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THE DUKE POWER ANNUAL PLAN
SEPTEMBER 1, 2001

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INTRODUCTION

Duke Power, a division of Duke Energy Corp., (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 purchased 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 2001 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 resources continue to be cost effective and flexible options for planners.

- The customer incentives and expenses necessary for demand-side resources continue to hamper the cost effectiveness of these options.

The risks imposed and opportunities presented by the competitive wholesale power market demand that companies maintain flexible resource portfolio strategies to meet customer energy needs in a reliable and cost-effective manner. The Duke Power 2001 Annual Plan represents a balanced strategy which incorporates the perspectives of customers, shareholders, and the public with options for flexibility.

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 2001 Annual Plan reflects the results of Duke's Capacity Request for Proposals ("RFP") issued January 2000. The first phase of the RFP indicated that the combination of Duke's Mill Creek Combustion Turbine Station and the Carolina Power & Light (CP&L) Rowan 1 Purchased Power Contract were the most cost effective alternatives to meet Duke's 2003 capacity needs. Duke is finalizing evaluations and negotiations in the second phase of the 2000 RFP on a combination of purchased power capacity and Self Build peaking capacity to meet the capacity needs beyond 2003.

The 2001 Annual Plan incorporates a 15-year load forecast, near-term purchased 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 target planning reserve margin of 17%. 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 the North Carolina Utilities Commission (NCUC) Order dated April 4, 2001 in Docket No. E-100, Sub 88, 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 Public Service Commission of South Carolina (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 many factors including existing generation performance, lead times needed to acquire or develop new resources and product availability in the purchased power market.

In 1997, Duke adopted a planning reserve margin target of 17%. Duke adjusted its target reserve margin at that time to reflect increased availability of generation, shorter construction lead times, and the evolving market for purchased power resources. The flexibility of shorter lead time generation alternatives has enabled Duke to more effectively use these resources to satisfy reserve margin requirements. These considerations have allowed for a closer match between generation resource commitments and customer needs while maintaining reliability.

Duke's operating experience, involving approximately 19,300 MWs of existing generation, 1,200 MWs of purchased power contracts, and 900 MWs of interruptible Demand Side Management (DSM) resources, illustrates that under current conditions continuing to utilize a planning reserve margin target of 17% is appropriate. As Duke nears each peak demand season, a greater level of certainty regarding the customer load forecast and total system capability exists due to greater knowledge of near term weather conditions and 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 Interruptible 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.

As part of its justification for maintaining a 17% planning reserve margin, Duke reviews retrospectively how this planning reserve margin has performed in the past. Between June 1999 and July 2001, there has been one day where generating reserves, defined as available Duke generation plus the net of firm purchases less sales, dropped below 500 MW. When DSM is added to generating reserves, the lowest amount of reserves was 1346 MW. 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 2001 through July 31. Based upon successful operations utilizing the 17% planning reserve margin, Duke concludes that its continued use is appropriate at this time.

DEMAND SIDE MANAGEMENT ACTIVATION HISTORY

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved
8/00 – 8/01	Standby Generators	1 Capacity Need	70 MW	70 MW
7/99 – 8/00	Standby Generators	1 Capacity Need	70 MW	70 MW
9/97 – 9/98	Standby Generators	2 Capacity Needs	68 MW	58 MW
9/97 – 9/98	Interruptible Service	1 Capacity Need	570 MW	500 MW
9/96 – 9/97	Standby Generators	4 Capacity Needs	62 MW	50 MW
9/96 – 9/97	Interruptible Service	1 Capacity Need	650 MW	550 MW

DEMAND SIDE MANAGEMENT TEST HISTORY

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved
8/00– 8/01	Air Conditioners	1 Communication Test	N/A	N/A
8/00 – 8/01	Water Heaters	1 Communication Test	N/A	N/A
8/00 – 8/01	Standby Generators	Monthly Test	N/A	N/A
8/00 – 8/01	Interruptible Service	1 Communication Test	N/A	N/A
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	Monthly Test	N/A	N/A
7/99 – 8/00	Interruptible Service	1 Communication Test	N/A	N/A
9/98 – 7/99	Air Conditioners	None	N/A	N/A
9/98 – 7/99	Water Heaters	None	N/A	N/A
9/98 – 7/99	Standby Generators	Monthly Test	N/A	N/A
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	Monthly Test	N/A	N/A
9/97 – 9/98	Interruptible Service	1 Communication Test	N/A	N/A
9/96 – 9/97	Air Conditioners	1 Communication Test	N/A	N/A
9/96 – 9/97	Water Heaters	None	N/A	N/A
9/96 – 9/97	Standby Generators	Monthly Test	N/A	N/A
9/96 – 9/97	Interruptible Service	2 Communication Tests	N/A	N/A

TRANSMISSION SYSTEM ADEQUACY:

Duke 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's internal transmission models cover the next ten years and are prepared to accurately reflect available generating resources and projected load. The Duke internal transmission 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 Duke's Transmission 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 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 – 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, The Tennessee Valley Authority (TVA), Entergy, Oglethorpe, and MEAG
3. VEM – VACAR, East Central Area Reliability Council (ECAR) and the Mid-Atlantic Area Council (MAAC)
4. VST – VACAR, Southern, TVA, Entergy, Oglethorpe, and MEAG

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

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). CP&L provided 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.

In its order dated April 4, 2001 in Docket No. E-100, Sub 88, the NCUC noted that much of the transmission data recommended by the Public Staff to be included in the Transmission Adequacy sections of the Annual Plan filings is contained within the reports, but that it is not clear how difficult it would be to compile the data in the form needed for the Annual Plan filing. The NCUC further noted that SERC's report to NERC addresses the same concerns about transmission adequacy, but it does not contain the detailed data recommended by the Public Staff. The NCUC required that the parties continue their dialogue regarding an efficient and responsive reporting mechanism for transmission adequacy and complete such dialogue in time to incorporate the appropriate information in the Annual Plan filings due September 1, 2001.

In connection with this Docket and Docket No. E-100, Sub 92 (regarding Investigation of Infrastructure Necessary to Support Development of Electric Generating Capacity in North Carolina), Duke met with the Public Staff on July 6, 2001 and presented certain detailed information regarding its transmission system. The Public Staff recognizes the confidential nature of certain portions of this data. As a result of these discussions, in addition to the data required by Rule R8-60, Duke is including as Appendix D to this Annual Plan a copy of its most recent FERC Form 715 and attachments and exhibits thereto. Duke shall continue to include copies of FERC Form 715 in future Annual Plan filings. Further, in connection with future filings, Duke shall meet with the Public Staff within 30 days following the filing of its Annual Plan to present detailed information concerning its transmission line inter-tie capabilities, transmission line loading constraints and planned new construction and upgrades for the planning period under consideration provided that all confidential information is kept confidential pursuant to N.C. Gen. Stat. § 132-1.2.

Duke is involved in efforts to create an independent regional transmission organization (RTO). The FERC issued an Order on March 14, 2001 provisionally approving the application of CP&L, Duke and SCE&G to establish GridSouth Transco, LLC (GridSouth). In addition, Duke is participating in a FERC-ordered mediation to explore the formation of a Southeast-wide RTO. CP&L and Duke's application with the NCUC requesting authority to transfer functional control of their transmission assets to GridSouth is being held in abeyance pending the outcome of the mediation. CP&L, Duke, and SCE&G have a similar application pending before the PSCSC.

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:

80MW For North Carolina
16MW 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 meeting the energy needs of all new and existing customers within Duke's service territory. Currently, certain wholesale customers have the option of obtaining all or a portion of their future energy needs from suppliers other than Duke Power. This may impact long range planning by reducing the Duke obligation to serve the wholesale customer energy needs.

As part of the joint ownership arrangement for the Catawba Nuclear Station, NCEMC, the Saluda River Electric Cooperative Incorporated (SR) and NCMPA1 took sole responsibility for their supplemental load requirements beginning January 1, 2001. As a result, NCEMC, SR and NCMPA1 supplemental load requirements, above their ownership portions of the Catawba Nuclear Station, are not reflected in the forecast commencing in 2001. Piedmont Municipal Power Agency (PMPA) has given notice that they will be solely responsible for their supplemental load requirements beginning January 1, 2006. Therefore, 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 1.7%. Winter peaks are forecasted to grow at an average annual rate of 1.4%, and the average annual territorial energy need is forecasted to grow at 2.0%. The growth rates use 2001 as the base year with 18,134 MW summer peak, 16,198 MW winter peak, and 98,846 GWH average annual territorial energy need.

YEAR[1,2]	SUMMER (MW)[3]	WINTER (MW)[4]	TERRITORIAL ENERGY (GWH)[5]
2002	18,504	16,474	101,244
2003	18,872	16,750	103,638
2004	19,238	17,028	106,000
2005	19,610	17,309	108,432
2006	19,842	17,460	110,602
2007	20,204	17,726	112,923
2008	20,573	18,002	115,177
2009	20,946	18,268	117,495
2010	21,318	18,528	119,812
2011	21,688	18,794	122,062
2012	22,056	19,063	124,255
2013	22,425	19,319	126,452
2014	22,780	19,573	128,696
2015	23,143	19,829	130,857
2016	23,510	20,094	133,189

Note 1: This forecast is not the same as the one included in the 2001 Duke Power Forecast beginning January 1, 2001 due to removal of NCEMC, SR and NCMPA1 supplemental load above retained ownership and beginning January 1, 2006 due to removal of PMPA supplemental load above retained ownership.

Note 2: The impact of energy efficiency DSM programs is accounted for in the load forecast.

Note 3: Summer peak demand is for the calendar years indicated and includes a portion of the demand of the other joint owners of the Catawba Nuclear Station (CNS). Supplemental load above retained ownership for NCEMC, SR and NCMPA1 is not included. Also, beginning on January 1, 2006, supplemental load above the PMPA retained ownership is not included.

Note 4: Winter peak demand includes a portion of the demand of the other joint owners of the CNS. Supplemental load above retained ownership for NCEMC, SR and NCMPA1 is not included. Also, beginning on January 1, 2006, supplemental load above the PMPA retained ownership is not included.

Note 5: 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. Energy above NCEMC, SR and NCMPA1 retained ownership is not included. Also, beginning on January 1, 2006, energy above PMPA retained ownership is not included.

