The Duke Energy Carolinas Annual Plan

September 1, 2006

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EXECUTIVE SUMMARY

Duke Power, d/b/a Duke Energy Carolinas, ("Duke Energy Carolinas" or "the Company"), a subsidiary of Duke Energy Corporation, is responsible for meeting its customers' energy needs in a reliable, economical manner with a least-cost mix of generation resources and demand-reduction measures. Duke Energy Carolinas faces a significant resource need over the next decade for new baseload, intermediate/peaking and demand-side management (DSM)[1] resources to meet the growing demand for electricity.

Consistent with the responsibility to meet customer energy needs in a reliable, economical manner, the Company's resource planning approach includes both quantitative analysis and qualitative considerations. A quantitative analysis can provide insights on future risks and uncertainties associated with fuel prices, load growth rates, capital and operating costs and other variables. Qualitative perspectives such as the state of competitive markets, the importance of fuel diversity, the Company's environmental profile, the stage of technology deployment and regional economic development are also important factors to consider as long-term decisions are made regarding new resources.

Company management uses all of these perspectives and analyses to ensure that Duke Energy Carolinas will meet near-term and long-term load obligations, while maintaining flexibility to adjust to evolving economic, environmental and operating circumstances in the future.

Although Duke Energy Corporation completed a merger with Cinergy Corp. ("Midwest") in April 2006, the Duke Energy Carolinas annual planning analysis is conducted separately from the Midwest resource planning.

Planning Process Results

The Spring 2006 Forecast indicates that Duke Energy Carolinas resource needs increase significantly over the 15 year planning horizon. The need grows to approximately 2100 MW by 2011 and 6100 MW by 2021. The factors that influence this are:

- Future load growth projections
- Reduction of available capacity and energy (resources), and
- A 17 percent target planning reserve margin over the 15 year horizon.

The quantitative and qualitative analyses suggest that a combination of additional baseload, intermediate and/or peaking generation and DSM programs are required over the next fifteen years. New coal and nuclear capacity additions, complemented by

[1] The term "energy efficiency" is often being used today to describe what has historically been called Demand Side Management (including typical demand response, energy efficiency, and related rate products). For the purposes of the Annual Plan, Duke Energy Carolinas will continue to utilize the term "Demand Side Management".

natural gas combustion turbine and/or combined-cycle units, are attractive supply-side options under a variety of sensitivities and scenarios. In light of these analyses, as well as the public policy debate on energy and environmental issues and the state of competitive markets, Duke Energy Carolinas has developed a strategy to ensure that the Company can meet customers' energy needs reliably and economically while maintaining flexibility pertaining to long-term resource decisions.

The Company will take the following actions in the upcoming year:

- Complete the acquisition of the Rockingham Power Facility.
  - North Carolina Utilities Commission (NCUC) approval was received on July 25, 2006.
  - Early termination of the Hart-Scott-Rodino Antitrust Improvement Act of 1976 waiting period was granted by the Department of Justice (DOJ) on July 20, 2006.
  - On July 28, 2006, Duke Energy Carolinas submitted its section 203 application to the Federal Energy Regulatory Commission (FERC) for approval of the Rockingham acquisition. FERC's ruling on the application is anticipated by November 1, 2006.
- Actively pursue new coal generation, with the objective of bringing additional capacity on line by 2011 at the existing Cliffside Steam Station.
  - Duke Energy Carolinas filed an application and supporting testimony with the NCUC for a Certificate of Public Convenience and Necessity for up to 1600 MWs of new coal-fired generation.
  - Duke Energy Carolinas submitted a complete air-quality permit application to the North Carolina Division of Air Quality on December 16, 2005.
- Maintain the option to license and permit a new combined-cycle/peaking facility.
  - Duke Energy Carolinas filed preliminary information for a CPCN with the NCUC for 600 MWs of combined-cycle generation.
- Continue to evaluate new nuclear generation by pursuing the Nuclear Regulatory Commission's Combined Construction and Operating License, with the objective of potentially bringing a new plant on line by 2016.
  - Duke Energy Carolinas has entered into an agreement with Southern Company to evaluate potential nuclear plant construction at the jointly-owned Cherokee County, S.C. location.
- Establish collaborative partnerships to further define, develop, implement and promote potential demand response and energy efficiency products and services.
- Continue to assess opportunities to benefit from economies of scale in new resource decisions by considering the prospects for joint ownership and/or sales agreements.
- Continue to monitor renewable generation options.
- Continue to monitor energy-related statutory and regulatory activities.

I. INTRODUCTION

Duke Energy Carolinas has an obligation to provide reliable, economical electric service to its customers in North Carolina and South Carolina. To meet this obligation, the Company conducted a resource planning process that serves as the basis for its 2006 Annual Plan.

This 2006 Annual Plan will discuss the:

- Current state of Duke Energy Carolinas, including existing generation, demand and purchased power agreements
- 15-year load forecast and resource need projection
- Target planning reserve margin
- New generation, demand-side and purchased power opportunities
- Results of the planning process, and
- Near-term actions needed to meet customers' energy needs that maintain flexibility if operating environments change.

II. DUKE ENERGY CAROLINAS CURRENT STATE

Overview

Duke Energy Carolinas is one of the largest investor-owned utilities in the United States, with an approximately 22,000-square-mile service area in central and western North Carolina and western South Carolina. In addition to retail sales to approximately 2.27 million customers, Duke Energy Carolinas also sells wholesale electricity to incorporated municipalities and to public and private utilities. Although Duke Energy Corporation completed a merger with Cinergy Corp. ("Midwest") in April 2006, the Duke Energy Carolinas integrated resource planning analysis is conducted separately from the Midwest resource planning. The tables below show numbers of customers and sales of electricity by customer groupings.

Table 2.1
Retail Customers (1000s, by number billed)

	2005	2004	2003
Residential	1,874	1,841	1,814
General Service	312	306	300
Industrial	8	8	8
Nantahala Power & Light	68	67	66
Other	13	12	11
Total	2,275	2,234	2,199

(Number of customers is average of monthly figures)

Table 2.2
Electricity Sales (GWH Sold - Years Ended December 31)

Electric Operations	**2005**	**2004**	**2003**
Residential	25,460	24,542	23,356
General Service	25,236	24,775	23,933
Industrial	25,361	25,085	24,645
Nantahala Power & Light	2,079	1,995	1,898
Other[a]	266	267	268
Total Retail Sales	78,402	76,664	74,100
Wholesale Sales[b]	2,251	1,969	2,359
Total GWH sold	80,653	78,633	76,459

[a] Other = Municipal street lighting and traffic signals
[b] Wholesale sales include sales to customers under the Schedule 10A rate, Western Carolina University, City of Highlands and the joint owners of the Catawba Nuclear Station (Catawba Owners). Short-term, non-firm wholesale sales subject to the Bulk Power Market sharing agreement are not included.

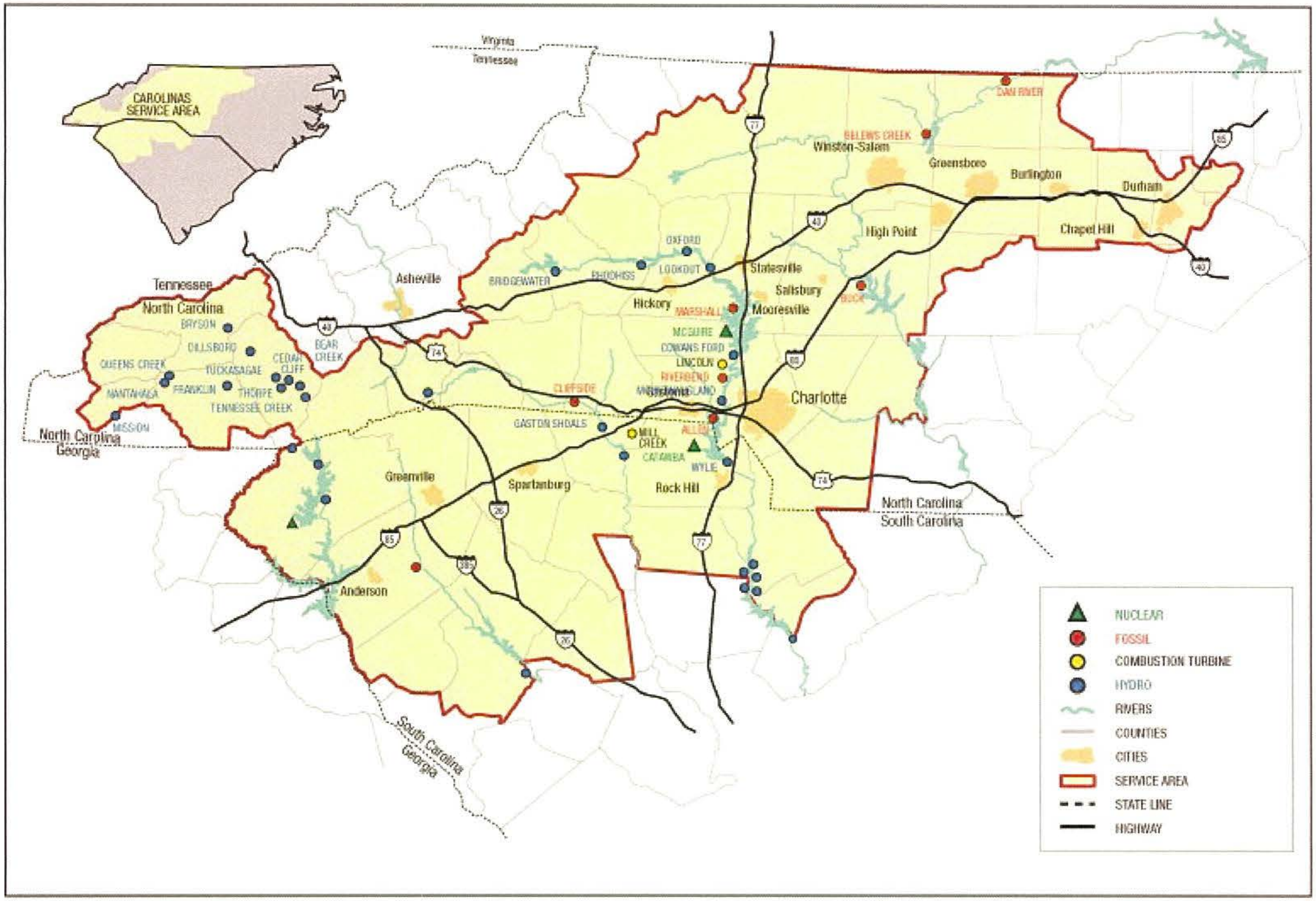
Duke Energy Carolinas meets energy demand in part by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets:

- Three nuclear generating stations with a combined net capacity of 6,996 MW (including all of Catawba Nuclear Station)
- Eight coal-fired stations with a combined capacity of 7,754 MW
- 30 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 3,162 MW, and
- Seven combustion turbine stations with a combined capacity of 2,447 MW.

Duke Energy Carolinas' power delivery system consists of approximately 95,000 miles of distribution lines and 13,000 miles of transmission lines. The transmission system is directly connected to all the utilities that surround the Duke Energy Carolinas service area. There are 33 circuits connecting with eight different utilities – Progress Energy Carolinas, American Electric Power, Tennessee Valley Authority, Southern Company, Yadkin, Southeastern Power Administration (SEPA), South Carolina Electric and Gas and Santee Cooper (also known as South Carolina Public Service Authority). These interconnections allow utilities to work together to provide an additional level of reliability. The strength of the system is also reinforced through coordination with other electric service providers in the Virginia-Carolinas (VACAR) subregion, Southeastern Electric Reliability Council (SERC) and North American Electric Reliability Council (NERC).

The following map provides a high-level view of the Duke Energy Carolinas system.

Duke Energy's Generating System in the Carolinas



Transmission System Adequacy [2]

Duke Energy Carolinas monitors the adequacy and reliability of its transmission system and interconnections through internal analysis and participation in regional reliability groups. Internal transmission planning looks ahead 10 years at available generating resources and projected load to identify transmission system upgrade and expansion requirements. Corrective actions are planned and implemented in advance to ensure continued cost-effective and high-quality service. The Duke Energy Carolinas' transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability.

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with Duke Energy Carolinas' Transmission Planning Guidelines for voltage and thermal loading, using screening methods that comply with SERC policy and NERC Reliability Standards. The screening results identify the need for future transmission system expansion and upgrades and are used as inputs into the Duke Energy Carolinas – Power Delivery Asset Management Plan (PDAMP). The PDAMP process evaluates problem-solution alternatives and their priority, scope, cost, and timing. The result of the PDAMP process is a budget and schedule of transmission system projects.

Duke Energy Carolinas currently evaluates all transmission reservation requests for impact on transfer capability as well as compliance with the Company's Transmission Planning Guidelines and the FERC Open Access Transmission Tariff (OATT). Studies are performed to ensure transfer capability is acceptable to meet our customers expected use of the transmission system. The PDAMP process is also used to manage projects for improvement of transfer capability.

Lessons learned from the August 2003 blackout in the northeast United States have been incorporated into Duke Energy Carolinas' processes. Operators now have additional monitoring tools and training to enhance their ability to recognize deteriorating system conditions. Refined procedures have also been developed in the event a black start is required to restore the system.

SERC audits Duke Energy Carolinas every three years for compliance with NERC Reliability Standards. Specifically, the audit requires Duke Energy Carolinas to demonstrate that its transmission planning practices meet NERC standards and to provide data supporting the Company's annual compliance filing certifications.

[2] NCUC Order dated February 22, 2005 in Docket No. E-100, Sub 102 requires utilities to address transmission system adequacy in annual plans and to provide FERC Form 715. Appendix C to this Annual Plan includes a copy of Duke Energy Carolinas' most recent FERC Form 715 with attachments and exhibits. Duke Energy Carolinas' FERC Form 715 is confidential pursuant to N.C. Gen. Stat. § 132-1.2, and Appendix C is filed under seal as specified in NCUC Rule R8-60.

Duke Energy Carolinas participates in a number of regional reliability groups to coordinate analysis of regional, sub-regional and inter-control area transfer capability and interconnection reliability. The reliability groups:

- Assess the interconnected system's capability to handle large firm and non-firm transactions
- Ensure that planned future transmission system improvements do not adversely affect neighboring systems, and
- Ensure the interconnected system's compliance with NERC Reliability Standards.

Regional reliability groups evaluate transfer capability and compliance with NERC Reliability Standards for the upcoming peak season and five and ten-year periods. The groups also perform computer simulation tests for high transfer levels to verify satisfactory transfer capability.

NERC's six regional councils that encompass the Eastern Interconnection formed the Eastern Interconnection Reliability Assessment Group (ERAG) effective August 1, 2006. The six regional councils, including SERC Reliability Corporation of which Duke Energy Carolinas is a member, created ERAG to enhance reliability of the international bulk power system through reviews of generation and transmission expansion programs and forecasted system conditions within the boundaries of the Eastern Interconnection.

The Company serves as Reliability Coordinator for the VACAR sub-region. NERC conducted a readiness assessment of Duke Energy Carolinas' Reliability Coordinator function in June 2005 and found that VACAR has adequate facilities, processes and procedures to perform its Reliability Coordinator functions. NERC also determined that the staff is knowledgeable and competent, and identified several "Examples of Excellence" during the assessment.

Existing Generation Plants in Service

Duke Energy Carolinas' generation portfolio is a balanced mix of resources with different operating and fuel characteristics. This mix is designed to provide energy at the lowest reasonable cost to meet the Company's obligation to serve customers. Duke Energy Carolinas-owned generation, as well as purchased power, is evaluated on a real-time basis in order to select and dispatch the lowest-cost resources to meet system load requirements. In 2005, Duke Energy Carolinas' nuclear (45.7%) and coal-fired generating units (52.5%) met the vast majority of customer needs. Hydroelectric and combustion-turbine generation and economical purchases from the wholesale market supplied the remainder.

The tables below list the Duke Energy Carolinas plants in service in North Carolina and South Carolina with plant statistics, and the system's total generating capability.

Table 2.3
North Carolina [a,b,c,d,e]

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Allen	1	165.0	170.0	Belmont, N.C.	Conventional Coal
Allen	2	165.0	170.0	Belmont, N.C.	Conventional Coal
Allen	3	265.0	274.0	Belmont, N.C.	Conventional Coal
Allen	4	280.0	286.0	Belmont, N.C.	Conventional Coal
Allen	5	270.0	279.0	Belmont, N.C.	Conventional Coal
Allen Steam Station		**1145.0**	**1179.0**		
Belews Creek	1	1135.0	1160.0	Belews Creek, N.C.	Conventional Coal
Belews Creek	2	1135.0	1160.0	Belews Creek, N.C.	Conventional Coal
Belews Creek Steam Station		**2270.0**	**2320.0**		
Buck	3	75.0	76.0	Salisbury, N.C.	Conventional Coal
Buck	4	38.0	39.0	Salisbury, N.C.	Conventional Coal
Buck	5	128.0	131.0	Salisbury, N.C.	Conventional Coal
Buck	6	128.0	131.0	Salisbury, N.C.	Conventional Coal
Buck Steam Station		**369.0**	**377.0**		
Cliffside	1	38.0	39.0	Cliffside, N.C.	Conventional Coal
Cliffside	2	38.0	39.0	Cliffside, N.C.	Conventional Coal
Cliffside	3	61.0	62.0	Cliffside, N.C.	Conventional Coal
Cliffside	4	61.0	62.0	Cliffside, N.C.	Conventional Coal
Cliffside	5	562.0	568.0	Cliffside, N.C.	Conventional Coal
Cliffside Steam Station		**760.0**	**770.0**		
Dan River	1	67.0	69.0	Eden, N.C.	Conventional Coal
Dan River	2	67.0	69.0	Eden, N.C.	Conventional Coal
Dan River	3	142.0	145.0	Eden, N.C.	Conventional Coal
Dan River Steam Station		**276.0**	**283.0**		
Marshall	1	385.0	385.0	Terrell, N.C.	Conventional Coal
Marshall	2	385.0	385.0	Terrell, N.C.	Conventional Coal
Marshall	3	670.0	670.0	Terrell, N.C.	Conventional Coal
Marshall	4	670.0	670.0	Terrell, N.C.	Conventional Coal
Marshall Steam Station		**2110.0**	**2110.0**		
Riverbend	4	94.0	96.0	Mt. Holly, N.C.	Conventional Coal
Riverbend	5	94.0	96.0	Mt. Holly, N.C.	Conventional Coal
Riverbend	6	133.0	136.0	Mt. Holly, N.C.	Conventional Coal
Riverbend	7	133.0	136.0	Mt. Holly, N.C.	Conventional Coal
Riverbend Steam Station		**454.0**	**464.0**		
TOTAL N.C. CONVENTIONAL COAL		**7384.0 MW**	**7503.0 MW**		

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Buck	7C	31.0	31.0	Salisbury, N.C.	Combustion Turbine
Buck	8C	31.0	31.0	Salisbury, N.C.	Combustion Turbine
Buck	9C	31.0	31.0	Salisbury, N.C.	Combustion Turbine
Buck Station CTs		**93.0**	**93.0**		
Dan River	4C	30.0	30.0	Eden, N.C.	Combustion Turbine
Dan River	5C	30.0	30.0	Eden, N.C.	Combustion Turbine
Dan River	6C	25.0	25.0	Eden, N.C.	Combustion Turbine
Dan River Station CTs		**85.0**	**85.0**		
Lincoln	1	79.2	93.0	Stanley, N.C.	Combustion Turbine
Lincoln	2	79.2	93.0	Stanley, N.C.	Combustion Turbine
Lincoln	3	79.2	93.0	Stanley, N.C.	Combustion Turbine
Lincoln	4	79.2	93.0	Stanley, N.C.	Combustion Turbine
Lincoln	5	79.2	93.0	Stanley, N.C.	Combustion Turbine
Lincoln	6	79.2	93.0	Stanley, N.C.	Combustion Turbine
Lincoln	7	79.2	93.0	Stanley, N.C.	Combustion Turbine
Lincoln	8	79.2	93.0	Stanley, N.C.	Combustion Turbine
Lincoln	9	79.2	93.0	Stanley, N.C.	Combustion Turbine
Lincoln	10	79.2	93.0	Stanley, N.C.	Combustion Turbine
Lincoln	11	79.2	93.0	Stanley, N.C.	Combustion Turbine
Lincoln	12	79.2	93.0	Stanley, N.C.	Combustion Turbine
Lincoln	13	79.2	93.0	Stanley, N.C.	Combustion Turbine
Lincoln	14	79.2	93.0	Stanley, N.C.	Combustion Turbine
Lincoln	15	79.2	93.0	Stanley, N.C.	Combustion Turbine
Lincoln	16	79.2	93.0	Stanley, N.C.	Combustion Turbine
Lincoln Station CTs		**1268.0**	**1488.0**		
Riverbend	8C	30.0	30.0	Mt. Holly, N.C.	Combustion Turbine
Riverbend	9C	30.0	30.0	Mt. Holly, N.C.	Combustion Turbine
Riverbend	10C	30.0	30.0	Mt. Holly, N.C.	Combustion Turbine
Riverbend	11C	30.0	30.0	Mt. Holly, N.C.	Combustion Turbine
Riverbend Station CTs		**120.0**	**120.0**		
TOTAL N.C. COMB. TURBINE		**1566.0 MW**	**1786.0 MW**		
McGuire	1	1100.0	1156.0	Huntersville, N.C.	Nuclear
McGuire	2	1100.0	1156.0	Huntersville, N.C.	Nuclear
McGuire Nuclear Station		**2200.0**	**2312.0**		
TOTAL N.C. NUCLEAR		**2200.0 MW**	**2312.0 MW**		
Bridgewater	1	11.5	11.5	Morganton, N.C.	Hydro
Bridgewater	2	11.5	11.5	Morganton, N.C.	Hydro

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Bridgewater Hydro Station		**23.0**	**23.0**		
Bryson City	1	0.48	0.48	Whittier, N.C.	Hydro
Bryson City	1	0.5	0.5	Whittier, N.C.	Hydro
Bryson City Hydro Station		**0.98**	**0.98**		
Cowans Ford	1	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	2	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	3	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	4	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford Hydro Station		**325.0**	**325.0**		
Dillsboro	1	0.175	0.175	Dillsboro, N.C.	Hydro
Dillsboro	2	0.05	0.05	Dillsboro, N.C.	Hydro
Dillsboro Hydro Station		**0.225**	**0.225**		
Lookout Shoals	1	9.3	9.3	Statesville, N.C.	Hydro
Lookout Shoals	2	9.3	9.3	Statesville, N.C.	Hydro
Lookout Shoals	3	9.3	9.3	Statesville, N.C.	Hydro
Lookout Shoals Hydro Station		**28.0**	**28.0**		
Mountain Island	1	14	14	Mount Holly, N.C.	Hydro
Mountain Island	2	15	15	Mount Holly, N.C.	Hydro
Mountain Island	3	15	15	Mount Holly, N.C.	Hydro
Mountain Island	4	14	14	Mount Holly, N.C.	
Mountain Island Hydro Station		**58.0**	**58.0**		
Oxford	1	20.0	20.0	Conover, N.C.	Hydro
Oxford	2	20.0	20.0	Conover, N.C.	Hydro
Oxford Hydro Station		**40.0**	**40.0**		
Rhodhiss	1	11.0	11.0	Rhodhiss, N.C.	Hydro
Rhodhiss	2	11.0	11.0	Rhodhiss, N.C.	Hydro
Rhodhiss	3	8.0	8.0	Rhodhiss, N.C.	Hydro
Rhodhiss Hydro Station		**30.0**	**30.0**		
Tuxedo	1	3.2	3.2	Flat Rock, N.C.	Hydro
Tuxedo	2	3.2	3.2	Flat Rock, N.C.	Hydro
Tuxedo Hydro Station		**6.4**	**6.4**		
Bear Creek	1	9.45	9.45	Tuckasegee, N.C.	Hydro
Bear Creek Hydro Station		**9.45**	**9.45**		
Cedar Cliff	1	6.4	6.4	Tuckasegee, N.C.	Hydro
Cedar Cliff Hydro Station		**6.4**	**6.4**		
Franklin	1	0.5	0.5	Franklin, N.C.	Hydro
Franklin	2	0.5	0.5	Franklin, N.C.	Hydro

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Franklin Hydro Station		**1.0**	**1.0**		
Mission	1	0.6	0.6	Murphy, N.C.	Hydro
Mission	2	0.6	0.6	Murphy, N.C.	Hydro
Mission	3	0.6	0.6	Murphy, N.C.	Hydro
Mission Hydro Station		**1.8**	**1.8**		
Nantahala	1	50.0	50.0	Topton, N.C.	Hydro
Nantahala Hydro Station		**50.0**	**50.0**		
Tennessee Creek	1	9.8	9.8	Tuckasegee, N.C.	Hydro
Tennessee Creek Hydro Station		**9.8**	**9.8**		
Thorpe	1	19.7	19.7	Tuckasegee, N.C.	Hydro
Thorpe Hydro Station		**19.7**	**19.7**		
Tuckasegee	1	2.5	2.5	Tuckasegee, N.C.	Hydro
Tuckasegee Hydro Station		**2.5**	**2.5**		
Queens Creek	1	1.44	1.44	Topton, N.C.	Hydro
Queens Creek Hydro Station		**1.44**	**1.44**		
TOTAL N.C. HYDRO		**613.7 MW**	**613.7 MW**		
TOTAL N.C. CAPABILITY		**11,763.7 MW**	**12,214.7 MW**		

Table 2.4
South Carolina [a,b,c,d,e]

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Lee	1	100.0	100.0	Pelzer, S.C.	Conventional Coal
Lee	2	100.0	102.0	Pelzer, S.C.	Conventional Coal
Lee	3	170.0	170.0	Pelzer, S.C.	Conventional Coal
Lee Steam Station		**370.0**	**372.0**		
TOTAL S.C. CONVENTIONAL COAL		**370.0 MW**	**372.0 MW**		
Buzzard Roost	6C	22.0	22.0	Chappels, S.C.	Combustion Turbine
Buzzard Roost	7C	22.0	22.0	Chappels, S.C.	Combustion Turbine
Buzzard Roost	8C	22.0	22.0	Chappels, S.C.	Combustion Turbine
Buzzard Roost	9C	22.0	22.0	Chappels, S.C.	Combustion Turbine
Buzzard Roost	10C	18.0	18.0	Chappels, S.C.	Combustion Turbine
Buzzard Roost	11C	18.0	18.0	Chappels, S.C.	Combustion Turbine
Buzzard Roost	12C	18.0	18.0	Chappels, S.C.	Combustion Turbine
Buzzard Roost	13C	18.0	18.0	Chappels, S.C.	Combustion Turbine
Buzzard Roost	14C	18.0	18.0	Chappels, S.C.	Combustion Turbine
Buzzard Roost	15C	18.0	18.0	Chappels, S.C.	Combustion Turbine
Buzzard Roost Station CTs		**196.0**	**196.0**		
Lee	4C	30.0	30.0	Pelzer, S.C.	Combustion Turbine
Lee	5C	30.0	30.0	Pelzer, S.C.	Combustion Turbine
Lee	6C	30.0	30.0	Pelzer, S.C.	Combustion Turbine
Lee Station CTs		**90.0**	**90.0**		
Mill Creek	1	74.42	92.4	Blacksburg, S.C.	Combustion Turbine
Mill Creek	2	74.42	92.4	Blacksburg, S.C.	Combustion Turbine
Mill Creek	3	74.42	92.4	Blacksburg, S.C.	Combustion Turbine
Mill Creek	4	74.42	92.4	Blacksburg, S.C.	Combustion Turbine
Mill Creek	5	74.42	92.4	Blacksburg, S.C.	Combustion Turbine
Mill Creek	6	74.42	92.4	Blacksburg, S.C.	Combustion Turbine
Mill Creek	7	74.42	92.4	Blacksburg, S.C.	Combustion Turbine
Mill Creek	8	74.42	92.4	Blacksburg, S.C.	Combustion Turbine
Mill Creek Station CTs		**595.0**	**739.0**		
TOTAL S.C. COMB TURBINE		**881.0 MW**	**1025.0 MW**		
Catawba	1	1129.0	1163.0	York, S.C.	Nuclear
Catawba	2	1129.0	1163.0	York, S.C.	Nuclear
Catawba Nuclear Station		**2258.0**	**2326.0**		
Oconee	1	846.0	865.0	Seneca, S.C.	Nuclear

