The Duke Energy Carolinas Integrated Resource Plan

November 3, 2008

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2008 Integrated Resource Plan – abbreviations

Alternating Current	AC
Certificate of Public Convenience and Necessity	CPCN
Clean Air interstate Rule	CAIR
Clean Air Mercury Rule	CAMR
Combined Construction and Operating License	COL
Comprehensive Relicensing Agreement	CRA
Compressed Air Energy Storage	CAES
Cooling degree days	CDD
Curtailable Service Program	Rider CS
Demand Side Management	DSM
Direct Current	DC
Duke Energy Annual Plan	The Plan
Duke Energy Carolinas	DEC
Duke Energy Carolinas	The Company
Eastern Interconnection Reliability Assessment Group	ERAG
Economic redevelopment rate	Rider ER
Electric Power Research Institute	EPRI
Electronically-commutated fan motors	ECM
Energy Efficiency	EE
Environmental Protection Agency	EPA
Federal Energy Regulatory Commission	FERC
Future Measurement and Verification	MV&V
Gross state product	GSP
Heating degree days	HDD
Integrated Gasification Combined Cycle	IGCC
Integrated Resource Plan	IRP
Liquefied Natural Gas	LNG
Load, Capacity, and Reserve Margin Table	LCR Table
Load-serving entities	LSE
Midwest Independent System Operator	Midwest ISO
Nantahala Power & Light	NP&L
New source performance standard	NSPS
Nitrogen Oxide	NOx
North American Electric Reliability Corporation	NERC
North Carolina Division of Air Quality	NCDAQ
North Carolina Electric Membership Corporation	NCEMC
North Carolina Municipal Power Agency #1	NCMPA1
North Carolina Transmission Planning Collaborative	NCTPC
North Carolina Utility Commission	NCUC
North Carolina Wildlife Resources Commission	NCWRC
Nuclear Regulatory Commission	NRC
Open Access Same Time Information System	OASIS
Open Access Transmission Tariff	OATT
Palmetto Clean Energy	PaCE
Piedmont Electric Membership Corporation	PEMC
Piedmont Municipal Power Agency	PMPA
Power Delivery Asset Management Plan	PDAMP
Present Value Revenue Requirements	PVRR
Public Service Commission of South Carolina	PSCSC
Public Utility Holding Company Act	PUHCA
Purchase Power Agreement	PPA
Rate Impact Measure	RIM
Renewable Energy and Energy Efficiency Portfolio Standard	REPS
Renewable Portfolio Standard	RPS
Request for Proposal	RFP
Saluda River Electric Cooperative	SR
South Carolina Department of Natural Resources	SCDNR
South Carolina Electric & Gas	SCE&G
Southeastern Electric Reliability Corporation	SERC
Southeastern Power Administration	SEPA
State Implementation Plan	SIP
Sulfur Dioxide	SO2
Total Resource Cost	TRC
United States Fish and Wildlife Service	USFWS
US Department of Energy	DOE
Utility Cost Test	UCT
Virginia-Carolinas	VACAR
Western Carolina University	WCU

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, reliable and environmentally-compliant alternatives to meet the projected energy needs of customers. 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 continues to be the most dynamic in Duke Energy Carolinas' 100-year-plus history. 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 2012, approximately 2,890 MW of additional resources are needed; by 2028, that number grows to 9,010 MW. The Cliffside 6 advanced clean coal unit and the Buck and Dan River Combined Cycle units are expected to be operational by the summer of 2012 which will fulfill 2,065 MW of this need. These resource needs also reflect the Company's commitment to retire 445 MW of older coal units by 2012 and an additional retirement of 600 MW of older coal by 2018. The factors that influence resource needs are:

- Future load growth projections;

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

- 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.

A key purpose of the IRP is to provide management with information to aid in making the decisions necessary to ensure that Duke Energy Carolinas has a reliable, diverse, environmentally-sound, and reasonably-priced portfolio of resources as these resources are needed over time. In this year's IRP, the analysis focuses on the near-term resource needs (from the present until 2012) and the time frame in which new nuclear capacity could be in place (as early as 2018). There is sufficient time in later IRPs to focus on specific resources needed for the intervening years.