Seasonal Projections of Load, Capacity, and Reserves
for Duke Power and Nantahala Power and Light
2001 Annual Plan Base Case

W = WINTER, S = SUMMER	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
	01/02	2002	02/03	2003	03/04	2004	04/05	2005	05/06	2006	06/07	2007	07/08	2008	08/09
Forecast															
1 Duke System Peak	16,474	18,504	16,750	18,872	17,028	19,238	17,309	19,610	17,460	19,842	17,726	20,204	18,002	20,573	18,268
Cumulative System Capacity															
2 Generating Capacity	19,350	19,350	19,350	19,350	19,960	19,960	19,960	19,960	19,960	19,960	19,764	19,644	19,644	19,644	19,644
3 Capacity Additions				610											
4 Capacity Retirements	0	0	0	0	0	0	0	0	0	(196)	(120)	0	0	0	(268)
5 Cumulative Generating Capacity	19,350	19,350	19,350	19,960	19,960	19,960	19,960	19,960	19,960	19,764	19,644	19,644	19,644	19,644	19,376
6 Cumulative Purchase Contracts	993	1,144	1,144	1,144	492	492	492	482	272	272	272	121	121	121	121
7 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Future Resource Additions				(-175)											
Peaking/Intermediate	0	275	0	100	0	1,170	0	1,640	0	2,320	680	3,126	1,486	3,450	1,810
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Cumulative Production Capacity	20,343	20,769	20,494	21,204	20,452	21,622	20,452	22,082	20,232	22,356	20,596	22,891	21,251	23,215	21,307
Reserves w/o DSM															
10 Generating Reserves	3,869	2,265	3,744	2,332	3,424	2,384	3,143	2,472	2,772	2,514	2,870	2,687	3,249	2,642	3,039
11 % Reserve Margin	23.5%	12.2%	22.4%	12.4%	20.1%	12.4%	18.2%	12.6%	15.9%	12.7%	16.2%	13.3%	18.0%	12.8%	16.6%
12 % Capacity Margin	19.0%	10.9%	18.3%	11.0%	16.7%	11.0%	15.4%	11.2%	13.7%	11.2%	13.9%	11.7%	15.3%	11.4%	14.3%
DSM															
13 Cumulative DSM Capacity	470	888	468	890	466	890	465	869	464	861	463	853	462	846	461
14 Cumulative Equivalent Capacity	20,813	21,657	20,962	22,094	20,918	22,512	20,917	22,951	20,696	23,217	21,059	23,744	21,713	24,061	21,768
Reserves w/DSM															
15 Equivalent Reserves	4,339	3,153	4,212	3,222	3,890	3,274	3,608	3,341	3,236	3,375	3,333	3,540	3,711	3,488	3,500
16 % Reserve Margin	26.3%	17.0%	25.1%	17.1%	22.8%	17.0%	20.8%	17.0%	18.5%	17.0%	18.8%	17.5%	20.6%	17.0%	19.2%
17 % Capacity Margin	20.8%	14.6%	20.1%	14.6%	18.6%	14.5%	17.2%	14.6%	15.6%	14.5%	15.8%	14.9%	17.1%	14.5%	16.1%

Seasonal Projections of Load, Capacity, and Reserves
for Duke Power and Nantahala Power and Light
2001 Annual Plan Base Case

W = WINTER, S = SUMMER	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S
	2009	09/10	2010	10/11	2011	11/12	2012	12/13	2013	13/14	2014	14/15	2015	15/16	2016
Forecast															
1 Duke System Peak	20,946	18,528	21,318	18,794	21,688	19,063	22,056	19,319	22,425	19,573	22,780	19,829	23,143	20,094	23,510
Cumulative System Capacity															
2 Generating Capacity	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376
3 Capacity Additions															
4 Capacity Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Cumulative Generating Capacity	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376
6 Cumulative Purchase Contracts	121	121	121	121	121	121	121	121	121	33	33	33	33	33	33
7 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Future Resource Additions															
Peaking/Intermediate	4,256	2,616	4,742	3,102	5,066	3,426	5,548	3,908	6,030	4,390	6,516	4,876	6,998	5,358	7,322
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Cumulative Production Capacity	23,753	22,113	24,239	22,599	24,563	22,923	25,045	23,405	25,527	23,799	25,925	24,285	26,407	24,767	26,731
Reserves w/o DSM															
10 Generating Reserves	2,807	3,585	2,921	3,805	2,875	3,860	2,989	4,087	3,102	4,226	3,145	4,457	3,264	4,673	3,221
11 % Reserve Margin	13.4%	19.4%	13.7%	20.2%	13.3%	20.3%	13.6%	21.2%	13.8%	21.6%	13.8%	22.5%	14.1%	23.3%	13.7%
12 % Capacity Margin	11.8%	16.2%	12.1%	16.8%	11.7%	16.8%	11.9%	17.5%	12.2%	17.8%	12.1%	18.4%	12.4%	18.9%	12.1%
DSM															
13 Cumulative DSM Capacity	839	460	833	460	826	459	820	459	814	459	808	459	803	460	798
14 Cumulative Equivalent Capacity	24,592	22,573	25,072	23,059	25,389	23,382	25,865	23,864	26,341	24,258	26,733	24,744	27,210	25,227	27,529
Reserves w/DSM															
15 Equivalent Reserves	3,646	4,045	3,754	4,265	3,701	4,319	3,809	4,546	3,916	4,685	3,953	4,916	4,067	5,133	4,019
16 % Reserve Margin	17.4%	21.8%	17.6%	22.7%	17.1%	22.7%	17.3%	23.5%	17.5%	23.9%	17.4%	24.8%	17.6%	25.5%	17.1%
17 % Capacity Margin	14.8%	17.9%	15.0%	18.5%	14.6%	18.5%	14.7%	19.0%	14.9%	19.3%	14.8%	19.9%	14.9%	20.3%	14.6%

ASSUMPTIONS OF LOAD, CAPACITY, AND RESERVES TABLE

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 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. Capacity Additions reflect a natural gas fired combustion turbine facility. This facility, the Mill Creek Combustion Turbine facility, has a net Summer Rating of 610 MW and will be operational May/June 2003.

4. The 196 MW capacity retirement in 2006 represents the projected retirement date for CT's at Buzzard Roost(Wst & GE).
   The 120 MW capacity retirement in 2007 represents the projected retirement date for CTs at Riverbend.
   The 90 MW capacity retirement in 2009 represents the projected retirement date for CTs at Lee.
   The 93 MW capacity retirement in 2009 represents the projected retirement date for the existing CTs at Buck.
   The 85 MW capacity retirement in 2009 represents the projected retirement date for CTs at Dan River.
   On May 23, 2000, the NRC issued to Duke a renewed facility operating license for its three nuclear units at Oconee. Duke now has the option to operate its Oconee units for up to 20 years following the year 2013. Duke will evaluate on an ongoing basis the viability of operating past the year 2013. See Section 6 of Annual Plan for further details.
   The Hydro facilities for which Duke has submitted an application to FERC for licence renewal are assumed to continue operation through the planning horizon. See Section 6 of Annual Plan for further details.
   All retirement dates are subject to review on an ongoing basis.

6. 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 include the 88 MW Cherokee Cogen contract which began in June 1998 and expires June 2013 and the 10 MW 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 151 MW from CP&L began June 1, 2001 and expires December 31, 2005.
   F. Purchase of 151 MW summer peak capacity from June 1, 2002 to May 31, 2007 from CP&L.
   G. Purchase of 600 MW from Dynegy began July 1, 2000 and expires December 31, 2003.

8. 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 the target planning reserve margin.

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

12. 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

13. Cumulative Demand Side Management capacity represents the demand-side management contribution toward meeting the load. The programs reflected in these numbers include Interruptible Demand Side Management 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.

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

Continued

2. EXISTING PLANTS IN SERVICE, continued

NAME	UNIT #	MW CAPACITY	LOCATION	PLANT TYPE
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)		1129		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 Power has selected a site for its newest electric generating facility. The site is in Cherokee County, S.C., for a 640 MW (nominal), natural gas-fired power plant. The new plant will be located off Elm Road near Blacksburg, S.C. Duke Power expects to begin construction in January 2002 and plans to have the Mill Creek Combustion Turbine facility operational in the Summer of 2003. On July 23, 2001, Duke Power received the PSCSC Certificate of Environmental Compatibility and Public Convenience and Necessity for this station.

Duke has also filed an application for a 640 MW (nominal) natural gas-fired power plant in Rowan County, N.C. The plant would be located at the existing Buck Station which is located off Longs Ferry Road near Salisbury, N.C.

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.

Line 8 of the Seasonal Projections of Load, Capacity, and Reserves for Duke Power and Nantahala Power and Light identifies cumulative future resource additions needed to maintain a target planning reserve margin of 17%. Resource additions 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.

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
Buzzard Roost 6C	22	Chappels, SC	6/30/2006
Buzzard Roost 7C	22	Chappels, SC	6/30/2006
Buzzard Roost 8C	22	Chappels, SC	6/30/2006
Buzzard Roost 9C	22	Chappels, SC	6/30/2006
Buzzard Roost 10C	18	Chappels, SC	6/30/2006
Buzzard Roost 11C	18	Chappels, SC	6/30/2006
Buzzard Roost 12C	18	Chappels, SC	6/30/2006
Buzzard Roost 13C	18	Chappels, SC	6/30/2006
Buzzard Roost 14C	18	Chappels, SC	6/30/2006
Buzzard Roost 15C	18	Chappels, SC	6/30/2006
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
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
Lee 4C	30	Pelzer, SC	12/31/2008
Lee 5C	30	Pelzer, SC	12/31/2008
Lee 6C	30	Pelzer, SC	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	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 have 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. Duke now has the option to operate its Oconee units for up to 20 years following the original license expiration dates. Duke will evaluate on an ongoing basis the economic viability of operating past the year 2013. Maintenance work is normally performed during regularly scheduled refueling outages.

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	Year 2043
Catawba 2	2/24/2026	Year 2043

In June 2001, Duke Energy submitted 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 up to 20 years. A 20 year extension would move the license expiration dates from 2021 for McGuire Unit 1 and 2023 for McGuire Unit 2 to 2041 and 2043, respectively. In addition, an extension would move the license expiration dates from 2024 for Catawba Unit 1 and 2026 for Catawba Unit 2 to 2043 for each unit. Maintenance work is normally performed during regularly scheduled refueling outages.

6. GENERATING UNITS WITH PLANS FOR LIFE EXTENSION, continued

STATION	NOTICE OF INTENT TO RELICENSE FILED	PRESENT LICENSE EXPIRATION DATE
Queens Creek Project No. 2694	9/12/1996	10/1/2001
Bryson Project No. 2601	1/27/2000	7/31/2005
Dillsboro Project No. 2602	1/19/2000	7/31/2005
Franklin Project No. 2603	1/27/2000	7/31/2005
Mission Project No. 2619	2/15/2000	8/31/2005
East Fork Project No. 2698	7/25/2000	1/31/2006
West Fork Project No. 2686	7/28/2000	1/31/2006
Nantahala Project No. 2692	8/7/2000	2/28/2006
Catawba/Wateree Project No. 2232		9/1/2008

Over the next several years, Duke will be pursuing FERC approval of the License Renewal of nine (9) Hydroelectric Projects. On September 27, 1999, Nantahala Power & Light, a division of Duke Energy Corp., (NP&L) filed an "Application for a New License" for the Queens Creek Hydroelectric Project, FERC Project No. 2694. During 2000, NP&L also filed a "Notice of Intent to File an Application for a New License" for the Bryson, Dillsboro, Franklin, Mission, East Fork, West Fork, and Nantahala Projects, as detailed above. Duke anticipates filing a "Notice of Intent to File an Application for a New License" for the Catawba/Wateree Project No. 2232 in 2003, five years prior to expiration of the license. At the present time, a new FERC license for a hydropower facility can range from 30 to 50 years dependent on various factors at the time of relicensing.

The Catawba-Wateree Project includes the following developments: Bridgewater, Rhodhiss, Oxford, Lookout Shoals, Cowans Ford, Mountain Island, Wylie, Fishing Creek, Great Falls, Dearborn, Rocky Creek, Cedar Creek, and Wateree. The West Fork Project includes the following developments: Thorpe and Tuckasegee. The East Fork Project includes Cedar Cliff, Bear Creek, and Tennessee Creek. The Nantahala Project includes the following developments: Nantahala, Dicks Creek and White Oak.

Duke is not proposing capacity upgrades of these projects at this time. Maintenance work is normally performed during regularly scheduled outages.

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 significant planned construction projects in Duke's transmission system.

