Duke Energy

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August 31, 1999

SEP 1999
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State Energy Office

Mr. Gary E. Walsh, Executive Director
The Public Service Commission of South Carolina
P. O. Drawer 11649
Columbia, SC 29211

Re: Docket Nos. 95-844-E and 87-223-E

Dear Mr. Walsh:

Pursuant to Section 58-33-430 of the Code of Laws of South Carolina, the Commission's Order No. 98-151, dated February 25, 1998, and Order No. 98-502, dated July 2, 1998, in Docket No. 87-223-E, I am enclosing 15 copies of the Duke Power Annual Plan.

Very truly yours,

Sally G. Helweg

Sally G. Helweg
Senior Counsel

SGH/fhb
Encl.

cc: Mr. Wayne Burdett
Mr. Philip S. Porter

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of Duke Power's Annual Report on the following parties by depositing a copy of same in the United States mail, first class postage prepaid:

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This the 31st day of August, 1999.

Sally G. Helweg

Sally G. Helweg

THE DUKE POWER ANNUAL PLAN
SEPTEMBER 1, 1999

TABLE OF CONTENTS

INTRODUCTION:

Duke has developed an annual resource plan that will meet customers' energy needs with a combination of existing generation, customer demand-side options, and short-term purchase power transactions. Duke will meet future capacity needs by assessing the supply and demand-side markets and determining the best way to acquire the needed resources.

OVERVIEW:

The Duke Power 1999 Annual Plan reflects our commitment to meeting our customers' need for a highly reliable energy supply at the lowest reasonable cost. We recognize several trends that are key drivers in the plan:

- Robust wholesale purchased power markets have developed which provide a variety of products, opportunities and risks for both planners and market participants.

- Supply-side resource costs and construction lead times have continued to decrease, making these resources more cost effective and flexible to planners.

- Customer incentives and expenses for demand-side resources continue to hamper their cost effectiveness.

The risks imposed by an increasingly competitive industry demand that companies develop flexible, low-cost resource strategies to meet customer energy needs. The Duke Power 1999 Annual Plan represents a balanced strategy which incorporates the perspectives of customers, shareholders, and the public with options for flexibility.

Changes in the utility industry such as an expanding purchase power market and the decreasing costs of new supply-side resources enable Duke to consider multiple options to meet customer energy needs reliably and at the lowest reasonable cost.

Recognizing the risks and uncertainties of the future, Duke has developed a resource acquisition strategy that allows us to meet near-term obligations in a manner that does not impose undue exposure to long-term financial burdens. Duke will review and select the most cost-effective options the market has to offer to meet customer needs in a reliable manner. Such options include purchased power options and peaking and intermediate generation technologies.

The 1999 Annual Plan incorporates a 15-year load forecast, near-term purchase power contracts, existing generation, Demand-Side Management (DSM), and peaking and intermediate generation technologies. The plan is developed with the objective of minimizing revenue requirements with a planning reserve margin of 17 percent. The annual plan includes a detailed explanation of the basis for, and a justification for the adequacy and appropriateness of, the level of projected reserve margins and a discussion of the adequacy of the transmission system.

The following information is supplied pursuant to NCUC Rules R8-60 and R8-62(p) and the NCUC Order dated July 13, 1999 in Docket No. E-100, SUB 82 as well as the PSCSC Order No. 98-151, dated February 25, 1998, Order No. 98-502, dated July 2, 1998, in Docket No. 87-223-E and Section 58-33-430 of the Code of Laws of South Carolina.

RESERVE MARGIN EXPLANATION AND JUSTIFICATION:

Reserve margins are necessary to help ensure adequate resources will be available in light of customer demand uncertainty, unit outages, and weather extremes. Appropriate levels of reserves are impacted by existing generation performance, lead times needed to acquire or develop new resources, and product availability in the purchase power market. In recent years, Duke has reduced its planning reserve margin requirements. The reduction was primarily due to increased availability of existing generation, shorter lead times for construction of new generation, and the emergence of new purchase power options. The additional flexibility of shorter lead time generation alternatives has enabled Duke to more effectively use these resources to satisfy reserve margin requirements. Reductions in planning reserves under these circumstances has allowed for a closer match between generation resource commitments and customer needs while maintaining reliability.

Based on Duke's operating experience with 19,300 MW's of existing generation, 1,200 MW's of purchase power contracts, and 1000 MW's of interruptible Demand Side Management (DSM) resources, Duke adopted a planning reserve margin target of 17 percent in 1997. As Duke nears each peak demand season, there is a greater level of certainty regarding the customer load forecast and total system capability due to near term weather conditions and greater knowledge of generation unit availability. The Duke total system capability includes the expected capacity of each generating station and the net of firm purchases less sales. Changes to the total system capability associated with seasonal capacity re-ratings and scheduled outages reveal the expected amount of sustainable generation available to meet load requirements. This capacity is then utilized in evaluating the potential exposure to DSM activations. If necessary, Duke would acquire additional capacity in the short-term power market. The adjusted system capacity, along with the Load Control DSM capability, are used to satisfy our NERC Policy 1 Reserve Requirements (see Appendix A) and contingencies such as higher than expected unavailability of generating units or increased customer load due to extreme weather conditions.

Duke continually reviews the generating system capability, level of potential DSM activations, scheduled maintenance, purchased power availability and transmission capability to assess Duke's capability to reliably meet the customer load.

For the past three years Duke Power has utilized a 17 percent planning reserve margin. During Summer peak times, there have been 15 days between June 1997 and July 1999 where generating reserves dropped below 3 percent. Generating reserves do not include purchases or DSM. When purchases and DSM are factored in, the lowest margin of actual reserves was 12 percent. From 1997, Duke has had sufficient reserves to reliably meet customer load with limited need to activate interruptible programs. The following table illustrates Duke's limited use of interruptible capacity, including the summer of 1999 through August 1. Based upon successful operations utilizing the 17 percent planning reserve margin, Duke concludes that its continued use is appropriate at this time.

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved
9/98 – 7/99	Air Conditioners	None		
9/98 – 7/99	Water Heaters	None		
9/98 – 7/99	Standby Generators	Monthly Test		
9/98 – 7/99	Interruptible Service	1 Communication Test	N/A	N/A
9/97 – 9/98	Air Conditioners	1 Load Test	180 MW	170 MW
9/97 – 9/98	Water Heaters	1 Communication Test	N/A	N/A
		1 Load Test	7 MW	7 MW
9/97 – 9/98	Standby Generators	2 Capacity Needs	68 MW	58 MW
		Monthly Test		
9/97 – 9/98	Interruptible Service	1 Communication Test	N/A	N/A
		1 Capacity Need	570 MW	500 MW
9/96 – 9/97	Air Conditioners	1 Communication Test	N/A	N/A
9/96 – 9/97	Water Heaters	None		
9/96 – 9/97	Standby Generators	4 Capacity Needs	62 MW	50 MW
		Monthly Test		
9/96 – 9/97	Interruptible Service	2 Communication Tests	N/A	N/A
		1 Capacity Need	650 MW	550 MW

TRANSMISSION SYSTEM ADEQUACY:

Duke Electric Transmission (ET) monitors the adequacy and reliability of the transmission system and its interconnections through analysis of internal transmission system models and participation in regional reliability groups. Corrective actions are planned and implemented in advance to ensure continued cost-effective high quality electric service is provided. Duke ET internal models cover the next ten years and are prepared in close coordination with Duke's resource planning and distribution personnel to accurately reflect available generating resources and load. The Duke ET internal model data is also used as input into industry models employed by regional reliability groups in their analyses.

Transmission system reliability is constantly monitored through evaluation of changes in load, generating capacity, transactions, or topography. Annually, a detailed screening of an internal model three years out is performed to identify any voltage or thermal loading violations of ET's Planning Guidelines. The screening methods are in compliance with Southeastern Electric Reliability Council (SERC) and North American Electric Reliability Council (NERC) planning guidelines. The annual screening results are used to evaluate a 10-year planning horizon that accounts for load growth, transmission reservations, and planned changes in generation and system topography. The screening results are a major input for the Transmission Asset Management Plan (TAMP). The TAMP controls the allocation of resources to ensure proper prioritization and funding of projects to maintain system reliability.

Duke ET participates in the following regional reliability groups for coordination of analysis of regional, sub-regional and inter-control area transfer capability and interconnection reliability:

1. VACAR - Virginia–Carolinas Subregion of SERC
2. VAST – VACAR, American Electric Power (AEP), Southern and the Tennessee Valley Authority (TVA)
3. VEM – VACAR, East Central Area Reliability Council (ECAR) and the Mid-Atlantic Area Council (MAAC)
4. VSTO – VACAR, Southern, TVA and Oglethorpe

Each of these reliability groups evaluates the bulk transmission system to: 1) assess the interconnected system's capability to handle large firm and non-firm transactions, 2) ensure planned future transmission system improvements do not adversely affect neighboring systems and 3) ensure the interconnected systems' compliance with selected NERC Planning Standards.

Regional reliability groups normally participate in the evaluation of transfer capability and compliance to the NERC Planning Standards for the next peak load period through the next five to ten years. The regional reliability groups perform tests at sufficiently high transfer levels to verify satisfactory transfer capability is maintained for years in advance. Duke evaluates all requests for transmission reservation for their impact on transfer capability and compliance with ET's Planning Guidelines. Studies, including transfer capability assessments, are performed to ensure transfer capability is acceptable and exceeds VACAR Reserve Sharing Agreement requirements. The VACAR Reserve Sharing Agreement ensures that all VACAR member control areas have sufficient generation to meet their largest single generation contingency. The TAMP process is also used to manage projects for improvement of transfer capability.

Duke ET's internal analyses, participation with industry reliability councils, and process for managing transmission system projects contribute to system security and reliable operation.

ANNUAL PLAN INFORMATION CONTENTS

1. LOAD FORECAST AND LOAD CAPACITY AND RESERVES (LCR) TABLE

This section includes a tabulation of summer and winter peak loads, annual energy forecast, generating capability, and reserve margins for each year, and a description of the methods and assumptions used to prepare the forecast.

THE LOAD FORECAST:

To determine customer energy needs, Duke prepares a load forecast of energy sales and peak demand using state-of-the-art econometric and end-use analytical methodologies. The current forecast includes plans for the energy needs of all new and existing customers within Duke's service territory. This requirement may change in any restructured electric industry. Currently, certain wholesale customers have the option of obtaining all or a portion of their future energy needs from suppliers other than Duke Power.

As part of the joint ownership arrangement for the Catawba Nuclear Station, the North Carolina Electric Membership Cooperative (NCEMC) and Saluda River Electric Cooperative Incorporated (SR) have given notice that they will be solely responsible for their total load requirements beginning January 1, 2001. As a result, NCEMC and SR supplemental load requirements, above their ownership portions of the Catawba Nuclear Station, are not reflected in the forecast commencing in 2001.

The current forecast over a 15-year period reflects an average annual growth in summer peak demand of 1.9 percent. Winter peaks are forecasted to grow at an average annual rate of 1.5 percent, and the average annual territorial energy is forecasted to grow at 2.1 percent. The growth rates use 1999 as the base year with 18,367 MW summer peak, 16,096 MW winter peak, and 96,261 GWH average annual territorial energy.