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Oconee	2	846.0	865.0	Seneca, S.C.	Nuclear
Oconee	3	846.0	865.0	Seneca, S.C.	Nuclear
Oconee Nuclear Station		**2538.0**	**2595.0**		
TOTAL S.C. NUCLEAR		**4796.0 MW**	**4921.0 MW**		
Jocassee	1	170.0	170.0	Salem, S.C.	Pumped Storage
Jocassee	2	170.0	170.0	Salem, S.C.	Pumped Storage
Jocassee	3	170.0	170.0	Salem, S.C.	Pumped Storage
Jocassee	4	170.0	170.0	Salem, S.C.	Pumped Storage
Jocassee Pumped Hydro Station		**680.0**	**680.0**		
Bad Creek	1	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	2	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	3	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	4	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek Pumped Hydro Station		**1360.0**	**1360.0**		
TOTAL PUMPED STORAGE		**2040.0 MW**	**2040.0 MW**		
Cedar Creek	1	13.0	13.0	Great Falls, S.C.	Hydro
Cedar Creek	2	15.0	15.0	Great Falls, S.C.	Hydro
Cedar Creek	3	15.0	15.0	Great Falls, S.C.	Hydro
Cedar Creek Hydro Station		**43.0**	**43.0**		
Dearborn	1	14.0	14.0	Great Falls, S.C.	Hydro
Dearborn	2	14.0	14.0	Great Falls, S.C.	Hydro
Dearborn	3	14.0	14.0	Great Falls, S.C.	Hydro
Dearborn Hydro Station		**42.0**	**42.0**		
Fishing Creek	1	11.0	11.0	Great Falls, S.C.	Hydro
Fishing Creek	2	9.5	9.5	Great Falls, S.C.	Hydro
Fishing Creek	3	9.5	9.5	Great Falls, S.C.	Hydro
Fishing Creek	4	11.0	11.0	Great Falls, S.C.	Hydro
Fishing Creek	5	8.0	8.0	Great Falls, S.C.	Hydro
Fishing Creek Hydro Station		**49.0**	**49.0**		
Gaston Shoals	3	1.0	1.0	Blacksburg, S.C.	Hydro
Gaston Shoals	4	1.0	1.0	Blacksburg, S.C.	Hydro
Gaston Shoals	5	1.0	1.0	Blacksburg, S.C.	Hydro
Gaston Shoals	6	1.7	1.7	Blacksburg, S.C.	Hydro

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Gaston Shoals Hydro Station		**4.7**	**4.7**		
Great Falls	1	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	2	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	3	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	4	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	5	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	6	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	7	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	8	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls Hydro Station		**24.0**	**24.0**		
Rocky Creek	1	2.9	2.9	Great Falls, S.C.	Hydro
Rocky Creek	2	2.9	2.9	Great Falls, S.C.	Hydro
Rocky Creek	3	2.9	2.9	Great Falls, S.C.	Hydro
Rocky Creek	4	2.9	2.9	Great Falls, S.C.	Hydro
Rocky Creek	5	4.8	4.8	Great Falls, S.C.	Hydro
Rocky Creek	6	4.8	4.8	Great Falls, S.C.	Hydro
Rocky Creek	7	2.9	2.9	Great Falls, S.C.	Hydro
Rocky Creek	8	2.9	2.9	Great Falls, S.C.	Hydro
Rocky Creek Hydro Station		**27.0**	**27.0**		
Wateree	1	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	2	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	3	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	4	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	5	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree Hydro Station		**85.0**	**85.0**		
Wylie	1	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie	2	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie	3	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie	4	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie Hydro Station		**72.0**	**72.0**		
99 Islands	1	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	2	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	3	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	4	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	5	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	6	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands Hydro Station		**9.6**	**9.6**		
Keowee	1	76.0	76.0	Seneca, S.C.	Hydro
Keowee	2	76.0	76.0	Seneca, S.C.	Hydro
Keowee Hydro		**152.0**	**152.0**		

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Station					
TOTAL S.C. HYDRO		508.3 MW	508.3 MW		
TOTAL S.C. CAPABILITY		8595.3 MW	8866.2 MW		

Table 2.5
Total Generation Capability [a,b,c,d,e]

NAME	SUMMER CAPACITY MW	WINTER CAPACITY MW
TOTAL DUKE ENERGY CAROLINAS GENERATING CAPABILITY	20,359	21,081

Note a: Unit information is provided by state, but resources are dispatched on a system-wide basis.

Note b: Summer and winter capability does not take into account reductions due to future environmental emission controls.

Note c: Summer and winter capability reflects system configuration as of September 1, 2006.

Note d: Catawba Units 1 and 2 capacity reflects 100% of the station's capability, and does not factor in the North Carolina Municipal Power Agency #1's (NCMPA#1) decision to sell or utilize its 832 MW retained ownership in Catawba.

Note e: The Catawba units' multiple owners and their effective ownership percentages are:

CATAWBA OWNER	PERCENT OF OWNERSHIP
Duke Energy Carolinas	12.5%
North Carolina Electric Membership Corporation (NCEMC)	28.125%
NCMPA#1	37.5%
Piedmont Municipal Power Agency (PMPA)	12.5%
Saluda River (SR)	9.375%

Fuel Supply

Duke Energy Carolinas burns approximately 18 million tons of coal annually. Coal is procured primarily from Central Appalachian coal mines and delivered by Norfolk Southern or CSX railroads. The Company assesses coal market conditions to determine the appropriate mix of contract and spot purchases in order to reduce the Company's exposure to the risk of price fluctuations. The Company will evaluate its diversity of coal supply going forward from sources throughout the United States and international sources.

To provide fuel for Duke Energy Carolinas' nuclear fleet, the Company maintains a diversified portfolio of natural uranium and downstream services (conversion, enrichment and fabrication) supply contracts from around the world. The majority of the energy production from Duke Energy Carolinas generating units has come from the coal and nuclear units (98%). Hence, the recent increases in natural gas and oil prices have had less impact on Duke Energy Carolinas' cost to produce energy than utilities who are more dependent upon oil and natural gas.

Renewable Energy Initiatives

Duke Energy Carolinas has supported development of renewable energy through:

- Financial and in-kind support of the North Carolina GreenPower program (a voluntary program that promotes the development of renewable generation resources in North Carolina)
- Development of the Model Small Generator Interconnection Standards (a very streamlined process in support of small customer generators interconnecting with Duke Energy Carolinas' electrical system which was approved in North Carolina and filed in South Carolina)
- Development of the Small Customer Generator Rider (Rider SCG)
- Development of the Net Metering Rider (Rider NM)
- Existing contracts with Qualifying Facilities, and
- Existing Duke Energy Carolinas hydroelectric power generation.

The North Carolina GreenPower Program is a statewide initiative approved by the NCUC. The mission of NC GreenPower is to encourage renewable generation development from resources such as sun, wind, hydro and organic matter by enabling North Carolina electric consumers, businesses, and organizations to help offset the cost to produce green energy. Duke Energy Carolinas supports NC GreenPower by facilitating customer contributions to the program. As a part of the Merger with Cinergy, Duke Energy Carolinas donated $2,000,000 to NC Green Power. This money will aid in the growth of energy from renewable sources in North Carolina. NC GreenPower has been instrumental in the growth of renewable generation in North Carolina and there have been discussions to bring this concept into South Carolina.

Duke Energy Carolinas, other utilities and stakeholders worked collaboratively to develop Model Small Generator Interconnection Standards. These standards provide potential owners of small distributed generation systems, including renewable energy sources, with uniform, simplified standard criteria and procedures for interconnecting with electric utilities in North Carolina. Duke Energy Carolinas has filed with the NCUC both the Net Metering (Rider NM) and Small Customer Generator (Rider SCG) Riders that incorporate these standards.

Duke Energy Carolinas currently has purchased power agreements with the following Qualifying Facility renewable energy providers:

- Salem Energy Systems, the Hanes Road Landfill in Winston-Salem - 3 MW
- Catawba County Blackburn Landfill facility - 3 MW
- Northbrook Carolina Hydro (5 facilities) - 6 MW
- Town of Lake Lure Hydro - 2 MW
- 19 hydro energy providers - 5 MW total *

* See Appendix J for further details on the 19 hydro energy providers.

Duke Energy Carolinas also owns and operates 30 hydroelectric stations having a combined generating capacity of 3162 MW. In order to preserve the viability of the conventional hydro facilities, Duke Energy Carolinas is pursuing FERC license renewal approval for seven hydroelectric projects and will surrender one license over the next several years. The duration of a new FERC license for a hydropower facility can range from 30 to 50 years depending on various factors at the time of relicensing. See Appendix M for additional details.

In addition to the aforementioned efforts to promote renewable energy, Duke Energy Carolinas, in 2005, performed tests to determine the feasibility of co-firing food grease with coal. The food grease was collected by a commercial vendor from restaurants. In addition, 5,000 – 6,000 gallons of used oil collected from Duke Energy Carolinas facilities is co-fired annually at the Lee Steam Station in South Carolina. Duke Energy Carolinas will continue to evaluate renewable projects for their economic and environmental viability.

Current Demand-Side Management[3] (DSM) Programs

Duke Energy Carolinas uses DSM programs to help manage customer demand in an efficient, cost-effective manner. DSM programs can vary greatly in their dispatch characteristics, size and duration of load response, certainty of load response and frequency of customer participation. In general, DSM programs include two primary

[3] The term "energy efficiency" is often being used today to describe what has historically been called Demand Side Management (including typical demand response, energy efficiency, and related rate products). For the purposes of the Annual Plan, Duke Energy Carolinas will continue to utilize the term "Demand Side Management".

categories: programs that reduce energy consumption (energy efficiency programs) and programs that reduce energy demand (demand response programs and certain rate structures).

Demand Response – Load Control Curtailment Programs

These programs can be dispatched by the utility and have the highest level of certainty. Once a customer agrees to participate in a demand response load control curtailment program, the Company controls the timing, frequency and nature of the load response. Duke Energy Carolinas' load control curtailment programs include:

- Residential Air Conditioning Direct Load Control
- Residential Water Heating Direct Load Control

Demand Response – Interruptible and Related Rate Structures

These programs rely either on the customer's ability to respond to a utility-initiated signal requesting curtailment or on rates with price signals that provide an economic incentive to reduce or shift load. Timing, frequency and nature of the load response depend on customers' voluntary actions. Duke Energy Carolinas' interruptible and time of use curtailment programs include:

- Programs using utility-requested curtailment signal
    - Interruptible Power Service
    - Standby Generator Control
- Rates using price signals
    - Residential Time-of-Use (including a Residential Water Heating rate)
    - General Service and Industrial Optional Time-of-Use rates
    - Hourly Pricing for Incremental Load and Hourly Pricing – Flex

Beginning September 1, 2006, firm wholesale agreements become effective between Duke Energy Carolinas and three entities, Blue Ridge Electric Membership Cooperative, Piedmont Electric Membership Cooperative, and Rutherford Electric Membership Cooperative. These contracts may add approximately 60 MW of demand response capability to Duke Energy Carolinas. At this time, Duke Energy Carolinas is studying the exact size and nature of this additional capability. For the purposes of this IRP, this capability has not been included in demand response program capacity due to the uncertainties about its size and characteristics.

Energy Efficiency Programs

These programs are typically non-dispatchable, conservation-oriented education or incentive programs. Energy and capacity savings are achieved by changing customer behavior or through the installation of more energy-efficient equipment or structures. All effects of these existing programs are reflected in the customer load forecast. Duke Energy Carolinas' existing energy efficiency programs include:

- Residential Energy Star rates for new construction
- Existing Residential Housing Program

- Special Needs Energy Products Loan Program

A more detailed description of each program can be found in Appendix D. A discussion of potential programs can be found in Appendix I.

Curtailable Service

Duke Energy Carolinas offers a Curtailable Service Rider (Rider CS) to customers as a pilot program. This program mitigates the Company's financial risk of being forced, by capacity problems, to purchase power to supply native load during times of very high wholesale prices. Payments are closely aligned with market prices of energy, allowing the Company to offset high-cost energy purchases by paying participating customers to curtail load. This ultimately benefits all customers.

Wholesale Power Sales Commitments

Duke Energy Carolinas provides full requirements wholesale power sales to Western Carolina University (WCU), the city of Highlands and to customers served under Rate Schedule 10A. These customers' load requirements are included in the Duke Energy Carolinas load obligation (see Chart 3.1 and Cumulative Resource Additions to Meet a 17 Percent Planning Reserve Margin). Under Interconnection Agreements, Duke Energy Carolinas is obligated to provide backstand service for NCEMC throughout the 15-year planning horizon and Saluda River until January 1, 2009, up to the amount of their ownership entitlement in Catawba Nuclear Station. In 2009, the Saluda River ownership portion of Catawba will not be reflected in the forecast due to a future sale of this interest, which will cause Saluda River to become a full-requirements customer of another utility.

PMPA has served notice to end its Interconnection Agreements with Duke Energy Carolinas effective January 1, 2006. With that termination, the Company no longer has an obligation to supply supplemental energy to PMPA or to backstand PMPA's load up to its ownership entitlement in the Catawba Nuclear Station.

Beginning January 1, 2005, two firm wholesale agreements became effective between Duke Energy Carolinas and NCMPA1. The first is a 75 MW capacity sale that expires 12/31/2007. The second is a backstand agreement of up to 432 MW (depending on operation of the Catawba and McGuire facilities) that expires December 31, 2007.

Beginning September 1, 2006, firm wholesale agreements become effective between Duke Energy Carolinas and three entities, Blue Ridge Electric Membership Cooperative, Piedmont Electric Membership Cooperative, and Rutherford Electric Membership Cooperative. Duke Energy Carolinas will supply their supplemental resource needs through 2021. This need grows to approximately 700 MW by 2011 and approximately 900 MW by 2021.

Wholesale Purchased Power Agreements

Duke Energy Carolinas is an active participant in the wholesale market for capacity and energy. The Company has issued RFPs for purchased power capacity over the past several years, and has entered into purchased power arrangements for over 2,000 MWs over the past 10 years. In addition, Duke Energy Carolinas has contracts with a number of Qualifying Facilities. Table 2.6 shows both the purchased power capacity obtained through RFPs as well as the larger Qualifying Facility agreements. See Appendix J for additional information on all purchases from Qualifying Facilities.

Table 2.6
Wholesale Purchased Power Commitments

SUPPLIER	CITY	STATE	SUMMER FIRM CAPACITY (MW)	WINTER FIRM CAPACITY (MW)	CONTRACT START	CONTRACT EXPIRATION
Catawba County	Newton	N.C.	3	3	8/23/99	8/22/14
Cherokee County Cogeneration Partners, L.P.	Gaffney	S.C.	88	95	7/1/96	6/30/13
Ecusta Business Development Center	Brevard	N.C.	3	3	4/15/04	4/14/09
Northbrook Carolina Hydro, LLC	Various	Both	6	6	12/4/96	12/4/06[4]
Progress Ventures, Inc. Unit 1	Salisbury	N.C.	153	185	6/1/07	12/31/10
Progress Ventures, Inc. Unit 2	Salisbury	N.C.	151	184	1/1/06	12/31/10
Progress Ventures, Inc. Unit 3	Salisbury	N.C.	153	185	6/1/04	5/31/08
Progress Ventures, Inc. Unit 3	Salisbury	N.C.	153	185	6/1/08	12/31/10
Rockingham Power, LLC	Wentworth	N.C.	165	165	1/1/06	12/31/10[5]

[4] Northbrook Carolina Hydro, LLC is in negotiations with Duke Energy Carolinas to renew this purchased power contract.
[5] As a result of Duke Energy Carolinas' most recent RFP process for capacity, Duke Energy Carolinas and Rockingham, LLC entered into a purchase agreement of the Rockingham Power Facility. Once this purchase of the Rockingham Power Facility is completed, the purchased power commitment will cease.

SUPPLIER	CITY	STATE	SUMMER FIRM CAPACITY (MW)	WINTER FIRM CAPACITY (MW)	CONTRACT START	CONTRACT EXPIRATION
Rowan County Power, LLC Unit 1	Salisbury	N.C.	152	185	6/1/02	5/31/07
Salem Energy Systems, LLC	Winston-Salem	N.C.	3	3	7/10/96	7/10/11
Town of Lake Lure	Lake Lure	N.C.	2	2	2/18/99	2/17/06[6]
Misc. Small Hydro	Various	Both	5	5	Various	Assumed Evergreen

Summary of Wholesale Purchased Power Commitments[7]
(as of January 1, 2007)

	WINTER 06/07	SUMMER 07
Total Non-Utility Generation	836 MW	732 MW
Duke Energy Carolinas allocation of SEPA capacity	19 MW	19 MW
Total Firm Purchases	855 MW	751 MW

Legislative and Regulatory Issues

Duke Energy Carolinas is subject to the jurisdiction of many federal agencies, including FERC and EPA, as well as state commissions and agencies. The Company can also be affected by public policy actions that states and the federal government may take. For example, Duke Energy Carolinas is currently implementing the North Carolina Clean Smokestacks Act to reduce sulfur dioxide (SO_2) and nitrogen oxide (NOx) emissions from its generation facilities, and will also have to comply with the federal rules (Clean Air Interstate Rule and Clean Air Mercury Rule) to reduce SO_2, NOx and mercury emissions.

In addition, policy debate has increased on the issue of global climate change at both the state and federal levels. There is a significant amount of uncertainty regarding future federal climate change policy, and meanwhile a patchwork of state approaches is emerging. These issues, as well as the development of competitive markets and other regulatory matters, could have an impact on new generation decisions. See Appendix M for further discussion.

See Changes to Existing Resources portion of the Resource Needs Assessment (Future State) section for further information.
[6] The Town of Lake Lure is currently in negotiations with Duke Energy Carolinas to renew this purchased power contract.
[7] The Rockingham, LLC PPA is included in these figures.

III. RESOURCE NEEDS ASSESSMENT (FUTURE STATE)

To meet the future needs of our customers, it is necessary to understand the load and resource balance. For each year of the planning horizon, Duke Energy Carolinas develops a load forecast of energy sales and peak demand. To determine total resources needed, the Company considers the load obligation plus a 17 percent target planning reserve margin. The capability of existing resources, including generating units, demand-side management programs and purchased power contracts, are measured against the total resource need. Any deficit in future years will be met by a mix of additional resources that reliably and cost-effectively meet the load obligation.

The following sections provide detail on the load forecast and the changes to existing resources.

Load Forecast

The Spring 2006 Forecast includes projections for meeting the energy needs of new and existing customers in Duke Energy Carolinas service territory. Certain wholesale customers have the option of obtaining all or a portion of their future energy needs from other suppliers. While this may reduce Duke Energy Carolinas obligation to serve those customers, Duke Energy Carolinas assumes for planning purposes that its existing wholesale customer load (excluding Catawba owner loads as discussed below) will remain part of the load obligation.

The forecasts for 2006 through 2021 include the energy needs of the following customer classes:

- Duke Energy Carolinas retail
- Nantahala Power & Light (NP&L) retail
- Duke Energy Carolinas wholesale customers under Schedule 10A
- NP&L wholesale customers Western Carolina University and the Town of Highlands
- NCEMC load relating to ownership of Catawba

In addition, the forecast includes:

- Load equating to the portion of Catawba ownership related to the Saluda River Electric Cooperative Inc. (SR) until January 1, 2009
- Blue Ridge, Piedmont and Rutherford Electric Membership Cooperatives' supplemental load requirements from 2006 through 2021

Notes (c), (e) and (f) of Table 3.2 give additional detail on how the four Catawba Joint Owners were considered in the forecasts.

The current 15-year forecast reflects a 1.7 percent average annual growth in summer peak demand, while winter peaks are forecasted to grow at an average annual rate of 1.1 percent. The forecast for average annual territorial energy need is 1.6 percent. The growth rates use 2006 as the base year with a 17,318 MW summer peak, a 15,493 MW winter peak and a 92,339 GWH average annual territorial energy need.

Duke Energy Carolinas retail sales have grown at an average annual rate of 1.8 percent from 1990 to 2005. (Retail sales, excluding line losses, are approximately 83 percent of the total energy considered in the 2006 Annual Plan.) This 15-year period of history reflects 10 years of strong load growth from 1990 to 2000 followed by five years of very little growth from 2000 to 2005. The following table shows historical and projected major customer class growth rates.

Table 3.1
Retail Load Growth

Time Period	Total Retail	Residential	General Service	Industrial Textile	Industrial Non-Textile
1990 to 2005	1.8%	2.6%	3.5%	-3.5%	1.6%
1990 to 2000	2.5%	2.6%	4.1%	-0.3%	2.5%
2000 to 2005	0.4%	2.7%	2.4%	-9.5%	0.0%
2005 to 2016	1.4%	1.7%	2.6%	-4.8%	1.2%

A decline in the Industrial Textile class was the key contributor to the low load growth from 2000 to 2005, offset by growth in the Residential and General Service classes over the same period. Over the last 5 years, an average of almost 49,000 new residential customers per year was added to the Duke Energy Carolinas service area.

Duke Energy Carolinas' total retail load growth over the planning horizon is driven by the expected growth in Residential and General Service classes. Sales to the Industrial Textile class are expected to decline, but not as much as in the last five years. The Industrial Non-Textile class is expected to show positive growth, particularly in the Automobile, Rubber and Plastics, Instruments and Chemicals industries. (Additional details on the current forecast can be found in the Spring 2006 Forecast Book.)

The load forecast for the 2006 Annual Plan is the following:

<u>Table 3.2</u>
Load Forecast

YEAR[a,b,c,d,e,f]	SUMMER (MW)[g]	WINTER (MW)[g]	TERRITORIAL ENERGY (GWH)[g]
2007	17,731	15,798	94,351
2008	18,021	15,996	95,344
2009	18,097	15,962	95,128
2010	18,374	16,134	96,595
2011	19,029	16,679	99,910
2012	19,340	16,862	101,550
2013	19,639	17,025	103,124
2014	19,957	17,183	104,662
2015	20,271	17,319	106,233
2016	20,581	17,476	107,879
2017	20,910	17,652	109,617
2018	21,240	17,800	111,356
2019	21,567	17,939	113,130
2021	21,902	18,062	114,864
2021	22,210	18,152	116,602

Note a: The MW (demand) forecasts above are the same as those shown on page 32 of the Spring 2006 Forecast Book, but the peak forecasts vary from those shown on pages 27-30 of the Forecast Book, primarily because Spring 2006 Forecast Book's peak forecasts include the total resource needs for all Catawba Joint Owners and do not include the total resource needs of NP&L.

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

Note c: As part of the joint ownership arrangement for Catawba Nuclear Station, NCEMC and SR took sole responsibility for their supplemental load requirements beginning January 1, 2001. As a result, SR's supplemental load requirements above its ownership interest in Catawba are not reflected in the forecast. Beginning in 2009, the SR ownership portion of Catawba will not be reflected in the forecast due to a future sale of this interest, which will cause SR to become a full-requirements customer of another utility. SR exercised the three-year notice to terminate the Interconnection Agreement (which includes provisions for reserves) in September 2005, which will result in termination at the end of September 2008.

Note d: The load forecast includes Duke Energy Carolinas' contract to serve Blue Ridge, Piedmont and Rutherford Electric Membership Cooperatives' supplemental load requirements from 2006 through 2021.

Note e: As part of the joint ownership arrangement for the Catawba Nuclear Station, the NCMPA1 took sole responsibility for its supplemental load requirements beginning January 1, 2001. As a result, NCMPA1 supplemental load requirements above its ownership interest in Catawba Nuclear Station are not reflected in the forecast. In 2002, NCMPA1 entered into a firm-capacity sale beginning January 1, 2003, when it sold 400 MW of its ownership interest in

Catawba. In 2003, NCMPA1 entered into another agreement beginning January 2004, when it chose not to buy reserves for its remaining ownership interest (432 MW) from Duke Energy Carolinas. These changes reduce the Duke Energy Carolinas load forecast by the forecasted NCMPA1 load in the control area (988 MW at 2005 summer peak) and the available capacity to meet the load obligation by its Catawba ownership (832 MW). The Plan assumes that the reductions remain over the 15-year planning horizon.

Note f: The PMPA assumed sole responsibility for its supplemental load requirements beginning January 1, 2006. Therefore, PMPA supplemental load requirements above its ownership interest in Catawba Nuclear Station are not reflected in the load forecast beginning in 2006. Neither will the PMPA ownership interest in Catawba be included in the load forecast beginning in 2006, because PMPA also terminated its existing Interconnection Agreement with Duke Energy Carolinas effective January 1, 2006. Therefore, Duke Energy Carolinas is not responsible for providing reserves for the PMPA ownership interest in Catawba. These changes reduce the Duke Energy Carolinas load forecast by the forecasted PMPA load in the control area (456 MW at 2005 summer peak) and the available capacity to meet the load obligation by its Catawba ownership (277 MW). The Plan assumes that the reductions remain over the 15-year planning horizon.

Note g: Summer peak demand, winter peak demand and territorial energy are for the calendar years indicated. (The customer classes are described at the beginning of this section.) Territorial energy includes losses and unbilled sales (adjustments made to create calendar billed sales from billing period sales).

Changes to Existing Resources

Duke Energy Carolinas will adjust the capabilities of its resource mix over the 15-year planning horizon. Retirements of generating units, system capacity uprates and derates, purchased power contract expiration, and adjustments in DSM capability affect the amount of resources Duke Energy Carolinas will have to meet its load obligation. Below are the known or anticipated changes and their impacts on the resource mix.

Lee Steam Station Combustion Turbine Units
In September 2006, Duke Energy Carolinas will replace the three Lee Combustion Turbine units of 90 MW combined capacity with two natural gas fired combustion turbine units of approximately 80 MW combined capacity. These units will provide secondary back-up black-start provision for the Oconee Nuclear Station.