As approved by the North Carolina Utilities Commission and the Public Service Commission of South Carolina, Duke Energy Carolinas is conducting project development work to evaluate the addition of the proposed William States Lee, III Nuclear Station in Cherokee County, South Carolina. The IRP nuclear analysis focuses on the impact of various uncertainties, such as nuclear capital costs, the impact of greenhouse gas legislation, and the availability of options such as federal loan guarantees that can help reduce the costs customers would pay for this greenhouse gas-emission free baseload resource.

The IRP analysis included sensitivities on each of these uncertainties. With regard to nuclear capital costs, three costs were modeled. These costs, identified as a low, mid, and high range of costs, are based on the latest information available for cost of the proposed Lee Nuclear Station.

With regard to the impact of greenhouse gas legislation, there is much uncertainty with regard to the level of greenhouse gas reduction that may be required by legislation and how the regulation could be administered. Due to this uncertainty, two reference cases were analyzed in this year's IRP process. The two cases are based on proposed greenhouse gas legislation that has been introduced in Congress in the past 3 years.

> Lower Carbon Case: The prices used for the Lower Carbon case are based on the safety-valve allowance price trajectory contained in legislation (S. 1766) introduced in July of 2007 by Senators Bingaman and Specter. The legislation proposed a gradually declining economy-wide greenhouse gas emissions cap beginning in 2012 and ending in 2030 at 1990 emission levels. The Senate has taken no action on the proposal. In general terms this legislation would control the nationwide growth of greenhouse gas emissions but did not result in net reductions of greenhouse gas emissions.
>
> Higher Carbon Case: The prices used for the Higher Carbon case are based on the results of modeling of legislation (S. 2191) introduced in October of 2007 by Senators Lieberman and Warner. The legislation proposed a declining economy-wide greenhouse gas emissions cap beginning in 2012 and ending in 2050 at a level 70% below 2005 emission levels. The legislation was passed by the Senate

Committee on Environment and Public Works in December of 2007, and was subsequently defeated in a procedural vote on the Senate floor in June of 2008.

With regard to nuclear financing options, this year's IRP incorporated tax and financing savings for the nuclear options. The Energy Policy Act of 2005 included incentives for new nuclear generation including production tax credits and federal loan guarantees. In addition, state and local incentives are available to support new nuclear development. Also, the impact of collecting construction financing costs prior to commercial operations, thereby lowering the ultimate cost to customers, was incorporated into the analysis. Such treatment is allowed in both North Carolina and South Carolina, but to different degrees. Depending on the assumptions related to tax and financing savings, the overall nuclear project cost can be reduced 13% to 32% over traditional utility tax and financing options. The nuclear cost, referenced as "traditional financing" in the 2008 Annual Plan analyses included production tax credits, state and local incentives, and the ability to obtain construction financing cost prior to commercial operation, which lowers the total project cost approximately 13% over standard utility tax and financing options. The nuclear cost referenced as "favorable financing" in the 2008 IRP included the advantages included in traditional financing above, as well as the advantages from securing the federal loan guarantees, which lower the project cost by a total of 32%.

The results of the quantitative and qualitative analyses suggest that a combination of additional baseload, intermediate, and peaking generation, renewable resources, and EE and DSM programs are required over the next 20 years. The near-term resource needs can be met with new EE and DSM programs, completing construction of the Buck, Dan River, and Cliffside Projects, as well as pursuing nuclear uprates and renewable resources.

With regard to the timeframe for new nuclear capacity, installation of one to two nuclear units in the 2018/2019 timeframe is the best option in the Higher Carbon scenario, as compared to meeting the generation need with natural gas generation. The selection of one or two nuclear units is dependent on the impact of greenhouse gas regulation, the commercial life of the nuclear asset, the ability to secure favorable financing and the installed price of the generation.

Both DSM and EE 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 Energy and Energy Efficiency Portfolio Standard (REPS). Energy savings resulting from EE programs may also be used in part to meet the REPS obligations. The Company has also prepared a REPS Compliance Plan as a part of its resource planning activities.

