTAL NET PROJECT COSTS	MILLS	[109]	50.00	53.54	54.94	55.53	66.98	75.58	94.46	103.65

NORTH CAROLINA MUNICIPAL POWER AGENCY NUMBER 3
PROJECTED OPERATING RESULTS UNDER
PROPOSED ARRANGEMENT WITH C P & L
CASE A

SCHEDULE 1 - SUMMARY OF PROJECT COSTS

DESCRIPTION			1998	1999	2000	2001	2002	2003
BRUNSWICK								
NET CAPACITY COSTS	\$000	[1]	\$ 62,704	\$ 64,990	\$ 67,485	\$ 70,230	\$ 73,242	\$ 76,555
NET ENERGY COSTS	\$000	[2]	56,609	61,824	67,602	73,912	80,801	88,309
TOTAL NET COSTS	\$000	[3]	\$119,312	\$126,814	\$135,087	\$144,142	\$154,043	\$164,865
NET PROJECT CAPACITY	MW	[4]	295.5	295.5	295.5	295.5	295.5	295.5
NET PROJECT GENERATION	GWH	[5]	1,746.1	1,746.1	1,746.1	1,746.1	1,746.1	1,746.1
CAPACITY FACTOR	%	[6]	67.46	67.46	67.46	67.46	67.46	67.46
NET PROJECT FIXED COSTS	\$/KW	[7]	212.22	219.93	228.41	237.70	247.89	259.11
NET PROJECT ENERGY COSTS	MILLS	[8]	32.42	35.41	38.72	42.33	46.28	50.58
TOTAL NET PROJECT COSTS	MILLS	[9]	60.33	72.62	77.37	82.55	88.22	94.42
HARRIS								
NET CAPACITY COSTS	\$000	[11]	\$267,769	\$280,271	\$293,574	\$307,220	\$319,428	\$332,084
NET ENERGY COSTS	\$000	[12]	77,622	90,005	104,291	120,165	136,698	154,823
TOTAL NET COSTS	\$000	[13]	\$345,391	\$370,276	\$397,865	\$427,385	\$456,126	\$486,907
NET PROJECT CAPACITY	MW	[14]	455.3	475.2	495.4	514.8	530.1	544.5
NET PROJECT GENERATION	GWH	[15]	2,691.0	2,808.3	2,928.0	3,042.3	3,133.1	3,217.9
CAPACITY FACTOR	%	[16]	67.46	67.46	67.48	67.46	67.47	67.46
NET PROJECT FIXED COSTS	\$/KW	[17]	588.05	589.80	592.64	596.78	602.62	609.89
NET PROJECT ENERGY COSTS	MILLS	[18]	28.84	32.05	35.62	39.50	43.63	48.11
TOTAL NET PROJECT COSTS	MILLS	[19]	128.35	131.85	135.88	140.48	145.58	151.31
ROXBORO								
NET CAPACITY COSTS	\$000	[21]	\$ 8,911	\$ 9,151	\$ 9,494	\$ 9,785	\$ 10,187	\$ 10,532
NET ENERGY COSTS	\$000	[22]	37,082	30,239	44,076	35,940	52,388	42,718
TOTAL NET COSTS	\$000	[23]	\$ 45,993	\$ 39,389	\$ 53,569	\$ 45,725	\$ 62,575	\$ 53,250
NET PROJECT CAPACITY	MW	[24]	85.8	85.8	85.8	85.8	85.8	85.8
NET PROJECT GENERATION	GWH	[25]	437.4	327.2	437.4	327.2	437.4	327.2
CAPACITY FACTOR	%	[26]	58.20	43.53	58.20	43.53	58.20	43.53
NET PROJECT FIXED COSTS	\$/KW	[27]	103.85	106.65	110.65	114.04	118.73	122.75
NET PROJECT ENERGY COSTS	MILLS	[28]	94.77	92.42	100.75	109.85	117.76	130.57
TOTAL NET PROJECT COSTS	MILLS	[29]	105.14	120.39	122.46	139.75	143.05	162.76

NORTH CAROLINA MUNICIPAL POWER AGENCY NUMBER 3
PROJECTED OPERATING RESULTS UNDER
PROPOSED ARRANGEMENT WITH C P & L
CASE A

SCHEDULE 1 - SUMMARY OF PROJECT COSTS

DESCRIPTION			1998	1999	2000	2001	2002	2003
MAYO								
NET CAPACITY COSTS	\$000	[31]	\$ 41,933	\$ 43,406	\$ 44,999	\$ 46,676	\$ 48,462	\$ 50,405
NET ENERGY COSTS	\$000	[32]	79,277	91,151	98,546	111,857	122,258	137,133
TOTAL NET COSTS	\$000	[33]	\$121,210	\$134,558	\$143,545	\$158,534	\$170,720	\$187,539
NET PROJECT CAPACITY	MW	[34]	209.9	213.8	217.8	221.8	225.7	229.7
NET PROJECT GENERATION	GWH	[35]	919.0	968.1	959.4	998.3	999.8	1,028.5
CAPACITY FACTOR	%	[36]	49.99	51.68	50.29	51.39	50.56	51.12
NET PROJECT FIXED COSTS	\$/KW	[37]	199.79	202.98	206.61	210.48	214.70	219.46
NET PROJECT ENERGY COSTS	MILLS	[38]	86.26	94.16	102.72	112.05	122.28	133.33
TOTAL NET PROJECT COSTS	MILLS	[39]	131.89	138.99	149.62	158.80	170.76	182.34
TOTAL PROJECT COSTS								
NET CAPACITY COSTS	\$000	[101]	\$381,317	\$397,807	\$415,552	\$433,911	\$451,318	\$469,576
NET ENERGY COSTS	\$000	[102]	250,590	273,219	314,514	341,874	392,146	422,984
TOTAL NET COSTS	\$000	[103]	\$631,907	\$671,027	\$730,067	\$775,785	\$843,464	\$892,560
NET PROJECT CAPACITY	MW	[104]	1,046.5	1,070.3	1,094.4	1,117.8	1,137.0	1,155.4
NET PROJECT GENERATION	GWH	[105]	5,793.6	5,849.7	6,071.0	6,113.9	6,316.4	6,319.6
CAPACITY FACTOR	%	[106]	53.20	62.39	63.32	62.44	63.41	62.44
NET PROJECT FIXED COSTS	\$/KW	[107]	364.38	371.68	379.70	388.18	396.92	406.40
NET PROJECT ENERGY COSTS	MILLS	[108]	43.25	46.71	51.81	55.92	62.08	66.93
TOTAL NET PROJECT COSTS	MILLS	[109]	109.07	114.71	120.25	126.80	133.54	141.24