Rockingham Power Facility Acquisition
Duke Energy Carolinas is in the process of acquiring from Rockingham Power, L.L.C. the Rockingham Power Facility , an 825 MW combustion turbine facility constructed in 2000. For the purpose of the Annual Plan, this acquisition is assumed to be completed during the 4th quarter of 2006. NCUC approval was received on July 25, 2006. Early termination of the Hart-Scott-Rodino Antitrust Improvement Act of 1976 waiting period was granted by the DOJ on July 20, 2006. On July 28, 2006, Duke Energy Carolinas submitted its section 203 application to FERC for approval of the Rockingham acquisition. FERC's ruling on the application is anticipated by November 1, 2006. The facility has existing contracts to sell capacity consisting of a total of 215 MW through the end of 2008 and dropping to 50 MW through the end of 2010. For additional details regarding the acquisition, please see Appendix E.

Pending CPCN Proceedings

New Cliffside Pulverized Coal Units
During May 2005, the Company filed preliminary information with the NCUC for a CPCN for up to 1600 MW of pulverized coal generation at the Cliffside Steam Station in Cliffside, NC. The CPCN application and supporting testimony were filed by the Company in June 2006. The hearing is currently scheduled for September 12, 2006.

As a part of the development of this IRP, the Company continued to study the economics of these proposed new coal-fired units. The results of this continued analysis are discussed later in this document.

Potential Buck Combined Cycle Units
During May 2005, the Company filed a preliminary CPCN for up to 600 MW of combined cycle generation at the Buck Steam Station in Salisbury, N.C. Duke Energy Carolinas continues to evaluate intermediate capacity options.

Purchased Power Contract Expirations
Duke Energy Carolinas has secured various purchased power contracts with power marketers Progress Ventures Inc. and Rockingham Power that are currently in effect or will begin over the next couple of years. In 2007, the overall capability of the purchased power contracts is approximately 585 MW. The capability in megawatts varies depending on the contract start times, their duration and capability of each contract. All current contracts will expire by Dec. 31, 2010. For details, see Table 2.6, Wholesale Purchased Power Commitments.

Generating Units Projected To Be Retired
Various factors have an impact on decisions to retire existing generating units. These factors, including the investment requirements necessary to support ongoing operation of generation facilities, are continuously evaluated as future resource needs are considered. The following table reflects current assessments of generating units with identified decision dates for retirement or major refurbishment. The conditions of the units are evaluated annually and decision dates are revised as appropriate.

Table 3.3[a]
Projected Unit Retirements

STATION	CAPACITY IN MW	LOCATION	DECISION DATE	PLANT TYPE
Buzzard Roost 6C	22	Chappels, S.C.	6/30/2010	Combustion Turbine
Buzzard Roost 7C	22	Chappels, S.C.	6/30/2010	Combustion Turbine
Buzzard Roost 8C	22	Chappels, S.C.	6/30/2010	Combustion Turbine
Buzzard Roost 9C	22	Chappels, S.C.	6/30/2010	Combustion Turbine
Buzzard Roost 10C	18	Chappels, S.C.	6/30/2010	Combustion Turbine
Buzzard Roost 11C	18	Chappels, S.C.	6/30/2010	Combustion Turbine
Buzzard Roost 12C	18	Chappels, S.C.	6/30/2010	Combustion Turbine
Buzzard Roost 13C	18	Chappels, S.C.	6/30/2010	Combustion Turbine
Buzzard Roost 14C	18	Chappels, S.C.	6/30/2010	Combustion Turbine
Buzzard Roost 15C	18	Chappels, S.C.	6/30/2010	Combustion Turbine
Riverbend 8C	30	Mt. Holly, N.C.	12/31/2010	Combustion Turbine
Riverbend 9C	30	Mt. Holly, N.C.	12/31/2010	Combustion Turbine
Riverbend 10C	30	Mt. Holly, N.C.	12/31/2010	Combustion Turbine
Riverbend 11C	30	Mt. Holly, N.C.	12/31/2010	Combustion Turbine
Buck 7C	31	Spencer, N.C.	12/31/2010	Combustion Turbine
Buck 8C	31	Spencer, N.C.	12/31/2010	Combustion Turbine
Buck 9C	31	Spencer, N.C.	12/31/2010	Combustion Turbine
Dan River 4C	30	Eden, N.C.	12/31/2010	Combustion Turbine
Dan River 5C	30	Eden, N.C.	12/31/2010	Combustion Turbine
Dan River 6C	25	Eden, N.C.	12/31/2010	Combustion Turbine

Note a: Duke Energy Carolinas had an operating lease for the Buzzard Roost Hydro Unit which expired June 30, 2006.

Reserve Margin Explanation and Justification

Considering customer demand uncertainty, unit outages, transmission constraints and weather extremes, reserve margins are necessary to help ensure the availability of adequate resources to meet load obligations. Many factors have an impact on the appropriate levels of reserves, including existing generation performance, lead times needed to acquire or develop new resources, and product availability in the purchased power market.

Duke Energy Carolinas' experience has shown that a 17 percent target planning reserve margin is sufficient to provide reliable power supplies, based on the prevailing expectations of reasonable lead times for the development of new generation, siting of transmission facilities and procurement of purchased capacity. As part of the Company's process for determining its target planning reserve margins, Duke Energy Carolinas reviews whether the current target planning reserve margin was adequate in the prior period. From July 2004 through July 2006, generating reserves, defined as available Duke Energy Carolinas generation plus the net of firm purchases less sales, never dropped below 500 MW. Since 1997, Duke Energy Carolinas has had sufficient reserves to meet customer load reliably with limited need for activation of interruptible programs. The DSM Activation History in Appendix D illustrates Duke Energy Carolinas' limited activation of interruptible programs through the end of July 2006.

Duke Energy Carolinas also continually reviews its generating system capability, level of potential DSM activations, scheduled maintenance, environmental retrofit equipment and environmental compliance requirements, purchased power availability and transmission capability to assess its capability to reliably meet customer demand. The Company will continue to monitor lead times for permitting and construction of new generation and transmission facilities, to procure power in the purchased power market and to assess its power supply planning process (reserve margins) for possible changes.

While Duke Energy Carolinas uses a 17% target planning reserve margin for long-term planning, it also assesses its reserve margins on a short-term basis to determine whether to pursue additional capacity in the short-term power market. As each peak demand season approaches, the Company has a greater level of certainty regarding the customer load forecast and total system capability, due to greater knowledge of near-term weather conditions and generation unit availability.

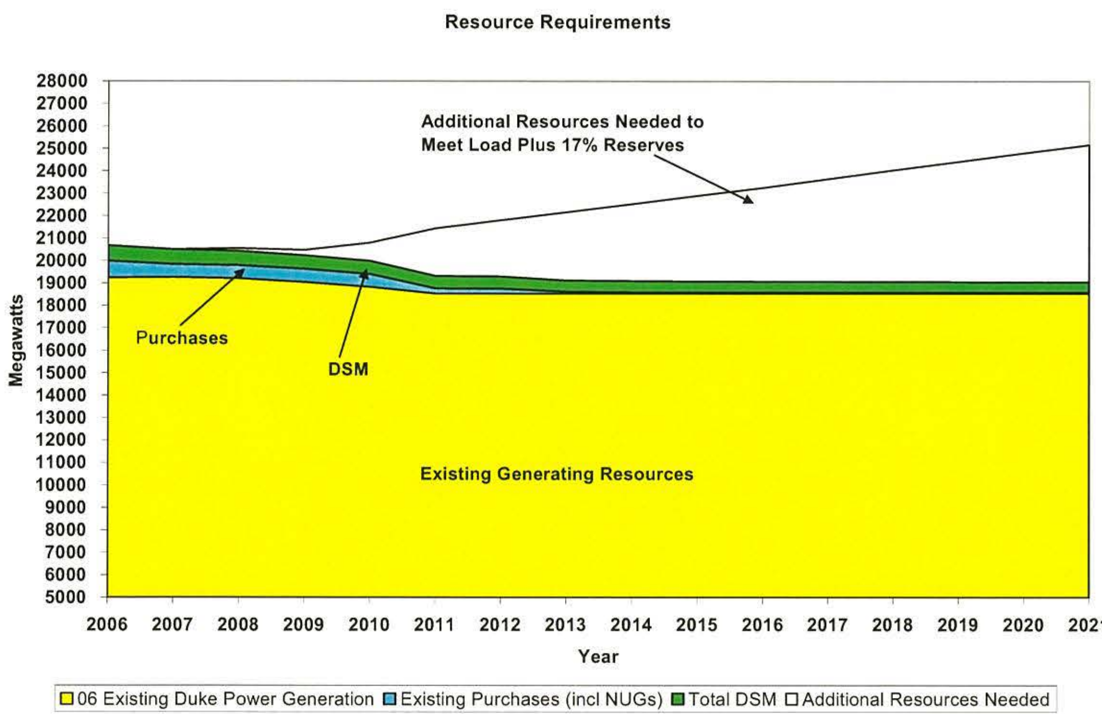
Duke Energy Carolinas uses adjusted system capacity[8], along with Interruptible DSM capability to satisfy Duke Energy Carolinas' NERC Reliability Standards requirements for operating and contingency reserves. Contingencies include events such as higher than expected unavailability of generating units and increased customer load due to extreme weather conditions.

[8] Adjusted system capacity is calculated by adding the expected capacity of each generating unit plus firm purchased power capacity, less firm wholesale capacity sales.

Load & Resource Balance

The following chart shows the existing resources and resource requirements to meet the load obligation, plus the 17 percent target planning reserve margin. Beginning in 2006, existing resources, consisting of existing generation, DSM, and purchased power to meet load requirements, total 20,682 MW. The load obligation plus the 17 percent target planning reserve margin is 20,395 MW, indicating sufficient resources to meet Duke Energy Carolinas obligation through 2007. The need for additional capacity grows over time due to load growth, unit capacity adjustments, unit retirements, DSM program reductions and expirations of purchased-power contracts. The need grows to approximately 2100 MW by 2011 and 6,100 MW by 2021.

Chart 3.1
Load & Resource Balance



Cumulative Resource Additions To Meet A 17 Percent Planning Reserve Margin

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Resource Need	0	120	230	810	2120	2510	3030	3430	3810	4180

Year	2017	2018	2019	2020	2021
Resource Need	4570	4970	5360	5750	6120

IV. RESOURCE ALTERNATIVES TO MEET FUTURE ENERGY NEEDS

Many potential resource options are available to meet future energy needs. They range from expanding existing DSM programs to developing new DSM programs to adding new generation capacity to the Duke Energy Carolinas system.

Following are the generation (supply-side) technologies Duke Energy Carolinas considered in detail throughout the planning analysis:

Conventional Technologies (technologies in common use)

- 564 MW Combustion Turbine (CT)
- 585 MW Combined-Cycle (CC), with and without duct firing
- 800 MW Supercritical Conventional Fossil
- 1,600 MW Supercritical Conventional Fossil
- 2,234 MW Nuclear AP1000

Although Duke Energy Carolinas has filed an application for a CPCN for up to 1600 MW of new coal-fired capacity, the Company has not modeled this resource as a committed capacity addition. Rather, this resource was modeled as an alternative to be considered in the analysis in order to verify and refine the results of the 2005 Annual Plan analysis.

The Rural Utilities Service (RUS) issued a Request for Bid for the purchase of Saluda River's ownership interest in the Catawba Nuclear Station. The bid has been awarded to the North Carolina Electric Membership Corporation (NCEMC) with the sale to be effective in late 2008. Duke Energy Carolinas has appealed the award to the National Appeals Division of the Department of Agriculture and is seeking to reopen the bidding. In any case, the Catawba contracts with Saluda River provide that the remaining owners of Unit 1 have a right of first refusal for an amount based on their ownership interest. This provision gives Duke Energy Carolinas a right of first refusal for approximately 30.7% of Saluda River's interest, approximately 64 MW. This capacity was also modeled as a supply-side resource alternative.

Below are the DSM programs that were considered in the planning process:

Demand Response Programs

- New Demand Response Programs
- New Energy Efficiency Programs

Duke Energy Carolinas has recently established collaborative groups that consist of various stakeholders from across its service area. The objective of these collaborative efforts will be to design and recommend a new set of DSM-related programs for its customers. Currently, Duke Energy Carolinas has included 100 MW of additional demand response program capability and 100 MW of additional programs that reduce energy consumption as placeholders in the 2006 Annual Plan pending the development of specific initiatives. Duke Energy Carolinas anticipates that the collaborative efforts will provide a more detailed analysis of the size and character of potential programs that will be implemented and included in future Annual Plans. See Appendix I for a discussion of resources evaluated and the process used to screen the supply-side options to reach the list above.

V. OVERALL PLANNING PROCESS CONCLUSIONS

Duke Energy Carolinas' Resource Planning process provides a framework for the Company to assess, analyze and implement a cost-effective approach to meet customers' growing energy needs reliably. In addition to assessing qualitative factors, a quantitative assessment was conducted using a simulation model. A variety of sensitivities and scenarios were tested against a base set of inputs, allowing the Company to better understand how potentially different future operating environments such as fuel commodity price changes, environmental emission mandates and structural regulatory requirements can affect resource choices and ultimately the cost of electricity to customers. (Appendix A provides a detailed description and results of the quantitative analyses).

The quantitative analyses suggest that a combination of additional baseload, intermediate and/or peaking generation and energy efficiency and demand response programs is required over the next fifteen years to reliably and cost effectively meet customer demand. The generation resource mix consists of natural gas combustion turbine and/or combined-cycle units as well as coal and nuclear capacity. On a present value of revenue requirements basis, the plan featuring 1,600 MW of new coal capacity and 1,734 MW of new nuclear capacity was the most robust across all of the sensitivities and scenarios tested

In light of the quantitative issues such as the state of competitive markets, the importance of fuel diversity, the Company's environmental profile, the stage of technology deployment and regional economic development, Duke Energy Carolinas has developed a strategy to ensure that the Company can meet customers' energy needs reliably and economically while maintaining flexibility pertaining to long-term resource decisions. The Company will take the following actions in the upcoming year:

- Complete the acquisition of the Rockingham Power Facility.
  - NCUC approval was received on July 25, 2006.
  - Early termination of the Hart-Scott-Rodino Antitrust Improvement Act of 1976 waiting period was granted by the DOJ on July 20, 2006.
  - On July 28, 2006, Duke Energy Carolinas submitted its section 203 application to FERC for approval of the Rockingham acquisition. FERC's ruling on the application is anticipated by November 1, 2006.
- Actively pursue new coal generation, with the objective of bringing additional capacity on line by 2011 at the existing Cliffside Steam Station.
  - Duke Energy Carolinas filed an application and supporting testimony with the NCUC for a Certificate of Public Convenience and Necessity for up to 1600 MWs of new coal-fired generation.

- Duke Energy Carolinas submitted a complete air-quality permit application to the North Carolina Division of Air Quality on December 16, 2005.
- Maintain the option to license and permit a new combined-cycle/peaking facility.
    - Duke Energy Carolinas filed preliminary information for a CPCN with the NCUC for 600 MWs of combined-cycle generation.
- Continue to evaluate new nuclear generation by pursuing the Nuclear Regulatory Commission's Combined Construction and Operating License, with the objective of potentially bringing a new plant on line by 2016.
    - Duke Energy Carolinas has entered into an agreement with Southern Company to evaluate potential nuclear plant construction at the jointly-owned Cherokee County, S.C. location.
- Establish collaborative partnerships to further define, develop, implement and promote potential demand response and energy efficiency products and services.
- Continue to assess opportunities to benefit from economies of scale in new resource decisions by considering the prospects for joint ownership and/or sales agreements.
- Continue to monitor renewable generation options.
- Continue to monitor energy-related statutory and regulatory activities.

The seasonal projections of load, capacity, and reserves of the most robust expansion plan are provided in tabular form below. The planning process must be dynamic and adaptable to changing conditions. While this plan is the most appropriate resource plan at this point in time, good business practice requires Duke Energy Carolinas to continue to study the options, and make adjustments as necessary and practical to reflect improved information and changing circumstances. Consequently, a good business planning analysis is truly an evolving process that can never be considered complete.

Seasonal Projections of Load, Capacity, and Reserves

W = WINTER, S = SUMMER	W 06/07	S 2007	W 07/08	S 2008	W 08/09	S 2009	W 09/10	S 2010	W 10/11	S 2011	W 11/12	S 2012	W 12/13	S 2013	W 13/14
Forecast															
1 Duke System Peak	15,798	17,731	15,996	18,021	15,962	18,097	16,134	18,374	16,679	19,029	16,862	19,340	17,025	19,639	17,183
Cumulative System Capacity															
2 Generating Capacity	19,962	19,840	20,586	19,839	20,386	19,829	20,540	19,807	20,321	19,153	19,875	19,153	19,875	19,153	19,875
3 Capacity Additions	612	50	0	0	165	0	0	0	50	0	0	0	0	0	0
4 Capacity Derates	(12)	(26)	(25)	(25)	0	(11)	(11)	(12)	0	0	0	0	0	0	0
5 Capacity Retirements	0	0	0	0	0	0	0	(196)	(496)	0	0	0	0	0	0
6 Cumulative Generating Capacity	20,562	19,864	20,561	19,814	20,551	19,818	20,529	19,599	19,875	19,153	19,875	19,153	19,875	19,153	19,875
7 Cumulative Purchase Contracts	690	586	690	586	690	586	690	583	243	236	240	233	183	88	66
8 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Cumulative Future Resource Additions															
Peaking/Intermediate	0	0	0	0	0	0	0	564	640	1,128	1,280	1,128	1,280	1,692	1,920
Base Load	0	0	0	0	0	64	64	64	64	864	864	1,664	1,664	1,664	1,664
10 Cumulative Production Capacity	21,252	20,450	21,251	20,400	21,241	20,468	21,283	20,810	20,822	21,381	22,259	22,178	23,002	22,597	23,525
Reserves w/o DSM															
11 Generating Reserves	5,454	2,719	5,255	2,379	5,279	2,371	5,149	2,436	4,143	2,352	5,397	2,838	5,977	2,958	6,342
12 % Reserve Margin	34.5%	15.3%	32.9%	13.2%	33.1%	13.1%	31.9%	13.3%	24.8%	12.4%	32.0%	14.7%	35.1%	15.1%	36.9%
13 % Capacity Margin	25.7%	13.3%	24.7%	11.7%	24.9%	11.6%	24.2%	11.7%	19.9%	11.0%	24.2%	12.8%	26.0%	13.1%	27.0%
DSM															
14 Cumulative DSM Capacity	399	704	413	736	428	766	431	760	434	756	435	739	423	718	423
Existing DSM Capacity	389	666	376	638	365	613	353	587	341	563	329	538	317	517	317
New DSM Capacity	10	38	37	98	63	153	78	173	93	193	106	201	106	201	106
15 Cumulative Equivalent Capacity	21,651	21,154	21,664	21,136	21,669	21,234	21,714	21,570	21,256	22,137	22,694	22,917	23,425	23,315	23,948
Reserves w/DSM															
16 Equivalent Reserves	5,853	3,423	5,668	3,115	5,707	3,137	5,580	3,196	4,577	3,108	5,832	3,577	6,400	3,676	6,765
17 % Reserve Margin	37.0%	19.3%	35.4%	17.3%	35.8%	17.3%	34.6%	17.4%	27.4%	16.3%	34.6%	18.5%	37.6%	18.7%	39.4%
18 % Capacity Margin	27.0%	16.2%	26.2%	14.7%	26.3%	14.8%	25.7%	14.8%	21.5%	14.0%	25.7%	15.6%	27.3%	15.8%	28.2%
Firm Wholesale Sales															
19 Equivalent Sales	127	127	127	127	73	73	73	73							
Equivalent Reserves	5719	3290	5595	3042	5634	3064	5507	3123	4577	3108	5832	3577	6400	3676	6765
% Reserve Margin	36.0%	18.5%	35.0%	16.9%	35.3%	16.9%	34.1%	17.0%	27.4%	16.3%	34.6%	18.5%	37.6%	18.7%	39.4%
% Capacity Margin	26.4%	15.6%	25.8%	14.4%	26.0%	14.4%	25.4%	14.5%	21.5%	14.0%	25.7%	15.6%	27.3%	15.8%	28.2%

Seasonal Projections of Load, Capacity, and Reserves

W = WINTER, S = SUMMER	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S
	2014	14/15	2015	15/16	2016	16/17	2017	17/18	2018	18/19	2019	19/20	2020	20/21	2021
Forecast															
1 Duke System Peak	19,957	17,319	20,271	17,476	20,581	17,652	20,910	17,800	21,240	17,939	21,567	18,062	21,902	18,152	22,210
Cumulative System Capacity															
2 Generating Capacity	19,153	19,875	19,153	19,875	19,153	19,875	19,153	19,875	19,153	19,875	19,153	19,875	19,153	19,875	19,153
3 Capacity Additions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 Capacity Derates	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Capacity Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Cumulative Generating Capacity	19,153	19,875	19,153	19,875	19,153	19,875	19,153	19,875	19,153	19,875	19,153	19,875	19,153	19,875	19,153
7 Cumulative Purchase Contracts	66	63	63	63	63	63	63	63	63	63	63	63	63	63	63
8 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Cumulative Future Resource Additions															
Peaking/Intermediate	1,692	1,920	2,256	2,560	2,256	2,560	2,256	2,560	2,256	2,560	2,256	2,560	2,256	2,560	2,771
Base Load	1,664	1,664	1,664	1,664	2,281	3,398	3,398	3,398	3,398	3,398	3,398	3,398	3,398	3,398	3,398
10 Cumulative Production Capacity	22,575	23,522	23,136	24,162	23,753	25,896	24,870	25,896	24,870	25,896	24,870	25,896	24,870	25,896	25,385
Reserves w/o DSM															
11 Generating Reserves	2,618	6,203	2,865	6,686	3,172	8,244	3,960	8,096	3,630	7,957	3,303	7,834	2,968	7,744	3,175
12 % Reserve Margin	13.1%	35.8%	14.1%	38.3%	15.4%	46.7%	18.9%	45.5%	17.1%	44.4%	15.3%	43.4%	13.6%	42.7%	14.3%
13 % Capacity Margin	11.6%	26.4%	12.4%	27.7%	13.4%	31.8%	15.9%	31.3%	14.6%	30.7%	13.3%	30.3%	11.9%	29.9%	12.5%
DSM															
14 Cumulative DSM Capacity	708	423	699	423	691	423	683	424	676	425	669	425	663	426	657
Existing DSM Capacity	507	317	498	317	490	317	482	318	475	319	468	319	462	320	456
New DSM Capacity	201	106	201	106	201	106	201	106	201	106	201	106	201	106	201
15 Cumulative Equivalent Capacity	23,283	23,945	23,835	24,585	24,444	26,319	25,553	26,320	25,546	26,321	25,539	26,321	25,533	26,322	26,042
Reserves w/DSM															
16 Equivalent Reserves	3,326	6,626	3,564	7,109	3,863	8,667	4,643	8,520	4,306	8,382	3,972	8,259	3,631	8,170	3,832
17 % Reserve Margin	16.7%	38.3%	17.6%	40.7%	18.8%	49.1%	22.2%	47.9%	20.3%	46.7%	18.4%	45.7%	16.6%	45.0%	17.3%
18 % Capacity Margin	14.3%	27.7%	15.0%	28.9%	15.8%	32.9%	18.2%	32.4%	16.9%	31.8%	15.6%	31.4%	14.2%	31.0%	14.7%
Firm Wholesale Sales															
19 Equivalent Sales															
Equivalent Reserves	3326	6626	3564	7109	3863	8667	4643	8520	4306	8382	3972	8259	3631	8170	3832
% Reserve Margin	16.7%	38.3%	17.6%	40.7%	18.8%	49.1%	22.2%	47.9%	20.3%	46.7%	18.4%	45.7%	16.6%	45.0%	17.3%
% Capacity Margin	14.3%	27.7%	15.0%	28.9%	15.8%	32.9%	18.2%	32.4%	16.9%	31.8%	15.6%	31.4%	14.2%	31.0%	14.7%

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 103 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for NCMPA1 firm capacity sale to Southern Energy Company.
   Also, on January 1, 2006, Generating Capacity reflects a 277 MW reduction to account for PMPA termination of their interconnection agreement with Duke Energy Carolinas.
   Because the Lee CTs serve as a redundant safe-shutdown facility for Oconee Nuclear Station and are required by the NRC for operation of Oconee, the retirement of the existing CTs at Lee in 2006 will coincide with the addition of new CTs at Lee also in 2006 of 80 MW.

3. Capacity Additions reflect an estimated 2 MW Marshall unit double flow IP rotor upgrade, a 50 MW capacity uprate at the Jocassee pumped storage facility from increased efficiency from the new runners and 825 MW for the Rockingham Power Plant Facility acquisition assumed to be completed during the 4th quarter of 2006 net the pre-existing capacity contracts that expire in years 2009 and 2011.

4. The expected Capacity Derates reflect the impact of parasitic loads from planned scrubber additions to various Duke fossil generating units. The units, in order of time sequence on the LCR table is Marshall 1 - 4, Belews Creek 1 & 2, Allen 1 - 5 and Cliffside 5.

5. The 120 MW capacity retirement in winter 2010/2011 represents the projected retirement date for all CTs at Riverbend.
   The 88 MW capacity retirement in summer 2010 represents the projected retirement date for 4 CT's at Buzzard Roost(Wst).
   The 93 MW capacity retirement in winter 2010/2011 represents the projected retirement date for the existing CTs at Buck.
   The 108 MW capacity retirement in summer 2010 represents the projected retirement date for 6 CT's at Buzzard Roost(GE).
   The 85 MW capacity retirement in winter 2010/2011 represents the projected retirement date for CTs at Dan River.
   On May 23, 2000, the NRC issued to Duke renewed facility operating licenses for its three nuclear units at Oconee for a 20 year extension beginning in 2013 for units 1 and 2 and 2014 for unit 3.
   On December 5, 2003, the NRC issued to Duke Energy Carolinas a renewed facility operating license for McGuire unit 1 for a 20 year extension beginning in 2021.
   The Hydro facilities for which Duke has submitted an application to FERC for licence renewal are assumed to continue operation through the planning horizon.
   The retirement of Cliffside 1-4 is contingent upon addition of proposed coal addition at Cliffside.
   All retirement dates are subject to review on an ongoing basis.

7. Cumulative Purchase Contracts have several components:

   A. Piedmont Municipal Power Agency has given notice that it will be solely responsible for total load requirements beginning January 1, 2006. This reduces the SEPA allocation from 94 MW to 19 MW in 2006, which is attributed to Schedule 10A customers who continue to be served by Duke.
   B. Purchased capacity from PURPA Qualifying Facilities includes the 88 MW Cherokee County Cogeneration Partners contract which began in June 1998 and expires June 2013 and miscellaneous other QF projects totaling 22 MW.
   C. Purchase of 152 MW from Rowan County Power, LLC, Unit 1 began June 1, 2002 and expires May 31, 2007.
   D. Purchase of 153 MW from Rowan County Power, LLC, Unit 3 began June 1, 2004 and expires May 31, 2008.
   E. Purchase of 151 MW from Progress Ventures, Inc. Rowan Unit 2 began January 1, 2006 and expires December 31, 2010.
   F. Purchase of 153 MW from Progress Ventures, Inc. Rowan Unit 1 began June 1, 2007 and expires December 31, 2010.
   G. Purchase of 153 MW from Progress Ventures, Inc. Rowan Unit 3 began June 1, 2008 and expires December 31, 2010.