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's accomplishments in the past year and action to be taken in the next are summarized below:

- 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 filed its Energy Efficiency plan with the North Carolina Utilities Commission (NCUC) in May 2007. Following NCUC issuance of rules related to energy efficiency filings, the Company filed testimony which updated its Energy Efficiency plan. The NCUC held evidentiary hearings in July and August 2008.
  - Duke Energy Carolinas filed its Energy Efficiency plan with the Public Service Commission of South Carolina (PSCSC) in September 2007. Evidentiary hearings were held by the PSCSC in February 2008.
  - No order has been received on the proposed plan from either commission as of the date of the finalization of this IRP.
  - The Company will implement its Energy Efficiency plan upon commission approval.
- Continue construction of the 825 MW[2] Cliffside 6 unit, with the objective of bringing additional capacity on line by 2012 at the existing Cliffside Steam Station.
  - Duke Energy Carolinas received an air-quality permit from the North Carolina Division of Air Quality (NCDAQ) in January 2008. Various challenges to the air permit are ongoing.
  - Construction began immediately following the issuance of the air permit and is on-going.
- License, permit, and begin construction of new combined-cycle/peaking generation.
  - Duke Energy Carolinas received the Certificates of Public Convenience and Necessity (CPCN) from the NCUC for 1,240 MW (total) of combined-cycle natural gas generation at the Buck Steam Station and the Dan River Steam Station in June 2008.
    - The air permit application for the Buck combined cycle project was submitted the fourth quarter of 2007, and the final permit was received in October 2008. Construction is expected to begin the first quarter of 2010.
    - The air permit application for the Dan River combined cycle project was submitted in October 2008, with the final permit expected to be received by the end of 2009. Construction is expected to begin the first quarter of 2010.

[2] After final equipment selection and detailed engineering completed, Cliffside 6 is expected to have a net output of 825 MW versus the 800 MW used in previous IRPs.

- Duke Energy Carolinas filed preliminary CPCN information required by NCUC rules for expansion of the existing Rockingham Combustion Turbine Station by 632 MW in 2011. The Company has not decided whether this project will go forward, but the preliminary filing ensures the option to have peaking capacity on line in 2011. Other options may also be used to address remaining 2011 needs.

- Continue to preserve the option to secure new nuclear generating capacity.
  - Duke Energy Carolina filed an application with the Nuclear Regulatory (NRC) for a Combined Construction and Operating License (COL) in December 2007, with the objective of potentially bringing a new plant on line during the next decade.
  - NCUC and PSCSC approved the Company's request for approval of its decision to continue to incur nuclear project development costs
  - Pursue available federal, state and local tax incentives and favorable financing options at the federal and state level.
  - 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 renewable energy proposals was released in April 2007 which produced a proposed 1,942 megawatts of electricity from alternative sources from 26 different companies. The Company has entered into PPAs with two renewable energy facilities: one solar farm and one landfill gas (methane) facilities. Negotiations are underway for purchase of power from other potential projects.
- 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.[3] To meet this obligation, the Company conducted an integrated resource planning process that serves as the basis for its 2008 IRP.

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 greenhouse gas regulation 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?
- Greenhouse Gas Regulation: What type of greenhouse gas 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 DSM and EE 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?
- Coal Prices: What is the future of coal prices and supply? Will world demand keep coal prices elevated or is this a spike and will return to the long term trend?

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

[3] 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.

the options necessary to meet customers' needs. The process and resulting conclusions are discussed in this document.

This 2008 IRP will discuss the:

- Compliance with Appendix A, Article 11, Rule R8-60 Integrated Resource Planning and Filing requirements.
- 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 provides electric service to 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 2.37 million customers, Duke Energy Carolinas also sells wholesale electricity to incorporated municipalities and to public and private utilities. Table 2.1 and Table 2.2 show recent historical values for the number of customers and sales of electricity by customer groupings.