PROJECT	VOLTAGE	LOCATION OF CONNECTION STATION	LINE CAPACITY	SCHEDULED OPERATION
London Creek Line	230 kV	Riverview Switching Station to Peach Valley Tie	Double circuit upgrade to bundled 795 conductor - 819 MVA	June 1, 2005
Ripp Line	230 kV	Ripp Switching Station to Shelby Tie	Double circuit upgrade to bundled 954 conductor - 916 MVA	June 1, 2003
Sadler Tie Autotransformer Addition	230/100 kV	Sadler Tie	Add 230/100 kV Autotransformer - 400 MVA	October 1, 2001
Rural Hall Tie Autotransformer Addition	230/100 kV	Rural Hall Tie	Add 230/100 kV Autotransformer - 400 MVA	April 1, 2002
Pacolet Tie Autotransformer Addition	230/100 kV	Pacolet Tie	Add 230/100 kV Autotransformer - 200 MVA	June 1, 2002
Harrisburg Tie Autotransformer Addition	230/100 kV	Harrisburg Tie	Add 230/100 kV Autotransformer - 200 MVA	June 1, 2002

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 current 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.

SPECIAL NEEDS ENERGY PRODUCTS LOAN PROGRAM

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.

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

INTERRUPTIBLE DEMAND-SIDE OPTIONS:

These existing interruptible DSM options are identified on line 13 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.

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

INTERRUPTIBLE DEMAND SIDE PROGRAMS DATA

Number of Customers

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
AC/LC	197,152	195,202	192,410	189,618	186,826	184,034	181,243	178,451	175,659	172,867	170,075	167,284	164,492	161,700	158,908	156,116
WH/LC	40,794	36,516	33,776	31,036	28,296	25,556	22,816	20,076	17,336	14,596	11,856	9,116	6,376	3,636	896	0
IS	196	196	196	196	196	196	196	196	196	196	196	196	196	196	196	196
SG	142	144	146	148	150	152	154	156	158	160	162	164	166	168	170	172

Demand (kw)

	2001		2002		2003		2004		2005		2006		2007		2008	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
AC/LC	0	360,000	0	360,000	0	360,000	0	360,000	0	339,000	0	330,000	0	322,000	0	315,000
WH/LC	27,000	8,000	23,000	6,000	20,000	6,000	17,000	5,000	15,000	4,000	13,000	4,000	11,000	3,000	9,000	2,000
IS	375,000	439,000	375,000	439,000	375,000	439,000	375,000	439,000	375,000	439,000	375,000	439,000	375,000	439,000	375,000	439,000
SG	71,000	82,000	72,000	83,000	73,000	85,000	74,000	86,000	75,000	87,000	76,000	88,000	77,000	89,000	78,000	90,000
Total	473,000	889,000	470,000	888,000	468,000	890,000	466,000	890,000	465,000	869,000	464,000	861,000	463,000	853,000	462,000	846,000

Demand (kw)

	2009		2010		2011		2012		2013		2014		2015		2016	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
AC/LC	0	306,000	0	299,000	0	292,000	0	285,000	0	278,000	0	272,000	0	265,000	0	259,000
WH/LC	7,000	2,000	5,000	2,000	4,000	1,000	3,000	1,000	2,000	1,000	1,000	0	0	0	0	0
IS	375,000	439,000	375,000	439,000	375,000	439,000	375,000	439,000	375,000	439,000	375,000	439,000	375,000	439,000	375,000	439,000
SG	79,000	92,000	80,000	93,000	81,000	94,000	81,000	95,000	82,000	96,000	83,000	97,000	84,000	99,000	85,000	100,000
Total	461,000	839,000	460,000	833,000	460,000	826,000	459,000	820,000	459,000	814,000	459,000	808,000	459,000	803,000	460,000	798,000

	2001	2002	2003	2004	2005	2006
AC/LC	$6,336,000	$6,246,000	$6,157,000	$6,068,000	$5,978,000	$5,889,000
WH/LC	$942,000	$876,000	$811,000	$745,000	$679,000	$613,000
IS	$16,389,000	$16,389,000	$16,389,000	$16,389,000	$16,389,000	$16,389,000
SG	$2,393,000	$2,427,000	$2,461,000	$2,494,000	$2,528,000	$2,562,000
Total	$26,060,000	$25,938,000	$25,818,000	$25,696,000	$25,574,000	$25,453,000

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 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)
175 MW Combustion Turbine
80 MW Combustion Turbine
512 MW Combined Cycle
400 MW Subcritical Conventional Fossil
400 MW Gas Fired Boiler
1050 MW Pumped Storage

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

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

175 MW Combustion Turbine
80 MW Combustion Turbine
512 MW Combined Cycle

10. WHOLESALE PURCHASED 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 MW of capacity and energy generated by the power plant. The contract term began July 1, 2000 and runs through the end of 2003.

2. Duke Power has entered into a contract to purchase 151 MW for the period June 1, 2001 to December 31, 2005 from the CP&L Rowan County North Carolina Plant Unit 2. Duke Power entered into a contract to purchase 151 MW for the period June 1, 2002 to May 31, 2007 from the CP&L Rowan County North Carolina Plant Unit 1.

3. Duke purchases 88 MW of capacity from Cherokee Cogeneration on an annual basis, through June 2013.

4. 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 to Western Carolina University (WCU), the city of Highlands, and customers under Schedule 10A. The load requirements of WCU, the city of Highlands, and Schedule 10A customers are reflected in the Seasonal Projections of Load, Capacity and Reserves table. Sales in 2000 totaled 69 GWH for WCU and the city of Highlands and 1431 GWH for the Schedule 10A customers as reported in Duke Energy's 2000 FERC Form 1 filing.

Throughout the 15 year planning horizon, this Annual Plan reflects Duke's obligation to serve the load of NCEMC, Saluda River, and NCMPA1 up to their ownership entitlement in the Catawba Nuclear Station. Through 2005, the Annual Plan reflects the entire load of PMPA. Beginning January 1, 2006, the Annual Plan reflects Duke's obligation to serve the PMPA load up to its ownership entitlement in the Catawba Nuclear Station.

PMPA and Saluda River have served notice to end their Interconnection Agreements effective January 1, 2006 and May 31, 2006 respectively. A new Interconnection Agreement will be required as of the aforementioned dates and absent similar provisions for Duke to serve the load of Saluda River and PMPA up to their ownership entitlement in the Catawba Nuclear Station, the wholesale power sales commitment reflected in the Annual Plan will change.

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

Version 1a

Re-approved by OC on March 28–29, 2001 for interim implementation through July 11, 2001.

See changes to DCS in Section A.

Policy Subsections

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 nonspinning 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~~ 15 minutes of the start of the DISTURBANCE.

Changes to Sections 3.2.2.2, 3.2.5, and 3.3 were approved by the Operating Committee on November 15, 2000 for Interim Implementation through March 29, 2001. See related change in

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~~ 15 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~~ 15 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.

APPENDIX B:

The following are Duke's 2000 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, 2000

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	Jocassee	Bad Creek	525.00	525.00	Tower	9.24		1
4	McGuire SW	Antioch Tie	525.00	525.00	Tower	54.35		1
5	McGuire	Newport	525.00	525.00	Tower	32.26		1
6	McGuire-Pleasant Garden	East Durham-Parkwood	525.00	525.00	Tower	131.81		1
7	Newport	Rockingham	525.00	525.00	Tower	48.68		1
8	Oconee	Newport	525.00	525.00	Tower	107.92		1
9	Oconee	Norcross	525.00	525.00	Tower	22.51		1
10	Oconee	Jocassee-McGuire	525.00	525.00	Tower	140.77		1
11	————————							
12	Total 525kv Lines					575.19		9
13	————————							
14								
15								
16	Allen	Pacolet-Tiger	230.00	230.00	Tower	80.22		[illegible]
17	Allen	Beckerdite	230.00	230.00	Tower	79.89		2
18	Allen	Riverbend	230.00	230.00	Tower	12.50		2
19	Allen	Woodlawn	230.00	230.00	Tower	8.13		2
20	Antioch Tie	Wilkes Tie	230.00	230.00	Tower	4.32		2
21	Beckerdite	Pleasant Garden-Eno	230.00	230.00	Tower	71.26		2
22	Beckerdite	Rural Hall	230.00	230.00	Tower	107.03		2
23	Belews Creek	Sadler Tie	230.00	230.00	Tower	26.31		2
24	Catawba	Peacock	230.00	230.00	Tower	14.82		2
25	Central	Anderson	230.00	230.00	Tower	23.13		2
26	Cliffside	Pacolet	230.00	230.00	Tower	23.01		2
27	Cliffside	Shelby	230.00	230.00	Tower	14.12		2
28	East Durham	Parkwood-Eno-Roxboro	230.00	230.00	Tower	33.00		2
29	Eno Tie - East Durham	CP&L	230.00	230.00	Tower	15.80		2
30	Greenville	Shady Grove-Central	230.00	230.00	Tower/Poles	34.01		2
31	Greenville	Shiloh-Pisgah Forest	230.00	230.00	Tower	30.82		2
32	Hartwell	Anderson-Hodges	230.00	230.00	Tower	36.96		2
33	Jocassee Tie	Tuckaseegee	230.00	230.00	Tower	26.63		2
34	Lincoln CT	Longview Tie	230.00	230.00	Tower	31.22		2
35	Longview	McDowell	230.00	230.00	Tower	31.96		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, 2000

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
	20,264,522	95,371,778	115,636,300					11
	20,264,522	95,371,778	115,636,300					12
								13
								14
								15
954 & 1272								16
954								17
954 & 1272								18
2156								19
954 & 1272								20
954								21
954 & 2156								22
1272								23
1272								24
954								25
954								26
954								27
1272								28
1272								29
954 & 2515								30
954								31
954 & 2515								32
1272								33
795								34
954								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, 2000

TRANSMISSION LINE STATISTICS

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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	Longview	230.00	230.00	Tower	29.06		2
2	Marshall	Mitchell River	230.00	230.00	Tower	49.49		2
3	Marshall	Winecoff	230.00	230.00	Tower	24.36		2
4	McGuire-Harrisburg-Oakboro	Newport-Catawba	230.00	230.00	Tower	139.44		[illegible]
5	McGuire SW	Lincoln CT	230.00	230.00	Tower	5.34		2
6	Mitchell	Rural Hall	230.00	230.00	Tower	43.74		2
7	Newport	Parr-Bush River	230.00	230.00	Tower	63.25		1
8	Oconee	Central	230.00	230.00	Tower	17.64		2
9	Oconee	Jocassee-Shiloh-Tiger	230.00	230.00	Tower/Poles	85.54		2
10	Pisgah Forest	Skyland	230.00	230.00	Tower	14.42		2
11	Riverbend	Lakewood (Pinoca)	230.00	230.00	Tower	10.64		2
12	Riverbend	McGuire-Marshall-Beckerdite	230.00	230.00	Tower	79.95		2
13	Riverbend	Shelby-Peach Valley-Tiger	230.00	230.00	Tower	109.42		2
14	Tiger	North Greenville	230.00	230.00	Tower	18.40		2
15	———————							
16	Total 230kv Lines					1,395.83		63
17	———————							
18								
19								
20	Dan River	Appalachian	138.00	138.00	Tower/Poles	6.50		1
21	Greenwood	Clark Hill	110.00	110.00	Wood Poles	35.76		1
22	Horseshoe Tie	Skyland CP&L	115.00	115.00	Tower/Poles	7.63		1
23	Lake Emory S. S.	Webster	161.00		S pole	12.00		1
24	Nantahala	Marble S. S.	161.00		Steel tower	17.00		2
25	Nantahala	Robbinsville S. S.	161.00		Steel tower	8.00		1
26	Oak Grove	Lake Emory S. S.	161.00		H frame	7.00		1
27	Oak Grove	Nantahala	161.00		Steel tower	14.00		2
28	Robbinsville S. S.	Santeetlah	161.00		Steel tower	11.00		1
29	Saluda Dam	Bush River Tie	110.00	110.00	Tower	11.48		2
30	Thorpe	Tuckaseegee Tie	161.00		H frame	2.00		1
31	Tuckaseegee Tie	Thorpe Hydro	161.00	161.00	Tower	1.40		1
32	Tuckaseegee Tie	Webster	161.00		Steel tower	9.00		2
33	Webster	Oak Grove	161.00		Steel tower	13.00		2
34	100kv Lines		100.00	100.00	Tower	3,020.88		[illegible]
35	100kv Lines		100.00	100.00	Poles	348.49		[illegible]
36					TOTAL			

