Duke Energy

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August 31, 1998

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

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

Dear Mr. Walsh:

Pursuant to 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 Duke Power's Annual Plan.

Very truly yours,

William Larry Porter
Deputy General Counsel
Jefferson D. Griffith III
Associate General Counsel

WLP/fhb
Encl.

cc: Mr. Philip S. Porter

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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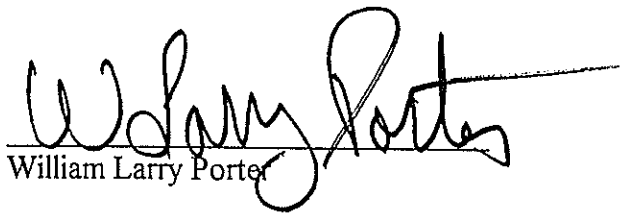
This the 31st day of August, 1998.



William Larry Porter

DUKE POWER'S ANNUAL PLAN FOR THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

SEPTEMBER 1, 1998

Docket No. 87-223-E
Docket No. 95-844-E

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Note 1: Responses correspond to issues set forth in PSCSC Order No. 98-502, Docket No. 87-223-E, July 2, 1998.

OVERVIEW:

Traditionally, utilities have built most of the generation needed to serve the loads of their regulated service territories. In South Carolina, an electric restructuring implementation process was submitted by the Public Service Commission on February 3, 1998 to the General Assembly. Restructuring would result in a competitive environment in which utilities cannot assume that the customers within their geographic boundaries will remain exclusively theirs. With this in mind, Duke has developed a plan that keeps rates competitive and offers customers innovative and valuable ways to use electricity.

While competition presents many challenges, it also presents opportunities for growth and increased customer satisfaction. Customers' energy needs will be met by 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.

THE PLAN:

The risks imposed by an increasingly competitive industry demand that companies develop flexible, low-cost resource strategies to meet customer energy needs. Duke Power's 1998 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 1998 Annual Plan incorporates a 15-year load forecast, near-term purchase power contracts, existing generation, Demand-Side Management (DSM), and peaking, intermediate, and baseload generation technologies. The plan is developed with the objective of minimizing revenue requirements with an operational planning reserve margin of 17%. The following information is supplied pursuant to PSCSC Order No. 98-502 – Docket No. 87-223-E dated July 2, 1998.

(1) A demand and energy forecast for at least a 15-year period.

THE LOAD FORECAST:

To determine customer energy needs, Duke prepares a load forecast of energy sales and peak demand using econometric and end-use analytical methodologies. The current forecast assumes that Duke will meet the energy needs of all new and existing customers within its service territory. This requirement is changing as a restructured industry evolves. 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) has given notice that it will be solely responsible for its total load requirements beginning January 1, 2001. Additionally, Saluda River Electric Cooperative Incorporated (SR), another joint owner of the Catawba Nuclear Station, has the option to be responsible for its total load requirement beginning January 1, 2001. As a result, SR supplemental load requirements above its ownership portions of the Catawba Nuclear Station are not reflected in the forecast commencing in 2001.

The current forecast over a 15-year period (shown in the following figure with the removal of NCEMC's and SR's supplemental loads beginning in 2001) predicts an average annual growth in summer peak demand of 1.6 percent. Winter peaks are forecasted to grow at an average annual rate of 1.2 percent, and the average annual territorial energy is forecasted to grow 2.1 percent. The growth rates use 1998 as the base year with 18,133 MW summer peak, 16,114 MW winter peak, and 93,376 GWH average annual territorial energy.

YEAR	SUMMER (MW)[1]	WINTER (MW)[2]	TERRITORIAL ENERGY (GWH)[3]
1999	18,244	16,420	95,982
2000	18,708	16,731	98,176
2001	18,385	16,539	99,926
2002	18,815	16,396	101,951
2003	19,215	16,628	103,984
2004	19,666	16,865	106,458
2005	19,963	17,087	108,738
2006	20,367	17,514	111,133
2007	20,666	17,634	113,562
2008	21,022	17,901	115,674
2009	21,395	18,123	117,983
2010	21,799	18,410	120,461
2011	22,144	18,778	122,944
2012	22,523	19,032	125,479
2013	22,927	19,161	128,072

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: The forecast listed above is not comparable to that included in the 1998 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.

(2) A supplier's or producer's program for meeting the requirements shown in its forecast in an economic and reliable manner, including both demand-side and supply-side options.

Annual Projections of Load, Capacity, and Reserves for Duke Power Company (values in MW)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Forecast										
1 Duke System Peak	18,244	18,708	18,385	18,815	19,215	19,666	19,963	20,367	20,666	21,022
Cumulative System Capacity										
2 Generating Capacity	19,276	19,276	19,276	19,276	19,276	19,276	19,156	19,156	19,066	18,973
3 Capacity Retirements	0	0	0	0	0	(120)	0	(90)	(93)	0
4 Cumulative Generating Capacity	19,276	19,276	19,276	19,276	19,276	19,156	19,156	19,066	18,973	18,973
5 Cumulative Purchase Contracts	632	1,232	1,232	982	982	382	382	382	382	382
6 Cumulative Sales Contracts	(400)	0	0	0	0	0	0	0	0	0
7 Cumulative Future Resource Additions										
Peaking/Intermediate	500	400	100	860	1,316	2,532	2,836	3,444	3,922	4,378
Base Load	0	0	0	0	0	0	0	0	0	0
8 Cumulative Production Capacity	20,008	20,908	20,608	21,118	21,574	22,070	22,374	22,892	23,277	23,733
Reserves w/o DSM										
9 Generating Reserves	1,764	2,200	2,223	2,303	2,359	2,404	2,411	2,525	2,611	2,711
10 % Reserve Margin	9.7%	11.8%	12.1%	12.2%	12.3%	12.2%	12.1%	12.4%	12.6%	12.9%
11 % Capacity Margin	8.8%	10.5%	10.8%	10.9%	10.9%	10.9%	10.8%	11.0%	11.2%	11.4%
DSM										
12 Cumulative DSM Capacity	994	993	990	988	987	985	983	982	980	978
13 Cumulative Equivalent Capacity	21,002	21,901	21,598	22,106	22,561	23,055	23,357	23,874	24,257	24,711
Reserves w/DSM										
14 Equivalent Reserves	2,758	3,193	3,213	3,291	3,346	3,389	3,394	3,507	3,591	3,689
15 % Reserve Margin	15.1%	17.1%	17.5%	17.5%	17.4%	17.2%	17.0%	17.2%	17.4%	17.5%
16 % Capacity Margin	13.1%	14.6%	14.9%	14.9%	14.8%	14.7%	14.5%	14.7%	14.8%	14.9%