YEAR[4,5]	SUMMER (MW)[1]	WINTER (MW)[2]	TERRITORIAL ENERGY (GWH)[3]
2000	**18,861**	**16,431**	**98,903**
2001	**18,727**	**16,148**	**99,872**
2002	**19,126**	**16,371**	**102,171**
2003	**19,540**	**16,641**	**104,362**
2004	**20,067**	**16,966**	**106,884**
2005	**20,459**	**17,236**	**109,372**
2006	**20,952**	**17,612**	**111,861**
2007	**21,394**	**17,792**	**114,341**
2008	**21,807**	**18,081**	**116,864**
2009	**22,234**	**18,371**	**119,404**
2010	**22,712**	**18,669**	**121,904**
2011	**23,091**	**19,088**	**124,426**
2012	**23,553**	**19,421**	**126,937**
2013	**23,991**	**19,575**	**129,423**
2014	**24,507**	**20,047**	**131,934**

Note 1: Summer peak demand is for the calendar years indicated and includes the demand of the other joint owners of the Catawba Nuclear Station (CNS). Beginning on January 1, 2001 total demand above NCEMC and SR retained ownership is not included.

Note 2: Winter peak demand is for the specified years beginning in January and includes the demand of the other joint owners of the CNS. Beginning on January 1, 2001 total demand above NCEMC and SR retained ownership is not included.

Note 3: Territorial energy is the total projected energy needs of the Duke service area, including losses and unbilled sales, and the energy requirements of the other joint owners of the CNS. Beginning on January 1, 2001 total energy above NCEMC and SR retained ownership is not included.

Note 4: This forecast is not comparable to that included in the 1999 Duke Power Forecast beginning in 2001 due to removal of NCEMC and SR supplemental loads.

Note 5: The impact of energy efficiency DSM programs is accounted for in the load forecast.

Seasonal Projections of Load, Capacity, and Reserves
for Duke Power and Nantahala Power and Light
1999 Annual Plan Base Case

W = WINTER, S = SUMMER	W 99/00	S 2000	W 00/01	S 2001	W 01/02	S 2002	W 02/03	S 2003	W 03/04	S 2004	W 04/05	S 2005	W 05/06	S 2006	W 06/07	S 2007
Forecast																
1 Duke System Peak	16,431	18,861	16,148	18,727	16,371	19,126	16,641	19,540	16,966	20,067	17,236	20,459	17,612	20,952	17,792	21,394
Cumulative System Capacity																
2 Generating Capacity	19,282	19,282	19,282	19,282	19,282	19,282	19,282	19,282	19,282	19,282	19,282	19,282	19,282	19,192	19,192	19,072
3 Capacity Retirements	0	0	0	0	0	0	0	0	0	0	0	0	(90)	0	(120)	0
4 Cumulative Generating Capacity	19,282	19,282	19,282	19,282	19,282	19,282	19,282	19,282	19,282	19,282	19,282	19,282	19,192	19,192	19,072	19,072
5 Cumulative Purchase Contracts	376	1,226	976	1,226	976	976	976	976	376	376	376	376	376	376	376	376
6 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Cumulative Future Resource Additions																
Peaking/Intermediate	0	550	0	450	0	1,150	0	1,650	0	2,916	2,916	3,398	3,398	4,046	4,046	4,690
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Production Capacity	19,658	21,058	20,258	20,958	20,258	21,408	20,258	21,908	19,658	22,574	22,574	23,056	22,966	23,614	23,494	24,138
Reserves w/o DSM																
9 Generating Reserves	3,227	2,197	4,110	2,231	3,887	2,282	3,617	2,368	2,692	2,507	5,338	2,597	5,354	2,662	5,702	2,744
10 % Reserve Margin	19.6%	11.6%	25.5%	11.9%	23.7%	11.9%	21.7%	12.1%	15.9%	12.5%	31.0%	12.7%	30.4%	12.7%	32.0%	12.8%
11 % Capacity Margin	16.4%	10.4%	20.3%	10.6%	19.2%	10.7%	17.9%	10.8%	13.7%	11.1%	23.6%	11.3%	23.3%	11.3%	24.3%	11.4%
DSM																
12 Cumulative DSM Capacity	577	1,011	576	997	574	981	573	965	572	950	571	936	570	921	569	907
13 Cumulative Equivalent Capacity	20,235	22,069	20,834	21,955	20,832	22,389	20,831	22,873	20,230	23,524	23,145	23,992	23,536	24,535	24,063	25,045
Reserves w/DSM																
14 Equivalent Reserves	3,804	3,208	4,686	3,228	4,461	3,263	4,190	3,333	3,264	3,457	5,909	3,533	5,924	3,583	6,271	3,651
15 % Reserve Margin	23.2%	17.0%	29.0%	17.2%	27.2%	17.1%	25.2%	17.1%	19.2%	17.2%	34.3%	17.3%	33.6%	17.1%	35.2%	17.1%
16 % Capacity Margin	18.8%	14.5%	22.5%	14.7%	21.4%	14.6%	20.1%	14.6%	16.1%	14.7%	25.5%	14.7%	25.2%	14.6%	26.1%	14.6%

W = WINTER, S = SUMMER	W 07/08	S 2008	W 08/09	S 2009	W 09/10	S 2010	W 10/11	S 2011	W 11/12	S 2012	W 12/13	S 2013	W 13/14	S 2014
Forecast														
1 Duke System Peak	18,081	21,807	18,371	22,234	18,669	22,712	19,088	23,091	19,421	23,553	19,575	23,991	20,047	24,507
Cumulative System Capacity														
2 Generating Capacity	19,072	19,072	19,072	18,806	18,806	18,806	18,806	18,806	18,806	18,806	18,806	18,806	18,806	18,806
3 Capacity Retirements	0	0	(266)	0	0	0	0	0	0	0	0	0	0	0
4 Cumulative Generating Capacity	19,072	19,072	18,806	18,806	18,806	18,806	18,806	18,806	18,806	18,806	18,806	18,806	18,806	18,806
5 Cumulative Purchase Contracts	376	376	376	376	376	376	376	376	376	376	376	376	296	296
6 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Cumulative Future Resource Additions														
Peaking/Intermediate	4,690	5,176	5,176	5,982	5,982	6,946	6,946	7,108	7,108	7,594	7,594	8,242	8,242	9,206
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Production Capacity	24,138	24,624	24,358	25,164	25,164	26,128	26,128	26,290	26,290	26,776	26,776	27,424	27,344	28,308
Reserves w/o DSM														
9 Generating Reserves	6,057	2,817	5,987	2,930	6,495	3,416	7,040	3,199	6,869	3,223	7,201	3,433	7,297	3,801
10 % Reserve Margin	33.5%	12.9%	32.6%	13.2%	34.8%	15.0%	36.9%	13.9%	35.4%	13.7%	36.8%	14.3%	36.4%	15.5%
11 % Capacity Margin	25.1%	11.4%	24.6%	11.6%	25.8%	13.1%	26.9%	12.2%	26.1%	12.0%	26.9%	12.5%	26.7%	13.4%
DSM														
12 Cumulative DSM Capacity	569	893	568	880	569	867	568	854	569	841	570	830	571	818
13 Cumulative Equivalent Capacity	24,707	25,517	24,926	26,044	25,733	26,995	26,696	27,144	26,859	27,617	27,346	28,254	27,915	29,126
Reserves w/DSM														
14 Equivalent Reserves	6,626	3,710	6,555	3,810	7,064	4,283	7,608	4,053	7,438	4,064	7,771	4,263	7,868	4,619
15 % Reserve Margin	36.6%	17.0%	35.7%	17.1%	37.8%	18.9%	39.9%	17.6%	38.3%	17.3%	39.7%	17.8%	39.2%	18.8%
16 % Capacity Margin	26.8%	14.5%	26.3%	14.6%	27.5%	15.9%	28.5%	14.9%	27.7%	14.7%	28.4%	15.1%	28.2%	15.9%

The following notes are numbered to match the line numbers on the SEASONAL PROJECTIONS OF LOAD, CAPACITY, AND RESERVES table. All values are MW except where shown as a Percent.

1. Planning is done for the peak demand for the Duke System including Nantahala. Nantahala became a division of Duke Power August 3, 1998.

2. Generating Capacity. Capacity must be online by June 1 to be included in the available capacity for the summer peak of that year. Capacity must be online by Dec 1 to be included in the available capacity for the winter peak of that year. Includes 100 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station (2258 MW).

3. The 90 MW capacity retirement in 2006 represents the projected retirement date for CTs at Lee.
The 120 MW capacity retirement in 2007 represents the projected retirement date for CTs at Riverbend.
The 93 MW capacity retirement in 2009 represents the projected retirement date for the CTs at Buck.
The 173 MW capacity retirement in 2009 represents the projected retirement date for CTs at Dan River & Bz Rst (Wst).
The table assumes Oconee Nuclear Station will be relicensed.
All retirement dates are subject to review on an ongoing basis.

5. Purchase Contracts have several components, including the following purchases from SEPA, customer generation (COGEN), and small power producers (SPP):

	2000 +	
SEPA Purchase	225	MW
Cogeneration, Small Power Producers	71	MW

Total Firm Purchases	296	MW

Purchase of 250 MW maximum summer peak capacity from PECO began in June 1998 and ends Sept. 2001.
Cogeneration megawatts have increased due to the 80 MW Cherokee Cogen contract which began in June 1998 and ends June 2013.
Purchase of 600 MW from Dynegy begins July 1, 2000 and ends December 31, 2003.

7. Future Resource Additions represent new capacity resources or capability increases which are being considered. Neither the date of operation, the type of resource, nor the size is firm. All Future Resource Additions are uncommitted and represent capacity required to maintain a minimum planning reserve margin.

10. Reserve margin is shown for reference only.
Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand

11. Capacity margin is the industry standard term. A 14.6 percent capacity margin is equivalent to a 17.0 percent reserve margin.
Capacity Margin = (Cumulative Capacity - System Peak Demand)/Cumulative Capacity

12. Cumulative Interruptible and Direct Load Control capacity represents the demand-side management contribution toward meeting the load. The programs reflected in these numbers include dispatchable load control programs designed to be activated during capacity shortages.

2. EXISTING PLANTS IN SERVICE

This section includes a list of the existing plants in service with capacity, plant type, and location.

