

Attachment M

The Duke Power Annual Plan
September 1, 2000

THE DUKE POWER ANNUAL PLAN
SEPTEMBER 1, 2000

TABLE OF CONTENTS

INTRODUCTION	2
Overview	2
Reserve Margin explanation and justification	3
Transmission System Adequacy	6
Customers Served Under Economic Development Rates	9
ANNUAL PLAN INFORMATION CONTENTS	
1 Load Forecast and Load Capacity and Reserves (LCR) Table.	10
2 Existing Plants in Service.	16
3 Generating Units Under Construction or Planned	18
4 Proposed Generating Units at Locations Not Known	19
5 Generating Units Projected to be Retired.	20
6 Generating Units With Plans for Life Extension	21
7 Transmission Lines and Other Associated Facilities Under Construction	22
8 Generation or Transmission Lines Subject to Construction Delays	24
9 Demand-Side Options and Supply-Side Options Reflected in the Plan ..	25
10 Wholesale Purchase Power Commitments Reflected in the Plan	29
11 Wholesale Power Sales Commitments Reflected in the Plan	30
APPENDICES	31

INTRODUCTION:

Duke has developed an annual resource plan that will meet customers' energy needs with a combination of existing generation, customer demand-side options, short-term purchase power transactions, and self-build options. 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 2000 Annual Plan reflects commitment to meeting customers' need for a highly reliable energy supply at the lowest reasonable cost. Duke recognizes 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 continue to make these resources cost effective and flexible options for planners.
- Customer incentives and expenses for demand-side resources continue to hamper their cost effectiveness.

The risks imposed and opportunities presented by an increasingly competitive industry demand that companies develop flexible resource portfolio strategies to meet customer energy needs in a reliable and cost-effective manner. The Duke Power 2000 Annual Plan represents a balanced strategy which incorporates the perspectives of customers, shareholders, and the public with options for flexibility.

The market for purchase power contracts has continued to expand and improve. Purchase power and self-build supply side resources are viable, complementary strategies for meeting 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 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 self-build peaking and intermediate generation technologies.

The 2000 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 order dated June 21, 2000 in Docket No. E-100, Sub 84, 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 considering 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 approximately 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 Duke's NERC Policy 1 Reserve Requirements (see Appendix A) and contingencies. Contingencies include events such as higher than expected unavailability of generating units and 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 four years Duke Power has utilized a 17 percent planning reserve margin. Between June 1998 and July 2000, there have been 15 days where generating reserves dropped below 3 percent. Generating reserves do not include purchases or DSM. When purchases and DSM are added to generating reserves, the lowest margin of 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 2000 through July 31. Based upon successful operations utilizing the 17 percent planning reserve margin, Duke concludes that its continued use is appropriate at this time.

<u>Time Frame</u>	<u>Program</u>	<u>Times Activated</u>	<u>Reduction Expected</u>	<u>Reduction Achieved</u>
7/99 – 8/00	Air Conditioners	1 Load Test	170 – 200 MW	175 – 200 MW
7/99 – 8/00	Water Heaters	1 Load Test	6 MW	Included in Air Conditioners
7/99 – 8/00	Standby Generators	1 Capacity Need	70 MW	70 MW
		Monthly Test		
7/99 – 8/00	Interruptible Service	1 Communication Test	N/A	N/A
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 – Carolina Power & Light (CP&L), Duke Power (DP), Fayetteville Public Works Comm., North Carolina Electric Membership Corporation (NCEMC), North Carolina Eastern Municipal Power Agency (NCEMPA), North Carolina Municipal Power Agency No. 1 (NCMPA1), South Carolina Electric & Gas (SCE&G), South Carolina Public Service Authority (SCPSA), Southeastern Power Administration (SEPA), Dominion Virginia Power, and Yadkin, Inc.
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 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.

On July 18, 2000 CP&L Energy, Duke Energy and SCANA Corporation announced the formation of an independent regional transmission organization (RTO) in compliance with the Federal Energy Regulatory Commission's Order 2000. The RTO is to be known as GridSouth and would be responsible for operating and planning the transmission systems of the three companies.

