North Carolina Electric Membership Corporation
Raleigh, North Carolina

Alternative Evaluation Study

Prepared for Submittal to the
Rural Utilities Service

by

North Carolina Electric
Membership Corporation
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Pratt & Whitney Combustion Turbine Projects

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Executive Summary

North Carolina Electric Membership Corporation ("NCEMC") is a power supply cooperative headquartered in Raleigh, North Carolina. NCEMC has 26 distribution cooperative members ("Members") with service territories located throughout the state.[1] Of those 26 Members, NCEMC serves 22 on an "all requirements" basis. These 22 members are referred to as Participating Members. Their loads are referred to herein as NCEMC load requirements. The remaining four members are referred to as Independent Members. The Independent Members have an on-going obligation for an allocated share of certain NCEMC resources. NCEMC, in turn, has an obligation to supply the Independent Members with capacity and energy to which they are entitled. The Independent Members are responsible for their own future needs. The proposed projects are to meet the needs of the 22 Participating Members.

NCEMC currently meets a part of its Members requirements through its 56.25% ownership interest in the Catawba Nuclear Station Unit # 1 (644 MW, guaranteed through a reliability exchange between the Catawba Nuclear Station and the McGuire Nuclear Station that results in an effective guaranteed capacity of 624 MW). NCEMC also has ownership of peaking plants on the Outer Banks of North Carolina (18 MW), and a portfolio of base, intermediate and peaking contracts from regional power suppliers. NCEMC obtains seasonal and short-term purchases with the help of ACES Power Marketing. In addition, NCEMC's Members have capacity allocations from the Southeastern Power Administration ("SEPA"). All of these resources are used to meet the most recent forecasted loads of the 22 Participating Members projected to grow at 2.3% (demand) and 2.2% (energy) over the next ten years, as well as meet the obligations for the four Independent Members.

NCEMC has an 800 MW peaking purchase contract with Carolina Power & Light d/b/a Progress Energy Carolinas, Inc. ("PEC") that expires at the end of 2004. The expiration of this contract, along with load growth for the Participating Members, creates a need for additional capacity beginning in 2005. In order to meet these additional requirements, NCEMC issued a Request for Proposals ("RFP 1009") in early 2003 to solicit bids for power supply resources. All feasible alternatives from the RFP were reviewed along with consideration of renewable generation and energy conservation alternatives. Based on this analysis NCEMC has concluded that building combustion turbine generation at two different sites in combination with purchasing power is the most economical way to provide a reliable, integrated source of power to meet its needs.

[1] There is one distribution cooperative headquartered in North Carolina which is not a member of NCEMC and receives all of its power requirements directly from elsewhere.

1 Introduction

NCEMC has the obligation to meet the full requirements needs of 22 of its 26 Members and to provide capacity for four of its 26 Members under existing contracts.[2] In order to comply with its obligations, NCEMC is proposing to construct combustion turbine generation at two different sites along with the purchase of power. This Alternative Evaluation Study is a description of the process that NCEMC underwent to arrive at this recommended plan.

The format of this analysis is to: 1) Provide a profile of NCEMC and its Members, 2) Describe the purpose and need for the project, based on the projected load growth and a description of the existing resources to serve this load, 3) Provide a description of the characteristics of the load, and 4) Provide a description of the alternatives considered to meet this load.

2 Profile of NCEMC and its Members

NCEMC was formed in 1958 through a merger of two of the state's cooperative umbrella organizations. In 1975, NCEMC assumed its present day profile of a generation and transmission cooperative, focusing on power supply issues. This focus culminated in 1981 with the purchase of a part ownership in Catawba Nuclear Station, and further in 1989 with the undivided ownership in diesel generation peaking plants. In the early 1990s, in response to the changing nature of the wholesale electricity market, NCEMC decided to change the direction of its power supply arrangements. The generation and transmission cooperative began to reduce its reliance on requirements purchases from the surrounding investor-owned utilities and to shift its focus to fixed capacity contracts with wholesale power suppliers through independent bids and negotiations.

In 1997 NCEMC's Board of Directors elected to institute a policy of member choice, allowing its 26 distributive cooperatives to choose whether or not to participate in new resource commitments made by NCEMC. In two subsequent contract negotiations and after thorough evaluation by the member cooperatives, all 26 members cooperatives agreed to the new contracts.

In 2001, the NCEMC Board revised its Member Power Supply Resource Policy to clarify an Independent Member's full responsibility for provision of all future power supply resource needs. Independent Members remain responsible for all resources committed to prior to becoming independent. Such commitment is on a take-or-pay basis. In June 2003, exercising the voluntary nature of participation in the power supply program of NCEMC, four distribution cooperatives gave notice under the Member Power Supply Resource Policy that they would become Independent Members. In December 2003, the Rural Utilities Service ("RUS") approved the Wholesale Power Sales Agreement

[2] These four members have the responsibility to meet their future needs over and above the existing contractual obligations.

between the Independent Members and NCEMC. As of January 1, 2004, this arrangement was implemented.

The predominance of the energy supplied by the NCEMC's Members is residential (73%). Small commercial & seasonal (16%), large commercial/industrial (7%) and other (4%) make up the remainder of the energy supplied. The total numbers of customers served in 2003 were 814,000 of which 553,000 were served by distribution cooperatives that were to remain Participating Members and 261,000 by the four distribution cooperatives that elected to become Independent Members as of January 1, 2004.

3 Purpose and Need for the Projects

The purpose of the projects is to continue to meet the requirements of the 22 Participating Members. These requirements are driven by two factors; expiration of existing power supply contracts and load growth for NCEMC's Participating Members. To meet this purpose, NCEMC conducts annual updates to its load forecast. This forecast serves as the basis for the NCEMC Load Forecast that was most recently submitted to RUS in December 2003. This Power Requirements Study, which is pending approval by RUS, provides the basis for the load forecast requirements used in this analysis.