NAME	UNIT #	MW CAPACITY	LOCATION	PLANT TYPE
Allen	1	165	Belmont, N. C.	Fossil
Allen	2	165	Belmont, N. C.	Fossil
Allen	3	265	Belmont, N. C.	Fossil
Allen	4	275	Belmont, N. C.	Fossil
Allen	5	270	Belmont, N. C.	Fossil
Belews Creek	1	1120	Walnut Cove, N. C.	Fossil
Belews Creek	2	1120	Walnut Cove, N. C.	Fossil
Buck	3	75	Spencer, N. C.	Fossil
Buck	4	38	Spencer, N. C.	Fossil
Buck	5	128	Spencer, N. C.	Fossil
Buck	6	128	Spencer, N. C.	Fossil
Buck	7C	31	Spencer, N. C.	Combustion Turbine
Buck	8C	31	Spencer, N. C.	Combustion Turbine
Buck	9C	31	Spencer, N. C.	Combustion Turbine
Buzzard Roost	6C	22	Chappels, S. C.	Combustion Turbine
Buzzard Roost	7C	22	Chappels, S. C.	Combustion Turbine
Buzzard Roost	8C	22	Chappels, S. C.	Combustion Turbine
Buzzard Roost	9C	22	Chappels, S. C.	Combustion Turbine
Buzzard Roost	10C	18	Chappels, S. C.	Combustion Turbine
Buzzard Roost	11C	18	Chappels, S. C.	Combustion Turbine
Buzzard Roost	12C	18	Chappels, S. C.	Combustion Turbine
Buzzard Roost	13C	18	Chappels, S. C.	Combustion Turbine
Buzzard Roost	14C	18	Chappels, S. C.	Combustion Turbine
Buzzard Roost	15C	18	Chappels, S. C.	Combustion Turbine
Cliffside	1	38	Cliffside, N. C.	Fossil
Cliffside	2	38	Cliffside, N. C.	Fossil
Cliffside	3	61	Cliffside, N. C.	Fossil
Cliffside	4	61	Cliffside, N. C.	Fossil
Cliffside	5	562	Cliffside, N. C.	Fossil
Dan River	1	67	Eden, N. C.	Fossil
Dan River	2	67	Eden, N. C.	Fossil
Dan River	3	142	Eden, N. C.	Fossil
Dan River	4C	30	Eden, N. C.	Combustion Turbine
Dan River	5C	30	Eden, N. C.	Combustion Turbine
Dan River	6C	25	Eden, N. C.	Combustion Turbine
Lee	1	100	Pelzer, S. C.	Fossil
Lee	2	100	Pelzer, S. C.	Fossil
Lee	3	170	Pelzer, S. C.	Fossil
Lee	4C	30	Pelzer, S. C.	Combustion Turbine
Lee	5C	30	Pelzer, S. C.	Combustion Turbine
Lee	6C	30	Pelzer, S. C.	Combustion Turbine
Lincoln	1	75	Lowesville, N. C.	Combustion Turbine
Lincoln	2	75	Lowesville, N. C.	Combustion Turbine

Continued

EXISTING PLANTS IN SERVICE, continued

NAME	UNIT #	MW CAPACITY	LOCATION	PLANT TYPE
Lincoln	3	75	Lowesville, N. C.	Combustion Turbine
Lincoln	4	75	Lowesville, N. C.	Combustion Turbine
Lincoln	5	75	Lowesville, N. C.	Combustion Turbine
Lincoln	6	75	Lowesville, N. C.	Combustion Turbine
Lincoln	7	75	Lowesville, N. C.	Combustion Turbine
Lincoln	8	75	Lowesville, N. C.	Combustion Turbine
Lincoln	9	75	Lowesville, N. C.	Combustion Turbine
Lincoln	10	75	Lowesville, N. C.	Combustion Turbine
Lincoln	11	75	Lowesville, N. C.	Combustion Turbine
Lincoln	12	75	Lowesville, N. C.	Combustion Turbine
Lincoln	13	75	Lowesville, N. C.	Combustion Turbine
Lincoln	14	75	Lowesville, N. C.	Combustion Turbine
Lincoln	15	75	Lowesville, N. C.	Combustion Turbine
Lincoln	16	75	Lowesville, N. C.	Combustion Turbine
Marshall	1	385	Terrell, N. C.	Fossil
Marshall	2	385	Terrell, N. C.	Fossil
Marshall	3	660	Terrell, N. C.	Fossil
Marshall	4	660	Terrell, N. C.	Fossil
Riverbend	4	94	Mt. Holly, N. C.	Fossil
Riverbend	5	94	Mt. Holly, N. C.	Fossil
Riverbend	6	133	Mt. Holly, N. C.	Fossil
Riverbend	7	133	Mt. Holly, N. C.	Fossil
Riverbend	8C	30	Mt. Holly, N. C.	Combustion Turbine
Riverbend	9C	30	Mt. Holly, N. C.	Combustion Turbine
Riverbend	10C	30	Mt. Holly, N. C.	Combustion Turbine
Riverbend	11C	30	Mt. Holly, N. C.	Combustion Turbine
Catawba	1	1129	Clover, S. C.	Nuclear
Catawba	2	1129	Clover, S. C.	Nuclear
McGuire	1	1100	Cornelius, N. C.	Nuclear
McGuire	2	1100	Cornelius, N. C.	Nuclear
Oconee	1	846	Seneca, S. C.	Nuclear
Oconee	2	846	Seneca, S. C.	Nuclear
Oconee	3	846	Seneca, S. C.	Nuclear
Jocassee	1	152.5	Salem, S. C.	Pumped Storage
Jocassee	2	152.5	Salem, S. C.	Pumped Storage
Jocassee	3	152.5	Salem, S. C.	Pumped Storage
Jocassee	4	152.5	Salem, S. C.	Pumped Storage
Bad Creek	1	266.25	Salem, S. C.	Pumped Storage
Bad Creek	2	266.25	Salem, S. C.	Pumped Storage
Bad Creek	3	266.25	Salem, S. C.	Pumped Storage
Bad Creek	4	266.25	Salem, S. C.	Pumped Storage
Hydro (in various locations)		1128		Hydro

3. GENERATING UNITS UNDER CONSTRUCTION OR PLANNED

A list of generating units under construction or planned at plant locations for which property has been acquired, for which certificates have been received, or for which applications have been filed with location, capacity, plant type, and proposed date of operation included.

Duke has no generating units under construction or planned.

4. PROPOSED GENERATING UNITS AT LOCATIONS NOT KNOWN

This section includes a list of proposed generating units at locations not known with capacity, plant type, and date of operation included to the extent known.

The following table contains the recommended resource additions for maintaining the current minimum planning reserve margin through 2014. Neither the resource, date of operation, type, nor size is firm. Additionally, new resources may be a combination of short/long-term capacity purchases from the wholesale market, capacity purchase options, and building or contracting to build new generation. Near-term purchase power resources are assumed through year 2003 due to construction lead times of generating units.

CAPACITY[1] (MW)	SUPPLY SIDE RESOURCES	DATES OF OPERATION
550	Purchased Power	06/1/2000 – 09/30/2000
450	Purchased Power	06/1/2001 – 9/30/2001
1150	Purchased Power	06/1/2002 – 9/30/2002
1650	Purchased Power	06/1/2003 – 9/30/2003
2916	Peaking/Intermediate	06/01/2004
482	Peaking/Intermediate	06/01/2005
648	Peaking/Intermediate	06/01/2006
644	Peaking/Intermediate	06/01/2007
486	Peaking/Intermediate	06/01/2008
806	Peaking/Intermediate	06/01/2009
644	Peaking/Intermediate	06/01/2010
162	Peaking/Intermediate	06/01/2011
486	Peaking/Intermediate	06/01/2012
648	Peaking/Intermediate	06/01/2013
964	Peaking/Intermediate	06/01/2014

Note 1: Capacity amounts placed in service may vary due to selection of actual purchase amounts, generation technology capacity ratings, etc.

5. GENERATING UNITS PROJECTED TO BE RETIRED

This section includes a list of units projected to be retired from service with location, capacity and expected date of retirement from the system. The following table reflects decision dates for retirements or refurbishments during the planning horizon and are subject to review on an ongoing basis.

STATION	CAPACITY IN MW	LOCATION	DECISION DATE
Lee 4C	30	Pelzer, SC	12/31/2005
Lee 5C	30	Pelzer, SC	12/31/2005
Lee 6C	30	Pelzer, SC	12/31/2005
Riverbend 8C	30	Mt. Holly, NC	12/31/2006
Riverbend 9C	30	Mt. Holly, NC	12/31/2006
Riverbend 10C	30	Mt. Holly, NC	12/31/2006
Riverbend 11C	30	Mt. Holly, NC	12/31/2006
Buck 7C	31	Spencer, NC	12/31/2008
Buck 8C	31	Spencer, NC	12/31/2008
Buck 9C	31	Spencer, NC	12/31/2008
Buzzard Roost 6C	22	Chappels, SC	12/31/2008
Buzzard Roost 7C	22	Chappels, SC	12/31/2008
Buzzard Roost 8C	22	Chappels, SC	12/31/2008
Buzzard Roost 9C	22	Chappels, SC	12/31/2008
Dan River 4C	30	Eden, NC	12/31/2008
Dan River 5C	30	Eden, NC	12/31/2008
Dan River 6C	25	Eden, NC	12/31/2008

6. GENERATING UNITS WITH PLANS FOR LIFE EXTENSION

This section includes a list of units for which there are specific plans for life extension, refurbishment or upgrading. The reporting utility shall also provide the expected (or actual) date removed from service, general location, capacity rating upon return to service, expected return to service date, and a general description of work to be performed.

STATION	PRESENT RETIREMENT DATE	PROPOSED RETIREMENT DATE
OCONEE 1	2/2013	2/2033
OCONEE 2	10/2013	10/2033
OCONEE 3	7/2014	7/2034

On July 6, 1998, Duke Energy submitted an application to the Nuclear Regulatory Commission for license renewal of the three units at Oconee Nuclear Station located near Seneca, South Carolina. With renewal, the original 40 year licenses for the three units will be extended for 20 years. The 20 year extension moves the license expiration dates from 2013 for Units 1 and 2 and 2014 for Unit 3 to 2033 and 2034, respectively. Maintenance work is normally performed during regularly scheduled refueling outages. No capacity upgrades of the units are currently being planned.

7. TRANSMISSION LINES AND OTHER ASSOCIATED FACILITIES UNDER CONSTRUCTION

This section includes a list of transmission lines and other associated facilities (161 KV or over) which are under construction or for which there are specific plans including the capacity and voltage levels, location, and schedules for completion and operation.

The following table identifies construction of connection stations for three projects in Duke's transmission system.

PROJECT	VOLTAGE	LOCATION OF CONNECTION STATION	LINE CAPACITY	SCHEDULED OPERATION
Dynegy – New generation (~760MW)	230 kV	Sadler line–new connection station midway between Sadler Tie & Belews Creek Steam Station (Rockingham County)	Double circuit Belews Creek to Dynegy–478 MVA/circuit (upgrade from single circuit)	June 1, 2000
			Six wire single circuit Dynegy to Sadler Tie-956 MVA(upgrade from three wire single circuit)	June 1, 2000
SkyGen Energy LLC-New generation (~500MW)	230 kV	London Creek line-new connection station between Peach Valley and Ripp Tie, 3 miles east of Gaffney, SC (Cherokee County)	Double circuit Peach Valley to Skygen to Ripp Tie-409 MVA/circuit (No upgrade)	August 1, 2000
Carolina Power & Light – New generation (~800MW)	500 kV	Guardian line–new connection station between McGuire Nuclear Station & Pleasant Garden, ~ 29 miles from McGuire (Rowan County)	Single circuit McGuire to CP&L to Pleasant Garden – 1666 MVA (No Upgrade)	June 1, 2001

In addition, NCUC Rule R8-62(p) requires the following information for existing transmission lines:

(1) For existing lines, the information required on FERC Form 1 pages 422, 423, 424, and 425.

Please see Appendix B for Duke's 1998 FERC Form 1 pages 422, 423, 422.1, 423.1, 422.2, 423.2, 422.3, 423.3, 424 and 425.

(2) For lines under construction, the following:

a. commission docket number;
b. location of end point(s);
c. length;
d. range of right-of-way width;
e. range of tower heights;
f. number of circuits;
g. operating voltage;
h. design capacity;
i. date construction started;
j. projected in-service date.

Duke has no new transmission lines under construction.

(3) For all other proposed lines, as the information becomes available, the following:

a. county location of end point(s);
b. approximate length;
c. typical right-of-way width for proposed type of line;
d. typical tower height for proposed type of line;
e. number of circuits;
f. operating voltage;
g. design capacity;
h. estimated date for starting construction;
i. estimated in-service date.