Initially, the three utilities will continue to own their existing transmission networks, while the RTO assumes broad operational and planning responsibilities to ensure open and non-discriminatory access to the grid. The intent of the three companies is to create a framework that may lead to a broad, regional independent transmission company that spans the Southeast.

Historically, the three utilities have done an excellent job coordinating the planning and operation of their interconnected transmission systems to maintain a high degree of system reliability and adequacy. The formation of GridSouth, as the transmission operator for the combined transmission system, will further enhance the reliability of the interconnected systems. GridSouth will be uniquely positioned to coordinate not only the planning and operating activities of the three companies but to also coordinate the planning and operating activities with neighboring utilities and RTOs. This broader view may allow GridSouth to identify potential issues that the individual utilities previously may not have been able to identify.

The NCUC order dated June 21, 2000 in Docket No. E-100, Sub 84 required that the Annual Plan due September 1, 2000 include a discussion of efforts by the interested parties to meet and develop an efficient and responsive reporting mechanism for transmission adequacy. On August 15, 2000, CP&L, Duke, Dominion, NCEMC and the Public Staff met to discuss reporting on transmission adequacy. The utilities explained

that transmission reliability is the subject of certain assessments and reports provided periodically by the utilities to the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Council (NERC), the Department of Energy (DOE) and to the Southeastern Electric Reliability Council (SERC). The parties agreed that the utilities shall provide copies of the published reports to the Public Staff. After the Public Staff reviews the reports, the parties will have additional meetings, as necessary, in an effort to resolve this issue.

CP&L has agreed to provide to the Public Staff, on behalf of CP&L, Duke, Dominion, and NCEMC, copies of the following reports:

VST 2003 Summer Study

VACAR 2003 Reliability Study

1999 SERC Reliability Review Subcommittee Report

2000 Summer VAST Reliability Study

2000 Summer VEM Reliability Assessment

Each company's FERC Form 715 Filings from April, 2000.

CUSTOMERS SERVED UNDER ECONOMIC DEVELOPMENT

The incremental load (demand) for which customers are receiving credits under the economic development rates and/or self-generation deferral rates (Rider EC) is:

48MW For North Carolina

29MW For South Carolina

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 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), the Saluda River Electric Cooperative Incorporated (SR) and the North Carolina Municipal Power Agency #1 (NCMPA) have given notice that they will be solely responsible for their total load requirements beginning January 1, 2001. As a result, NCEMC, SR and NCMPA supplemental load requirements, above their ownership portions of the Catawba Nuclear Station, are not reflected in the forecast commencing in 2001. Likewise, Piedmont Municipal Power Agency (PMPA) has given notice that they will be solely responsible for their total load requirements beginning January 1, 2006. As a result, PMPA supplemental load requirements, above their ownership portions of the Catawba Nuclear Station, are not reflected in the forecast commencing in 2006.

The current forecast over a 15-year period reflects 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 at 1.8 percent. The growth rates use 2000 as the base year with 18,693 MW summer peak, 16,485 MW winter peak, and 98,016 GWH average annual territorial energy.

YEAR ^{4,5}	SUMMER (MW) ¹	WINTER (MW) ²	TERRITORIAL ENERGY (GWH) ³
2001	18,335	16,241	98,568
2002	18,737	16,162	100,962
2003	19,122	16,399	103,230
2004	19,543	16,658	105,507
2005	19,951	16,934	107,758
2006	20,156	17,160	109,704
2007	20,540	17,431	111,913
2008	20,946	17,711	114,093
2009	21,364	17,954	116,126
2010	21,761	18,256	118,338
2011	22,164	18,527	120,414
2012	22,574	18,777	122,397
2013	22,943	19,056	124,476
2014	23,330	19,327	126,477
2015	23,763	19,583	128,410

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, SR and NCMPPA retained ownership is not included. Also, beginning on January 1, 2006 total demand above PMPA retained ownership is not included.

Note 2: Winter peak demand includes the demand of the other joint owners of the CNS. Beginning on January 1, 2001 total demand above NCEMC, SR and NCMPPA retained ownership is not included. Also, beginning on January 1, 2006 total demand above PMPA retained ownership is not included.

