The Duke Energy Carolinas Annual Plan

November 15, 2007

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EXECUTIVE SUMMARY

Duke Energy Carolinas (Duke Energy Carolinas) or (the Company), a subsidiary of Duke Energy Corporation, utilizes an integrated resource planning approach to ensure that it can reliably and economically meet the electric energy needs of its customers well into the future. The planning process takes into consideration the most economic and reliable alternatives to meet the projected energy needs of customers while incorporating environmental compliance planning. The end result is the Company's Integrated Resource Plan (IRP) or Annual Plan. Duke Energy Carolinas considers a diverse range of resources including renewable, nuclear, coal, gas, energy efficiency (EE), and demand-side management (DSM)[1] resources.

Consistent with the responsibility to meet customer energy needs in a reliable and economic manner, the Company's resource planning approach includes both quantitative analysis and qualitative considerations. Quantitative analysis provides 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 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 customer needs, while maintaining flexibility to adjust to evolving economic, environmental, and operating circumstances in the future. The environment for planning the Company's system has never been more dynamic. As a result, the Company believes prudent planning for customer needs requires a plan that is robust under many possible future scenarios. At the same time, it is important to maintain a number of options to respond to many potential outcomes of major planning uncertainties (e.g., federal greenhouse gas emission legislation).

Planning Process Results

Duke Energy Carolinas' resource needs increase significantly over the 20-year planning horizon. By 2011, approximately 2,300 MW of additional resources are needed; by 2027, that number grows to 10,700 MW. The factors that influence this are:

- Future load growth projections;
- Reduction of available capacity and energy resources (for example, due to unit retirements and expiration of purchased power agreements); and
- A 17 percent target planning reserve margin over the 20-year horizon.

The quantitative and qualitative analyses suggest that a combination of additional baseload, intermediate, and peaking generation, renewable resources, and EE and DSM

[1] Throughout this Annual Plan, the term Energy Efficiency (EE) will denote conservation programs while the term Demand-Side Management (DSM) will denote Demand Response programs.

programs are required over the next 20 years. New natural gas and nuclear capacity additions are attractive supply-side options under a variety of sensitivities and scenarios. Both conservation and demand response programs play important roles in the development of a balanced, cost-effective portfolio. Renewable generation alternatives are also necessary to meet North Carolina's recently-enacted Renewable and Energy Efficiency Portfolio Standard.

In light of these analyses, as well as the public policy debate on energy and environmental issues, Duke Energy Carolinas has developed a strategy to ensure that the Company can meet customers' energy needs reliably and economically. Importantly, Duke Energy Carolinas' strategic action plan for long-term resources maintains prudent flexibility in the face of these dynamics.

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

- Continue to seek regulatory approval of the Company's greatly-expanded portfolio of demand-side management and energy efficiency programs, and continue on-going collaborative work to develop and implement additional EE and DSM products and services.
    - ➢ Duke Energy Carolinas made an Energy Efficiency filing with the North Carolina Utilities Commission (NCUC) in May 2007.
    - ➢ Duke Energy Carolinas made an Energy Efficiency filing with the Public Service Commission of South Carolina (PSCSC) in September 2007.
- Upon receipt of remaining regulatory approvals, begin construction of the 800 MW Cliffside 6 unit, with the objective of bringing additional capacity on line by 2012 at the existing Cliffside Steam Station.
    - ➢ Duke Energy Carolinas obtained a Certificate of Public Convenience and Necessity (CPCN) for Cliffside 6 in March 2007.
    - ➢ Duke Energy Carolinas submitted an air-quality permit application to the North Carolina Division of Air Quality (NCDAQ) on December 16, 2005, and a draft air permit was issued on August 14, 2007. There was a September 18, 2007, public hearing on the draft air permit. The final air permit has not been issued as of the date of publication of this document.
- License and permit new combined-cycle/peaking generation.
    - ➢ Duke Energy Carolinas filed preliminary information for CPCNs with the NCUC for approximately 1,200 to 1,600 MW (total) of combined-cycle generation at the Buck Steam Station and the Dan River Steam Station on June 29, 2007.
    - ➢ File CPCN applications for Buck and Dan River combined cycle projects by end of 2007.
- Seek regulatory approval for up to 2,234 MW of new nuclear generating capacity.
    - ➢ File an application with the Nuclear Regulatory (NRC) for a Combined Construction and Operating License, with the objective of potentially bringing a new plant on line during the next decade.
    - ➢ File nuclear project development cost applications with the NCUC and

PSCSC.

    - Prepare to file a combined application for a combined Certificate of Environmental Compatibility and Public Convenience and Necessity and Base Load Review Order with the PSCSC.
    - Prepare to file an application for determination of need and cost with NCUC.

- 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 the evaluation of market options for traditional and renewable generation and enter into contracts as appropriate.
    - A Request for Proposals (RFP) for conventional intermediate and peaking resource proposals was released in May 2007. Ten bidders submitted a total of forty-five bids spanning time periods of two to twenty years. Bid evaluation and short list selection are underway.
    - An RFP for renewable energy proposals was released in April 2007 which produced a proposed 1,942 megawatts of electricity from alternative sources from 26 different companies. Bid evaluation is underway.
- Continue to monitor energy-related statutory and regulatory activities.

I. INTRODUCTION

Duke Energy Carolinas has an obligation to provide reliable and economic electric service to its customers in North Carolina and South Carolina.[2] To meet this obligation, the Company conducted an integrated resource planning process that serves as the basis for its 2007 Annual Plan.

Integrated resource planning is about charting a course for the future in an uncertain world. Arguably, the planning environment has never been more dynamic. A few of the key uncertainties include, but are not limited to:

- Load Forecasts: How elastic is the demand for electricity? Will environmental regulations such as a carbon costs result in higher costs of electricity and, thus, lower electricity usage? Can a highly successful energy efficiency program actually flatten or even reduce demand growth?
- Nuclear Generation: Is the region ready for a nuclear revival? What is the timeframe needed to license and build nuclear plants? What level of certainty can be established with respect to the capital costs of a new nuclear power plant?
- Carbon Costs: What type of carbon legislation will be passed? Will it be industry-specific or economy-wide? Will it be a “cap-and-trade” system? How will allowances be allocated? Will there be a “safety valve” on allowance prices?
- Renewable Energy: Will utilities be able to secure sufficient renewable resources to meet renewable portfolio standards? Will a federal standard be set? Will it have a “safety valve” price?
- Demand-Side Management and Energy Efficiency: Can DSM and EE deliver the anticipated capacity and energy savings reliably? Are customers ready to embrace energy efficiency? Will an investment in Demand-Side Management and Energy Efficiency be treated equally with investments in a generating plant?
- Building Materials Availability and Cost: Will the worldwide demand for building materials and equipment continue to cause significant price increases and lengthened delivery times? Is this an aberration or a long-term trend?
- Gas Prices: What is the future of natural gas prices and supply? Will Liquified Natural Gas (LNG) facilities come to fruition as envisioned?

Duke Energy Carolinas’ resource planning process seeks to identify what actions the Company must take to ensure there is a safe, reliable, reasonably-priced supply of electricity regardless of how these uncertainties unfold. The planning process considers a wide range of assumptions and uncertainties and develops an action plan that preserves the options necessary to meet customers’ needs. The process and resulting conclusions are discussed in this document.

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

This 2007 Annual Plan will discuss the:

- Current state of Duke Energy Carolinas, including existing generation, energy efficiency, demand-side management, and purchased power agreements;
- 20-year load forecast and resource need projection;
- Target planning reserve margin;
- New generation, energy efficiency, demand-side management and purchased power opportunities;
- Results of the planning process; and
- Near-term actions required to meet customers' energy needs while maintaining 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 2.32 million customers, Duke Energy Carolinas also sells wholesale electricity to incorporated municipalities and to public and private utilities. The tables below show recent historical values for the number of customers and sales of electricity by customer groupings.

Table 2.1
Retail Customers (1,000s - by number billed)

	2006	2005	2004	2003
Residential	1,909	1,874	1,841	1,814
General Service	318	312	306	300
Industrial	7	8	8	8
Nantahala Power & Light	70	68	67	66
Other[a]	13	13	12	11
Total	2,317	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	**2006**	**2005**	**2004**	**2003**
Residential	25,147	25,460	24,542	23,356
General Service	25,585	25,236	24,775	23,933
Industrial	24,396	25,361	25,085	24,645
Nantahala Power & Light	1,256	1,227	1,163	1,134
Other[a]	269	266	267	268
Total Retail Sales	76,653	77,550	75,832	73,336
Wholesale Sales[b]	2,318	2,251	1,969	2,359
Total GWH sold	78,971	79,801	77,801	75,695

[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.

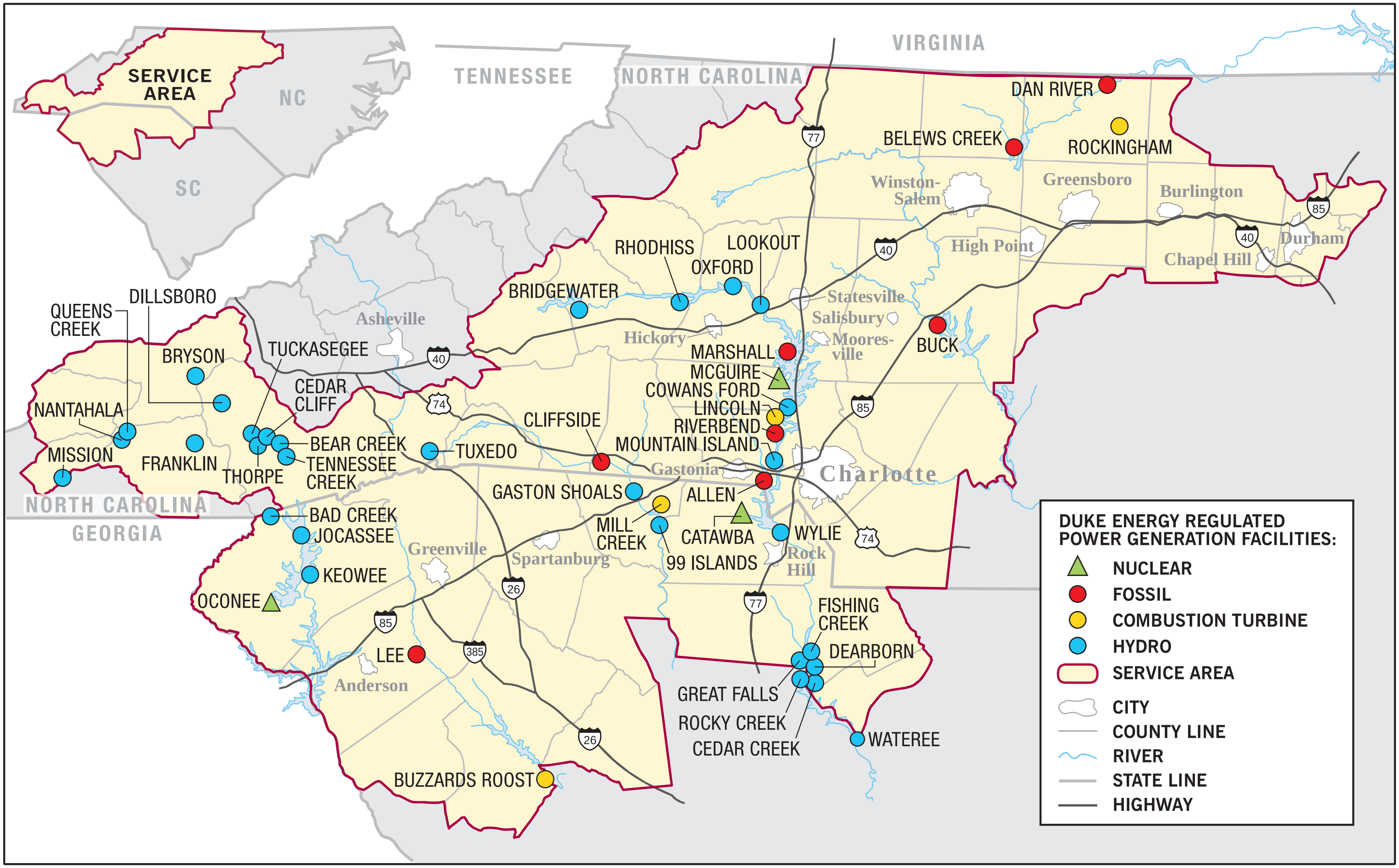
Duke Energy Carolinas meets energy demand, in part, by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets:

- 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 3,168 MW; and
- Eight combustion turbine stations with a combined capacity of 3,262 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, SERC Reliability Corporation (SERC) (formerly Southeastern Electric Reliability Council), and North American Electric Reliability Corporation (NERC).

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

Duke Energy – Carolinas Power Generation Facilities



Transmission System Adequacy

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 Federal Energy Regulatory Commission (FERC) Open Access Transmission Tariff (OATT). Studies are performed to ensure transfer capability is acceptable to meet 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.

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 for purposes of economic access to resources and system reliability;

- 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 (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.

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 2006, Duke Energy Carolinas' nuclear and coal-fired generating units met the vast majority of customer needs by providing 47% and 52%, respectively, of Duke Energy Carolinas' energy from generation. Hydroelectric and combustion-turbine generation and economical purchases from the wholesale market supplied the remainder.

The tables on the following pages list the Duke Energy Carolinas plants in service in North Carolina and South Carolina along 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		**1,145.0**	**1,179.0**		
Belews Creek	1	1,135.0	1,160.0	Belews Creek, N.C.	Conventional Coal
Belews Creek	2	1,135.0	1,160.0	Belews Creek, N.C.	Conventional Coal
Belews Creek Steam Station		**2,270.0**	**2,320.0**		
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		**2,110.0**	**2,110.0**		
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		**7,384.0 MW**	**7,503.0 MW**		

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Buck	7C	31.0	31.0	Salisbury, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Buck	8C	31.0	31.0	Salisbury, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Buck	9C	31.0	31.0	Salisbury, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Buck Station CTs		**93.0**	**93.0**		
Dan River	4C	30.0	30.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Dan River	5C	30.0	30.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Dan River	6C	25.0	25.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Dan River Station CTs		**85.0**	**85.0**		
Lincoln	1	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	2	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	3	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	4	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	5	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	6	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	7	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	8	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	9	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	10	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	11	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	12	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	13	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	14	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	15	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	16	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Lincoln Station CTs		**1267.2**	**1488.0**		
Riverbend	8C	30.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	9C	30.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	10C	30.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	11C	30.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend Station CTs		**120.0**	**120.0**		
Rockingham	1	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	2	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	3	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	4	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	5	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham CTs		**825.0**	**825.0**		
TOTAL N.C. COMB. TURBINE		**2,390.2 MW**	**2,611.0 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		**2,200.0 MW**	**2,312.0 MW**		
Bridgewater	1	11.5	11.5	Morganton, N.C.	Hydro
Bridgewater	2	11.5	11.5	Morganton, N.C.	Hydro
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

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
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	0.050	0.050	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	14	14	Mount Holly, N.C.	Hydro
Mountain Island	3	17	17	Mount Holly, N.C.	Hydro
Mountain Island	4	17	17	Mount Holly, N.C.	
Mountain Island Hydro Station		**62.0**	**62.0**		
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	9.5	9.5	Rhodhiss, N.C.	Hydro
Rhodhiss	2	11.5	11.5	Rhodhiss, N.C.	Hydro
Rhodhiss	3	9.0	9.0	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
Franklin Hydro Station		**1.0**	**1.0**		
Mission	1	0.6	0.6	Murphy, N.C.	Hydro

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
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		**617.7 MW**	**617.7 MW**		
TOTAL N.C. CAPABILITY		**12,591.9 MW**	**13,043.7 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.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	7C	22.0	22.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	8C	22.0	22.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	9C	22.0	22.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	10C	18.0	18.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	11C	18.0	18.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	12C	18.0	18.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	13C	18.0	18.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	14C	18.0	18.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	15C	18.0	18.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost Station CTs		**196.0**	**196.0**		
Lee	7C	40.0	40.0	Pelzer, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Lee	8C	40.0	40.0	Pelzer, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Lee Station CTs		**80.0**	**80.0**		
Mill Creek	1	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	2	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	3	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Mill Creek	4	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	5	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	6	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	7	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	8	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek Station CTs		**595.4**	**739.2**		
TOTAL S.C. COMB TURBINE		**871.4 MW**	**1,015.2 MW**		
Catawba	1	1,129.0	1,163.0	York, S.C.	Nuclear
Catawba	2	1,129.0	1,163.0	York, S.C.	Nuclear
Catawba Nuclear Station		**2,258.0**	**2,326.0**		
Oconee	1	846.0	865.0	Seneca, S.C.	Nuclear
Oconee	2	846.0	865.0	Seneca, S.C.	Nuclear
Oconee	3	846.0	865.0	Seneca, S.C.	Nuclear
Oconee Nuclear Station		**2,538.0**	**2,595.0**		
TOTAL S.C. NUCLEAR		**4,796.0 MW**	**4,921.0 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		**1,360.0**	**1,360.0**		
TOTAL PUMPED STORAGE		**2,040.0 MW**	**2,040.0 MW**		
Cedar Creek	1	15.0	15.0	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		**45.0**	**45.0**		
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

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
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
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**		

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
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 Station		**152.0**	**152.0**		
TOTAL S.C. HYDRO		**510.3 MW**	**510.3 MW**		
TOTAL S.C. CAPABILITY		**8,587.7 MW**	**8,858.5 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	**21,180**	**21,902**

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, 2007.

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 OWNERSHIP
Duke Energy Carolinas	12.500%
North Carolina Electric Membership Corporation (NCEMC)	28.125%
NCMPA#1	37.500%
Piedmont Municipal Power Agency (PMPA)	12.500%
Saluda River (SR)	9.375%

Fuel Supply

Duke Energy Carolinas burns approximately 19 million tons of coal annually. Coal is procured primarily from Central Appalachian coal mines and delivered by Norfolk Southern and CSX railroads. The Company continually 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 also evaluates its diversity of coal supply 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 supply contracts (conversion, enrichment, and fabrication) from around the world. Spot market prices for uranium concentrates have increased more than tenfold since market lows occurred in calendar year 2000. However, the average unit cost of Duke Energy Carolinas' purchases of uranium remains well below the current spot market price due to legacy contracts. Industry consultants expect spot market prices for uranium to continue to rise in the near term as exploration, mine construction, and production gear up. As fuel with a low cost basis is discharged from Duke's reactors and lower-priced legacy contracts are replaced with contracts at higher market prices, nuclear fuel expense is expected to gradually increase in the future.

The majority of the energy production from Duke Energy Carolinas generating units has come from the coal and nuclear units (99%). Hence, the increases in natural gas and oil prices over the past few years have had less impact on Duke Energy Carolinas' cost to produce energy than utilities that are more dependent upon oil and natural gas.

Renewable Energy Initiatives

Duke Energy Carolinas has supported and continues to support the development of renewable energy in North Carolina. Examples of activity range from voluntary renewable energy purchase programs for customers, interconnection standards, Qualifying Facility purchased power, hydro operations, a renewable request for proposals, and renewable research.

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 voluntary 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 and has been instrumental in the growth of renewable generation.

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 and received approval for 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; and 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 3,168 MW. In order to preserve the viability of the conventional hydro facilities, Duke Energy Carolinas is pursuing FERC license renewal approval for eight 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 re-licensing. See Appendix M for additional details.

An RFP for renewable energy proposals was released on April 20, 2007. This RFP process produced a proposed 1,942 megawatts of electricity from alternative sources from 26 different companies. The bids were represented by wind, solar, biomass, biodiesel, landfill gas, hydro, and biogas projects. Bid evaluation is underway with anticipated selection of the first tier of bidders within the next few months.

In addition to the aforementioned efforts to promote renewable energy, Duke Energy Carolinas conducted test burns this summer of co-fired biomass at Lee Steam Station. Duke Energy Carolinas also recently completed tests on the use of biodiesel fuel at the Mill Creek Combustion Turbine Station. The results will help the Company evaluate the potential use of biomass and biodiesel in its power plants.

Duke Energy Carolinas is also working with the Nicholas Institute, Duke University and Cavanaugh Engineering and with other North Carolina stakeholders to promote the conversion of North Carolina hog waste lagoons to advanced waste management technologies. This collaboration is working on the development of a comprehensive technical and business model to determine the optimal technology installation when considering renewable energy production and the emerging agricultural carbon offset market.

Duke Energy Carolinas is in the initial stages of investigating offshore wind potential in the Carolinas. Efforts are underway to work with Clemson University and North Carolina
State University to set meteorological towers for additional wind data at 50 meter heights. It is anticipated that this wind research will also be conducted with the input from several stakeholder groups in the Carolinas.

Current Energy Efficiency and Demand-Side Management Programs

Duke Energy Carolinas uses EE and DSM programs to help manage customer demand in an efficient, cost-effective manner. These 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, programs include two primary categories: EE programs that reduce energy consumption (conservation programs) and DSM 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' current 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' current 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

On September 1, 2006, firm wholesale agreements became effective between Duke Energy Carolinas and three entities, Blue Ridge Electric Membership Cooperative, Piedmont Electric Membership Cooperative, and Rutherford Electric Membership

Cooperative. These contracts added approximately 48 MW of demand response capability to Duke Energy Carolinas[3].

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 conservation programs include:

- Residential Energy Star® rates for new construction
- Existing Residential Housing Program
- Special Needs Energy Products Loan Program
- Energy Efficiency Kits for Residential Customers
- Energy Efficiency Video for Residential Customers
- Large Business Customer Energy Efficiency Assessments
- Large Business Customer Energy Efficiency Tools

A description of each current program can be found in Appendix D.

The Company currently has on file in both North and South Carolina requests to re-structure the current regulatory approach for investing in EE and DSM programs and to significantly expand the EE and DSM program offerings to customers. The Company's proposals could significantly increase the level of EE and DSM program contributions to Duke Energy Carolinas' supply portfolio. A more detailed discussion of the Company's proposal is contained in Section IV, Resource Alternatives to Meet Future Energy Needs, and in Appendix I.

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 20-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. NCEMC is purchasing a

[3] Those demand-response impacts are already included in the forecast of loads for these customers, so no additional demand response capability was modeled in the analysis for this Annual Plan.

portion of Saluda's share of Catawba which is added to the NCEMC total beginning in 2009.

PMPA ended 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.

On 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. The backstand agreement was extended through 2010.

Beginning September 1, 2006, firm wholesale agreements became 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 600 MW by 2011 and approximately 800 MW by 2021. The analyses in this IRP assumed that these contracts would be renewed or extended through the end of the planning horizon.

Duke Energy Carolinas has entered into a firm shaped capacity sale with NCEMC which begins on January 1, 2009, and expires on December 31, 2038. Initially, 72 MW will be supplied on peak with the option to NCEMC to increase the peak purchase to 147 MW by 2020.

The table on the following page contains information concerning Duke Energy Carolinas' wholesale sales contracts.

WHOLESALE SALES CONTRACTS

Wholesale Customer	Contract Designation	Type	Contract Term	Commitment (MW)																			
				2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Schedule 10A City of Concord, NC Town of Dallas, NC Town of Forest City, NC Town of Kings Mountain, NC Clemson University Lockhart Power Company Town of Due West, SC Town of Prosperity, SC	Full Requirements	Native Load Priority	December 31, 2008 with annual renewals. Can be terminated on one years notice by either party after current contract term.	271	271	272	273	273	274	274	275	275	276	277	277	278	278	279	280	280	281	281	282
NP&L Wholesale Western Carolina University Town of Highlands, NC	Full Requirements	Native Load Priority	Annual renewals. Can be terminated on one years notice by either party.	17	18	18	19	20	20	21	22	22	23	24	25	25	26	26	27	27	28	28	29
Blue Ridge EMC **See Note 1**	Partial Requirements	Native Load Priority	December 31, 2021	157	162	163	167	169	171	178	183	184	188	191	195	203	203	206	210	213	219	224	229
Piedmont EMC **See Note 1**	Partial Requirements	Native Load Priority	December 31, 2021	25	23	22	89	91	92	95	98	98	100	102	104	108	107	109	111	113	116	118	120
Rutherford EMC **See Note 1**	Partial Requirements	Native Load Priority	December 31, 2021	82	91	94	260	269	276	292	303	308	318	329	339	355	359	370	379	388	402	414	426
NCEMC **See Note 2**	Catawba Contract Backstand	Native Load Priority/System Firm	Through Operating Life of Catawba Nuclear Station and McGuire Nuclear Station	627	687	687	687	687	687	687	687	687	687	687	687	687	687	687	687	687	687	687	687
Saluda River EC **See Note 2**	Catawba Contract Backstand	Native Load Priority	September 30, 2008	209																			
NCMPA1	Generation Backstand	Native Load Priority	January 1, 2008 through December 31, 2010	73	73	73																	
NCEMC	Shaped Capacity Sale	Native Load Priority	January 1, 2009 through December 31, 2038		72	72	97	97	97	97	97	122	122	122	122	147	147	147	147	147	147	147	147

Note 1: The analyses in this Annual Plan assumed that the contracts would be renewed or extended through the end of the planning horizon.
Note 2: The annual commitment shown is the ownership share of Catawba Nuclear Station and is included in the load forecast. Equivalent capacity is included as a portion of the Catawba Nuclear Station resource.

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 MW 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	NC	3	3	8/23/99	8/22/14
Cherokee County Cogeneration Partners, L.P.	Gaffney	SC	88	95	7/1/96	6/30/13
Northbrook Carolina Hydro, LLC	Various	Both	6	6	12/4/06	Ongoing
Southern Company Rowan Unit 1	Salisbury	NC	153	185	6/1/07	12/31/10
Southern Company Rowan Unit 2	Salisbury	NC	153	185	1/1/06	12/31/10
Southern Company Rowan Unit 3	Salisbury	NC	153	185	6/1/04	5/31/08
Southern Company Rowan Unit 3	Salisbury	NC	153	185	6/1/08	12/31/10
Salem Energy Systems, LLC	Winston-Salem	NC	4	4	7/10/96	7/10/11
Town of Lake Lure	Lake Lure	NC	2	2	2/21/06	2/20/11
Misc. Small Hydro/Other	Various	Both	5	5	Various	Assumed Evergreen

Summary of Wholesale Purchased Power Commitments
(as of October 1, 2007)

	WINTER 06/07	SUMMER 07
Total Non-Utility Generation	670 MW	567 MW
Duke Energy Carolinas allocation of SEPA capacity	19 MW	19 MW
Total Firm Purchases	689 MW	586 MW

Legislative and Regulatory Issues

Duke Energy Carolinas is subject to the jurisdiction of many federal agencies, including FERC and Environmental Protection Agency (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 (CAIR) and Clean Air Mercury Rule (CAMR)) 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. There is also considerable debate at the federal level regarding the potential imposition of a Renewable Portfolio Standard (RPS). North Carolina recently enacted an RPS, although the implementation rules have not been finalized yet. These issues, as well as other regulatory matters, could have an impact on new generation decisions. See Appendix M for further discussion.

III. RESOURCE NEEDS ASSESSMENT (FUTURE STATE)

To meet the future needs of Duke Energy Carolinas' 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 (see Reserve Margin discussion below). The capability of existing resources, including generating units, energy efficiency and demand-side management programs, and purchased power contracts, is 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 meets the load obligation.

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

Load Forecast

The Spring 2007 Forecast includes projections for meeting the energy needs of new and existing customers in the 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 2007 through 2027 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 2027
- Capacity and energy sale to NCEMC beginning January 1, 2009, which consists of a fixed hourly schedule each year of the agreement

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

The current 20-year forecast reflects a 1.6 percent average annual growth in summer peak demand, while winter peaks are forecasted to grow at an average annual rate of 1.4 percent. The forecast for average annual territorial energy need is 1.4 percent. The growth rates use 2007 as the base year with a 17,870 MW summer peak, a 15,725 MW winter peak and a 93,599 GWh average annual territorial energy need.