Duke has no proposed new transmission lines.

8. GENERATION OR TRANSMISSION LINES SUBJECT TO CONSTRUCTION DELAYS

This section includes a list of any generation and associated transmission facilities under construction which have delays of over six months in the previously reported in-service dates and the major causes of such delays. Upon request from the Commission Staff, the reporting utility shall supply a statement of the economic impact of such delays.

There are no delays in the stated in-service dates.

9. DEMAND-SIDE OPTIONS AND SUPPLY-SIDE OPTIONS REFLECTED IN THE PLAN

This section includes a list of demand-side options and supply-side options reflected in the resource plan.

ENERGY EFFICIENCY DEMAND-SIDE OPTIONS:
All effects of existing energy efficiency DSM programs listed below are captured in the customer load forecast:

RESIDENTIAL SERVICE WATER HEATING - CONTROLLED/SUBMETERED

This program shifts a participating customer's water heating usage to off peak periods as determined by Duke. The program is currently available in accordance with rate Schedule WC. The customer is billed at a lower rate for all water heating energy consumption in exchange for allowing Duke to control the water heater.

EXISTING RESIDENTIAL HOUSING PROGRAM

This residential program represents Duke's activities in the existing residential market to encourage increased energy efficiency in existing residential structures. The program consists of loans for heat pumps and energy efficiency measures such as insulation, HVAC tune-up, duct sealant, etc.

Duke is currently reviewing two energy efficiency pilot programs and they are:

Special Needs Energy Products Loan
Neighborhood Revitalization Program

These residential programs represent Duke's activities in the existing residential market to encourage increased energy efficiency in existing residential structures for low income customers. The pilots are designed to determine the effect of leveraging ownership oriented rehabilitation programs with utility funds. The programs consist of loans for heat pumps and energy efficiency measures such as insulation, HVAC tune-up, duct sealant, etc.

INTERRUPTIBLE DEMAND-SIDE OPTIONS:

These existing interruptible DSM options are identified on line 12 of the Seasonal Projections of Load, Capacity, and Reserves table. The interruptible DSM Options are not included in the customer load forecast because load control contribution depends upon actuation. No new interruptible DSM programs are being considered at this time.

RESIDENTIAL LOAD CONTROL

This program is designed to provide a source of interruptible capacity to Duke at any time it encounters capacity problems. For air conditioning control, participants receive billing credits during the billing months of July through October for allowing Duke to interrupt electric service to their central air conditioning systems. For water heating control, participants receive billing credits each month for allowing Duke to interrupt electric service to their water heaters. Water heating load control was closed to new customers on January 1, 1993 in North Carolina and on February 17, 1993 in South Carolina.

STANDBY GENERATOR CONTROL

This program is designed to provide a source of interruptible capacity to Duke at any time it encounters capacity problems during the year. Participants in the program contractually agree to transfer electrical loads from the Duke source to their standby generators when so requested by Duke. The generators in this program do not operate in parallel with Duke's system and, therefore, cannot "backfeed" (or export power) into the Duke system. Participating customers receive payments for capacity and/or energy based on the amount of capacity and/or energy transferred to their generator.

INTERRUPTIBLE POWER SERVICE

This program is designed to provide a source of interruptible capacity to Duke at any time it encounters capacity problems during the year. Participants in the program contractually agree to reduce their electrical loads to specified levels when so requested by Duke. Failure to do so results in a penalty for the increment of demand which exceeds a specified level. The program has not been available to new participants since 1992.

In 1999, as of August 1, Duke has not activated any interruptible programs for capacity problems.

Projected data on the Interruptible DSM Programs are contained on the following page.

INTERRUPTIBLE DEMAND SIDE PROGRAMS DATA

Number of Customers																
	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
AC/LC	205,307	203,184	201,062	198,940	196,818	194,696	192,573	190,451	188,329	186,207	184,085	181,962	179,840	177,718	175,596	173,474
WH/LC	43,224	39,878	36,533	33,187	29,841	26,496	23,150	19,805	16,459	13,113	9,768	6,422	3,077	0	0	0
IS	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208
SG	139	142	145	148	151	154	157	160	163	166	169	172	175	178	181	184

Demand (kw)																
	1999		2000		2001		2002		2003		2004		2005		2006	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
AC/LC	383,000	0	365,000	0	349,000	0	333,000	0	316,000	0	301,000	0	285,000	0	270,000	0
WH/LC	8,000	29,000	7,000	26,000	7,000	23,000	6,000	20,000	5,000	17,000	4,000	15,000	4,000	12,000	3,000	10,000
IS	568,000	484,000	568,000	484,000	568,000	484,000	568,000	484,000	568,000	484,000	568,000	484,000	568,000	484,000	568,000	484,000
SG	70,000	66,000	71,000	67,000	73,000	69,000	74,000	70,000	76,000	72,000	77,000	73,000	79,000	75,000	80,000	76,000
Total	1,029,000	579,000	1,011,000	577,000	997,000	576,000	981,000	574,000	965,000	573,000	950,000	572,000	936,000	571,000	921,000	570,000

Demand (kw)																
	2007		2008		2009		2010		2011		2012		2013		2014	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
AC/LC	255,000	0	240,000	0	226,000	0	212,000	0	198,000	0	184,000	0	171,000	0	158,000	0
WH/LC	2,000	8,000	2,000	6,000	1,000	4,000	1,000	3,000	0	1,000	0	0	0	0	0	0
IS	568,000	484,000	568,000	484,000	568,000	484,000	568,000	484,000	568,000	484,000	568,000	484,000	568,000	484,000	568,000	484,000
SG	82,000	77,000	83,000	79,000	85,000	80,000	86,000	82,000	88,000	83,000	89,000	85,000	91,000	86,000	92,000	87,000
Total	907,000	569,000	893,000	569,000	880,000	568,000	867,000	569,000	854,000	568,000	841,000	569,000	830,000	570,000	818,000	571,000

Budget						
	1999	2000	2001	2002	2003	2004
AC/LC	$6,570,000	$6,502,000	$6,434,000	$6,366,000	$6,298,000	$6,230,000
WH/LC	$1,037,000	$957,000	$877,000	$796,000	$716,000	$636,000
IS	$21,963,000	$21,963,000	$21,963,000	$21,963,000	$21,963,000	$21,963,000
SG	$2,263,000	$2,312,000	$2,361,000	$2,410,000	$2,458,000	$2,507,000

Note: Only includes credits paid to customers.

Energy (kwh)	
AC/LC	None
WH/LC	None
IS	None
SG	None

Target Market Segment	
AC/LC	Residential
WH/LC	Residential
IS	Commercial & Industrial
SG	Commercial & Industrial

9. **DEMAND-SIDE OPTIONS AND SUPPLY-SIDE OPTIONS REFLECTED IN THE PLAN, continued**

The Supply-Side Options selected for the expansion plan are subjected to a two phase screening process (cost-benefit analysis) to determine cost effective supply side technologies. An initial screen identifies the most viable supply-side technologies. The selected options are then allowed to compete against each technology's capital and operational costs as they interact in a computer simulated system.

Initial Supply-Side screening results:

Conventional Technologies: (technologies in common use)
162 MW Combustion Turbine
482 MW Combined Cycle
600 MW Conventional Fossil
400 MW Gas Fired Boiler
1600 MW Pumped Storage

Demonstrated Technologies: (technologies with limited acceptance and not in widespread use)
20 MW Lead Acid Battery
220 MW Compressed Air Energy Storage (CAES)

The technologies that were selected by the simulation run were:

162 MW Combustion Turbine
482 MW Combined Cycle
600 MW Conventional Fossil
220 MW CAES

Of these technologies, only the 162 MW Combustion Turbine and the 482 MW Combined Cycle were chosen for developing an expansion plan. Since there are no viable sites applicable for the 220 MW CAES in the Duke Power service territory, it was not used to develop an expansion plan. The 600 MW Conventional Fossil was not selected due to the uncertainty associated with more stringent EPA emission constraints for NOX and potential global climate greenhouse gas emission constraints on coal burning facilities.

10. WHOLESALE PURCHASE POWER COMMITMENTS REFLECTED IN THE PLAN

1. Dynegy Power Corp. is constructing a gas-fired, four-unit, 760 MW generation facility in Rockingham County, NC. Duke Power has a contract to purchase 600 megawatts of capacity and energy generated by the power plant. The contract term begins July 1, 2000 and runs through the end of 2003, with options to extend through 2008.

2. Duke Power has acquired capacity purchase options of 250 MW from PECO Energy. The contract term began in June 1998 and will continue through September 2001. This contract is applicable during summer months only (June - September).

3. Duke purchases 225 MW of capacity from SEPA on an annual basis throughout the planning horizon.

4. Duke purchases 80 MW of capacity from Cherokee Cogeneration on an annual basis, through June 2013.

5. Duke expects to purchase approximately 71 MW annually from other cogeneration and small power producers as identified in Appendix C.

11. WHOLESALE POWER SALES COMMITMENTS REFLECTED IN THE PLAN

Duke provides wholesale power sales under Schedule 10A. The load requirements of Schedule 10A customers are reflected in the Seasonal Projections of Load, Capacity and Reserves table. Sales in 1998 totaled 1286 GWH as reported in Duke Energy's 1998 FERC Form 1 filing.

APPENDICES

APPENDIX A:

The following pages are the NERC Policy 1 Generation Control and Performance, Section A for Operating Reserve.

Policy 1 — Generation Control and Performance

Policy Subsections

A. Operating Reserve
B. Automatic Generation Control
C. Frequency Response and Bias
D. Time Control
E. Performance Standard

Effective Beginning Feb. 1, 1997
Compliance Expected Feb. 1, 1998

F. Inadvertent Interchange
G. Control Surveys
H. Control and Monitoring Equipment

General Criteria

Each system shall either operate a CONTROL AREA or make arrangements to be included in a Control Area operated by another system. All load, generation, and transmission operating in an Interconnection must be included within the metered boundaries of a Control Area.

A. Operating Reserve

[Appendix 1A – Area Control Error Equation]
[Performance Standard Training Document]

Criteria

Each CONTROL AREA shall operate its MW power resources to provide for a level of OPERATING RESERVE sufficient to account for such factors as errors in forecasting, generation and transmission equipment unavailability, number and size of generating units, system equipment forced outage rates, maintenance schedules, regulating requirements, and Regional and system load diversity. Following loss of resources or load, a CONTROL AREA shall take appropriate steps to reduce its AREA CONTROL ERROR to meet the Disturbance Control Standard (DCS). It shall take prompt steps to protect itself against the next contingency.

Each Region, subregion or RESERVE SHARING GROUP shall specify its operating reserve policies, including the minimum reserve requirement for the group, its allocation among members, the permissible mix of SPINNING RESERVE and non-spinning reserve, and procedure for applying operating reserve in practice, and the limitations, if any, upon the amount of interruptible load which may be included.

Requirements

1. **Operating reserve distribution.** OPERATING RESERVE shall be dispersed throughout the system and shall consider the effective use of capacity in an emergency, time required to be effective, transmission limitations, and local area requirements.

2. **Contingency review.** All Regions, subregions, RESERVE SHARING GROUPS, and CONTROL AREAS shall frequently review probable contingencies to determine the adequacy of operating reserve.