Winter peak demand of 2001 is December 2000 which still includes the NCEMC, SR and NCMPPA demand above their retained ownership. Winter peak demand of 2002 does not include NCEMC, SR and NCMPPA demand above their retained ownership.

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, SR and NCMPPA retained ownership is not included. Also, beginning on January 1, 2006 total energy above PMPA retained ownership is not included.

Note 4: This forecast is not comparable to that included in the 2000 Duke Power Forecast beginning January 1, 2001 due to removal of NCEMC, SR and NCMPPA supplemental loads and beginning January 1, 2006 due to removal of PMPA 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
2000 Annual Plan Base Case**

W = WINTER, S = SUMMER

	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S
	00/01	2001	01/02	2002	02/03	2003	03/04	2004	04/05	2005	05/06	2006	06/07	2007	07/08	2008
Forecast																
1 Duke System Peak	16,241	18,335	16,162	18,737	16,399	19,122	16,658	19,543	16,934	19,951	17,160	20,156	17,431	20,540	17,711	20,946
Cumulative System Capacity																
2 Generating Capacity	19,290	19,357	19,290	19,357	19,290	19,357	19,290	19,357	19,290	19,357	19,290	19,267	19,200	19,147	19,080	19,147
3 Capacity Retirements	0	0	0	0	0	0	0	0	0	0	(90)	0	(120)	0	0	0
4 Cumulative Generating Capacity	19,290	19,357	19,290	19,357	19,290	19,357	19,290	19,357	19,290	19,357	19,200	19,267	19,080	19,147	19,080	19,147
5 Cumulative Purchase Contracts	1,144	1,243	993	993	993	993	341	341	341	331	121	121	121	121	121	121
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	0	0	600	0	1,070	0	2,245	0	2,735	200	3,379	644	3,865	1,130	4,347
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Production Capacity	20,434	20,600	20,283	20,950	20,283	21,420	19,631	21,943	19,631	22,423	19,521	22,767	19,845	23,133	20,331	23,615
Reserves w/o DSM																
9 Generating Reserves	4,193	2,265	4,121	2,213	3,884	2,298	2,973	2,400	2,697	2,472	2,361	2,611	2,414	2,593	2,620	2,669
10 % Reserve Margin	25.8%	12.4%	25.5%	11.8%	23.7%	12.0%	17.6%	12.3%	15.9%	12.4%	13.8%	13.0%	13.8%	12.6%	14.8%	12.7%
11 % Capacity Margin	20.5%	11.0%	20.3%	10.6%	19.1%	10.7%	15.1%	10.9%	13.7%	11.0%	12.1%	11.5%	12.2%	11.2%	12.9%	11.3%
DSM																
12 Cumulative DSM Capacity	566	1,003	564	980	562	959	560	940	559	920	557	900	556	882	555	862
13 Cumulative Equivalent Capacity	21,000	21,603	20,847	21,930	20,845	22,379	20,191	22,883	20,190	23,343	20,078	23,667	20,401	24,015	20,886	24,477
Reserves w/DSM																
14 Equivalent Reserves	4,759	3,268	4,685	3,193	4,446	3,257	3,533	3,340	3,256	3,392	2,918	3,511	2,970	3,475	3,175	3,531
15 % Reserve Margin	29.3%	17.6%	29.0%	17.0%	27.1%	17.0%	21.2%	17.1%	19.2%	17.0%	17.0%	17.4%	17.0%	16.9%	17.9%	16.9%
16 % Capacity Margin	22.7%	15.1%	22.5%	14.6%	21.3%	14.6%	17.5%	14.6%	16.1%	14.5%	14.5%	14.8%	14.6%	14.5%	15.2%	14.4%