NORTH CAROLINA MUNICIPAL POWER AGENCY NUMBER 3
PROJECTED OPERATING RESULTS UNDER
PROPOSED ARRANGEMENT WITH C P & L
CASE A

SCHEDULE 2 - PARTIAL REQUIREMENTS PURCHASES FROM CP&L

DESCRIPTION			1982	1983	1984	1985	1986	1987	1988	1989	1990
1. SUPPLEMENTAL POWER											
SUPPLEMENTAL DEMAND	MW	[111]	806.2	628.7	654.0	675.5	659.9	695.0	674.4	686.0	671.7
COST	\$/KW/YR	[112]	55.87	59.56	61.00	69.77	102.18	99.23	113.96	115.64	119.18
CAPACITY COSTS	\$000	[113]	\$45,042	\$37,450	\$39,891	\$47,128	\$47,426	\$68,959	\$74,859	\$79,326	\$80,053
SUPPLEMENTAL ENERGY	GWH	[114]	3,358.2	2,184.6	1,779.4	2,014.8	1,997.6	1,809.9	1,726.3	1,445.3	1,434.0
COST	MILLS	[115]	15.01	16.65	19.36	20.20	21.05	22.32	22.77	26.03	29.17
ENERGY COSTS	\$000	[116]	\$50,411	\$36,385	\$34,457	\$40,708	\$42,051	\$40,391	\$39,307	\$37,623	\$41,830
TOTAL SUPPLEMENTAL COSTS	\$000	[117]	\$95,452	\$73,835	\$74,348	\$87,836	\$109,477	\$109,350	\$116,166	\$116,949	\$121,883
2. PROJECT RESERVE SERVICE											
RESERVE CAPACITY	MW	[118]	47.8	80.6	109.1	92.2	78.7	119.6	107.4	149.7	130.6
COST	\$/KW/YR	[119]	54.17	62.30	66.62	79.91	113.17	113.31	128.53	137.46	141.34
CAPACITY COSTS	\$000	[120]	\$2,592	\$5,025	\$7,269	\$7,365	\$8,907	\$13,549	\$13,802	\$20,500	\$18,461
RESERVE ENERGY	GWH	[121]	420.7	706.8	955.8	807.6	689.4	1,047.4	941.1	1,306.4	1,144.5
COST	MILLS	[122]	15.01	16.65	19.36	20.20	21.05	22.32	22.77	26.03	29.17
RESERVE ENERGY COSTS	\$000	[123]	\$6,314	\$11,772	\$18,508	\$16,319	\$14,513	\$23,375	\$21,428	\$34,008	\$33,386
DEFICIENCY ENERGY	GWH	[124]	2.5	24.5	7.7	4.4	43.2	8.2	37.7	6.1	35.5
COST	MILLS	[125]	20.93	22.95	26.55	27.87	31.79	33.57	36.80	41.92	45.97
DEFICIENCY ENERGY COSTS	\$000	[126]	\$51	\$562	\$205	\$120	\$1,373	\$276	\$1,386	\$257	\$1,631
SPINNING RESERVES	MW	[127]	9.7	20.2	21.1	22.2	25.0	25.4	28.5	30.1	32.8
COST	MILLS	[128]	14.12	15.28	15.18	16.55	18.74	18.58	20.88	21.07	24.13
SPINNING RESERVES COSTS	\$000	[129]	\$120	\$271	\$281	\$329	\$411	\$414	\$522	\$555	\$694
TOTAL RESERVE COSTS	\$000	[130]	\$9,078	\$17,630	\$26,263	\$24,137	\$25,204	\$37,614	\$37,137	\$55,320	\$54,171
3. TRANSMISSION SERVICE											
CAPACITY REQUIREMENTS	MW	[131]	1,010.5	1,054.6	1,098.6	1,142.6	1,186.6	1,230.7	1,274.7	1,318.7	1,362.8
COST	\$/KW/YR	[132]	12.46	13.69	15.60	18.00	21.92	22.87	22.88	23.00	23.24
CAPACITY COSTS	\$000	[133]	\$12,595	\$14,434	\$17,134	\$21,595	\$26,016	\$28,150	\$29,167	\$30,334	\$31,675
TOTAL TRANSMISSION SERVICE	\$000	[137]	\$12,595	\$14,434	\$17,134	\$21,595	\$26,016	\$28,150	\$29,167	\$30,334	\$31,675
TOTAL PARTIAL REQUIREMENTS											
FIXED COSTS	\$000	[138]	\$60,228	\$56,908	\$64,294	\$76,088	\$102,348	\$110,658	\$119,828	\$130,160	\$130,189
VARIABLE COSTS	\$000	[139]	\$6,896	\$8,990	\$3,451	\$7,480	\$8,348	\$64,457	\$62,642	\$72,442	\$77,540
TOTAL	\$000	[140]	\$117,125	\$105,899	\$117,744	\$133,568	\$160,697	\$175,115	\$182,470	\$202,603	\$207,730