3. **Operating reserve.** Each Region, subregion, or RESERVE SHARING GROUP shall specify, and each CONTROL AREA shall provide, as a minimum, operating reserve as follows:

3.1. **Regulating reserve.** An amount of SPINNING RESERVE, responsive to AGC, which is sufficient to provide normal regulating margin, plus

3.2. **Contingency reserve.** An additional amount of OPERATING RESERVE sufficient to reduce AREA CONTROL ERROR to meet the Disturbance Control Standard following the most severe single contingency.

3.2.1. **Spinning reserve.** At least 50% of this operating reserve shall be SPINNING RESERVE, which will automatically respond to frequency deviations.

3.2.1.1. **Jointly owned generation with dynamic schedules.** CONTROL AREAS that share JOINTLY OWNED UNITS and incorporate DYNAMIC SCHEDULES or PSEUDO-TIES shall include only their share of the unit in their SPINNING RESERVE calculations.

3.2.1.2. **Jointly owned generation with fixed schedules.** CONTROL AREAS receiving their share of JOINTLY OWNED UNITS as fixed schedules should not include the jointly owned units' share(s) on which the schedules are based in their SPINNING RESERVE calculations. The CONTROL AREA in which the jointly owned unit resides may include the SPINNING RESERVES for its share of the unit.

3.2.2. **Reserve sharing group.** Each RESERVE SHARING GROUP shall comply with the Disturbance Control Standard as if it were a single CONTROL AREA. A RESERVE SHARING GROUP shall be considered in a DISTURBANCE condition any time a group member is in a DISTURBANCE condition and calls for reserves. Compliance may be demonstrated in either of the following two methods:

3.2.2.1. **Group compliance to Disturbance Control Standard.** The RESERVE SHARING GROUP reviews group ACE (or equivalent) and demonstrates compliance.

3.2.2.2. **Group member compliance to Disturbance Control Standard.** The RESERVE SHARING GROUP reviews each member's ACE in response to a call for reserves; to be in compliance each member's ACE must return to zero or to its respective pre-disturbance level within ten minutes of the start of the DISTURBANCE.

3.2.3. **RESERVE SHARING GROUP monitoring.** Each RESERVE SHARING GROUP shall monitor operating reserve availability and actual response.

3.2.4. **Reduction in SPINNING RESERVE.** The SPINNING RESERVE component may be reduced below 50% of the OPERATING RESERVE providing the Region, subregion, or reserve sharing group can demonstrate that with this reduction and upon its most severe single contingency, it will still be able to meet or exceed established Performance Standards, and not jeopardize the reliable operation of the Interconnection.

3.2.5. **INTERRUPTIBLE LOAD.** INTERRUPTIBLE LOAD may be included in the non-spinning reserve provided that it can be interrupted within ten minutes.

3.2.6. **Disturbance Control Performance Adjustment.** Each control area or reserve sharing group *not meeting the Disturbance Control Standard* during a given quarter, shall increase its Contingency Reserve obligation for the calendar quarter (offset by a month) following the evaluation. The increase shall be directly proportional to the control area's or reserve sharing group's non-compliance to the Disturbance Control Standard. (See the "Performance Standard Training Document," Section C.)

3.3. **Jointly owned generation in another CONTROL AREA.** CONTROL AREAs using fixed schedules for JOINTLY OWNED UNITS that reside outside their CONTROL AREA may include their share of the facility in their OPERATING RESERVE calculations. The OPERATING RESERVE is constrained by their share of the unit(s) capability and their share of the unit(s) ramp capability achievable over a ten-minute period. Included in the ten minutes is the time necessary to schedule the generation into the CONTROL AREA.

3.4. **Reestablishing OPERATING RESERVE.** An additional amount of reserve shall be made available as soon as practicable to aid in reestablishing this minimum OPERATING RESERVE after such reserve has been used.

B. Automatic Generation Control

[Appendix 1A – The Area Control Error (ACE) Equation]
[Performance Standard Training Document]

Criteria

Each CONTROL AREA shall operate sufficient generating capacity under automatic control to meet its obligation to continuously balance its generation and INTERCHANGE schedules to its load. It shall also provide its proper contribution to INTERCONNECTION frequency regulation.

Requirements

1. **CONTROL AREA components.** All load, generation, and transmission operating in an INTERCONNECTION must be included within the metered boundaries of a CONTROL AREA.
2. **AGC calculation.** AUTOMATIC GENERATION CONTROL (AGC) shall compare total net actual interchange to total net scheduled INTERCHANGE plus frequency bias contribution to determine the CONTROL AREA's AREA CONTROL ERROR (ACE).
3. **Regulating capability.** Each CONTROL AREA shall maintain generating regulating capability, synchronized to the INTERCONNECTION that can be increased or decreased by AGC to provide for adequate system regulation and Control Performance.
4. **Manual control.** If AGC has become inoperative, manual control shall be used to adjust generation to maintain scheduled INTERCHANGE.
5. **Regulation service.** It is the responsibility of the CONTROL AREA providing REGULATION SERVICE to notify the entity for whom it is controlling if it is unable to provide the service.

Guides

1. **AGC.** All generating units of consequential size, including JOINTLY OWNED UNITS capable of regulating, should be equipped with AGC to ensure that the CONTROL AREA can continuously balance its generation with its demand plus net scheduled INTERCHANGE.

    1.1. **Data scan rates for ACE.** Data acquisition for and calculation of ACE should occur at least every four seconds.

APPENDIX B:

The following are Duke's 1998 FERC Form 1 pages 422, 423, 422.1, 423.1, 422.2, 423.2, 422.3, 423.3, 424 and 425.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1								
2	Antioch Tie	Appalachian Power	525.00	525.00	Tower	27.65		1
3	McGuire SW	Antioch Tie	525.00	525.00	Tower	54.35		1
4	McGuire	Newport	525.00	525.00	Tower	32.26		1
5	McGuire	Pl. Garden-E. Dur-Pkwood	525.00	525.00	Tower	131.81		1
6	Newport	Rockingham	525.00	525.00	Tower	48.68		1
7	Oconee	Newport	525.00	525.00	Tower	107.92		1
8	Oconee	Norcross	525.00	525.00	Tower	22.51		1
9	Oconee	Jocassee-McGuire	525.00	525.00	Tower	140.77		1
10	Jocassee	Bad Creek	525.00	525.00	Tower	9.24		1
11	--------------------------							
12	Total 525kv Lines					575.19		9
13	--------------------------							
14								
15	Allen	Allison-Pacolet-Tiger	230.00	230.00	Tower	80.22		[illegible]
16	Allen	Beckerdite	230.00	230.00	Tower	79.89		2
17	Allen	Riverbend	230.00	230.00	Tower	12.50		2
18	Allen	Woodlawn	230.00	230.00	Tower	8.13		2
19	Antioch Tie	Wilkes Tie	230.00	230.00	Tower	4.32		2
20	Beckerdite	Pleasant Garden-Eno	230.00	230.00	Tower	71.26		2
21	Beckerdite	Rural Hall	230.00	230.00	Tower	107.03		2
22	Belews Creek	Sadler Tie	230.00	230.00	Tower	26.27		2
23	Catawba	Peacock	230.00	230.00	Tower	14.82		2
24	Central	Anderson	230.00	230.00	Tower	23.13		2
25	Cliffside	Pacolet	230.00	230.00	Tower	23.01		2
26	Cliffside	Shelby	230.00	230.00	Tower	14.12		2
27	East Durham	Parkwood	230.00	230.00	Tower	33.00		2
28	Eno Tie - East Durham	CP&L	230.00	230.00	Tower	15.80		2
29	Greenville	Shady Grove-Central	230.00	230.00	Tower/Poles	34.01		2
30	Greenville	Shiloh-Pisgah Forest	230.00	230.00	Tower	30.82		2
31	Hartwell	Anderson-Hodges	230.00	230.00	Tower	36.96		2
32	Jocassee Tie	Tuckaseegee	230.00	230.00	Tower	26.63		2
33	Lincoln CT	Longview Tie	230.00	230.00	Tower	31.22		2
34	Longview	McDowell	230.00	230.00	Tower	31.96		2
35	Marshall	Longview	230.00	230.00	Tower	29.06		2
36					TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
2515								2
2515								3
2515								4
2515								5
2515								6
2515								7
2515								8
2515								9
2515								10
	20,267,123	92,419,152	112,686,275					11
	20,267,123	92,419,152	112,686,275					12
								13
								14
954 & 1272								15
954								16
954 & 1272								17
2156								18
954 & 1272								19
954								20
954 & 2156								21
1272								22
1272								23
954								24
954								25
954								26
1272								27
1272								28
954 & 2515								29
954								30
954 & 2515								31
1272								32
795								33
954								34
1272								35
								36

Name of Respondent Duke Energy Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year of Report Dec. 31, 1998

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Marshall	Mitchell River	230.00	230.00	Tower	49.49		2
2	Marshall	Winecoff	230.00	230.00	Tower	24.36		2
3	McGuire	Harrisbg-Oakbor-Newport-Cat	230.00	230.00	Tower	139.44		[illegible]
4	McGuire SW	Lincoln CT	230.00	230.00	Tower	5.34		2
5	Mitchell	Rural Hall	230.00	230.00	Tower	43.74		2
6	Newport	Parr-Bush River	230.00	230.00	Tower	63.25		1
7	Oconee	Central	230.00	230.00	Tower	17.64		2
8	Oconee	Jocassee-Shiloh-Tiger	230.00	230.00	Tower/Poles	85.54		2
9	Pisgah Forest	Skyland	230.00	230.00	Tower	14.42		2
10	Riverbend	Lakewood (Pinoca)	230.00	230.00	Tower	10.64		2
11	Riverbend	McGuire-Marshall-Beckerdite	230.00	230.00	Tower	79.95		2
12	Riverbend	Shelby-Peach Valley-Tiger	230.00	230.00	Tower	109.42		2
13	Tiger	North Greenville	230.00	230.00	Tower	18.40		2
14	--------------------------							
15	Total 230kv Lines					1,395.79		63
16	--------------------------							
17								
18	Dan-River	Appalachian	138.00	138.00	Tower/Poles	6.50		1
19	Horseshoe Tie	Skyland CP&L	115.00	115.00	Tower/Poles	7.63		1
20	Saluda Dam	Bush River Tie	110.00	110.00	Tower	11.48		2
21	Greenwood	Clarke Hill	110.00	110.00	Wood Poles	35.76		1
22	Lake Emory Substation	Webster	161.00		Spole&Hframe	12.00		1
23	Nantahala	Marble Substation	161.00		Steel Tower	17.00		2
24	Nantahala	Santeetlah	161.00		Steel Tower	19.00		1
25	Oak Grove	Lake Emory Substation	161.00		S. Pole	7.00		1
26	Oak Grove	Nantahala	161.00		Steel Tower	14.00		2
27	Tuckaseegee Tie	Thorpe Hydro	161.00	161.00	Tower	1.40		1
28	Tuckaseegee Tie	Webster	161.00		Steel Tower	9.00		2
29	Webster	Oak Grove	161.00		Steel Tower	13.00		2
30	Thorpe	Tuckaseegee Tie	161.00		H frame	2.00		1
31	100kv Lines		100.00	100.00	Tower	3,025.25		[illegible]
32	100kv Lines		100.00	100.00	Poles	323.01		[illegible]
33	100kv Lines		100.00	100.00	Underground	1.78		[illegible]
34	--------------------------							
35	Total 100kv Lines					3,505.81		18
36					TOTAL			

Name of Respondent Duke Energy Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year of Report Dec. 31, 1998