NCEMC's annual peak demand is forecasted to occur during the summer and is projected to grow at 2.3% per year over the next 15 years. Annual energy is projected to grow at 2.2% per year.

3.1 Projected Demand and Energy

Historically, NCEMC's cooperative consumers have experienced a trend of continually increasing load requirements. This is due to: 1) growth in numbers of consumers, 2) a general trend of increased economic activity, and 3) a general trend of increasing usage by the average consumer.

Figures 1 and 2 below graphically represent the historical and forecasted summer peak demands and annual energy. Table 1 below shows the percentage growth in five-year increments.

The attached appendix shows a map of the state with all of the distribution cooperatives service territories.

Table 1 Historical and Forecasted Peak Demands and Energy				
Period	**Peak Demand**		**Annual Energy**	
Historical	Participating Members	All Members	Participating Members	All Members
1999-2003	3.4%	3.1%	4.1%	3.9%
1994-2003	4.7%	4.7%	4.6%	4.5%
1989-2003	4.5%	4.4%	4.9%	4.7%
Forecasted				
2003-2007	2.3%	N/A	2.2%	N/A
2003-2012	2.3%	N/A	2.2%	N/A
2003-2017	2.3%	N/A	2.2%	N/A

Figure 1: NCEMC Historical and Forecasted Summer Peak Demands

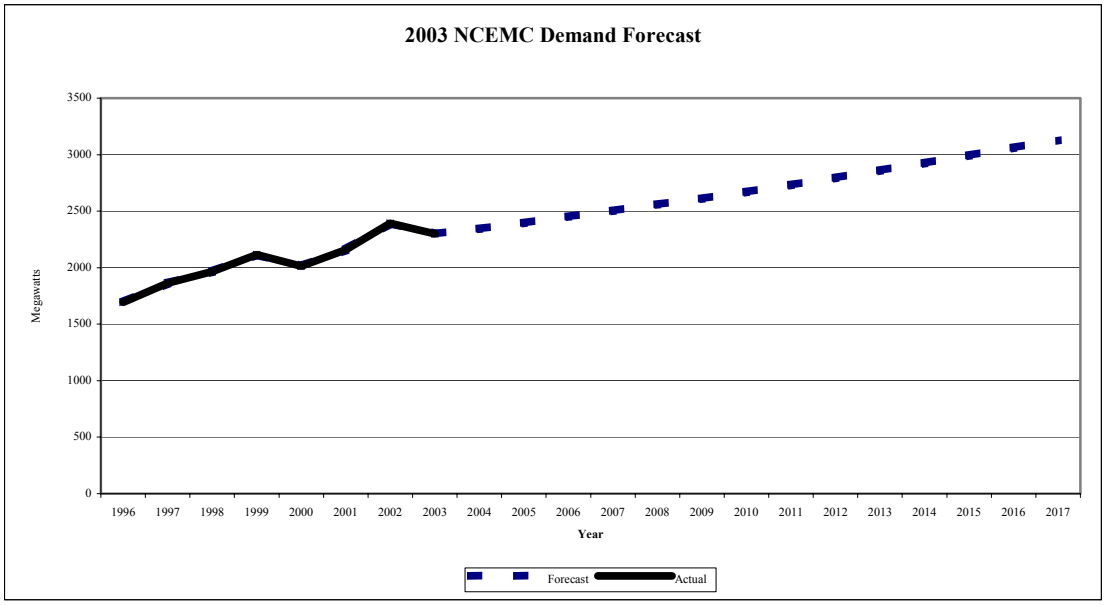
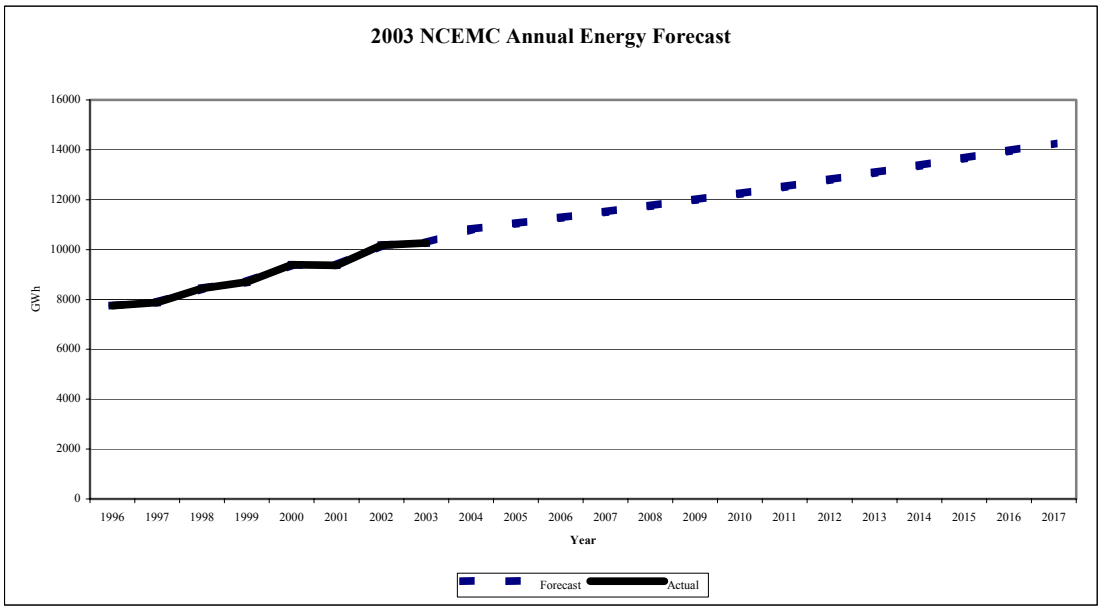


Figure 2: NCEMC Historical and Forecasted Annual Energy



Using this load forecast, NCEMC has outlined the future capacity requirements as of March 2004. These are shown in Table 2.