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

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Residential	1,626	1,669	1,710	1,758	1,782	1,814	1841	1,874	1,909	1,952
General Service	266	276	280	288	293	300	306	312	318	323
Industrial	9	9	8	8	8	8	8	8	7	7
Nantahala P&L	58	60	61	63	64	66	67	68	70	71
Other	9	10	10	11	11	11	12	13	13	13
Total	1,968	2,023	2,070	2,128	2,159	2,198	2,234	2,275	2,317	2,366
(Number of customers is average of monthly figures)										

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

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Electric Operations										
Residential	21,508	21,394	22,334	22,719	23,898	23,356	24,542	25,460	25,147	26,782
General Service	20,749	21,458	22,467	23,282	23,831	23,933	24,775	25,236	25,585	26,977
Industrial	30,514	29,767	29,632	26,784	26,141	24,645	25,085	25,361	24,396	23,829
Nantahala P&L	976	992	1,070	1,057	1,099	1,134	1,163	1,227	1,256	1,255
Other[a]	275	284	295	279	269	268	267	266	269	276
Total Retail Sales	74,022	73,895	75,797	74,121	75,238	73,336	75,832	77,550	76,653	79,119
Wholesale sales[b]	0,000	0,000	0,000	0,000	0,000	2,359	1,969	2,251	2,318	2,399
Total GWH Sold	74,022	73,895	75,797	74,121	75,238	75,695	77,801	79,801	78,971	81,518
[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 currently meets energy demand, in part, by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets:

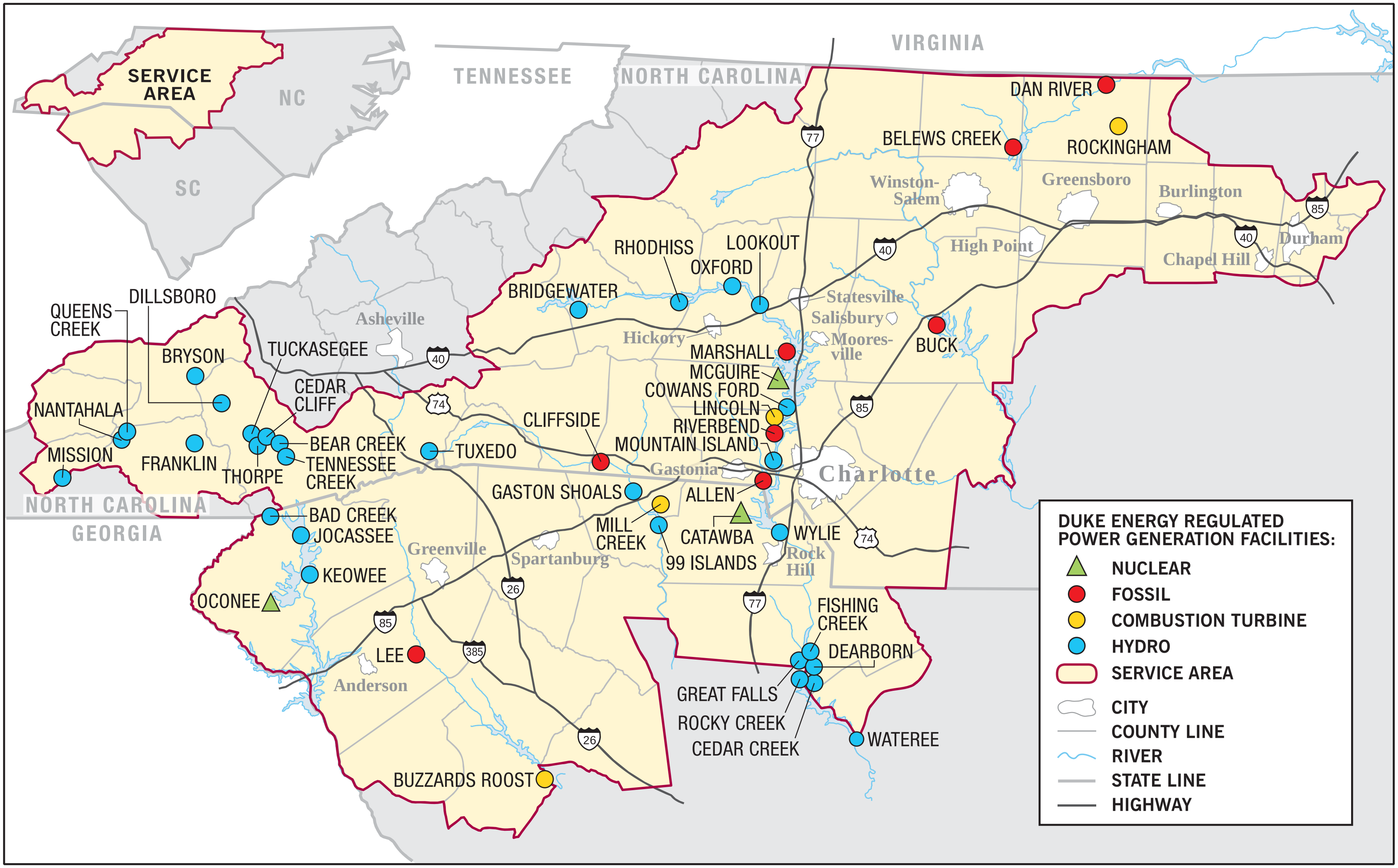
- Three nuclear generating stations with a combined net capacity of 6,996 MW (including all of Catawba Nuclear Station);