9. Cumulative Future Resource Additions represent a combination of new capacity resources or capability increases from the most robust plan.

12. Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand

13. Capacity Margin = (Cumulative Capacity - System Peak Demand)/Cumulative Capacity

14. Cumulative Demand Side Management capacity represents the existing interruptible demand-side management programs that are designed to be activated during capacity problem situations. The Cumulative Demand Side Management capacity also includes new Demand Side Management capacity representing placeholders for demand response and energy efficiency programs.

19. Beginning January 1, 2005, two firm wholesale agreements became effective between Duke Energy Carolinas and NCMPA1. The first is a 75 MW capacity sale that expires December 31, 2007. The second is a backstand agreement of up to 432 MW (depending on operation of the Catawba and McGuire facilities) that expires December 31, 2007. For this table, the estimated backstand on peak amount is 52 MW.

The following table represents the annual incremental additions reflected in the Seasonal Projections of Load, Capacity, and Reserves Table of the most robust expansion plan.

ANNUAL CAPACITY ADDITIONS		
YEAR	**PEAKING/INTERMEDIATE ADDITIONS MW**[a]	**BASELOAD ADDITIONS MW**
2006	825 MW Rockingham Acquisition less PPAs	
2007		
2008		
2009		
2010	564 MW Combustion Turbine/Combined Cycle	
2011		800 MW Coal
2012		800 MW Coal
2013	564 MW Combustion Turbine/Combined Cycle	
2014		
2015	564 MW Combustion Turbine/Combined Cycle	
2016		617 MW Nuclear[b]
2017		1117 MW Nuclear
2018		
2019		
2020		
2021	515 MW Combustion Turbine/ Combined Cycle	

Note a: Although the gas-fired capacity additions shown in the most robust plan were combustion turbines, the final determination of whether the capacity should be peaking or intermediate will be based on circumstances at the time the decision is made.

Note b: Duke Energy Carolinas has announced it has entered into an agreement with Southern Company to evaluate potential nuclear plant construction at the jointly owned Cherokee County, S.C. location.

APPENDICES

APPENDIX A: QUANTITATIVE ANALYSIS

This appendix provides an overview of the quantitative analysis of resource options available to meet customers' future energy needs.

Overview of Analytical Process

Assess Resource Needs

Duke Energy Carolinas estimates the required load and generation resource balance needed to meet future customer demands by assessing:

- Customer load forecast peak and energy – identifying future customer aggregate demands to identify system peak demands and developing the corresponding energy load shape

- Existing supply-side resources – summarizing each existing generation resource's operating characteristics including unit capability, potential operational constraints and life expectancy

- Existing DSM resources – detailing DSM resource program characteristics including customer participation levels, demand reduction potential and reliability

- Operating parameters – determining operational requirements including target planning reserve margins and other regulatory considerations.

Customer load growth coupled with the expiration of purchased power contracts results in significant resource needs to meet energy and peak demands, based on the following assumptions:

- 1.7% average summer peak system demand growth over the next 15 years
- Generation reductions of more than 600 MW due to purchased power contract expirations by 2011
- Generation retirements of approximately 500 MW of old fleet combustion turbines by 2011
- Approximately 122 MW of net generation reductions due to new environmental equipment
- Continued operational reliability of existing generation portfolio
- Continued operational reliability of the existing DSM interruptible capacity (666 MW in 2007)
- Using a 17 percent target planning reserve margin for the planning horizon

Identify and Screen Resource Options for Further Consideration

Options reflect a diverse mix of technologies and fuel sources (gas, coal, nuclear and renewable) as well as near-term and long-term timing and availability. Supply-side and DSM options are initially screened based on the following attributes:

- Technically feasible and commercially available in the marketplace
- Compliant with all federal and state requirements
- Long-run reliability
- Reasonable cost parameters.

Capacity options were compared within their respective fuel types and operational capabilities, with the most cost-effective options being selected for inclusion in the portfolio analysis phase. DSM options should also cover multiple customer segments including residential, commercial and industrial. For additional information, please see Appendix I.

Resource Options

The screening analysis revealed that the economies of scale associated with developing one or two 800 MW coal units at an existing plant site ("brownfield") would likely offer substantially lower construction and operating costs than smaller units. As a result, given the significant capacity need over the planning horizon, only 800 MW and 1600 MW (2 – 800 MW units) coal options were included in the portfolio analysis phase. IGCC was not included in the portfolio analysis because it exhibited higher costs than the other coal options and no known viable options for geological carbon sequestration exist in the service area. Nuclear and natural gas-fired capacity options also exhibited cost advantages in the capacity screening process and were therefore included in the portfolio analysis.

Based on the results of the screening analysis, the following technologies were included in the quantitative analysis as potential supply-side resource options to meet future capacity needs:

- Pulverized coal - 800 MW, and 1,600 MW (2 X 800)
- Natural gas combined-cycle with duct firing – 585 MW
- Natural gas simple-cycle combustion turbine – 564 MW (4-unit plant)
- Nuclear AP 1000 – 2,234 MW (2 X 1117)[9]

Although Duke Energy Carolinas has filed an application for a CPCN for up to 1600 MW of new coal-fired capacity, the Company has not modeled this resource as a committed capacity addition. Rather, this resource was modeled as an alternative to be considered in the analysis in order to verify and refine the results of the 2005 Annual Plan analysis.

[9] Duke Energy Carolinas has announced it has entered into an agreement with Southern Company to evaluate potential nuclear plant construction at the jointly owned Cherokee County, S.C. location.

Wind and other renewable technologies were not explicitly assumed to be able to deliver material capacity at this time, due primarily to resource constraints in the region. However, Duke Energy Carolinas continues to evaluate opportunities to incorporate new renewable energy generation into its supply portfolio.

DSM programs continue to be an important part of Duke Energy Carolinas' system mix. 100 MW of unspecified demand response options and 100 MW of unspecified energy efficiency options were included in the analysis as placeholders pending the development of specific initiatives. In addition, the plan includes an option for a 1 MW energy efficiency program based on the $2,000,000 program required by the NCUC order in Docket E-7, Sub 795. Refer to Appendix I for details regarding the various DSM Options.

Develop Theoretical Portfolio Configurations

A second screening analysis using a simulation model was conducted to identify the most attractive capacity options under the expected load profile as well as under a range of risk cases. This step began with a nominal set of varied inputs to test the system under different future conditions such as changes in fuel prices, load levels, and construction costs. These analyses yielded many different theoretical configurations of the total operating (production) and capital costs required to meet an annual 17 percent target planning reserve margin while minimizing the long-run revenue requirements to customers.

The nominal set of inputs included:

- Fuel costs and availability for coal, gas, and nuclear generation
- Development, operation and maintenance costs of both new and existing generation
- Compliance with current and potential environmental regulations
- Cost of capital
- System operational needs for load ramping, voltage/VAR support, spinning reserve (10 to 15-minute start-up) and other requirements as a result of VACAR / North American Electric Reliability Council (NERC) agreements
- The projected load and generation resource need, and
- A menu of new resource options with corresponding costs and timing parameters.

Duke Energy Carolinas reviewed a number of variations to the theoretical portfolios to aid in the development of the portfolio options discussed in the following section.

Develop Various Portfolio Options

Using the insights gleaned from developing theoretical portfolios, Duke Energy Carolinas created a representative range of generation plans reflecting plant designs, lead times and environmental emissions limits.

Recognizing that different generation plans expose customers to different sources and levels of risk, a variety of portfolios were developed to assess the impact of various risk factors on the costs to serve customers. For example, in considering the possibility of a new nuclear plant, the permitting process may delay or even prevent its development. Therefore, in addition to the nominal input of a nuclear availability date, additional test portfolios assumed either a delay in nuclear plant availability or no availability at all. All portfolios containing coal unit additions assume the additions occur at Cliffside Steam Station. The retirement of Cliffside units 1 – 4 is contingent upon building new coal-fired capacity at Cliffside.

The following table outlines the planning options that were considered in the portfolio analysis phase:

Plan	New Generation Portfolios
HighCoal, High Nuclear	2 – 800 MW brownfield coal units with retirement of Cliffside 1 - 4; 1,734 MW nuclear; 2770 MW combustion turbine (CT)
Medium Coal, High Nuclear	1 – 800 MW brownfield coal unit with retirement of Cliffside 1 - 4; 1,734 MW nuclear; 585 MW CC; 2,990 MW CT
High Coal, Hich Nuclear, with Retirements	2 – 800 MW brownfield coal units with retirement of Cliffside 1 - 4; 1,734 MW nuclear; 3,345 MW CT; 800 MW of existing old coal retirements;
No Coal, High Nuclear	1,734 MW nuclear; 1,170 MW CC; 3,010 MW CT; reflects capital costs for selective catalytic reduction on Marshall 4
No Coal, No Nuclear	2,925 MW CC; 2,990 MW CT; reflects capital costs for selective catalytic reduction on Marshall 4
High Coal, No Nuclear	2 – 800 MW brownfield coal units with retirement of Cliffside 1 - 4; 1,755 MW CC; 2,756 MW CT

In addition, each of the above portfolio options contains 101 MW of additional energy efficiency DSM programs and 100 MW of additional load response DSM programs (see Appendix I for additional details). Furthermore, each portfolio reflects Duke Energy Carolinas exercising the right of first refusal for 64 MW of Catawba nuclear capacity from Saluda River beginning January 1, 2009, as discussed previously in the Resource Alternatives To Meet Future Energy Needs Section. Analysis showed that this capacity was an economic addition to the system under all conditions.

Conduct Portfolio Analysis

Portfolio options were tested under the nominal set of inputs as well as a variety of risk sensitivities and scenarios, in order to understand the strengths and weaknesses of various resource configurations and evaluate the long-term costs to customers under various potential outcomes.

The following sensitivities were evaluated:

- Construction cost sensitivity[10]
  - High costs to construct a new coal plant (20% higher than base case)
  - High costs to construct a new nuclear plant (20% higher than base case)
- Load forecast variations
  - Increase relative to base forecast (growth rates of 2.1% and 2.0% for peak demand and energy, respectively, versus 1.7% and 1.6%, respectively, in the base case forecast)
  - Decrease relative to base forecast (growth rates of 1.3% and 1.1% for peak demand and energy, respectively, versus 1.7% and 1.6%, respectively, in the base case forecast)
- Fuel price variability
  - High coal prices
  - Low coal prices
  - High natural gas prices
  - Low natural gas prices
  - Higher coal prices and natural gas
  - Lower coal prices and natural gas
- Carbon tax[11]

In addition to the above sensitivities, the following scenarios were evaluated to understand the inter-relationship of multiple assumptions changing concurrently:

- Higher coal and natural gas prices AND higher new coal construction costs
- Higher coal and natural gas prices AND higher new nuclear construction costs
- Carbon tax AND higher natural gas prices
- Carbon tax AND lower than base load forecast

Quantitative Analysis Results

Yearly revenue requirements for various resource planning strategies were calculated based on production cost simulation and levelized capital recovery over a 35-year analysis time frame. For each sensitivity and scenario, the present value revenue requirements (PVRR) of each plan were compared to the average PVRR of the six portfolios analyzed, both on a percentage basis and on a total dollar basis.

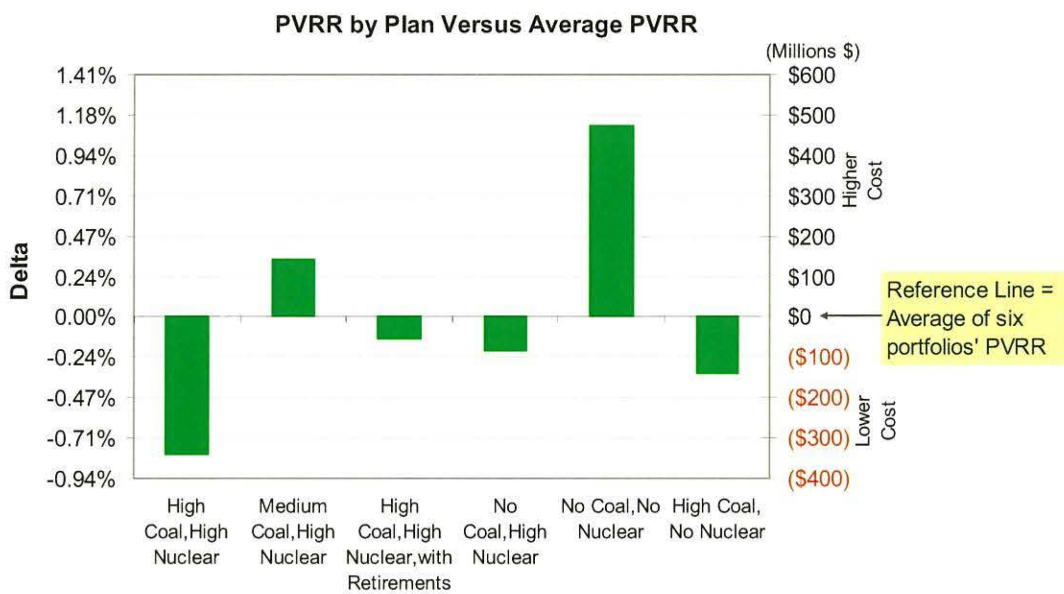
[10] These sensitivities test the risks from increases in construction costs of one type of supply-side resource at a time. In reality, cost increases of many construction component inputs such as labor, concrete and steel would affect all supply-side resources to varying degrees rather than affecting one technology in isolation.

[11] Despite significant uncertainty surrounding potential future climate change policy, Duke Energy Carolinas has incorporated a climate change policy sensitivity in its resource planning process. Inclusion of this sensitivity is not intended to reflect Duke Energy Carolinas' or Duke Energy's preferences regarding future climate change policy.

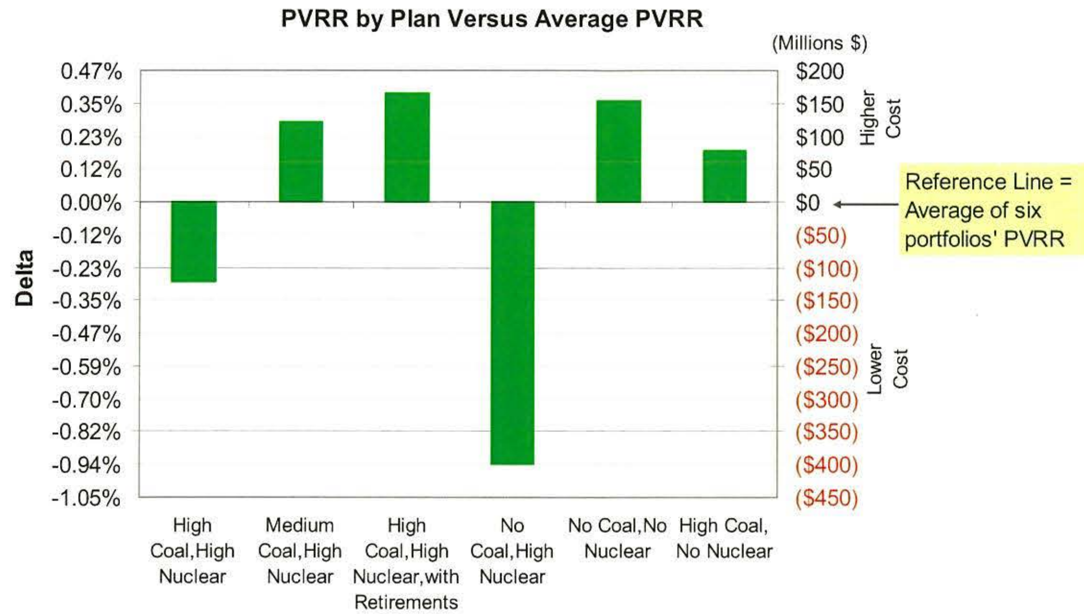
It should be noted that the PVRR variances for the results shown below should not be compared across sensitivities (high natural gas prices vs. base case for example) since the reference line of each sensitivity is based on average costs specific to a given sensitivity.

Base Case

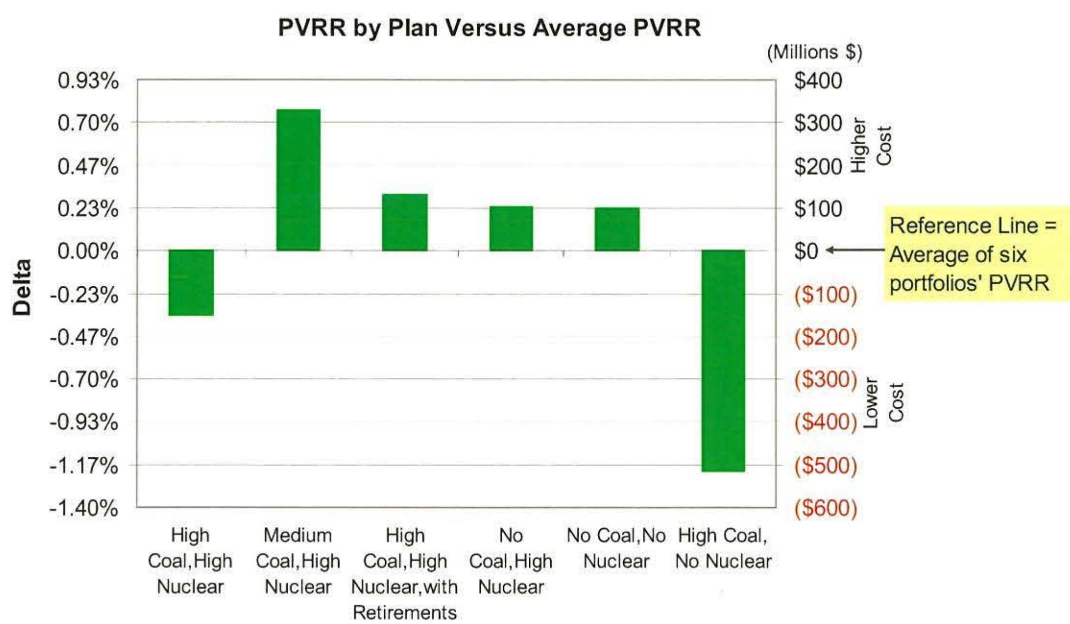
The assumptions for the base case include Duke Energy Carolinas' expected load growth, projected commodity prices and expected asset development costs and timing.



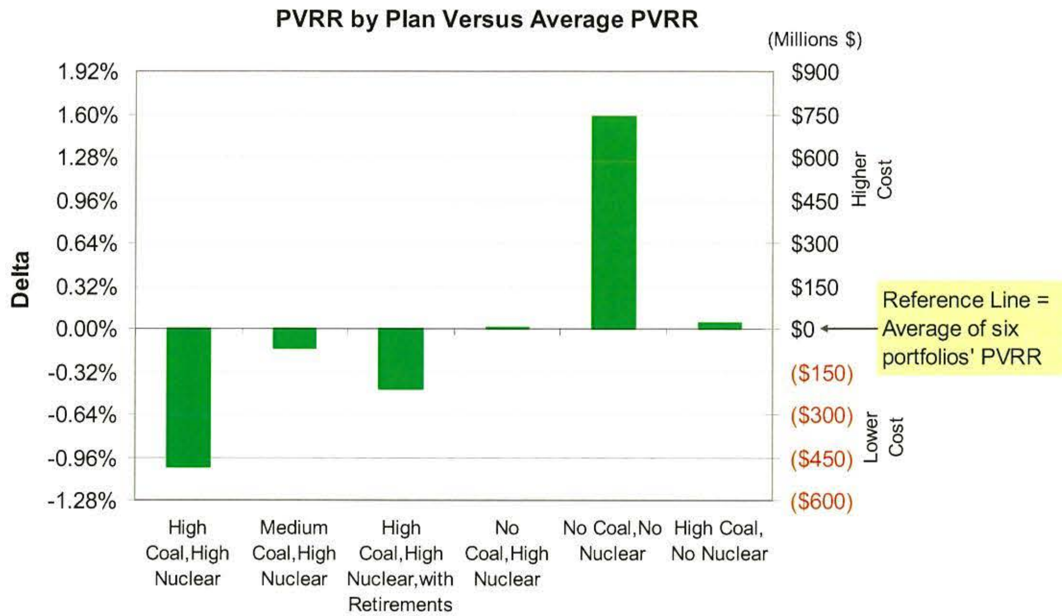
Sensitivities:
Sensitivity: Coal Construction Costs Increase



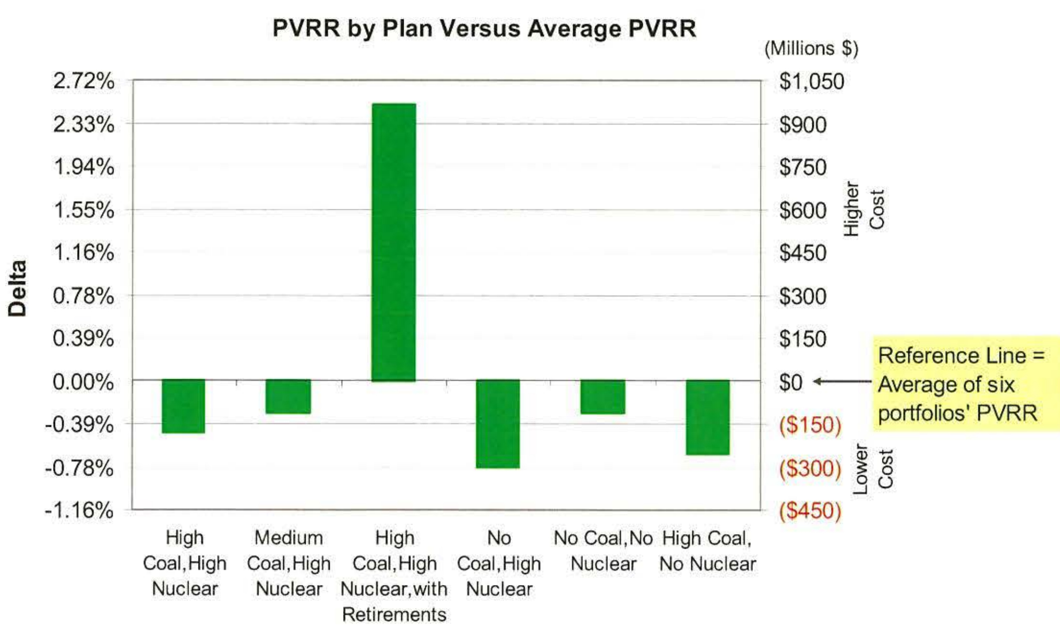
Sensitivity: Nuclear Construction Costs Increase