Table 2
Projected NCEMC Power Capacity Requirements (MW)

Description	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Projected Load[3]	2400	2452	2509	2561	2620	2672	2732	2796	2862	2928
Obligations[4]	834	518	518	518	518	454	454	332	332	221
Total Requirements	3234	2970	3027	3079	3137	3127	3186	3128	3194	3149
Existing Resources	3300	2475	2224	2274	2344	2344	2344	2139	2139	1739
Planned PEC Power Purchase Agmt.	0	500	750	450	300	300	300	300	300	300
Surplus/(Shortfall)[5]	66	5	(53)	(355)	(494)	(483)	(542)	(689)	(755)	(1110)

Table 2 shows that beginning in 2006, the combination of load and obligations, coupled with the decline in existing resources (due to expiration of existing power supply contracts) leaves a requirement for additional resources.

[3] Includes the loads of the 22 Participating Members, including losses.
[4] Includes the obligations to serve the four Independent Members.
[5] Future requirements will require reserves, either as part of a project or purchased independently.

3.2 Planning History

NCEMC's history of planning with RUS began with its application for funding to purchase its share of the Catawba Nuclear Station in the 1970s. Also, in 2002, after consulting with RUS, NCEMC applied for RUS funding for capital additions at the Catawba Nuclear Station. At present, this request is pending RUS approval.

Subsequently, NCEMC has continued to provide RUS with planning scenarios and reports. These include NCEMC tariffs backed up with a summary of the annual budgets, FERC Forms 12, annual Power Requirements Study, annual Audited Financial Statements, Supplemental Reports and Reports on Compliance and Internal Controls. Finally, NCEMC has sought RUS approval on any Power Supply Agreements with terms of over five years.

Although NCEMC is not regulated by the North Carolina Utilities Commission for rate-making purposes, it does provide an annual plan summarizing its generation and transmission plans. This plan was most recently updated in March 2004.

3.3 Existing Resources

NCEMC presently meets its load requirements and obligations through several sources. The majority of the resources are obtained through purchased power contracts of varying sources and lengths. These contracts augment generation assets owned by NCEMC as well as demand side management resources and entitlements to Federal Power Marketing capacity through the SEPA. Detailed discussion of each classification of resources follows.

3.3.1 Existing Generation Resources

At present, NCEMC has two separate generation assets. First, NCEMC is part owner in the Catawba Nuclear Station at York, South Carolina. NCEMC has an undivided ownership in 56.25% of Catawba Unit Number 1 along with an ownership portion of all common and support facilities. Through a mutual agreement with the other owners, NCEMC exchanges a portion of this output with three other nuclear generators. An equal portion of the output from Catawba Unit No. 1 is exchanged for a like output from Catawba Unit No. 2 – the Catawba Reliability Exchange. Further, a portion of the combined output of the Catawba Nuclear Station is exchanged for a like portion of the output from the McGuire Nuclear Station (Catawba's sister nuclear station) – the McGuire Reliability Exchange. The effect of the ownership and the reliability exchanges is that NCEMC has an entitlement to 624 MW of capacity from Catawba. This entitlement is used to serve load requirements and to meet obligations. NCEMC can use any excess output over certain load requirements to sell to third parties.

Second, NCEMC owns six diesel combustion turbine generators on the Outer Banks of North Carolina. Five of these – 15 MW – are located at Buxton, North Carolina. One – 3 MW – is located in Ocracoke, North Carolina. These generators provide peaking capacity for NCEMC to meet its load requirements and can also be used to provide system reliability for distribution cooperatives located in these remote areas.

Table 3 shows the existing generation resources and their uses presently owned by NCEMC.

Table 3
Existing NCEMC Generation Resources (MW)

Description	Fuel	Type	Capacity
Catawba with Reliability Exchanges	Nuclear	Base load	624
Diesel Generators	Oil	Peaking	18
Total			642

3.3.2 Existing Purchased Power Contracts

NCEMC has several long-term purchased power contracts with various wholesale power suppliers. NCEMC presently has no short-term purchased power contracts. A description of these contracts follows.

Appalachian Power Company Purchase: This resource purchase includes base load power from Appalachian Power Company, on behalf of the American Electric Power ("AEP") integrated system, in the amount of 205 MW through December 31, 2010.

American Electric Power Service Corporation Purchase: This resource purchase includes base load firm power from the Ohio Power and Columbus Southern Power systems. This resource capacity is for 150 MW through December 31, 2012.

Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. Peaking: The PEC Peaking Resource is a purchased power contract for peaking power delivered to the PEC and Duke Energy ("Duke") Supply Areas from 2001 through December 2004. The contracted capacity is for 800 MW. The agreement is structured to allow NCEMC the flexibility to schedule the 800 MW to either area as needed.

PEC Service Obligation Resources ("SORs"): The SORs are detailed in the Power Supply Agreement between PEC and NCEMC dated November 2, 1998, as amended, and include mostly base load resources. In 2004 there will remain three 225 MW SOR resources. NCEMC recently re-negotiated extensions of two of the 225 MW SORs for additional five-year terms. As a result, one of the resources will be maintained through 2013 and another through 2015. The remaining 225 MW SOR was scheduled to expire on December 31, 2004. It has been extended to 2019, and the capacity will increase so that by 2008 it will be 420 MW.

Planned PEC Power Purchase Agreement: The agreement with PEC will provide 500 MW for calendar year 2005, 750 MW for calendar year 2006, 450 MW for calendar year 2007 and 300 MW beginning January 1, 2008 through December 31, 2024.

South Carolina Electric & Gas Company ("SCE&G") Purchase: The SCE&G Intermediate Resource includes 250 MW of system firm intermediate capacity from January 1, 2004 through December 31, 2012. This resource is used to serve both the load requirements of Participating Members and obligations of Independent Members. Also supplied by SCE&G is a 100 MW system firm peaking capacity purchase from January 1, 2004 through December 31, 2005.