Duke Energy Carolinas' retail sales have grown at an average annual rate of 1.5 percent from 1991 to 2006. (Retail sales, excluding line losses, are approximately 83 percent of the total energy considered in the 2007 Annual Plan.) This 15-year period of history reflects ten years of strong load growth from 1991 to 2001 followed by five years of very little growth from 2001 to 2006. 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
1991 to 2006	1.5%	2.3%	3.4%	-4.4%	1.5%
1991 to 2001	2.0%	2.4%	4.1%	-2.5%	1.8%
2001 to 2006	0.6%	2.1%	1.9%	-8.1%	0.7%
2006 to 2027	1.5%	1.8%	2.4%	-4.4%	1.0%

A decline in the Industrial Textile class was the key contributor to the low load growth from 2001 to 2006, offset by growth in the Residential and General Service classes over the same period. Over the last five years, approximately 50,000 new residential customers were added to the Duke Energy Carolinas service area on average each year.

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 Automobile, Rubber & Plastics and Chemicals (excluding Man-Made Fibers). (Additional details on the current forecast can be found in the Spring 2007 Forecast Book.)

The load forecast for the 2007 IRP is the following:

Table 3.2
Load Forecast

YEAR[a,b,c,d,e]	SUMMER (MW)[f]	WINTER (MW)[f]	TERRITORIAL ENERGY (GWh)[f]
2008	18,187	15,954	94,867
2009	18,422	16,084	95,477
2010	18,725	16,304	96,690
2011	19,297	16,800	99,242
2012	19,623	17,062	100,766
2013	19,947	17,303	102,338
2014	20,286	17,541	103,850
2015	20,620	17,763	105,394
2016	20,968	18,031	107,113
2017	21,303	18,298	108,729
2018	21,643	18,553	110,409
2019	21,985	18,812	112,125
2020	22,363	19,095	113,947
2021	22,688	19,327	115,518
2022	23,027	19,579	117,074
2023	23,366	19,833	118,637
2024	23,704	20,088	120,183
2025	24,051	20,366	121,693
2026	24,392	20,596	123,155
2027	24,733	20,826	124,617

Note a: The MW (demand) forecasts above are the same as those shown on page 32 of the Spring 2007 Forecast Book, but the peak forecasts vary from those shown on pages 27-30 of the Forecast Book, primarily because the Spring 2007 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: 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 c: The load forecast includes Duke Energy Carolinas' contract to serve Blue Ridge, Piedmont and Rutherford Electric Membership Cooperatives' supplemental load requirements from 2006 through 2027. A new contract between Duke Energy Carolinas and NCEMC will provide additional hourly electricity sales to NCEMC beginning in January 2009.

Note d: 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 (953 MW at 2006 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 20-year planning horizon.

Note e: 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 is the PMPA ownership interest in Catawba 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 (445 MW at 2006 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 20-year planning horizon.

Note f: 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).

The IRP also includes additional undesignated wholesale load for planning purposes. This load was assumed to be 100 MW beginning in 2010, 300 MW in 2011, and 500 MW in 2012 and thereafter as being representative of potential future wholesale load sales.

Changes to Existing Resources

Duke Energy Carolinas will adjust the capabilities of its resource mix over the 20-year planning horizon. Retirements of generating units, system capacity uprates and derates, purchased power contract expirations, and adjustments in EE and 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.

New Cliffside Pulverized Coal Unit
On March 21, 2007, the NCUC granted a CPCN for the construction of one 800-MW supercritical pulverized coal unit at the existing Cliffside Station. The CPCN order and the status of the air permit are discussed more fully in Appendix E.

Catawba Nuclear Station
In December 2006, Duke Energy Carolinas announced an agreement to purchase a portion of Saluda River Electric Cooperative, Inc.'s ownership interest in the Catawba

Nuclear Station. Under the terms of the agreement, Duke Energy Carolinas will pay approximately $158 million for the additional ownership interest in the station. Following the close of the transaction, Duke Energy Carolinas will own approximately 19 percent of the Catawba Nuclear Station, compared to the current ownership of 12.5 percent. The transaction, which is expected to close in the third quarter of 2008, is subject to approval by various state and federal agencies, including the PSCSC for a CPCN, the NRC, and FERC. The filings for these approvals are expected to begin during the fourth quarter of 2007.

Bridgewater Hydro Powerhouse Upgrade
The two existing 11.5 megawatt units at Bridgewater Hydro Station are being replaced by two 15 megawatt units and a small 1.5 megawatt unit to be used to meet continuous release requirements. The NCUC granted a CPCN to install the new replacement powerhouse and generation equipment on June 7, 2007. This project is discussed more fully in Appendix E.

Buck and Dan River Combined Cycle Units
Preliminary CPCN information for adding approximately 600-800 MW each of combined cycle generation at the existing Buck Steam Station in Salisbury, N.C., and at the existing Dan River Steam Station in Eden, N.C., was filed with the NCUC. These projects are discussed more fully in Appendix E.

Purchased Power Contract Expirations
Duke Energy Carolinas has secured various purchased power contracts with power marketers and non-utility generators 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 567 MW. The capability in megawatts varies depending on the start times, duration, and capability of each contract. The majority of these contracts (459 MW) will expire at the end of 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. Table 3.3 reflects current assessments of generating units with identified decision dates for retirement or major refurbishment, including the commitments associated with the conditions in the NCUC Order in Docket No. E-7, Sub 790, granting a CPCN to build Cliffside Unit 6[4]. This table shows the assumptions used for planning purposes rather than firm commitments concerning the specific units to be retired and/or their exact retirement dates. The conditions of the units are evaluated annually and decision dates

[4] The commitments included retiring the existing Cliffside Units 1-4 no later than the commercial operation date of the new unit, and retiring older coal-fired generating units (in addition to Cliffside Units 1-4) on a MW-for-MW basis, considering the impact on the reliability of the system to account for actual load reductions realized from the new EE and DSM programs up to the MW level added by the new Cliffside unit.

are revised as appropriate. Duke Energy Carolinas will develop orderly retirement plans that consider the implementation, evaluation, and achievement of EE and DSM goals, system reliability considerations, long-term generation maintenance and capital spending plans, manpower allocations, long-term contracts including fuel supply and contractors, long-term transmission planning, and major site retirement activities.

<u>Table 3.3</u>
Projected Unit Retirements

STATION	CAPACITY IN MW	LOCATION	DECISION DATE	PLANT TYPE
Buck 4*	38	Salisbury, N.C.	6/30/2010	Conventional Coal
Buck 3*	75	Salisbury, N.C.	6/30/2011	Conventional Coal
Cliffside 1*	38	Cliffside, N.C.	6/30/2012	Conventional Coal
Cliffside 2*	38	Cliffside, N.C.	6/30/2012	Conventional Coal
Cliffside 3*	61	Cliffside, N.C.	6/30/2012	Conventional Coal
Cliffside 4*	61	Cliffside, N.C.	6/30/2012	Conventional Coal
Dan River 1*	67	Eden, N.C.	6/30/2013	Conventional Coal
Dan River 2*	67	Eden, N.C.	6/30/2013	Conventional Coal
Dan River 3*	142	Eden, N.C.	6/30/2013	Conventional Coal
Buzzard Roost 6C	22	Chappels, S.C.	6/30/2014	Combustion Turbine
Buzzard Roost 7C	22	Chappels, S.C.	6/30/2014	Combustion Turbine
Buzzard Roost 8C	22	Chappels, S.C.	6/30/2014	Combustion Turbine
Buzzard Roost 9C	22	Chappels, S.C.	6/30/2014	Combustion Turbine
Buzzard Roost 10C	18	Chappels, S.C.	6/30/2014	Combustion Turbine
Buzzard Roost 11C	18	Chappels, S.C.	6/30/2014	Combustion Turbine
Buzzard Roost 12C	18	Chappels, S.C.	6/30/2014	Combustion Turbine
Buzzard Roost 13C	18	Chappels, S.C.	6/30/2014	Combustion Turbine
Buzzard Roost 14C	18	Chappels, S.C.	6/30/2014	Combustion Turbine
Buzzard Roost 15C	18	Chappels, S.C.	6/30/2014	Combustion Turbine
Riverbend 8C	30	Mt. Holly, N.C.	6/30/2015	Combustion Turbine
Riverbend 9C	30	Mt. Holly, N.C.	6/30/2015	Combustion Turbine
Riverbend 10C	30	Mt. Holly, N.C.	6/30/2015	Combustion Turbine
Riverbend 11C	30	Mt. Holly, N.C.	6/30/2015	Combustion Turbine
Buck 7C	31	Spencer, N.C.	6/30/2015	Combustion Turbine
Buck 8C	31	Spencer, N.C.	6/30/2015	Combustion Turbine
Buck 9C	31	Spencer, N.C.	6/30/2015	Combustion Turbine
Dan River 4C	30	Eden, N.C.	6/30/2015	Combustion Turbine
Dan River 5C	30	Eden, N.C.	6/30/2015	Combustion Turbine
Dan River 6C	25	Eden, N.C.	6/30/2015	Combustion Turbine
Riverbend 4*	94	Mt. Holly, N.C.	6/30/2015	Conventional Coal
Riverbend 5*	94	Mt. Holly, N.C.	6/30/2015	Conventional Coal
Riverbend 6*	133	Mt. Holly, N.C.	6/30/2016	Conventional Coal
Riverbend 7*	133	Mt. Holly, N.C.	6/30/2017	Conventional Coal

* Retirement assumptions associated with the conditions in the NCUC Order in Docket No. E-7, Sub 790, granting a CPCN to build Cliffside Unit 6.

Reserve Margin Explanation and Justification

Reserve margins are necessary to help ensure the availability of adequate resources to meet load obligations due to consideration of customer demand uncertainty, unit outages, transmission constraints, and weather extremes. 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' historical experience has shown that a 17 percent target planning reserve margin was 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 August 2007, generating reserves, defined as available Duke Energy Carolinas generation plus the net of firm purchases less sales, never dropped below 450 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 August 2007.

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. There are a number of increased risks that need to be considered with regard to Duke Energy Carolinas' reserve margin target. These risks include: 1) the increasing age of existing units on the system; 2) the inclusion of a significant amount of renewables (which are generally less reliable than traditional supply-side resources) in the plan due to the enactment of a Renewable Portfolio Standard in North Carolina; 3) uncertainty regarding the impacts associated with significant increases in the Company's energy efficiency and demand-side management programs; 4) longer lead times for building baseload capacity such as coal and nuclear; 5) increasing environmental pressures which may cause additional unit derates and/or unit retirements; and 6) increases in derates of units due to extreme hot weather and drought conditions. Each of these risks would negatively impact the resources available to provide reliable service to customers. Duke Energy Carolinas will continue to monitor these risks in the future and make any necessary adjustments to the reserve margin target in future plans.

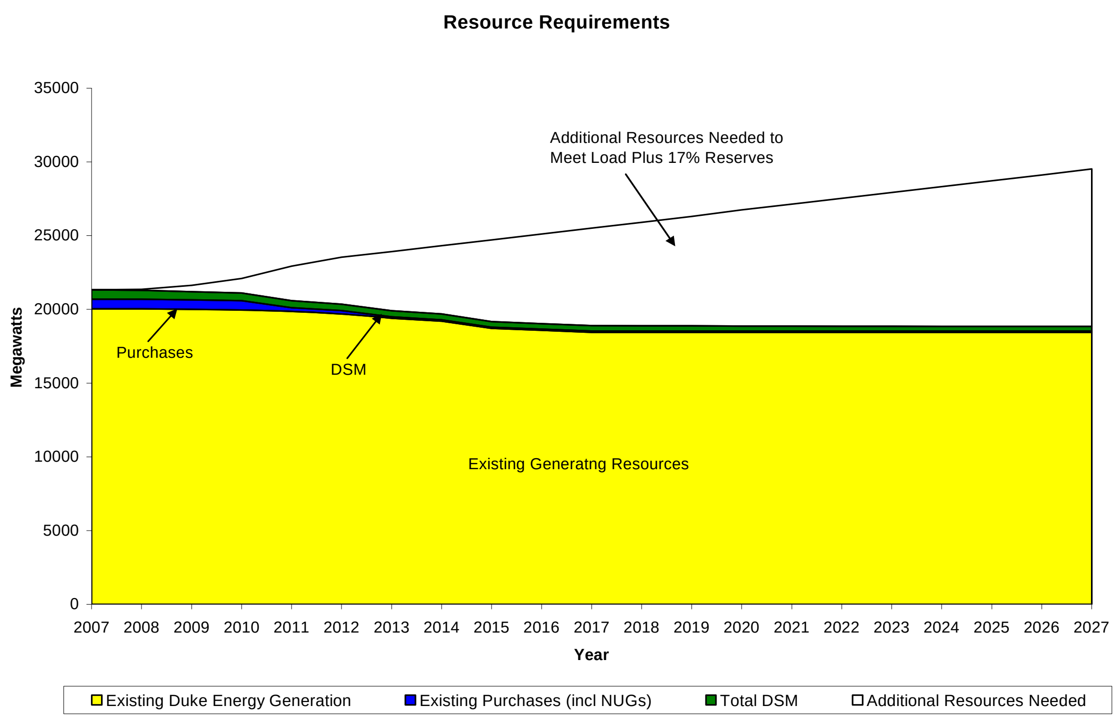
Duke Energy Carolinas also assesses its reserve margins on a short-term basis to determine whether to pursue additional capacity in the short-term power market. As each peak demand season approaches, the Company has a greater level of certainty regarding the customer load forecast and total system capability,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

Duke Energy Carolinas uses adjusted system capacity[5], 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, increased customer load due to extreme weather conditions, and loss of generating capacity because of extreme weather conditions such as the severe drought conditions occurring in 2007.

Load and 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 2007, existing resources, consisting of existing generation, DSM, and purchased power to meet load requirements, total 21,330 MW. The load obligation plus the target planning reserve margin is 20,907 MW, indicating sufficient resources to meet Duke Energy Carolinas' obligation through 2008. The need for additional capacity grows over time due to load growth, unit capacity adjustments, unit retirements, existing DSM program reductions, and expirations of purchased-power contracts. The need grows to approximately 6,600 MW by 2017 and to 10,700 MW by 2027.

<u>Chart 3.1</u>
Load and Resource Balance



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

Cumulative Resource Additions To Meet A 17 Percent Planning Reserve Margin

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Resource Need	0	60	430	990	2,340	3,190	4,030	4,630	5,540	6,090	6,620

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Resource Need	7,020	7,430	7,880	8,270	8,670	9,070	9,470	9,880	10,280	10,680

IV. RESOURCE ALTERNATIVES TO MEET FUTURE ENERGY NEEDS

Many potential resource options are available to meet future energy needs. They range from expanding existing EE and DSM programs to developing new programs to adding new generation capacity and/or purchases (including renewables) 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)

- Base Load – 800 MW supercritical pulverized coal units
- Base Load – Two 1,117 MW nuclear units (AP1000)
- Peaking/Intermediate – 632 MW natural gas combustion turbine facility comprised of four units
- Peaking/Intermediate – 620 MW natural gas combined cycle facility comprised of 2-on-1 units with inlet chilling and duct firing

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

- Base Load - 630 MW class IGCC

Renewable Technologies- Purchase Power Agreements (PPAs)

- On Shore Wind PPA (15% contribution to capacity on peak)
- Solar PPA (70% contribution to capacity on peak)
- Biomass Firing PPA
- Hog Waste Digester PPA
- Poultry Waste PPA

A portion of the Renewable Portfolio Standard requirements was also assumed to be provided by EE and DSM, co-firing biomass in some of Duke Energy Carolinas' existing units, and by purchasing Renewable Energy Certificates (RECS) from out of state, as allowed in the legislation.

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

Energy Efficiency and Demand-Side Management Programs

- New Demand Response Programs
- New Conservation Programs

Duke Energy Carolinas has shown by its recent activities and filings that it is making a strong commitment to energy efficiency and demand-side management. Duke Energy Carolinas has proposed a new save-a-watt approach that fundamentally changes both the way these programs are perceived and the role of the Company in achieving results. The new approach recognizes EE and DSM as a reliable, valuable resource, that is, a "fifth fuel," that should be part of the portfolio available to meet customers' growing need for electricity along with coal, nuclear, natural gas, and renewable energy. The "fifth fuel" helps customers meet their energy needs with less electricity, less cost and less environmental impact. The Company will manage EE and DSM as a reliable "fifth fuel" and provide customers with universal access to these services and new technology. Duke Energy Carolinas has the expertise, infrastructure, and customer relationships to produce results and make it a significant part of its resource mix. Duke Energy Carolinas accepts the challenge to develop, implement, adjust as needed, and verify the results of innovative energy efficiency programs for the benefit of its customers.

With this new approach, Duke Energy Carolinas would be compensated similarly for meeting customer demand, whether through saving a watt or producing a watt. The approach encourages the expansion of cost-effective energy efficiency and demand-side management programs by driving program costs down and innovation up. The Company would be compensated for the results it produces.

This is a novel and progressive approach. To compensate and encourage the Company to produce such capacity by "saving" watts, Duke Energy Carolinas has requested authorization to recover the amortization of and a return on 90% of the costs avoided by producing save-a-watts. The EE and DSM plan will be updated annually based on the performance of programs, market conditions, economics, consumer demand, and avoided costs.

Duke Energy Carolinas' recent Energy Efficiency filings consider spending at least $50 million on future conservation and demand response programs each year, assuming suitable regulatory treatment. This would increase the Company's potential EE impacts significantly over the coming years, as used in the analysis for this IRP. However, pursuing energy efficiency and demand-side management initiatives will not meet all our growing demands for electricity. The Company still envisions the need to build clean coal, nuclear, and gas generation as well as cost-effective renewable generation, but the save-a-watt approach can address a significant portion of the 3,190 MW needed by 2012 by producing up to 1,318 MW[6] of energy efficiency and demand-side management over the next four years.

Duke Energy Carolinas' proposal is designed to expand the reach of EE and DSM programs in its retail service territory by providing the Company with appropriate regulatory incentives to aggressively pursue such expansion. The proposed regulatory treatment enables the Company to meet a portion of its substantial near-term capacity resource needs on a cost-effective basis, while at the same time reducing overall air

[6] This does not include a potential 548 MW capacity impact that may be derived from pilot demand response and conservation programs which depend on advanced metering and communication upgrades that were not included in the IRP analysis.

emissions. Further, customers will be provided more options to control their energy bills. Over the long term, the regulatory treatment proposed by the Company should encourage the Company to pursue additional EE and DSM initiatives, further offsetting capacity needs.

In 2006, Duke Energy Carolinas established EE and DSM-related collaborative groups, consisting of stakeholders from across its service area, and charged them with recommending a new set of EE and DSM-related programs for the Company's customers. Collaborative participants include: Environmental Defense, the Sierra Club, North Carolina Sustainable Energy Association (visitor), Environmental Edge Consulting, Air Products, The Timken Company, Lowe's Home Improvement Corporation, Food Lion, Greenville County Schools, Charlotte-Mecklenburg Schools, University of North Carolina Chapel Hill, University of South Carolina Upstate, South Carolina State Energy Office, North Carolina State Energy Office, North Carolina Attorney General's Office, South Carolina Office of Regulatory Staff, NCUC Public Staff, Duke Energy Carolinas, and Advanced Energy (as meeting facilitator). Collaborative efforts to date have been very productive, resulting in the Company's May 7, 2007 North Carolina Energy Efficiency Filing[7], September 28, 2007 South Carolina Energy Efficiency Filing[8], and the proposed implementation of approximately 1,865 MW and 743 GWh of DSM across North and South Carolina by 2011. Future Measurement and Verification (M&V) analyses along with ongoing product management decisions will be utilized to incorporate updated information into the Company's IRP.

[7] Docket No. E-7, Sub 831
[8] PSCSC Docket No. 2007-358-E

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 for various resource mixes, 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 peaking generation, renewable resources, energy efficiency, and demand-side management programs is required over the next twenty years to meet customer demand reliably and cost-effectively. The optimal resource mix is different under different sensitivities. For example, if an assumption is made that there is no carbon regulation on the planning horizon, portfolios without nuclear look best. If an assumption is made assuming carbon regulation with CO_2 allowances at safety-valve prices, portfolios with one nuclear unit perform well. If higher CO_2 allowance prices are assumed, portfolios with two nuclear units are cost-beneficial to customers. The analyses performed did not include the potential value of production tax credits for the nuclear alternatives, which would improve the relative economics of portfolios with nuclear units.

To demonstrate that the Company is planning adequately for customers, a single portfolio (or, in this year's case, two portfolios) is selected for the purposes of preparing the Load, Capacity, and Reserve Margin Table (LCR Table). For this purpose, the portfolio consisting of 1,240 MW[9] of new natural gas combined cycle capacity, 3,560 MW[9] of new natural gas combustion turbine capacity, 1,117 MW of new nuclear capacity, 1,016 MW of Demand-Side Management, 790 MW of Energy Efficiency, and 1,135 MW of renewable resources was selected. However, significant challenges remain such as obtaining the necessary regulatory approvals to implement the demand-side, energy efficiency, and supply-side resources, finding sufficient cost-effective, reliable renewable resources to meet the standard, integrating renewables into the resource mix, and ensuring sufficient transmission capability for these resources. Because of these uncertainties, Duke Energy Carolinas' action plan, as discussed below, includes actions that go beyond this single portfolio plan. For example, because of the possibility that CO_2 allowance prices may be higher than estimated in the base carbon case, the action plan includes licensing for two nuclear units, rather than the single unit reflected in the Load, Capacity, and Reserve Margin Table (LCR Table). In light of the quantitative issues such as the importance of fuel diversity, the Company's environmental profile, the stage of technology deployment and regional economic development, Duke Energy Carolinas has

[9] The ultimate sizes of the units may change somewhat depending on the vendor selected.

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 next year:

- Continue to seek regulatory approval of the Company's greatly-expanded portfolio of demand-side management and energy efficiency programs, and continue on-going collaborative work to develop and implement additional EE and DSM products and services.
  - Duke Energy Carolinas made an Energy Efficiency filing with the NCUC in May 2007.
  - Duke Energy Carolinas made an Energy Efficiency filing with the PSCSC in September 2007.
- Upon receipt of remaining regulatory approvals, begin construction of the 800 MW Cliffside 6 unit, with the objective of bringing additional capacity on line by 2012 at the existing Cliffside Steam Station.
  - Duke Energy Carolinas obtained a CPCN for Cliffside 6 in March 2007.
  - Duke Energy Carolinas submitted an air-quality permit application to the NCDAQ on December 16, 2005, and a draft air permit was issued on August 14, 2007. There was a September 18, 2007, public hearing on the draft air permit. The final air permit has not been issued as of the date of publication of this document.
- License and permit new combined-cycle/peaking generation.
  - Duke Energy Carolinas filed preliminary information for CPCNs with the NCUC for approximately 1,200 to 1,600 MW (total) of combined-cycle generation at the Buck Steam Station and the Dan River Steam Station on June 29, 2007.
  - File CPCN applications for Buck and Dan River combined cycle projects by end of 2007.
- Seek regulatory approval for up to 2,234 MW of new nuclear generating capacity.
  - File an application with the NRC for a Combined Construction and Operating License, with the objective of potentially bringing a new plant on line during the next decade.
  - File nuclear project development cost applications with the NCUC and PSCSC.
  - Prepare to file a combined application for a combined Certificate of Environmental Compatibility and Public Convenience and Necessity and Base Load Review Order with the PSCSC.
  - Prepare to file an application for determination of need and cost with NCUC.
- 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 the evaluation of market options for traditional and renewable generation and enter into contracts as appropriate.
  - An RFP for conventional intermediate and peaking resource proposals

was released in May 2007. Ten bidders submitted a total of forty-five bids spanning time periods of two to twenty years. Bid evaluation and short list selection are underway.

  - An RFP for renewable energy proposals was released in April 2007 which produced a proposed 1,942 megawatts of electricity from alternative sources from 26 different companies. Bid evaluation is underway.

- Continue to monitor energy-related statutory and regulatory activities.

The seasonal projections of load, capacity, and reserves of the selected plan are provided in tabular form below. Due to the load forecast differences between the Reference Case scenario and the Carbon Case scenario (discussed more fully in Appendix A), two tables are shown. The first table shows Reference Case conditions and the second table shows Carbon Case conditions.

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.