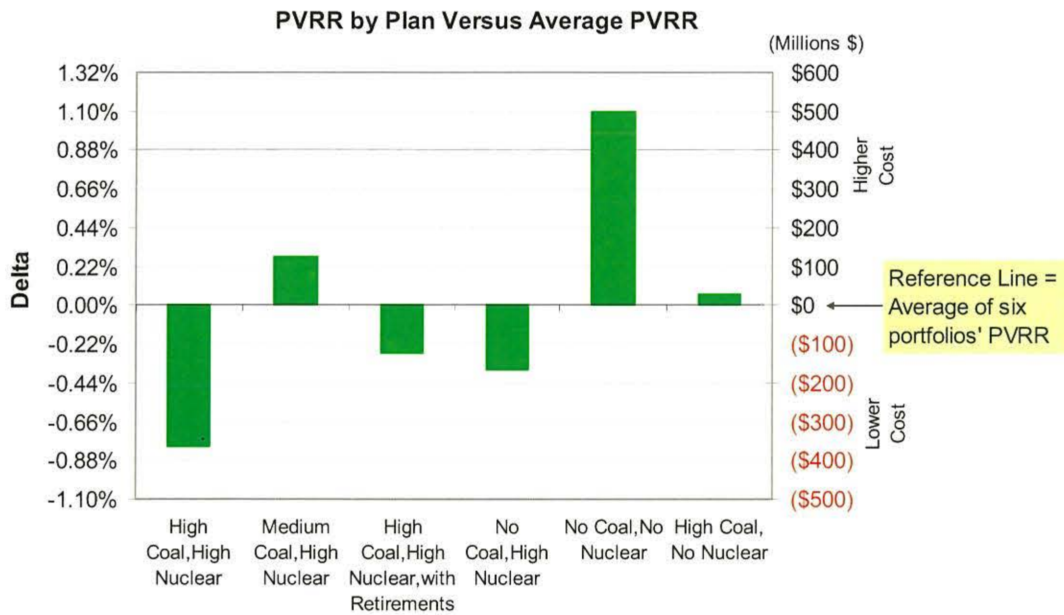
Sensitivity: High Load



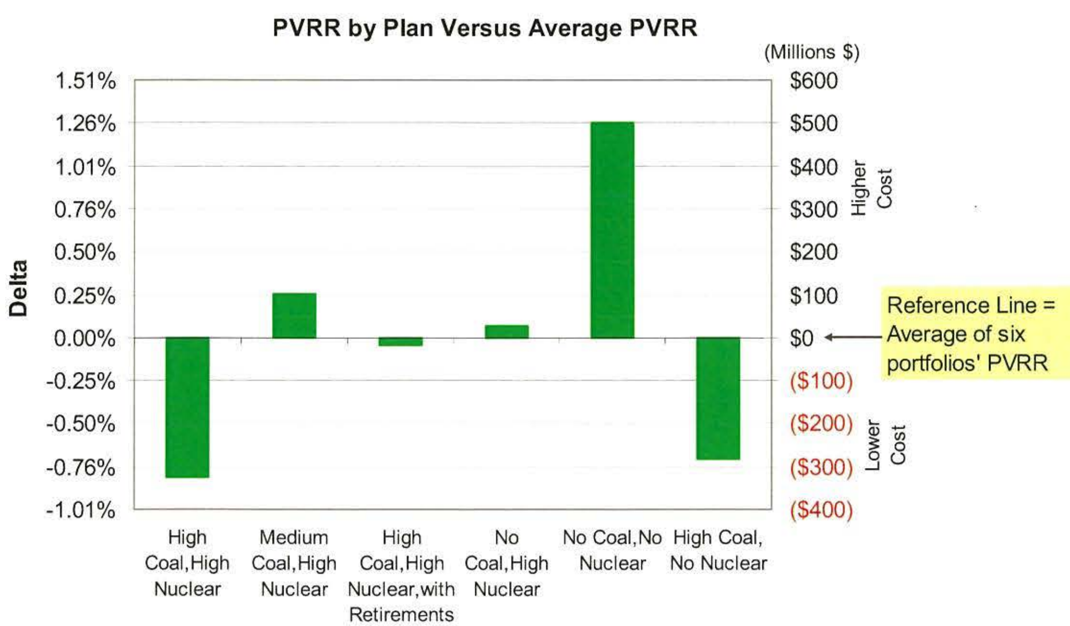
Sensitivity: Low Load



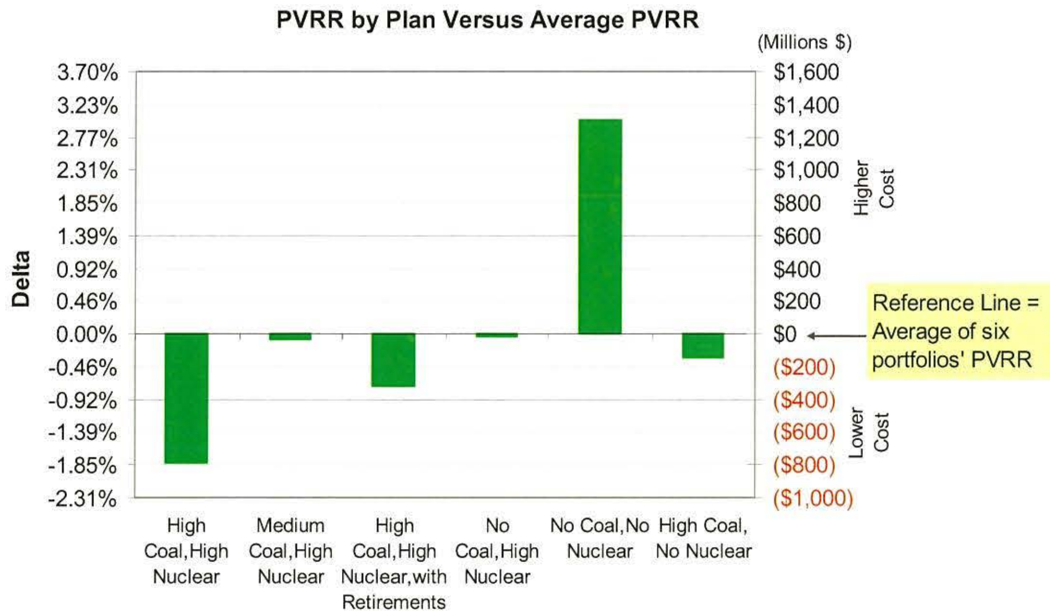
Sensitivity: High Coal Prices



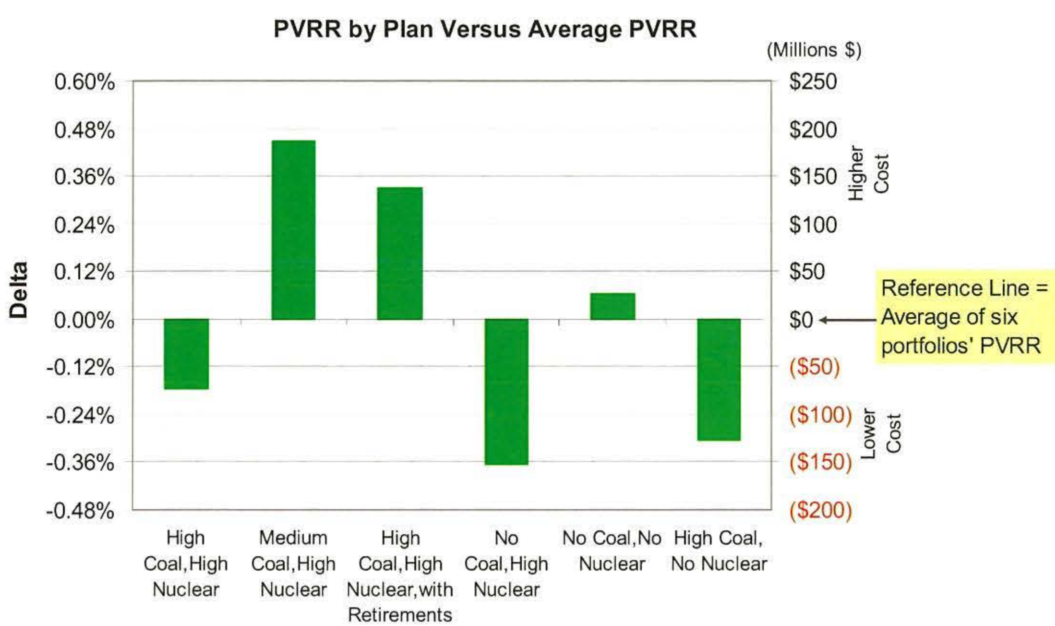
Sensitivity: Low Coal Prices



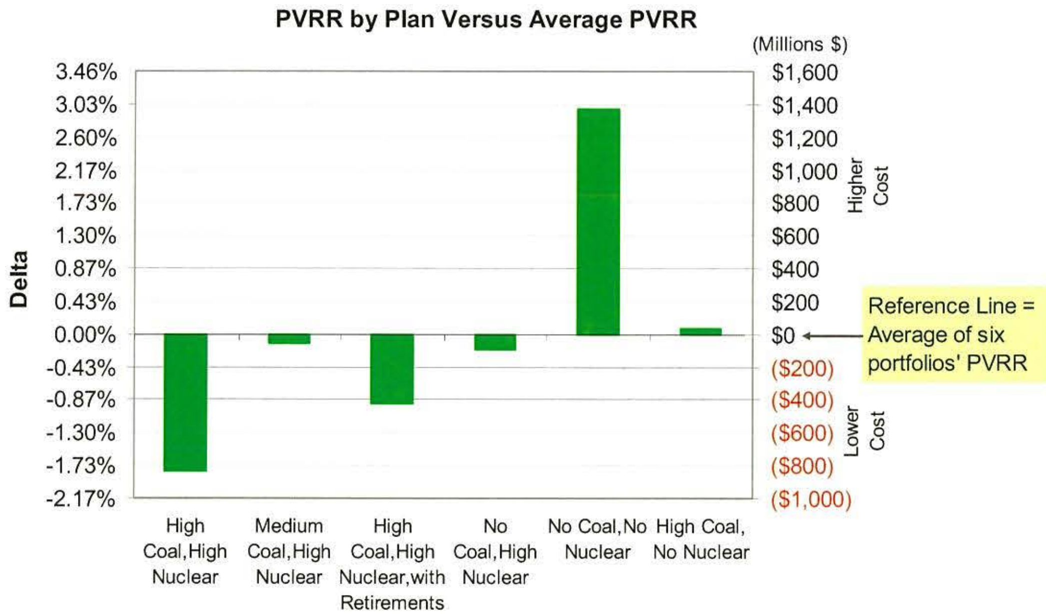
Sensitivity: High Natural Gas Prices



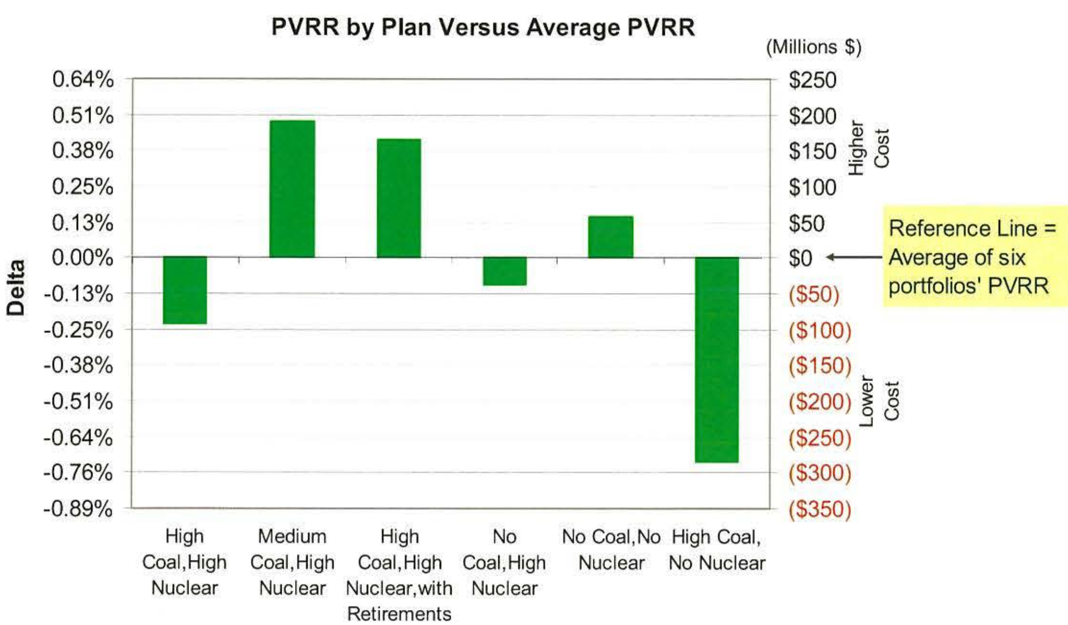
Sensitivity: Low Natural Gas Prices



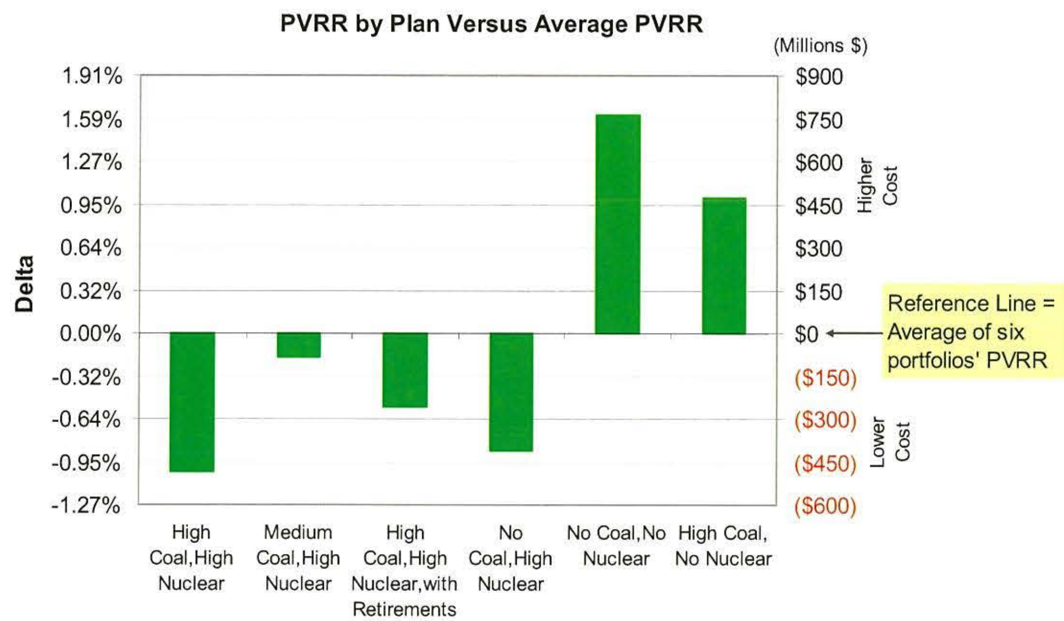
Sensitivity: Higher Coal and Natural Gas Prices



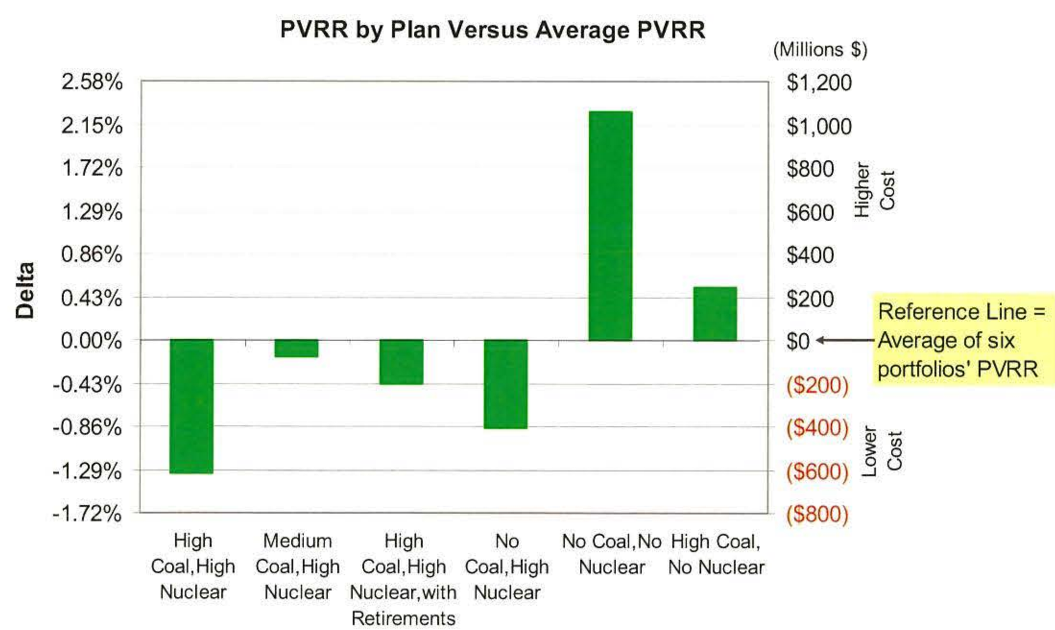
Sensitivity: Lower Coal and Natural Gas Prices



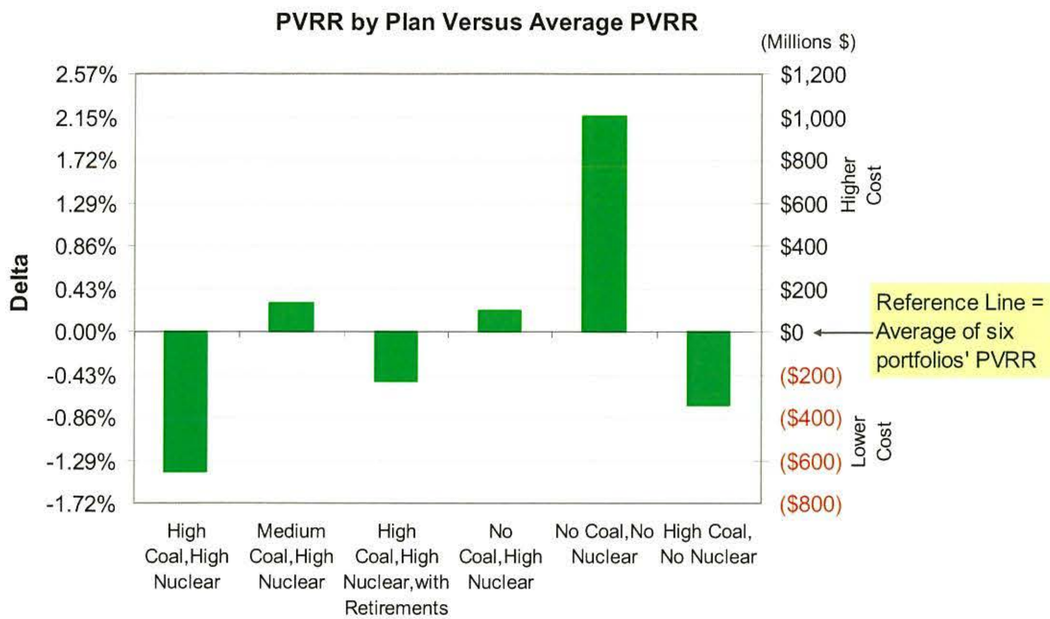
Sensitivity: Carbon Tax



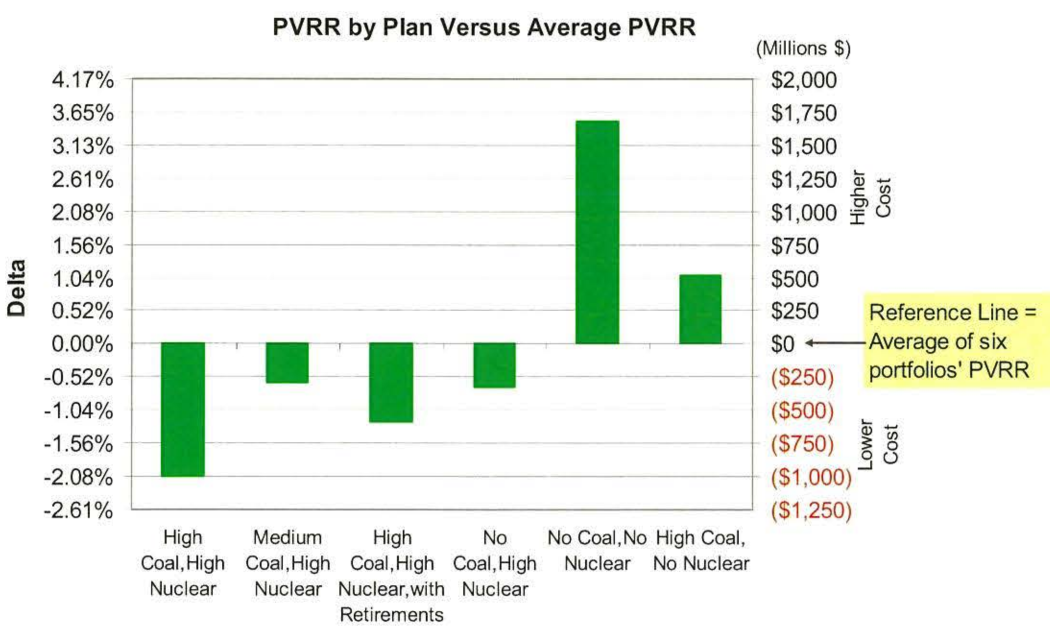
Scenario: Higher Coal and Natural Gas Prices and Higher New Coal Construction Costs



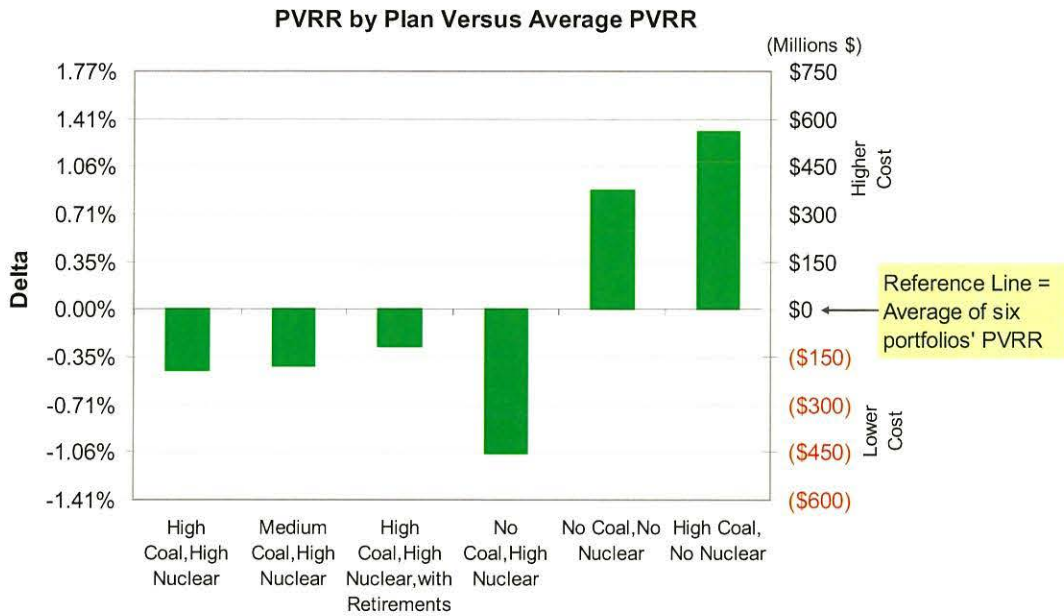
Scenario: Higher Coal and Natural Gas Prices and Higher New Nuclear Construction Costs



Scenario: Carbon Tax with Higher Natural Gas Prices



Scenario: Carbon Tax with Lower Load



The results of the quantitative analyses indicate that significant additions of baseload, intermediate/peaking and demand-side management resources to the Duke Energy Carolinas portfolio are required over the next decade. The projected relative revenue requirements of the portfolio options demonstrate the value of new nuclear and coal capacity to customers, not only under base assumptions, but also under the wide range of sensitivities and scenarios considered.

In nearly all of the sensitivities and scenarios tested, the plan featuring 1,600 MW of new coal capacity and 1,734 MW of new nuclear capacity was the most robust of all the plans under consideration. It was the least cost plan in the base case as well as in nine of the fifteen sensitivities and it was the second lowest cost plan in four of the remaining six sensitivities, and it was never ranked lower than third. The consistency among the results was driven primarily by the significant fuel cost advantage of nuclear generation and the capital and operational cost savings associated with siting new coal units at an existing plant.

In addition to the quantitative analyses, qualitative perspectives must be considered when developing a strategy to ensure that the Company can meet customers' energy needs reliably and economically while maintaining flexibility pertaining to long-term resource decisions.

APPENDIX B: CROSS-REFERENCE OF ANNUAL PLAN REQUIREMENTS

The following table cross-references Annual Plan regulatory requirements for North Carolina and South Carolina, and identifies where those requirements are discussed in the Plan.

Requirement	**Location**
Quantitative Analysis	Appendix A
2006 FERC Form 715	Appendix C
Reserve Margin Explanation and Justification	Resource Needs Assessment (Future State) section and Appendix D for DSM Activation History.
Transmission System Adequacy	Duke Energy Carolinas Current State section
Load Forecast and Seasonal Projections of Load Capacity and Reserves for Duke Energy Carolinas	Resource Needs Assessment (Future State) section and Overall Planning Process Conclusions section
Existing Plants in Service	Duke Energy Carolinas Current State section
Generating Units Under Construction or Planned	Appendix E
Proposed Generating Units at Locations Not Known	Appendix F
Generating Units Projected To Be Retired	Resource Needs Assessment (Future State) section
Generating Units with Plans for Life Extension	Appendix M
Transmission Lines and Other Associated Facilities that are Planned or Under Construction	Appendix G
Generating or Transmission Lines Subject to Construction Delays	Appendix H
Demand-Side Options and Supply-Side Options Referenced in the Annual Plan	Duke Energy Carolinas Current State section for existing DSM and Appendix I for supply-side and DSM

	options considered in the planning process
Wholesale Purchased Power Commitments Reflected in the Annual Plan	Duke Energy Carolinas Current State section
Wholesale Power Sales Commitments Reflected in the Annual Plan	Duke Energy Carolinas Current State section
Supplier's Program for Meeting the Requirements Shown in its Forecast in an Economic and Reliable Manner, including DSM and Supply-Side Options	Although entire document refers to Duke Energy Carolinas' resource plan to meet the load obligation, please refer to Duke Energy Carolinas Current State section and Appendix I for demand-side options, Appendix I for supply-side options, Resource Needs Assessment (Future State) section and Resource Alternatives To Meet Future Energy Needs section for Seasonal Projections of LCR for Duke Energy Carolinas
Brief description and summary of cost-benefit analysis, if available, of each option considered, including those not selected	Appendix I for supply-side and demand-side options
Supplier's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy service, and a description of the external, environmental and economic consequences of the plan to the extent practicable	Entire document, especially Legislative and Regulatory Issues portion of the Duke Energy Carolinas Current State section and Appendix M for environmental and the Fuel Supply portion of the Duke Energy Carolinas Current State section for fuel
Non-utility Generation, Customer-owned Generation, Standby Generation	Appendix J
Duke Energy Carolinas' 2005 FERC Form 1 pages 422, 423, 422.1, 423.1, 422.2, 423.2, 424 and 425	Appendix K
Other Information (economic development)	Appendix L

APPENDIX C: 2006 FERC Form 715

The 2006 FERC Form 715 filed April 2006 is confidential and filed under seal.

APPENDIX D: CURTAILABLE SERVICE PILOT & EXISTING DSM[12] PROGRAMS

The following describes the existing Curtailable Service pilot and DSM programs. The tables list the existing DSM projection and activation history.

Curtailable Service

Participants agree in individual monthly contracts to voluntarily reduce their electrical loads to specified levels upon request by Duke Energy Carolinas. For any curtailable service month, each participating customer is asked to contract for a curtailable load by specifying a firm contract demand for that month. Customers who make that commitment to curtail service receive a capacity payment for the month and also an energy payment if curtailment is actually requested and the customer actually curtails load. No payments are made to customers who do not make a curtailable load commitment or who make a commitment but fail to curtail load at the Company's request. The Duke Energy Carolinas Curtailable Service pilot program targets the Commercial and Industrial sectors and currently has 8 customers who are notified about Curtailable Service events.

Demand-Side Management Programs

The following programs are designed to provide a source of interruptible capacity to Duke Energy Carolinas whenever it encounters capacity problems:

Demand Response – Load Control Curtailment Programs

Residential Air Conditioning Direct Load Control
Participants receive billing credits during the billing months of July through October in exchange for allowing Duke Energy Carolinas the right to interrupt electric service to their central air conditioning systems.

Residential Water Heating Direct Load Control
Participants receive billing credits for each billing month in exchange for allowing Duke Energy Carolinas the right to interrupt electric service to their water heaters. Water heating load control was closed in 1993 to new customers in North Carolina and South Carolina.

[12]The term "energy efficiency" is often being used today to describe what has historically been called Demand Side Management (including typical demand response, energy efficiency, and related rate products). For the purposes of the Annual Plan, Duke Energy Carolinas will continue to utilize the term "Demand Side Management".

Demand Response – Interruptible Programs

Interruptible Power Service
Participants agree contractually to reduce their electrical loads to specified levels upon request by Duke Energy Carolinas. If customers fail to do so during an interruption, they receive a penalty for the increment of demand exceeding the specified level.

Standby Generator Control
Participants agree contractually to transfer electrical loads from the Duke Energy Carolinas source to their standby generators upon request by Duke Energy Carolinas. The generators in this program do not operate in parallel with Duke Energy Carolinas' system and therefore, cannot "backfeed" (e.g., export power) into the Duke Energy Carolinas system. Participating customers receive payments for capacity and/or energy, based on the amount of capacity and/or energy transferred to their generators.

Other DSM programs include:

Demand Response – Time of Use Programs

Residential Time-of-Use
This category of rates for residential customers incorporates differential seasonal and time-of-day pricing that encourages customers to shift electricity usage from on-peak time periods to off-peak periods. In addition, there is a Residential Water Heating rate for off-peak water heating electricity use.

General Service and Industrial Time-of-Use
This category of rates for general service and industrial customers incorporates differential seasonal and time-of-day pricing that encourages customers to use less electricity during on-peak time periods and more during off-peak periods.

Hourly Pricing for Incremental Load and Hourly Pricing – Flex
This category of rates for general service and industrial customers incorporates prices that reflect Duke Energy Carolinas' estimation of hourly marginal costs. In addition, a portion of the customer's bill is calculated under their embedded-cost rate. Customers on this rate can choose to modify their usage depending on hourly prices.

Energy Efficiency Programs

Residential Energy Star Rates
This rate promotes the development of homes that are significantly more energy-efficient than a standard home. Homes are certified when they meet the standards set by the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Energy. To earn the symbol, a home must be at least 30 percent more efficient than the national Model Energy Code for homes, or 15 percent more efficient than the state energy code, whichever is more rigorous. Independent third-party inspectors test the homes to ensure they meet the standards to receive the Energy Star symbol. The independent home

inspection is the responsibility of the homeowner or builder. Electric space heating and/or electric domestic water heating are not required.