Southeastern Power Administration Allocation: NCEMC's Participating Members receive a total of 78 MW of capacity from SEPA.[6]

Southern Power Company Purchase: This resource consists of 100 MW of system firm peaking capacity from January 1, 2004 through December 31, 2005.

Virginia Electric and Power Company Purchase: The Virginia Power Power Purchase Agreement ("PPA") provides system firm capacity and energy. In 2004 this resource will provide 250 MW of capacity. In 2005, this capacity is reduced to 150 MW. This contractual capacity remains in effect through 2014 and is used to supply both the load requirements of Participating Members and obligations of Independent Members. Additionally, Virginia Electric and Power Company will provide 50 MW of system firm peaking capacity from January 1, 2004 through December 31, 2005.

Table 4 summarizes the existing purchased power contracts.

Table 4
Existing NCEMC Purchased Power Contracts

Description	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
SEPA Allocation	78	78	77	77	77	77	77	77	77	77
AEP (Appalachian) Base load	205	205	205	205	205	205	205	0	0	0
AEP (Ohio & Columbus Southern) Firm	150	150	150	150	150	150	150	150	150	0
PEC Peaking	800	0	0	0	0	0	0	0	0	0
PEC SORs	675	750	750	800	870	870	870	870	870	870
Planned PEC Power Purchase Agreement	0	500	750	450	300	300	300	300	300	300
SCE&G Purchase & Peaking	350	350	250	250	250	250	250	250	250	0
Southern Peaking	100	100	0	0	0	0	0	0	0	0
Virginia Power Purchase & Peaking	300	200	150	150	150	150	150	150	150	150
Total	2658	2333	2332	2082	2002	2002	2002	1797	1797	1397

[6] A contract change anticipated in 2006 will reduce this to 77 MW.

3.3.3 Existing Demand Side Management Resources

NCEMC's existing demand side management program consists of direct load control and distributed generation. NCEMC's potential for peak demand reduction for its Participating Members through demand side management is forecast to be 233 MW.

All of the Participating Members of NCEMC have the capability to control demand at the time of the NCEMC peak. This is achieved through remote activation of devices that control the operation of residential appliances such as water heaters and air conditioners. In addition, some of the Participating Members' larger customers have distributed generation capability (behind-the-meter peak shaving diesel generators) that, upon notification by NCEMC, can isolate the customers' loads from the NCEMC system, thereby reducing NCEMC's requirements. The reported capability of the distributed generation makes up 117 MW of the 233 MW total potential for demand reduction. NCEMC's forecasted load requirements have taken this potential for demand reduction into account.

NCEMC's Members have a variety of programs in place to promote energy efficiency and conservation. These programs include providing free energy audits, providing low interest loans for energy conservation, promoting, selling and installing energy efficient appliances (some with rebates), and making energy saving tips available to their consumers.

Table 5 summarizes NCEMC's existing demand side management capabilities.

Table 5
Existing NCEMC Demand Side Management Capability

Description	Capability (MW)
Direct Load Control (Appliance control, etc.)	116
Distributed Generation	117
Total Potential	233

3.3.4 Incremental Upgrades

At present, NCEMC has no plans for incremental upgrades to its diesel generating plants. There have been discussions among all of the joint owners of the Catawba Nuclear Station for some capital projects at the station that will have the impact of potential upgrades in capacity. However, through some contractual restrictions with the plant's operator – Duke Power Co., it is not clear that there will be a direct benefit to NCEMC from these projects and therefore, there has been no formal approval to move forward with any of these projects.

3.3.5 Power Pool Member Resources

NCEMC is not currently a member of a power pool or a regional system.

3.3.6 Transmission System Constraints

NCEMC is a transmission-dependent utility with load in three separate supply areas. NCEMC purchases transmission from PEC, Duke and Dominion Virginia Power ("VEPCO") under their respective Open Access Transmission Tariffs. NCEMC purchases Network Service from PEC, Duke, and VEPCO, the terms of which are discussed in the Network Integration Transmission Service Agreement and the Network Operating Agreement for each company. NCEMC also purchases Firm Point-to-Point transmission service from the following transmission providers: AEP, SCE&G, and Southern Company. These purchases are used to bring generation resources into the supply areas where NCEMC's load resides. The Duke and PEC supply areas both present challenges due to the utilization of the existing transmission systems.

NCEMC has found it difficult to import power into Duke from surrounding regions, due mainly to the high utilization of existing transmission lines into Duke from Southern Company and AEP. The transmission systems of Southern Company and AEP are fully subscribed and long-term reservations are not available. The transmission capacity from TVA into Duke is also very limited and subject to frequent maintenance because of the mountainous terrain that the tie line crosses.

The PEC control area is completely constrained, with no import capability on any interface. This problem became apparent to NCEMC following the RFP 1008 process which was conducted in 2001.

RFP 1008 resulted in NCEMC selecting three power suppliers to provide a total of 950 MW of intermediate capacity. One of the suppliers was VEPCO, which was to supply 420 MW in the PEC and Duke supply areas. It was originally VEPCO's intent to supply this power through the addition of new gas-fired generating facilities in the PEC supply area. However, VEPCO's plans changed, and they decided to import this capacity from their system as well as other systems into PEC. As a result, NCEMC requested a Designated Network Resource (DNR) for 420 MW in the PEC control area sourced out of VEPCO and sinking into PEC commencing 1/1/2005 and ending on 12/31/2030.

PEC required a System Impact Study associated with NCEMC's request. The results of the System Impact Study showed multiple problems associated with the DNR request. As a result, NCEMC lowered its DNR request from 420 MW to 250 MW. The results of the second System Impact Study and associated Facilities Study were equally problematic. This Facilities Study showed that NCEMC could import only 100 MW in 2005 and 2006, 125 MW in 2007, and 250 MW in 2008 and 2009. No roll-over rights would be granted beyond 2009.