NORTH CAROLINA MUNICIPAL POWER AGENCY NUMBER 3
PROJECTED OPERATING RESULTS UNDER
PROPOSED ARRANGEMENT WITH C P & L
CASE A

SCHEDULE 2 - PARTIAL REQUIREMENTS PURCHASES FROM CP&L

DESCRIPTION			1991	1992	1993	1994	1995	1996	1997	1998
1. SUPPLEMENTAL POWER										
SUPPLEMENTAL DEMAND	MW	[111]	683.0	653.6	656.2	621.8	619.5	635.9	651.8	668.5
COST	\$/KW/YR	[112]	118.47	139.30	140.72	156.34	155.03	151.26	170.61	198.71
CAPACITY COSTS	\$000	[113]	\$ 80,911	\$ 91,037	\$ 92,340	\$ 97,214	\$ 96,041	\$ 96,184	\$111,201	\$132,035
SUPPLEMENTAL ENERGY	GWH	[114]	1,235.7	1,019.3	716.5	513.2	299.7	443.6	642.4	559.7
COST	MILLS	[115]	32.89	34.03	36.42	37.01	40.57	44.84	49.91	55.39
ENERGY COSTS	\$000	[116]	\$ 40,640	\$ 34,585	\$ 25,097	\$ 18,994	\$ 12,161	\$ 19,890	\$ 32,063	\$ 31,001
TOTAL SUPPLEMENTAL COSTS	\$000	[117]	\$121,551	\$125,722	\$118,437	\$116,207	\$108,202	\$116,074	\$143,263	\$163,036
2. PROJECT RESERVE SERVICE										
RESERVE CAPACITY	MW	[118]	167.8	156.2	214.1	202.9	266.4	228.2	197.9	217.4
COST	\$/KW/YR	[119]	146.66	173.29	184.45	208.86	222.90	224.93	251.16	285.85
CAPACITY COSTS	\$000	[120]	\$ 24,605	\$ 27,066	\$ 39,491	\$ 42,367	\$ 59,375	\$ 51,338	\$ 49,710	\$ 62,131
RESERVE ENERGY	GWH	[121]	1,469.7	1,368.4	1,761.6	1,629.2	1,918.7	1,688.2	1,564.2	1,643.1
COST	MILLS	[122]	32.89	34.03	36.42	37.01	40.57	44.84	49.91	55.39
RESERVE ENERGY COSTS	\$000	[123]	\$ 48,334	\$ 46,563	\$ 64,161	\$ 60,294	\$ 77,842	\$ 75,701	\$ 78,067	\$ 91,014
DEFICIENCY ENERGY	GWH	[124]	22.8	69.3	53.7	44.0	13.5	51.3	98.6	72.9
COST	MILLS	[125]	49.58	52.04	56.26	60.87	67.44	73.80	80.53	87.62
DEFICIENCY ENERGY COSTS	\$000	[126]	\$ 1,132	\$ 3,607	\$ 3,020	\$ 2,678	\$ 913	\$ 2,531	\$ 7,132	\$ 6,389
SPINNING RESERVES	MW	[127]	34.4	37.9	39.8	43.6	45.8	47.1	48.4	49.7
COST	MILLS	[128]	25.62	28.63	31.82	35.55	39.90	45.61	50.27	55.52
SPINNING RESERVES COSTS	\$000	[129]	\$ 772	\$ 950	\$ 1,110	\$ 1,357	\$ 1,599	\$ 1,881	\$ 2,132	\$ 2,418
TOTAL RESERVE COSTS	\$000	[130]	\$ 74,846	\$ 78,185	\$107,782	\$106,495	\$139,730	\$131,451	\$137,040	\$161,951
3. TRANSMISSION SERVICE										
CAPACITY REQUIREMENTS	MW	[131]	1,406.8	1,450.8	1,494.8	1,538.9	1,582.9	1,626.9	1,671.0	1,715.0
COST	\$/KW/YR	[132]	23.51	23.79	24.03	24.37	24.61	24.84	25.05	25.26
CAPACITY COSTS	\$000	[133]	\$ 33,078	\$ 34,511	\$ 35,922	\$ 37,500	\$ 38,957	\$ 40,406	\$ 41,862	\$ 43,315
TOTAL TRANSMISSION SERVICE	\$000	[137]	\$ 33,078	\$ 34,511	\$ 35,922	\$ 37,500	\$ 38,957	\$ 40,406	\$ 41,862	\$ 43,315
TOTAL PARTIAL REQUIREMENTS										
FIXED COSTS	\$000	[138]	\$138,595	\$152,613	\$167,753	\$177,081	\$194,373	\$187,928	\$202,773	\$238,281
VARIABLE COSTS	\$000	[139]	90,880	85,805	94,388	83,322	92,516	100,003	119,393	130,820
TOTAL	\$000	[140]	229,474	238,418	262,141	260,403	286,889	287,931	322,166	369,101