Summer Projections of Load, Capacity, and Reserves
for Duke Power and Nantahala Power and Light
2007 Annual Plan Reference Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Forecast																				
1 Duke System Peak	18,187	18,422	18,825	19,597	20,123	20,447	20,786	21,120	21,468	21,803	22,143	22,485	22,863	23,188	23,527	23,866	24,204	24,551	24,892	25,233
EE $2M Merger of 1 MW	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
New EE Programs	39	109	174	236	301	371	436	498	563	633	698	760	787	787	787	787	787	787	787	787
2 Duke System Peak Less Projected EE	18,147	18,312	18,650	19,360	19,821	20,075	20,349	20,621	20,904	21,169	21,443	21,723	22,075	22,401	22,739	23,078	23,416	23,763	24,104	24,445
Cumulative System Capacity																				
3 Generating Capacity	20,035	19,821	20,000	19,948	19,873	19,675	19,399	19,203	18,717	18,584	18,451	18,451	18,451	18,451	18,451	18,451	18,451	18,451	18,451	18,451
4 Capacity Additions	50	190	9																	
5 Capacity Derates	(50)	(11)	(23)																	
6 Capacity Retirements	0	0	(38)	(75)	(198)	(276)	(196)	(486)	(133)	(133)	0	0	0	0	0	0	0	0	0	0
7 Cumulative Generating Capacity	20,035	20,000	19,948	19,873	19,675	19,399	19,203	18,717	18,584	18,451	18,451	18,451	18,451	18,451	18,451	18,451	18,451	18,451	18,451	18,451
8 Cumulative Purchase Contracts	651	640	640	239	239	94	94	72	72	72	72	72	72	72	72	72	72	72	72	72
9 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 Cumulative Future Resource Additions																				
Base Load	0	0	0	0	800	800	800	800	800	800	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917
Peaking/Intermediate	0	0	316	1,568	1,872	1,872	2,504	3,136	3,768	4,400	4,400	4,400	4,400	4,400	4,400	5,032	5,032	5,652	5,652	6,252
Renewables (Peak Contribution)	0	0	6	6	71	99	110	296	296	434	630	630	740	893	893	893	893	893	893	893
11 Cumulative Production Capacity	20,686	20,640	20,910	21,686	22,656	22,263	22,710	23,021	23,520	24,157	25,469	25,469	25,579	25,732	25,732	26,364	26,364	26,984	26,984	27,584
Reserves w/o DSM																				
12 Generating Reserves	2,538	2,327	2,260	2,326	2,835	2,188	2,361	2,399	2,616	2,988	4,026	3,746	3,504	3,332	2,993	3,286	2,948	3,221	2,880	3,139
13 % Reserve Margin	14.0%	12.7%	12.1%	12.0%	14.3%	10.9%	11.6%	11.6%	12.5%	14.1%	18.8%	17.2%	15.9%	14.9%	13.2%	14.2%	12.6%	13.6%	11.9%	12.8%
14 % Capacity Margin	12.3%	11.3%	10.8%	10.7%	12.5%	9.8%	10.4%	10.4%	11.1%	12.4%	15.8%	14.7%	13.7%	12.9%	11.6%	12.5%	11.2%	11.9%	10.7%	11.4%
DSM																				
15 Cumulative DSM Capacity	761	898	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016
Existing DSM Capacity Projection	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM Program Projection	761	898	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016
16 Cumulative Equivalent Capacity	21,447	21,537	21,925	22,701	23,672	23,279	23,726	24,036	24,535	25,172	26,485	26,485	26,595	26,748	26,748	27,380	27,380	28,000	28,000	28,600
Reserves w/DSM																				
17 Equivalent Reserves	3,299	3,225	3,275	3,341	3,851	3,204	3,376	3,415	3,632	4,003	5,041	4,761	4,519	4,347	4,009	4,302	3,964	4,237	3,896	4,155
18 % Reserve Margin	18.2%	17.6%	17.6%	17.3%	19.4%	16.0%	16.6%	16.6%	17.4%	18.9%	23.5%	21.9%	20.5%	19.4%	17.6%	18.6%	16.9%	17.8%	16.2%	17.0%
19 % Capacity Margin	15.4%	15.0%	14.9%	14.7%	16.3%	13.8%	14.2%	14.2%	14.8%	15.9%	19.0%	18.0%	17.0%	16.3%	15.0%	15.7%	14.5%	15.1%	13.9%	14.5%
Firm Wholesale Sales																				
75 MW Sale with need of 8.5% reserves																				
Catawba Owner Backstand	73	73	73																	
20 Equivalent Reserves	3226	3152	3202	3341	3851	3204	3376	3415	3632	4003	5041	4761	4519	4347	4009	4302	3964	4237	3896	4155
21 % Reserve Margin	17.8%	17.2%	17.2%	17.3%	19.4%	16.0%	16.6%	16.6%	17.4%	18.9%	23.5%	21.9%	20.5%	19.4%	17.6%	18.6%	16.9%	17.8%	16.2%	17.0%
22 % Capacity Margin	15.0%	14.6%	14.6%	14.7%	16.3%	13.8%	14.2%	14.2%	14.8%	15.9%	19.0%	18.0%	17.0%	16.3%	15.0%	15.7%	14.5%	15.1%	13.9%	14.5%

Winter Projections of Load, Capacity, and Reserves
for Duke Power and Nantahala Power and Light
2007 Annual Plan Reference Case

	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Forecast																				
1 Duke System Peak	15,954	16,084	16,391	17,061	17,497	17,738	17,976	18,198	18,466	18,733	18,988	19,247	19,530	19,762	20,014	20,268	20,523	20,801	21,031	21,261
EE $2M Merger of 1 MW	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
New EE Programs	5	72	142	200	262	328	399	457	519	585	656	714	771	771	771	771	771	771	771	771
2 Duke System Peak Less Projected EE	15,947	16,011	16,248	16,860	17,234	17,408	17,576	17,741	17,946	18,146	18,331	18,533	18,758	18,990	19,242	19,496	19,751	20,029	20,259	20,489
Cumulative System Capacity																				
3 Generating Capacity	20,784	20,569	20,698	20,674	20,671	20,596	20,398	19,926	19,926	19,440	19,307	19,174	19,174	19,174	19,174	19,174	19,174	19,174	19,174	19,174
4 Capacity Additions	50	154	36	9																
5 Capacity Derates	(51)	(25)	(22)	(12)																
6 Capacity Retirements	0	0	0	0	(75)	(198)	(276)	0	(486)	(133)	(133)	0	0	0	0	0	0	0	0	0
7 Cumulative Generating Capacity	20,783	20,698	20,712	20,671	20,596	20,398	20,122	19,926	19,440	19,307	19,174	19,174	19,174	19,174	19,174	19,174	19,174	19,174	19,174	19,174
8 Cumulative Purchase Contracts	755	755	744	246	246	94	94	72	72	72	72	72	72	72	72	72	72	72	72	72
9 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 Cumulative Future Resource Additions																				
Base Load	0	0	0	0	0	800	800	800	800	800	800	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917
Peaking/Intermediate	0	0	0	316	1,568	1,872	1,872	2,504	3,136	3,768	4,400	4,400	4,400	4,400	4,400	4,400	5,032	5,032	5,652	5,652
Renewables	0	0	0	6	6	71	99	110	296	296	434	630	630	740	893	893	893	893	893	893
11 Cumulative Production Capacity	21,538	21,453	21,456	21,239	22,416	23,234	22,986	23,411	23,744	24,243	24,880	26,192	26,192	26,302	26,455	26,455	27,087	27,087	27,707	27,707
Reserves w/o DSM																				
12 Generating Reserves	5,590	5,441	5,207	4,379	5,182	5,826	5,411	5,671	5,798	6,096	6,549	7,659	7,434	7,312	7,213	6,959	7,336	7,058	7,448	7,218
13 % Reserve Margin	35.1%	34.0%	32.0%	26.0%	30.1%	33.5%	30.8%	32.0%	32.3%	33.6%	35.7%	41.3%	39.6%	38.5%	37.5%	35.7%	37.1%	35.2%	36.8%	35.2%
14 % Capacity Margin	26.0%	25.4%	24.3%	20.6%	23.1%	25.1%	23.5%	24.2%	24.4%	25.1%	26.3%	29.2%	28.4%	27.8%	27.3%	26.3%	27.1%	26.1%	26.9%	26.1%
DSM																				
15 Cumulative DSM Capacity	490	620	732	732	732	732	732	732	732	732	732	732	732	732	732	732	732	732	732	732
Existing DSM Capacity Projection	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM Program Projection	490	620	732	732	732	732	732	732	732	732	732	732	732	732	732	732	732	732	732	732
16 Cumulative Equivalent Capacity	22,028	22,073	22,187	21,971	23,148	23,966	23,718	24,143	24,475	24,974	25,611	26,924	26,924	27,034	27,187	27,187	27,819	27,819	28,439	28,439
Reserves w/DSM																				
17 Equivalent Reserves	6,081	6,061	5,939	5,111	5,914	6,558	6,142	6,402	6,530	6,828	7,281	8,391	8,166	8,044	7,945	7,691	8,068	7,790	8,180	7,950
18 % Reserve Margin	38.1%	37.9%	36.6%	30.3%	34.3%	37.7%	34.9%	36.1%	36.4%	37.6%	39.7%	45.3%	43.5%	42.4%	41.3%	39.4%	40.8%	38.9%	40.4%	38.8%
19 % Capacity Margin	27.6%	27.5%	26.8%	23.3%	25.5%	27.4%	25.9%	26.5%	26.7%	27.3%	28.4%	31.2%	30.3%	29.8%	29.2%	28.3%	29.0%	28.0%	28.8%	28.0%
Firm Wholesale Sales																				
75 MW Sale with need of 8.5% reserves																				
Catawba Owner Backstand	73	73	73																	
20 Equivalent Reserves	6008	5988	5866	5111	5914	6558	6142	6402	6530	6828	7281	8391	8166	8044	7945	7691	8068	7790	8180	7950
21 % Reserve Margin	37.7%	37.4%	36.1%	30.3%	34.3%	37.7%	34.9%	36.1%	36.4%	37.6%	39.7%	45.3%	43.5%	42.4%	41.3%	39.4%	40.8%	38.9%	40.4%	38.8%
22 % Capacity Margin	27.3%	27.1%	26.4%	23.3%	25.5%	27.4%	25.9%	26.5%	26.7%	27.3%	28.4%	31.2%	30.3%	29.8%	29.2%	28.3%	29.0%	28.0%	28.8%	28.0%

Summer Projections of Load, Capacity, and Reserves
for Duke Power and Nantahala Power and Light
2007 Annual Plan Carbon Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Forecast										
1 Duke System Peak	18,187	18,422	18,825	19,597	20,123	20,335	20,564	20,785	21,016	21,310
EE $2M Merger of 1 MW	1	1	1	1	1	1	1	1	1	1
New EE Programs	39	109	174	236	301	371	436	498	563	633
2 Duke System Peak Less Projected EE	18,147	18,312	18,651	19,360	19,821	19,963	20,127	20,286	20,452	20,676
Cumulative System Capacity										
3 Generating Capacity	20,035	19,821	20,000	19,948	19,873	19,675	19,399	19,203	18,717	18,584
4 Capacity Additions	50	190	9							
5 Capacity Derates	(50)	(11)	(23)							
6 Capacity Retirements	0	0	(38)	(75)	(198)	(276)	(196)	(486)	(133)	(133)
7 Cumulative Generating Capacity	20,035	20,000	19,948	19,873	19,675	19,399	19,203	18,717	18,584	18,451
8 Cumulative Purchase Contracts	651	640	640	239	239	94	94	72	72	72
9 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0
10 Cumulative Future Resource Additions										
Base Load	0	0	0	0	800	800	800	800	800	800
Peaking/Intermediate	0	0	316	1,568	1,872	1,872	2,504	3,136	3,136	3,768
Renewables (Peak Contribution)	0	0	6	6	71	99	110	296	296	434
11 Cumulative Production Capacity	20,686	20,640	20,910	21,686	22,656	22,263	22,710	23,021	22,888	23,525
Reserves w/o DSM										
12 Generating Reserves	2,538	2,327	2,259	2,325	2,835	2,300	2,583	2,734	2,436	2,849
13 % Reserve Margin	14.0%	12.7%	12.1%	12.0%	14.3%	11.5%	12.8%	13.5%	11.9%	13.8%
14 % Capacity Margin	12.3%	11.3%	10.8%	10.7%	12.5%	10.3%	11.4%	11.9%	10.6%	12.1%
DSM										
15 Cumulative DSM Capacity	761	898	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016
Existing DSM Capacity Projection	0	0	0	0	0	0	0	0	0	0
New DSM Program Projection	761	898	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016
16 Cumulative Equivalent Capacity	21,447	21,537	21,925	22,701	23,672	23,279	23,726	24,036	23,903	24,540
Reserves w/DSM										
17 Equivalent Reserves	3,299	3,225	3,275	3,341	3,851	3,316	3,599	3,750	3,451	3,865
18 % Reserve Margin	18.2%	17.6%	17.6%	17.3%	19.4%	16.6%	17.9%	18.5%	16.9%	18.7%
19 % Capacity Margin	15.4%	15.0%	14.9%	14.7%	16.3%	14.2%	15.2%	15.6%	14.4%	15.7%
Firm Wholesale Sales										
75 MW Sale with need of 8.5% reserves										
Catawba Owner Backstand	73	73	73							
20 Equivalent Reserves	3226	3152	3202	3341	3851	3316	3599	3750	3451	3865
21 % Reserve Margin	17.8%	17.2%	17.2%	17.3%	19.4%	16.6%	17.9%	18.5%	16.9%	18.7%
22 % Capacity Margin	15.0%	14.6%	14.6%	14.7%	16.3%	14.2%	15.2%	15.6%	14.4%	15.7%

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Forecast										
1 Duke System Peak	21,608	21,907	22,240	22,485	22,740	22,994	23,245	23,502	23,753	24,002
EE $2M Merger of 1 MW	1	1	1	1	1	1	1	1	1	1
New EE Programs	698	760	787	787	787	787	787	787	787	787
2 Duke System Peak Less Projected EE	20,909	21,146	21,452	21,697	21,952	22,206	22,457	22,714	22,965	23,214
Cumulative System Capacity										
3 Generating Capacity	18,451	18,451	18,451	18,451	18,451	18,451	18,451	18,451	18,451	18,451
4 Capacity Additions										
5 Capacity Derates										
6 Capacity Retirements	0	0	0	0	0	0	0	0	0	0
7 Cumulative Generating Capacity	18,451	18,451	18,451	18,451	18,451	18,451	18,451	18,451	18,451	18,451
8 Cumulative Purchase Contracts	72	72	72	72	72	72	72	72	72	72
9 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0
10 Cumulative Future Resource Additions										
Base Load	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917
Peaking/Intermediate	3,768	3,768	3,768	3,768	3,768	3,768	3,768	4,400	4,400	4,800
Renewables (Peak Contribution)	630	630	740	893	893	893	893	893	893	893
11 Cumulative Production Capacity	24,837	24,837	24,947	25,100	25,100	25,100	25,100	25,732	25,732	26,132
Reserves w/o DSM										
12 Generating Reserves	3,928	3,691	3,495	3,403	3,148	2,894	2,643	3,018	2,767	2,918
13 % Reserve Margin	18.8%	17.5%	16.3%	15.7%	14.3%	13.0%	11.8%	13.3%	12.0%	12.6%
14 % Capacity Margin	15.8%	14.9%	14.0%	13.6%	12.5%	11.5%	10.5%	11.7%	10.8%	11.2%
DSM										
15 Cumulative DSM Capacity	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016
Existing DSM Capacity Projection	0	0	0	0	0	0	0	0	0	0
New DSM Program Projection	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016	1,016
16 Cumulative Equivalent Capacity	25,853	25,853	25,963	26,116	26,116	26,116	26,116	26,748	26,748	27,148
Reserves w/DSM										
17 Equivalent Reserves	4,944	4,707	4,511	4,419	4,164	3,910	3,659	4,034	3,783	3,934
18 % Reserve Margin	23.6%	22.3%	21.0%	20.4%	19.0%	17.6%	16.3%	17.8%	16.5%	16.9%
19 % Capacity Margin	19.1%	18.2%	17.4%	16.9%	15.9%	15.0%	14.0%	15.1%	14.1%	14.5%
Firm Wholesale Sales										
75 MW Sale with need of 8.5% reserves										
Catawba Owner Backstand										
20 Equivalent Reserves	4944	4707	4511	4419	4164	3910	3659	4034	3783	3934
21 % Reserve Margin	23.6%	22.3%	21.0%	20.4%	19.0%	17.6%	16.3%	17.8%	16.5%	16.9%
22 % Capacity Margin	19.1%	18.2%	17.4%	16.9%	15.9%	15.0%	14.0%	15.1%	14.1%	14.5%

Winter Projections of Load, Capacity, and Reserves
for Duke Power and Nantahala Power and Light
2007 Annual Plan Carbon Case

	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Forecast																				
1 Duke System Peak	15,954	16,084	16,391	17,061	17,497	17,640	17,782	17,905	18,073	18,304	18,523	18,746	18,990	19,154	19,335	19,517	19,699	19,901	20,057	20,211
EE $2M Merger of 1 MW	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
New EE Programs	5	72	142	200	262	328	399	457	519	585	656	714	771	771	771	771	771	771	771	771
2 Duke System Peak Less Projected EE	15,948	16,012	16,248	16,860	17,234	17,311	17,382	17,447	17,553	17,718	17,866	18,031	18,218	18,382	18,563	18,745	18,927	19,129	19,285	19,439
Cumulative System Capacity																				
3 Generating Capacity	20,784	20,569	20,698	20,674	20,671	20,596	20,398	19,926	19,926	19,440	19,307	19,174	19,174	19,174	19,174	19,174	19,174	19,174	19,174	19,174
4 Capacity Additions	50	154	36	9																
5 Capacity Derates	(51)	(25)	(22)	(12)																
6 Capacity Retirements	0	0	0	0	(75)	(198)	(276)	0	(486)	(133)	(133)	0	0	0	0	0	0	0	0	0
7 Cumulative Generating Capacity	20,783	20,698	20,712	20,671	20,596	20,398	20,122	19,926	19,440	19,307	19,174	19,174	19,174	19,174	19,174	19,174	19,174	19,174	19,174	19,174
8 Cumulative Purchase Contracts	755	755	744	246	246	94	94	72	72	72	72	72	72	72	72	72	72	72	72	72
9 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 Cumulative Future Resource Additions																				
Base Load	0	0	0	0	0	800	800	800	800	800	800	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917
Peaking/Intermediate	0	0	0	316	1,568	1,872	1,872	2,504	3,136	3,136	3,768	3,768	3,768	3,768	3,768	3,768	3,768	3,768	4,400	4,400
Renewables	0	0	0	6	6	71	99	110	296	296	434	630	630	740	893	893	893	893	893	893
11 Cumulative Production Capacity	21,538	21,453	21,456	21,239	22,416	23,234	22,986	23,411	23,744	23,611	24,248	25,560	25,560	25,670	25,823	25,823	25,823	25,823	26,455	26,455
Reserves w/o DSM																				
12 Generating Reserves	5,590	5,441	5,208	4,379	5,182	5,924	5,604	5,964	6,191	5,893	6,382	7,529	7,342	7,288	7,260	7,078	6,896	6,694	7,170	7,016
13 % Reserve Margin	35.1%	34.0%	32.1%	26.0%	30.1%	34.2%	32.2%	34.2%	35.3%	33.3%	35.7%	41.8%	40.3%	39.6%	39.1%	37.8%	36.4%	35.0%	37.2%	36.1%
14 % Capacity Margin	26.0%	25.4%	24.3%	20.6%	23.1%	25.5%	24.4%	25.5%	26.1%	25.0%	26.3%	29.5%	28.7%	28.4%	28.1%	27.4%	26.7%	25.9%	27.1%	26.5%
DSM																				
15 Cumulative DSM Capacity	490	620	732	732	732	732	732	732	732	732	732	732	732	732	732	732	732	732	732	732
Existing DSM Capacity Projection	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM Program Projection	490	620	732	732	732	732	732	732	732	732	732	732	732	732	732	732	732	732	732	732
16 Cumulative Equivalent Capacity	22,028	22,073	22,187	21,971	23,148	23,966	23,718	24,143	24,475	24,342	24,979	26,292	26,292	26,402	26,555	26,555	26,555	26,555	27,187	27,187
Reserves w/DSM																				
17 Equivalent Reserves	6,080	6,061	5,940	5,111	5,914	6,656	6,336	6,696	6,923	6,625	7,113	8,261	8,074	8,020	7,992	7,810	7,628	7,426	7,902	7,748
18 % Reserve Margin	38.1%	37.9%	36.6%	30.3%	34.3%	38.4%	36.5%	38.4%	39.4%	37.4%	39.8%	45.8%	44.3%	43.6%	43.1%	41.7%	40.3%	38.8%	41.0%	39.9%
19 % Capacity Margin	27.6%	27.5%	26.8%	23.3%	25.5%	27.8%	26.7%	27.7%	28.3%	27.2%	28.5%	31.4%	30.7%	30.4%	30.1%	29.4%	28.7%	28.0%	29.1%	28.5%
Firm Wholesale Sales																				
75 MW Sale with need of 8.5% reserves																				
Catawba Owner Backstand	73	73	73																	
20 Equivalent Reserves	6007	5988	5867	5111	5914	6656	6336	6696	6923	6625	7113	8261	8074	8020	7992	7810	7628	7426	7902	7748
21 % Reserve Margin	37.7%	37.4%	36.1%	30.3%	34.3%	38.4%	36.5%	38.4%	39.4%	37.4%	39.8%	45.8%	44.3%	43.6%	43.1%	41.7%	40.3%	38.8%	41.0%	39.9%
22 % Capacity Margin	27.3%	27.1%	26.4%	23.3%	25.5%	27.8%	26.7%	27.7%	28.3%	27.2%	28.5%	31.4%	30.7%	30.4%	30.1%	29.4%	28.7%	28.0%	29.1%	28.5%

ASSUMPTIONS OF LOAD, CAPACITY, AND RESERVES TABLE

The following notes are numbered to match the line numbers on the SUMMER AND WINTER PROJECTIONS OF LOAD, CAPACITY, AND RESERVES tables. 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 Energy Carolinas (formerly Duke Power) in 1998.

3. 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.
   Generating Capacity also reflects a 277 MW reduction in Catawba Nuclear Station to account for PMPAs termination of their interconnection agreement with Duke Energy Carolinas.

4. Capacity Additions reflect an estimated 50 MW capacity uprate at the Jocassee pumped storage facility from increased efficiency from the new runners, a 154 MW addition in Catawba Nuclear Station resulting from the Saluda River acquisition assumed to be completed during the 4th quarter of 2008, a 36 MW increase in Belews Creek capacity due to LP rotor changeouts, and an 8.75 MW increase in capacity at Bridgewater Hydro by summer 2009.

5. 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.

6. The 38 MW capacity retirement in summer 2010 represents the projected retirement date for Buck 4.
   The 75 MW capacity retirement in summer 2011 represents the projected retirement date for Buck 3.
   The 198 MW capacity retirement in summer 2012 represents the projected retirement date for Cliffside units 1-4.
   The 276 MW capacity retirement in summer 2013 represents the projected retirement date for Dan River units 1-3.
   The 196 MW capacity retirement in summer 2014 represents the projected retirement date for all CT's at Buzzard Roost.
   The 486 MW capacity retirement in summer 2015 represents the projected retirement date for CTs at Dan River (85), Buck (93) and Riverbend (120). Riverbend units 4 and 5 (88 MW each) are also assumed candidates for retirement in this year.
   The 133 MW capacity retirement in summer 2016 represents the projected retirement date for Riverbend 6.
   The 133 MW capacity retirement in summer 2017 represents the projected retirement date for Riverbend 7.
   The NRC has issued renewed energy facility operating licenses for all Duke Energy Carolinas' nuclear facilities.
   The Hydro facilities for which Duke has submitted an application to FERC for licence renewal are assumed to continue operation through the planning horizon.
   All retirement dates are subject to review on an ongoing basis.

8. Cumulative Purchase Contracts have several components:

   A. Piedmont Municipal Power Agency took sole responsibility 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 Rowan Unit 2 began January 1, 2006 and expires December 31, 2010.
   F. Purchase of 153 MW from Rowan Unit 1 began June 1, 2007 and expires December 31, 2010.
   G. Purchase of 153 MW from Rowan Unit 3 began June 1, 2008 and expires December 31, 2010.

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

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

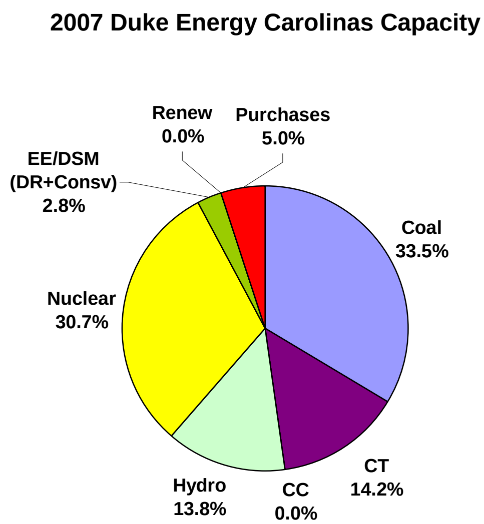
14. Capacity Margin = (Cumulative Capacity - System Peak Demand)/Cumulative Capacity

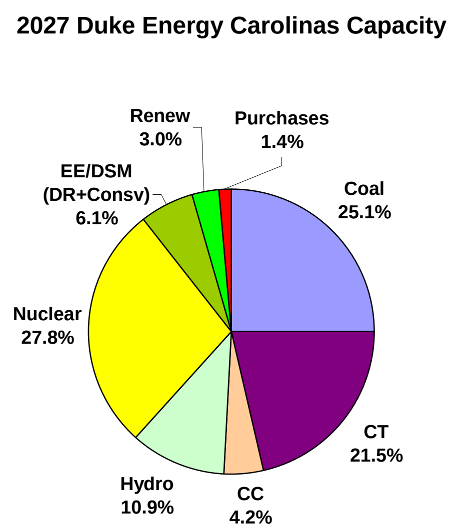
15. Cumulative Demand Side Management capacity represents the existing interruptible demand-side management programs that are designed to be activated during capacity problem situations. The Cumulative Demand Side Management capacity also includes new Demand Side Management capacity representing placeholders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

20. Equivalent Reserves:

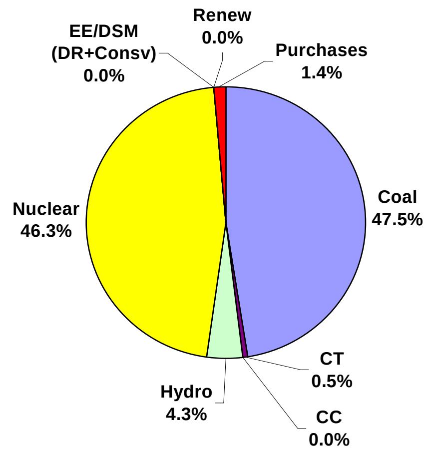
    Beginning January 1, 2005, two firm wholesale agreements became effective between Duke Energy Carolinas and NCMPA1. The first is a 75 MW capacity sale that expires December 31, 2007. The second is a backstand agreement of up to 432 MW (depending on operation of the Catawba and McGuire facilities) that expires December 31, 2007. The backstand agreement was extended through 2010.

The charts below show the changes in Duke Energy Carolinas' capacity mix and energy mix between 2007 and 2027 under Carbon Case conditions. The relative shares of renewables, energy efficiency, and gas all increase, while the relative share of coal decreases.

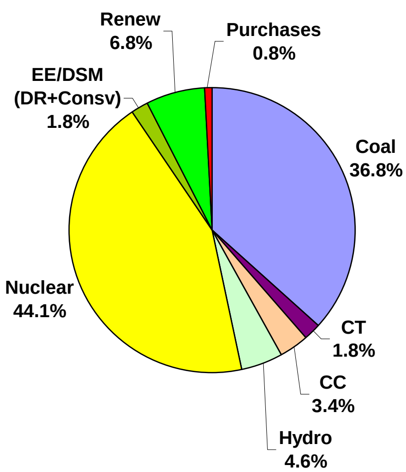




2007 Duke Energy Carolinas Energy



2027 Duke Energy Carolinas Energy



The table on the following page represents the annual incremental additions reflected in the LCR Table of the most robust expansion plan, under both Reference Case and Carbon Case conditions. The (Ph) designation of some of the CTs and CCs in 2010-2012 denotes that the combined cycle capacity may be "phased-in" by first placing the CT capacity in service and then completing the combined cycle portion of the construction. The plans contain the new levels of demand response and conservation programs shown in the Projected Energy Efficiency and Demand-Side Management Load Impacts table in Appendix I. In addition, the plans contain the addition of Cliffside Unit 6 in 2012 and the unit retirements shown in Table 3.3.

	Reference Case	Carbon Case
	CCs Early/ Nuclear/ No Renewables/ New EE	*CCs Early/ Nuclear/ Renewables/ New EE*
2007		
2008	New EE and DSM	New EE and DSM
2009		
2010		9 MW Renewables
	316 MW New CTs (Ph)	316 MW New CTs (Ph)
2011	620 MW New CCs (Ph)	620 MW New CCs (Ph)
	316 MW New CTs(Ph)	316 MW New CTs(Ph)
	632 MW New CTs	632 MW New CTs
2012	800 MW Cliffside 6	800 MW Cliffside 6
		156 MW Renewables
	620 MW New CCs (Ph)	620 MW New CCs (Ph)
2013		28 MW Renewables
	632 MW New CTs	
2014		11 MW Renewables
		632 MW New CTs
2015		239 MW Renewables
	1264 MW New CTs	632 MW New CTs
2016		
2017		138 MW Renewables
	632 MW New CTs	632 MW New CTs
2018		290 MW Renewables
	1117 MW New Nuclear	1117 MW New Nuclear
2019		
2020		110 MW Renewables
2021		154 MW Renewables
	632 MW New CTs	
2022		
2023	620 MW New CCs	
2024	620 MW New CCs	
2025		632 MW New CTs
2026	620 MW New CCs	
2027	260 MW New CTs	400 MW New CTs

<u>MW Added</u>		
Nuclear	1,117	1,117
Coal	800	800
CC	3,100	1,240
CT	4,052	3,560
Renewables	0	1,135
EE	790	790
DSM	1,016	1,016
<u>MW Retired</u>		
Coal	1,041	1,041
Gas/Oil	494	494

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 EE and DSM resources – detailing EE and 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:

- 1.6% average summer peak system demand growth over the next 20 years
- Generation reductions of more than 450 MW due to purchased power contract expirations by 2011
- Generation retirements of approximately 500 MW of old fleet combustion turbines by 2015
- Generation retirements of approximately 1,000 MW of older coal units associated with the addition of Cliffside Unit 6 and the increase in EE and DSM programs
- Approximately 84 MW of net generation reductions due to new environmental equipment
- Continued operational reliability of existing generation portfolio
- 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 EE 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 and EE options should also cover multiple customer segments including residential, commercial and industrial. For additional information, see Appendix I.