The results of the second System Impact Study showed a combination of 16 projects and operating procedures to allow NCEMC to import a portion of the requested amount. The study also noted that a phase angle issue in the 500 kV tie line with Duke would not allow NCEMC's import of 250 MW beyond 2009. No solutions were identified by PEC in this study. However, in late April 2004, PEC, independent of the NCEMC's request, released a report identifying a new 500kV line connecting to Duke as a possible solution to the phase angle issue. The estimated cost for this possible solution is $350 million. The cost of this solution, if selected, would most likely be included in PEC's rate base. PEC estimates it will take 9 to 12 years to implement this solution. Due to this transmission situation and other factors, NCEMC made other arrangements to meet its power supply needs in place of the 420 MW purchase from VEPCO.

3.3.7 Characteristics of Energy Needs

In compliance with North Carolina's General Statutes, the North Carolina Utilities Commission ("NCUC") has adopted regulations that require NCEMC to file an Annual Report with the NCUC, such Annual Report taking the place of a Least Cost Integrated Resource Plan. The NCUC also requires NCEMC to file an amended Annual Report during the year if there are material changes in the filed Annual Report. NCEMC filed its Annual Report with the NCUC on September 2, 2003 and subsequently filed a Revised Annual Report with the NCUC on March 8, 2004. The information contained in the Revised Annual Report corresponds with the information contained in this report.

The conclusions of the Revised Annual Report and this Alternative Evaluation Study are the same. With existing generation resources, existing purchased power contract and existing demand side management resources, NCEMC will experience capacity deficits beginning in 2005 and these will increase over time. The primary reason for these deficits is the projected peak load requirements of the Participating Members driven by the expiration of power contracts and system load growth.

3.4 Summary Conclusions of Resource Needs

As summarized in Table 2, beginning in 2005, NCEMC Total Requirements will exceed its Existing Resources. As can be seen in the table, NCEMC's need is for approximately 800 MW firm, or approximately 900 MW with reserves in the 2006 through 2010 time period. Part of this need will be provided by the Planned PEC Power Purchase Agreement. The remaining shortfall will be met with 620 MW of combustion turbines and uncommitted future resources.

4 Capacity Alternatives

In seeking to meet its resource needs, NCEMC pursued looking at several alternatives before reaching any conclusions. Following is a description of each alternative, the process of evaluating the alternative and the conclusion regarding the alternative.

4.1 Load Management

A description of NCEMC's existing demand side management program is contained in 3.4.1.

NCEMC recently completed a study that concluded that the operation of the existing load control system continued to provide benefit, but prospective expansion of this system did not provide benefits when compared to costs. Further, the larger consumers on the systems of the Participating Members are typically 2 MW and below. Distributed generation has been encouraged by NCEMC as an alternative to central generation, and as a means of load management. However, it is limited by potential as well as economics, both of which make this alternative not feasible when considered as an alternative to meet NCEMC's need for future resources.

NCEMC's members continue to support efforts that promote the conservation of energy through consumer education and community outreach. Coupled with a program that ensures that adequate supply will be available when demand warrants, energy conservation continues to provide benefits for the individual consumer. Energy conservation, by itself will not ensure that demand is served reliably.

4.2 Renewable Energy

Renewable energy sources are generally covered by wind, solar, biomass and hydroelectric. Wind energy, while recently making inroads economically, remains non-competitive. Recent presentations before the North Carolina Utilities Commission by wind energy proponents continue to indicate that wind energy projects require a direct subsidy and a renewable portfolio standard to be economically viable. Further, wind energy proponents indicated that even in areas where winds are frequent, capacity factors of wind generation hover around 30-35%. This means that 1000 MW of reliable wind capacity would need approximately 3000 MW of installed capacity.[7] Further, a wind resources map, published by U. S. Department of Energy's National Renewable Energy Laboratory shows the southeast generally to be a very poor area for wind availability. In North Carolina, most of the area that is not in the higher altitudes or very close to the coastal sounds offers no potential for wind generation. Based on these findings, the limited geographical restrictions of siting large scale projects due to wind availability, and the limited amount of time to meet the needs of installed resources for NCEMC, wind energy projects are not a viable alternative.

There are three primary reasons that solar energy projects cannot provide for NCEMC's incremental needs. First, the size of the needs would require that a solar project be very large. Second, although the sun is the source of all energy, its availability at any given time is unreliable. Finally, a solar project to meet NCEMC's needs does not meet the economic threshold that would bring it into consideration.[8]

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[7] Report to the NCUC by Carolina Green Energy, LLC on February 18, 2004 and Tellus Institute *Energy Report*, November 1993.

[8] For example, on a large scale, current photovoltaic technology produces electricity in excess of 20 cents per megawatt-hour.

Energy from biomass remains a niche market constrained by the availability of waste products as feedstock in electric generation. The widespread introduction of biomass power generation on a competitive basis depends on "The successful development of a new generation of efficient power generation technology…" which is estimated to be at least a decade into the future.[9] Timing considerations make this technology inappropriate for the scale of NCEMC's power requirements.

NCEMC is presently in discussions with several local animal producers who are interested in developing small-scale projects to use animal waste as a feedstock for power generation – after conversion to methane. The largest of these is 15 MW and is projected to serve little more than an existing facility's electric requirements. To date, discussions with the project developers indicate that the projects under consideration will require outside subsidization to make them economical. In addition, these projects are planned to be operated as base load generation. This type of operation is not compatible with NCEMC's need for dispatchable peaking resources.

As a rule, hydroelectric generation is a very economical alternative. One of the problems of developing hydroelectric sites is the quantity of land required for reservoirs making potential sites highly dependent on land costs. In addition, the geography of North Carolina makes the development of any additional hydroelectric sites very limited. Further, hydroelectric production is dependent on water availability. Recent drought conditions and other concerns such as alternative uses for water (e.g., recreation and water supplies) restrict water availability for hydroelectric generation. These restrictions are particularly severe in the summer months – the months when it is most crucial that capacity be available. For these reasons, hydroelectric generation is not considered a feasible alternative to provide for NCEMC's power requirements.