W = WINTER, S = SUMMER

	W	S	W	S	W	S	W	S	W	S	W	S	W	S
	08/09	2009	09/10	2010	10/11	2011	11/12	2012	12/13	2013	13/14	2014	14/15	2015
Forecast														
1 Duke System Peak	17,954	21,364	18,256	21,761	18,527	22,164	18,777	22,574	19,056	22,943	19,327	23,330	19,583	23,763
Cumulative System Capacity														
2 Generating Capacity	19,080	18,881	18,814	18,881	18,814	18,881	18,814	18,881	18,814	18,881	18,814	18,881	18,814	18,773
3 Capacity Retirements	(266)	0	0	0	0	0	0	0	0	0	0	0	(108)	0
4 Cumulative Generating Capacity	18,814	18,881	18,814	18,881	18,814	18,881	18,814	18,881	18,814	18,881	18,814	18,881	18,706	18,773
5 Cumulative Purchase Contracts	121	121	121	121	121	121	121	121	121	121	33	33	33	33
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	1,612	5,157	2,422	5,643	2,908	6,125	3,390	6,611	3,876	7,093	4,358	7,575	4,840	8,223
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Production Capacity	20,547	24,159	21,357	24,645	21,843	25,127	22,325	25,613	22,811	26,095	23,205	26,489	23,579	27,029
Reserves w/o DSM														
9 Generating Reserves	2,593	2,795	3,101	2,884	3,316	2,963	3,548	3,039	3,756	3,152	3,878	3,159	3,998	3,266
10 % Reserve Margin	14.4%	13.1%	17.0%	13.3%	17.9%	13.4%	18.9%	13.5%	19.7%	13.7%	20.1%	13.5%	20.4%	13.7%
11 % Capacity Margin	12.6%	11.6%	14.5%	11.7%	15.2%	11.8%	15.9%	11.9%	16.5%	12.1%	16.7%	11.9%	16.9%	12.1%
DSM														
12 Cumulative DSM Capacity	554	845	554	828	554	811	553	794	553	778	554	763	555	749
13 Cumulative Equivalent Capacity	21,101	25,004	21,911	25,473	22,397	25,938	22,878	26,407	23,364	26,873	23,759	27,252	24,134	27,778
Reserves w/DSM														
14 Equivalent Reserves	3,147	3,640	3,655	3,712	3,870	3,774	4,101	3,833	4,309	3,930	4,432	3,922	4,551	4,015
15 % Reserve Margin	17.5%	17.0%	20.0%	17.1%	20.9%	17.0%	21.8%	17.0%	22.6%	17.1%	22.9%	16.8%	23.2%	16.9%
16 % Capacity Margin	14.9%	14.6%	16.7%	14.6%	17.3%	14.5%	17.9%	14.5%	18.4%	14.6%	18.7%	14.4%	18.9%	14.5%

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).

Capacity changes are due to Summer (May - Sept) Lincoln Fogger capacity of 67MW.

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 108 MW capacity retirement in 2015 represents the projected retirement date for CTs at Buzzard Roost(GE).
Oconee Nuclear Station is relicensed.
All retirement dates are subject to review on an ongoing basis.
5. Purchase Contracts have several components:
 - A. Effective January 1, 2001, the SEPA allocation will be reduced to 72MW. This reflects self scheduling by Seneca, Greenwood, Saluda River, NCEMC, and NCMPA1. The 72MW reflects allocations for PMPA and Schedule 10A customers who continue to be served by Duke.
 - B. Piedmont Municipal Power Agency has given notice that they will be solely responsible for total load requirements beginning January 1, 2006. This reduces the SEPA allocation to 13 MW, which is attributed to Schedule 10A customers who continue to be served by Duke.
 - C. Purchase of 250 MW maximum summer peak capacity from PECO began in June 1998 and expires Sept. 2001.
 - D. Cogeneration megawatts have increased due to the 88 MW Cherokee Cogen contract which began in June 1998 and expires June 2013, and an additional 10 MW due to the firm purchase contract with the Kannapolis Energy Partners signed February 2000 and expires February 2005. The RJReynold's contract for 52MW expires December 31, 2003.
 - E. Purchase of 302 MW summer peak capacity from July 1, 2000 to May 31, 2001 from CP&L, and 151 MW from June 1, 2001 to December 31, 2005.
 - F. Purchase of 600 MW from Dynegy began July 1, 2000 and expires 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 problem situations.