Resource Options

<u>Supply-Side</u>
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:

- Supercritical Pulverized coal – 800 MW
- Natural gas combined-cycle with duct firing and inlet cooling – 620 MW
- Natural gas simple-cycle combustion turbine – 632 MW (4-unit plant)
- Nuclear AP 1000 – 2,234 MW (2 – 1,117 MW units)
- Integrated Coal Gasification Combined Cycle (IGCC) – 630 MW
- On Shore Wind PPA – 50 MW (15% contribution to capacity on peak)
- Solar PPA (70% contribution to capacity on peak)
- Biomass Firing PPA
- Hog Waste Digester PPA
- Poultry Waste PPA

Although the supply-side screening curves showed that some of these resources would be screened out, they were included in the next step of the quantitative analysis for completeness. With the exception of Wind, which was constrained to two-50 MW blocks per year, up to a total of 250 MW, the model was allowed to select the sizes of the renewable PPAs needed to most economically meet the RPS.

Duke Energy Carolinas has received a CPCN to build one unit of new coal-fired capacity at Cliffside and has modeled this resource as a committed capacity addition in 2012.

Energy Efficiency and Demand-Side Management
EE and DSM programs continue to be an important part of Duke Energy Carolinas' system mix. Both demand response and conservation programs were considered.

The DSM programs were modeled as two separate "bundles" (one bundle of Non-Residential programs and one bundle of Residential programs) that could be selected based on economics. The costs and impacts included in Duke Energy Carolinas' Energy Efficiency filing (excluding pilot programs) were modeled and the assumption was made that these costs and impacts would continue throughout the planning period.

The EE programs were modeled as three separate bundles that could be selected based on economics. Bundle 1 corresponded to the costs and impacts for conservation programs included in Duke Energy Carolinas' Energy Efficiency filing (excluding pilot programs) for 2008 through 2012. From years 2013 through 2027 it was assumed that the measures would be replaced in kind (with associated costs) such that there would be no decline in the impacts over time (i.e., continuous commissioning of impacts). Bundles 2 and 3 were modeled identically to Bundle 1, but they were not allowed to start until 2012 and 2016, respectively, and their costs utilized the costs of Bundle 1 escalated at the rate of inflation. In addition, the modeling included a 1 MW EE program based on the $2,000,000 program required by the NCUC order in Docket E-7, Sub 795.

Appendix I contains details regarding the various EE and 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 resources required to meet an annual 17 percent target planning reserve margin while minimizing the long-run revenue requirements to customers, with differing operating (production) and capital costs.

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 / 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. The portfolios analyzed for the development of this IRP were chosen in order to focus on the near-term (i.e., within the next five years) decisions that must be made while placing less emphasis on differences in portfolios ten to twenty years in the future that Duke Energy Carolinas will have the opportunity to re-visit in subsequent IRPs. For example, the Company has a substantial need for additional resources beginning as early as 2010 that can be filled by a combination of CTs, CCs, EE and DSM programs, and Renewable resources, so variations in these resource combinations were studied.

While potential new nuclear plant capacity could not go in service until 2016 at the earliest, decisions concerning continuing to pursue this alternative are needed to preserve this option. The screening results demonstrate that the optimal timing of nuclear varies widely from no nuclear to two units with timeframes from 2016 to 2023. For the purposes of the detailed modeling, portfolios were developed with no nuclear units, one unit in 2018, or a two-unit plant with staggered operation dates of 2018 and 2020. The use of a 2018 date is for modeling purposes only and the actual planned operational date may be accelerated or delayed as additional information becomes available on critical issues such as enactment of carbon legislation.

The tables shown on the following pages outline the planning options that were considered in the portfolio analysis phase. Each portfolio contains the maximum amount of both demand response and conservation that was available, with the exception of the CT and CTR portfolios, which contain only the existing levels of EE and DSM. In addition, each portfolio contains the addition of Cliffside Unit 6 in 2012 and the unit retirements shown in Table 3.3.

The key to the portfolio names is as follows:

CT	Portfolio with CTs early then CCs
CC	Portfolio with CCs early then CTs
N or 2N	Portfolio with one or two 1,117 MW nuclear units; if no “N”, the portfolio does not have new nuclear
R	Portfolio with renewables included (assumes the renewables portion of the standard will be met with renewables, co-firing biomass in existing generating units, EE, and purchasing RECs up to the amount allowed)
EE	New EE and DSM levels; if no “EE”, then existing EE and DSM are assumed to continue

Reference Case

	CT	***CTEE***	***CCEE***	***CTNEE***	***CCNEE***
	CTs Early/ No Nuclear/ No Renewables/ Existing EE	***CTs Early/ No Nuclear/ No Renewables/ New EE***	***CCs Early/ No Nuclear/ No Renewables/ New EE***	***CTs Early/ Nuclear/ No Renewables/ New EE***	***CCs Early/ Nuclear/ No Renewables/ New EE***
2007					
2008					
2009					
2010	1264 MW New CTs	632 MW New CTs	316 MW New CTs (Ph)	632 MW New CTs	316 MW New CTs (Ph)
2011			620 MW New CCs (Ph)		620 MW New CCs (Ph)
			316 MW New CTs (Ph)		316 MW New CTs (Ph)
	1264 MW New CTs	1264 MW New CTs	632 MW New CTs	1264 MW New CTs	632 MW New CTs
2012			620 MW New CCs (Ph)		620 MW New CCs (Ph)
2013	632 MW New CTs	632 MW New CTs	632 MW New CTs	632 MW New CTs	632 MW New CTs
2014	620 MW New CCs	620 MW New CCs			
2015	1240 MW New CCs	620 MW New CCs		620 MW New CCs	
			1264 MW New CTs	632 MW New CTs	1264 MW New CTs
2016	632 MW New CTs				
2017		632 MW New CTs	632 MW New CTs	632 MW New CTs	632 MW New CTs
2018	620 MW New CCs	620 MW New CCs	620 MW New CCs		
				1117 MW New Nuclear	1117 MW New Nuclear
2019	632 MW New CTs				
2020		632 MW New CTs	632 MW New CTs		
2021	620 MW New CCs			620 MW New CCs	
					632 MW New CTs
2022	620 MW New CCs	620 MW New CCs	620 MW New CCs		
2023				620 MW New CCs	620 MW New CCs
		632 MW New CTs	632 MW New CTs		
2024				620 MW New CCs	620 MW New CCs
	632 MW New CTs				
2025	620 MW New CCs	620 MW New CCs	620 MW New CCs		
2026		620 MW New CCs	620 MW New CCs	620 MW New CCs	620 MW New CCs
2027	490 MW New CTs	120 MW New CTs	120 MW New CTs	260 MW New CTs	260 MW New CTs

<u>MW Added</u>					
Nuclear	0	0	0	1117	1117
CC	4340	3720	3720	3100	3100
CT	5546	4544	4544	4052	4052
Renewables	0	0	0	0	0

Carbon Case

	CTR	CTREE	CCREE	CTNREE	CCNREE	CC2NREE
	CTs Early/ No Nuclear/ Renewables/ Existing EE	***CTs Early/ No Nuclear/ Renewables/ New EE***	***CCs Early/ No Nuclear/ Renewables/ New EE***	***CTs Early/ Nuclear/ Renewables/ New EE***	***CCs Early/ Nuclear/ Renewables/ New EE***	***CCs Early/ 2 Units Nuclear/ Renewables/ New EE***
2007						
2008						
2009						
2010	9 MW Renewables	9 MW Renewables	9 MW Renewables	9 MW Renewables	9 MW Renewables	9 MW Renewables
	1264 MW New CTs	632 MW New CTs	316 MW New CTs (Ph)	632 MW New CTs	316 MW New CTs (Ph)	316 MW New CTs (Ph)
2011			620 MW New CCs (Ph)		620 MW New CCs(Ph)	620 MW New CCs (Ph)
			316 MW New CTs(Ph)		316 MW New CTs(Ph)	316 MW New CTs (Ph)
	1264 MW New CTs	1264 MW New CTs	632 MW New CTs	1264 MW New CTs	632 MW New CTs	632 MW New CTs
2012	215 MW Renewables	156 MW Renewables	156 MW Renewables	156 MW Renewables	156 MW Renewables	156 MW Renewables
			620 MW New CCs (Ph)		620 MW New CCs (Ph)	620 MW New CCs (Ph)
2013	28 MW Renewables	28 MW Renewables	28 MW Renewables	28 MW Renewables	28 MW Renewables	28 MW Renewables
	632 MW New CTs					
2014	60 MW Renewables	11 MW Renewables	11 MW Renewables	11 MW Renewables	11 MW Renewables	11 MW Renewables
		620 MW New CCs				
			632 MW New CTs	632 MW New CTs	632 MW New CTs	632 MW New CTs
2015	294 MW Renewables	239 MW Renewables	239 MW Renewables	239 MW Renewables	239 MW Renewables	239 MW Renewables
	620 MW New CCs			620 MW New CCs		
		632 MW New CTs	632 MW New CTs		632 MW New CTs	632 MW New CTs
2016	55 MW Renewables					
	620 MW New CCs					
2017	150 MW Renewables	138 MW Renewables	138 MW Renewables	138 MW Renewables	138 MW Renewables	138 MW Renewables
		632 MW New CTs	632 MW New CTs	632 MW New CTs	632 MW New CTs	632 MW New CTs
2018	290 MW Renewables	290 MW Renewables	290 MW Renewables	290 MW Renewables	290 MW Renewables	290 MW Renewables
	632 MW New CTs					
				1117 MW New Nuclear	1117 MW New Nuclear	1117 MW New Nuclear
2019						
2020	140 MW Renewables	110 MW Renewables	110 MW Renewables	110 MW Renewables	110 MW Renewables	110 MW Renewables
		620 MW New CCs				
	632 MW New CTs		632 MW New CTs			
						1117 MW New Nuclear
2021	154 MW Renewables	154 MW Renewables	154 MW Renewables	154 MW Renewables	154 MW Renewables	154 MW Renewables
2022						
2023	632 MW New CTs	632 MW New CTs	632 MW New CTs			
2024						
2025	620 MW New CCs	620 MW New CCs	620 MW New CCs			
				632 MW New CTs	632 MW New CTs	
2026						
2027	380 MW New CTs	280 MW New CTs	280 MW New CTs	400 MW New CTs	400 MW New CTs	

MW Added						
Nuclear	0	0	0	1117	1117	2234
CC	1860	1860	1860	620	1240	1240
CT	5436	4072	4072	4192	3560	2528
Renewables	1395	1135	1135	1135	1135	1135

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. For this IRP analysis, the scenarios considered were as follows:

- Reference Case Without CO_2 regulation
- Carbon Case With CO_2 regulation[10] plus a Renewable Portfolio Standard (RPS)

The sensitivities chosen to be performed for these scenarios were those representing the highest risks going forward. The following sensitivities were evaluated in the Reference Case scenario:

- Load forecast variations
    - Increase relative to base forecast (growth rates of 1.9% and 1.7% for peak demand and energy, respectively, versus 1.6% and 1.4%, 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 1.6% and 1.4%, respectively, in the base case forecast)

The sensitivities evaluated in the Carbon Case scenario were as follows:

- Construction cost sensitivity[11]
    - Higher costs to construct new CC and CT plants (20% higher than base case)
    - Higher costs to construct a new nuclear plant (20% higher than base case)
- Fuel price variability
    - Higher coal prices (10% higher than base case)
    - Higher natural gas prices (20% higher than base case)
- Emission allowance price variability
    - Alternative emission allowance prices for SO_2, NOx, and Hg
    - High CO_2 prices[12]
- High CO_2 prices plus higher natural gas prices (20% higher than base case)

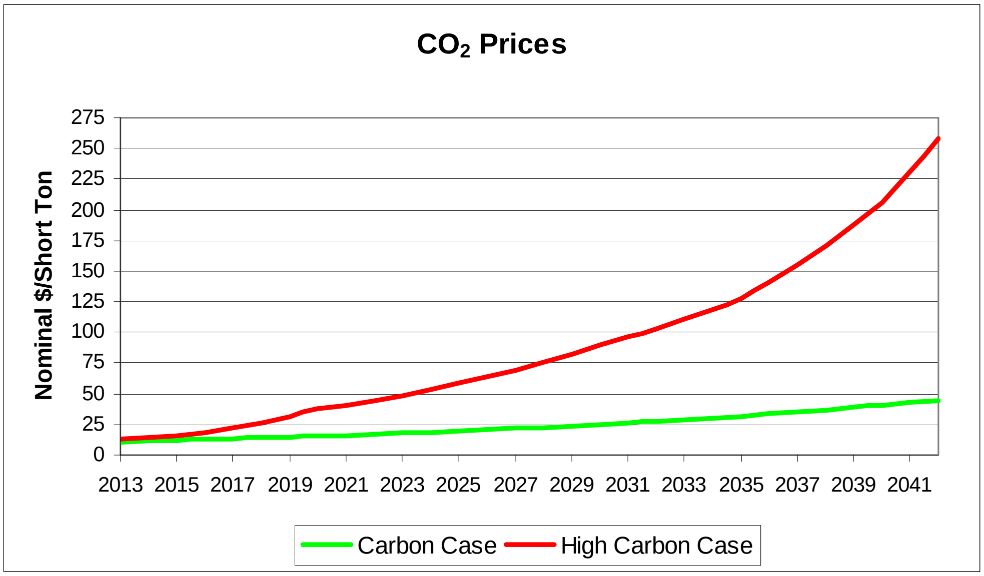
[10] Despite significant uncertainty surrounding potential future climate change policy, Duke Energy Carolinas has incorporated a climate change policy scenario in its resource planning process. Inclusion of this scenario is not intended to reflect Duke Energy Carolinas' or Duke Energy's preferences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

[11] 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.

[12] The Company continues to believe that there will be a price control mechanism incorporated into climate change legislation that is ultimately enacted to prevent high emission allowance prices and reduce price volatility. Given the uncertainty around the price levels that will result from the price control mechanism, however, this IRP analysis considered a range of potential prices.

In the Carbon Case scenario, the base level of load was adjusted downward to reflect that some level of "price-induced" conservation may occur in a carbon-constrained scenario. In addition, the fuel prices and emission allowance prices were adjusted to reflect expected changes in this type of scenario.

The graph below shows the CO_2 prices utilized in the analysis which were based on the legislation proposed by Senator Bingamann.



The RPS assumptions are based on recently-enacted legislation in North Carolina. The assumptions for planning purposes are as follows:

<u>Overall Requirements/Timing</u>

- 3% of 2011 load by 2012
- 6% of 2014 load by 2015
- 10% of 2017 load by 2018
- 12.5% of 2020 load by 2021

<u>Additional Requirements</u>

- Up to 25% from EE through 2020
- Up to 40% from EE starting in 2021
- Up to 25% of the requirements can be met with Renewable Energy Certificates (RECs)
- Solar requirement
    - 0.02% by 2010
    - 0.07% by 2012
    - 0.14% by 2015
    - 0.20% by 2018

- Hog waste requirement
    - 0.07% by 2012
    - 0.14% by 2015
    - 0.20% by 2018
- Poultry waste requirement (using Duke Energy Carolinas' share of total North Carolina load which is approximately 42%)
    - 71,400 MWh by 2012
    - 294,000 MWh by 2013
    - 378,000 MWh by 2014

These requirements were applied to all native loads served by Duke Energy Carolinas (i.e., both retail and wholesale, and regardless of the location of the load) to take into account the potential that a Federal RPS may be imposed that would affect all loads.

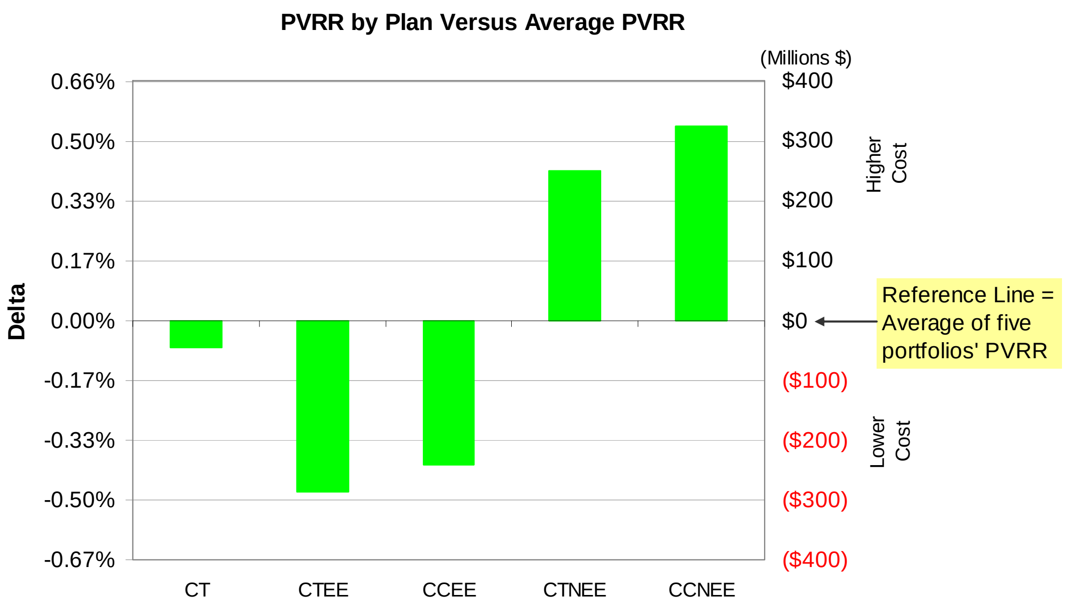
Quantitative Analysis Results

Yearly revenue requirements for various resource planning strategies were calculated based on production cost simulation and 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 portfolios analyzed, both on a percentage basis and on a total dollar basis.

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.

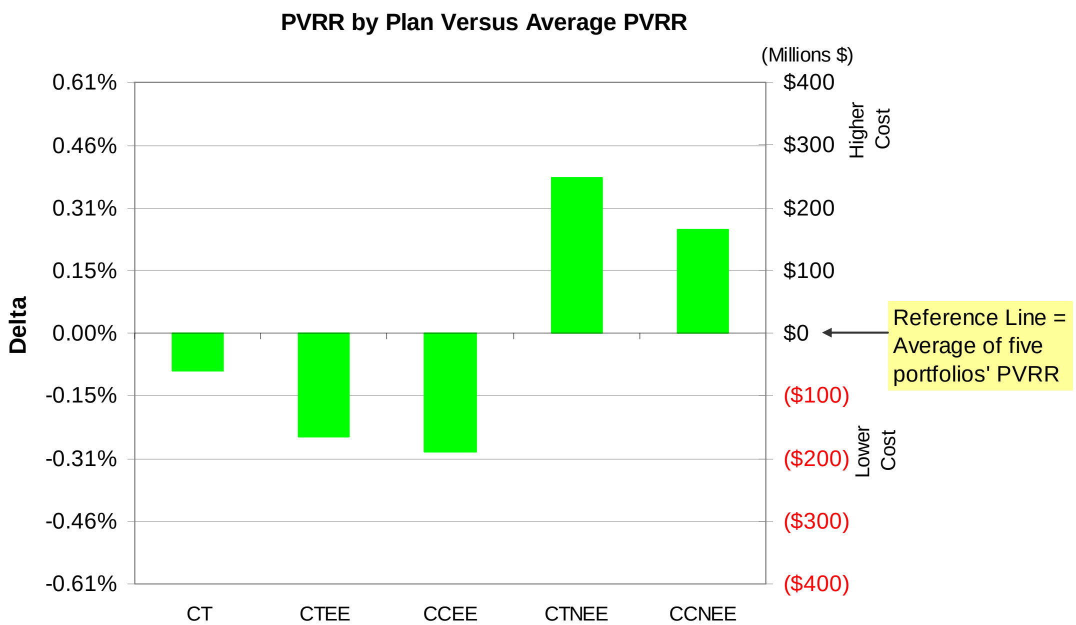
The Reference Case assumptions include Duke Energy Carolinas' expected load growth, projected commodity prices and expected asset development costs and timing.

Reference Case

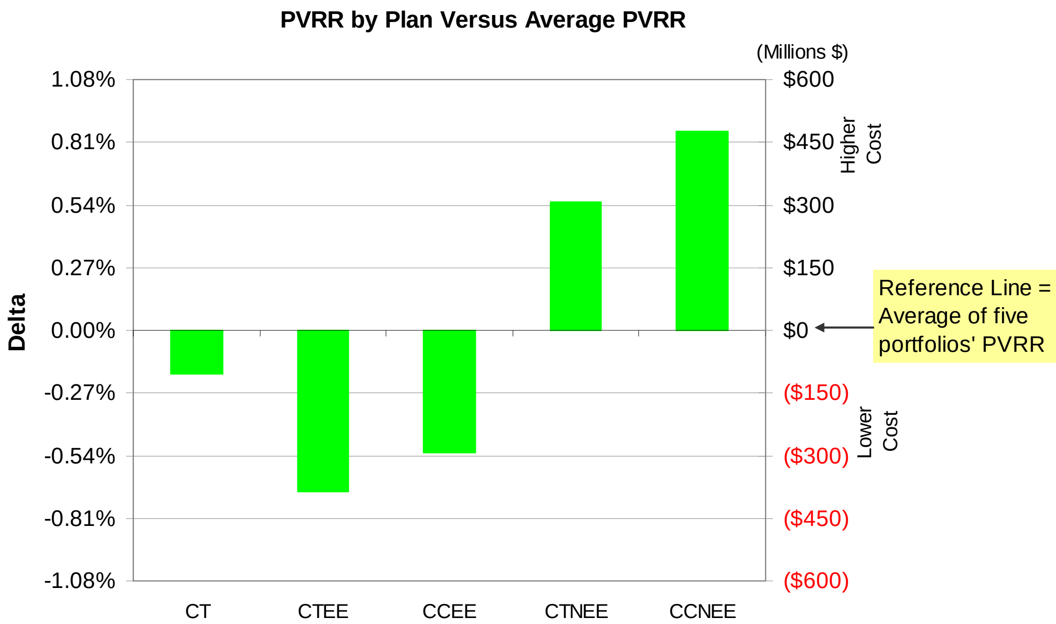


Sensitivities:

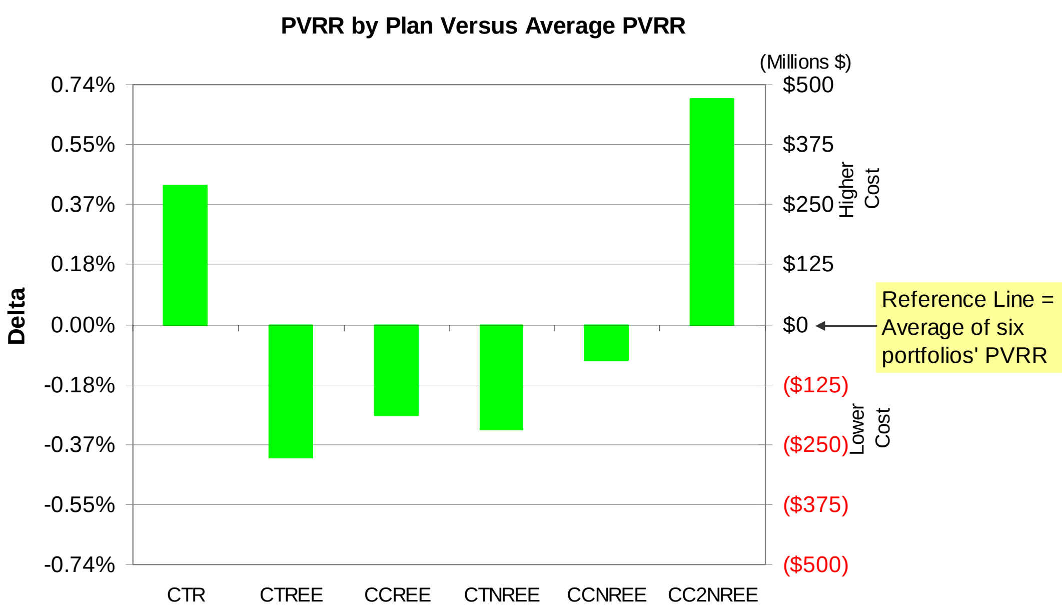
Sensitivity: High Load



Sensitivity: Low Load

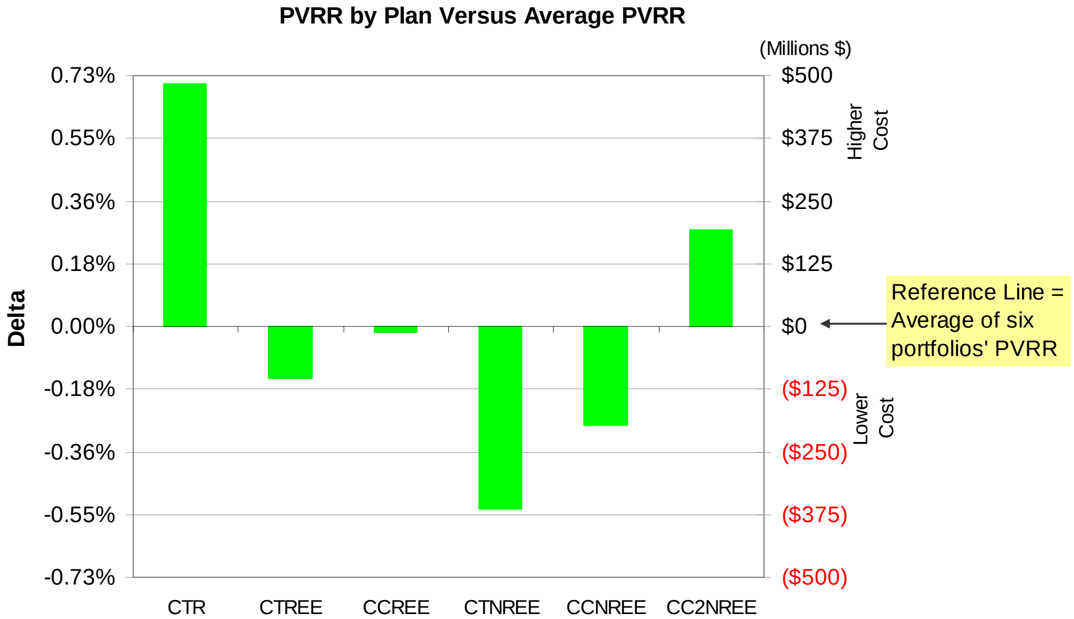


Carbon Case

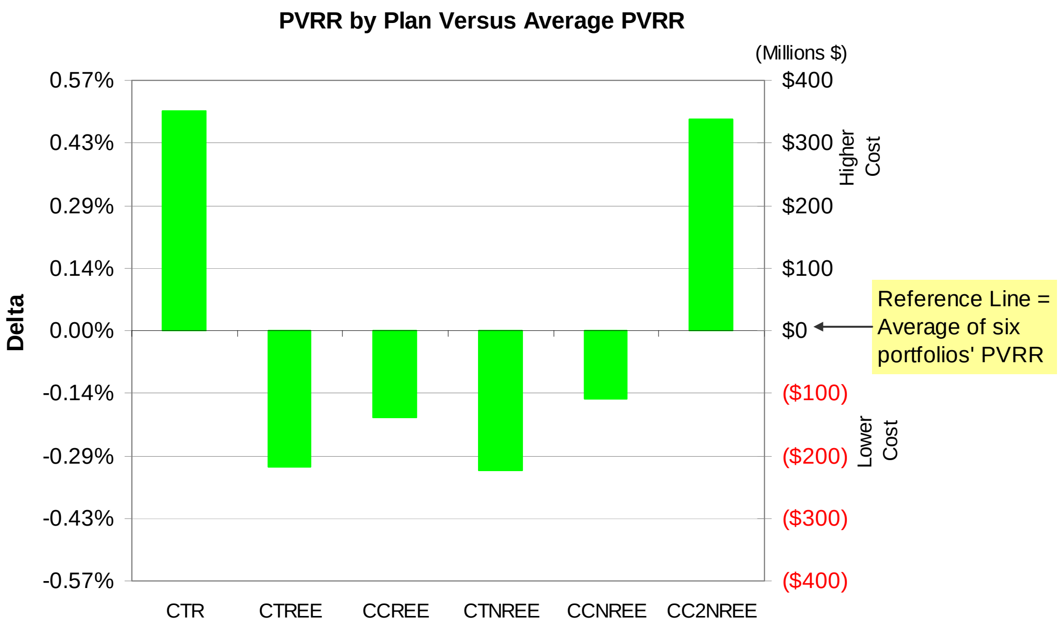


Sensitivities:

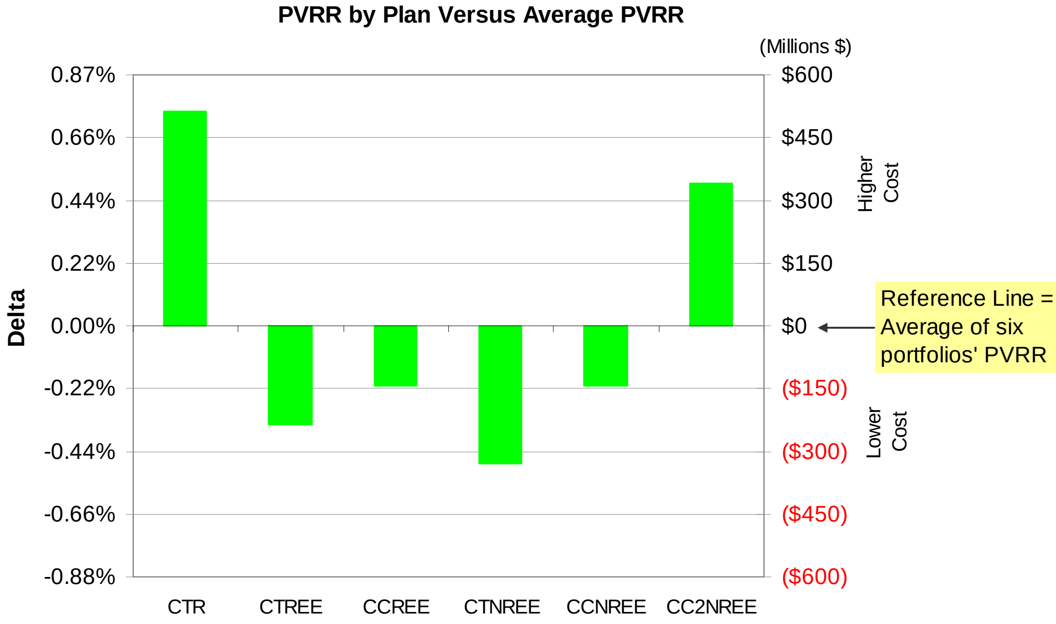
Sensitivity: Higher Natural Gas Prices



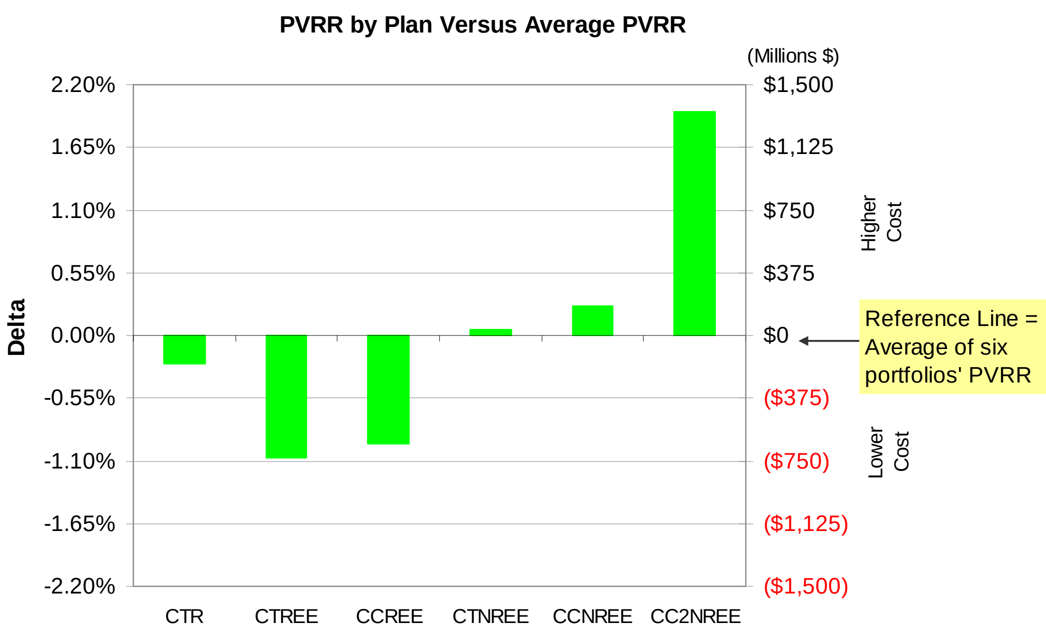
Sensitivity: Higher Coal Prices



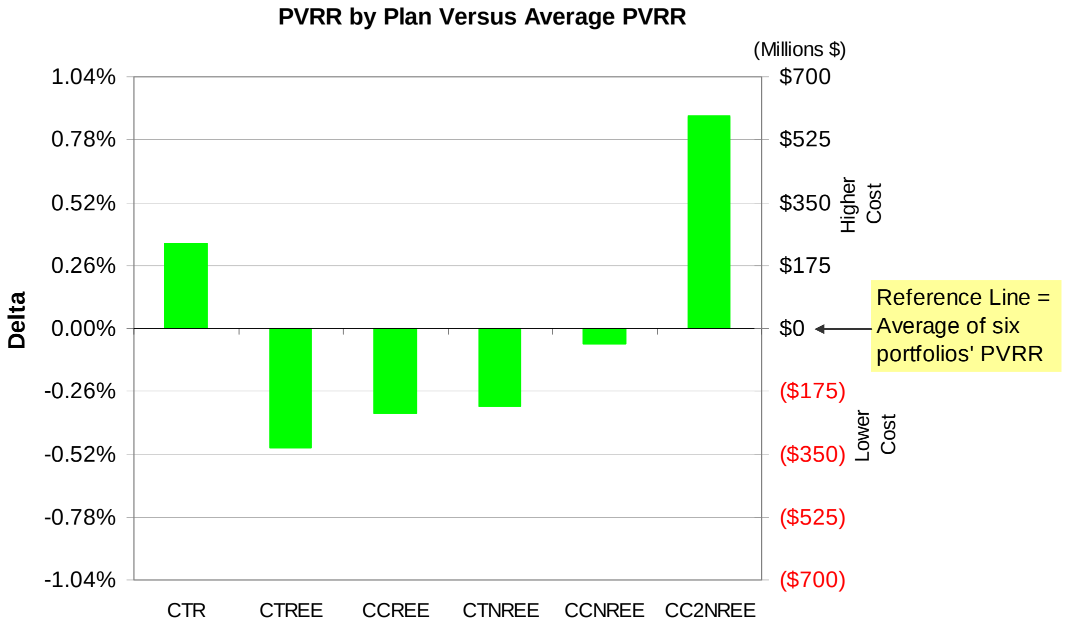
Sensitivity: CC/CT Construction Costs Increase



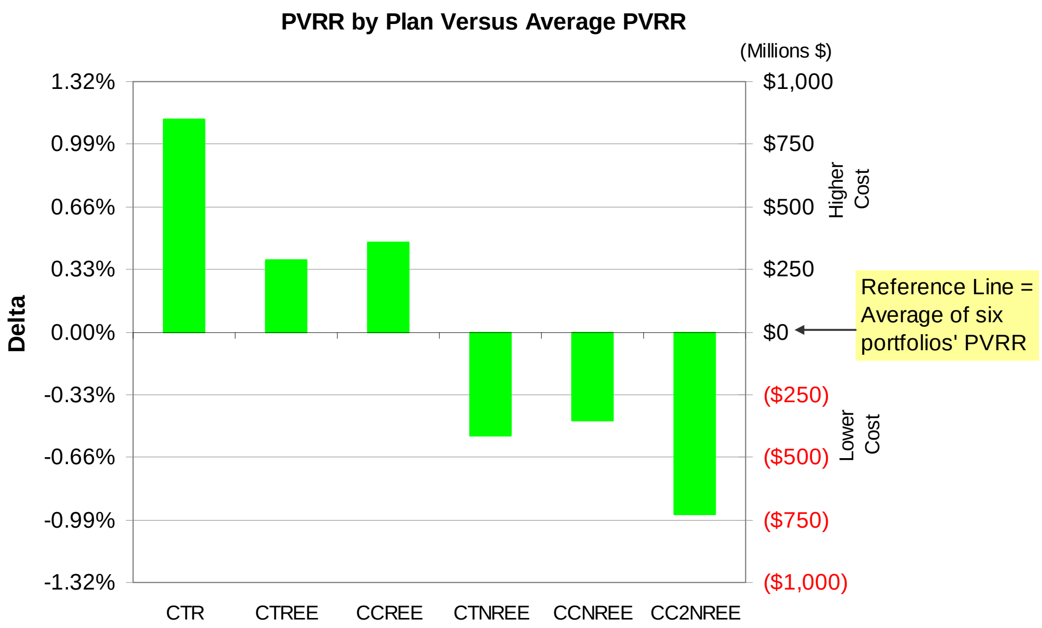
Sensitivity: Nuclear Construction Costs Increase



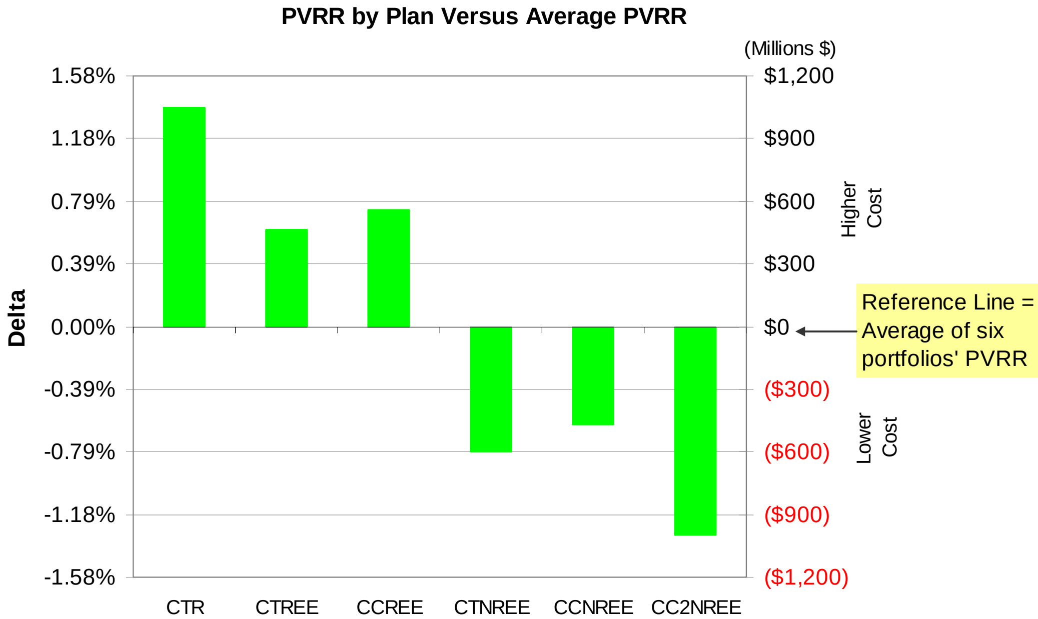
Sensitivity: Alternative Emission Allowance Prices



Sensitivity: High CO_2 Prices



Sensitivity: High CO2 Prices with Higher Natural Gas Prices



The results of the quantitative analyses indicate that significant additions of baseload, intermediate, peaking, EE, DSM, and renewable resources to the Duke Energy Carolinas portfolio are required over the next decade. Conclusions based on these analyses are:

- The new levels of EE and DSM and the save-a-watt methodology are cost-effective for customers
  - ➢ In every scenario and sensitivity, the portfolios with the new EE and DSM were lower cost than the portfolios with the existing EE and DSM
- Significant renewable resources will be needed to meet the new North Carolina Renewable Energy Portfolio Standard (and potentially a federal standard)
- Gas-fired generation is an important part of the portfolio
- The addition of combined-cycle capacity provides additional flexibility and hedging capability
  - ➢ The long-term costs (as measured by PVRR) for the CC portfolios and the CT portfolios are nearly identical
  - ➢ Adding CCs will diversify Duke Energy Carolinas' portfolio which currently has no CCs in its resource mix
  - ➢ The CT portfolios have higher modeled CT capacity factors than would normally be expected
- Continuing to pursue regulatory approval of new nuclear facilities is prudent and allows the company to preserve the nuclear option
  - ➢ Under Carbon Case conditions, the portfolios with nuclear capacity perform well

- In the High Carbon sensitivity, portfolios with two nuclear units are superior to those with one or no nuclear units
- The analyses performed did not include the potential value of production tax credits for the nuclear alternatives, which would improve the relative economics of portfolios with nuclear units.

Based on the above, for the purpose of demonstrating that there will be sufficient resources to meet customers' needs, Duke Energy Carolinas has selected a portfolio which, over the 20-year planning horizon provides for the following: 1,806 MW equivalent of incremental capacity under the new save-a-watt energy efficiency and demand-side management programs, 1,117 MW of new nuclear capacity, 1,240 MW of new Combined Cycle capacity, 3,560 MW of new CT capacity, and 1,135 MW of renewable capacity (i.e., the CCNREE Plan). The plan with CC units early was chosen over the plan with CTs in the early years because of the nearly identical long-term costs, the higher than normal CT capacity factors shown in the modeled CT portfolio (indicating a need for more intermediate capacity), and the lack of CC capacity currently in the Duke Energy Carolinas generation portfolio.

Significant challenges remain such as obtaining the necessary regulatory approvals to implement the EE and DSM programs and supply side resources and finding sufficient cost-effective, reliable renewable resources to meet the standard, integrating renewables into the resource mix, and ensuring sufficient transmission capability for these resources.

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
2007 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
Energy Efficiency and Demand-Side Options and Supply-Side Options Referenced in the Annual Plan	Duke Energy Carolinas Current State section for existing EE and DSM and Appendix I for supply-side and EE 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 EE and 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 EE and DSM 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 EE and DSM 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
Legislative and Regulatory Issues	Appendix M

APPENDIX C: 2007 FERC Form 715

The 2007 FERC Form 715 filed April 2007 is confidential and filed under seal.

APPENDIX D: EXISTING ENERGY EFFICIENCY (EE) AND DEMAND-SIDE MANAGEMENT (DSM) PROGRAMS

The following describes the existing EE and DSM programs offered by Duke Energy Carolinas. Duke Energy Carolinas previously offered the Curtailable Service Program (Rider CS), a pilot program, but the program has been cancelled, as approved by both the North Carolina and South Carolina commissions. The tables at the end of this appendix list the existing DSM projection and activation history.

<u>Current Energy Efficiency and Demand-Side Management Programs</u>

The following demand response programs are designed to provide a source of interruptible capacity to Duke Energy Carolinas:

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.

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 the Duke Energy Carolinas system and therefore, cannot "backfeed" (i.e., 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.

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
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.

Conservation 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. EPA and the U.S. Department of Energy (DOE). 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.

The Commission's May 22, 2006 Order Approving the Joint Recommendation of Duke Energy Carolinas, the Public Staff, and the Attorney General for Conservation and Energy

Efficiency Programs approved the programs and required Duke Energy Carolinas to file a status report as to the funding and implementation of the programs on or before July 2, 2007. Duke Energy Carolinas has completed the contribution requirements to Energy Efficiency and Conservation through the programs listed above. The following provides descriptions of the initiatives undertaken and the impacts to customers.

Energy Efficiency Kits for Residential Customers
This program was offered in 2006-2007 as part of the NC Commission's May 22, 2006 Order Approving the Joint Recommendations of Duke Energy Carolinas, the Public Staff, and the Attorney General for Conservation and Energy Efficiency Programs. As part of this order, Duke Energy Carolinas distributed energy efficiency starter kits with energy saving measures including a low flow shower head, window sealant material, high efficiency fluorescent bulbs, weather stripping, wall outlet and switch plate insulation material, and faucet aerators. Total program costs were $685,934.

Approximately 60,000 kits were distributed to residential customers in North Carolina through various channels including North Carolinas Assistance Agencies and in conjunction with Duke Energy Carolinas' Personalized Energy Report program. Duke Energy Carolinas surveyed a number of participants and currently estimates an average energy savings of 403 kWh per kit, yielding a total estimated annual savings of 24,200 MWh for all kits distributed. These savings estimates are for the measures only and do not include any customer behavioral changes or additional measures purchased by the customer after exposure to the kit and other DSM materials.

Energy Efficiency Video for Residential Customers
This program was offered in 2006-2007 as part of the NC Commission's May 22, 2006 Order Approving the Joint Recommendations of Duke Energy Carolinas, the Public Staff, and the Attorney General for Conservation and Energy Efficiency Programs. Duke Energy Carolinas distributed a home education, video-based energy efficiency series for residential customers for a cost of $177,109. Individual videos covered energy saving tips for summer, winter, around the house, humidity, and HVAC.

The video series was distributed on DVD to approximately 135,600 customers through various channels including NC Assistance Agencies, Duke Energy Carolinas' Personalized Energy Report program, and Duke Energy Carolinas pay locations. The videos are also available on Duke Energy's website at http://www.duke-energy.com/north-carolina/savings/energy-efficiency-videos.asp and have been viewed by approximately 1,000 customers since April 2007. The videos focus on energy savings and comfort improvement in the home as well as provide several no cost/low cost tips for saving energy. Information presented may also be useful for a homeowner when making an equipment purchase decision. All DVDs and EE kits were delivered to customers in 2007.

Large Business Customer Energy Efficiency Assessments
This program was offered in 2006-2007 as part of the NC Commission's May 22, 2006 Order Approving the Joint Recommendations of Duke Energy Carolinas, the Public Staff,

and the Attorney General for Conservation and Energy Efficiency Programs. Duke Energy Carolinas provided phone-based and on-site energy efficiency assessments to North Carolina commercial, industrial, and institutional customers. Where applicable, companies partnering with Duke Carolinas to provide assessments used energy simulation software to develop models for customer facilities.

Approximately 100 customer facilities participated in a phone-based and/or on-site assessment. Total program costs were $1,152,123.

Customers participating in the assessments received energy saving recommendations in areas such as compressed air, lighting, air washers, cooling towers, building solar loads, hot water, HVAC, and boilers. The reports also presented general energy consumption histories including trending and identification of potential usage anomalies. Where applicable, customers received Energy Star® benchmark ratings in order to compare their facilities to others throughout the nation.

Based on the completed assessments, North Carolina customers have been presented opportunities to save approximately 118,000 MWh of energy and 8,000 kW of demand resulting in a potential financial savings for customers of approximately $7 million per year.

Large Business Customer Energy Efficiency Tools

This program was offered in 2006-2007 as part of the NC Commission's May 22, 2006 Order Approving the Joint Recommendations of Duke Energy Carolinas, the Public Staff, and the Attorney General for Conservation and Energy Efficiency Programs. Duke Energy Carolinas provided an online assessment tool for commercial, manufacturing, and institutional customers through Duke Energy Carolinas' Business Services Newsline. This assessment tool was developed through cooperation between Duke Energy Carolinas and the provider of the Newsline service and resulted in no additional cost to Duke Energy Carolinas.

Approximately 40 customers have used the online tool to generate a report of potential energy-saving opportunities. The online audits provide energy-saving ideas for customers in a general manner based on customer responses to a few questions. The report provides numerous links to articles in the Newsline for areas of particular interest.

As stated above, Duke Energy Carolinas worked with several partners to perform Energy Efficiency Assessments. Where applicable, additional energy efficiency modeling tools such as eQuest (a U.S. DOE modeling tool found at www.doe2.com) and Energy Star® Portfolio Manager were used to further evaluate customer facilities and enhance the value of the assessments.

Existing EE and DSM Program Details

Impacts of Existing EE and Demand-Side Management Programs

	Projected Conservation Impacts		Projected MW Demand Response Impacts - Summer					
	MWH	MW	Load Control		Interruptible			Total Peak
Year	$2 Million Program		AC	WH	IS	SG	Total	Impacts
2008	4,394	1	236	4	277	84	602	603
2009	4,394	1	223	4	248	85	560	561
2010	4,394	1	210	4	219	86	519	520
2011	4,394	1	198	3	190	87	479	480
2012	4,394	1	188	3	161	89	441	442
2013	4,394	1	177	3	132	90	402	403
2014	4,394	1	167	3	132	91	392	393
2015	4,394	1	157	2	132	92	384	385
2016	4,394	1	148	2	132	93	376	377
2017	4,394	1	140	2	132	94	368	369
2018	4,394	1	132	2	132	95	361	362
2019	4,394	1	124	2	132	96	354	355
2020	4,394	1	117	1	132	97	347	348
2021	4,394	1	110	1	132	98	342	343
2022	4,394	1	104	1	132	99	336	337
2023	4,394	1	98	1	132	100	331	332
2024	4,394	1	92	1	132	101	326	327
2025	4,394	1	87	1	132	103	322	323
2026	4,394	1	82	1	132	104	318	319
2027	4,394	1	77	1	132	105	314	315

See Appendix I for tables that include projections for proposed EE and DSM programs.

DEMAND-SIDE MANAGEMENT ACTIVATION HISTORY

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
8/06 – 8/07	Air Conditioners	Cycling Test	N/A	N/A	8/30/2007
		Load Test (PLC only)	N/A	N/A	8/7/2007
		Load Test	120 MW	88 MW	8/2/2007
	Water Heaters	Cycling Test	N/A	N/A	8/30/2007
		Load Test (PLC only)	N/A	N/A	8/7/2007
		Load Test	2 MW	Included in Air Conditioners.	8/2/2007
	Standby Generators	Capacity Need	82 MW	88 MW	8/10/2007
		Capacity Need	82 MW	90 MW	8/9/2007
		Capacity Need	82 MW	79 MW	8/8/2007
		Capacity Need	82 MW	85 MW	8/1/2006
		Monthly Test			
	Interruptible Service	Capacity Need	306 MW	301 MW	8/10/2007
		Capacity Need	306 MW	323 MW	8/9/2007
		Capacity Need	341 MW	391 MW	8/1/2006
		Communicaton Test	N/A	N/A	4/24/2007
8/05 – 7/06	Air Conditioners	Load Test	110 MW	107 MW	6/21/2006
		Cycling Test	N/A	N/A	9/21/2005
		Cycling Test	N/A	N/A	9/20/2005
	Water Heaters	Load Test	2 MW	Included in Air Conditioners.	6/21/2006
		Cycling Test	N/A	N/A	9/21/2005
		Cycling Test	N/A	N/A	9/20/2005
	Standby Generators	Monthly Test			
	Interruptible Service	Communicaton Test	N/A	N/A	4/25/2006
8/04 – 7/05	Air Conditioners	Load Test	140 MW	148 MW	7/21/2005
		Cycling Test	N/A	N/A	8/19/2004
		Cycling Test	N/A	N/A	8/18/2004
	Water Heaters	Load Test	2 MW	Included in Air Conditioners.	7/21/2005
		Cycling Test	N/A	N/A	8/19/2004
		Cycling Test	N/A	N/A	8/18/2004
	Standby Generators	Monthly Test			
8/03 – 7/04	Air Conditioners	Load Test	110 MW	170 MW	7/14/2004
		Cycling Test	N/A	N/A	8/20/2003
	Water Heaters	Cycling Test	N/A	N/A	8/20/2003
	Standby Generators	Monthly Test			
	Interruptible Service	Communicaton Test	N/A	N/A	4/28/2004

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
8/02 – 7/03	Air Conditioners	Load Test	120 MW	195 MW	7/16/2003
		Cycling Test	N/A	N/A	6/18/2003
		Cycling Test	N/A	N/A	9/18/2002
		Load Test	82 MW	122 MW	8/21/2002
	Water Heaters	Load Test	5 MW	Included in Air Conditioners.	7/16/2003
		Cycling Test	N/A	N/A	6/18/2003
		Cycling Test	N/A	N/A	9/18/2002
		Load Test	6 MW	Included in Air Conditioners.	8/21/2002
	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	5/7/2003
		Communication Test	N/A	N/A	11/19/2002
8/01 – 7/02	Air Conditioners	Cycling Test	N/A	N/A	7/17/2002
		Cycling Test	N/A	N/A	6/19/2002
		Cycling Test	N/A	N/A	8/31/2001
		Load Test	150 MW	151 MW	8/17/2001
	Water Heaters	Cycling Test	N/A	N/A	7/17/2002
		Cycling Test	N/A	N/A	6/19/2002
		Cycling Test	N/A	N/A	8/31/2001
		Load Test	6 MW	Included in Air Conditioners.	8/17/2001
	Standby Generators	Capacity Need	80 MW	20 MW Estimation due to communication problems.	6/13/2002
		Monthly Test			
	Interruptible Service	Capacity Need	403 MW	370 MW	6/13/2002
		Communication Test	N/A	N/A	4/17/2002
8/00 – 7/01	Air Conditioners	Communication Test	N/A	N/A	9/14/2000
	Water Heaters	Communication Test	N/A	N/A	9/14/2000
	Standby Generators	Capacity Need	70 MW	70 MW	8/7/2000
		Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	5/8/2001
7/99 – 8/00	Air Conditioners	Load Test	170-200 MW	175-200 MW	6/15/2000
	Water Heaters	Load Test	6 MW	Included in Air Conditioners.	6/15/2000
	Standby Generators	Capacity Need	70 MW	70 MW	7/2/2000
		Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	5/17/2000
		Communication Test	N/A	N/A	10/20/1999

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
9/98 – 7/99	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	5/11/1999
		Communication Test	N/A	N/A	10/27/1998
9/97 – 9/98	Air Conditioners	Load Test	180 MW	170 MW	8/18/1998
	Water Heaters	Load Test	7 MW	7 MW	8/18/1998
		Communication Test	N/A	N/A	5/29/1998
	Standby Generators	Capacity Need	68 MW	58 MW	8/31/1998
		Capacity Need	68 MW	58 MW	6/12/1998
		Monthly Test			
	Interruptible Service	Capacity Need	570 MW	500 MW	8/31/1998
		Communication Test	N/A	N/A	5/29/1998
9/96 – 9/97	Air Conditioners	Communication Test	N/A	N/A	6/17/1997
	Standby Generators	Capacity Need	62 MW	50 MW	7/28/1997
		Capacity Need	62 MW	50 MW	7/15/1997
		Capacity Need	62 MW	50 MW	7/14/1997
		Capacity Need	62 MW	50 MW	12/20/1996
		Monthly Test			
	Interruptible Service	Capacity Need	650 MW	550 MW	7/28/1997
		Communication Tests	N/A	N/A	6/17/1997
		Communication Tests	N/A	N/A	10/16/1996

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 Unit
On March 21, 2007, the NCUC granted a CPCN for the construction of one 800-MW supercritical pulverized coal unit at the existing Cliffside Station. A number of conditions were also part of the order, including: 1) retiring the existing Cliffside Units 1-4 no later than the commercial operation date of the new unit, 2) honoring Duke Energy Carolinas' commitment to invest 1% of its annual retail revenues in energy efficiency and demand-side management programs (subject to the results of the ongoing collaborative workshops and appropriate regulatory treatment), and 3) that Duke Energy Carolinas shall retire older coal-fired generating units (in addition to Cliffside Units 1-4) on a MW-for-MW basis, considering the impact on the reliability of the system to account for actual load reductions realized from the new EE and DSM programs up to the MW level added by the new Cliffside unit. On May 30, 2007, Duke Energy Carolinas filed the first updated estimated cost of Cliffside 6 with the Commission as required by the Commission's order. Cost estimate reports continue to be filed on a monthly basis.