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954								1
1272								2
954 & 1272								3
795								4
954 & 2156								5
954								6
795 & 1272								7
1272 & 2156								8
954								9
795 & 954								10
954 & 1272								11
795 & 954								12
954								13
	40,969,082	188,052,771	229,021,853					14
	40,969,082	188,052,771	229,021,853					15
								16
								17
477								18
477 & 1272								19
336								20
398								21
636	1,603,980	30,689,066	32,293,046	19,441	227,232	3,013	249,686	22
795								23
636								24
795								25
795								26
1272								27
795								28
795								29
397.5								30
								31
								32
								33
	47,128,635	281,011,550	328,140,185					34
	48,732,615	311,700,616	360,433,231	19,441	227,232	3,013	249,686	35
								36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	---------------------------							
2								
3	44kv Lines		44.00	44.00	Tower	283.97		
4	44kv Lines		44.00	44.00	Poles	2,217.99		
5	44kv Lines		44.00	44.00	Underground	0.73		1
6	Bear Creek	Thorpe	66.00		Hframe	4.00		1
7	Bryson Plant	E. Bryson Tap	66.00		Hframe	4.00		1
8	Cherokee Substation Tap	Bryson Plant	66.00		S Pole	1.00		1
9	Cherokee Substation Tap	Cherokee Substation	66.00		Spole&Hframe	4.00		1
10	Cullowee Tap	Cullowhee Substation	66.00		Spole&Hframe	1.00		1
11	Cullowee Tap	Webster	66.00		Hframe	4.00		1
12	E. Bryson Tap	E. Bryson Substation	66.00		Spole&Hframe	1.00		1
13	E. Franklin Substation	Otto Sunstation Tap	66.00		Spole&Hframe	3.00		1
14	Gateway	Cherokee Substation Tap	66.00		S pole	2.00		1
15	Glenville	Sapphire	66.00		S pole	4.00		1
16	Jenkins Branch Tap	E. Bryson Tap	66.00		Spole&Hframe	2.00		1
17	Jenkins Branch Tap	Jenkins Branch Substation	66.00		S pole			1
18	Lake Emory Substation	E. Franklin Substation	66.00		S pole	2.00		1
19	N. Franklin Substation	Lake Emory Substation	66.00		S pole	2.00		1
20	Oak Grove	Jenkins Branch Tap	66.00		Spole&Hframe	12.00		1
21	Otto Substation Tap	Otto Substation	66.00		S pole	8.00		1
22	Otto Substation Tap	S. Franklin Substation	66.00		Spole&Hframe	2.00		1
23	S. Franklin Substation	W. Franklin Substation	66.00		S pole	2.00		1
24	Tennessee Creek	Bear Creek	66.00		H frame	4.00		1
25	Thorpe	Cullowhee Tap	66.00		H frame	7.00		1
26	Thorpe	Shortoff Substation	66.00		H frame	12.00		1
27	Thorpe	Cashiers Substation	66.00		Spole&Hframe	8.00		1
28	W. Franklin Substation	N. Franklin Substation	66.00		S pole	4.00		1
29	Webster	Gateway	66.00		S pole	8.00		1
30	Webster	Sylva Substation	66.00		H frame	3.00		1
31	---------------------------							
32	Total 44kv & 66 kv Lines					2,606.69		26
33	---------------------------							
34	33kv Lines		33.00	33.00	Poles	5.46		1
35	22kv Lines		22.00	22.00	Poles	118.61		
36					TOTAL			

Name of Respondent Duke Energy Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year of Report Dec. 31, 1998

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
								2
								3
								4
								5
266.8								6
3/0								7
397.5								8
266.8								9
3/0								10
397.5								11
3/0								12
795								13
397.5								14
636								15
397.5								16
397.5								17
636								18
397.5								19
397.5								20
636								21
266.8								22
397.5								23
159								24
397.5								25
266.8								26
795	2,972,770	9,025,326	11,998,096	38,613	224,991	11,321	274,925	27
397.5								28
397.5								29
Various								30
	19,446,607	101,050,502	120,497,109					31
	22,419,377	110,075,828	132,495,205	38,613	224,991	11,321	274,925	32
								33
								34
								35
								36

Name of Respondent Duke Energy Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year of Report Dec. 31, 1998

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	13kv Lines		13.00	13.00	Poles	36.63		
2	13kv Lines		13.00	13.00	Underground	0.25		1
3	--------------------------							
4	Total 33kv & 66 Kv Lines					160.95		2
5	--------------------------							
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	8,244.43		118

Name of Respondent Duke Energy Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year of Report Dec. 31, 1998

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
								2
	565,108	3,441,963	4,007,071					3
	565,108	3,441,963	4,007,071					4
				1,652,735	11,365,893	11,526	13,030,154	5
								6
								7
								8
								9
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	132,953,305	705,690,330	838,643,635	1,710,789	11,818,116	25,860	13,554,765	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	To (b)	Line Length in Miles (c)	SUPPORTING STURCTURE Type (d)	Average Number per Miles (e)	CIRCUITS PER STURCTURE Present (f)	Ultimate (g)
1	Overhead Construction						
2	Coming Inc Tap		6.61	Pole	7.00	1	
3	Rudd Ret Tap		3.41	Tower/Pole	7.00	1	
4	Surry Yadkin EMC Del # 7		0.10	Pole	20.00	1	
5	Unifi Madison T&D Tap		2.82	Pole	12.00	2	
6	Broad River Elec Del # 15		0.78	Pole	6.00	1	
7	Mills River Ret Tap		0.02	N/A		1	
8	Cresent EMC Del # 24		0.12	Pole	33.00	1	
9	Crowders Creek Ret Tap		0.27	Pole	15.00	1	
10	Spectrum Dyed Yarns (Marion						
11	Plt) Tap		0.47	Pole	6.00	1	
12	Ball Park (White Horse) Tap		1.08	Pole	27.00	1	
13	Blue Ridge Elec Del # 24		0.07	Pole	29.00	1	
14	York Elec Del # 21 Tap		0.12	Pole	25.00	1	
15	Thorpe	Cashiers Substation	8.30	Spole&Hframe	11.00	1	1
16							
17							
18							
19							
20							
21							
22	Underground Construction:						
23	UNC Chapel Hill Del #3		1.25			1	
24							
25							
26							
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43							
44	TOTAL		25.42		198.00	15	1

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating)	LINE COST				Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Total (o)	
								1
556.5	ACSR		100	756,601	844,770	620,973	2,222,344	2
556.5	ACSR		100		361,195	126,906	488,101	3
556.5	ACSR		100	2,592	47,325	26,850	76,767	4
556.5	ACSR		100	553,218	1,199,906	399,968	2,153,092	5
556.5	ACSR		100	24,970	102,888	57,875	185,733	6
556.5	ACSR		100			33,199	33,199	7
556.5	ACSR		44		17,967	50,310	68,277	8
556.5	ACSR		44		16,235	16,978	33,213	9
								10
556.5	ACSR		44	86,452	65,465	78,868	230,785	11
2 / 0	CU		44		96,777	57,517	154,294	12
556.5	ACSR		44	507	61,840	33,260	95,607	13
556.5	ACSR		44		12,218	55,636	67,854	14
795	ACSR		66	747,977	1,171,186	501,937	2,421,100	15
								16
								17
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								22
750.0	CU		100			511,606	511,606	23
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				2,172,317	3,997,772	2,571,883	8,741,972	44

APPENDIX C:

The following table is the 1999 Non-Utility Generation Status Report filed September 1999.

Duke Power
A Duke Energy Company

1999 NON-UTILITY GENERATION STATUS REPORT

NCUC Docket No. E-100, Sub. 41B
NCUC Docket No. E-100, Sub. 82

September 1, 1999

SECTION I

SECTION I: NON-UTILITY GENERATORS WHO HAVE CONTACTED DUKE POWER BUT NOT YET EXECUTED A CONTRACT

Project Number	Owner/Developer Address City State Zip	Contact Phone Plant Name Plant Location	Capacity Fuel/Technology	Status
98-01 C			Gas Fired Cogen	Initial Inquiry. Preliminary - investigating facility to provide steam & thermal energy to sunflower milling operation & heat / cooling for storage space & sales of electricity to Duke. <<INACTIVE since 11/98>>
98-02 C			Solar / Hydro Generation	Initial Inquiry. Checking into possibilities of installing solar & hydro gen. with storage batteries for a residence in Duke Service Area. <<INACTIVE since 11/98>>
98-03 C			Small Hydro	Initial Inquiry. <<INACTIVE since 11/98>>
98-04 C			Small Hydro	Initial Inquiry. <<INACTIVE since 11/98>>
98-05 C			5MW Wood-Fired Generation	Initial Inquiry. <<INACTIVE since 11/98>>

Project Number	Owner/Developer Address City State Zip	Contact Phone Plant Name Plant Location	Capacity Fuel/Technology	Status
98-06 C			Small Hydro	Initial Inquiry. <<INACTIVE since 11/98>>
98-08 C			Unknown Small Hydro	Initial Inquiry. <<INACTIVE since 11/98>>
98-09 C			Unknown Landfill Gas	Initial Inquiry. <<INACTIVE since 11/98>>
98-10 C			1-3KW Photovoltaic System	Initial Inquiry. Building house with a photovoltaic system operating in parallel with Duke - would displace purchases and sell excess energy occasionally. <<INACTIVE since 11/98>>
98-11 C			Unknown	Initial Inquiry. <<INACTIVE since 11/98>>
98-12 C			300 KW Run-of-River Hydro	Inquiry - interested in purchasing existing PP hydro facility (11/98)

Project Number	Owner/Developer Address City State Zip	Contact Phone Plant Name Plant Location	Capacity Fuel/Technology	Status
98-13 C			Unknown Small Hydro	Inquiry - info regarding small hydro operations (11/98)
98-14 C			Unknown Unknown	Initial Inquiry. (12/98)
98-15 C			4,000 KW Coal/Waste	Initial Inquiry regarding self-generation. (12/98)
98-16 C			300 KW Run-of-River Hydro	Inquiry - interested in purchasing existing PP hydro facility (12/98)
98-17 C			300 KW Run-of-River Hydro	Inquiry - interested in purchasing existing PP hydro facility (12/98)
98-18 N	Jim Horton 1800 Statesville Blvd Salisbury NC 28144	Jim Horton 704-638-0506 Idols Hydro Winston-Salem, NC	1,411 KW Run-of-River Hydro	Inquiry - interested in purchasing damaged hydro facility (12/98)

Project Number	Owner/Developer Address City State Zip	Contact Phone Plant Name Plant Location	Capacity Fuel/Technology	Status
99-01 C			250,000 KW Coal	Inquiry regarding power sales. (3/99)
99-02 C			50 KW Unknown	Initial Inquiry regarding generation of power (3/99)
99-03 C			Unknown Solar PV	Inquiry regarding residential PV systems (4/99)
99-04 C			Unknown Diesel Reciprocating	Inquiry regarding PP rates and interconnection (4/99)
99-05 C			Unknown Solar PV	Inquiry regarding residential PV systems (4/99)
99-06 C			Unknown Solar PV	Inquiry regarding residential PV systems (4/99)