NORTH CAROLINA MUNICIPAL POWER AGENCY NUMBER 3
PROJECTED OPERATING RESULTS UNDER
PROPOSED ARRANGEMENT WITH C P & L

CASE A

SCHEDULE 2 - PARTIAL REQUIREMENTS PURCHASES FROM CP&L

DESCRIPTION	1999	2000	2001	2002	2003
1. SUPPLEMENTAL POWER					
SUPPLEMENTAL DEMAND					
COST					
CAPACITY COSTS					
	{111}	688.7	708.6	729.2	779.7
	{112}	202.50	227.57	263.47	270.02
	{113}	\$139,533	\$161,259	\$192,134	\$203,612
					\$236,992
SUPPLEMENTAL ENERGY					
COST	{114}	483.5	797.9	737.7	640.2
	{115}	61.75	68.50	76.16	84.47
	{116}	\$29,856	\$54,657	\$56,184	\$54,078
					\$86,751
TOTAL SUPPLEMENTAL COSTS	{117}	\$169,390	\$215,915	\$248,319	\$257,689
					\$323,743
2. PROJECT RESERVE SERVICE					
RESERVE CAPACITY					
COST	{118}	251.2	188.0	218.8	248.1
	{119}	307.22	336.62	380.45	398.67
	{120}	\$77,173	\$63,291	\$83,227	\$98,910
					\$92,935
RESERVE ENERGY					
COST	{121}	1,890.0	1,474.2	1,733.0	1,878.0
	{122}	61.75	68.50	76.16	84.47
	{123}	\$116,709	\$100,985	\$131,994	\$158,438
					\$161,120
DEFICIENCY ENERGY					
COST	{124}	53.2	140.3	106.1	63.4
	{125}	95.99	104.55	114.44	125.06
	{126}	\$5,109	\$14,690	\$12,147	\$7,927
					\$18,336
SPINNING RESERVES					
COST	{127}	50.8	52.0	53.1	54.0
	{128}	51.03	67.12	72.89	79.15
	{129}	\$2,718	\$3,057	\$3,390	\$3,745
					\$4,132
TOTAL RESERVE COSTS	{130}	\$201,709	\$182,022	\$230,758	\$269,220
					\$276,524
3. TRANSMISSION SERVICE					
CAPACITY REQUIREMENTS					
COST	{131}	1,759.0	1,803.0	1,847.1	1,891.1
	{132}	25.42	25.57	25.72	25.86
	{133}	\$44,715	\$46,096	\$47,513	\$48,910
					\$50,451
TOTAL TRANSMISSION SERVICE	{137}	\$44,715	\$46,096	\$47,513	\$48,910
					\$50,451
TOTAL PARTIAL REQUIREMENTS					
FIXED COSTS	{138}	\$261,421	\$270,546	\$323,875	\$351,432
VARIABLE COSTS	{139}	154,392	173,388	203,716	224,388
					\$270,340
TOTAL	{140}	415,813	444,034	525,591	575,820
					\$650,718

NORTH CAROLINA MUNICIPAL POWER AGENCY W/ ER 3
PROJECTED OPERATING RESULTS UNDER
PROPOSED ARRANGEMENT WITH C P & L
CASE A

SCHEDULE 3 - TOTAL AGENCY COSTS

DESCRIPTION			1982	1983	1984	1985	1986	1987	1988	1989
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ADDITIONAL AGENCY COSTS										
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AGENCY A & G EXPENSES	0000	[151]	\$ 2,072	\$ 2,259	\$ 2,462	\$ 2,683	\$ 2,925	\$ 3,188	\$ 3,475	\$ 3,788
DEBT SERVICE -										
WORKING CAPITAL	0000	[152]	1,337	2,860	3,081	3,289	4,015	4,580	5,177	6,244
SUBTOTAL	0000	[153]	\$ 3,409	\$ 5,119	\$ 5,543	\$ 5,972	\$ 6,940	\$ 7,768	\$ 8,652	\$ 10,032
COSTS ASSOCIATED WITH										
ARRANGEMENTS WITH VEPCO	0000	[154]	6,834	7,315	7,821	8,119	8,559	8,924	9,260	9,656
TOTAL ADDITIONAL COSTS	0000	[155]	\$ 10,243	\$ 12,434	\$ 13,364	\$ 14,091	\$ 15,499	\$ 16,692	\$ 17,912	\$ 19,688
<hr/>										
TOTAL COSTS UNDER AGENCY ARRANGEMENT										
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FIXED COSTS	0000	[161]	\$ 59,405	\$ 65,364	\$ 98,383	\$ 107,444	\$ 120,949	\$ 147,926	\$ 214,544	\$ 224,674
VARIABLE COSTS	0000	[162]	65,209	69,497	80,487	87,575	93,847	103,316	109,724	127,470
TOTAL COSTS	0000	[163]	\$ 124,614	\$ 134,862	\$ 178,870	\$ 195,019	\$ 214,796	\$ 251,243	\$ 324,268	\$ 352,144
<hr/>										
DEMAND AND ENERGY REQUIREMENTS										
@ GENERATION LEVEL										
<hr/>										
CP&L CITIES:										
PEAK DEMANDS	MW	[171]	654.7	683.0	711.4	739.7	768.0	796.4	824.7	853.1
ENERGY REQUIREMENTS	QWH	[172]	3,052.2	3,184.5	3,316.7	3,449.0	3,581.3	3,713.6	3,845.8	3,978.1
VEPCO CITIES:										
PEAK DEMANDS	MW	[173]	355.9	371.5	387.2	402.9	418.6	434.3	450.0	465.6
ENERGY REQUIREMENTS	QWH	[174]	1,702.5	1,777.4	1,852.2	1,927.1	2,002.0	2,076.9	2,151.8	2,226.7
TOTAL AGENCY:										
PEAK DEMANDS	MW	[175]	1,010.5	1,054.6	1,098.6	1,142.6	1,186.6	1,230.7	1,274.7	1,318.7
ENERGY REQUIREMENTS	QWH	[176]	4,754.6	4,961.8	5,169.0	5,376.1	5,583.3	5,790.5	5,997.6	6,204.8

NORTH CAROLINA MUNICIPAL POWER AGENCY NUMBER 3
PROJECTED OPERATING RESULTS UNDER
PROPOSED ARRANGEMENT WITH C P & L
CASE A