The draft air permit was issued for public comment and there was a public hearing on September 18, 2007. A final permit is anticipated to be issued by year end 2007. Other permit approvals such as erosion control permits, wastewater discharge permits, and landfill permits are expected over the next year. Construction is expected to start in the first quarter of 2008.

Bridgewater Hydro Powerhouse Upgrade
Seismic remediation requirements for the Linville Dam at Lake James resulted in a compacted fill design that would require removal of the existing Bridgewater powerhouse and generation. There were two options to accomplish water release: 1) installation of flow valves, or 2) a new powerhouse and generation equipment. The latter option was selected with the two existing 11.5 MW units being replaced by two 15 MW units and a small 1.5 MW unit to be used to meet continuous release requirements. The NCUC granted a CPCN to install the new replacement powerhouse and generation equipment on June 7, 2007. The current schedule projects powerhouse construction to begin in March 2008 with a release to dispatch date of June 2010.

Pending CPCN Proceedings

Buck Combined Cycle Unit

On June 29, 2007, the Company filed preliminary CPCN information for adding approximately 600-800 MW of combined cycle generation at the Buck Steam Station in Salisbury, N.C. A CPCN application is expected to be filed by the end of 2007. The CPCN approval is anticipated to be received by the beginning of the third quarter of 2008. The air permit application is expected to be submitted during the fourth quarter of 2007, with the final permit expected to be received by the third quarter of 2008. The unit may be "phased-in" so that the simple cycle capacity would be available for operation by the summer of 2010, with the combined cycle operation available by the summer of 2011.

Dan River Combined Cycle Unit

On June 29, 2007, the Company also filed preliminary CPCN information for adding approximately 600-800 MW of combined cycle generation at the Dan River Steam Station in Eden, N.C. A CPCN application is expected to be filed by the end of 2007. The unit may also be "phased-in" so that the simple cycle capacity would be available for operation by the summer of 2011, with the combined cycle operation available by the summer of 2012.

Other Planned Units

New William States Lee III Nuclear Station Generating Units

In 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. Site characterization work is now complete. Currently, the Combined Construction and Operating License (COL) application is being finalized with submittal to the NRC planned for December 2007. Duke Energy continues working with the nuclear industry on plant standardization and design finalization.

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 10 of the LCR Table 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 unknown locations 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
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
Duke – CPLE tie line	230 kV	Pleasant Garden Tie to Asheboro Switchyard	Minimum of 1100 MVA	6/1/2011

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, 423.3, 424, 425, and 450.1.)

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

Nantahala – Fontana 161 kV Line
- Commission docket number: No docket required due to existing line rebuild
- Location of end point(s): Macon County, NC – Graham County, NC
- Length: 20 Miles
- Range of right-of-way width: 225 ft
- Range of tower heights: 140 ft
- Number of circuits: 1 additional circuit
- Operating voltage: 161 kV
- Design capacity: 500 MVA / Circuit

- Date construction started: February 15, 2007
- Projected in-service date: August 1, 2009

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

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: ENERGY EFFICIENCY, DEMAND-SIDE MANAGEMENT, AND SUPPLY-SIDE OPTIONS REFERENCED IN THE PLAN.

Supply-Side Options

Supply-side options considered in the IRP are subjected to an economic screening process to determine the most cost-effective technologies to be passed along for consideration in the quantitative analysis phase of the process. Generally, 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 being screened is based on research and information from several sources. In addition to internal sources, bids from the Renewable RFP, the Electric Power Research Institute (EPRI) Technology Assessment Guide (TAG®), and studies performed by and/or information gathered from entities such as the DOE, LaCapra, Navigant, Fibrowatt, and others were used in the estimation of capital and operating costs, and operational characteristics for the supply-side alternatives. The EPRI information along with any information or estimates from external studies is not site-specific, but generally reflects the costs and operating parameters for installation in the Southeast.

Finally, every effort is made to ensure, as much as possible, that the cost and other parameters are current, on a common basis, and include similar scope across the technology types being screened. While this has always been important, keeping cost estimates across a variety of technology types consistent in today's construction material, manufactured equipment, and commodity markets is getting very difficult to maintain. The rapidly escalating prices in these markets often make cost estimates and other price/cost information out-of-date in as little as six months. In addition, vendor quotes once relied upon as being a good indicator of, or basis for, the cost of a generating project, may have lives as short as 30 days.

In the 2006 IRP, a list of eighty-eight supply-side resources was developed as potential alternatives for the IRP process. Learning and experience from the 2006 analyses allowed a more focused approach to resource screening for this IRP. As a result, less effort was spent on economically screening the multiple sizes and similar technology variants such as greenfield/brownfield, single rail/dual rail and single/multiple units of the specific technologies. In the 2006 IRP, the largest sizes of each technology were the lowest cost due to economies of scale, and the differences caused by the other variations were minor. The elimination of some of these variations allowed more time to concentrate on ensuring consistency of treatment across the technologies. This approach also allowed the Company to examine renewable technologies such as wind, biomass, hydro, animal waste, and solar in more depth in this year's analysis.

From the remaining subset of alternatives, several additional technologies were eliminated from further consideration. A brief explanation of the technologies excluded and the logic for their exclusion follows:

- Coal-fired Circulating Fluidized Bed combustion is a conventional, commercially-proven technology in utility use. However, boiler size remains generally limited to 300-350 MW. In addition, the new source performance standards (NSPS) generally dictate that post-boiler clean-up equipment must be installed to meet the standards when burning coal, which effectively eliminates one of the advantages of this technology. Both of these issues cause it to be one of the higher-cost baseload alternatives available on a utility scale.

- Advanced Battery storage technologies remain relatively expensive and are generally suitable for small-scale emergency back-up and/or power quality applications with short-term duty cycles of three hours or less. In addition, the current energy storage capability is generally 100 MWh or less. Research, development, and demonstration continue, but this technology is generally not commercially available on a larger utility scale.

- Compressed Air Energy Storage (CAES), although demonstrated on a utility scale and generally commercially available, is not a widely applied technology. This is due to the fact that suitable sites that possess the proper geological formations and conditions necessary for the compressed air storage reservoir are relatively scarce. There are no viable sites in the Duke Energy Carolinas service territory to support the application of this technology.

- Fuel Cells, although originally envisioned as being a competitor for combustion turbines and central power plants, are now targeted to mostly distributed power generation systems. The size of the distributed generation applications ranges from a few kilowatts to tens of megawatts in the long-term. Cost and performance issues have generally limited their application to niche markets and/or subsidized installations. While a medium level of research and development continues, this technology is not commercially available for utility-scale application.

Below is a listing of the technologies screened, placed into general Conventional and Demonstrated categories:

Conventional Technologies (technologies in common use):

<u>Base Load Technologies</u>
800 MW class Supercritical Coal (Greenfield)
2-1117 MW Nuclear units, AP1000

<u>Peak / Intermediate Technologies</u>
4-160 MW Combustion Turbines – GE 7FA
460 MW Unfired + 120 MW Duct Fired + 40 MW Inlet Chilling Combined Cycle – 7FA

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

Base Load Technologies
630 MW class IGCC (Brownfield)

In anticipation of the state of North Carolina passing RPS legislation, Duke Energy Carolinas issued an RFP for renewable resources on April 20, 2007; bids were received at the end of July 2007. The bids were of the following types:

- On-Shore Wind
- Off-Shore Wind
- Biomass
  - Biomass Firing
  - Poultry Waste Firing
  - Digester Biogas Firing
  - Hog Digester Biogas Firing
- Solar PV
- Landfill Gas
- Biodiesel Firing

The analysis for the IRP utilized an average composite of the bids to perform the renewables screening since this was the most up-to-date information available.

This year a slightly different approach to screening was utilized, in that the renewable technologies were screened within their own category, rather than being screened together with conventional technologies within the baseload or peaking/intermediate categories.

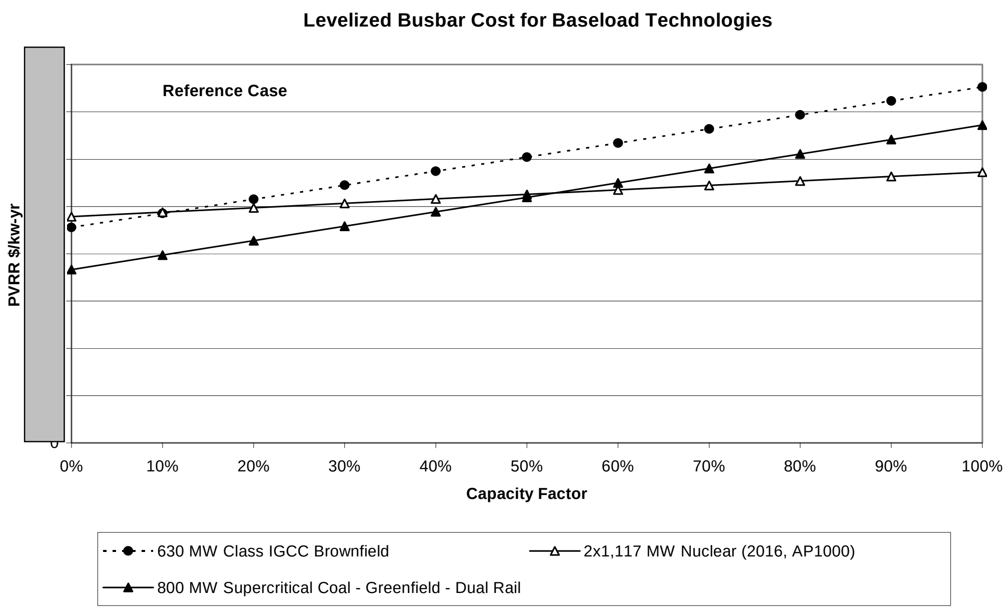
The technologies were screened under both Reference Case and Carbon Case assumptions. The Reference Case includes the impacts of the traditional regulated emissions of SO_2, NOx, and mercury generally associated with the Clean Air Act Amendments of 1990, the USEPA CAIR/CAMR, and the 2002 North Carolina Clean Smokestacks Act. The Carbon Case also includes consideration of CO_2 regulations and a Renewable Portfolio Standard. These scenarios were discussed in more detail in Appendix A.

The following sets of estimated Levelized Busbar Cost[13]charts provide an economic comparison of the technologies considered both under the Reference Case and the Carbon Case scenarios.

[13] While these estimated 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.

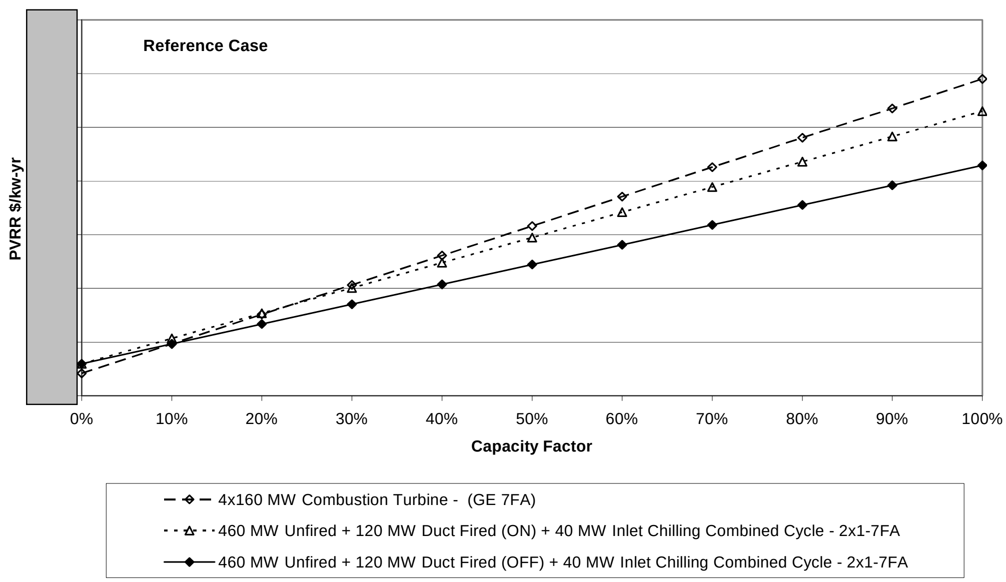
One must remember that busbar charts comparisons involving some renewable resources, particularly wind and solar resources, can be somewhat misleading. The reason for this is that these resources do not contribute their full installed capacity at the time of the system peak[14]. Since busbar charts attempt to levelize and compare costs on an installed kW basis, wind and solar resources appear to be more economic than they would be if the comparison was performed on a peak kW basis. In addition, because the costs utilized in the screening for the Renewable resources were based on "must take" bids at specified capacity factors, the Renewables Busbar Chart shows a single point for each type of resource at the particular capacity factor specified.

Reference Case Busbar Charts by Technology Category



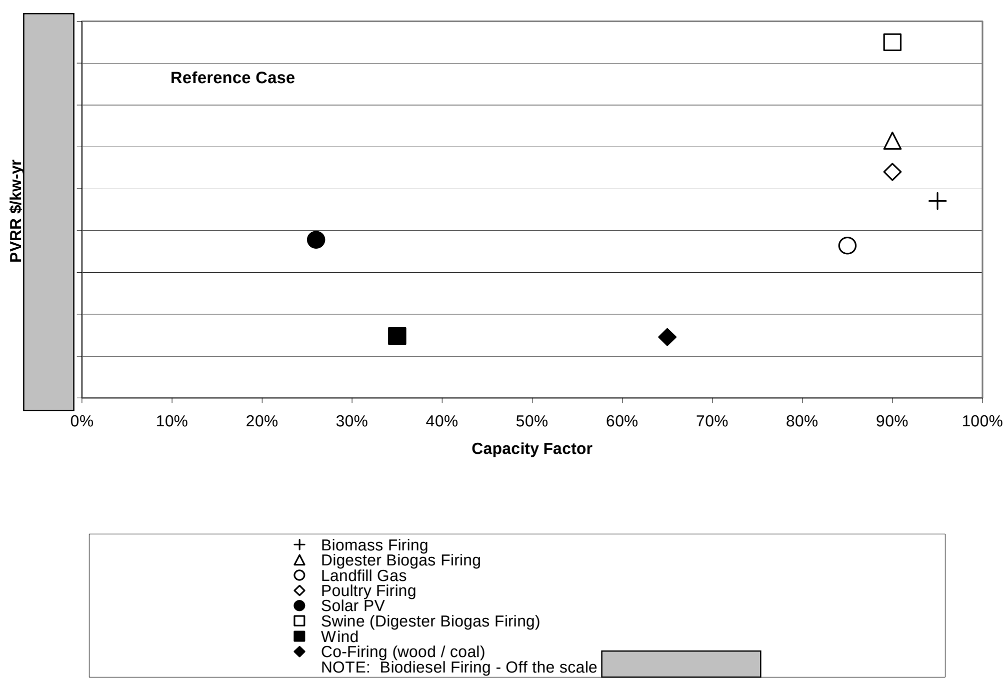
[14] For purposes of this Annual Plan, wind resources are assumed to contribute 15% of installed capacity at the time of peak and solar resources are assumed to contribute 70% of installed capacity at the time of peak.

Levelized Busbar Cost for Peak / Intermediate Technologies



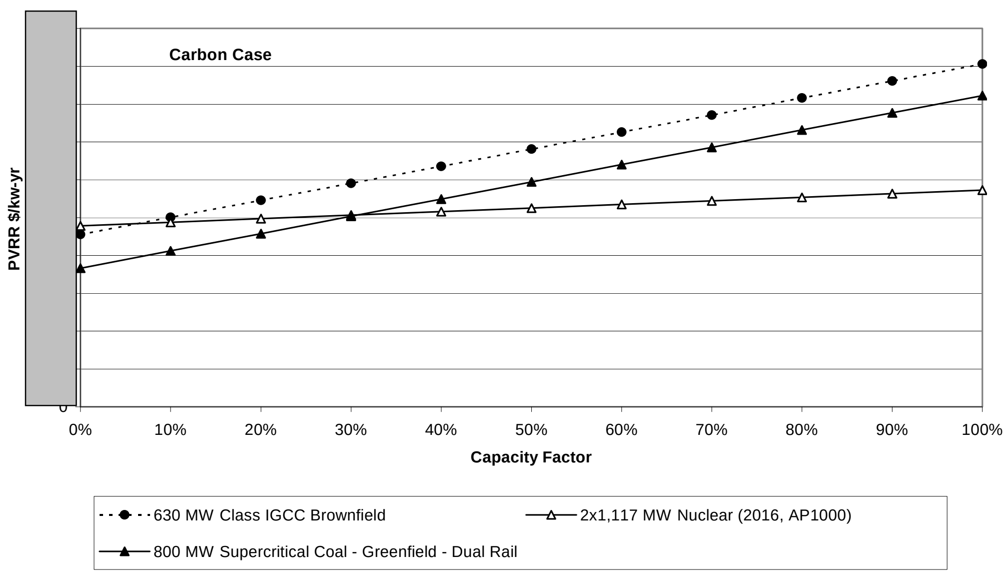
Note: The combined cycle alternative has been shown two ways in the above busbar chart: with the duct firing on and with it off. The unit alternatives are identical in that both curves include the capital costs of duct firing equipment; the only difference in the curves is the additional cost (loss in efficiency) to operate the duct firing equipment to achieve the higher level of unit capacity.

Levelized Busbar Cost for Renewable Technologies

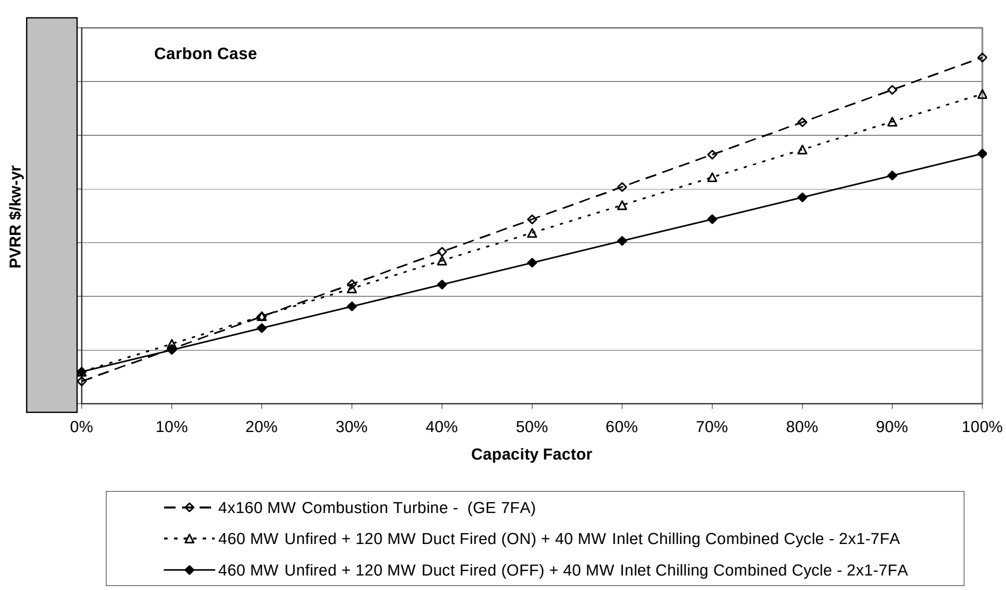


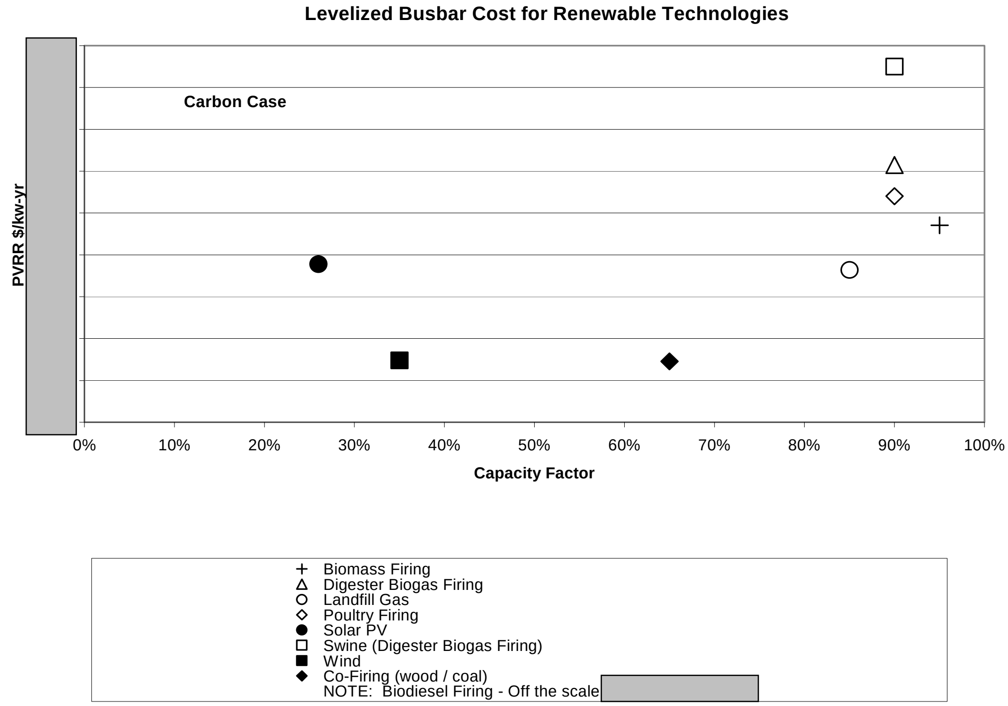
Carbon Case Busbar Charts by Technology Category

Levelized Busbar Cost for Baseload Technologies



Levelized Busbar Cost for Peak / Intermediate Technologies





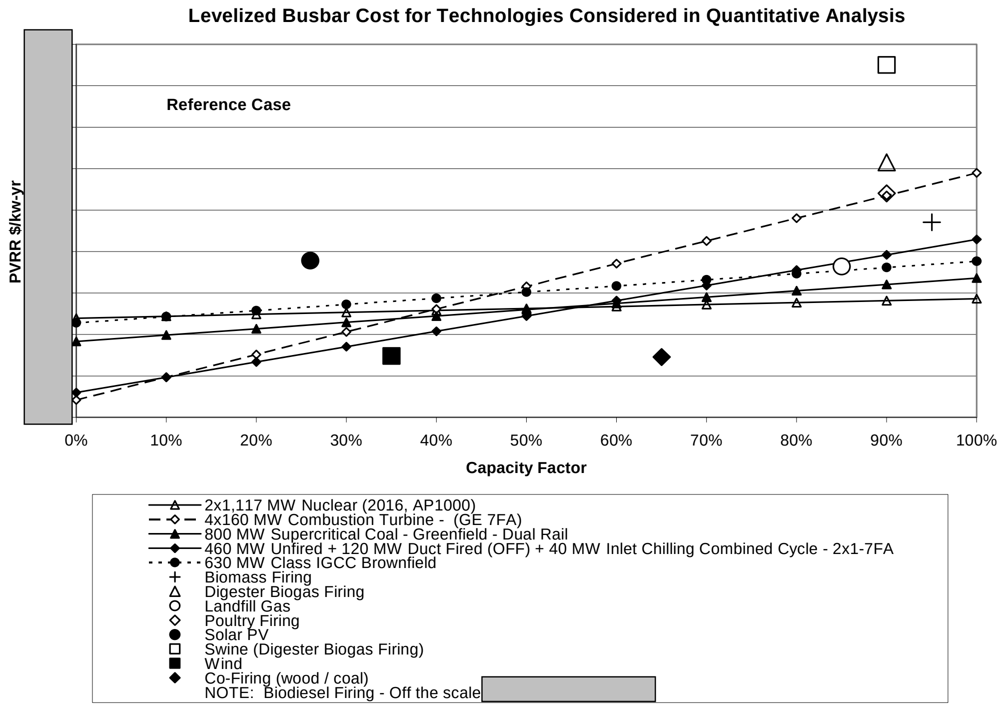
Technologies from each of the three general categories screened (Baseload, Peaking/Intermediate, and Renewables) which were the "best," i.e., the lowest levelized busbar cost for a given capacity factor range within each of these categories, were passed on to the quantitative analysis phase for further evaluation. Due to the modeling of a RPS in this IRP, more Renewable technologies were passed to the quantitative analysis phase than what the screening curve analysis showed to be economic.

The following technologies were selected for the quantitative analysis for both the Reference Case and the Carbon Case:

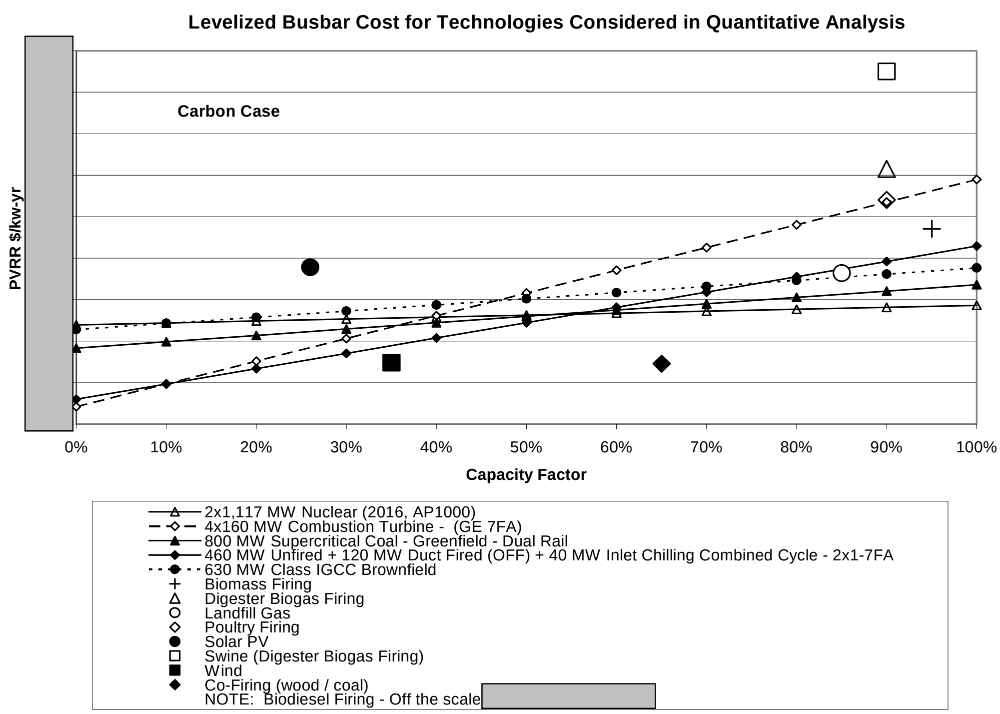
- Base Load – 800MW Supercritical Pulverized Coal
- Base Load – 630 MW IGCC
- Base Load – 2-1,117MW Nuclear units (AP1000)
- Peaking/Intermediate – 4-160MW Combustion Turbines (7FA)
- Peaking/Intermediate –460 MW Unfired+120MW Duct Fired+40MW Inlet Chilled N. Gas Combined Cycle
- Renewable – 50 MW Wind PPA - On-Shore
- Renewable - Solar Photovoltaic PPA
- Renewable - Biomass Firing PPA
- Renewable –Hog Waste Digester PPA
- Renewable –Poultry Waste PPA

The two charts below show the technologies that were the "best" from each of the three general categories screened on one chart for the Reference Case and the Carbon Case.