2. EXISTING PLANTS IN SERVICE

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

<u>NAME</u>	<u>UNIT #</u>	<u>MW CAPACITY</u>	<u>LOCATION</u>	<u>PLANT TYPE</u>
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

Continued

EXISTING PLANTS IN SERVICE, continued

<u>NAME</u>	<u>UNIT #</u>	<u>MW CAPACITY</u>	<u>LOCATION</u>	<u>PLANT TYPE</u>
Lincoln	1	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	2	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	3	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	4	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	5	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	6	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	7	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	8	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	9	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	10	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	11	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	12	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	13	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	14	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	15	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	16	79.19	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)		1136		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 2015. 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.

CAPACITY ¹ (MW)	SUPPLY SIDE RESOURCES	DATES OF OPERATION
600	Peaking/Intermediate	06/01/2002
470	Peaking/Intermediate	06/01/2003
1175	Peaking/Intermediate	06/01/2004
490	Peaking/Intermediate	06/01/2005
644	Peaking/Intermediate	06/01/2006
486	Peaking/Intermediate	06/01/2007
482	Peaking/Intermediate	06/01/2008
810	Peaking/Intermediate	06/01/2009
486	Peaking/Intermediate	06/01/2010
482	Peaking/Intermediate	06/01/2011
486	Peaking/Intermediate	06/01/2012
482	Peaking/Intermediate	06/01/2013
482	Peaking/Intermediate	06/01/2014
648	Peaking/Intermediate	06/01/2015

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

Note 2: Duke is currently evaluating responses to its Request For Proposal (RFP) issued January 5, 2000. Potential outcomes could include self build resources, purchased power resources, or a combination of both. In early 2001, Duke may issue another RFP for resource additions.

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
Buzzard Roost 10C	18	Chappels, SC	12/31/2014
Buzzard Roost 11C	18	Chappels, SC	12/31/2014
Buzzard Roost 12C	18	Chappels, SC	12/31/2014
Buzzard Roost 13C	18	Chappels, SC	12/31/2014
Buzzard Roost 14C	18	Chappels, SC	12/31/2014
Buzzard Roost 15C	18	Chappels, SC	12/31/2014

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	ORIGINAL LICENSE EXPIRATION DATE	REVISED LICENSE EXPIRATION DATE
OCONEE 1	2/2013	2/2033
OCONEE 2	10/2013	10/2033
OCONEE 3	7/2014	7/2034

On May 23,2000, the Nuclear Regulatory Commission approved the License Renewal for all three units of the Oconee Nuclear Station located near Seneca, South Carolina. With renewal, the original 40 year licenses for the three units has been 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.

STATION	PRESENT LICENSE EXPIRATION DATE	PROPOSED LICENSE EXPIRATION DATE
McGuire 1	6/12/2021	6/12/2041
McGuire 2	3/3/2023	3/3/2043
Catawba 1	12/6/2024	12/6/2044
Catawba 2	2/24/2026	2/24/2046

In 2001, Duke Energy plans to submit an application to the Nuclear Regulatory Commission for license renewal of four additional units. The two units at McGuire Nuclear Station located near Huntersville, North Carolina and the two units at Catawba Nuclear Station located near Clover, South Carolina. With renewal, the original 40 year licenses for the four units will be extended for 20 years. The 20 year extension moves the license expiration dates from 2021 for McGuire Unit 1 and 2023 for McGuire Unit 2 to 2041 and 2043, respectively. In addition, the 20 year extension moves the license expiration dates from 2024 for Catawba Unit 1 and 2026 for Catawba Unit 2 to 2044 and 2046, 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 one connection station for a project in Duke's transmission system.

PROJECT	VOLTAGE	LOCATION OF CONNECTION STATION	LINE CAPACITY	SCHEDULED OPERATION
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 1999 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 over six months 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, central air conditioning systems, and energy efficiency measures such as insulation, HVAC tune-up, duct sealant, etc.