- Eight coal-fired stations with a combined capacity of 7,672 MW;
- 30 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 3,218 MW; and
- Eight combustion turbine stations with a combined capacity of 3,265 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 34 circuits connecting with eight different utilities – Progress Energy Carolinas, American Electric Power, Tennessee Valley Authority, Southern Company, Yadkin, Southeastern Power Administration (SEPA), South Carolina Electric and Gas, and Santee Cooper (also known as South Carolina Public Service Authority). These interconnections allow utilities to work together to provide an additional level of reliability. The strength of the system is also reinforced through coordination with other electric service providers in the Virginia-Carolinas (VACAR) subregion, Southeastern Electric Reliability 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. An audit was completed in April 2008 and Duke Energy Carolinas was found compliant in all areas of the audit.

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 group's purpose is to:

- 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 2007, Duke Energy Carolinas' nuclear and coal-fired generating units met the vast majority of customer needs by providing 46% and 53%, 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 below list the Duke Energy Carolinas plants in service in North Carolina and South Carolina with plant statistics, and the system's total generating capability.

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

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Allen	1	165.0	170.0	Belmont, N.C.	Conventional Coal
Allen	2	165.0	170.0	Belmont, N.C.	Conventional Coal
Allen	3	265.0	274.0	Belmont, N.C.	Conventional Coal
Allen	4	280.0	286.0	Belmont, N.C.	Conventional Coal
Allen	5	270.0	279.0	Belmont, N.C.	Conventional Coal
Allen Steam Station		**1145.0**	**1179.0**		
Belews Creek	1	1110.0	1135.0	Belews Creek, N.C.	Conventional Coal
Belews Creek	2	1110.0	1135.0	Belews Creek, N.C.	Conventional Coal
Belews Creek Steam Station		**2220.0**	**2320.0**		
Buck	3	75.0	76.0	Salisbury, N.C.	Conventional Coal
Buck	4	38.0	39.0	Salisbury, N.C.	Conventional Coal
Buck	5	128.0	131.0	Salisbury, N.C.	Conventional Coal
Buck	6	128.0	131.0	Salisbury, N.C.	Conventional Coal
Buck Steam Station		**369.0**	**377.0**		
Cliffside	1	38.0	39.0	Cliffside, N.C.	Conventional Coal
Cliffside	2	38.0	39.0	Cliffside, N.C.	Conventional Coal
Cliffside	3	61.0	62.0	Cliffside, N.C.	Conventional Coal
Cliffside	4	61.0	62.0	Cliffside, N.C.	Conventional Coal
Cliffside	5	562.0	568.0	Cliffside, N.C.	Conventional Coal
Cliffside Steam Station		**760.0**	**770.0**		
Dan River	1	67.0	69.0	Eden, N.C.	Conventional Coal
Dan River	2	67.0	69.0	Eden, N.C.	Conventional Coal
Dan River	3	142.0	145.0	Eden, N.C.	Conventional Coal
Dan River Steam Station		**276.0**	**283.0**		
Marshall	1	380.0	380.0	Terrell, N.C.	Conventional Coal
Marshall	2	380.0	380.0	Terrell, N.C.	Conventional Coal
Marshall	3	658.0	658.0	Terrell, N.C.	Conventional Coal
Marshall	4	660.0	660.0	Terrell, N.C.	Conventional Coal
Marshall Steam Station		**2078.0**	**2078.0**		
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		**7302.0 MW**	**7421.0 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
Lincoln Station CTs		**1267.2**	**1488.0**		