SCHEDULE 3 - TOTAL AGENCY COSTS

DESCRIPTION			1982	1983	1984	1985	1986	1987	1988	1989
<hr/>										
ALLOCATED BULK POWER SUPPLY COSTS										
<hr/>										
CP&L CITIES:										
FIXED COSTS	\$000	[177]	\$ 34,058	\$ 37,597	\$ 58,641	\$ 64,301	\$ 72,743	\$ 89,951	\$132,820	\$139,095
VARIABLE COSTS	\$000	[178]	41,860	44,603	51,645	56,183	60,196	66,259	70,358	81,725
TOTAL COSTS	\$000	[179]	\$ 75,918	\$ 82,200	\$110,286	\$120,483	\$132,940	\$156,210	\$203,178	\$220,820
VEPCO CITIES:										
FIXED COSTS	\$000	[180]	\$ 25,347	\$ 27,767	\$ 39,742	\$ 43,144	\$ 48,205	\$ 57,975	\$ 81,724	\$ 85,579
VARIABLE COSTS	\$000	[181]	23,349	24,895	28,842	31,392	33,651	37,057	39,366	45,744
TOTAL COSTS	\$000	[182]	\$ 48,696	\$ 52,662	\$ 68,584	\$ 74,536	\$ 81,856	\$ 95,032	\$121,091	\$131,324
TOTAL AGENCY:										
FIXED COSTS	\$000	[183]	\$ 59,405	\$ 65,364	\$ 98,383	\$107,444	\$120,949	\$147,926	\$214,544	\$224,674
VARIABLE COSTS	\$000	[184]	65,209	69,497	80,487	87,575	93,847	103,316	109,724	127,470
TOTAL COSTS	\$000	[185]	\$124,614	\$134,862	\$178,870	\$195,019	\$214,796	\$251,243	\$324,268	\$352,144
<hr/>										
DEMAND AND ENERGY DELIVERIES										
<hr/>										
CP&L CITIES:										
BILLING DEMANDS	MW-MO	[186]	6,320.9	6,593.8	6,866.8	7,139.7	7,412.6	7,685.6	7,958.5	8,231.4
ENERGY DELIVERIES	GWH	[187]	2,951.5	3,079.4	3,207.3	3,335.2	3,463.1	3,591.0	3,718.9	3,846.8
VEPCO CITIES:										
BILLING DEMANDS	MW-MO	[188]	3,372.1	3,520.2	3,668.3	3,816.4	3,964.5	4,112.6	4,260.7	4,408.8
ENERGY DELIVERIES	GWH	[189]	1,583.7	1,653.4	1,723.1	1,792.7	1,862.4	1,932.0	2,001.7	2,071.4
<hr/>										
AVERAGE COSTS OF ALL REQUIREMENTS BULK POWER SUPPLY										
<hr/>										
CP&L CITIES:										
FIXED COSTS	\$/KW/MO	[191]	5.39	5.70	8.54	9.01	9.81	11.70	16.69	16.90
VARIABLE COSTS	MILLS	[192]	14.18	14.48	16.10	16.85	17.38	18.45	18.92	21.24
COSTS ASSOCIATED WITH ARRANGEMENTS WITH VEPCO:										
FIXED COSTS	\$/KW/MO	[193]	2.13	2.19	2.29	2.30	2.35	2.39	2.49	2.51
VARIABLE COSTS	MILLS	[194]	.56	.57	.64	.67	.69	.73	.75	.84
VEPCO CITIES:										
FIXED COSTS	\$/KW/MO	[195]	7.52	7.89	10.83	11.30	12.16	14.10	19.18	19.41
VARIABLE COSTS	MILLS	[196]	14.74	15.06	16.74	17.51	18.07	19.18	19.67	22.08
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AVERAGE ADDITIONAL COSTS FOR VEPCO CITIES	MILLS	[197]	5.03	5.16	5.42	5.45	5.57	5.69	5.86	6.00

NORTH CAROLINA MUNICIPAL POWER AGENCY NUMBER 3
PROJECTED OPERATING RESULTS UNDER
PROPOSED ARRANGEMENT WITH C P & L
CASE A

SCHEDULE 3 - TOTAL AGENCY COSTS

DESCRIPTION	1990	1991	1992	1993	1994	1995	1996	1997
ADDITIONAL AGENCY COSTS								
AGENCY A & G EXPENSES								
DEBT SERVICE -								
WORKING CAPITAL								
SUBTOTAL								
COSTS ASSOCIATED WITH								
ARRANGEMENTS WITH VEPCO								
TOTAL ADDITIONAL COSTS								
TOTAL COSTS UNDER AGENCY ARRANGEMENT								
FIXED COSTS								
VARIABLE COSTS								
TOTAL COSTS								

DEMAND AND ENERGY REQUIREMENTS
AT GENERATION LEVEL

CP&L CITIES:								
PEAK DEMANDS								
ENERGY REQUIREMENTS								
VEPCO CITIES:								
PEAK DEMANDS								
ENERGY REQUIREMENTS								
TOTAL AGENCY:								
PEAK DEMANDS								
ENERGY REQUIREMENTS								

NORTH CAROLINA MUNICIPAL POWER AGENCY NUMBER 3
PROJECTED OPERATING RESULTS UNDER
PROPOSED ARRANGEMENT WITH C P & L
CASE A