2009	2010	2011	2012	2013
21,395	21,799	22,144	22,523	22,927
18,973	18,800	18,800	18,800	18,800
(173)	0	0	0	0
18,800	18,800	18,800	18,800	18,800
382	382	382	382	382
0	0	0	0	0
5,008	5,486	5,790	6,268	6,268
0	0	0	0	600
24,190	24,668	24,972	25,450	26,050
2,795	2,869	2,828	2,927	3,123
13.1%	13.2%	12.8%	13.0%	13.6%
11.6%	11.6%	11.3%	11.5%	12.0%
977	975	972	969	966
25,167	25,643	25,944	26,419	27,016
3,772	3,844	3,800	3,896	4,089
17.6%	17.6%	17.2%	17.3%	17.8%
15.0%	15.0%	14.6%	14.7%	15.1%

The following notes are numbered to match the line numbers on the ANNUAL 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 120 MW capacity retirement in 2004 represents the retirement decision date for CTs at Riverbend.
   The 90 MW capacity retirement in 2006 represents the retirement decision date for CTs at Lee.
   The 93 MW capacity retirement in 2007 represents the retirement decision date for the CTs at Buck.
   The 173 MW capacity retirement in 2009 represents the retirement decision date for CTs at Dan River & Bz Rst (Wst).
   Oconee Nuclear Station is assumed to 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):

	1999	+
SEPA Purchase	225	MW
Cogeneration, Small Power Producers	157	MW
Total Firm Purchases	382	MW

   Purchase of 250 MW maximum summer peak capacity from PECO begins in June 1998 and ends Sept. 2001.
   Purchase of 600 MW from Dynegy Letter of Intent begins June 1, 2000 and ends December 31, 2003.

   Cogeneration megawatts have increased due to the 80 MW Cherokee Cogen contract beginning June 1998 and ending June 2013.

6. Sales Contracts represent the following sales:

   CP&L sale (400 MW thru 6/30/99).

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.

11. Capacity margin is the industry standard term. A 14.6 percent capacity margin is equivalent to a 17.0 percent reserve margin.

12. Cumulative DSM capacity represents the demand-side management contribution toward meeting the load. The DSM programs reflected in these numbers include direct load control programs designed to be activated during capacity shortages.

(3) A brief description and summary of cost-benefit analysis, if available, of each option, which was considered, including those not selected.

SUPPLY-SIDE OPTIONS:

The Supply-Side Options selected for the expansion plan are taken through 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)
152 MW Combustion Turbine
478 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
180 MW Combustion Turbine with Inlet Air Cooling (IAC)
220 MW Compressed Air Energy Storage

The technologies that were selected by the simulation run were:

152 MW CT
180 MW CT with IAC
478 MW Combined Cycle
600 MW Conventional Fossil

Of these units only the 152 MW Combustion Turbine, 478 MW Combined Cycle, and 600 MW Conventional Fossil were chosen to generate an expansion plan. Since the 180 MW Combustion Turbine with IAC is a modification to the 152 MW Combustion Turbine it was not included in the final supply-side options.

DEMAND-SIDE OPTIONS:

All effects of energy efficiency DSM programs are captured in the customer load forecast. The DSM Options listed below are not included in the customer load forecast because load control contribution depends upon actuation:

RESIDENTIAL LOAD CONTROL - AIR CONDITIONING

This program is designed to provide a source of interruptible capacity to Duke at any time it encounters capacity problems during the cooling months of the year. 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 when capacity problems arise.

RESIDENTIAL LOAD CONTROL - WATER HEATING

This program is designed to provide a source of interruptible capacity to Duke at any time it encounters capacity problems during the year. Participants receive billing credits each month of the year for allowing Duke to interrupt electric service to their water heaters when capacity problems arise. This program was closed to new installations on January 1, 1993 in NC, and on February 17, 1993 in SC.

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.

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.

(4) The supplier's and producer's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy service, and a description of the external, environmental and economic consequences of the plan to the extent practicable.

Duke Power Company's 1998 Annual Plan reflects our commitment to meet our customers' needs 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 schedules have continued to decline, increasing their flexibility and attractiveness to planners

- Large customer incentives and expenses for demand-side resources continue to hamper their attractiveness in today's more competitive marketplace

- Duke filed a restructuring plan with the South Carolina Public Service Commission in June 1997. The Commission presented its Proposed Electric Restructuring Implementation Process to the legislature on February 3, 1998.

Duke's Annual Plan is focused on keeping costs low while maintaining the high reliability our customers expect. The Plan targets approximately a 17% operational planning reserve margin, achieved through a mix of supply-side and demand-side resources.