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TRANSMISSION LINE STATISTICS (Continued)

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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.
1272								1
954								2
1272								3
954 & 1272								4
795								5
954 & 2156								6
954								7
795 & 1272								8
1272 & 2156								9
954								10
795 & 954								11
954 & 1272								12
795 & 954								13
954								14
	39,484,314	190,275,434	229,759,748					15
	39,484,314	190,275,434	229,759,748					16
								17
								18
								19
477								20
398								21
477 & 1272								22
636								23
795								24
636								25
795								26
795								27
636								28
336								29
397.5								30
1272								31
795								32
795								33
								34
								35
								36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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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 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	100kv Lines		100.00	100.00	Underground	1.78		
2								
3	Total 100kv Lines					3,526.92		19
4								
5								
6								
7	44kv Lines		44.00	44.00	Tower	281.05		
8	44kv Lines		44.00	44.00	Poles	2,711.78		
9	44kv Lines		44.00	44.00	Underground	0.73		1
10	Bear Creek	Thorpe	66.00		H frame	4.00		1
11	Bryson plant	E. Bryson tap	66.00		Spole&Hframe	4.00		1
12	Cashiers	Shortoff S. S.	66.00		H frame	4.00		1
13	Cherokee S. S. tap	Bryson plant	66.00		S pole	1.00		1
14	Cherokee S. S. tap	Cherokee S. S.	66.00		Spole&Hframe	4.00		1
15	Cullowee tap	Cullowee S. S.	66.00		H frame	1.00		1
16	Cullowee tap	Webster	66.00		H frame	4.00		1
17	Depot Street S. S.	Lake Emory S. S.	66.00		S pole	2.00		1
18	E. Bryson tap	E. Bryson S. S.	66.00		Spole&Hframe	1.00		1
19	E. Franklin S. S.	Otto S. S. tap	66.00		Spole&Hframe	3.00		1
20	Gateway	Cherokee S. S. tap	66.00		S pole	2.00		1
21	Glenville	Cashiers	66.00		H frame	2.00		1
22	Glenville	Sapphire	66.00		S pole	4.00		1
23	Jenkins Branch tap	E. Bryson tap	66.00		Spole&Hframe	2.00		1
24	Lake Emory S. S.	E. Franklin S. S.	66.00		S pole	2.00		1
25	N. Franklin S. S.	Lake Emory S. S.	66.00		S pole	2.00		1
26	Oak Grove	Jenkins Branch S. S.	66.00		Spole&Hframe	12.00		1
27	Otto S. S. tap	Depot Street S. S.	66.00		S pole	2.00		1
28	Otto S. S. tap	Otto S. S.	66.00		S pole	8.00		1
29	Otto S. S. tap	S. Franklin S. S.	66.00		Spole&Hframe	2.00		1
30	S. Cullowee S. S.	Cullowee tap	66.00		S pole	1.00		1
31	S. Franklin S. S.	W. Franklin S. S.	66.00		S pole	2.00		1
32	Tennessee Creek	Bear Creek	66.00		H frame	4.00		1
33	Thorpe	Cashiers S. S.	66.00		Spole&Hframe	8.00		1
34	Thorpe	Glenville	66.00		H frame	6.00		1
35	Thorpe	S. Cullowee S. S.	66.00		H frame	7.00		1
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, 2000

TRANSMISSION LINE STATISTICS (Continued)

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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
	48,663,606	293,879,780	342,543,386					2
	48,663,606	293,879,780	342,543,386					3
								4
								5
								6
								7
								8
								9
266.8								10
795								11
266.8								12
397.5								13
266.8								14
3/0								15
397.5								16
397.5								17
3/0								18
795								19
397.5								20
266.8								21
636								22
397.5								23
636								24
397.5 & 795								25
397.5								26
397.5								27
636								28
266.8								29
397.5								30
397.5								31
159								32
795	7,368,145	74,766,953	82,135,098					33
266.8								34
397.5								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, 2000

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	W. Franklin S. S.	N. Franklin S. S.	66.00		S pole	4.00		1
2	Webster	Gateway	66.00		S pole	8.00		1
3	Webster	Sylva S. S.	66.00		H frame	3.00		1
4	————————							
5	Total 44kv & 66kv Lines					2,602.56		30
6	————————							
7								
8								
9	33kv Lines		33.00	33.00	Poles	5.46		1
10	22kv Lines		22.00	22.00	Poles	118.61		
11	13kv Lines		13.00	13.00	Poles	36.63		
12	13kv Lines		13.00	13.00	Underground	0.25		1
13	————————							
14	Total 13-33kv Lines					160.95		2
15	————————							
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	8,261.45		123

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, 2000

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)	
397.5 & 795								1
397.5								2
397.5								3
	19,828,792	108,666,203	128,494,995					4
	27,196,937	183,433,156	210,630,093					5
								6
								7
								8
								9
								10
								11
								12
	568,683	3,499,532	4,068,215					13
	568,683	3,499,532	4,068,215					14
								15
								16
				1,588,550	12,238,750		13,827,300	17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	136,178,062	766,459,680	902,637,742	1,588,550	12,238,750		13,827,300	36

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)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Overhead Construction:						
2	Brawley School Retail Tap		3.49	Pole	8.00	1	
3	Crescent EMC Del #6 Tap		0.29	Pole	14.00	1	
4	Broad River EMC Del #16 Tap		0.06	Pole	17.00	1	
5	Fuji Film (Litho Plate S2) Tap		0.62	Pole	10.00	1	
6	Greer City Del #3 Tap		0.01			1	
7	Knights Retail Tap		0.08	Pole	25.00	1	
8	York Elec Del #20 Tap		0.98	Pole	9.00	1	
9	Spartan Green - MEMC Tap		0.47	Pole	9.00	1	
10	TNS Mills (Green Pit) Tap		0.63	Pole	10.00	1	
11	Tanner Retail Tap		0.04			1	
12	East Spartanburg Tie	Woodruff Tie	0.40	Pole	13.00	1	
13	Walker Tie Tap		0.08	Pole	38.00	1	
14	York Elec Del #13 Tap		0.05	Pole	20.00	1	
15	Lake Emory Substation	Depot Street Substation	2.00	S Pole	25.00	1	1
16	Depot Street Substation	Otto Substation Tap	2.00	S Pole	25.00	1	1
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		11.20		223.00	15	2

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, 2000

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	LINE COST				Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Total (o)	No.
								1
556.5	ACSR		100	14,516	373,585	228,972	617,073	2
556.5	ACSR		100		145,748	89,329	235,077	3
795	ACSR		100		93,539	57,330	150,869	4
556.5	ACSR		100		97,096	59,510	156,606	5
556.5	ACSR		100			68,513	68,513	6
336.4	ACSR		100	3,997	25,525	15,644	45,166	7
556.5	ACSR		100	994,936	95,720	58,667	1,149,323	8
556.5	ACSR		100		71,443	43,787	115,230	9
336.4	ACSR		100		85,188	52,212	137,400	10
336.4	ACSR		100			32,394	32,394	11
556.5	ACSR		44		74,057	45,390	119,447	12
336.4	ACSR		44		24,271	14,876	39,147	13
336.4	ACSR		44		28,474	17,452	45,926	14
795	ACSR		66					15
795	ACSR		66	2,468,594	1,581,016	1,581,016	5,630,626	16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
				3,482,043	2,695,662	2,365,092	8,542,797	44

APPENDIX C:

The following table is the 2001 Non-Utility Generation Status Report filed September 2001.

Duke Power
A Duke Energy Company

NCUC Docket No. E-100, Sub. 41B
NCUC Docket No. E-100, Sub. 84

SECTION I

2001 NON-UTILITY GENERATION STATUS REPORT

September 1, 2001

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
1998-18 N	Jim Horton 1800 Statesville Blvd Salisbury NC 28144	Jim Horton 704-638-0506 Idols Hydro Winston-Salem, NC	1,400 KW Run-of-River Hydro	Inquiry - interested in purchasing damaged hydro facility (02/98). FERC application pending. (8/01)
1999-14 N	GenPower Anderson LLC	Bruce J Arnold 781-444-9980 Anderson County SC	640,000 KW Gas-fired Combined Cycle	Merchant Plant - Certificate approved by SCPSC; CO in Fall 2003. .
1999-15 C				Inquiry regarding PP rates and interconnection (11/99) <<INACTIVE since 09/00>>
1999-16 C			Hydroelectric	Inquiry regarding PP rates and interconnection (11/99) <<INACTIVE since 09/00>>
2000-01 C			Unknown Wind	Inquiry regarding interconnection and buy-back of excess energy on residential system (4/00) <<INACTIVE since 09/00>>

Project Number	Owner/Developer Address City State Zip	Contact Phone Plant Name Plant Location	Capacity Fuel/Technology	Status
2000-02 C			Unknown Hydro - water wheel	Inquiry regarding PP rates and interconnection (3/00) <<INACTIVE since 09/00>>
2000-03 C			600 KW Run-of-River Hydroelectric	Inquiry - interested in purchasing existing PP hydro facility (2/00) <<INACTIVE since 09/00>>
2000-04 C			1,500 KW each Gas-fired CT	Inquiry regarding use of 1.5 MW CTs for peaking needs. (7/00) <<INACTIVE since 09/00>>
2000-05 C				Initial Inquiry. (7/00) <<INACTIVE since 09/00>>
2000-06 C			Unknown Hydroelectric	Inquiry regarding hydro plants located in the county. (9/00) <<INACTIVE since 09/00>>
2000-07 C			Unknown Gas-fired CT	Possible merchant plant facilities in Duke service area. (9/00)

Project Number	Owner/Developer Address City State Zip	Contact Phone Plant Name Plant Location	Capacity Fuel/Technology	Status
2001-01 C			Unknown Hydroelectric	Initial inquiry regarding hydro generation (2/01)
2001-02 C				Inquiry regarding PP rates and interconnection (3/01)
2001-03 C				Inquiry regarding PP rates and interconnection (4/01)
2001-04 C				Inquiry re green power (5/01)
2001-05 C			Wind	Inquiry re 25 MW wind generator in NC mountains (5/01)
2001-06 C			600,000 KW Gas combined cycle	Proposed merchant plant. (5/01)

Project Number	Owner/Developer Address City State Zip	Contact Phone Plant Name Plant Location	Capacity Fuel/Technology	Status
2001-07 C			500,000 KW Gas combined cycle	Proposed merchant plant. (6/01)
2001-08 N	Entergy Wholesale Operations 20 Greenway Plaza E Houston TX	Kurt Castelberry 281-297-3010 Greenville LLC Greenville County, SC	600,000 KW Gas-fired CT Peaker	Proposed merchant plant. Certificate approved. (5/01)
2001-08 N	Entergy Wholesale Operations 20 Greenway Plaza E Houston TX	Kurt Castelberry 281-297-3010 Rowan LLC Rowan County, NC	600,000 KW Gas-fired CT and Combined cycle	Proposed merchant plant. Certificate approved. (5/01)
2001-09 C			Unknown	Inquiry re miscellaneous NUG technologies and issues. (6/01)
2001-10 C			Unknown Solar PV	Inquiry regarding PP rates and interconnection/net metering. (7/01)
2001-11 C			Unknown	Inquiry regarding PP rates and interconnection/net metering. (7/01)