SCHEDULE 3 - TOTAL AGENCY COSTS

DESCRIPTION	1990	1991	1992	1993	1994	1995	1996	1997
ALLOCATED BULK POWER SUPPLY COSTS								
CP&L CITIES:								
FIXED COSTS	\$000							
VARIABLE COSTS	\$000							
	(177)	\$165,849	\$114,092	\$187,198	\$199,275	\$246,220	\$340,400	\$375,419
	(178)	97,559	115,709	129,071	140,598	150,375	190,532	215,585
TOTAL COSTS	\$000	\$263,408	\$229,801	\$316,269	\$339,873	\$396,595	\$530,931	\$591,004
VEPCO CITIES:								
FIXED COSTS	\$000							
VARIABLE COSTS	\$000							
	(180)	\$100,754	\$105,914	\$114,068	\$121,058	\$147,403	\$200,164	\$219,916
	(181)	54,627	64,813	72,321	78,803	84,307	106,878	120,961
TOTAL COSTS	\$000	\$155,381	\$170,727	\$186,389	\$199,861	\$231,711	\$307,041	\$340,877
TOTAL AGENCY:								
FIXED COSTS	\$000							
VARIABLE COSTS	\$000							
	(183)	\$256,603	\$280,006	\$318,266	\$320,333	\$393,624	\$540,563	\$595,335
	(184)	152,186	180,522	213,392	219,401	234,682	297,409	336,546
TOTAL COSTS	\$000	\$408,789	\$460,528	\$531,658	\$539,734	\$628,306	\$837,973	\$931,881
DEMAND AND ENERGY DELIVERIES								
CP&L CITIES:								
BILLING DEMANDS	MW-MO							
ENERGY DELIVERIES	GWH							
	(186)	8,504.4	8,777.3	9,050.2	9,323.2	9,596.1	10,142.0	10,414.9
	(187)	3,974.7	4,102.7	4,230.6	4,358.5	4,486.4	4,742.2	4,870.1
VEPCO CITIES:								
BILLING DEMANDS	MW-MO							
ENERGY DELIVERIES	GWH							
	(188)	4,556.9	4,705.0	4,853.1	5,001.2	5,149.3	5,345.5	5,593.6
	(189)	2,141.0	2,210.7	2,280.4	2,350.0	2,419.7	2,559.0	2,628.7
AVERAGE COSTS OF ALL REQUIREMENTS								
MILK POWER SUPPLY								
CP&L CITIES:								
FIXED COSTS	\$/KW/MO							
VARIABLE COSTS	MILLS							
	(191)	19.50	19.83	20.75	21.37	25.66	33.56	36.05
	(192)	24.54	26.20	30.51	32.26	33.52	40.18	44.27
COSTS ASSOCIATED WITH								
ARRANGEMENTS WITH VEPCH								
FIXED COSTS	\$/KW/MO							
VARIABLE COSTS	MILLS							
	(193)	2.61	2.68	2.75	2.83	2.97	3.19	3.27
	(194)	.97	1.11	1.21	1.27	1.32	1.59	1.75
VEPCO CITIES:								
FIXED COSTS	\$/KW/MO							
VARIABLE COSTS	MILLS							
	(195)	22.11	22.51	23.50	24.21	28.63	36.76	39.32
	(196)	25.51	29.32	31.71	33.53	34.84	41.77	46.02
AVERAGE ADDITIONAL COSTS								
FOR VEPCH CITIES								
	MILLS	6.30	6.59	6.84	7.07	7.36	8.03	8.72

NORTH CAROLINA MUNICIPAL POWER AGENCY NUMBER 3
PROJECTED OPERATING RESULTS UNDER
PROPOSED ARRANGEMENT WITH C P & L
CASE A

SCHEDULE 3 - TOTAL AGENCY COSTS

DESCRIPTION			1998	1999	2000	2001	2002	2003
<hr/>								
ADDITIONAL AGENCY COSTS								
<hr/>								
AGENCY A & O EXPENSES	\$000	[151]	\$ 8,227	\$ 8,967	\$ 9,774	\$ 10,654	\$ 11,613	\$ 12,658
DEBT SERVICE -								
WORKING CAPITAL	\$000	[152]	10,754	10,751	10,757	10,741	10,741	10,741
SUBTOTAL	\$000	[153]	18,981	19,718	20,531	21,395	22,354	23,399
COSTS ASSOCIATED WITH								
ARRANGEMENTS WITH VEPCO	\$000	[154]	14,911	15,483	16,043	16,627	17,202	17,763
TOTAL ADDITIONAL COSTS	\$000	[155]	33,892	35,201	36,574	38,022	39,556	41,160
<hr/>								
TOTAL COSTS UNDER AGENCY ARRANGEMENT								
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FIXED COSTS	\$000	[161]	\$ 653,490	\$ 694,430	\$ 722,772	\$ 794,808	\$ 842,306	\$ 891,115
VARIABLE COSTS	\$000	[162]	381,411	427,612	487,902	545,590	616,534	693,323
TOTAL COSTS	\$000	[163]	\$1,034,900	\$1,122,041	\$1,210,674	\$1,340,398	\$1,458,840	\$1,584,438
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DEMAND AND ENERGY REQUIREMENTS								
* GENERATION LEVEL								
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CP&L CITIES:								
PEAK DEMANDS	MW	[171]	1,108.2	1,136.5	1,164.9	1,193.2	1,221.6	1,249.9
ENERGY REQUIREMENTS	GWH	[172]	5,168.6	5,300.9	5,433.2	5,565.4	5,697.7	5,830.0
VEPCO CITIES:								
PEAK DEMANDS	MW	[173]	606.8	622.5	638.2	653.8	669.5	685.2
ENERGY REQUIREMENTS	GWH	[174]	2,900.7	2,975.6	3,050.4	3,125.3	3,200.2	3,275.1
TOTAL AGENCY:								
PEAK DEMANDS	MW	[175]	1,715.0	1,759.0	1,803.0	1,847.1	1,891.1	1,935.1
ENERGY REQUIREMENTS	GWH	[176]	8,069.3	8,276.4	8,483.6	8,690.8	8,897.9	9,105.1