Existing Residential Housing Program
This residential program encourages 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-ups, duct sealant, etc.

Special Needs Energy Products Loan Program
This residential program encourages 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-ups, duct sealant, etc.

Existing DSM Program Details

Program	Target Market Segment	Customers	Expected Total MW Reduction (2007 Summer)	Expected Total MW Reduction (2006/2007 Winter)
Residential Air Conditioning Direct Load Control	Residential	187,052	252	0
Residential Water Heating Direct Load Control	Residential	34,254	5	17
Interruptible Power Service	Commercial and Industrial	146	328	289
Standby Generator Control	Commercial and Industrial	154	81	83
Energy Efficiency	All Segments	Results are implicit in the load forecast		

INTERRUPTIBLE DEMAND SIDE PROGRAMS DATA

Number of Customers																
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
AC/LC	189,339	187,052	184,765	182,479	180,192	177,905	175,618	173,332	171,045	168,758	166,472	164,185	161,898	159,612	157,325	155,038
WH/LC	35,645	34,254	32,863	31,472	30,080	28,689	27,298	25,907	24,516	23,125	21,734	20,343	18,952	17,561	16,169	14,778
IS	152	146	140	134	128	122	116	110	110	110	110	110	110	110	110	110
SG	152	154	156	158	160	162	164	166	168	170	172	174	176	178	180	182

Demand (Mw)																
	2006		2007		2008		2009		2010		2011		2012		2013	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
AC/LC	0	266	0	252	0	238	0	225	0	212	0	200	0	189	0	179
WH/LC	18	5	17	5	15	4	14	4	13	4	12	3	11	3	10	3
IS	301	341	289	328	277	314	266	301	254	287	242	274	230	260	218	247
SG	82	80	83	81	84	82	85	83	86	84	87	85	88	86	89	88
Total	401	692	389	666	376	638	365	613	353	587	341	563	329	538	317	517

Demand (Mw)																
	2014		2015		2016		2017		2018		2019		2020		2021	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
AC/LC	0	168	0	159	0	150	0	142	0	133	0	126	0	119	0	112
WH/LC	9	2	8	2	7	2	6	2	6	2	5	1	4	1	4	1
IS	218	247	218	247	218	247	218	247	218	247	218	247	218	247	218	247
SG	90	89	91	90	92	91	93	92	94	93	96	94	97	95	98	96
Total	317	507	317	498	317	490	317	482	318	475	319	468	319	462	320	456

Estimated Customer Credits						
	2006	2007	2008	2009	2010	2011
AC/LC	$ 6,509,030	$ 6,446,831	$ 6,383,891	$ 6,322,216	$ 6,260,814	$ 6,199,689
WH/LC	$ 970,663	$ 940,439	$ 910,281	$ 879,192	$ 849,173	$ 819,225
IS	$ 12,777,014	$ 12,273,278	$ 11,769,549	$ 11,265,826	$ 10,763,110	$ 10,259,401
SG	$ 2,724,875	$ 2,760,184	$ 2,796,501	$ 2,832,825	$ 2,868,157	$ 2,904,496
Total	$22,981,582	$22,420,732	$21,860,222	$21,300,059	$20,741,253	$20,182,811

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

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

DEMAND-SIDE MANAGEMENT ACTIVATION HISTORY

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved
8/05 – 7/06	None			
8/04 – 8/05	None			
8/03 – 8/04	None			
8/02 – 8/03	None			
8/01 – 8/02	Standby Generators	1 (Capacity Need)	80 MW	20 MW
8/01 – 8/02	Interruptible Service	1 (Capacity Need)	403 MW	370 MW
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
8/05 – 7/06	Air Conditioners	Load Test	110 MW	107 MW
		2 Cycling Tests	N/A	N/A
8/05 – 8/06	Water Heaters	Load Test	2 MW	Included in Air Conditioners
		2 Cycling Tests	N/A	N/A
8/05 – 8/06	Standby Generators	Monthly Test	N/A	N/A
8/05 – 8/06	Interruptible Service	Communication Test	N/A	N/A
8/04 - 8/05	Air Conditioners	Load Test	140 MW	148 MW
		2 Cycling Tests	N/A	N/A
8/04 – 8/05	Water Heaters	Load Test	2 MW	Included in Air Conditioners
		2 Cycling Tests	N/A	N/A
8/04 – 8/05	Standby Generators	Monthly Test	N/A	N/A
8/04 – 8/05	Interruptible Service	Communication Test	N/A	N/A
8/03 – 8/04	Air Conditioners	Load Test	110 MW	170 MW
		Cycling Test	N/A	N/A
8/03 – 8/04	Water Heaters	Cycling Test	N/A	N/A
8/03 – 8/04	Standby Generators	Monthly Test	N/A	N/A
8/03 – 8/04	Interruptible Service	Communication Test	N/A	N/A
8/02 – 8/03	Air Conditioners	2 Cycling Tests and 1 Load Test 1 Load Test	N/A 88 MW 120 MW	N/A 122 MW 195 MW
8/02 – 8/03	Water Heaters	2 Cycling Tests 1 Load Test 1 Load Test	N/A 6 MW 5 MW	N/A Included in Air Conditioners
8/02 – 8/03	Standby Generators	Monthly Test	N/A	N/A
8/02 – 8/03	Interruptible Service	2 Communication Tests	N/A	N/A
8/01 – 8/02	Air Conditioners	3 Cycling Tests and 1 Load Test	N/A 150 MW	N/A 151 MW
8/01 – 8/02	Water Heaters	3 Cycling Tests and 1 Load Test	N/A 6 MW	N/A Included in Air Conditioners
8/01 – 8/02	Standby	Monthly Test	N/A	N/A

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved
	Generators			
8/01 – 8/02	Interruptible Service	1 Communication Test	N/A	N/A
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

APPENDIX E: 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 include:

Duke Energy Carolinas continues to assess the viability of all of its generating units in relation to new generation and purchased power.

New Cliffside Pulverized Coal Units
During May 2005, the Company filed preliminary information with the NCUC for a CPCN for up to 1600 MW of pulverized coal generation at the Cliffside Steam Station in Cliffside, N.C. The CPCN application and supporting testimony were filed by the Company in June 2006. The hearing is currently scheduled for September 12, 2006.

As a part of the development of the 2006 Annual Plan, the Company continued to study the economics of these proposed new coal-fired units. The results of this continued analysis are discussed in Appendix A of this document.

Potential Buck Combined Cycle:
During May 2005, the Company filed preliminary a preliminary CPCN for up to 600 MW of combined cycle generation at the Buck Steam Station in Salisbury, N.C. Duke Energy Carolinas continues to evaluate intermediate capacity options.

New William States Lee III Nuclear Station Generating Units
During 2005, the Company began work to pursue a new nuclear combined construction and operating license. The Westinghouse Advanced Passive 1000 reactor technology was selected for the application after an extensive review of multiple technologies. A contractor was chosen to assist with application preparation.

In 2006, a site in Cherokee County, S.C. was selected for the project. Currently, site characterization work is underway at this location. Duke Energy continues working with the nuclear industry on additional license standardization development and technology design finalization. Duke Energy Carolinas has announced it has entered into an agreement with Southern Company to evaluate potential nuclear plant construction at the jointly owned Cherokee County, S.C. location.

The Company will continue to study the economics of additional nuclear generation as it looks forward to meeting growing customer needs using a diverse energy mix.

Rockingham Power Facility
The Rockingham Power Facility, located in Rockingham County, North Carolina, is an 825 MW peaking facility that consists of five Westinghouse 501F machines (5 units at 165 MW per unit). The plant came on-line commercially in July 2000 and is connected to Duke Energy Carolinas' 230 kV transmission line. Duke Energy Carolinas agreed to acquire the Rockingham Power Facility from Rockingham Power, L.L.C. on May 21, 2006 Duke Energy Carolinas also will assume the obligation to engage in certain firm wholesale sales of power from the facility during the 2006-2010 time periods. The acquisition of the Rockingham plant represented the least cost means for Duke Energy Carolinas to meet some of its capacity obligations and it has the additional benefit of enhancing Duke Energy Carolinas' ability to provide continued reliable transmission service.

The purchase of the Rockingham plant requires regulatory approvals from the following entities: North Carolina Utilities Commission (NCUC), Department of Justice (DOJ), and the Federal Energy Regulatory Commission (FERC). NCUC approval was received on July 25, 2006. Early termination of the Hart-Scott-Rodino Antitrust Improvement Act of 1976 waiting period was granted by the DOJ on July 20, 2006. On July 28, 2006, Duke Energy Carolinas submitted its section 203 application to FERC for approval of the Rockingham acquisition. FERC's ruling on the application is anticipated by November 1, 2006.

For Annual Plan modeling purposes, Duke Energy Carolinas assumed that the transfer of the Rockingham asset would be approved and would occur by January 1, 2007.

APPENDIX F: PROPOSED GENERATING UNITS AT LOCATIONS NOT KNOWN

A list of proposed generating units at locations not known with capacity, plant type, and date of operation included to the extent known:

Line 9 of the Seasonal Projections of Load, Capacity, and Reserves for Duke Energy Carolinas identifies cumulative future resource additions needed to meet customer load reliably. Resource additions may be a combination of short/long-term capacity purchases from the wholesale market, capacity purchase options, and building or contracting of new generation. In the preliminary filings with the NCUC for the CPCNs at Buck and Cliffside Steam Stations, the Company noted its intent to also pursue CPCNs for coal and combined cycle capacity at sites in South Carolina. However, no decision has been made with regard to pursuit of South Carolina CPCNs at the time of the filing of this Plan.

APPENDIX G: TRANSMISSION LINES AND OTHER ASSOCIATED FACILITIES PLANNED OR UNDER CONSTRUCTION

The following table identifies significant planned construction projects and those currently under construction in Duke Energy Carolinas' transmission system.

PROJECT	VOLTAGE	LOCATION OF CONNECTION STATION	LINE CAPACITY	SCHEDULED OPERATION
Dutchover Line	230 kV	Riverbend Steam Station to Lincoln Combustion Turbine Station	Reconfigure Riverbend – McGuire (Schoonover) Line and McGuire – Lincoln Combustion Turbine (Dutchman) Line to bypass McGuire – 598 MVA	Dec. 1, 2006
Duke – TVA tie line	161 kV	Nantahala through Robbinsville and Santeetlah to Fontana	Add second circuit to existing line – approximately 600 MVA	8/1/2009
Beckerdite Tie Static Var Compensator (SVC)	100 kV	Add -100 MVAR/ +300 MVAR SVC at Beckerdite Tie	N/A	6/1/2007
Belews Creek Steam Station capacitor	230 kV	Add 300 MVAR capacitor	N/A	6/1/2007
Tuckasegee Tie capacitor	161 kV	Add 54 MVAR capacitor	N/A	6/1/2007

In addition, NCUC Rule R8-62(p) requires the following information.

1. For existing lines, the information required on FERC Form 1, pages 422, 423, 424 and 425: (Please see Appendix K for Duke Energy Carolinas' current FERC Form 1 pages 422, 423, 422.1, 423.1, 422.2, 423.2, 424 and 425.)

2. For lines under construction:
    - Commission docket number
    - Location of end point(s)
    - Length
    - Range of right-of-way width
    - Range of tower heights
    - Number of circuits
    - Operating voltage
    - Design capacity
    - Date construction started
    - Projected in-service date.

Duke Energy Carolinas has no lines rated at 161 KV or greater under construction.

3. For all other proposed lines, as the information becomes available:
    - County location of end point(s)
    - Approximate length
    - Typical right-of-way width for proposed type of line
    - Typical tower height for proposed type of line
    - Number of circuits
    - Operating voltage
    - Design capacity
    - Estimated date for starting construction
    - Estimated in-service date.

Nantahala – Fontana 161 kV Line

- county location of end point(s); Macon County, NC – Graham County, NC
- approximate length; 20 Miles
- typical right-of-way width for proposed type of line; 225 ft
- typical tower height for proposed type of line; 140 ft
- number of circuits; 1 additional circuit
- operating voltage; 161 kV
- design capacity; 500 MVA / Circuit
- estimated date for starting construction; March 12, 2007
- estimated in-service date; August 1, 2009

APPENDIX H: GENERATION AND ASSOCIATED TRANSMISSION FACILITIES SUBJECT TO CONSTRUCTION DELAYS

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.

APPENDIX I: DEMAND-SIDE AND SUPPLY-SIDE OPTIONS REFERENCED IN THE PLAN.

Supply-Side Options

Supply-side options considered in the Annual Plan are subjected to an economic screening process to determine the most cost-effective technologies. Conventional, demonstrated and emerging technologies must pass a cost screen, a commercial availability screen, and a technical feasibility screen to be considered for further evaluation.

The data for each technology is based on research by Duke Energy Carolina's Generation team, Duke Energy Analytical and Investment Engineering, the Electric Power Research Institute (EPRI) Technology Assessment Guide, and fuel and operating costs developed by internal and other sources. The EPRI information is not site-specific but reflects costs and operating parameters that are adjusted for installation in the Southeast.

After an initial round of screening of eighty-eight potential supply-side technologies, the following were selected for further evaluation:

Conventional Technologies (technologies in common use):

- 4x160 MW Combustion Turbines Brownfield GE 7FA
- 4x160 MW Combustion Turbines Greenfield GE 7FA
- 484 MW Unfired + 120 MW Fired Combined Cycle, 7FA Brownfield
- 484 MW Unfired + 120 MW Fired Combined Cycle, 7FA Greenfield
- 2x800 MW Supercritical Conventional Fossil, Brownfield Cliffside, Single Rail
- 2x800 MW Supercritical Conventional Fossil, Brownfield Cliffside, Dual Rail
- 800 MW Supercritical Conventional Fossil, Brownfield Cliffside, Single Rail
- 800 MW Supercritical Conventional Fossil, Brownfield Cliffside, Dual Rail
- 2x800 MW Supercritical Conventional Fossil, Greenfield, Dual Rail
- 800 MW Supercritical Conventional Fossil, Greenfield, Dual Rail
- 3x250 MW Circulating Fluidized Bed Combustion Coal
- 2x1117 MW Nuclear, AP1000
- 64 MW Saluda River Electric Coop Share of Catawba Nuclear (2009)

Demonstrated Technologies (technologies with limited acceptance and not in widespread use):

- 632 MW IGCC, Brownfield Cliffside
- 100 MW Biomass IGCC
- 15 MW Advanced Battery
- 350 MW Compressed Air Energy Storage, Rock Cavern
- 2 MW Solid Oxide Fuel Cell, Pressurized
- 80 MW Solar Thermal, Gas Hybrid
- 100 MW Wind Project

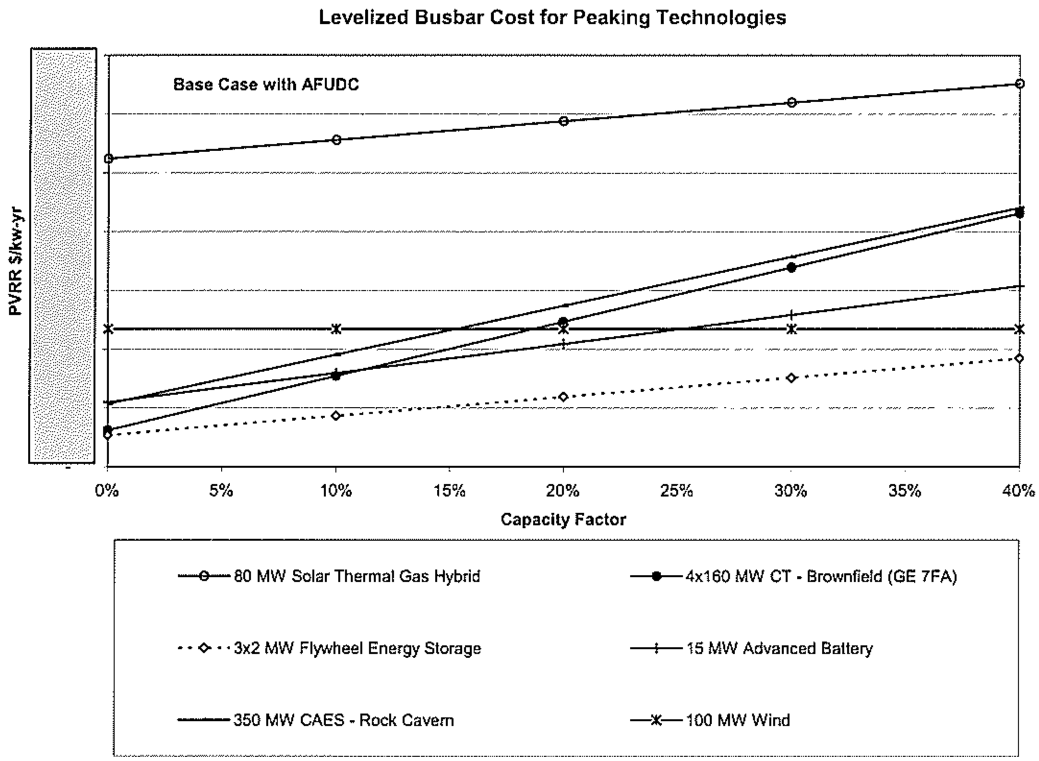
Emerging Technologies (technologies in the developmental stage or that have not been used in the electric utility industry):

- 3x2 MW Flywheel Energy Storage

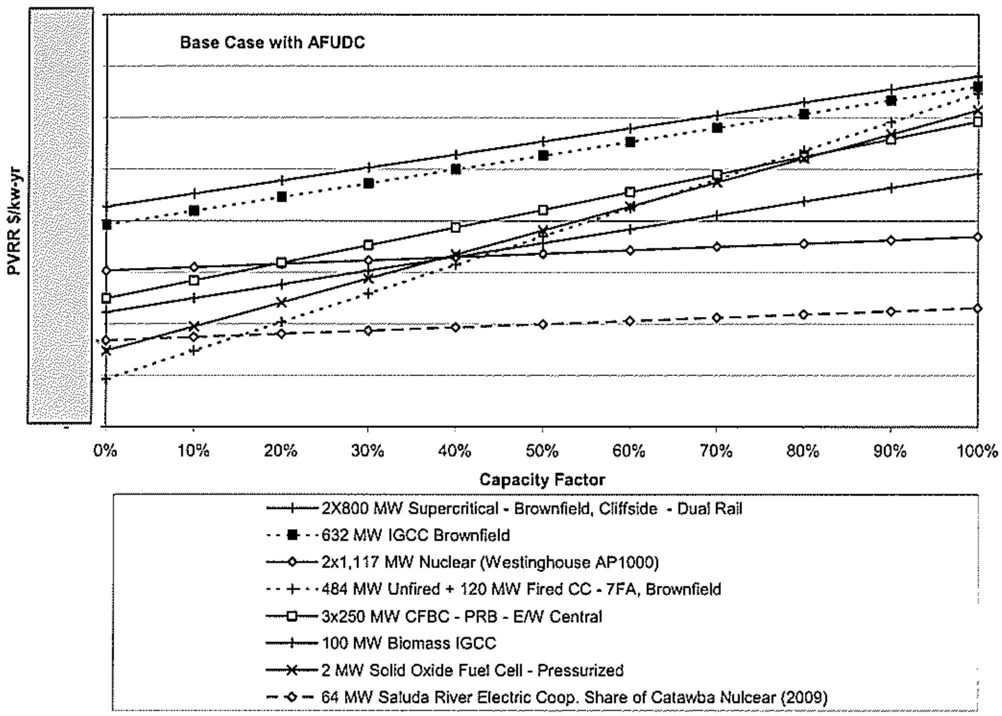
The following Levelized Busbar Cost[13] charts provide an economic comparison of the technologies considered for further evaluation. For simplicity of presentation, all of the Greenfield versus Brownfield and Single Rail versus Dual Rail variations have not been shown.

[13] While this levelized busbar costs provide a reasonable basis for initial screening of technologies, simple busbar cost information has limitations. In isolation, busbar cost information has limited applicability in decision-making because it is highly dependent on the circumstances being considered. A complete analysis of feasible technologies must include consideration of the interdependence of the technologies and Duke Energy Carolinas' existing generation portfolio.

[BEGIN CONFIDENTIAL]



Levelized Busbar Cost for Baseload & Intermediate Technologies



[END CONFIDENTIAL]

Technologies which are commercially available, cost-effective, and technically feasible for use in the Carolinas were passed on to the quantitative analysis phase for further evaluation. The following points explain why various technologies were eliminated from further consideration:

- Coal based IGCC is still developing as a fully commercial technology. Currently, several 600 MW class commercially offered plants are in the development stages, including Duke Energy Indiana's proposed project being developed for a new 600 MW IGCC plant in Indiana. Additional issues, such as higher costs and the lack of suitable geologic formations to support future CO_2 sequestration in the Carolinas, make IGCC unsuitable for Duke Energy Carolinas' near-term baseload needs.

- Although Circulating Fluidized Bed Coal combustion is a conventional technology that is technically feasible and in utility use, boiler size generally is limited to 300 - 350 MW. Current clean air standards also require further SO_2 emission reductions using equipment installed after the boiler. Both of these facts cause it to be one of the higher-cost generation technologies in the utility scale baseload duty cycle.

- Wind Power is not a reliably dispatchable capacity resource, limiting its effectiveness and competitiveness against dispatchable peaking duty cycle technologies. In regions with viable and exploitable wind resources, this technology may provide relatively low cost and clean displacement energy on an as-available basis. However, potentially sufficient wind energy in the Carolinas is found only on the ridge-lines of the North Carolina mountains and along the Atlantic coast. The future of proposed projects on the ridge-lines is subject to interpretation of the North Carolina Mountain Ridge Protection Act. Proposed projects along the Carolina coast are likely to experience opposition such as that experienced by the Cape Wind project off the coast of Massachusetts.

- Advanced Battery technology, remains relatively expensive and is currently applicable for small scale emergency operations (short-term duty cycles) of three hours or less. Application on a larger utility scale is in the pilot phase, and generally not commercially available.

- Compressed Air Energy Storage, although demonstrated on a utility scale, is generally not a widely available technology. This is due to the fact that suitable sites containing the proper geological conditions for the underground compressed air reservoir are relatively scarce, and there are no viable sites in Duke Energy Carolinas' service territory to support it.

- Flywheel Energy Storage technology continues to undergo development. It is not commercially available for a utility-scale application.

- Solid Oxide Fuel Cell technology continues to undergo developmental testing at several demonstration projects. It is not commercially available for a utility scale application.

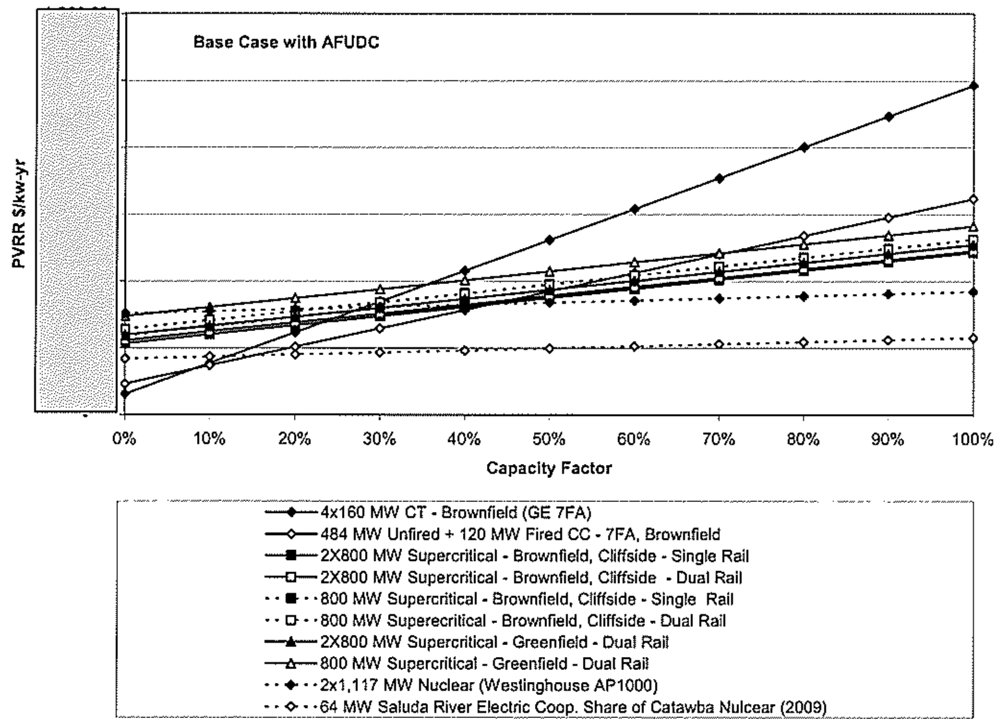
- Biomass based IGCC technology continues to undergo development. It is not commercially available for a utility scale application, and is one of the higher-cost baseload duty cycle technologies.

- Solar Thermal (and Photovoltaic) technology is still an evolving technology. It is not dispatchable without energy storage and photovoltaic is better suited for remote niche applications that require small scale (watt-to-kilowatt) power. In addition, large-scale solar thermal and photovoltaic applications are not cost competitive with peaking and intermediate duty cycle technologies.

The chart below shows the technologies which are commercially available, cost-effective and technically feasible for use in the Carolinas. Combustion turbine is the most cost-effective technology for peaking duty cycles, combined cycle for intermediate duty cycles and an assortment of coal and nuclear for baseload duty cycles.

[BEGIN CONFIDENTIAL]

Levelized Busbar Cost for Technologies Considered in Quantitative Analysis



[END CONFIDENTIAL]

These technologies were selected for the quantitative analysis:

- 4x160 MW Combustion Turbines Brownfield GE 7FA
- 484 MW Unfired + 120 MW Fired Combined Cycle, 7FA Brownfield
- 2x800 MW Supercritical Conventional Fossil, Brownfield Cliffside, Single Rail
- 2x800 MW Supercritical Conventional Fossil, Brownfield Cliffside, Dual Rail
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- 2x800 MW Supercritical Conventional Fossil, Greenfield, Dual Rail
- 800 MW Supercritical Conventional Fossil, Greenfield, Dual Rail
- 2x1117 MW Nuclear, Westinghouse AP1000
- 64 MW Saluda River Electric Coop Share of Catawba Nuclear (2009)

Demand-Side Management

Duke Energy Carolinas has recently established collaborative groups that consist of various stakeholders from across its service area. The objective of these collaborative efforts will be to design and recommend a new set of DSM-related programs for its customers. Currently, Duke Energy Carolinas has included 100 MW of additional demand response program capability and 101 MW of additional programs that reduce energy consumption as placeholders in the 2006 Annual Plan pending the development of specific intiatives. Duke Energy Carolinas anticipates that the collaborative efforts will provide a more detailed analysis of the size and character of potential programs that will be implemented and included in future Annual Plans. The ultimate levels and timing of additional EE programs developed by the collaborative process may differ from the assumptions included in the modeling for this Annual Plan. Future analyses will incorporate the updated information.