Reference Case Composite Busbar Chart



Carbon Case Composite Busbar Chart



New Energy Efficiency and Demand-Side Management Programs

In 2006, Duke Energy Carolinas established EE and DSM-related collaborative groups, consisting of stakeholders from across its service area, and charged them with recommending a new set of EE and DSM-related programs for the Company's customers. Collaborative participants include: Environmental Defense, the Sierra Club, North Carolina Sustainable Energy Association (visitor), Environmental Edge Consulting, Air Products, The Timken Company, Lowe's Home Improvement Corporation, Food Lion, Greenville County Schools, Charlotte-Mecklenburg Schools, University of North Carolina Chapel Hill, University of South Carolina Upstate, South Carolina State Energy Office, North Carolina State Energy Office, North Carolina Attorney General's Office, South Carolina Office of Regulatory Staff, NCUC Public Staff, Duke Energy Carolinas, and Advanced Energy (as meeting facilitator). Collaborative efforts to date have been very productive, resulting in the Company's May 7, 2007 North Carolina Energy Efficiency Filing[15], September 28, 2007 South Carolina Energy Efficiency Filing[16], and the proposed implementation of approximately 1,865 MW and 743 GWh of EE and DSM across North and South Carolina by 2011. Future Measurement and Verification (M&V) analyses along with ongoing product management decisions will be utilized to incorporate updated information into the Company's IRP.

Below is a summary of the proposed demand response and conservation programs that were considered in the resource planning process.

Demand Response Programs

Power Manager

Power Manager is a residential load control program. Participants receive billing credits during the billing months of July through October in exchange for allowing Duke Energy Carolinas the right to cycle their central air conditioning systems and, additionally, to interrupt the central air conditioning when the Company has capacity needs.

Information about the Power Manager program will be provided in bill inserts and on Duke Energy Carolinas' Web site, but the program will not be actively marketed until two-way communication is available.

Duke Energy Carolinas has proposed to convert customers from the previous Rider LC onto this program and may add other customers who wish to participate.

PowerShare®

PowerShare® is a non-residential curtailable program consisting of two options, an Emergency Option and a Voluntary Option. The Emergency Option customers will receive capacity credits monthly based on the amount of load they agree to curtail during utility-initiated emergency events. Customers enrolled in the Emergency Option may also be enrolled in the Voluntary Option and eligible to earn additional credits. Voluntary

[15] Docket No. E-7, Sub 831
[16] PSCSC Docket No. 2007-358-E

Option customers will be notified of pending emergency or economic events and can log on to a Web site to view a posted energy price for that particular event. Customers will then have the option to nominate load for the event and will be paid the posted energy credit for load curtailed.

Duke Energy Carolinas has proposed to convert customers from the previous Rider IS and Rider SG onto this program and may add other customers who wish to participate.

Conservation Programs

Residential Energy Assessments
This program will assist residential customers in assessing their energy usage and provide recommendations for more efficient use of energy in their homes. The program will also help identify those customers who could benefit most by investing in new demand-side management measures, undertaking more energy-efficient practices and participating in Duke Energy Carolinas programs. The types of available energy assessments and demand-side management products are as follows:

- Mail-in Analysis. The customer provides information about their home, number of occupants, equipment, and energy usage on a mailed energy profile survey, from which Duke Energy Carolinas will perform an energy use analysis and provide a Personalized Home Energy Report including specific energy-saving recommendations.
- Online Analysis. The customer provides information about their home, number of occupants, energy usage and equipment through an online energy profile survey. Duke Energy Carolinas will provide an Online Home Energy Audit including specific energy-saving recommendations.
- On-site Audit and Analysis. Duke Energy Carolinas will perform one on-site assessment of an owner-occupied home and its energy efficiency-related features during the life of this program.
- Low-Income Multi-Family Assessment Pilot. Duke Energy Carolinas will select property managers to coordinate communication and scheduling of property audits with tenants. Assessments will focus primarily on building envelope and HVAC.

Smart $aver® for Residential Customers
The Smart $aver® Program will provide incentives to residential customers who purchase energy-efficient equipment. The program has two components – compact fluorescent light bulbs and high-efficiency air conditioning equipment.

This residential compact fluorescent light bulbs (CFLs) incentive program will provide market incentives to customers and market support to retailers to promote use of CFLs. Special incentives to buyers and in-store support will increase demand for the products, spur store participation, and increase availability of CFLs to customers. Part of this program is to educate customers on the advantages (functionality and savings) of CFLs so that they will continue to purchase these bulbs in the future when no direct incentive is available.

The residential air conditioning program will provide incentives to customers, builders, and heating contractors (HVAC dealers) to promote the use of high-efficiency air conditioners and heat pumps with electronically-commutated fan motors (ECM). The program is designed to increase the efficiency of air conditioning systems in new homes and for replacements in existing homes.

Low Income Services
The purpose of this program is to assist low income residential customers with demand-side management measures to reduce energy usage through energy efficiency kits or through assistance in the cost of equipment or weatherization measures.

Energy Efficiency Education Program for Schools
The purpose of this program is to educate students about sources of energy and energy efficiency in homes and schools through a curriculum provided to public and private schools. This curriculum includes lesson plans, energy efficiency materials, and energy audits.

Non-Residential Energy Assessments
The purpose of this program is to assist non-residential customers in assessing their energy usage and to provide recommendations for more efficient use of energy. The program will also help identify those customers who could benefit from other Duke Energy Carolinas DSM non-residential programs.

The types of available energy assessments are as follows:

- Online Analysis. The customer provides information about their facility. Duke Energy Carolinas will provide a report including energy-saving recommendations.
- Telephone Interview Analysis. The customer provides information to Duke Energy Carolinas through a telephone interview, after which billing data, and, if available, load profile data, will be analyzed. Duke Energy Carolinas will provide a detailed energy analysis report with an efficiency assessment along with recommendations for energy-efficiency improvements. A 12-month usage history may be required to perform this analysis.
- On-site Audit and Analysis. For customers who have completed either an Online Analysis or a Telephone Interview Analysis, Duke Energy Carolinas will cover 50% of the costs of an on-site assessment. Duke Energy Carolinas will provide a detailed energy analysis report with an efficiency assessment along with recommendations, tailored to the customer’s facility and operation, for energy efficiency improvements. The Company reserves the right to limit the number of off-site assessments for customers who have multiple facilities on the Duke Energy Carolinas system. Duke Energy Carolinas may provide additional engineering and analysis, if requested, and the customer agrees to pay the full cost of the additional assessment.

Smart $aver® for Non-Residential Customers
The purpose of this program is to encourage the installation of high-efficiency equipment in new and existing non-residential establishments. The program will provide incentive payments to offset a portion of the higher cost of energy-efficient equipment. The following types of equipment are eligible for incentives: high-efficiency lighting, high-efficiency air conditioning equipment, high-efficiency motors, and high-efficiency pumps. Customer incentives may be paid for other high-efficiency equipment as determined by the Company to be evaluated on a case-by-case basis.

Pilot Programs
A number of Pilot Programs have also been proposed by Duke Energy Carolinas. However, the impacts of these programs have not been included explicitly in the IRP modeling because more research is needed.

Advanced Power Manager Program (Demand Response)
This is a pilot research and development program to evaluate new technologies, advanced metering, and new rate structures to study the feasibility of an energy management system that enables customers to participate in demand-side management without disrupting their lifestyle or normal business operations. This program would include three phases: (1) a technology trial to determine the operating characteristics of the equipment and prove its viability; (2) a customer trial to determine the appropriate offer structure that benefits customers and accomplishes program goals; and (3) a product roll-out, provided the technology and customer trials are successful. Additionally, this program will test demand response load aggregation concepts for non-residential customers. New offers and rate structures developed for this pilot will be filed with the Commission for approval as they are developed.

Residential Bill Check Program (Conservation)
This is a pilot research and development program designed to assist residential customers in assessing their energy usage and to provide recommendations for more efficient use of energy through monitoring of usage. Participants in this program will be provided information on energy usage patterns and alerts when significant changes in usage are detected.

Under this pilot program, the customer will be provided monthly reports including, but not limited to, graphs and comparisons, correlation of bills to weather, other major findings, analysis of impact on energy usage of efficiency measures, and the opportunity to discuss the report with a Duke Energy Carolinas representative each quarter.

Non-Residential Energy Assessment Program with Monitoring (Conservation)
The purpose of this pilot program is to assist non-residential customers in assessing their energy usage and to provide recommendations for more efficient use of energy. Under this pilot program, the customer will be provided quarterly reports including, but not limited to, graphs and comparisons, correlation of bills to weather, other major findings,

analysis of impact on energy usage of efficiency measures, and the opportunity to discuss the report with a Duke Energy Carolinas representative each quarter. The research will confirm the appropriate price, incentive, and product offer for the customer.

Efficiency Savings Plan (Conservation)
This is a pilot program designed to learn about and develop a financing structure that helps customers overcome up-front capital outlays for energy efficiency equipment financing. This program will allow residential and non-residential customers to install energy efficiency products with no up-front payment. The customer would pay for these products through a tariff charge on their Duke Energy Carolinas bill. The tariff would be a utility charge that would remain with the facility, not the customer.

The first table below provides the projection of new conservation and demand response products as well as a potential portfolio of products and services and their associated load impacts through 2027 that were included as placeholders in the quantitative analysis. The cost-effectiveness results for the programs are provided in subsequent tables.

PROJECTED ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT LOAD IMPACTS

Conservation and Demand Response Programs

	Conservation Program Load Impacts								Demand Response Impacts			
	MWH				Summer Peak MW				Summer Peak MW			Summer Peak
Year	Residential	Non-Residential	$2 Million Program	Total	Residential	Non-Residential	$2 Million Program	Total EE	Power Share	Power Manager	Total DR	Total MW Impacts
2008	70,884	27,048	4,394	102,326	31	7	1	40	517	244	761	801
2009	209,399	79,277	4,394	293,070	88	21	1	110	653	244	898	1,008
2010	339,275	134,200	4,394	477,869	139	35	1	175	771	244	1,016	1,190
2011	462,983	192,473	4,394	659,850	185	51	1	237	771	244	1,016	1,253
2012	594,609	247,610	4,394	846,612	237	65	1	302	771	244	1,016	1,318
2013	731,649	299,272	4,394	1,035,315	293	78	1	373	771	244	1,016	1,388
2014	861,534	354,193	4,394	1,220,121	344	93	1	437	771	244	1,016	1,453
2015	985,243	412,483	4,394	1,402,120	390	108	1	499	771	244	1,016	1,515
2016	1,118,318	468,202	4,394	1,590,914	442	122	1	565	771	244	1,016	1,581
2017	1,253,913	519,295	4,394	1,777,601	499	136	1	635	771	244	1,016	1,651
2018	1,383,790	574,188	4,394	1,962,372	549	150	1	700	771	244	1,016	1,716
2019	1,507,494	632,478	4,394	2,144,365	595	166	1	762	771	244	1,016	1,778
2020	1,571,146	661,730	4,394	2,237,270	615	172	1	789	771	244	1,016	1,805
2021	1,566,746	660,015	4,394	2,231,155	615	172	1	789	771	244	1,016	1,805
2022	1,566,755	660,015	4,394	2,231,164	615	172	1	789	771	244	1,016	1,805
2023	1,566,774	660,027	4,394	2,231,195	615	172	1	789	771	244	1,016	1,805
2024	1,571,129	661,730	4,394	2,237,253	615	172	1	789	771	244	1,016	1,805
2025	1,566,755	660,013	4,394	2,231,162	615	172	1	789	771	244	1,016	1,805
2026	1,566,756	660,031	4,394	2,231,181	615	172	1	789	771	244	1,016	1,805
2027	1,566,746	660,015	4,394	2,231,155	615	172	1	789	771	244	1,016	1,805
2028	1,571,128	661,726	4,394	2,237,248	615	172	1	789	771	244	1,016	1,805
2029	1,568,201	660,579	4,394	2,233,173	615	172	1	789	771	244	1,016	1,805
2030	1,568,209	660,625	4,394	2,233,228	615	172	1	789	771	244	1,016	1,805
2031	1,568,205	660,608	4,394	2,233,207	615	172	1	789	771	244	1,016	1,805
2032	1,571,125	661,739	4,394	2,237,258	615	172	1	789	771	244	1,016	1,805

Cost-Effectiveness Results for Duke Energy Carolinas

Existing and Proposed Programs

Energy Efficiency Education Program for Schools				
	UCT	**TRC**	**RIM**	**Participant**
Avoided T&D	10,174,656	10,174,656	10,174,656	
Cost-Based Avoided Production	33,565,222	33,565,222	33,565,222	
Cost-Based Avoided Capacity	25,216,137	25,216,137	25,216,137	
Lost Revenue				64,224,950
Net Lost Revenue			49,739,870	
Administration Costs				
Implementation Costs	21,064,975	21,064,975	21,064,975	
Incentives				
Other Utility Costs	1,851,096	1,851,096	1,851,096	
Participant Costs				
Total Benefits	68,956,015	68,956,015	68,956,015	64,224,950
Total Costs	22,916,070	22,916,070	72,655,941	
Benefit/Cost Ratios	**3.01**	**3.01**	**0.95**	

Data represents present value of costs and benefits over the life of the program.

Cost-Effectiveness Results for Duke Energy Carolinas

Existing and Proposed Programs

Low Income Services				
	UCT	**TRC**	**RIM**	**Participant**
Avoided T&D	4,413,133	4,413,133	4,413,133	
Cost-Based Avoided Production	15,078,766	15,078,766	15,078,766	
Cost-Based Avoided Capacity	9,843,891	9,843,891	9,843,891	
Lost Revenue				28,818,623
Net Lost Revenue			22,361,587	
Administration Costs				
Implementation Costs	11,879,896	11,879,896	11,879,896	
Incentives				
Other Utility Costs	4,452,300	4,452,300	4,452,300	
Participant Costs				
Total Benefits	29,335,790	29,335,790	29,335,790	28,818,623
Total Costs	16,332,195	16,332,195	38,693,782	
Benefit/Cost Ratios	**1.80**	**1.80**	**0.76**	

Data represents present value of costs and benefits over the life of the program.

Cost-Effectiveness Results for Duke Energy Carolinas

Existing and Proposed Programs

Residential Energy Assessments				
	UCT	**TRC**	**RIM**	**Participant**
Avoided T&D	4,897,249	4,897,249	4,897,249	
Cost-Based Avoided Production	14,067,152	14,067,152	14,067,152	
Cost-Based Avoided Capacity	10,484,200	10,484,200	10,484,200	
Lost Revenue				26,742,762
Net Lost Revenue			20,449,474	
Administration Costs				
Implementation Costs	11,030,985	11,030,985	11,030,985	
Incentives				
Other Utility Costs	96,234	96,234	96,234	
Participant Costs				
Total Benefits	29,448,601	29,448,601	29,448,601	26,742,762
Total Costs	11,127,219	11,127,219	31,576,693	
Benefit/Cost Ratios	**2.65**	**2.65**	**0.93**	

Data represents present value of costs and benefits over the life of the program.

Cost-Effectiveness Results for Duke Energy Carolinas

Existing and Proposed Programs

Smart $aver® for Non-Residential Customers				
	UCT	**TRC**	**RIM**	**Participant**
Avoided T&D	23,814,233	23,814,233	23,814,233	
Cost-Based Avoided Production	51,440,986	51,440,986	51,440,986	
Cost-Based Avoided Capacity	30,502,814	30,502,814	30,502,814	
Lost Revenue				92,371,442
Net Lost Revenue			66,095,976	
Administration Costs	10,487,108	10,487,108	10,487,108	
Implementation Costs	174,234	174,234	174,234	
Incentives	22,767,889		22,767,889	22,767,889
Other Utility Costs	5,678,660	5,678,660	5,678,660	
Participant Costs		52,408,996		52,408,996
Total Benefits	105,758,034	105,758,034	105,758,034	115,139,331
Total Costs	39,107,892	68,748,999	105,203,867	52,408,996
Benefit/Cost Ratios	**2.70**	**1.54**	**1.01**	**2.20**

Data represents present value of costs and benefits over the life of the program.

Cost-Effectiveness Results for Duke Energy Carolinas

Existing and Proposed Programs

Smart $aver® for Residential Customers				
	UCT	**TRC**	**RIM**	**Participant**
Avoided T&D	10,331,924	10,331,924	10,331,924	
Cost-Based Avoided Production	28,872,634	28,872,634	28,872,634	
Cost-Based Avoided Capacity	20,009,837	20,009,837	20,009,837	
Lost Revenue				56,728,648
Net Lost Revenue			44,333,512	
Administration Costs				
Implementation Costs	3,934,845	3,934,845	3,934,845	
Incentives	10,164,849		10,164,849	10,164,849
Other Utility Costs	4,438,413	4,438,413	4,438,413	
Participant Costs		16,455,945		16,455,945
Total Benefits	59,214,396	59,214,396	59,214,396	66,893,497
Total Costs	18,538,107	24,829,203	62,871,619	16,455,945
Benefit/Cost Ratios	**3.19**	**2.38**	**0.94**	**4.07**

Data represents present value of costs and benefits over the life of the program.

Cost-Effectiveness Results for Duke Energy Carolinas

Existing and Proposed Programs

Power Manager				
	UCT	**TRC**	**RIM**	**Participant**
Avoided T&D	65,363,430	65,363,430	65,363,430	
Cost-Based Avoided Production	102,437,877	102,437,877	102,437,877	
Cost-Based Avoided Capacity	138,465,548	138,465,548	138,465,548	
Lost Revenue				
Net Lost Revenue				
Administration Costs	2,382,482	2,382,482	2,382,482	
Implementation Costs				
Incentives	43,381,473		43,381,473	43,381,473
Other Utility Costs				
Participant Costs				
Total Benefits	306,266,855	306,266,855	306,266,855	43,381,473
Total Costs	45,763,954	2,382,482	45,763,954	
Benefit/Cost Ratios	**6.69**	**128.55**	**6.69**	

Data represents present value of costs and benefits over the life of the program.

Cost-Effectiveness Results for Duke Energy Carolinas

Existing and Proposed Programs

	PowerShare®			
	UCT	**TRC**	**RIM**	**Participant**
Avoided T&D	210,914,705	210,914,705	210,914,705	
Cost-Based Avoided Production	344,249,721	344,249,721	344,249,721	
Cost-Based Avoided Capacity	505,677,272	505,677,272	505,677,272	
Lost Revenue				
Net Lost Revenue				
Administration Costs	4,847,719	4,847,719	4,847,719	
Implementation Costs				
Incentives	270,924,042		270,924,042	270,924,042
Other Utility Costs				
Participant Costs		431,115		431,115
Total Benefits	1,060,841,697	1,060,841,697	1,060,841,697	270,924,042
Total Costs	275,771,761	5,278,834	275,771,761	431,115
Benefit/Cost Ratios	**3.85**	**200.96**	**3.85**	**628.43**

Data represents present value of costs and benefits over the life of the program.

Cost-Effectiveness Results for Duke Energy Carolinas

Existing and Proposed Programs

Interruptible Power Service (Existing Rider IS)				
	UCT	**TRC**	**RIM**	**Participant**
Avoided T&D	77,046,957	77,046,957	77,046,957	
Cost-Based Avoided Production	116,532,221	116,532,221	116,532,221	
Cost-Based Avoided Capacity	183,717,268	183,717,268	183,717,268	
Lost Revenue				
Net Lost Revenue				
Administration Costs	274,854	274,854	274,854	
Implementation Costs				
Incentives	90,655,279		90,655,279	90,655,279
Other Utility Costs				
Participant Costs		108,317		108,317
Total Benefits	377,296,446	377,296,446	377,296,446	90,655,279
Total Costs	90,930,133	383,171	90,930,133	108,317
Benefit/Cost Ratios	**4.15**	**984.67**	**4.15**	**836.95**

Data represents present value of costs and benefits over the life of the program.

Cost-Effectiveness Results for Duke Energy Carolinas

Existing and Proposed Programs

Residential Load Control (Existing Rider LC)				
	UCT	**TRC**	**RIM**	**Participant**
Avoided T&D	58,069,387	58,069,387	58,069,387	
Cost-Based Avoided Production	100,455,942	100,455,942	100,455,942	
Cost-Based Avoided Capacity	138,465,548	138,465,548	138,465,548	
Lost Revenue				
Net Lost Revenue				
Administration Costs	2,382,482	2,382,482	2,382,482	
Implementation Costs				
Incentives	43,381,473		43,381,473	43,381,473
Other Utility Costs				
Participant Costs				
Total Benefits	296,990,877	296,990,877	296,990,877	43,381,473
Total Costs	45,763,954	2,382,482	45,763,954	
Benefit/Cost Ratios	**6.49**	**124.66**	**6.49**	

Data represents present value of costs and benefits over the life of the program.

Cost-Effectiveness Results for Duke Energy Carolinas

Existing and Proposed Programs

Standby Generator Control (Existing Rider SG)				
	UCT	**TRC**	**RIM**	**Participant**
Avoided T&D	33,361,733	33,361,733	33,361,733	
Cost-Based Avoided Production	58,012,703	58,012,703	58,012,703	
Cost-Based Avoided Capacity	80,035,398	80,035,398	80,035,398	
Lost Revenue				
Net Lost Revenue				
Administration Costs	3,216,493	3,216,493	3,216,493	
Implementation Costs				
Incentives	34,160,535		34,160,535	34,160,535
Other Utility Costs				
Participant Costs		154,751		154,751
Total Benefits	171,409,833	171,409,833	171,409,833	34,160,535
Total Costs	37,377,029	3,371,244	37,377,029	154,751
Benefit/Cost Ratios	**4.59**	**50.84**	**4.59**	**220.75**

Data represents present value of costs and benefits over the life of the program.

Cost-Effectiveness Results for Duke Energy Carolinas

Existing and Proposed Programs

Advanced Power Manager Research Pilot Program				
	UCT	**TRC**	**RIM**	**Participant**
Avoided T&D	128,614,985	128,614,985	128,614,985	
Cost-Based Avoided Production	195,217,704	195,217,704	195,217,704	
Cost-Based Avoided Capacity	251,282,394	251,282,394	251,282,394	
Lost Revenue				
Net Lost Revenue				
Administration Costs	2,554,904	2,554,904	2,554,904	
Implementation Costs	22,218,476	22,218,476	22,218,476	
Incentives	1,315,919		1,315,919	1,315,919
Other Utility Costs				
Participant Costs				
Total Benefits	575,115,083	575,115,083	575,115,083	1,315,919
Total Costs	26,089,299	24,773,380	26,089,299	
Benefit/Cost Ratios	**22.04**	**23.22**	**22.04**	

Data represents present value of costs and benefits over the life of the program.

Cost-Effectiveness Results for Duke Energy Carolinas

Existing and Proposed Programs

Custom Renewables Research Pilot Program				
	UCT	**TRC**	**RIM**	**Participant**
Avoided T&D	12,426	12,426	12,426	
Cost-Based Avoided Production	25,603	25,603	25,603	
Cost-Based Avoided Capacity	24,965	24,965	24,965	
Lost Revenue				33,715
Net Lost Revenue			24,645	
Administration Costs				
Implementation Costs	715,016	715,016	715,016	
Incentives				
Other Utility Costs	20,000	20,000	20,000	
Participant Costs				
Total Benefits	62,994	62,994	62,994	33,715
Total Costs	735,016	735,016	759,661	
Benefit/Cost Ratios	**0.09**	**0.09**	**0.08**	

Data represents present value of costs and benefits over the life of the program.

Cost-Effectiveness Results for Duke Energy Carolinas

Existing and Proposed Programs

Residential Bill Check Research Pilot Program				
	UCT	**TRC**	**RIM**	**Participant**
Avoided T&D	5,132	5,132	5,132	
Cost-Based Avoided Production	14,167	14,167	14,167	
Cost-Based Avoided Capacity	13,062	13,062	13,062	
Lost Revenue				27,259
Net Lost Revenue			21,111	
Administration Costs				
Implementation Costs	57,774	57,774	57,774	
Incentives	13,332		13,332	13,332
Other Utility Costs	124,027	124,027	124,027	
Participant Costs				
Total Benefits	32,361	32,361	32,361	40,592
Total Costs	195,133	181,801	216,244	
Benefit/Cost Ratios	**0.17**	**0.18**	**0.15**	

Data represents present value of costs and benefits over the life of the program.

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 (and each subsequent IRP order), 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 IRP.

PURPA QUALIFYING FACILITIES (SELLING POWER TO DUKE)

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]
Byron P. Matthews	Chapel Hill	NC	3	Photovoltaic	Yes[1]
Catawba County - Blackburn Landfill	Newton	NC	4,000	Landfill Gas	Yes[1]
Cliffside Mills, LLC	Cliffside	NC	1,600	Hydroelectric	Yes[1]
David K. Birkhead	Hillsborough	NC	2	Photovoltaic	Yes[1]
David Wiener dba JZ Solar Electric	Chapel Hill	NC	3	Photovoltaic	Yes[1]
Frances L. Thompson (formery Habitat)	Hickory	NC	4	Photovoltaic	Yes[1]
Hardins Resources Company	Hardins	NC	820	Hydroelectric	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]
Holzworth Holdings, Inc.	Durham	NC	3	Photovoltaic	Yes[1]
Jafasa Farms - Residence	Mills River	NC	6	Photovoltaic	Yes[1]
Jafasa Farms - Greenhouse	Mills River	NC	6	Photovoltaic	Yes[1]
James B. Sherman	Chapel Hill	NC	5	Photovoltaic	Yes[1]
Mark A. Powers	Chapel Hill	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]
MegaWatt Solar	Hillsborough	NC	5	Photovoltaic	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]
Shawn L. Slome	Chapel Hill	NC	2	Photovoltaic	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-Long Shoals Hydro	Long Shoals	NC	900	Hydroelectric	Yes[1]
Town of Chapel Hill	Chapel Hill	NC	4	Photovoltaic	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 Power
Note 2: Formerly Northbrook Carolina, LLC - Spencer Mountain Hydro
Note 3: Formerly Northbrook Carolina, LLC - Stice Shoals Hydro

MERCHANT GENERATORS

NAME	CITY	STATE	NAMEPLATE KW	PRIMARY FUEL TYPE	PART OF TOTAL SUPPLY RESOURCES [1]
Southern Power	Salisbury	NC	458,000	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 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]
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]
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]
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.