Project Number	Owner/Developer Address City State Zip	Contact Phone Plant Name Plant Location	Capacity Fuel/Technology	Status
2001-12 C			Unknown Micro Gas Turbine	Inquiry regarding small gas turbines for residential use. (7/01)
2001-13 C			300 KW Micro Gas Turbine	Inquiry regarding installation and testing of small turbines. (2/01)
2001-14 C			10 KW Wind Turbine	Inquiry regarding PP rates and interconnection. (7/01)
2001-15 C			450 KW Hydroelectric	Inquiry regarding PP rates and interconnection. (8/01)

Duke Power
A Duke Energy Company

2001 NON-UTILITY GENERATION STATUS REPORT

September 1, 2001

NCUC Docket No. E-100, Sub. 41B
NCUC Docket No. E-100, Sub. 84

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
01	Carolina Power & Light Company P.O. Box 1551, CPB 10A Raleigh NC 27602 *Rowan County CT Unit 1*	Kent Fonvielle 919-546-3257 151,000 KW 151,000 KW	Gas-fired Simple Cycle CT w/ Fuel Oil Backup Total Output - Dispatchable 1/23/2001 6/1/2002	Negotiated Fixed, levelized capacity payments Fuel indexed, VOM esc; Start Cost esc 5 years June 2001
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

2001 NON-UTILITY GENERATION STATUS REPORT

September 1, 2001

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 *Piedmont Hydro - SC*	Beth Harris 864-281-9630 X-105 1,050 KW 1,050 KW	Hydroelectric Total Output 02/13/1998 12/29/1997	Schedule PP (SC) Variable 1 year, then yearly thereafter	Owned by Consolidated Hydro Southeast, Inc. Pre-PURPA 12/28/1997
02	Aquenergy Systems, Inc. P.O. Box 8597 Greenville SC 29604 *Ware Shoals Hydro - SC*	Beth Harris 864-281-9630 X-105 6,300 KW 6,300 KW	Hydroelectric Total Output 02/13/1998 12/29/1997	Schedule PP (SC) Variable 1 year, then yearly thereafter	Owned by Consolidated Hydro Southeast, Inc. Pre-PURPA 12/28/1997
03	Aquenergy Systems, Inc. P.O. Box 8597 Greenville SC 29604 *Woodside I Hydro - SC*	Beth Harris 864-281-9630 X-105 450 KW 450 KW	Hydroelectric Total Output 02/13/1998 12/29/1997	Schedule PP (SC) Variable 1 year, then yearly thereafter	Owned by Consolidated Hydro Southeast, Inc. 12/29/1983 12/28/1997
04	Aquenergy Systems, Inc. P.O. Box 8597 Greenville SC 29604 *Woodside II Hydro - SC*	Beth Harris 864-281-9630 X-105 500 KW 500 KW	Hydroelectric Total Output 02/13/1998 12/29/1997	Schedule PP (SC) Variable 1 year, then yearly thereafter	Owned by Consolidated Hydro Southeast, Inc. 12/29/1983 12/28/1997

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
05	Avalon Hydro 1240 Springwood Church Road Gibsonville NC 27249 *Avalon Hydro - NC*	Timothy H. Henderson 336-449-5054 1,275 KW 212 KW	Hydroelectric Total Output 12/27/1994 04/26/1997	Schedule PP (NC) 15-year Fixed Ser.4, 1st Revised 15 years	Formerly H & H Properties. Assigned to Avalon Hydro on 8/25/98 4/26/1997 4/25/2012
06	Brushy Mountain Hydro-Electric Power Co. c/o Sure Power Inc P.O. Box 768 Jackson GA 30233-0016 *Millersville, NC*	J. Herb Warren/Winston Moore 404-775-5303 320 KW 350 KW	Hydroelectric Total Output 10/02/1985 09/23/1985	Schedule PP (NC) Variable 15 years	Formerly Brushy Mt. Power Co. (Contract Assigned 2/5/90) 6/14/1983 9/22/2000
07	Buck Creek Corporation P.O. Box 1330 Marion NC 28752 *Lake Tahoma Hydro - NC*	Bob King 704-355-3063 240 KW 159 KW	Hydroelectric Total Output 10/25/1999 08/14/1999	Schedule PP-H (NC) 15-year Fixed Ser.4, 1st Revised 15 years	Formerly McRay Energy, Inc. (Contract Assigned 9/15/92) 12/13/1982 8/13/2014
08	Carolina Power & Light Company P.O. Box 1551, CPB 10A Raleigh NC 27602 *Rowan Cty NC Unit 2*	Kent Fonvielle 919-546-3257 151,000 KW 151,000 KW	Gas-fired CT w/ oil backup Total Output-Dispatchable 03/22/2000 07/01/2000	Negotiated 5.5 years	Contract Capacity reduced to 151000 kW from 302000 kW on 6/1/2001. Delivery from Broad River through 5/31/01, then from Rowan County. 7/1/2000 12/31/2005
09	Catawba County P O Box 389 Newton NC 28658 *Blackburn Landfill Gas Facility - NC*	Barry B. Edwards 704-465-8260 4,000 KW 3,700 KW	Landfill Methane Gas Total Output 06/16/1997 08/23/1999	Schedule PP (NC) 15-year Fixed Ser.4, 3rd Revised 15 years	8/23/1999 8/22/2014

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
10	Catawba County P O Box 389 Newton NC 28658 *Newton Landfill Gas Facility - NC*	Barry B. Edwards 704-465-8260 2,000 KW 1,800 KW	Landfill Methane Gas Total Output 06/16/1997 08/23/1999	Schedule PP (NC) 15-year Fixed Ser.4, 3rd Revised 15 years	8/23/1999 8/22/2014
11	Cherokee County Cogeneration Partners, LLP 132 Peoples Creek Rd Gaffney SC 29340 *Cherokee County Cogeneration - NC*	Steve Patrick 864-488-3630 X-101 100,000 KW 88,000 KW	Gas-Fired Combined-Cycle Cogen Total Output 08/26/1994 07/01/1998	Negotiated (SC) 15 years escalating	4/18/1998 6/30/2013
12	Clearwater Hydro B 4 Chimney Rock Road Rutherfordton NC 28139 *Caroleen, NC*	Richard Gresham 520-473-3232 324 KW 187 KW	Hydroelectric Total Output 12/30/1999 01/06/2000	Schedule PP-H (NC) 15-year Fixed Ser.4, 1st Revised 15 years	Owner's address is 2907 E. Millbrae Ln, Gilbert, AZ 85234 8/13/1985 1/6/2015
13	Converse Energy Incorporated P.O. Box 243 Converse SC 29329 *Clifton Dam #3 Hydro - SC*	Tim Lamb 864-579-4640 1,250 KW 1,250 KW	Hydroelectric Total Output 01/07/1998 01/12/1998	Schedule PP (SC) Variable 1 year, then yearly thereafter	Formerly Bluestone Energy Design. Alt. Contact: Victoria Miller - 864-579-4640 7/16/1985 1/11/1999
14	Haw River Hydro Co. P O Box 1459 Asheboro NC 27204 *Haw River Hydro-Saxapahaw NC*	William H. Lee 336-824-2008 1,500 KW 1,500 KW	Hydroelectric Total Output 02/25/1997 01/08/1997	Schedule PP (NC) 15-year Fixed Ser.4, 3rd Revised 15 years	Formerly Deep River Hydro Co. (Change eff. 1/7/93) 1/8/1982 1/7/2012

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
15	Kannapolis Energy Partners, LLC 220 N. Main Street, Suite 603 Greenville SC 29601 *Kannapolis Power Project - NC*	Ralph Walker 864-242-4624 22,500 KW 9,000 KW	Pulverized Coal Cogeneration Total Output 09/08/2000 02/22/2000	Negotiated (NC) Fixed, levelized 5 years	Formally owned & operated self-generation by Fieldcrest-Cannon. Pre-PURPA 2/22/2005
16	Kannapolis Energy Partners, LLC 220 N. Main Street, Suite 603 Greenville SC 29601 *Spencer Power Project - NC*	Ralph Walker 864-242-4624 3,500 KW 1,000 KW	Pulverized Coal Cogeneration Total Output 09/08/2000 02/22/2000	Negotiated (NC) Fixed, levelized 5 years	Formally owned & operated self-generation by Fieldcrest-Cannon. Pre-PURPA 2/22/2005
17	Mayo Hydro 1240 Springwood Circle Gibsonville NC 27249 *Mayo Dam Hydroelectric Facility - NC*	Charles Wood 336-449-5054 951 KW 175 KW	Hydroelectric Total Output 08/11/1998 02/01/2001	Negotiated (NC) 10-year Fixed 10 years	2/1/2001 1/31/2011
18	Mill Shoals Hydro Company, Inc. P.O. Box 8597 Greenville SC 29604 *High Shoals Hydro - NC*	Beth Harris 864-281-9630 X-105 1,800 KW 1,800 KW	Hydroelectric Total Output 08/12/1997 04/02/1997	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) 4/2/1982 4/1/2012
19	Northbrook Carolina Hydro, LLC 300 West Washington St. Chicago IL 60606 *Boyd's Mill Hydro - SC*	Mark Sundquist 312-553-2136 1,500 KW 110 KW	Hydroelectric Total Output 12/04/1996 12/04/1996	Negotiated (SC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Pre-PURPA 12/4/2006, 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
20	Northbrook Carolina Hydro, LLC 300 West Washington St. Chicago IL 60606 *Holliday's Bridge Hydro - SC*	Mark Sundquist 312-553-2136 3,500 KW 2,230 KW	Hydroelectric Total Output 12/04/1996 12/04/1996	Negotiated (SC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Pre-PURPA 12/4/2006, if extended by Northbrook
21	Northbrook Carolina Hydro, LLC 300 West Washington St. Chicago IL 60606 *Saluda Hydro - SC*	Mark Sundquist 312-553-2136 2,400 KW 515 KW	Hydroelectric Total Output 12/04/1996 12/04/1996	Negotiated (SC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Pre-PURPA 12/4/2006, if extended by Northbrook
22	Northbrook Carolina Hydro, LLC 300 West Washington St. Chicago IL 60606 *Stice Shoals Hydro - NC*	Mark Sundquist 312-553-2136 600 KW 125 KW	Hydroelectric Total Output 12/04/1996 12/04/1996	Negotiated (NC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Pre-PURPA 12/4/2006, if extended by Northbrook
23	Northbrook Carolina Hydro, LLC 300 West Washington St. Chicago IL 60606 *Spencer Mountain Hydro - NC*	Mark Sundquist 312-553-2136 640 KW 560 KW	Hydroelectric Total Output 12/04/1996 12/04/1996	Negotiated (NC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Pre-PURPA 12/4/2006, if extended by Northbrook
24	Northbrook Carolina Hydro, LLC 300 West Washington St. Chicago IL 60606 *Turner Shoals Hydro - NC*	Mark Sundquist 312-553-2136 5,500 KW 3,000 KW	Hydroelectric Total Output 12/04/1996 12/04/1996	Negotiated (NC) Fixed, Escalating 7 years + 3 years	Previously owned by Duke Power. Pre-PURPA 12/4/2006, 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
25	Pacolet River Power Co. Inc. 5250 Clifton-Glendale Road Spartanburg *Clifton No. 1 Hydro - SC*	 SC	 29307-4618	Charles B. Mierek 864-579-4405 800 KW 800 KW	Hydroelectric Total Output 04/19/1988 03/20/1986	Schedule PP (SC) Variable 5 years	 3/10/1982 Yearly thereafter
26	Pelzer Hydro Co. P.O. Box 8597 Greenville *Lower Pelzer Hydro - SC*	 SC	 29602	Beth Harris 864-281-9630 X-105 3,300 KW 3,300 KW	Hydroelectric Total Output 09/11/1998 09/11/1998	Schedule PP (SC) Variable 1 year	Owned by Consolidated Hydro Southeast, Inc. Pre-PURPA Yearly thereafter
27	Pelzer Hydro Co. P.O. Box 8597 Greenville *Upper Pelzer Hydro - SC*	 SC	 29602	Beth Harris 864-281-9630 X-105 2,020 KW 2,020 KW	Hydroelectric Total Output 09/11/1998 09/11/1998	Schedule PP (SC) Variable 1 year	Owned by Consolidated Hydro Southeast, Inc. Pre-PURPA Yearly thereafter
28	Pharr Yarns,Inc. P. O. Box 1939 McAdenville *McAdenville, NC*	 NC	 28101	Jim Howard 1,056 KW 800 KW	Hydroelectric As-Available Excess 11/25/1992 11/19/1992	Schedule PP-H (NC) Variable 5 years	Formerly Known as Stowe Mills, Inc. 6/12/1984 11/18/1997
29	R.J. Reynolds Tobacco Company Bowman Gray Technical Center Winston-Salem *Tobaccoville Cogeneration Facility - NC*	 NC	 27102	Tom Casey 336-741-6224 80,000 KW 52,000 KW	Coal-fired Cogen Firm Excess 12/14/1998 12/22/1998	Negotiated (NC) Fixed Capacity Indexed Energy 5 years	 7/19/1985 12/31/2003