4.3 Distributed Generation

Distributed generation is the use of small, modular generators at or near the point of consumption in either a stand-alone or an integrated format. As an economic alternative to centrally located generation connected to the transmission grid, distributed generation is not attractive unless there are other considerations. These considerations include bypassing system constraints on the transmission and/or distribution system, power quality concerns and system reliability concerns.[10] Further, some of the more feasible distributed generation technologies present air emission problems that are at a disadvantage with more conventional combustion turbine technologies. At present, NCEMC has none of these other considerations and concludes that NCEMC financed distributed generation projects are not an economic alternative to meet its power requirements.

[9] "The Economics of Biomass Production in the United States". Graham, et. al., Bioenergy Information Network, Oak Ridge National Laboratory. 1996.
[10] "Distributed Generation: Understanding the Economics". Arthur D. Little whitepaper, 1999.

4.4 Fossil Fueled Generation

Following is a discussion of the alternative configurations of the planned generation additions projects

4.4.1 Natural Gas

NCEMC presently has no facilities that are fueled by natural gas. Therefore, there has been no consideration of expansion. New natural gas combustion turbines and combined cycle projects were evaluated as a part of the RFP process and were the favored means to meet the future load requirements of NCEMC.

4.4.2 Oil

At present, NCEMC has two facilities that are peaking generators fueled by diesel fuel. The locations of these two facilities are on remote barrier islands on North Carolina's Outer Banks. Both of these generation sites serve at the end of system lines. These two sites are currently used both for peaking generation and for system reliability. A major expansion of capacity on either or both of these sites is infeasible because of transmission constraints, the remoteness of the sites requiring fuel delivery and the capacity of the surrounding distribution cooperatives to absorb the load. The use of exclusively oil-fueled alternatives at other sites is deemed to be too limited by air emission standards. However, the use of oil as a fuel alternative for combustion turbines and combined cycle projects is considered as a means to meet the future load requirements of NCEMC.

4.4.3 Coal

NCEMC has no installed base-load coal generation. Further, the identified need for additional generation capacity in the intermediate term is for peaking capacity. In order for new coal generation to compete with combustion turbine generation, NCEMC's screening analysis indicates that load factors in excess of 50% are needed. Anticipated load factors associated with economic dispatch of NCEMC's future requirements are in the 6-12% range. Therefore, the installation of additional coal base-load generation is not an option at this time.

4.5 Repowering/uprating of Existing Generating Units

NCEMC owns 56.25% of Catawba Unit No. 1. Catawba is the only NCEMC asset for which an uprating might be considered. At present, there are capital projects under consideration for increasing the capacity of Catawba. However, none of the projects for uprating the unit will provide an adequate amount of capacity additions that NCEMC needs to meet its future requirements.

4.6 Participation in Another Company's Generation Project

As a part of RFP 1009, NCEMC received numerous bids from existing and planned merchant plants for a power purchase agreement. The proposals numbered 68 from 33 entities, which were independent power producers, unregulated affiliates of regulated utilities and regulated utilities. There were fifteen proposals for build/ownership options, eleven proposals for system power purchase and forty-two proposals for unit, plant or portfolio power. Most of the proposals received from existing or planned merchant plants required at least one wheel for delivery into the desired control area (Progress Energy Carolinas), which put them at a competitive disadvantage. Further, only two bidders provided for the entire amount requested in the RFP. When measured through the initial screening analysis and the more rigorous short-list analysis, none of these projects were competitive on an equivalent risk basis as measured against the outcome put forward by NCEMC in its RUS load applications.

4.7 Purchased Power

Having determined the need for additional capacity, NCEMC decided to issue RFP 1009 for up to 1000 MW. NCEMC requested both PPA and build/ownership options.

RFP 1009 was issued in April 2003 and responses were received in May 2003. NCEMC received 68 proposals from 33 bidders. These bids broke down as follows: 15 bids were build/ownership options, 11 bids were for system power and 42 bids were unit/plant or portfolio power. Capacity amounts of the bids ranged from 20 to 1000 MW.

There were several critical factors that were assessed during the evaluation process. Two of these were operational flexibility and the firmness of supply, both of which allowed NCEMC to limit risk of price volatility. Based on the initial screening of the bids, NCEMC concluded that there were limited purchase power alternatives. The initial economic screening process revealed three "short-list" proposals. Two of these were build/ownership options and one was a Power Purchase Agreement. All three of these were for 1000 MW.

Subsequently, in June 2003, four of the member distribution cooperatives provided notice that they intended to exercise their rights on January 1, 2004 under the Member Power Supply Resources Policy, adopted by NCEMC and approved by RUS in December 2003. This policy allows for those members who exercise their option to retain responsibility for capacity that exists under current contracts, but to take on full responsibility for any additional power requirements needed in the future. As a result of this action, NCEMC lowered its requirements to approximately 800 MW firm, approximately 900 MW with reserves.

4.7.1 PPA versus build/ownership option

Following is a description of the alternatives that passed the "short-list" evaluation by NCEMC.

- Build alternative with a swap option on power – life of the project
    - Utility A project
    - Engineering Procurement Contractor B as primary contractor
- Build alternatives – aeroderivatives – life of the project
    - Manufacturer A
    - Manufacturer B
    - Utility B as siting/gas supply contractor
- Power Purchase Agreement – 10-year term
    - Utility C

In the final analysis, all of these alternatives were for an adequate amount to meet the identified needs (as adjusted for the exercise of the Member Power Supply Resource Policy option by four distribution cooperatives) from the RFP.

4.8 New Transmission Capacity

Because of the transmission constraints identified in Section 3.4.4, NCEMC conducted a transmission screening analysis to provide an indication of the transmission impacts of various bids which included import from other service areas. This process was performed on a parallel path to the economic screening analysis and was utilized in the overall screening process.