Below is a summary of potential demand response programs that were considered in the planning process.

Direct Load Control
Direct load control could be designed to target residential or commercial class customers and dispatched to a geographic region or systemwide. Potential load sources that could be directly controlled include water heating, air conditioning and swimming pool pumps. Estimated load impacts are between .5 kW and 1.6 kW per residential customer and 2.5 kW per commercial customer.

Interruptible Service
Interruptible service could be designed to target large commercial or industrial customers and dispatched to a geographic region or systemwide. This program was assumed to have a load impact of approximately 2.06 MW per customer.

Standby Generation
Standby generation could be designed to target commercial or industrial customers and could be dispatched specifically to a geographic region or systemwide. This program was assumed to have a load impact of approximately 258 kW per customer.

Energy Efficiency (EE) Programs
The programs providing reductions in energy usage fall into two groups:

1. 100 MW of capability from a combination of potential future EE programs
2. $2MM funding for EE-related programs as required by the North Carolina Utilities Commission in its Order Docket Number E-7, Sub 795 approving the merger.

The analysis for the 101 MW of potential future EE capability was intended to be indicative of the level of opportunity available to Duke Energy Carolinas, rather than as a precise estimate of program costs and benefits. The full selection of EE programs will come through the collaborative effort. Potential programs identified for inclusion in the

101 MW EE capability include:

$2MM Energy Efficiency Funding

Program Name:	Energy Efficiency Kits
Program Description:	Provide an "energy efficiency" starter kit to residential North Carolina Duke-served customers. The kit includes various energy efficiency tools to support a corresponding educational video. These kits could include a booklet showing energy saving tips with how-to information, low flow shower head, window sealant material, high efficiency fluorescent bulbs, weather stripping, wall outlet and switch plate insulation material, and faucet aerators.
Program Name:	Energy Efficiency Video
Program Description:	Develop a home education, video-based content (delivered via DVD, VCR, and/or streaming media on the Duke Energy website) that focuses on home energy conversation and efficiency. This educational video would review various energy consuming systems within the home and provide energy saving tips and do-it-yourself energy saving home improvements. Topics could focus on HVAC systems, improving home envelope, lighting, water heating, kitchen and laundry appliances, Energy Star Appliances and other energy related issues.
Program Name:	Large Business Customer Energy Efficiency Audits
Program Description:	"Plus Assessments" via phone with metered data and provide customer with detailed report filled with customer-specific energy efficiency opportunities. "Premium Assessments" via on-site visit with metered data and provide customer with very detailed report filled with customer-specific energy efficiency opportunities. Provide software licenses for all assessments (Plus, Premium, and Comprehensive Audits) for Energy Profiler Online.
Program Name:	Large Business Customer Energy Efficiency Tools
Program Description:	Provide and promote an online assessment tool for commercial, manufacturing, and institutional customers based on actual customer data and currently available information. Duke would plan on delivering this service to its larger customers through the Business Services Newsline and Resource Library. Evaluate and purchase currently available energy simulation software tools and commercially available options to provide a comprehensive auditing tool for

complex structures and industrial processes (e.g. Trane Trace). This tool could be applied to any C&I customers but would most likely be used in conjunction with a detailed on-site (customer funded) multi-day energy assessment (the aforementioned "comprehensive assessment").

Portfolio Structure of Potential Energy-Efficiency Products

Duke Energy Carolinas believes energy efficiency products and services are best divided into three categories:

- EE-Education: Products and services which educate customers about energy efficiency, its benefits, and how it can benefit.
- EE-Audit: Products and services which show customers specific opportunities to implement energy efficiency on a cost-effective basis.
- EE-Implementation: Products and services which implement specific energy-efficiency opportunities for customers.

Through multiple collaborative partnerships, Duke Energy Carolinas will further define, develop, implement and promote potential energy efficiency products and services that fall into these categories. The collaborative partnerships include:

- A collaborative group to partner Duke with neighboring utilities in North Carolina and Advanced Energy for the purpose of sharing best practices, innovative product designs, and to collaborate on various state-wide energy efficiency initiatives
- A collaborative group to partner Duke with representatives from commercial, manufacturing, and institutional segments of customers. This collaborative would also include representatives from other regulatory, legal, and external stakeholder groups. The purpose of this collaborative group would be to design, develop, and promote potential energy efficiency products, services, and policies which would benefit these classes of customers.
- A collaborative group to partner Duke with representatives of the residential class of customers. This collaborative would also include representatives from other regulatory, legal, and external stakeholder groups. The purpose of this collaborative group would be to design, develop, and promote potential energy efficiency products, services, and policies which would benefit these classes of customers.

The table below provides the projection of new demand response products as well as a potential portfolio of energy efficiency products and services and their associated load impacts through 2021 that was included as placeholders in the quantitative analysis.

Projected DSM Load Impacts					
	100 MW Demand Response Program	100 MW Energy Efficiency Program		$2 Million Energy Efficiency Program	
	MW Impacts	MWH Impacts	MW Impacts	MWH Impacts	MW Impact
2007	25	46,248	12	4,394	1
2008	65	131,489	32	4,394	1
2009	100	216,730	52	4,394	1
2010	100	301,971	72	4,394	1
2011	100	386,854	92	4,394	1
2012	100	421,784	100	4,394	1
2013	100	421,784	100	4,394	1
2014	100	421,784	100	4,394	1
2015	100	421,784	100	4,394	1
2016	100	421,784	100	4,394	1
2017	100	421,784	100	4,394	1
2018	100	421,784	100	4,394	1
2019	100	421,784	100	4,394	1
2020	100	421,784	100	4,394	1
2021	100	421,784	100	4,394	1

APPENDIX J: NON-UTILITY GENERATION/CUSTOMER-OWNED GENERATION/STAND-BY GENERATION:

In NCUC Order dated Feb. 20, 2003, in Docket No. E-100, Sub 97, the NCUC required North Carolina utilities to provide a separate list of all non-utility electric generating facilities in the North Carolina portion of their control areas, including customer-owned and standby generating facilities, to the extent possible. Duke Energy Carolinas' response to that Order was based on the best available information, and the Company has not attempted to independently validate it. In addition, some of that information duplicates data that Duke Energy Carolinas supplies elsewhere in this Annual Plan.

CUSTOMER-OWNED STANDBY GENERATION				
CITY	STATE	NAMEPLATE KW	PRIMARY FUEL TYPE	PART OF TOTAL SUPPLY RESOURCES
Belmont	NC	350	Unknown	Yes[1]
Belmont	NC	350	Unknown	Yes[1]
Belmont	NC	500	Unknown	Yes[1]
Bessemer City	NC	440	Unknown	Yes[1]
Burlington	NC	550	Unknown	Yes[1]
Burlington	NC	600	Unknown	Yes[1]
Burlington	NC	650	Unknown	Yes[1]
Burlington	NC	225	Unknown	Yes[1]
Burlington	NC	200	Unknown	Yes[1]
Burlington	NC	1150	Unknown	Yes[1]
Butner	NC	750	Unknown	Yes[1]
Butner	NC	1250	Unknown	Yes[1]
Carrboro	NC	1135	Unknown	Yes[1]
Carrboro	NC	2000	Unknown	Yes[1]
Carrboro	NC	500	Unknown	Yes[1]
Chapel Hill	NC	500	Unknown	Yes[1]
Charlotte	NC	1750	Unknown	Yes[1]
Charlotte	NC	1000	Unknown	Yes[1]
Charlotte	NC	1200	Unknown	Yes[1]
Charlotte	NC	1250	Unknown	Yes[1]
Charlotte	NC	1135	Unknown	Yes[1]
Charlotte	NC	1135	Unknown	Yes[1]
Charlotte	NC	1500	Unknown	Yes[1]
Charlotte	NC	10000	Unknown	Yes[1]
Charlotte	NC	200	Unknown	Yes[1]
Charlotte	NC	2200	Unknown	Yes[1]
Charlotte	NC	700	Unknown	Yes[1]
Charlotte	NC	5600	Unknown	Yes[1]
Charlotte	NC	4000	Unknown	Yes[1]
Concord	NC	680	Unknown	Yes[1]
Danbury	NC	400	Unknown	Yes[1]
Durham	NC	1300	Unknown	Yes[1]
Durham	NC	2500	Unknown	Yes[1]
Durham	NC	1100	Unknown	Yes[1]
Durham	NC	3200	Unknown	Yes[1]
Durham	NC	1600	Unknown	Yes[1]
Durham	NC	1400	Unknown	Yes[1]
Durham	NC	1500	Unknown	Yes[1]
Durham	NC	2250	Unknown	Yes[1]
Durham	NC	4525	Unknown	Yes[1]
Durham	NC	1750	Unknown	Yes[1]
Durham	NC	1900	Unknown	Yes[1]
Durham	NC	7000	Unknown	Yes[1]

CUSTOMER-OWNED STANDBY GENERATION				
CITY	STATE	NAMEPLATE KW	PRIMARY FUEL TYPE	PART OF TOTAL SUPPLY RESOURCES
Durham	NC	4500	Unknown	Yes[1]
Durham	NC	6400	Unknown	Yes[1]
Durham	NC	625	Unknown	Yes[1]
Durham	NC	2000	Unknown	Yes[1]
Eden	NC	1700	Unknown	Yes[1]
Elkin	NC	400	Unknown	Yes[1]
Elkin	NC	500	Unknown	Yes[1]
Gastonia	NC	910	Unknown	Yes[1]
Gastonia	NC	680	Unknown	Yes[1]
Gastonia	NC	12500	Unknown	Yes[1]
Graham	NC	800	Unknown	Yes[1]
Greensboro	NC	1350	Unknown	Yes[1]
Greensboro	NC	125	Unknown	Yes[1]
Greensboro	NC	1000	Unknown	Yes[1]
Greensboro	NC	1500	Unknown	Yes[1]
Greensboro	NC	2000	Unknown	Yes[1]
Greensboro	NC	250	Unknown	Yes[1]
Greensboro	NC	750	Unknown	Yes[1]
Greensboro	NC	1280	Unknown	Yes[1]
Greensboro	NC	700	Unknown	Yes[1]
Hendersonville	NC	500	Unknown	Yes[1]
Hendersonville	NC	1000	Unknown	Yes[1]
Hendersonville	NC	1000	Unknown	Yes[1]
Hickory	NC	1500	Unknown	Yes[1]
Hickory	NC	750	Unknown	Yes[1]
Hickory	NC	1000	Unknown	Yes[1]
Hickory	NC	1500	Unknown	Yes[1]
Hickory	NC	1040	Unknown	Yes[1]
Hickory	NC	500	Unknown	Yes[1]
Huntersville	NC	2950	Unknown	Yes[1]
Huntersville	NC	775	Unknown	Yes[1]
Huntersville	NC	3200	Unknown	Yes[1]
Indian Trail	NC	900	Unknown	Yes[1]
King	NC	800	Unknown	Yes[1]
Lexington	NC	750	Unknown	Yes[1]
Lexington	NC	2950	Unknown	Yes[1]
Lincolnton	NC	300	Unknown	Yes[1]
Marion	NC	650	Unknown	Yes[1]
Matthews	NC	1450	Unknown	Yes[1]
Mebane	NC	400	Unknown	Yes[1]
Midland	NC	4000	Unknown	Yes[1]
Midland	NC	6000	Unknown	Yes[1]
Monroe	NC	400	Unknown	Yes[1]

CUSTOMER-OWNED STANDBY GENERATION				
CITY	STATE	NAMEPLATE KW	PRIMARY FUEL TYPE	PART OF TOTAL SUPPLY RESOURCES
Mooresville	NC	750	Unknown	Yes[1]
Morganton	NC	200	Unknown	Yes[1]
Mt. Airy	NC	600	Unknown	Yes[1]
Mt. Airy	NC	750	Unknown	Yes[1]
Mt. Holly	NC	210	Unknown	Yes[1]
N. Wilkesboro	NC	600	Unknown	Yes[1]
N. Wilkesboro	NC	155	Unknown	Yes[1]
North Wilkesboro	NC	1250	Unknown	Yes[1]
Pfafftown	NC	4000	Unknown	Yes[1]
Reidsville	NC	750	Unknown	Yes[1]
Research Triangle	NC	750	Unknown	Yes[1]
Research Triangle	NC	1000	Unknown	Yes[1]
Research Triangle	NC	350	Unknown	Yes[1]
Research Triangle	NC	750	Unknown	Yes[1]
Rural Hall	NC	1050	Unknown	Yes[1]
Rutherfordton	NC	800	Unknown	Yes[1]
Salisbury	NC	1500	Unknown	Yes[1]
Salisbury	NC	1500	Unknown	Yes[1]
Shelby	NC	4480	Unknown	Yes[1]
Valdese	NC	600	Unknown	Yes[1]
Valdese	NC	800	Unknown	Yes[1]
Welcome	NC	300	Unknown	Yes[1]
Winston	NC	750	Unknown	Yes[1]
Winston Salem	NC	1800	Unknown	Yes[1]
Winston Salem	NC	3360	Unknown	Yes[1]
Winston Salem	NC	1250	Unknown	Yes[1]
Winston Salem	NC	3000	Unknown	Yes[1]
Winston Salem	NC	2000	Unknown	Yes[1]
Winston Salem	NC	3000	Unknown	Yes[1]
Winston-Salem	NC	500	Unknown	Yes[1]
Winston-Salem	NC	3200	Unknown	Yes[1]
Winston-Salem	NC	400	Unknown	Yes[1]
Winston-Salem	NC	3750	Unknown	Yes[1]
Yadkinville	NC	500	Unknown	Yes[1]
Yadkinville	NC	1200	Unknown	Yes[1]
Anderson	SC	2250	Unknown	Yes[1]
Anderson	SC	1500	Unknown	Yes[1]
Bullock Creek	SC	275	Unknown	Yes[1]
Clinton	SC	447	Unknown	Yes[1]
Clover	SC	625	Unknown	Yes[1]
Clover	SC	75	Unknown	Yes[1]
Duncan	SC	600	Unknown	Yes[1]

CUSTOMER-OWNED STANDBY GENERATION				
CITY	STATE	NAMEPLATE KW	PRIMARY FUEL TYPE	PART OF TOTAL SUPPLY RESOURCES
Fort Mill	SC	1600	Unknown	Yes[1]
Gaffney	SC	1200	Unknown	Yes[1]
Greenville	SC	3650	Unknown	Yes[1]
Greenville	SC	2500	Unknown	Yes[1]
Greenville	SC	300	Unknown	Yes[1]
Greenville	SC	500	Unknown	Yes[1]
Greenville	SC	1500	Unknown	Yes[1]
Greenwood	SC	2400	Unknown	Yes[1]
Greenwood	SC	600	Unknown	Yes[1]
Greer	SC	125	Unknown	Yes[1]
Greer	SC	1250	Unknown	Yes[1]
Inman	SC	165	Unknown	Yes[1]
Kershaw	SC	165	Unknown	Yes[1]
Kershaw	SC	1500	Unknown	Yes[1]
Lancaster	SC	1500	Unknown	Yes[1]
Lancaster	SC	300	Unknown	Yes[1]
Lyman	SC	1000	Unknown	Yes[1]
Mt. Holly	SC	265	Unknown	Yes[1]
Simpsonville	SC	900	Unknown	Yes[1]
Simpsonville	SC	458	Unknown	Yes[1]
Spartanburg	SC	600	Unknown	Yes[1]
Spartanburg	SC	450	Unknown	Yes[1]
Spartanburg	SC	2900	Unknown	Yes[1]
Spartanburg	SC	650	Unknown	Yes[1]
Spartanburg	SC	2700	Unknown	Yes[1]
Spartanburg	SC	1600	Unknown	Yes[1]
Taylor	SC	350	Unknown	Yes[1]
Van Wyck	SC	450	Unknown	Yes[1]
Van Wyck	SC	365	Unknown	Yes[1]
Walhalla	SC	350	Unknown	Yes[1]

Note 1: Nameplate rating is typically greater than maximum net dependable capability that generator contributes to Duke resources. These customers currently participate in the customer standby generation program. The inclusion of their capability is expected to impact Duke system capacity needs.

PURPA QUALIFYING FACILITIES (SELLING POWER TO DUKE ENERGY CAROLINAS)					
NAME	CITY	STATE	NAMEPLATE KW	PRIMARY FUEL TYPE	PART OF TOTAL SUPPLY RESOURCES [1]
Advantage Investment Group, LLC [2]	Spencer Mtn	NC	640	Hydroelectric	Yes[1]
Barbara Ann Evans - Caroleen Mills	Caroleen	NC	324	Hydroelectric	Yes[1]
Catawba County - Blackburn Landfill	Newton	NC	4,000	Landfill Gas	Yes[1]
Cliffside Mills, LLC	Cliffside	NC	1,600	Hydroelectric	Yes[1]
Habitat for Humanity of Catawba County	Hickory	NC	4	Photovoltaic	Yes[1]
Haneline Power, LLC	Millersville	NC	365	Hydroelectric	Yes[1]
Haw River Hydro	Saxapahaw	NC	1,500	Hydroelectric	Yes[1]
Hayden-Harman Foundation	Burlington	NC	2	Photovoltaic	Yes[1]
Mayo Hydropower, LLC - Avalon Dam	Mayodan	NC	1,275	Hydroelectric	Yes[1]
Mayo Hydropower, LLC - Mayo Dam	Mayodan	NC	950	Hydroelectric	Yes[1]
Mill Shoals Hydro Co - High Shoals Hydro	High Shoals	NC	1,800	Hydroelectric	Yes[1]
Northbrook Carolina Hydro, LLC - Turner Shoals Hydro	Mill Springs	NC	5,500	Hydroelectric	Yes[1]
Pickens Mill Hydro, LLC - Stice Shoals Hydro [3]	Shelby	NC	600	Hydroelectric	Yes[1]
Salem Energy Systems	Winston-Salem	NC	4,270	Landfill Gas	Yes[1]
South Yadkin Power, Inc	Cooleemee	NC	1,400	Hydroelectric	Yes[1]
Spray Cotton Mills	Eden	NC	500	Hydroelectric	Yes[1]
Steve Mason Enterprises-Harden Hydro	Hardins	NC	820	Hydroelectric	Yes[1]
Steve Mason Enterprises-Long Shoals Hydro	Long Shoals	NC	900	Hydroelectric	Yes[1]
Town of Lake Lure	Lake Lure	NC	3,600	Hydroelectric	Yes[1]
Aquenergy Systems Inc	Piedmont	SC	1,050	Hydroelectric	Yes[1]
Aquenergy Systems Inc	Ware Shoals	SC	6,300	Hydroelectric	Yes[1]
Cherokee County Cogeneration Partners	Gaffney	SC	100,000	Natural gas	Yes[1]
Converse Energy Inc	Converse	SC	1,250	Hydroelectric	Yes[1]
Northbrook Carolina Hydro, LLC - Boyds Mill Hydro	Ware Shoals	SC	1,500	Hydroelectric	Yes[1]
Northbrook Carolina Hydro, LLC - Hollidays Bridge Hydro	Belton	SC	3,500	Hydroelectric	Yes[1]
Northbrook Carolina Hydro, LLC - Saluda Hydro	Greenville	SC	2,400	Hydroelectric	Yes[1]
Pacolet River Power Co	Clifton	SC	800	Hydroelectric	Yes[1]
Pelzer Hydro Co - Upper Hydro	Pelzer	SC	2,020	Hydroelectric	Yes[1]
Pelzer Hydro Co - Lower Hydro	Williamston	SC	3,300	Hydroelectric	Yes[1]

Note 1: Nameplate rating generally exceeds the contract capacity negotiated for Duke Energy Carolinas
Note 2: Formerly Northbrook Carolina, LLC - Stice Shoals Hydro
Note 3: Formerly Northbrook Carolina, LLC - Spencer Mountain Hydro

MERCHANT GENERATORS					
NAME	CITY	STATE	NAMEPLATE KW	PRIMARY FUEL TYPE	PART OF TOTAL SUPPLY RESOURCES [1]
Dynegy Power Marketing, Inc	Bethany	NC	810,000	Natural gas	Yes[1]
Progress Ventures, Inc	Salisbury	NC	500,000	Natural gas	Yes[1]
Broad River Energy Center, LLC	Gaffney	SC	875,000	Natural gas	No

Note 1: Nameplate rating generally exceeds the contract capacity negotiated for Duke Energy Carolinas

CUSTOMER-OWNED SELF-GENERATION				
COUNTY	STATE	NAMEPLATE KW	PRIMARY FUEL TYPE	PART OF TOTAL SUPPLY RESOURCES
Alamance	NC	250	Hydroelectric	No[1]
Burke	NC	800	Diesel	No[1]
Cabarrus	NC	32,000	Diesel	No[1]
Catawba	NC	250	Coal, Wood Cogen	No[1]
Catawba	NC	8,050	Diesel	No[1]
Cleveland	NC	9,525	Diesel	No[1]
Cleveland	NC	2,000	Diesel	No[1]
Forsyth	NC	8,400	Coal, Wood Cogen	No[1]
Gaston	NC	1,056	Hydroelectric	No[1]
Gaston	NC	11,500	Coal Cogen	No[1]
Gaston	NC	3,200	Diesel	No[1]
Guilford	NC	2,000	Diesel	No[1]
Guilford	NC	900	Diesel	No[1]
Guilford	NC	2,000	Diesel	No[1]
Iredell	NC	1,050	Diesel	No[1]
Orange	NC	28,000	Coal Cogen	No[1]
Rockingham	NC	5,480	Coal Cogen	No[1]
Rutherford	NC	1,625	Hydroelectric	No[1]
Rutherford	NC	6,400	Diesel	No[1]
Rutherford	NC	4,800	Diesel	No[1]
Rutherford	NC	750	Diesel	No[1]
Rutherford	NC	1,000	Diesel	No[1]
Rutherford	NC	350	Diesel	No[1]
Surry	NC	2,500	Unknown	No[1]
Union	NC	12,500	Diesel	No[1]
Union	NC	7,400	Diesel	No[1]
Union	NC	4,950	Diesel	No[1]
Union	NC	4,200	Diesel	No[1]
Union	NC	1,600	Diesel	No[1]
Union	NC	1,600	Diesel	No[1]
Union	NC	1,600	Diesel	No[1]
Abbeville	SC	3,250	Hydroelectric	No[1]
Abbeville	SC	2,865	Diesel	No[1]
Cherokee	SC	8,000	Diesel	No[1]
Cherokee	SC	4,140	Hydroelectric	No[1]
Greenville	SC	5,000	Natural Gas, Landfill Gas	No[1]
Greenville	SC	250	Unknown	No[1]
Greenville	SC	370	Digester Gas	No[1]
Greenville	SC	4,550	Diesel Cogen	No[1]
Lancaster	SC	22,500	Coal Cogen	No[1]
Laurens	SC	2,150	Diesel	No[1]
Laurens	SC	4,000	Diesel	No[1]

CUSTOMER-OWNED SELF-GENERATION				
COUNTY	STATE	NAMEPLATE KW	PRIMARY FUEL TYPE	PART OF TOTAL SUPPLY RESOURCES
Oconee	SC	700	Hydroelectric	No[1]
Oconee	SC	9,175	Diesel	No[1]
Oconee	SC	2,865	Diesel	No[1]
Pickens	SC	2,865	Diesel	No[1]
Pickens	SC	6,400	Diesel	No[1]
Spartanburg	SC	1,000	Hydroelectric	No[1]
Greenville	SC	2,550	Diesel	No[1]
Union	SC	15,900	Hydroelectric	No[1]
Union	SC	5,730	Diesel	No[1]
York	SC	42,500	Coal, Wood Cogen	No[1]
York	SC	29,000	Coal Cogen	No[1]
York	SC	3,000	Diesel	No[1]
York	SC	2,865	Diesel	No[1]
York	SC	2,865	Diesel	No[1]

Note 1: The Load Forecast in the Annual Plan reflects the impact of these generating resources

UTILITY-OWNED STANDBY GENERATION				
COUNTY	STATE	NAMEPLATE KW	PRIMARY FUEL TYPE	PART OF TOTAL SUPPLY RESOURCES
Alamance	NC	275	Diesel	No
Burke	NC	2,000	Diesel	No
Durham	NC	1,750	Diesel	No
Granville	NC	1,750	Diesel	No
Guilford	NC	1,750	Diesel	No
Mecklenburg	NC	1,750	Diesel	No
Mecklenburg	NC	1,500	Diesel	No
Mecklenburg	NC	150	Diesel	No
Mecklenburg	NC	200	Diesel	No
Mecklenburg	NC	400	Diesel	No
Mecklenburg	NC	1,000	Diesel	No
Mecklenburg	NC	500	Diesel	No
Surry	NC	125	Diesel	No
Wilkes	NC	2,000	Diesel	No
Greenville	SC	1,000	Diesel	No

APPENDIX K: FERC FORM 1 PAGES

Following are Duke Energy Carolinas' 2005 FERC Form 1 pages 422, 423, 422.1, 423.1, 422.2, 423.2, 424 and 425.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

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	Antioch Tie	Appalachian Power	525.00	525.00	Tower	27.67		1
2	Jocassee Tie	Bad Creek Hydro	525.00	525.00	Tower	9.25		1
3	Jocassee Tie	McGuire Switching	525.00	525.00	Tower	119.86		1
4	McGuire Switching	Antioch Tie	525.00	525.00	Tower	54.81		1
5	McGuire Switching	Woodleaf Switching	525.00	525.00	Tower	29.95		1
6	Newport Tie	CP&L Rockingham	525.00	525.00	Tower	48.66		1
7	Newport Tie	McGuire Switching	525.00	525.00	Tower & Pole	32.24		1
8	Oconee Nuclear	Newport Tie	525.00	525.00	Tower	108.12		1
9	Oconee Nuclear	South Hall	525.00	525.00	Tower & Pole	22.50		1
10	Oconee Nuclear	Jocassee Tie	525.00	525.00	Tower	20.90		1
11	Pleasant Garden Tie	Parkwood Tie	525.00	525.00	Tower	49.65		1
12	Woodleaf Switching	Pleasant Garden Tie	525.00	525.00	Tower	53.07		1
13								
14								
15	TOTAL 525 KV LINES					576.68		12
16								
17	Allen Steam	Catawba Nuclear	230.00	230.00	Tower	10.86		2
18	Allen Steam	Riverbend Steam	230.00	230.00	Tower	12.49		2
19	Allen Steam	Winecoff Tie	230.00	230.00	Tower	32.22		2
20	Allen Steam	Woodlawn Tie	230.00	230.00	Tower	8.12		2
21	Anderson Tie	Hodges Tie	230.00	230.00	Tower	25.79		2
22	Antioch Tie	Wilkes Tie	230.00	230.00	Tower	4.29		2
23	Beckerdite Tie	Belews Creek Steam	230.00	230.00	Tower	24.60		2
24	Beckerdite Tie	Pleasant Garden Tie	230.00	230.00	Tower	28.48		2
25	Belews Creek Steam	Ernest Switching Station	230.00	230.00	Tower	13.71		2
26	Belews Creek Steam	North Greensboro Tie	230.00	230.00	Tower	21.65		2
27	Belews Creek Steam	Pleasant Garden Tie	230.00	230.00	Tower & Pole	38.72		2
28	Belews Creek Steam	Rural Hall Tie	230.00	230.00	Tower	18.32		2
29	Bobwhite Switching	North Greensboro Tie	230.00	230.00	Tower	3.83		2
30	Buck Tie	Beckerdite Tie	230.00	230.00	Tower	23.63		2
31	Catawba Nuclear	Newport Tie	230.00	230.00	Tower & Pole	10.36		2
32	Catawba Nuclear	Pacolet Tie	230.00	230.00	Tower	41.26		2
33	Catawba Nuclear	Peacock Tie	230.00	230.00	Tower	14.85		2
34	Catawba Nuclear	Ripp Switching Station	230.00	230.00	Tower	24.44		2
35	Central Tie	Anderson Tie	230.00	230.00	Tower	23.12		2
36					TOTAL	8,233.80		158