Project Number	Owner/Developer Address City State Zip	Contact Phone Plant Name Plant Location	Capacity Fuel/Technology	Status
99-07 C			Unknown Unknown	Inquiry re interconnection equipment and installation (4/99)
99-08 C			Unknown Tire Burning Cogen	Initial inquiry regarding rates and procedures (5/99)
99-09 C			Unknown Solar PV	Inquiry regarding residential PV systems (5/99)
99-10 C			300 KW each Run-of-River Hydro	Inquiry - interested in abandoned hydro facility and existing PP hydro facility (6/99)
99-11 C			Unknown Landfill Gas	Initial inquiry re rates and interconnection (6/99)
99-12 C			Unknown Coal cogeneration	Initial inquiry regarding upgrading existing facility and sales to DP (7/99)

Project Number	Owner/Developer Address City State Zip	Contact Phone Plant Name Plant Location	Capacity Fuel/Technology	Status
99-13 C			Unknown Solar PV	Inquiry regarding residential PV systems (7/99)

Duke Power
A Duke Energy Company

1999 NON-UTILITY GENERATION STATUS REPORT

September 1, 1999

NCUC Docket No. E-100, Sub. 41B
NCUC Docket No. E-100, Sub. 82

SECTION II

SECTION II. NON-UTILITY GENERATORS WHO HAVE EXECUTED A CONTRACT WITH DUKE POWER BUT HAVE NOT BEGUN PRODUCING POWER

Project No.	Supplier Name Address City State Zip Facility Name/Location	Contact Telephone Installed Capacity Contract Capacity	Fuel/Technology Contract Type Contract Date Contract Delivery Date	Contract Rates Contract Term Anticipated Power Production Date
1	**Mayo Hydro** 1240 Springwood Circle Gibsonville NC 27249 Mayo Dam Hydroelectric Facility	Charles C. Wood 910-449-5054 951 KW 175 KW	Run-of-River Hydroelectric Total Output 8/11/98 On or Before 3/11/01	Negotiated (NC) Fixed, Levelized 10 years On or Before 3/11/01
2	**Rockingham Power, LLC** 1000 Louisiana St., Suite 5800 Houston TX 77002 Rockingham CT Facility	Jeanne Benedetti 713-767-8629 800,000 KW 600,000 KW	Gas-fired Peaking Combustion Turbine Dispatchable 9/30/98 July 1, 2000	Negotiated (NC) Fixed Capacity Indexed Fuel 3.5 years + up to 8.5 years July 1, 2000
Terminated	**Southern Power Corporation** 4162 Maria Street Chattanooga TN 37411-1209 Old Fort Generating Plant	Michael R. Knauff 423-624-0852 5,000 KW 4,500 KW	Waste-Wood Cogeneration Total Output 3/6/96 On or Before 9/6/98	Schedule PP(NC) 15-year Fixed Ser. 4, 3rd Revised 15 years Late 1998 (est'd)

Duke Power
A Duke Energy Company

1999 NON-UTILITY GENERATION STATUS REPORT

September 1, 1999

SECTION III. NON-UTILITY GENERATORS WHO HAVE EXECUTED A CONTRACT WITH DUKE POWER AND HAVE BEGUN PRODUCING POWER (includes only facilities selling power to Duke Power)

Project Number	Supplier Name / Address / City State Zip / Facility Name/Location	Contact / Telephone / Installed Capacity / Contract Capacity	Fuel/Technology / Contract Type / Contract Date / Contract Delivery Date	Contract Rates / Initial Contract Term	Comments / Initial Power Production Date / Initial Term Expires
01	Aquenergy Systems, Inc. P.O. Box 8597 Greenville SC 29604 Apalache Hydro	Jim Fulmer 864-281-9630 X-101 420KW 420KW	Hydroelectric Total Output 2/13/98 12/29/97	Schedule PP (SC) Variable 1 year, then yearly thereafter	Owned by Consolidated Hydro Southeast, Inc. 3/15/84 12/28/97
02	Aquenergy Systems, Inc. P.O. Box 8597 Greenville SC 29604 Piedmont Hydro	Jim Fulmer 864-281-9630 X-101 1,050KW 1,050KW	Hydroelectric Total Output 2/13/98 12/29/97	Schedule PP (SC) Variable 1 year, then yearly thereafter	Owned by Consolidated Hydro Southeast, Inc. Pre-PURPA 12/28/97
03	Aquenergy Systems, Inc. P.O. Box 8597 Greenville SC 29604 Ware Shoals Hydro	Jim Fulmer 864-281-9630 X-101 6,300KW 6,300KW	Hydroelectric Total Output 2/13/98 12/29/97	Schedule PP (SC) Variable 1 year, then yearly thereafter	Owned by Consolidated Hydro Southeast, Inc. Pre-PURPA 12/28/97
04	Aquenergy Systems, Inc. P.O. Box 8597 Greenville SC 29604 Woodside I Hydro	Jim Fulmer 864-281-9630 X-101 450KW 450KW	Hydroelectric Total Output 2/13/98 12/29/97	Schedule PP (SC) Variable 1 year, then yearly thereafter	Owned by Consolidated Hydro Southeast, Inc. 12/29/83 12/28/97
05	Aquenergy Systems, Inc. P.O. Box 8597 Greenville SC 29604 Woodside II Hydro	Jim Fulmer 864-281-9630 X-101 500KW 500KW	Hydroelectric Total Output 2/13/98 12/29/97	Schedule PP (SC) Variable 1 year, then yearly thereafter	Owned by Consolidated Hydro Southeast, Inc. 12/29/83 12/28/97

Project Number	Supplier Name Address City State Zip Facility Name/Location			Contact Telephone Installed Capacity Contract Capacity	Fuel/Technology Contract Type Contract Date Contract Delivery Date	Contract Rates Initial Contract Term	Comments Initial Power Production Date Initial Term Expires
06	**Avalon Hydro** 1240 Springwood Church Road Gibsonville Avalon Hydro	NC	27249	Timothy H. Henderson 910-449-5054 1,275KW 212KW	Hydroelectric Total Output 12/27/94 4/26/97	Schedule PP (NC) 15-year Fixed Ser.4, 1st Revised 15 years	Formerly H & H Properties. Assigned to Avalon Hydro on 8/25/98 4/26/97 4/25/12
07	**Bluestone Energy Design, Inc.** P.O. Box 181 Converse Clifton Dam #3 Hydro	SC	29329	Tim Lamb 864-579-4640 1,250KW 1,250KW	Hydroelectric Total Output 1/7/98 1/12/98	Schedule PP (SC) Variable 1 year, then yearly thereafter	Alt. Contact: Victoria Miller - 864-579-4640 7/16/85 1/11/99
08	**Bob Jones University** Wade Hampton Blvd. Greenville Bob Jones University	SC	29614	Attn: Business Office 4,500KW 2,000KW	Diesel-fired Cogen As-Available Excess 12/30/88 10/15/88	Schedule PG (SC) 5 years	10/15/88 Yearly thereafter
09	**Brushy Mountain Hydro-Electric Power Co.** Route 1, Box 383 Jackson Millersville, NC	GA	30233	J. Herb Warren/Winston Moore 404-775-5303 320KW 350KW	Hydroelectric Total Output 10/2/85 9/23/85	Schedule PP (NC) 15-year Fixed Ser.3, 7th Revised 15 years	Formerly Brushy Mt. Power Co. (Contract Assigned 2/5/90) Will go on new PPA on Sch PP-H, 15-yr rate eff. 8/14/99. 6/14/83 9/22/00
10	**Buck Creek Corporation** P.O. Box 1330 Marion Lake Tahoma Hydro	NC	28752	Bob King 704-355-3063 240KW 240KW	Hydroelectric Total Output 6/29/85 8/15/84	Schedule PP (NC) 15-year Fixed Ser.3, 6th Revised 15 years	Formerly McRay Energy, Inc. (Contract Assigned 9/15/92) 12/13/82 8/14/99
11	**Cascade Power Company** P.O. Box 1137 Brevard Brevard, NC	NC	28712	Charles Pickelshimer 704-884-9011 900KW 950KW	Hydroelectric Total Output 4/29/86 4/16/86	Schedule PP (NC) 15-year Fixed Ser.3, 10th Revised 15 years	4/16/86 4/15/01

Project Number	Supplier Name Address City State Zip Facility Name/Location			Contact Telephone Installed Capacity Contract Capacity	Fuel/Technology Contract Type Contract Date Contract Delivery Date	Contract Rates Initial Contract Term	Comments Initial Power Production Date Initial Term Expires
12	Catawba County P O Box 389 Newton Blackburn Landfill Gas Facility	 NC	 28658	Barry B. Edwards 704-465-8260 4,000KW 3,700KW	Landfill Methane Gas Total Output 6/16/97 8/23/99	Schedule PP (NC) 15-year Fixed Ser.4, 3rd Revised 15 years	8/23/99 8/22/14
13	Catawba County P O Box 389 Newton Newton Landfill Gas Facility	 NC	 28658	Barry B. Edwards 704-465-8260 2,000KW 175KW	Landfill Methane Gas Total Output 8/11/98 8/23/99	Schedule PP (NC) 15-year Fixed Ser.4, 3rd Revised 15 years	8/23/99 8/22/14
14	Cherokee County Cogeneration Partners, LLP 132 Peoples Creek Rd Gaffney Cherokee County Cogeneration	 SC	 29340	Steve Patrick 864-488-3630 X-101 100,000KW 80,000KW	Gas-Fired Combined-Cycle Cogen Total Output, up to 80 MW 8/26/94 7/1/98	Negotiated (SC) 15 years escalating	4/18/98 6/30/2013
15	Clearwater Hydro B 4 Chimney Rock Road Rutherfordton Caroleen, NC	 NC	 28139	Richard Gresham 520-473-3232 324KW 324KW	Hydroelectric Total Output 12/18/84 12/18/94	Schedule PP (NC) 15-year Fixed Ser.3, 6th Revised 15 years	8/13/85 12/17/99
16	Coltrane Mill Hydro 7023 Troy Caveness Road. Ramseur Randolph County, NC	 NC	 27316	Susan P. White 910-879-2594 60KW 60KW	Hydroelectric Total Output 8/17/83 8/16/83	Schedule PP-H (NC) Variable Yearly	Formerly Cook Industries, Inc. Initial term expired 8/15/98, extended by Duke to 3/1/99. PPA continues on Variable Rate. 8/16/83 2/15/99
17	Harden Manufacturing Co. 5265 Mallard Point Dr Lake Wylie Harden Hydro # 2 & # 3	 SC	 29710	Adrienne LaFar 552-5204 620KW 620KW	Hydroelectric Total Output 2/28/86 12/20/86	Schedule PP (NC) 15-year Fixed Ser.3, 9th Revised 15 years	12/20/85 12/19/00