The base case for the screening analysis was developed using the Summer 2007 VST (VACAR- Southern-TVA) case of the SERC 2003 VST series of cases. This case was complemented with transactions and system improvement plans developed after the case was originally produced. Two additional cases were developed modeling PEC's combined Transmission Reliability Margin (TRM) and contingency policy assumptions. Specifically, the additional cases involved removing from operation combinations of two of PEC's largest nuclear units from different sites and importing power from neighboring systems according to the TRM values.

NCEMC performed single contingency analysis on the base case, the two additional cases and each of ten scenarios. The list of 1,189 contingencies was composed of the contingencies that the VACAR subregion utilities use in its transmission assessments, additional contingencies provided by PEC, and automatically generated contingencies. These automatically generated contingencies take out all 230 kV branches, 500 kV branches, and 230/500 kV transformers in PEC, Duke and VEPCO one at a time. In addition, the automatically generated contingencies take out all the ties from PEC, Duke and VEPCO one at a time.

The three scenarios that resulted in the fewest problems under contingency involved at least 650 MW of generation installed in the central part of the PEC Eastern control area. The other six scenarios resulting in a greater number of problems included generation in the southwestern part of the PEC Eastern control area and/or the Duke control area. The thermal and voltage problems identified for this group tended to be located towards the

eastern part of the state. This is the result of large imports from VEPCO for one of the cases reflecting PEC's TRM and contingency policy. Imports from other control areas indicated additional transmission problems. Several of the problems identified in the analysis are likely to be resolved with system improvements scheduled to be in place after 2007. The acceleration of such system improvements to accommodate a particular generation project needs to be discussed with the appropriate transmission provider. Other identified problems may be alleviated by introducing operational procedures.

The transmission screening process identified areas that are preferable from a transmission perspective and those which may have additional transmission issues associated with their selection. As described above, generation near the central part of the PEC Eastern control area has a lesser impact to transmission problems than other sites. Imports from other areas show a greater number of transmission issues than those closer to the load to be served. Any transmission results are subject to changes as other users of the system, including the transmission owners indicate their future plans. Ultimately, NCEMC will request the transmission providers will perform generation interconnection studies that will confirm the results of NCEMC analysis and identify the appropriate solutions and their associated costs.

The timeline of NCEMC's identified resource needs makes new transmission capacity a problematic solution to which generation capacity expansion within the PEC Eastern control area a more favorable outcome.

4.9 Capacity Alternatives Summary

NCEMC went through a two-step process to analyze the alternatives to meet its load requirements. The first step was a screening analysis on the various alternatives. Demand-side and supply-side alternatives were screened. Several alternatives were eliminated from consideration during this initial screening due to: 1) Economics, 2) Scale considerations, 3) Reliability concerns and/or 4) Technical/operational feasibility. One alternative that was eliminated was distributed generation. This was due to economic and scale considerations. However, NCEMC remains committed to work with others who have expressed an interest in distributed generation. These are entities that have issues other than the economic generation of electricity to consider – such as reliability concerns (where there must be a constant source of power) or environmental concerns (such as controlling agricultural waste through conversion to power).

The alternatives that remained were largely conventional. To analyze these alternatives further, in April 2003 NCEMC issued RFP 1009 requesting up to 1000 MW of capacity. Through a detailed economic screening process, NCEMC narrowed the responses down to two combustion turbine build/ownership alternatives and one power purchase agreement alternative.

One of the build/ownership alternatives selected was unusual in nature. This type of proposal (referred to by NCEMC as a "Wrap") involved NCEMC owning capacity in the form of F class CTs. The responder utility was to provide engineering, procurement, and

construction services for the complete project, and would dispatch the plant to meet its load requirements. In return, NCEMC would purchase system firm energy from the responder utility. The system firm power that NCEMC would purchase would have provided greater operational flexibility than the actual generating units that NCEMC would own. For example, a lower minimum run-time and better hourly dispatching flexibility were available through this Wrap. Thus NCEMC would have the operating flexibility of much smaller machines while taking advantage of the lower fixed costs of the large F class turbines.

Negotiations began in earnest with each provider. As negotiations continued, it became apparent that there were major challenges with the Wrap proposal. In March 2004, the parties concluded that the Wrap alternative was no longer viable due to "common control" issues, and an alternative proposal for a 300 MW PPA was offered, which combined with NCEMC's ownership of 620 MW of combustion turbines, would provide for the NCEMC requirements. This PPA was similar to the original Wrap proposal but eliminated critical environmental permitting issues with the original proposal. This PPA also provided capacity beginning in 2005 through 2007, replacing NCEMC's expired purchased power contract until such time as NCEMC's planned combustion turbines become commercially operable.