Name of Respondent Duke Energy Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2515								1
2515								2
2515								3
2515								4
2515								5
2515								6
2515								7
2515								8
2515								9
2515								10
2515								11
2515								12
								13
	20,355,902	97,618,851	117,974,753					14
	20,355,902	97,618,851	117,974,753					15
								16
1272								17
1272								18
954 & 1272								19
2156								20
954								21
954								22
2156								23
954								24
1272								25
2156								26
2156								27
2156								28
2156								29
954								30
1272								31
954								32
1272								33
1272								34
954								35
	143,399,809	927,876,368	1,071,276,177	672,591	11,600,100		12,272,691	36

Name of Respondent Duke Energy Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

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	Cliffside Steam	Pacolet Tie	230.00	230.00	Tower	23.01		2
2	Cliffside Steam	Shelby Tie	230.00	230.00	Tower	14.16		2
3	Cowands Ford Hydro	McGuire Switching	230.00	230.00	Tower	1.67		2
4	East Durham Tie	Parkwood Tie	230.00	230.00	Tower	19.25		2
5	Eno Tap Bent	CP&L (Roxboro)	230.00	230.00	Tower	13.74		2
6	Eno Tap Bent	East Durham Tie	230.00	230.00	Tower	15.78		2
7	Ernest Switching Station	Sadler Tie	230.00	230.00	Tower	12.61		2
8	Harrisburg Tie	Oakboro Tie	230.00	230.00	Tower	21.52		2
9	Hartwell Hydro	Anderson Tie	230.00	230.00	Tower	10.30		2
10	Jocassee Switching	Shiloh Switching	230.00	230.00	Tower	22.52		2
11	Jocassee Switching	Tuckasegee Tie	230.00	230.00	Tower	26.62		2
12	Lakewood Tie	Riverbend Steam	230.00	230.00	Tower	10.64		2
13	Lincoln CT	Longview Tie	230.00	230.00	Tower	30.95		2
14	Longview Tie	McDowell Tie	230.00	230.00	Tower	31.93		2
15	Marshall Steam	Beckerdite Tie	230.00	230.00	Tower	52.61		2
16	Marshall Steam	Longview Tie	230.00	230.00	Tower	29.04		2
17	Marshall Steam	McGuire Switching	230.00	230.00	Tower	13.76		2
18	Marshall Steam	Stamey Tie	230.00	230.00	Tower	13.44		2
19	Marshall Steam	Winecoff Tie	230.00	230.00	Tower	24.35		2
20	McGuire Switching	Harrisburg Tie	230.00	230.00	Tower	36.27		2
21	McGuire Switching	Lincoln CT	230.00	230.00	Tower	5.35		2
22	Mitchell River Tie	Antioch Tie	230.00	230.00	Tower & Pole	16.90		2
23	Mitchell River Tie	Rural Hall Tie	230.00	230.00	Tower	26.85		2
24	Morningstar Tie	Oakboro Tie	230.00	230.00	Tower	32.55		1
25	North Greenville Tie	Central Tie	230.00	230.00	Tower & Pole	26.22		2
26	North Greenville Tie	Shiloh Switching	230.00	230.00	Tower	8.96		2
27	Newport Tie	Morningstar Tie	230.00	230.00	Tower & Pole	33.59		1
28	Newport Tie	SCE&G (Parr)	230.00	230.00	Tower	45.37		1
29	Oakboro Tie	CP&L (Rockingham)	230.00	230.00	Tower	5.13		2
30	Oconee Nuclear	Central Tie	230.00	230.00	Tower	17.62		2
31	Oconee Nuclear	Jocassee Swithcing	230.00	230.00	Tower & Pole	12.28		2
32	Oconee Nuclear	North Greenville Tie	230.00	230.00	Tower & Pole	29.25		2
33	Pacolet Tie	Tiger Tie	230.00	230.00	Tower	27.96		1
34	Peach Valley Tie	Tiger Tie	230.00	230.00	Tower	15.69		2
35	Pisgah Tie	CP&L (Skyland Steam)	230.00	230.00	Tower	14.41		2
36					TOTAL	8,233.80		158

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954								1
954								2
795								3
1272								4
1272								5
1272								6
1272								7
954								8
954								9
2156								10
1272								11
954								12
795								13
954								14
954								15
1272								16
1272								17
954								18
1272								19
1272								20
795								21
954								22
954								23
954								24
954								25
954								26
954								27
954								28
954								29
1272								30
2156								31
1272								32
954								33
795								34
954								35
	143,399,809	927,876,368	1,071,276,177	672,591	11,600,100		12,272,691	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

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 From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Pleasant Garden Tie	Eno Tie	230.00	230.00	Tower	42.85		2
2	Ripp Switching	Riverview Switching	230.00	230.00	Tower	9.70		2
3	Ripp Switching	Shelby Tie	230.00	230.00	Tower	9.95		2
4	Riverbend Steam	McGuire Switching	230.00	230.00	Tower	11.88		2
5	Riverbend Steam	Ripp Switching	230.00	230.00	Tower	30.12		2
6	Riverview Switching	Peach Valley Tie	230.00	230.00	Tower	19.33		2
7	SCE&G (Parr)	Bush River Tie	230.00	230.00	Tower	17.76		1
8	Shady Grove Tap	Shady Grove Tie	230.00	230.00	Tower	7.80		2
9	Shiloh Switching	Pisgah Tie	230.00	230.00	Tower	21.85		2
10	Shiloh Switching	Tiger Tie	230.00	230.00	Tower	21.46		2
11	Stamey Tie	Mitchell River Tie	230.00	230.00	Tower	35.92		2
12	Tiger Tie	North Greenville Tie	230.00	230.00	Tower	18.38		2
13	Winecoff Tie	Buck Tie	230.00	230.00	Tower	24.28		2
14								
15								
16	TOTAL 230 KV LINES					1,394.32		129
17								
18	Nantahala Tie	Marble S.S.	161.00	161.00	Tower	16.85		2
19	Nantahala Plant	Robbinsville S.S.	161.00	161.00	Tower	8.33		1
20	Santeetlah Plant	Robbinsville S.S.	161.00	161.00	Tower	11.14		1
21	Tuckasegee Tie	Thorpe Hydro	161.00	161.00	Tower & Pole	3.25		1
22	Tuckasegee Tie	West Mill Tie	161.00	161.00	Tower & Pole	10.42		2
23	Nantahala Hydro	Webster Tie	161.00	161.00	Tower	12.66		1
24	Webster Tie	Lake Emory S.S.	161.00	161.00	Tower	11.93		1
25	West Mill Tie	Lake Emory S.S.	161.00	161.00	Tower	6.78		1
26	West Mill Tie	Nantahala Tie	161.00	161.00	Tower	13.08		1
27								
28								
29	TOTAL 161 KV LINES					94.44		11
30								
31	Dan River	Appalachian	138.00	138.00	Tower & Pole	6.47		1
32	115 KV Lines		115.00	115.00	Tower & Pole	43.36		1
33	100 KV Lines		100.00	100.00	Tower	2,951.76		
34	100 KV Lines		100.00	100.00	Pole	514.24		
35	100 KV Lines		100.00	100.00	Underground	1.06		
36					TOTAL	8,233.80		158

Name of Respondent Duke Energy Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2005	Year/Period of Report End of 2005/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954								1
795								2
954								3
795 & 1272								4
795								5
795								6
954								7
2515								8
954								9
1272								10
954								11
954								12
954								13
								14
	40,039,092	201,825,398	241,864,490					15
	40,039,092	201,825,398	241,864,490					16
								17
795								18
636								19
636								20
397.5								21
795								22
795								23
636								24
795								25
795								26
								27
	2,075,654	31,710,928	33,786,582					28
	2,075,654	31,710,928	33,786,582					29
								30
477								31
								32
								33
								34
								35
	143,399,809	927,876,368	1,071,276,177	672,591	11,600,100		12,272,691	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

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	OH Construction: New Lines						
2	Christopher Road Retail Tap		0.07	Pole	29.00	1	
3	Huntersville City Del 2 Tap		0.04	Pole	25.00	1	
4	Kudzu Retail Tap		0.40	[redacted]	15.00	1	
5	Nix Road Retail Tap		2.04	[redacted]	9.00	2	
6	Peace Haven Retail Tap		2.80	Pole	11.00	1	
7	Sands Road Retail Tap		0.98	Pole	12.00	1	
8	Withers Retail Tap		0.02	[redacted]		1	
9	Chestnut Ridge	Stouffers Tap	4.05	[redacted]	10.00	1	
10	Blue Ridge EC Del 29		0.01	[redacted]	40.00	1	
11	Lin-Pac Tap		6.92	[redacted]	8.00	1	
12	Rural Hall Tie	Peace Haven Ret Tap	2.00	[redacted]	10.00	2	
13							
14							
15							
16							
17							
18							
19							
20	OH Lines: Major Rebuild						
21	Fairview Tie	McDowell Tie	11.30	[redacted]	8.00	2	
22	Woodlawn Tie	Elizabeth Avenue	1.50	Pole	18.00	2	
23	Zion Church Road Retail Tap		2.60	[redacted]	8.00	1	
24	Newberry Main	Whitmire Retail Tap	0.80	[redacted]	10.00	2	
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		35.53		213.00	20	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

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)	Asset Retire. Costs (o)	Total (p)	No.
									1
336.4	ACSR		100		43,073	40,690		83,763	2
556.5	ACSR		100		72,720	44,571		117,291	3
336.4	ACSR		100	38,755	454,632	135,469		628,856	4
556.5	ACSR		100	32,232	583,185	226,726		842,143	5
556.5	ACSR		100	1,990,317	981,632	601,645		3,573,594	6
556.5	ACSR		100	75,710	617,283	180,187		873,180	7
477.0	ACSR		100			31,654		31,654	8
556.5	ACSR		100	23,450	852,444	522,465		1,398,359	9
954.0	AAC		100		130,192	79,795		209,987	10
556.5	ACSR		100		841,932	516,023		1,357,955	11
556.5	ACSR		100		864,257	690,996		1,555,253	12
									13
									14
									15
									16
									17
									18
									19
									20
954.0	AAC		100		8,006,284	3,760,219		11,766,503	21
477.0	ACSR		100		882,005	305,110		1,187,115	22
556.5	ACSR		100		379,010	186,561		565,571	23
556.5	ACSR		100		314,443	192,723		507,166	24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				2,160,464	15,123,092	7,414,834		24,698,390	44

APPENDIX L: OTHER INFORMATION (ECONOMIC DEVELOPMENT)

Customers Served Under Economic Development:

In the NCUC Order dated Nov. 15, 2002, in Docket No. E-100, Sub 97, the NCUC ordered North Carolina utilities to review the combined effects of existing economic development rates within the approved Annual Planning process and file the results in its short-term action plan. The incremental load (demand) for which customers are receiving credits under economic development rates and/or self-generation deferral rates (Rider EC and Rider NL), as well as economic redevelopment rates (Rider ER) as of August 1, 2006, is:

Rider EC:

40 MW for North Carolina
39 MW for South Carolina

Rider ER:

1 MW for North Carolina
1 MW for South Carolina

Rider NL:

0 MW for North Carolina
0 MW for South Carolina

There are no customers enrolled on Rider NL at this time.

APPENDIX M: LEGISLATIVE AND REGULATORY ISSUES

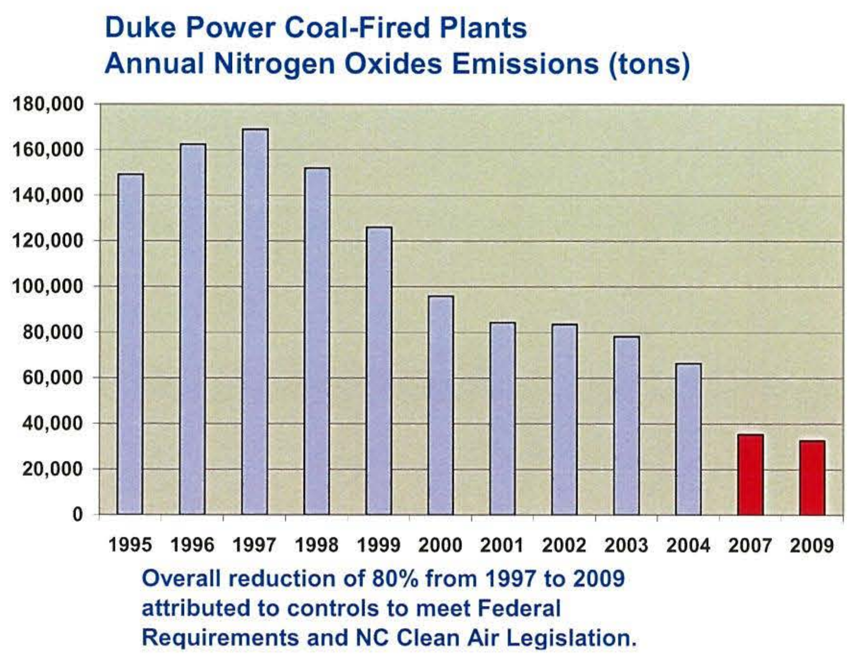
Duke Energy Carolinas is subject to the jurisdiction of federal agencies including the Federal Energy Regulatory Commissions (FERC), EPA and the Nuclear Regulatory Commission (NRC), as well as state commissions and agencies. In addition, state and federal policy actions have potential impact on the Company. This section provides a high-level description of several issues Duke Energy Carolinas is actively monitoring or engaged in that could have an impact on new generation decisions.

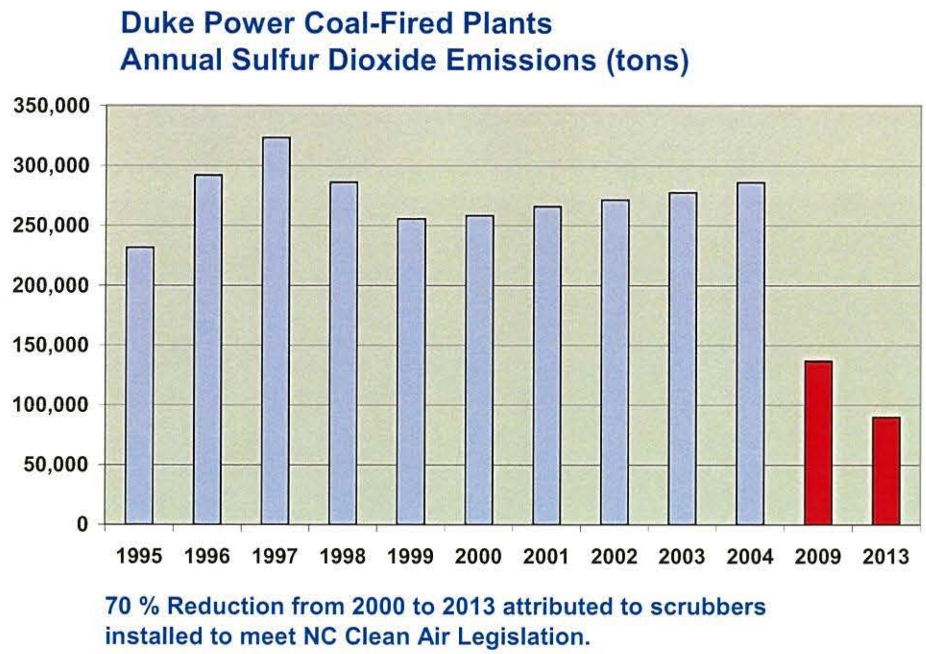
Air Quality

Duke Energy Carolinas is required to comply with federal regulations such as the Clean Air Act's Nitrogen Oxide (NOx) State Implementation Plan (SIP) Call, the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR) and the 2002 North Carolina Clean Smokestacks Act.

As a result of the North Carolina Clean Smokestacks Act, Duke Energy Carolinas will reduce sulfur dioxide (SO_2) emissions by about 70 percent by 2013 from 2000 levels. The law also calls for additional reductions in NOx emissions by 2007 and 2009, beyond those required by the federal NOx SIP Call. This landmark legislation, which was passed by the North Carolina General Assembly in June 2002, calls for some of the lowest state-mandated emission requirements in the nation, and was passed with Duke Energy Carolinas' input and support.

The following graphs show Duke Energy Carolinas' NOx and SO_2 emissions reductions to comply with the federal NOx SIP Call and the 2002 North Carolina Clean Smokestacks Act.





These charts do not show additional reductions that are necessary to comply with the federal Clean Air Interstate Rule, discussed below.

Duke Energy Carolinas must also comply with two new federal rules to reduce air emissions: the *Clean Air Interstate Rule* and the *Clean Air Mercury Rule.*

Clean Air Interstate Rule (CAIR)

In May 2005, the EPA issued a Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (CAIR), which affects 28 states including North Carolina and South Carolina. The rule requires affected states to reduce emissions of SO_2 and/or NOx. The emissions controls that Duke Energy Carolinas is installing to comply with the North Carolina Clean Smokestacks Act will contribute significantly to achieving compliance with the CAIR requirements. North Carolina has approved a state version of the federal CAIR rules. South Carolina is expected to adopt a state version of the federal CAIR rules by late 2006 or early 2007.

Federal Clean Air Mercury Rule (CAMR)

In May 2005, the EPA published the Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, for control of mercury. The rule establishes mercury emission-rate limits for new coal-fired steam generating units, as defined in Clean Air Act section 111(d). It also establishes a nationwide mercury cap-and-trade program covering existing and new coal-fired power units. Both North Carolina and South Carolina have issued proposed CAMR rules. Both states have held public hearings and stakeholder meetings and have accepted formal written comments on the proposed rules. Final rules are expected by late 2006 or early 2007.

The federal CAIR and CAMR rules were released concurrently because the emission controls that will be required under CAIR to reduce NOx and SO_2 also reduce mercury emissions. The controls that Duke Power is installing to comply with the North Carolina Clean Smokestacks Act will contribute significantly to achieving compliance with CAMR. However, both CAIR and CAMR may result in additional controls and/or costs for the Company beyond those required to meet the North Carolina Clean Smokestacks Act.

Global Climate Change

Duke Energy views climate change, particularly potential policy responses to the issue, as a significant strategic business issue. Current U.S. policy includes a goal to reduce the greenhouse gas emissions intensity of the economy through voluntary measures. However, concern that greenhouse gas emissions from human activities may be influencing changes in the earth's climate system has resulted in a variety of local, state and regional responses, as well as increased policy debate at the federal level.

Duke Energy believes that a federal policy response is preferable to a patchwork of different state requirements, because it would be less costly to society and more effective in managing greenhouse gas emissions. In addition, the Company believes that the best course of action going forward is U.S. federal legislation that will result in a gradual transition to a lower-carbon-intensive economy, such as applying a federal-level carbon tax to all sectors of the economy.

Energy Policy Act of 2005

The Energy Policy Act of 2005 encourages investment in energy infrastructure, confers upon FERC a new role in policing transmission expansion, boosts electric reliability, and promotes a diverse mix of fuels to generate electricity. The Act increases protections for electricity consumers, encourages energy efficiency and conservation and repeals the Public Utility Holding Company Act (PUHCA).

There are several key issues that the Energy Policy Act can impact which are of importance to Duke Energy Carolinas. Some of those issues are:

- Reliability – The Energy Policy Act establishes an electric reliability organization, governed by an independent board, with FERC oversight.
- PUHCA and Merger Review – Repeals PUHCA transferring consumer protections to FERC and the states.
- Transmission Siting and Incentive Pricing – Encourages energy infrastructure investment, FERC backstop siting authority, and DOE identified "national interest electric transmission corridor" to be used by FERC, as a starting point, to address bottlenecks in the national grid.

- Native Load Protection – Assures firm transmission rights for serving native load.
- Economic Dispatch – DOE to study and report on the benefits of economic dispatch annually.
- Participant Funding – Provides that FERC "may approve" participant funding plan if the plan is not unduly discriminatory or preferential with the result being just and reasonable rates.

Duke Energy Carolinas will closely monitor the implementation of the Energy Policy Act at the state and federal levels.

Hydroelectric Relicensing

On March 28, 2002, the FERC issued an Order Approving a Subsequent License to Duke Energy Carolinas for the Queens Creek Hydroelectric Project, FERC Project No. 2694. Over the next several years, Duke Energy Carolinas will be pursuing FERC license renewal approval for seven hydroelectric projects and will surrender one license.

During 2003, Duke Energy Carolinas filed applications to renew licenses for:

- Bryson
- Dillsboro
- Franklin
- Mission

In 2004, Duke Energy Carolinas filed applications to renew licenses for:

- East Fork Project (Cedar Cliff, Bear Creek, and Tennessee Creek)
- West Fork Project (Thorpe and Tuckasegee)
- Nantahala Project (Nantahala, Dicks Creek, and White Oak)

In May 2004, Duke Energy Carolinas filed an application to surrender the license for its Dillsboro Project, a result of binding settlement agreements with stakeholders related to the relicensing of the East Fork, West Fork, and Nantahala Projects. Those settlement agreements were filed with FERC in January 2004 and call for the removal of the Dillsboro Dam.

On August 12, 2005, FERC issued notices of authorization for continued project operation for each of the Bryson, Franklin and Mission projects, authorizing continued operation under the terms of the previous license. The FERC notice states, "[I]f issuance of a new license (or other disposition) does not take place on or before August 1, 2006, notice is hereby given that, pursuant to 18 CFR 16.18(c), an annual license under section 15(a)(1) of the FPA is renewed automatically without further order or notice by the Commission."

On September 6, 2005, FERC issued a notice of authorization for continued project operation for the Dillsboro project, authorizing continued operation under the terms of the previous license until "the Commission acts on its application for subsequent license, accepts its surrender application, or takes other appropriate action."

On March 9, 2006, FERC issued a notice of authorization for continued project operation for the Nantahala project, authorizing continued operation under the terms of the previous license until February 28, 2007. The FERC notice states, "[I]f issuance of a new license (or other disposition) does not take place on or before March 1, 2007, notice is hereby given that, pursuant to 18 CFR 16.18(c), an annual license under section 15(a)(1) of the FPA is renewed automatically without further order or notice by the Commission."

Duke Energy Carolinas filed 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. 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.

Duke Energy Carolinas' Catawba-Wateree Hydro Project's relicensing process gave early and ongoing involvement to local governments, state and federal resource agencies, special interest groups and the general public. More than 160 stakeholders from more than 80 organizations were involved in a collaborative process that involves two state licensing teams and four regional advisory groups. The goal of these groups was to reach a mutually acceptable agreement on all interests related to the project and include those agreements in Duke Energy's Federal Energy Regulatory Commission license application. Final agreement was reached with 82% of the stakeholders.

The duration of a new FERC license for a hydropower facility can range from 30 to 50 years depending on various factors at the time of relicensing. FERC's normal time frame to issue new licenses is 24 to 36 months after submittal.

Generating Units with Plans for Life Extension

STATION	NOTICE OF INTENT TO RELICENSE FILED	PRESENT LICENSE EXPIRATION DATE
Bryson Project No. 2601	1/27/2000	7/31/2007
Dillsboro Project No. 2602	1/19/2000	7/31/2007
Franklin Project No. 2603	1/27/2000	7/31/2007
Mission Project No. 2619	2/15/2000	7/31/2007
East Fork Project No. 2698	7/25/2000	1/31/2007
West Fork Project No. 2686	7/28/2000	1/31/2007
Nantahala Project No. 2692	8/7/2000	2/28/2007
Catawba/Wateree Project No. 2232	7/21/2003	9/1/2008

North Carolina Transmission Planning Process

Duke Energy Carolinas participated in a collaborative transmission planning process with North Carolina's major electric load-serving entities (LSEs). This effort has resulted in an agreement on a long-term comprehensive transmission planning process for North Carolina, facilitated by an independent third party, Gestalt, LLC, with input from other market participants. The process is designed to preserve reliability as well as enhance access by LSEs to a variety of generation resources.

In 2005, the Planning Working Group (PWG), under the direction of the Oversight Steering Committee (OSC), began a study of the 2011 summer. The study's purpose is to evaluate transmission system reliability for the combined Duke Energy Carolinas and Progress Energy Carolinas control areas. Also, an evaluation of access to alternative generation resources is to be examined. The study results and transmission expansion options are to be developed by the PWG so that a collaborative transmission plan will be available by late 2006.

Independent Transmission Coordinator Plan

On December 19, 2005, the FERC Approved Duke Energy Carolinas' plan to increase the independence and transparency of the operation of the Company's transmission system.
The FERC approved plan was a result of a year-long process of input and refinement, based on feedback received from various stakeholders. Duke Energy Carolinas will establish both an Independent Entity to serve as its transmission coordinator and an Independent Monitor to provide additional transparency and fair system administration. The Company plans to begin implementation in late 2006.

Under the proposal, the Independent Entity will be charged with performing key transmission functions under Duke Energy Carolinas' OATT. Duke Energy Carolinas will remain owner and operator of its transmission system, maintaining ultimate responsibility for providing transmission service. Duke Energy Carolinas has retained the Midwest Independent System Operator (Midwest ISO) to perform the role of Independent Entity.

While Duke Energy Carolinas is not joining the Midwest ISO, as Independent Entity the Midwest ISO is expected to perform a number of transmission functions, including:

- Evaluation and approval of all transmission service requests
- Calculation of Total Transfer Capability and Available Transfer Capability
- Operation and administration of the Duke Energy Carolinas Open-Access Same Time Information System (OASIS)
- Evaluation, processing and approval of all generation interconnection requests and performance of related interconnection studies, and

- Coordination of transmission planning.

The Independent Monitor will serve as an autonomous monitor of Duke Energy Carolinas' transmission system, providing a measure of neutrality in the Duke Energy Carolinas control area. The Independent Monitor will regularly perform a number of screens and other analyses related to the system, submitting quarterly reports to both FERC and regulatory commissions in North Carolina and South Carolina. Potomac Economics Ltd. has agreed to serve as Duke Energy Carolinas' Independent Monitor.

After two years of operation, Duke Energy Carolinas and the Independent Entity will convene a stakeholder conference to receive input and comments regarding whether the Independent Entity and Independent Monitor have measurably improved transmission service.