NORTH CAROLINA MUNICIPAL POWER AGENCY NUMBER 3
PROJECTED OPERATING RESULTS UNDER
PROPOSED ARRANGEMENT WITH C P & L
CASE A

SCHEDULE 3 - TOTAL AGENCY COSTS

DESCRIPTION			1998	1999	2000	2001	2002	2003
ALLOCATED BULK POWER SUPPLY COSTS								
CP&L CITIES:								
FIXED COSTS	\$000	{177}	\$ 412,637	\$ 439,681	\$ 456,592	\$ 502,712	\$ 532,983	\$ 564,107
VARIABLE COSTS	\$000	{178}	244,304	273,876	312,467	349,387	394,792	443,934
TOTAL COSTS	\$000	{179}	\$ 656,941	\$ 712,557	\$ 769,059	\$ 852,100	\$ 927,775	\$1,008,041
VEPCO CITIES:								
FIXED COSTS	\$000	{180}	\$ 240,853	\$ 255,748	\$ 266,180	\$ 292,095	\$ 309,323	\$ 327,008
VARIABLE COSTS	\$000	{181}	137,106	153,736	175,435	196,203	221,742	249,389
TOTAL COSTS	\$000	{182}	\$ 377,959	\$ 409,484	\$ 441,615	\$ 488,298	\$ 531,066	\$ 576,397
TOTAL AGENCY:								
FIXED COSTS	\$000	{183}	\$ 653,490	\$ 694,430	\$ 722,772	\$ 794,808	\$ 842,306	\$ 891,115
VARIABLE COSTS	\$000	{184}	381,411	427,612	487,902	545,590	616,534	693,323
TOTAL COSTS	\$000	{185}	\$1,034,900	\$1,122,041	\$1,210,674	\$1,340,398	\$1,458,840	\$1,584,438
DEMAND AND ENERGY DELIVERIES								
CP&L CITIES:								
BILLING DEMANDS	MW-MO	{186}	10,687.8	10,966.8	11,233.7	11,506.6	11,779.6	12,052.5
ENERGY DELIVERIES	GWH	{187}	4,998.0	5,125.9	5,253.9	5,381.8	5,509.7	5,637.6
VEPCO CITIES:								
BILLING DEMANDS	MW-MO	{188}	5,741.7	5,889.8	6,037.9	6,186.0	6,334.1	6,482.2
ENERGY DELIVERIES	GWH	{189}	2,698.4	2,768.0	2,837.7	2,907.3	2,977.0	3,046.7
AVERAGE COSTS OF ALL REQUIREMENTS BULK POWER SUPPLY								
CP&L CITIES:								
FIXED COSTS	\$/KW/MO	{191}	38.61	40.02	40.64	43.69	45.25	46.30
VARIABLE COSTS	MILLS	{192}	48.88	53.43	59.47	64.92	71.65	78.75
COSTS ASSOCIATED WITH ARRANGEMENTS WITH VEP CO:								
FIXED COSTS	\$/KW/MO	{193}	3.34	3.40	3.44	3.53	3.59	3.64
VARIABLE COSTS	MILLS	{194}	1.93	2.11	2.35	2.56	2.83	3.11
VEPCO CITIES:								
FIXED COSTS	\$/KW/MO	{195}	41.95	43.42	44.08	47.22	48.83	50.45
VARIABLE COSTS	MILLS	{196}	50.81	55.54	61.82	67.49	74.48	81.86
AVERAGE ADDITIONAL COSTS FOR VEP CO CITIES	MILLS	{197}	8.63	8.92	9.25	9.62	10.00	10.38

Question 13

List and describe all requests for, or indications of interest in, interconnection and/or coordination and purchases or sales of coordinating power and energy from adjacent utilities listed in Item 9 since 1960 and state applicant's response thereto. List and describe all requests for, or indications of interest in, supply of full or partial requirements of bulk power for the same period and state applicant's response thereto.

Response:

Not applicable to Power Agency. However, during the middle and late 1970's, North Carolina Municipal Power Agency Number 2 had studied various power supply alternatives and negotiated with VEPCO. None of these alternatives were undertaken, but an interconnection agreement with VEPCO was negotiated and executed.

Question 14

List (a) agreements to which applicant is a party (reproducing relevant paragraphs) and (b) State laws (supply citations only) which restrict or preclude coordination by, with, between, or among any electric utilities or systems identified in applicant's response to Items 8 and 9. List (a) agreements to which the applicant is a party (reproducing relevant paragraphs) and (b) State laws (supply citations only) which restrict or preclude substitution of service or establishment of service of full or partial bulk power supply requirements by an electric utility other than applicant to systems identified in Items 8 and 9. Where the contract provision appears in contracts or rate schedules on file with a Federal agency, identify each in the same form as in previous responses. Where the contract has not been filed with a Federal agency, a copy should be supplied unless it has been supplied pursuant to another item hereto. Where it is not in writing, it should be described.

Response.

Power Agency has no knowledge of any State laws and Power Agency is not a party to any agreements which restrict or preclude coordination by, with, between or among any electric utilities, or which restrict or preclude substitution of resale service or establishment of resale service of full or partial bulk power supply requirements by an electric utility, other than Power Agency, to systems identified in Items 8 and 9.

Article 6 of the Power Coordination Agreement between Power Agency and CP&L, supplied with this Application, requires Power Agency to give eight years prior written notice to CP&L if Power Agency desires to reduce the amount of its Supplemental Capacity obligation. However, that Article 6

permits Power Agency under certain circumstances to reduce its Supplemental Capacity obligation on less than eight years notice.

Power Agency is required to give ten years written notice to VEPCO to terminate service under the Agreement for Transmission Use and Other Electric Service, but it may terminate service at any delivery point upon five years written notice (with service to the City of Washington's delivery point being permitted to be terminated earlier if written notice is given within six months of July 30, 1981).