In the past year, Duke reviewed two energy efficiency pilot programs:

Special Needs Energy Products Loan
Neighborhood Revitalization Program

The pilots were combined into one program, Special Needs Energy Products Loan Program, effective February 24, 2000. This residential program represents Duke's activities in the existing residential market to encourage increased energy efficiency in existing residential structures for low income customers. The program consists of loans for heat pumps, central air conditioning systems, 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.

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.

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

INTERRUPTIBLE DEMAND SIDE PROGRAMS DATA

Number of Customers																
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
AC/LC	199,676	198,723	196,100	193,476	190,853	188,230	185,606	182,983	180,359	177,736	175,113	172,489	169,866	167,242	164,619	161,996
WH/LC	41,964	37,924	34,876	31,829	28,781	25,733	22,686	19,638	16,591	13,543	10,495	7,448	4,400	1,353	0	0
IS	203	203	203	203	203	203	203	203	203	203	203	203	203	203	203	203
SG	140	142	144	146	148	150	152	154	156	158	160	162	164	166	168	170

Demand (kw)																
	2000		2001		2002		2003		2004		2005		2006		2007	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
AC/LC	0	377,000	0	359,000	0	336,000	0	315,000	0	295,000	0	274,000	0	254,000	0	235,000
WH/LC	29,000	8,000	25,000	7,000	22,000	6,000	19,000	5,000	16,000	5,000	14,000	4,000	11,000	3,000	9,000	3,000
IS	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000
SG	70,000	84,000	71,000	85,000	72,000	86,000	73,000	87,000	74,000	88,000	75,000	90,000	76,000	91,000	77,000	92,000
Total	569,000	1,021,000	566,000	1,003,000	564,000	980,000	562,000	959,000	560,000	940,000	559,000	920,000	557,000	900,000	556,000	882,000

Demand (kw)																
	2008		2009		2010		2011		2012		2013		2014		2015	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
AC/LC	0	215,000	0	197,000	0	179,000	0	161,000	0	144,000	0	127,000	0	111,000	0	95,000
WH/LC	7,000	2,000	5,000	2,000	4,000	1,000	3,000	1,000	1,000	0	0	0	0	0	0	0
IS	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000
SG	78,000	93,000	79,000	94,000	80,000	96,000	81,000	97,000	82,000	98,000	83,000	99,000	84,000	100,000	85,000	102,000
Total	555,000	862,000	554,000	845,000	554,000	828,000	554,000	811,000	553,000	794,000	553,000	778,000	554,000	763,000	555,000	749,000

Budget						
	2000	2001	2002	2003	2004	2005
AC/LC	\$6,443,000	\$6,359,000	\$6,275,000	\$6,191,000	\$6,107,000	\$6,023,000
WH/LC	\$983	\$910	\$837	\$764	\$691	\$618
IS	\$20,107,000	\$20,107,000	\$20,107,000	\$20,107,000	\$20,107,000	\$20,107,000
SG	\$2,340,000	\$2,373,000	\$2,407,000	\$2,440,000	\$2,473,000	\$2,507,000
Total	\$28,890,983	\$28,839,910	\$28,789,837	\$28,738,764	\$28,687,691	\$28,637,618

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 an economic screening process to determine cost effective supply side technologies. The most viable supply-side technologies are selected.

Viable Supply-Side Options:

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 most economically attractive technologies that were selected for expansion planning analysis were:

162 MW Combustion Turbine
482 MW Combined Cycle

10. WHOLESALE PURCHASE POWER COMMITMENTS REFLECTED IN THE PLAN

1. Rockingham L.L.C. has constructed a gas-fired, five-unit, 750 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 began 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 Power has acquired capacity purchase contract of 302 MW from CP&L. The contract term begins July 1, 2000 to May 31, 2001 at 302 MW. The contract capacity then drops to 151 MW from June 1, 2001 to December 31, 2005.
4. Duke purchases 88 MW of capacity from Cherokee Cogeneration on an annual basis, through June 2013.
5. Duke expects to purchase approximately 82 MW annually from other cogeneration and small power producers as identified in Appendix C. These firm purchases will decrease over time as contracts expire.

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 1999 totaled 1347 GWH as reported in Duke Energy's 1999 FERC Form 1 filing.