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	Rockingham Power, LLC 1000 Louisiana St., Suite 5800 Houston TX 77002 *Rockingham CT Facility/Reidsville NC*	Ketan Patel 713-767-8760 800,000 KW 600,000 KW	Gas-fired CT w/ oil backup Dispatchable 09/30/1998 07/01/2000	Negotiated 3.5 years	 7/18/2000 12/31/2003
31	Salem Energy Systems, LLC 335 W. Hanes Mill Road Winston-Salem NC 27105 *Winston-Salem Gas Recovery - NC*	Robert (Bob) Biskeborn 336-776-1462 4,750 KW 4,170 KW	Landfill Gas-fueled Turbine Cogen Total Output 03/24/1995 07/10/1996	Schedule PP (NC) 15-year Fixed Ser.4, 1st Revised 15 years	Formerly Enerdyne II, LLC 7/10/1996 7/10/2011
32	South Yadkin Power, Inc. 6898A Coltrane Mill Rd. Greensboro NC 27406 *Cooleemee Dam Hydro Project - NC*	Lyn & Breck Bullock 704-284-4051 1,400 KW 280 KW	Hydroelectric Total Output 07/02/1997 07/09/1997	Negotiated (NC) Fixed Levelized, 5 + 5 10 years	Formerly Turbine Industries, Inc. 7/9/1997 7/8/2007
33	Spray Cotton Mills P O Box 3207 Eden NC 27280-3207 *Eden NC*	Mark Bishopric 336-627-6200 500 KW 500 KW	Hydroelectric Total Output 11/28/1994 11/03/1994	Schedule PP (NC) 15-year Fixed Ser.4, 1st Revised 15 years	 Pre-PURPA 11/2/2009
34	Steve Mason Enterprises Inc 2202 W Franklin Blvd Gastonia NC 28052 *Harden Hydro #1,2 & 3 - NC*	Steve Mason 704-678-1714 820 KW 200 KW	Hydroelectric Total Output 08/09/2001 05/01/2001	Schedule PP-H (NC) 15-year Fixed Ser.4, 1st Revised 15 years	Sold from Adrienne LaFar to Jason Lineberger to Steve Mason. New contract has all three units under single contract with 2 deliveries. 12/20/1985 4/30/2015

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
35	Steve Mason Enterprises Inc 2202 W Franklin Blvd Gastonia *Long Shoals Hydro - NC*	 NC	 28052	Steve Mason 704-678-1714 750 KW 308 KW	Hydroelectric Total Output 02/21/2001 02/16/2001	Schedule PP-H (NC) 15-year Fixed Ser.4, 1st Revised 15 years	Purchased from Consolidated Hydro Southeast, Inc. 6/4/1985 2/15/2016
36	Town of Lake Lure P.O. Box 2255 Lake Lure *Lake Lure Hydro Facility*	 NC	 28746	H.M. "Chuck" Place 828-625-9983 3,600 KW 2,500 KW	Hydroelectric Total Output 08/24/1999 02/18/1999	Negotiated (NC) 7-year Fixed 7 years	 Pre-PURPA 2/18/2006

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	Aquenergy Systems, Inc. P.O. Box 8597 Greenville SC 29604 Apalache Hydro - SC	Beth Harris 864-281-9630 X-105 420 KW 420 KW	Hydroelectric Total Output 02/13/1998 12/29/1997	Schedule PP (SC) Variable 1 year, then yearly there	Plant has discontinued operation. 3/15/1984 12/28/1997
Cancelled	BMW Manufacturing, Inc. P. O. Box 11000 Spartanburg SC 29304 BMW Cogeneration Facility - SC	Lennie Beamon, Fac.Coord. 5,000 KW 5,000 KW	Gas-Fired Cogen Total Output 01/27/1995 02/01/1995	Schedule PP (SC) Variable 10 years	Now using cogen plant for displacement purposes. 2/1/1995 1/31/2005
Cancelled	Bob Jones University Wade Hampton Blvd. Greenville SC 29614 Bob Jones University - SC	Attn: Business Office 4,500 KW 2,000 KW	Diesel-fired Cogen As-Available Excess 12/30/1988 10/15/1988	Schedule PG (SC) 5 years	Now using cogen plant for displacement purposes. 10/15/1988 Yearly thereafter
Cancelled	Cascade Power Company P.O. Box 1137 Brevard NC 28712 Brevard, NC	Charles Pickelshimer 704-884-9011 900 KW 950 KW	Hydroelectric Total Output 04/29/1986 04/16/1986	Schedule PP (NC) 15-year Fixed Ser.3, 10th Revised 15 years	Cancelled by request of owner at end of initial 15-year term. Plant discontinued operations. 4/16/1986 4/15/2001
Cancelled	Coltrane Mill Hydro 7023 Troy Caveness Road. Ramseur NC 27316 Randolph County, NC	Susan P. White 336-879-2594 60 KW 60 KW	Hydroelectric Total Output 08/17/1983 08/16/1983	Schedule PP-H (NC) Variable Yearly	Plant has discontinued operation. 8/16/1983 2/15/1999

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	FMC Corp./Lithium Div. P O Box 3925 Gastonia NC 28053 Bessemer City NC Plant	 11,500 KW 3,000 KW	Coal Fired Cogen As-Available Excess 03/21/1991 03/21/1991	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. 9/19/1986 3/20/1996
Terminated	Northbrook Carolina Hydro, LLC 300 West Washington St. Chicago IL 60606 Idols Hydro - NC	Mark Sundquist 312-553-2136 1,411 KW 163 KW	Hydroelectric Total Output 12/04/1996 12/04/1996	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 3/1/1999
Terminated	Preservation NC P O Box 12338 Winston-Salem NC 27117 Glencoe Hydro - NC	Kirk Carrison 336-798-0765 250 KW 250 KW	Hydroelectric Total Output 07/05/1984 02/10/1984	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. 2/10/1984 2/9/1999
Cancelled	R.J. Reynolds Tobacco Company Bowman Gray Technical Center Winston-Salem NC 27102 Whitaker Park Cogen Facility - NC	Tom Casey 336-741-6224 8,500 KW 8,500 KW	Coal-fired Cogen Total Output 03/06/1991 09/24/1990	Schedule PP (NC) Variable 5 years	Plant has discontinued operation. 9/24/1990 9/23/1995
Terminated	Whitney Mills 212 Range Road Kings Mountain NC 28086 Spartanburg, SC	Nelson Evans 704-739-9710 225 KW 225 KW	Hydroelectric Total Output 11/07/1997 04/30/1998	Schedule PP (SC) 5 yrs, yearly thereafter	Terminated on 7/9/2001 for failure to generate and failure to pay past due interconnection charges. 4/30/1998 4/29/2003

APPENDIX D:

The following contains the pages to the 2001 Duke FERC Form 715 filed April 2001

DUKE ENERGY CORPORATION

FERC FORM NO. 715

APRIL 2001

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FERC Form 715
Docket No. RM93-10-000
Appendix A - Part 1
Identification and Certification

Transmitting Utility:
Duke Energy Corporation
526 South Church Street
Charlotte, NC 28202

Contact Person:
James D. Hinton
Senior Vice-President
Electric Transmission
Phone: (704) 382-3575
Fax: (704) 382-7887

Certification:

The undersigned officer certifies that he/she has examined the accompanying report; that to the best of his/her knowledge, and belief, that as of the date this document was signed, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the above named respondent to each and every matter set forth therein.

J D Hinton
James D. Hinton
Senior Vice-President
Electric Transmission

3/5/01
Date Signed

FERC Form 715
Docket No. RM93-10-000
Appendix A - Part 2
Power Flow Base Cases

Duke Energy Corporation authorizes the SERC Administrative Manager to release electronic copies of current, power flow base cases in accordance with procedures established for such release. Such requests may be made to:

Mr. James N. Maughn
Administrative Manager
Southeastern Electric Reliability Council
600 North Eighteenth Street
P. O. Box 2641
12N-8250
Birmingham, Alabama 35291

Telephone (205) 257-6361
Facsimile (205) 257-0408

The current list of available PSS/E base cases includes:

1. 2001 Light Load NERC MMWG Base Case
2. 2001 Spring NERC MMWG Base Case
3. 2001 Summer VAST Base Case
4. 2001 Fall NERC MMWG Base Case
5. 2001/02 Winter NERC MMWG Base Case
6. 2002 Spring NERC MMWG Base Case
7. 2002 Summer NERC MMWG Base Case
8. 2002 Fall NERC MMWG Base Case
9. 2002/03 Winter NERC MMWG Base Case
10. 2005 Summer NERC MMWG Base Case
11. 2005/06 Winter NERC MMWG Base Case

A Data-Dictionary is included with the electronic copies of these files.

FERC Form 715
Docket No. RM93-10-000
Appendix A - Part 3
Transmitting Utility Maps and Diagrams

Enclosed are an original and one copy of the following:

Enclosure # 1 — Virginia-Carolinas Subregion, Southeastern Electric Reliability Council, Principal Generating Stations and Transmission Lines.

This is a multi-purpose transmission map indicating the geographic locations and names of generating plants, switching stations, substations, service areas, and interconnections with other utilities. The map also is a single-line schematic indicating AC transmission lines and facilities (nominal design voltages included in Data-Dictionary supplied with power flow base cases under Part 2), electrical connections, generating plants, transformation facilities, phase angle transformers (none). A listing of VAR control equipment is included in Data-Dictionary supplied with power flow base cases under Part 2.

The map includes a legend describing the symbols used.

Duke Energy Corporation subscribes to all applicable NERC and SERC Transmission Reliability criteria. Specifically, Duke Energy subscribes to NERC's Planning Standards, NERC's Transmission Transfer Capability document and SERC's Planning Principles and Guides. In addition, Duke Energy subscribes to its own Planning Guidelines (Enclosure 2).

A copy of NERC's Planning Standards and Transmission Transfer Capability document is available through the North American Electric Reliability Council, 116-390 Village Boulevard, Princeton, New Jersey, 08540-5731 or 609-452-8060.