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
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		**2390.2 MW**	**2611.0 MW**		
McGuire	1	1100.0	1156.0	Huntersville, N.C.	Nuclear
McGuire	2	1100.0	1156.0	Huntersville, N.C.	Nuclear
McGuire Nuclear Station		**2200.0**	**2312.0**		
TOTAL N.C. NUCLEAR		**2200.0 MW**	**2312.0 MW**		
Bridgewater	1	11.5	11.5	Morganton, N.C.	Hydro
Bridgewater	2	11.5	11.5	Morganton, N.C.	Hydro
Bridgewater Hydro Station		**23.0**	**23.0**		
Bryson City	1	0.48	0.48	Whittier, N.C.	Hydro
Bryson City	1	0.5	0.5	Whittier, N.C.	Hydro
Bryson City Hydro Station		**0.98**	**0.98**		
Cowans Ford	1	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	2	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	3	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	4	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford Hydro		**325.0**	**325.0**		

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Station					
Dillsboro	1	0.175	0.175	Dillsboro, N.C.	Hydro
Dillsboro	2	0.05	0.05	Dillsboro, N.C.	Hydro
Dillsboro Hydro Station		**0.225**	**0.225**		
Lookout Shoals	1	9.3	9.3	Statesville, N.C.	Hydro
Lookout Shoals	2	9.3	9.3	Statesville, N.C.	Hydro
Lookout Shoals	3	9.3	9.3	Statesville, N.C.	Hydro
Lookout Shoals Hydro Station		**28.0**	**28.0**		
Mountain Island	1	14	14	Mount Holly, N.C.	Hydro
Mountain Island	2	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		**12,509.9 MW**	**12,961.7 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	42.0	42.0	Pelzer, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Lee	8C	42.0	42.0	Pelzer, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Lee Station CTs		**84.0**	**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
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

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
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**	**743.2**		
TOTAL S.C. COMB TURBINE		**875.4 MW**	**1015.2 MW**		
Catawba	1	1129.0	1163.0	York, S.C.	Nuclear
Catawba	2	1129.0	1163.0	York, S.C.	Nuclear
Catawba Nuclear Station		**2258.0**	**2326.0**		
Oconee	1	846.0	865.0	Seneca, S.C.	Nuclear
Oconee	2	846.0	865.0	Seneca, S.C.	Nuclear
Oconee	3	846.0	865.0	Seneca, S.C.	Nuclear
Oconee Nuclear Station		**2538.0**	**2595.0**		
TOTAL S.C. NUCLEAR		**4796.0 MW**	**4921.0 MW**		
Jocassee	1	170.0	170.0	Salem, S.C.	Pumped Storage
Jocassee	2	170.0	170.0	Salem, S.C.	Pumped Storage
Jocassee	3	195.0	195.0	Salem, S.C.	Pumped Storage
Jocassee	4	195.0	195.0	Salem, S.C.	Pumped Storage
Jocassee Pumped Hydro Station		**680.0**	**680.0**		
Bad Creek	1	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	2	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	3	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	4	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek Pumped Hydro Station		**1360.0**	**1360.0**		
TOTAL PUMPED STORAGE		**2090.0 MW**	**2090.0 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
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

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

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
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		**8641.7 MW**	**8912.5 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	**21,152**	**21,874**

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 November 1, 2008.

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

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

CATAWBA OWNER	PERCENT OF OWNERSHIP
Duke Energy Carolinas	19.246%
North Carolina Electric Membership Corporation (NCEMC)	30.754%
NCMPA#1	37.5%
Piedmont Municipal Power Agency (PMPA)	12.5%

Fuel Supply

Duke Energy Carolinas fuel usage consists primarily of coal and uranium. Oil and gas are used for peaking generation, but natural gas usage will expand when the Buck and Dan River Combined Cycle units are brought on-line.