Project Number	Supplier Name Address City State Zip Facility Name/Location	Contact Telephone Installed Capacity Contract Capacity	Fuel/Technology Contract Type Contract Date Contract Delivery Date	Contract Rates Initial Contract Term	Comments Initial Power Production Date Initial Term Expires
18	**Haw River Hydro Co.** P O Box 1459 Asheboro NC 27204 Haw River Hydro-Saxapahaw	William H. Lee 910-824-2008 1,500KW 1,500KW	Hydroelectric Total Output 2/25/97 1/8/97	Schedule PP (NC) 15-year Fixed Ser.4, 3rd Revised 15 years	Formerly Deep River Hydro Co. (Change eff. 1/7/93) 1/8/82 1/7/12
19	**Kannapolis Energy Partners, LLC** 220 N. Main Street, Suite 603 Greenville SC 29601 Kannapolis Power Project	Randy Perkins 864-242-4624 22,500KW 0KW	Pulverized Coal Cogeneration Total Output 2/9/96 2/14/96	Schedule PP-N (NC) Variable - Energy Only 10 years	Formally owned & operated self-generation by Fieldcrest-Cannon. Contract: ENERGY ONLY. Pre-PURPA 2/13/05
20	**Kannapolis Energy Partners, LLC** 220 N. Main Street, Suite 603 Greenville SC 29601 Spencer Power Project	Randy Perkins 864-242-4624 3,500KW 0KW	Pulverized Coal Cogeneration Total Output 3/11/97 9/2/97	Schedule PP-N (NC) Variable - Energy Only 5 years	Formally owned & operated self-generation by Fieldcrest-Cannon. Contract: ENERGY ONLY. Pre-PURPA 9/01/02
21	**Mill Shoals Hydro Company, Inc.** P.O. Box 8597 Greenville SC 29604 High Shoals Hydro	Jim Fulmer 864-281-9630 X-101 1,800KW 1,800KW	Hydroelectric Total Output 8/12/97 4/2/97	Schedule PP (NC) 15-year Fixed Ser.4, 3rd Revised 15 years	Owned by Consolidated Hydro Southeast, Inc. Formerly McBess Industries, Inc. (Contract Assigned 7/14/93) 4/2/82 4/1/12
22	**Mill Shoals Hydro Company, Inc.** P.O. Box 8597 Greenville SC 29604 Long Shoals Hydro	Jim Fulmer 864-281-9630 X-101 900KW 1,000KW	Hydroelectric Total Output 11/20/84 11/20/84	Schedule PP (NC) 15-year Fixed Ser.3, 6th Revised 15 years	Owned by Consolidated Hydro Southeast, Inc. Formerly Long Shoals Hydro Inc. (Contract Assigned 7/14/93) 6/4/85 11/19/99
23	**Northbrook Carolina Hydro, LLC** 225 W. Wacker Dr., St. 2330 Chicago IL 60606 Boyd's Mill Hydro	Mark Sundquist 312-553-2136 1,500KW 110KW	Hydroelectric Total Output 12/4/96 12/4/96	Negotiated (SC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Pre-PURPA 12/4/06, if extended by Northbrook

Project Number	Supplier Name Address City State Zip Facility Name/Location			Contact Telephone Installed Capacity Contract Capacity	Fuel/Technology Contract Type Contract Date Contract Delivery Date	Contract Rates Initial Contract Term	Comments Initial Power Production Date Initial Term Expires
24	**Northbrook Carolina Hydro, LLC** 225 W. Wacker Dr., St. 2330 Chicago Holliday's Bridge Hydro	 IL	 60606	Mark Sundquist 312-553-2136 3,500KW 2,230KW	Hydroelectric Total Output 12/4/96 12/4/96	Negotiated (SC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Pre-PURPA 12/4/06, if extended by Northbrook
25	**Northbrook Carolina Hydro, LLC** 225 W. Wacker Dr., St. 2330 Chicago Saluda Hydro	 IL	 60606	Mark Sundquist 312-553-2136 2,400KW 515KW	Hydroelectric Total Output 12/4/96 12/4/96	Negotiated (SC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Pre-PURPA 12/4/06, if extended by Northbrook
26	**Northbrook Carolina Hydro, LLC** 225 W. Wacker Dr., St. 2330 Chicago Stice Shoals Hydro	 IL	 60606	Mark Sundquist 312-553-2136 600KW 125KW	Hydroelectric Total Output 12/4/96 12/4/96	Negotiated (NC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Pre-PURPA 12/4/06, if extended by Northbrook
27	**Northbrook Carolina Hydro, LLC** 225 W. Wacker Dr., St. 2330 Chicago Spencer Mountain Hydro	 IL	 60606	Mark Sundquist 312-553-2136 640KW 560KW	Hydroelectric Total Output 12/4/96 12/4/96	Negotiated (NC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Pre-PURPA 12/4/06, if extended by Northbrook
28	**Northbrook Carolina Hydro, LLC** 225 W. Wacker Dr., St. 2330 Chicago Turner Shoals Hydro	 IL	 60606	Mark Sundquist 312-553-2136 5,500KW 3,000KW	Hydroelectric Total Output 12/4/96 12/4/96	Negotiated (NC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Pre-PURPA 12/4/06, if extended by Northbrook
29	**Pacolet River Power Co. Inc.** 5250 Clifton-Glendale Road Spartanburg Clifton No. 1 Hydro	 SC	 29307-4618	Charles B. Mierek 864-579-4405 800KW 800KW	Hydroelectric Total Output 4/19/88 3/20/86	Schedule PP (SC) Variable 5 years	3/10/82 Yearly thereafter

Project Number	Supplier Name Address City State Zip Facility Name/Location	Contact Telephone Installed Capacity Contract Capacity	Fuel/Technology Contract Type Contract Date Contract Delivery Date	Contract Rates Initial Contract Term	Comments Initial Power Production Date Initial Term Expires
30	**Pelzer Hydro Co.** P.O. Box 8597 Greenville SC 29602 Lower Pelzer Hydro	Jim Fulmer 864-281-9630 X-101 3,300KW 3,300KW	Hydroelectric Total Output 9/11/98 9/11/98	Schedule PP (SC) Variable 1 year	Owned by Consolidated Hydro Southeast, Inc. Pre-PURPA Yearly thereafter
31	**Pelzer Hydro Co.** P.O. Box 8597 Greenville SC 29602 Upper Pelzer Hydro	Jim Fulmer 864-281-9630 X-101 2,020KW 2,020KW	Hydroelectric Total Output 9/11/98 9/11/98	Schedule PP (SC) Variable 1 year	Owned by Consolidated Hydro Southeast, Inc. Pre-PURPA Yearly thereafter
32	**Pharr Yarns,Inc.** P. O. Box 1939 McAdenville NC 28101	Jim Howard 1,056KW 800KW	Hydroelectric As-Available Excess 11/25/92 11/19/92	Schedule PP-H (NC) Variable 5 years	Formerly Known as Stowe Mills, Inc. 6/12/84 11/18/97
33	**R.J. Reynolds Tobacco Company** Bowman Gray Technical Center Winston-Salem NC 27102 Tobaccoville Cogeneration Facility	Tom Casey 336-741-6224 80,000KW 52,000KW	Coal-fired Cogen Firm Excess 12/14/98 12/22/98	Negotiated (NC) Fixed Capacity Indexed Energy 5 years	7/19/85 12/31/03
34	**R.J. Reynolds Tobacco Company** Bowman Gray Technical Center Winston-Salem NC 27102 Whitaker Park Cogen Facility	Tom Casey 336-741-6224 8,500KW 8,500KW	Coal-fired Cogen Total Output 3/6/91 9/24/90	Schedule PP (NC) Variable 5 years	Terms of Contract are yearly after Initial Term Expires 9/24/90 9/23/95
35	**Salem Energy Systems, LLC** 335 W. Hanes Mill Road Winston-Salem NC 27105 Winston-Salem Gas Recovery	Robert (Bob) Biskeborn 910-776-1462 4,750KW 4,170KW	Landfill Gas-fueled Turbine Cogen Total Output 3/24/95 7/10/96	Schedule PP (NC) 15-year Fixed Ser.4, 1st Revised 15 years	Formerly Enerdyne II, LLC 7/10/96 7/10/11

Project Number	Supplier Name Address City State Zip Facility Name/Location			Contact Telephone Installed Capacity Contract Capacity	Fuel/Technology Contract Type Contract Date Contract Delivery Date	Contract Rates Initial Contract Term	Comments Initial Power Production Date Initial Term Expires
36	South Yadkin Power, Inc. 6898A Coltrane Mill Rd. Greensboro Cooleemee Dam Hydro Project	NC	27406	Lyn & Breck Bullock 704-284-4051 1,400KW 280KW	Hydroelectric Total Output 7/2/97 7/9/97	Negotiated (NC) Fixed Levelized, 5 + 5 10 years	Formerly Turbine Industries, Inc. 7/9/97 7/8/07
37	Spray Cotton Mills P O Box 3207 Eden	NC	27280-3207	Mark Bishopric 910-627-6200 500KW 500KW	Hydroelectric Total Output 11/28/94 11/3/94	Schedule PP (NC) 15-year Fixed Ser.4, 1st Revised 15 years	Pre-PURPA 11/2/09
38	The Harden Company 5265 Mallard Point Dr Lake Wylie Harden Hydro # 1	SC	29710	Adrienne LaFar 552-5204 200KW 200KW	Hydroelectric Total Output 3/11/99 2/17/99	Schedule PP-H (NC) 5-year Fixed Proposed 1st Revised 5 years	Initial term expires 3/30/98, extended by Duke to 2/17/99. Currently on Proposed PP 5-yr rate pending decision by Harden on new PPA rates. 3/31/83 2/16/04
39	Town of Lake Lure P.O. Box 2255 Lake Lure Lake Lure Hydro Facility	NC	28746	H.M. "Chuck" Place 828-625-9983 3,600KW 2,500KW	Hydroelectric Total Output 8/24/99 2/18/99	Negotiated (NC) 7-year Fixed 7 years	Pre-PURPA 2/18/2006
40	Whitney Mills 212 Range Road Kings Mountain Spartanburg, SC	NC	28086	Nelson Evans 704-739-9710 225KW 225KW	Hydroelectric Total Output 11/7/97 4/30/98	Schedule PP (SC) 5 yrs, yearly thereafter	4/30/98 4/29/03

Project Number	Supplier Name Address City State Zip Facility Name/Location	Contact Telephone Installed Capacity Contract Capacity	Fuel/Technology Contract Type Contract Date Contract Delivery Date	Contract Rates Initial Contract Term	Comments Initial Power Production Date Initial Term Expires
Cancelled	**BMW Manufacturing, Inc.** P. O. Box 11000 Spartanburg SC 29304 BMW Cogeneration Facility	Lennie Beamon, Fac.Coord. 5,000KW 5,000KW	Gas-Fired Cogen Total Output 1/27/95 2/1/95	Schedule PP (SC) Variable 10 years	Now using cogen plant for displacement purposes. 2/1/95 1/31/05
Cancelled	**FMC Corp./Lithium Div.** P O Box 3925 Gastonia NC 28053 Bessemer City Plant	 11,500KW 3,000KW	Coal Fired Cogen As-Available Excess 3/21/91 3/21/91	Schedule PG (NC) 5 years	(03/12/91 is Operation Date for 5,000 KW condensing turbine gen. add'n) Now using cogen plant for displacement purposes. 9/19/86 3/20/96
Terminated	**Northbrook Carolina Hydro, LLC** 225 W. Wacker Dr., St. 2330 Chicago IL 60606 Idols Hydro	Mark Sundquist 312-553-2136 1,411KW 163KW	Hydroelectric Total Output 12/4/96 12/4/96	Negotiated (NC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Contract terminated by agreement of both parties effective May 1, 1998 due to the destruction of the facility by fire on Febryary 8, 1998. Pre-PURPA 3/1/99
Terminated	**Preservation NC** P O Box 12338 Winston-Salem NC 27117 Glencoe Hydro	Kirk Carrison 910-798-0765 250KW 250KW	Hydroelectric Total Output 7/5/84 2/10/84	Schedule PP (NC) 15-year Fixed Ser.3, 5th Revised 15 years	Formerly Glencoe Hydroelectric Co., Inc. Purchased by Preservation NC in 1997. (Contract Assigned 2/5/90) Supplier requested termination of PPA upon expiration. effective 2/9/99. 2/10/84 2/9/99