Section 3 of the Supplemental Power Sales Agreement between Power Agency and each Participant provides for Power Agency to sell and the Participants to purchase all requirements bulk power supply. This all requirements bulk power supply is in excess of any allotment of power which a Participant may receive from S&PA or certain resources which a Participant may install pursuant to Section 3 of the Supplemental Power Sales Agreement. Pursuant to the provisions of Section 2 of the Supplemental Power Sales Agreement, a Participant may terminate the Agreement on ten years prior written notice to Power Agency.

Question 15

State, at point of delivery, average future costs of power purchased from applicant to adjacent systems identified in applicant's response to item 9 in terms of dollars/month/kw for capacity, mills/kwh for energy and mills/kwh for both power and energy at purchaser's present load factor (a) at present load, (b) at 50 percent increase over present load, (c) at 100 percent increase over present load, and (d) at 200 percent increase over present load. (All costs should be determined under present rate schedules.) Where sales are made under contracts or rate schedules on file with a Federal agency and not included in the response to Item 9, identify each in the same form as in previous responses. Where the contract has not been filed with a Federal agency, a copy should be supplied.

Response:

Not applicable.

Question 16

State whether applicant has prepared, caused to be prepared, or received engineering studies for generation and transmission expansion programs which include loads of each system in Item 9.

Response:

None by or for Power Agency. However, North Carolina Municipal Power Agency Number 2 had a study of a combustion turbine project prepared for it in 1976 and a preliminary study of several power supply alternatives prepared for it in 1978.

Question 17

List adjacent systems to which applicant has offered to sponsor or to conduct system surveys in contemplation of an offer by applicant to purchase, merge or consolidate with said adjacent system, subsequent to January 1, 1960.

Response:

None.

Question 18

List applicant's offers or proposals to purchase, merge or consolidate with electric utilities, subsequent to January 1, 1960.

Response:

None.

Question 19

List all acquisitions of or mergers or consolidations with electric utilities by applicant, subsequent to January 1, 1960, including:

(a) The name and principal place of business of the system prior to acquisition, merger or consolidation;

(b) The date the acquisition, merger or consolidation was consummated;

(c) Gross annual revenue and most recent peak load, dependable capacity and the largest thermal generating unit of the system, prior to the date of consummation.

Response:

None.

Question. 20

State applicant's six (or fewer if there are not six) lowest industrial or large commercial rates for firm electric power supply in terms of cost for power and energy in mills per kilowatt hour (and separately, the demand and energy components) and indicate the portion of the charge attributed to bulk power supply. State the rates or rate blocks applicant utilizes for its six (or fewer if there are not six) promotional services such as electric space heating, electric hot water heating, and the like, in terms of mills per kilowatt hour for power and energy and indicate the portion of the rate or rate blocks attributed to bulk power supply.

Response:

Pursuant to Chapter 159B of the General Statutes of North Carolina, Power Agency is authorized "[t]o generate, produce, transmit, deliver, exchange, purchase, or sell for resale only, electric power or energy, and to enter into contracts for any or all such purposes" (Section 159B-11(15)). Accordingly, Power Agency does not have, and does not contemplate having, any rates of the type set forth in Question 20.

LIST OF POWER AGENCY'S MEMBERS

Town of Apex
Town of Ayden
Town of Belhaven*
Town of Benson
Town of Clayton
Town of Edenton*
City of Elizabeth City*
Town of Enfield*
Town of Farmville
Town of Fremont
City of Greenville*
Town of Hamilton*
Town of Hertford*
Town of Hobgood*
Town of Hookerton
City of Kinston
Town of LaGrange
City of Laurinburg
Town of Louisburg
City of Lumberton
City of New Bern
Town of Pikeville
Town of Red Springs
Town of Robersonville*
City of Rocky Mount
Town of Scotland Neck*
Town of Selma
Town of Smithfield
City of Southport
Town of Tarboro*
Town of Wake Forest
City of Washington*
Town of Waynesville
City of Wilson
Town of Windsor*
Town of Winterville*

* Members served by VEPCO (directly or indirectly) as of the date of this Application.

4. Communications

CP&L will be solely responsible hereafter for communications with NRC related to this application for Brunswick Units Nos. 1 and 2. Accordingly, all communications to CP&L or Power Agency pertaining to this application for Brunswick Units Nos. 1 and 2 should be sent to:


J. A. Jones
Vice Chairman
Carolina Power & Light Company
Post Office Box 1551
Raleigh, North Carolina 27602

and in addition, to:

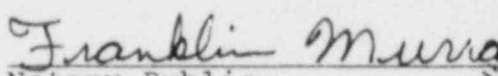
Charles D. Barham, Jr.
Vice President and Senior Counsel
Carolina Power & Light Company
Post Office Box 1551
Raleigh, North Carolina 27602

CAROLINA POWER & LIGHT COMPANY

BY:


J. A. Jones
Vice Chairman

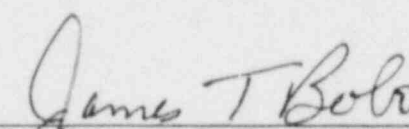
Sworn to and subscribed before me, this 3rd day of Sept., 1981.


Notary Public

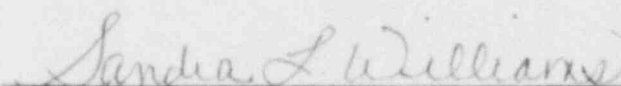
My Commission Expires:

NORTH CAROLINA MUNICIPAL POWER AGENCY
NUMBER 3

BY:


Assistant Secretary-Treasurer

Sworn to and subscribed before me, this 31 day of Aug., 1981.


Notary Public

My Commission Expires: 11-4-83