CUSTOMER-OWNED SELF-GENERATION				
COUNTY	STATE	NAMEPLATE KW	PRIMARY FUEL TYPE	PART OF TOTAL SUPPLY RESOURCES
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	5,025	Diesel	No[1]
Cleveland	NC	4,500	Diesel	No[1]
Cleveland	NC	2,000	Diesel	No[1]
Durham	NC	2	Photovoltaic	No[1]
Durham	NC	1	Photovoltaic	No[1]
Durham	NC	3	Photovoltaic	No[1]
Durham	NC	2	Photovoltaic	No[1]
Durham	NC	3	Photovoltaic	No[1]
Forsyth	NC	8,400	Coal, Wood Cogen	No[1]
Forsyth	NC	4	Photovoltaic	No[1]
Gaston	NC	1,056	Hydroelectric	No[1]
Guilford	NC	3	Photovoltaic	No[1]
Guilford	NC	2,000	Diesel	No[1]
Guilford	NC	900	Diesel	No[1]
Guilford	NC	2,000	Diesel	No[1]
Guilford	NC	2	Photovoltaic	No[1]
Guilford	NC	2	Photovoltaic	No[1]
Guilford	NC	3	Photovoltaic	No[1]
Iredell	NC	1,050	Diesel	No[1]
Iredell	NC	8	Photovoltaic	No[1]
Mecklenburg	NC	4	Photovoltaic	No[1]
Mecklenburg	NC	4	Photovoltaic	No[1]
Mecklenburg	NC	3	Photovoltaic	No[1]
Orange	NC	4	Photovoltaic	No[1]
Orange	NC	2	Photovoltaic	No[1]
Orange	NC	2	Photovoltaic	No[1]
Orange	NC	28,000	Coal Cogen	No[1]
Orange	NC	2	Photovoltaic	No[1]
Randolph	NC	2	Photovoltaic	No[1]
Randolph	NC	2	Photovoltaic	No[1]
Rockingham	NC	5,480	Coal Cogen	No[1]
Rockingham	NC	2	Photovoltaic	No[1]
Rowan	NC	8	Photovoltaic/Wind	No[1]
Rowan	NC	2	Photovoltaic	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]

Transylvania	NC	2	Photovoltaic	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]
Yadkin	NC	7	Photovoltaic	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	4,550	Diesel Cogen	No[1]
Greenville	SC	5,000	Natural Gas, Landfill Gas	No[1]
Greenville	SC	100	Photovoltaic	No[1]
Greenville	SC	370	Digester Gas	No[1]
Greenville	SC	250	Unknown	No[1]
Laurens	SC	2,150	Diesel	No[1]
Laurens	SC	4,000	Diesel	No[1]
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	6,000	Diesel	No[1]
Union	SC	5,730	Diesel	No[1]
York	SC	42,500	Coal, Wood 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' 2006 FERC Form 1 pages 422, 423, 422.1, 423.1, 422.2, 422.3, 423.2, 423.3, 424, 425, 450.1, and 450.2.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (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	54.40		1
5	McGuire Switching	Woodleaf Switching	525.00	525.00	Tower	29.95		1
6	Newport Tie	Progress Energy 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	TOTAL 525 KV LINES					576.27		12
15								
16	Allen Steam	Catawba Nuclear	230.00	230.00	Tower	10.86		2
17	Allen Steam	Riverbend Steam	230.00	230.00	Tower	12.49		2
18	Allen Steam	Winecoff Tie	230.00	230.00	Tower	32.22		2
19	Allen Steam	Woodlawn Tie	230.00	230.00	Tower & Pole	8.63		2
20	Anderson Tie	Hodges Tie	230.00	230.00	Tower	25.79		2
21	Antioch Tie	Wilkes Tie	230.00	230.00	Tower	4.29		2
22	Beckerdite Tie	Belews Creek Steam	230.00	230.00	Tower	24.60		2
23	Beckerdite Tie	Pleasant Garden Tie	230.00	230.00	Tower	28.48		2
24	Belews Creek Steam	Ernest Switching	230.00	230.00	Tower	13.71		2
25	Belews Creek Steam	North Greensboro Tie	230.00	230.00	Tower	21.65		2
26	Belews Creek Steam	Pleasant Garden Tie	230.00	230.00	Tower & Pole	38.72		2
27	Belews Creek Steam	Rural Hall Tie	230.00	230.00	Tower	18.32		2
28	Bobwhite Switching	North Greensboro Tie	230.00	230.00	Tower	3.83		2
29	Buck Tie	Beckerdite Tie	230.00	230.00	Tower	23.63		2
30	Catawba Nuclear	Newport Tie	230.00	230.00	Tower & Pole	10.36		2
31	Catawba Nuclear	Pacolet Tie	230.00	230.00	Tower	41.26		2
32	Catawba Nuclear	Peacock Tie	230.00	230.00	Tower	14.85		2
33	Catawba Nuclear	Ripp Switching	230.00	230.00	Tower	24.44		2
34	Central Tie	Anderson Tie	230.00	230.00	Tower	23.12		2
35	Cliffside Steam	Pacolet Tie	230.00	230.00	Tower	23.01		2
36					TOTAL	8,221.79		159

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/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
	20,355,902	99,245,582	119,601,484					13
	20,355,902	99,245,582	119,601,484					14
								15
1272								16
1272								17
954 & 1272								18
2156								19
954								20
954								21
2156								22
954								23
1272								24
2156								25
2156								26
2156								27
2156								28
954								29
1272								30
954								31
1272								32
1272								33
954								34
954								35
	145,332,374	987,482,386	1,132,814,760	600,747	6,171,866		6,772,613	36

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TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Cliffside Steam	Shelby Tie	230.00	230.00	Tower	14.16		2
2	Cowans Ford Hydro	McGuire Switching	230.00	230.00	Tower	1.67		2
3	East Durham Tie	Parkwood Tie	230.00	230.00	Tower	19.25		2
4	Eno Tap Bent	Progress Energy	230.00	230.00	Tower	13.74		2
5	Eno Tap Bent	East Durham Tie	230.00	230.00	Tower	15.78		2
6	Ernest Switching	Sadler Tie	230.00	230.00	Tower	12.61		2
7	Harrisburg Tie	Oakboro Tie	230.00	230.00	Tower	21.52		2
8	Hartwell Hydro	Anderson Tie	230.00	230.00	Tower	11.16		2
9	Jocassee Switching	Shiloh Switching	230.00	230.00	Tower	22.52		2
10	Jocassee Switching	Tuckasegee Tie	230.00	230.00	Tower	26.62		2
11	Lakewood Tie	Riverbend Steam	230.00	230.00	Tower	10.64		2
12	Lincoln CT	Longview Tie	230.00	230.00	Tower	30.95		2
13	Longview Tie	McDowell Tie	230.00	230.00	Tower	31.93		2
14	Marshall Steam	Beckerdite Tie	230.00	230.00	Tower	52.61		2
15	Marshall Steam	Longview Tie	230.00	230.00	Tower	29.04		2
16	Marshall Steam	McGuire Switching	230.00	230.00	Tower	13.76		2
17	Marshall Steam	Stamey Tie	230.00	230.00	Tower	13.44		2
18	Marshall Steam	Winecoff Tie	230.00	230.00	Tower	24.35		2
19	McGuire Switching	Harrisburg Tie	230.00	230.00	Tower	36.27		2
20	Mitchell River Tie	Antioch Tie	230.00	230.00	Tower & Pole	16.90		2
21	Mitchell River Tie	Rural Hall Tie	230.00	230.00	Tower	26.85		2
22	Morningstar Tie	Oakboro Tie	230.00	230.00	Tower	32.55		1
23	North Greenville Tie	Central Tie	230.00	230.00	Tower & Pole	26.22		2
24	North Greenville Tie	Shiloh Switching	230.00	230.00	Tower	8.96		2
25	Newport Tie	Morningstar Tie	230.00	230.00	Tower & Pole	33.59		1
26	Newport Tie	SCE&G (Parr)	230.00	230.00	Tower	45.38		1
27	Oakboro Tie	Progress Energy Rockingham	230.00	230.00	Tower	5.13		2
28	Oconee Nuclear	Central Tie	230.00	230.00	Tower	17.62		2
29	Oconee Nuclear	Jocassee Switching	230.00	230.00	Tower & Pole	12.28		2
30	Oconee Nuclear	North Greenville Tie	230.00	230.00	Tower & Pole	29.25		2
31	Pacolet Tie	Tiger Tie	230.00	230.00	Tower	27.96		2
32	Peach Valley Tie	Tiger Tie	230.00	230.00	Tower	15.69		2
33	Pisgah Tie	Progress Energy Skyland Stm	230.00	230.00	Tower	14.41		2
34	Pleasant GardenTie	Eno Tie	230.00	230.00	Tower	42.85		2
35	Ripp Switching	Riverview Switching	230.00	230.00	Tower	9.70		2
36					TOTAL	8,221.79		159

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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
1272								3
1272								4
1272								5
1272								6
954								7
954								8
2156								9
1272								10
954								11
795								12
954								13
954								14
1272								15
1272								16
954								17
1272								18
1272								19
954								20
954								21
954								22
954								23
954								24
954								25
954								26
954								27
1272								28
2156								29
1272								30
954								31
795								32
954								33
954								34
795								35
	145,332,374	987,482,386	1,132,814,760	600,747	6,171,866		6,772,613	36

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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	Ripp Switching	Shelby Tie	230.00	230.00	Tower	9.95		2
2	Riverbend Steam	Lincoln CT	230.00	230.00	Tower & Pole	11.59		2
3	Riverbend Steam	McGuire Switching	230.00	230.00	Tower	5.61		2
4	Riverbend Steam	Ripp Switching	230.00	230.00	Tower	30.12		2
5	Riverview Switching	Peach Valley Tie	230.00	230.00	Tower	19.33		2
6	SCE&G (Parr)	Bush River Tie	230.00	230.00	Tower	17.63		1
7	Shady Grove Tap	Shady Grove Tie	230.00	230.00	Tower	7.80		2
8	Shiloh Switching	Pisgah Tie	230.00	230.00	Tower	21.85		2
9	Shiloh Switching	Tiger Tie	230.00	230.00	Tower	21.46		2
10	Stamey Tie	Mitchell River Tie	230.00	230.00	Tower	35.92		2
11	Tiger Tie	North Greenville Tie	230.00	230.00	Tower	18.38		2
12	Winecoff Tie	Buck Tie	230.00	230.00	Tower	24.05		2
13								
14	TOTAL 230 KV LINES					1,395.31		130
15								
16	Nantahala Hydro	Webster Tie	161.00	161.00	Tower	12.66		1
17	Nantahala Plant	Robbinsville S.S.	161.00	161.00	Tower	8.33		1
18	Nantahala Tie	Marble Tie	161.00	161.00	Tower	16.85		2
19	Santeetlah Plant	Robbinsville S.S.	161.00	161.00	Tower	11.14		1
20	Tuckasegee Tie	Thorpe Hydro	161.00	161.00	Tower & Pole	3.25		1
21	Tuckasegee Tie	Wests Mill Tie	161.00	161.00	Tower & Pole	10.42		2
22	Webster Tie	Lake Emory S.S.	161.00	161.00	Tower	11.93		1
23	Wests Mill Tie	Lake Emory S.S.	161.00	161.00	Tower	6.78		1
24	Wests Mill Tie	Nantahala Tie	161.00	161.00	Tower	13.08		1
25								
26	TOTAL 161 KV LINES					94.44		11
27								
28	Dan River Steam	Appalachian Power	138.00	138.00	Tower & Pole	6.47		1
29	115 KV Lines		115.00	115.00	Tower & Pole	43.37		1
30	100 KV Lines		100.00	100.00	Tower	2,928.37		
31	100 KV Lines		100.00	100.00	Pole	560.94		
32	100 KV Lines		100.00	100.00	Underground	1.06		
33								
34	TOTAL 100 - 138 KV LINES					3,540.21		2
35								
36					TOTAL	8,221.79		159

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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
1272								3
795								4
795								5
954								6
2515								7
954								8
1272								9
954								10
954								11
954								12
	40,039,496	213,513,439	253,552,935					13
	40,039,496	213,513,439	253,552,935					14
								15
795								16
636								17
795								18
636								19
397.5								20
795								21
636								22
795								23
795								24
	2,078,504	31,898,452	33,976,956					25
	2,078,504	31,898,452	33,976,956					26
								27
477								28
								29
								30
								31
								32
	56,702,304	447,902,824	504,605,128					33
	56,702,304	447,902,824	504,605,128					34
								35
	145,332,374	987,482,386	1,132,814,760	600,747	6,171,866		6,772,613	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/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)	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)	On Structures of Another Line (g)	Number Of Circuits (h)
1	66 KV Lines		66.00	66.00	Pole	115.80		1
2								
3	TOTAL 66 KV LINES					115.80		1
4								
5	44 KV Lines		44.00	44.00	Tower	195.33		
6	44 KV Lines		44.00	44.00	Pole	2,176.18		
7	44 KV Lines		44.00	44.00	Underground	0.17		1
8								
9	TOTAL 44 KV LINES					2,371.68		1
10								
11	33 KV Lines		33.00	33.00	Pole	14.65		
12	24 KV Lines		24.00	24.00	Pole	86.02		
13	24 KV Lines		24.00	24.00	Underground	0.16		1
14	12 KV Lines		12.00	12.00	Tower & Pole	27.03		
15	12 KV Lines		12.00	12.00	Underground	0.22		1
16								
17	TOTAL 13-33 KV LINES					128.08		2
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	8,221.79		159

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/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	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
								1
	4,440,955	19,618,553	24,059,508					2
	4,440,955	19,618,553	24,059,508					3
								4
								5
								6
								7
	21,099,067	171,392,573	192,491,640					8
	21,099,067	171,392,573	192,491,640					9
								10
								11
								12
								13
								14
								15
	616,146	3,910,963	4,527,109					16
	616,146	3,910,963	4,527,109					17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
				600,747	6,171,866		6,772,613	34
								35
	145,332,374	987,482,386	1,132,814,760	600,747	6,171,866		6,772,613	36

Schedule Page: 422 Line No.: 1 Column: i

All Conductors in column (i) is ACSR shown in MCM.

Schedule Page: 422.2 Line No.: 30 Column: h

Number of Circuits - 1 & 2

Schedule Page: 422.2 Line No.: 31 Column: h

Number of Circuits - 1 & 2

Schedule Page: 422.2 Line No.: 32 Column: h

Number of Circuits - 1 & 2

Schedule Page: 422.3 Line No.: 5 Column: h

Number of Circuits - 1 & 2

Schedule Page: 422.3 Line No.: 6 Column: h

Number of Circuits - 1 & 2

Schedule Page: 422.3 Line No.: 11 Column: h

Number of Circuits - 1 & 2

Schedule Page: 422.3 Line No.: 12 Column: h

Number of Circuits - 1 & 2

Schedule Page: 422.3 Line No.: 14 Column: h

Number of Circuits - 1 & 2

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/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		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From	To		Type	Average Number per Miles	Present	Ultimate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	OH Construction: New Lines						
2	Allen Steam Station	Woodlawn Tie	0.32		22.00	2	
3	Pacolet Tie	Tiger Tie	27.96			2	
4	Bethware Retail Tap		0.09	Pole	11.00	1	
5	Waynick Retail Tap		0.02			1	
6	Pitt School Road Retail Tap		0.03	Pole	33.00	1	
7	Fair Grove Retail Tap		0.10	Pole	30.00	1	
8	Genelee Retail Tap		0.09	Pole	11.00	1	
9	IBM Tap		0.04	Pole	25.00	1	
10	Wildcat Tie	Mooresville Tie	5.40		11.00	1	
11	Wallace Road Retail Tap		0.89	Pole	13.00	1	
12	Banks Street Retail	Indian Land Retail	5.68	Pole	41.00	1	
13	Greer Retail Tap		0.09	Pole	11.00	1	
14	Mini Ranch Retail Tap		4.60	Pole	7.00	1	
15	Oneal Retail Tap		5.29	Pole	9.00	1	
16	RR Donnelly Tap		0.87	Pole	2.00	1	
17	Pisgah Tie	Lions Mountain Tie	0.40		10.00	1	
18	Ball Metal Tap		0.03	Pole	33.00	1	
19	UNCC Tap		0.10	Pole	20.00	1	
20							
21							
22							
23	OH Lines: Major Rebuild						
24	Wylie Switching Station	Allen Steam Station	11.80		10.00	2	
25	Tiger Tie	North Greenville Tie	13.20		5.00	2	
26	Cliffside Steam Staion	Fairview Tie	13.40		8.00	2	
27	High Rock Hydro	Linden Street	14.40		6.00	2	
28	North Greensboro Tie	Dan River Steam Station	2.90		11.00	1	
29	Wildcat Tie	Mooresville Tie	5.40	Pole	9.00	1	
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		113.10		338.00	30	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	12/31/2006	End of 2006/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 Size (h)	Specification (i)	Configuration and Spacing (j)	Voltage KV (Operating) (k)	LINE COST Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	Line No.
									1
2156.0	ACSR		230		957,181	586,659		1,543,840	2
954.0	ACSR		230			2,823,833		2,823,833	3
336.4	ACSR		100	19,726	69,951	42,873		132,550	4
556.5	ACSR		100			30,789		30,789	5
477.0	ACSR		100		17,175	10,526		27,701	6
556.5	ACSR		100		42,754	16,014		58,768	7
954.0	ACSR		100		21,943	13,449		35,392	8
556.5	ACSR		100		20,464	12,542		33,006	9
556.5	ACSR		100		1,423,524	872,482		2,296,006	10
556.5	ACSR		100	201,882	253,119	155,138		610,139	11
954.0	ACSR		100		566,005	346,906		912,911	12
336.4	ACSR		100	4,615	1,173,631	719,322		1,897,568	13
556.5	ACSR		100	25,079	1,252,750	767,814		2,045,643	14
556.5	ACSR		100	1,448,691	1,136,898	696,808		3,282,397	15
556.5	ACSR		100		27,752	17,009		44,761	16
556.5	ACSR		44	31	306,261	37,648		343,940	17
556.5	ACSR		44		33,898	20,776		54,674	18
336.4	ACSR		44		80,661	49,438		130,099	19
									20
									21
									22
									23
954.0	AAC		100		3,055,916	1,872,980		4,928,896	24
556.5	ACSR		100		1,944,691	1,010,186		2,954,877	25
556.5	ACSR		100		3,099,067	1,458,938		4,558,005	26
954.0	ACSR		100		4,838,441	2,524,756		7,363,197	27
556.5	ACSR		44		1,160,356	469,873		1,630,229	28
556.5	ACSR		44		990,954	607,359		1,598,313	29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				1,700,024	22,473,392	15,164,118		39,337,534	44

Schedule Page: 424 Line No.: 2 Column: d
Towers & Poles used in the new line

Schedule Page: 424 Line No.: 2 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 2 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 3 Column: d
No Structures used in the new line

Schedule Page: 424 Line No.: 4 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 4 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 5 Column: d
No Structures used in the new line

Schedule Page: 424 Line No.: 5 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 6 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 6 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 8 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 8 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 9 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 9 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 10 Column: d
Towers & Poles used in the new line

Schedule Page: 424 Line No.: 10 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 10 Column: n
All or porton of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 11 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 11 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 12 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 12 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 13 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 13 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 14 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 14 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 15 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 15 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

FOOTNOTE DATA

Schedule Page: 424 Line No.: 16 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 16 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 17 Column: d
Towers & Poles used in the new line

Schedule Page: 424 Line No.: 18 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 18 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 19 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 19 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 24 Column: d
Towers & Poles used in the new line

Schedule Page: 424 Line No.: 24 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 24 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 25 Column: d
Towers & Poles used in the new line

Schedule Page: 424 Line No.: 26 Column: d
Towers & Poles used in the new line

Schedule Page: 424 Line No.: 27 Column: d
Towers & Poles used in the new line

Schedule Page: 424 Line No.: 28 Column: d
Towers & Poles used in the new line

Schedule Page: 424 Line No.: 29 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 29 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

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 Plan 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), as well as economic redevelopment rates (Rider ER) as of August 1, 2007 is:

Rider EC:

52 MW for North Carolina
46 MW for South Carolina

Rider ER:

1   MW for North Carolina
1   MW for South Carolina

APPENDIX M: LEGISLATIVE AND REGULATORY ISSUES

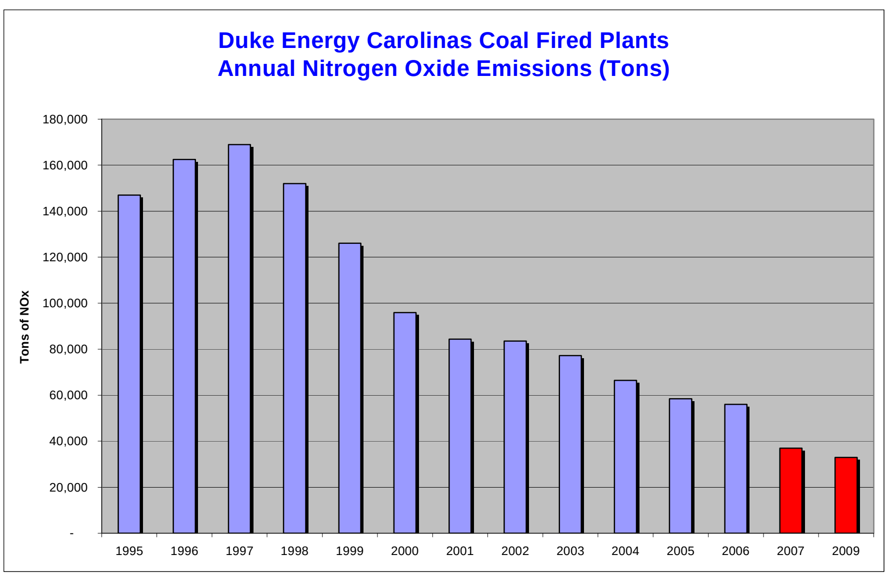
Duke Energy Carolinas is subject to the jurisdiction of federal agencies including the FERC, EPA, and the NRC, as well as state commissions and agencies. In addition, state and federal policy actions have potential impacts on the Company. This section provides a high-level description of several issues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

Air Quality

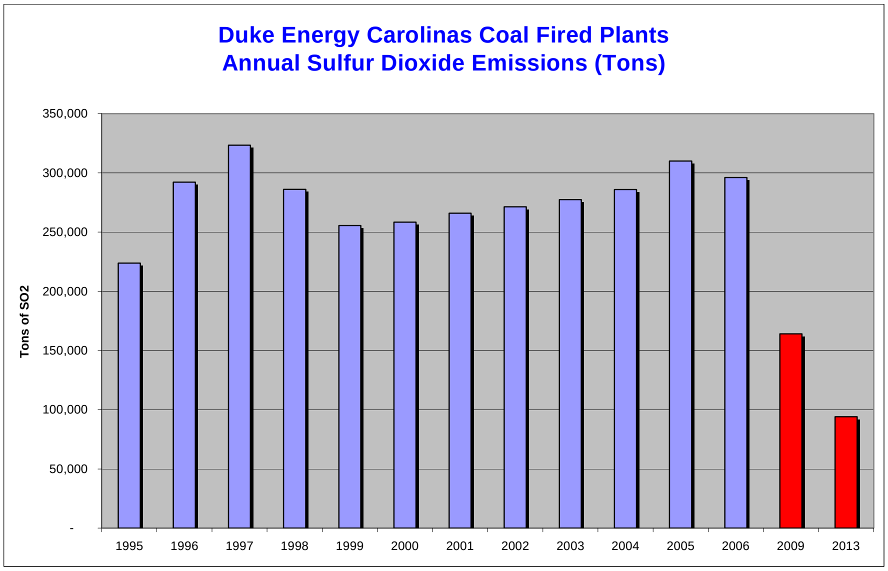
Duke Energy Carolinas is required to comply with federal regulations such as the Clean Air Act's Nitrogen Oxide (NOx) State Implementation Plan (SIP) Call, the Clean Air Interstate Rule, the Clean Air Mercury Rule, and the 2002 North Carolina Clean Smokestacks Act.

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.



Overall reduction of 80% from 1997 to 2009 attributed to Federal Requirements and the NC Clean Air Legislation



70% reduction from 1997 to 2013 attributed to scrubbers installed to meet NC Clean Air Legislation

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*, and the existing 8 hour ozone standard**.**

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. Both North and South Carolina have approved state versions of the federal CAIR rules.

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 issued proposed CAMR rules. Both states held public hearings and stakeholder meetings and accepted formal written comments on the proposed rules. Final rules were completed in 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 Energy Carolinas 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.

8 Hour Ozone Standard

The North Carolina Department of Air Quality (NCDAQ) was developing an ozone attainment demonstration for the Charlotte, NC, Metropolitan Statistical Area. In order to demonstrate compliance in the 2010 timeframe, additional utility NOx reductions were needed. Duke Energy Carolinas agreed to install an additional SCR at Marshall Steam Station Unit 3 by 2009 to meet this requirement. This SCR also provides needed compliance margin for the North Carolina Clean Smokestacks Act Phase II NOx cap and additional mercury reductions that will help meet the CAMR requirements.

Global Climate Change

Duke Energy views climate change, particularly potential regulatory responses to the issue, as a significant strategic business issue. Current U.S. policy calls for reducing 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 mandatory federal program 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. The Company believes that the best course of action going forward is enactment of federal legislation as soon as possible that will result in a gradual reduction in greenhouse gas emissions over time through the application of an economy-wide cap-and-trade program. The program should account for varying impacts across regions and economic sectors and include a safety valve to provide needed price certainty.

Renewable Portfolio Standard (RPS)

The North Carolina General Assembly has enacted a Renewable Portfolio Standard (RPS) that requires specific actions by North Carolina utilities to acquire and incorporate set amounts and types of renewable energy in the supply portfolio as well as established cost caps for consumers.

Federal Legislation for a nationwide RPS has been introduced, debated and defeated in the U.S. Senate, but passed in the U.S. House of Representatives. Because the issue must be decided in conference between the Senate and House, the ultimate fate of a national RPS is unclear. The issue may also be considered during debate on comprehensive climate change legislation later this year.

Duke Energy remains an active participant in these discussions and continues to educate members of Congress on the economic consequences of enacting a one-size-fits-all approach. Duke Energy believes that resource management is better left to the discretion of the states.

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."

On March 23, 2007, FERC issued a notice of authorization for continued project operation for the East Fork project, authorizing continued operation under the terms of the previous license until January 31, 2007. The FERC notice states, "[I]f issuance of a new license (or other disposition) does not take place on or before January 31, 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."

On March 23, 2007, FERC issued a notice of authorization for continued project operation for the West Fork project, authorizing continued operation under the terms of the previous license until January 31, 2007. The FERC notice states, "[I]f issuance of a new license (or other disposition) does not take place on or before January 31, 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 FERC license application. Final agreement was reached with 82% (70) 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	Good until license renewed
Dillsboro Project No. 2602	1/19/2000	Good until FERC acts on application for renewal or surrender
Franklin Project No. 2603	1/27/2000	Good until license renewed
Mission Project No. 2619	2/15/2000	Good until license renewed
East Fork Project No. 2698	7/25/2000	Good until license renewed
West Fork Project No. 2686	7/28/2000	Good until license renewed
Nantahala Project No. 2692	8/7/2000	Good until license renewed
Catawba/Wateree Project No. 2232	7/21/2003	9/1/2008

North Carolina Transmission Planning Process

Duke Energy Carolinas participates 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.

On January 25, 2007, the Participants achieved a major milestone with the publication of their first single Collaborative Transmission Plan for North Carolina. The N.C. regional planning study includes a base reliability analysis as well as analysis of potential resource supply options. The resource supply analysis provides the opportunity to evaluate transmission system impacts for various resource supply options to meet future native load requirements. A supplemental study report with an updated Collaborative Plan was published on April 26, 2007. The purpose of the supplemental analysis was to address one additional resource supply option, a transfer of 1,200 MW from Duke to Progress Energy's eastern N.C. service area, which was not included in the original 2006 study due to time constraints.

The updated 2006 Collaborative Plan is composed of 14 major transmission projects totaling $294 million in capital investment (down from the $400 million initially proposed). Major projects are defined as those requiring investments of more than $10 million. In addition, the supplemental analysis identified that the incremental cost to import 600 MW from Duke into Progress Energy's eastern service area would be reduced from $131 million to $68 million, while the incremental cost to import 1,200 MW was estimated to be $71 million.

The major transmission projects identified in the updated 2006 Collaborative Transmission Plan are expected to be implemented over the 10-year planning horizon by the transmission owners to preserve system reliability and improve economic transfers. These planned projects are part of an annual planning process and are subject to change based on evolving system conditions.

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 established both an Independent Entity to serve as its transmission coordinator and an Independent Monitor to provide additional transparency and fair system administration. The Company began implementation in late 2006.

Under the plan, the Independent Entity is charged with performing key transmission functions under Duke Energy Carolinas' Open Access Transmission Tariff (OATT). Duke Energy Carolinas remains 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 serves 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 regularly performs 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. serves 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.