A copy of SERC's Planning Principles and Guides is available through the Southeastern Electric Reliability Council Administrative Manager, 600 North Eighteenth Street, P. O. Box 2641, 12N-8250, Birmingham, Alabama 35291.

To satisfy the requirements of various reliability agreements, Duke Energy participates in a number of joint study groups who perform short-term operating and long-term reliability studies. Two of the groups (VAST: VACAR - AEP - Southern - TVA and VST: VACAR - Southern - TVA - Entergy) have published procedural manuals that are representative of typical operating and reliability studies respectively. Copies of the manuals are available through the Southeastern Electric Reliability Council Administrative Manager.

Duke Energy Corporation does not have a stand-alone document outlining its Transmission Planning Assessment Practices. Rather, this information is provided as a part of its Planning Guidelines (Enclosure 2). The VAST and VST Procedural Manuals referenced in Part 4, Transmission Planning Reliability Criteria, also contain assessment practices. Additionally, reports published by the various joint study groups in which Duke Energy Corporation participates (i.e. VST Reliability studies and VAST Operating studies) typically contain some description of the transmission planning assessment practices used and may also contain a listing of the contingencies considered. Copies of recent reports are available through the SERC Administrative Manager, 600 North Eighteenth Street, P. O. Box 2641, 12N-8250, Birmingham, Alabama 35291

FERC Form 715
Docket No. RM93-10-000
Appendix A - Part 6
Evaluation of Transmission System Performance

Duke Energy participates in a number of joint regional and sub-regional studies designed to evaluate the performance of the integrated transmission system. These studies include both near-term operating studies and long-term reliability studies. These studies contain an evaluation of the Duke Energy transmission system. Copies of recent studies are available through the SERC Administrative Manager.

In addition, Duke Energy conducts evaluations of its own system to insure conformance to applicable NERC, SERC, and internal reliability guidelines. Evaluation of the current transmission system has shown Duke Energy to be in compliance with all applicable NERC, SERC, and internal reliability guidelines.

DUKE ELECTRIC TRANSMISSION SYSTEM PLANNING GUIDELINES

Plan the System/Duke Electric Transmission

TABLE OF CONTENTS

I. SCOPE

This document was designed to provide a summary of the fundamental guidelines used by Plan The System employees to plan Duke Electric Transmission's 500 kV, 230 kV, 161 kV, 100 kV, 66 kV and 44 kV transmission systems.

Any reliable transmission network must be capable of moving power throughout its system without exceeding voltage, thermal and stability limits, during both normal and contingency conditions. These guidelines are designed to help Plan The System employees identify potential system conditions that require further study. **It does not provide criteria for which absolute decisions are made regarding transmission system improvements.** Duke Electric Transmission retains the right to amend, modify, or terminate any or all of these guidelines at its option.

II. TRANSMISSION PLANNING OBJECTIVES

The guidelines in this document are formulated to meet the following objectives:

- Provide an adequate transmission system to serve the native load of the Duke Electric Transmission service territory.
- Balance risks and expenditures to ensure a reliable system while maintaining flexibility to accommodate an uncertain future.
- Maintain adequate transmission thermal capacity and reactive power reserves (in the generation and transmission systems) to accommodate scheduled and unscheduled transmission and generation contingencies.
- Adhere to applicable requirements of SERC Principles and Guides for Reliability in System Planning, April 1995
- Achieve compliance with the NERC Planning Standards that are in effect.
- Adhere to applicable regulatory requirements.
- Minimize losses where cost effective.
- Provide for the efficient and economic use of all generating resources.
- Provide for comparable service under the Pro Forma Open Access Transmission Tariff.
- Satisfy contractual commitments and operating requirements of inter-system transactions.

III. PLANNING ASSUMPTIONS

A. Load Levels

- Summer Peak (for current year and next 10 years)
- Winter Peak (for current year and next 10 years)
- Fall Peak (for current year and next 2 years)
- Spring Valley (for current year and next 3 years)
- Loads plus losses at the transmission level will be scaled to match the system forecast for each load level. When conditions warrant, additional cases may be generated to examine the impact of other load levels.

B. Generation

1. Dispatch

Generation patterns may have a large impact on thermal loading levels and voltage profiles. Therefore, varying generation patterns shall be examined as a part of any analysis. Non-Duke generators with confirmed, firm transmission reservations are modeled as being in-service. Units serving native load are economically dispatched for normal and contingency conditions. Normal outages for maintenance, forced outages, and combinations of normal and forced outages are modeled. In addition, large plants are modeled at maximum output to check for constraints.

2. Voltage Schedules

An optimal power flow program is used to determine the voltage schedules for major system generating units. The schedules are tailored for season and load level to meet system reactive power requirements.

3. Reactive Capability Curves

Periodic testing is performed on system generating units to determine the reactive capability curve for each unit. This data is included in the base power flow models in an attempt to accurately represent system conditions. The dispatch module within the power flow analysis program utilizes the tested reactive limits when determining the voltage schedules and power output levels of each unit.

C. Power Transactions

Long-term power transactions between control areas are included in the appropriate power flow base cases and shall be consistent with contractual obligations. For an emergency transfer analysis, generation is reduced in a manner that will cause stress on the system.

Duke participates in several reliability groups that perform transfer studies on a regular basis: VACAR (Virginia-Carolinas Subregion of SERC), VST (VACAR-Southern-TVA-Entergy), VAST (VACAR-AEP-Southern-TVA), VEM (VACAR-ECAR-MAAC).

D. Equipment Ratings

The methodology used to rate transmission facilities encompasses all components (e.g., transformers, line conductors, breakers, switches, line traps, etc.) from bus to bus. Wind speed and angle, ambient temperature, acceptable operating temperatures, as well as other factors are used in determining facility ratings. All facilities are composed of eight ratings reflecting the following capabilities for both summer and winter seasons:

- continuous
- long-term emergency
- 12-hour emergency
- 1-hour emergency

E. Nominal Voltages

Nominal voltages on the Duke system are 500 kV, 230 kV, 161 kV, 100 kV, 66 kV and 44 kV. Additional nominal voltages of 138 kV, and 115 kV are utilized for some of Duke's interconnections with other utilities.

F. Common Right-of-Way

Part of the judgment used for any analysis is the definition of line outages on a common right-of-way. Clearly, there are situations where multiple lines may leave a station in a similar direction and along a common corridor for some short distance. While there are no clear cut rules, the length of exposure of a common right-of-way and the criticality of the circuits involved must be considered when defining which rights-of-way should be studied.

IV. STUDY PRACTICES

Duke conducts transmission planning studies including, but not limited to:

- Screening of Voltage Guidelines
- Screening of Thermal Guidelines
- Grid Voltage Study For Nuclear Loss-Of-Cooling Accident (LOCA)
- Spare Transformer Study
- Transformer Tertiary Study
- Optimal Power Flow Studies For Generator Voltage Schedules And Capacitor Additions
- Angle and Voltage Stability Analyses
- Power Transfer Studies (VACAR, VST, VAST, VEM, OASIS postings)
- System Impact Studies
- Fault Duty Analyses
- Miscellaneous Losses Evaluation
- Facilities Adequate Evaluations
- Severe Contingency Studies

V. PLANNING GUIDELINES

Plan The System is charged with planning the transmission system (500 kV, 230 kV, 161 kV, 100 kV, 66 kV, 44kV) and the system interconnections, as well as consulting in planning the distribution (24 kV and below) system. Voltages and thermal loadings that violate the following guidelines will result in further analyses. Studies of the bulk transmission system (500 kV, 230 kV, and 161 kV) give consideration to the effect we may have on the planning and operation of neighboring utilities as well as the effect they may have on our system.

As a part of the SERC Planning Principles and Guides (PP&G), each utility is charged with planning its system in a manner that avoids uncontrolled cascading beyond predetermined boundaries. This is to limit adverse system operations from crossing a control area boundary. To this extent, Duke participates in several regional reliability groups: VACAR (Virginia-Carolinas Subregion of SERC), VAST (VACAR-AEP-Southern-TVA), VST (VACAR-Southern-TVA-Entergy), and VEM (VACAR-ECAR-MAAC). Each of these reliability groups evaluates the bulk transmission system to ensure: 1) the interconnected system is capable of handling large economy and emergency transactions, 2) planned future transmission improvements do not adversely affect neighboring systems and 3) the interconnected system's compliance with selected NERC Planning Standards.

Each of these study groups has developed its own set of procedures that must be followed. These study groups do not have as one of their objectives the analysis and planning for any one individual system. The main objective of these groups is to maintain adequate transmission reliability through coordinated planning of the interconnected bulk transmission systems.

In addition to these regional reliability studies, Duke conducts its own assessments of the bulk transmission system. While these assessments are typically focused on the Duke system, they cannot be conducted without consideration of neighboring systems.

The effects of a 500 kV, 230 kV, or 161 kV event on lower voltage levels must also be considered in conducting analyses of the bulk transmission systems.

The voltage and thermal guidelines for the transmission system under normal and contingency conditions are described in Section A and Section B, respectively. The contingencies studied as part of any voltage or thermal evaluation are provided in Section C.

A. Voltage

Bus voltages are screened using the Transmission System Voltage Guidelines below. The guidelines specify minimum and maximum voltage levels, the percent voltage regulation during both normal and contingency conditions, and the percent voltage drop due to contingencies.

Absolute Voltage Limits are defined as the upper and lower operating limits of each bus on the system. The absolute voltage limits are expressed as a percent of the nominal voltage. All voltages should be maintained within the appropriate absolute voltage bounds for all conditions.

Voltage Regulation is defined as the difference between expected maximum voltage and minimum voltage at any particular delivery point. The voltage regulation limits are expressed as a percent of the nominal voltage and are defined for both normal and contingency conditions. Voltage regulation for delivery point voltages should not exceed the guidelines.

Contingency Voltage Drop is defined as the maximum decrease in voltage due to any single contingency.

Bulk Transmission System Voltage Guidelines

Nominal Voltage (kV)	Absolute Voltage Limits		Maximum Allowable Contingency Voltage Drop
	Minimum	Maximum	
161	95%	105%	5%
230	95%	105%	5%
500	100%	110%	5%

100 kV, 66 kV and 44 kV Transmission System Voltage Guidelines

Nominal Voltage (kV)	Absolute Voltage Limits		Voltage Regulation	
	Minimum	Maximum	Normal	Contingency
44	94%	109%	8.5%	10%
66	94%	109%	8.5%	10%
100	95%	107%	6%	7%

Autotransformer voltage limits are based on the secondary tap setting. The minimum voltage is 95% of the tap voltage and the maximum voltage is 105% of the tap voltage under full load and 110% of the tap voltage under no load. Thus, the voltage limits for transformers vary with both loading and tap setting. The secondary tap on most of Duke's 220/100 kV autotransformers is 100 kV. The one exception is AT-2 at Pisgah Tie; it is set at 95 kV. This implies a maximum voltage of 99.75 to 104.5 kV, depending on loading. The following table shows what stations have 220 kV transformers, how many there are at each station, and the MVA rating.

220/100 kV Autotransformers

Station	Number of 220 kV Autotrfs / Total	Top Nameplate (MVA)
Anderson	1 / 2	224,200
Beckerdite	3 / 4	200,200,200,336
Eno	1 / 4	200,200,336,336
Morning Star	2 / 3	150,150,200
N. Greenville	2 / 4	200,224,224,336
Pacolet	1 / 2	200,200
Pisgah*	1 / 2	200,200
Tiger	2 / 4	150,150,200,400
Other stations	0 / 64	-
Total	13 / 88**	

*Pisgah AT-2 is on the 95 kV tap.
**Expected in-service transformers for the summer of 2001.