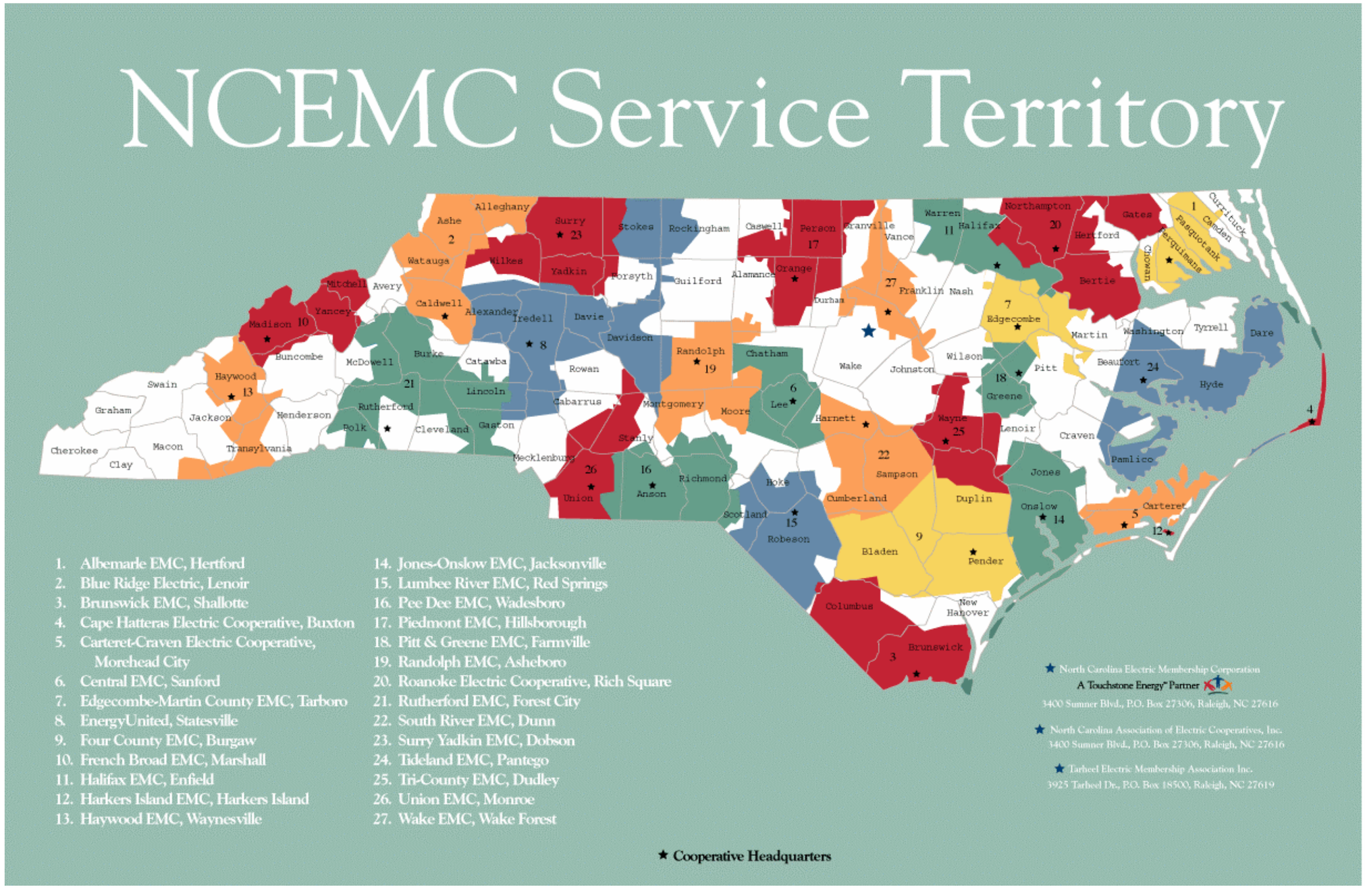
The economics of the ownership/PPA alternative showed that NCEMC would continue to realize the benefits of the build/ownership alternative through 2024, while eliminating some of the risks of all ownership through the PPA.

The NCEMC system is clearly in need of peaking capacity to meet the load requirements of the NCEMC Participating Members' native load. The capacity additions associated with the ownership/PPA proposal will result in NCEMC meeting their future requirements through the year 2009, without acquiring a surplus of capacity. The location of NCEMC's load in a transmission constrained control area contributes to the need to locate this capacity within the control area where the load resides. The RFP process that NCEMC underwent was a rigorous process that encompassed a considerable number of alternatives. The Projects that were selected through this process will provide the NCEMC Members with resources that are economic and effective.

5 Conclusion

After carefully weighing the risks and the cost/benefits, NCEMC decided that building combustion turbine generation at two different sites coupled with a power purchase agreement is the most economical way to provide a reliable, integrated source of power to meet its needs.

6 Appendix


NCEMC Service Territory
Alleghany
Ashe
Surry
Stokes
Rockingham
Caswell
Person
Granville
Vance
Warren
Halifax
Northampton
Gates
Currituck
Camden
Pasquotank
Perquimans
Chowan
Watauga
Wilkes
Yadkin
Forsyth
Guilford
Alamance
Orange
Durham
Franklin
Nash
Bertie
Hertford
Mitchell
Avery
Yancey
Caldwell
Alexander
Iredell
Davie
Davidson
Randolph
Chatham
Wake
Johnston
Wilson
Edgecombe
Martin
Washington
Tyrrell
Dare
Madison
Buncombe
McDowell
Burke
Catawba
Rowan
Haywood
Swain
Graham
Jackson
Henderson
Rutherford
Polk
Cleveland
Lincoln
Gaston
Cabarrus
Montgomery
Moore
Lee
Harnett
Greene
Pitt
Beaufort
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Wayne
Lenoir
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Pamlico
Cherokee
Clay
Macon
Transylvania
Mecklenburg
Stanly
Union
Anson
Richmond
Hoke
Scotland
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Cumberland
Sampson
Duplin
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Onslow
Carteret
Bladen
Pender
Columbus
New Hanover
Brunswick
1. Albemarle EMC, Hertford
2. Blue Ridge Electric, Lenoir
3. Brunswick EMC, Shallotte
4. Cape Hatteras Electric Cooperative, Buxton
5. Carteret-Craven Electric Cooperative, Morehead City
6. Central EMC, Sanford
7. Edgecombe-Martin County EMC, Tarboro
8. EnergyUnited, Statesville
9. Four County EMC, Burgaw
10. French Broad EMC, Marshall
11. Halifax EMC, Enfield
12. Harkers Island EMC, Harkers Island
13. Haywood EMC, Waynesville
14. Jones-Onslow EMC, Jacksonville
15. Lumbee River EMC, Red Springs
16. Pee Dee EMC, Wadesboro
17. Piedmont EMC, Hillsborough
18. Pitt & Greene EMC, Farmville
19. Randolph EMC, Asheboro
20. Roanoke Electric Cooperative, Rich Square
21. Rutherford EMC, Forest City
22. South River EMC, Dunn
23. Surry Yadkin EMC, Dobson
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