Nuclear voltage limits are based on the design of electrical auxiliary power systems within the plants and Nuclear Regulatory Commission (NRC) requirements. There are two sets of these limits: minimum and maximum generator bus voltage limits and minimum grid voltage limits.

When the units are on-line, they regulate the generator bus to a voltage schedule, set appropriately to maximize efficiency on the transmission system. For nuclear plants, this generator voltage schedule must be within the limits listed in the following table.

Nuclear Plant Generator Bus Voltage Limits

Plant	Unit	Base kV	Minimum Voltage (kV)	Maximum Voltage (kV)
Catawba	1	22	20.9	21.6
	2	22	20.9	21.6
McGuire	1	24	22.8	24.1
	2	24	22.8	23.7
Oconee	1	19	18.05	19.05
	2	19	18.05	19.15
	3	19	18.05	19.0

To determine compliance with the minimum grid voltage limit, the nuclear plants request studies to verify that the grid can provide sufficient voltage during a LOCA (Loss-of-Coolant Accident). These grid voltage limits are provided in the following table. Minimum voltage 1 is the minimum voltage required if one off-site source (e.g., one of the parallel generator step up transformers) is unavailable. Minimum voltage 2 is the minimum voltage required with all off-site sources available, but with one transmission contingency.

Nuclear Plant Grid Voltage Limits

Plant	Unit	Grid kV	Minimum Voltage 1 (kV)	Minimum Voltage 2 (kV)
Catawba	1	230	230.69	221.56
	2	230	230.69	221.56
McGuire	1	230	231.84	224.14
	2	500	525.63	503.37
Oconee*	1	230	230.21	230.21
	2	230	230.21	230.21
	3	500	230.21	230.21

*Unit 3 generator is connected to 500 kV, but the 230 kV is the off-site source for Unit 3.

B. *Thermal*

The following guidelines shall be used to ensure acceptable thermal loadings:

a) Under normal conditions, no facility should exceed its continuous thermal loading capability.
b) With a transmission contingency having an expected duration of less than 12 hours (line outage or single phase transformer outage where spare is available), no facility should exceed its 12-hour emergency loading capability.
c) With a transformer contingency having an expected duration of more than 12 hours, no facility should exceed its long-term emergency loading capability.

C. *Selected Contingencies*

The planning studies for the transmission system are performed for normal and contingency conditions. The thermal and voltage guidelines should not be violated for either normal operations or under the loss of:

a) A single transmission circuit
b) A single transformer
c) A single generating unit
d) A single reactive power source or sink
e) Combination of a single generating unit and a single transmission circuit, capacitor bank, or transformer
f) Combination of two generating units

Several 230 kV tie stations on the Duke system have incomplete Double bus or Breaker-and-a-half designs. Thus, abnormal single contingency configurations can result. To properly screen for violations of the guidelines, the following table indicates the contingencies that should be modeled.

Abnormal Single Contingency Configurations

Tie Station	Outaged facilities for 230 kV line fault	Outaged facilities for 230/100 kV autotransformer fault
Bush River	The line and transformer	The transformer and a line
Hodges	The line	The transformer and a line
Lakewood	The line	The transformer and a line
McDowell	The line and transformer	The transformer and a line
Morningstar	The line	The transformer and possibly a line *
Peacock	The line	The transformer and a line
Sadler	The line	The transformer
Tuckasegee**	The line	The transformer and a line
Woodlawn	The line and transformer	The transformer and possibly a line *

* Depends on which 230/100 kV transformer experiences the fault.
** 230/161 kV transformer

When appropriate, additional analyses will be conducted to review the impact of a combination of single contingencies, considering the probability of occurrence, the appropriate customer outage costs, and the possible system improvements to determine what, if any, remedial actions need to be taken.

D. *Miscellaneous*

1. Retail Station Power Factor Standard

Duke has established a retail station (distribution station) power factor standard for all retail stations as measured at the connection point. This standard is:

- 96.5% lagging power factor or better (equivalent to 98% on the low-side of the transformer) during Duke peak load conditions (leading power factors <u>are</u> acceptable) and
- 100% (Unity) power factor or below during valley load conditions (leading power factors are <u>not</u> acceptable).

The retail power factor standard is designed to allow full utilization of retail transformer capabilities, provide support of system voltage levels during peak loading conditions and contingencies, and to help prevent high system voltage levels during valley load conditions.

2. Spare Transformer Policy

This policy is reviewed periodically to account for changes in failure rates and outage costs. Currently, the following number of spares should be available in the event of a contingency:

Spare Transformer Requirements

Type of Transformer	# of Spares
230/100/xx kV Autotransformer	3
30/40/50 MVA 3 phase 100/44 kV	1
20/27/33 MVA 3 phase 100/44 kV	1
12/16/20 MVA 3 phase 100/44 kV	2
6 MVA single phase 100/44 kV	1
4 MVA single phase 100/44 kV	2
3 MVA single phase 100/44 kV	1

3. Transformer Tertiary Study

This study determines the minimum number of tertiaries required in service to operate the system reliably. Having only the required amount of tertiaries in service reduces failures from detrimental in-service events like faults.

4. Optimal Power Flow (OPF) Studies

OPF studies are conducted to determine the seasonal generator voltage schedules and for reactive power planning. OPF study results are utilized to reduce system losses by adjusting VAR resources and by planning additional resources.

5. Stability

a) Angle

Duke performs stability analyses on large generating units as major generation or transmission changes occur on the system and as required by the Nuclear Regulatory Commission for the nuclear plants. In addition, stability analysis will be performed to comply with NERC Planning Standards. These studies assess the ability of the interconnected network to maintain angular stability of the generating units under various contingency situations. Many different contingencies are considered and the selection is dependent on the type of study and location within the transmission system. The stability of the Duke system and neighboring systems must be maintained for the contingencies specified in the applicable sections of the NERC Planning Standards and the SERC PP&G.

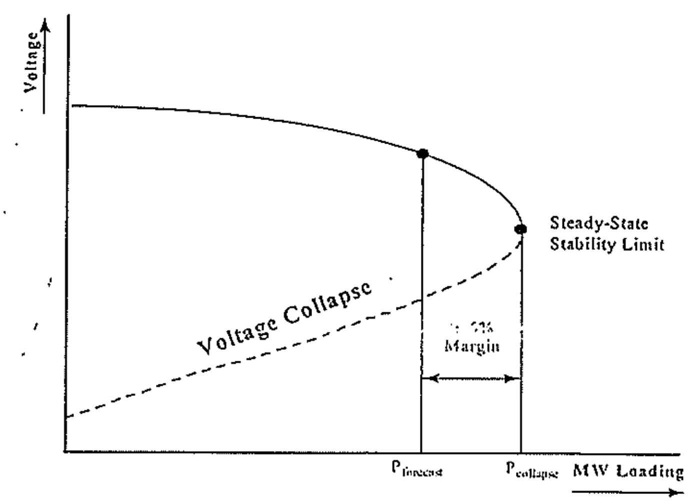
The corrective measures such as faster relaying, transmission upgrades, or unit tripping are determined on an individual basis after considering economics, probability of occurrence, and severity of the disturbance.

b) Voltage

An important part of preventing cascading outages is ensuring that voltage collapse will not occur for the applicable contingencies defined in the NERC Planning Standards and the SERC PP&G. To this end, and to ensure the security of the Duke transmission system, the following voltage collapse guidelines will be followed:

- The transmission system will be planned to avoid voltage collapse for the severe contingencies defined in the SERC PP&G.
- For single and double contingencies, the transmission system will be planned to maintain a margin to voltage collapse of greater than or equal to 5% of forecast system load. As shown in the figure below, $P_{collapse}$ must be greater than or equal to 105% of $P_{forecast}$.

Voltage Stability Margin



6. Power Transfer Studies

Power transfer studies may be conducted as a part of a facility addition or upgrade analysis, as a part of a system impact study, as well as with the regional study groups (VACAR, VST, VAST, VEM) to ensure system reliability.

Long-term Planning

An 1100 MW first contingency incremental transfer capability (FCITC) level should be maintained for imports into the Duke system from VACAR to ensure system reliability. Duke has an agreement with four systems within VACAR (CP&L, SCPSA, SCE&G, and VP) to share contingency reserves. By maintaining the 1100 MW level of FCITC with VACAR, Duke has the capability to import the shared reserve requirements from the member systems.

The following first contingency incremental transfer capability levels should be maintained for exports from the Duke system to ensure system reliability:

Non-Simultaneous Export Capability

Importing System	Minimum FCITC (MW)
CP&L	600
SCPSA	600
SCE&G	600
VP	600

Duke maintains adequate export capability with the four VACAR systems that share operating reserves to deliver Duke's portion of the reserve.

Available Transmission Capability ("ATC") is the measure of the transfer capability remaining in the physical transmission network for further transmission service over and above committed use. At the present time, the guidance for calculating and coordinating ATC is changing and becoming better defined. Duke is an active participant in industry organizations developing the methodologies and intends to apply applicable NERC, SERC and other industry guidance for calculating ATC.

7. Impact Study

Impact studies are performed to identify any problems associated with a requested/proposed system change. The following analyses are performed if necessary:

A. Power Flow Analysis
A power flow analysis will be performed to determine any violations of the planning guidelines due to the addition of the request. Projects that will be accelerated by the request will be identified as well as projects that will be needed to correct violations prior to implementation of the request.

B. Transfer Analysis
A transfer analysis will be performed to determine the impact on the bulk power system and to assess the changes that will occur in other areas resulting from the request.

C. Stability Analysis
A stability analysis will be performed to determine any violations to planning guidelines.

D. Fault Analysis
A fault analysis will be performed to determine information necessary for sizing equipment.

E. Other analyses as required for a particular request.

8. Fault Duty

Fault duty studies are performed to indicate the available fault duty for each transmission system (500, 230, 161, 100, 66, and 44 kV) breaker location. These fault duty study results are used to verify acceptable fault capability of breakers already in service. The results are also used to assist in the selection of new breakers to be installed. As system changes or additions are made, a fault duty study is done as needed for both current and future system configurations.

Network

Faults are evaluated for each breaker location to find the highest available fault current for the following conditions:

- single phase to ground fault
- two phase to ground fault
- three phase to ground fault
- fault resistance assumed to be zero
- location of fault assumed to be at terminals of the breaker in question
- all breakers at a bus in service
- breakers taken out, one at a time
- line mutual impedance included
- all generation units included
- adjacent system fault contributions included

The maximum calculated fault current at each breaker location and the associated breaker fault duty capability are compared to determine where violations of the breaker rating exist.

Radial

Fault duty for radial locations not explicitly modeled are calculated using fault duty at the associated network bus and the impedance of the radial elements.

9. Miscellaneous Losses Evaluations

Various equipment and system loss evaluations are performed to aid in the selection of equipment, to meet contractual obligations and to compare system configurations.

10. Facilities Adequate Evaluations

Facility evaluations are performed when a customer requests an increase in contract MW. The existing equipment, metering and analysis are evaluated for the proposed increase in load and a determination is made concerning any necessary improvements.

11. Severe Contingency Studies

SERC PP&G III.B.3 identifies contingencies that should not cause cascading. These events are considered during the severe contingency studies and are verified not to cause cascading.

The following contingencies are modeled to ensure compliance with SERC PP&G to avoid cascading outages:

a) Loss of all circuits on a common structure
b) Loss of all circuits on a common right-of-way
c) Loss of any single network 500 kV, 230 kV, or interconnection bus
d) Loss of a complete voltage level at a station
e) Loss of all generation at a station
f) Outage of a critical transmission line caused by a three-phase fault during the outage of another critical transmission line.
g) Delayed clearing of a three-phase fault on the system due to failure of a breaker to open.

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, 2001.

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