Duke Energy Carolinas burns approximately 19 million tons of coal annually. Coal is procured primarily from Central Appalachian coal mines and delivered by the Norfolk Southern and CSX Railroads. The Company continually assesses coal market conditions to determine the appropriate mix of contract and spot market purchases in order to reduce exposure to the risk of price fluctuations. The Company also evaluates its diversity of coal supply from sources throughout the United States as well as international sources.

Eastern U.S. coal market prices are at an all-time high. The primary drivers for these increases are declining Central Appalachian coal production, increasing global coal demand, disruption to international coal supplies, and a dramatic increase in east coast U.S. coal exports into much higher priced European markets. In response, the Company is working to develop opportunities which will increase its ability for greater coal quality and regional supply diversification. The Company's goal is to develop greater supply and transportation flexibility in order to leverage changing opportunities in the increasingly volatile domestic and international markets.

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 increased nearly twenty-fold from calendar year 2000 market lows prior to retreating more than fifty percent from this recent peak. During this period of volatility the average unit cost of Duke Energy Carolinas' purchases of uranium has remained well below ongoing spot market prices due to legacy contracts. Industry consultants expect spot market prices to remain high in comparison to historic norms as exploration, mine construction, and production gear up. As fuel with a low cost basis is used and lower-priced legacy contracts are replaced with contracts at higher market prices, nuclear fuel expense is expected to gradually increase in the future. However, the uranium cost is less than 10 % of the total production cost and an increase should not have a large impact on total price of nuclear fuel.

The majority of the current 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 continues to support the development of renewable energy as a part of an overall company strategy to expand our renewable energy generation portfolio and to decarbonize our generation fleet. In North Carolina, the Company is exploring numerous investments in research and development of renewable energy technologies. Duke Energy Carolina's commitment to a low-carbon future is demonstrated by the following: voluntary renewable energy and carbon offset purchase programs for customers, a 2008 agreement to purchase all power from an 21.5 MW Direct Current (DC)[4] solar farm in Davidson County, plans to invest $100 million for 20 MW (DC)[3] of distributed solar generation technology, assessments of biomass co-firing opportunities at existing generation stations, expansion of interconnection standards in South Carolina, assessment of net metering in North Carolina, Qualifying Facility purchased power, hydro operations, the overwhelming response to the company's renewable energy request for proposal (26 companies submitted 94 development proposal variations), and additional research into renewable energy technologies.

In August of 2007, the North Carolina General Assembly enacted the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard ("REPS"). The NC REPS law seeks to diversify resources, provide greater energy security, encourage private investment in renewable energy and provide improved air quality and other benefits. Duke Energy Carolinas has been actively planning to develop and invest in renewable energy technology in order to achieve the goals of REPS. The NC REPS law requires Duke Energy Carolinas to achieve 3% of its electrical energy from renewable energy resources by 2012 with increasing requirements totaling 12.5% of its electrical energy from renewable energy resources by 2021. Likewise, Duke Energy Carolinas plans to achieve up to a quarter of the annual renewable energy requirements from energy efficiency programs such as the Company's proposed energy efficiency plan. Additionally, certain minimum "carve-out" requirements are included in the overall renewable energy requirements for solar energy, poultry waste resources and swine waste resources. Duke Energy Carolinas NC 2008 REPS Compliance Plan is filed as a separate document in the same NCUC docket as the IRP.

Duke Energy Carolinas released a renewable energy request for proposal ("RFP") in April 2007 in advance of the passage of NC REPS. The 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 (wood waste resources), swine waste, biodiesel, landfill gas, hydro, and biogas projects. The RFP process sought to determine which qualified renewable resources would provide the greatest value to customers and deliver a mix of renewable energy resources to Duke Energy Carolinas. After a thorough evaluation of 94 permutations from 26 bidders, Duke Energy Carolinas has identified a short list of bidders for contract negotiation. Currently, numerous negotiations are underway to procure renewable energy resources for the Carolinas system. Additionally, Duke Energy has also received several bids outside of the formal RFP process for poultry waste resources and other renewable energy resources.

[4] Approximately 80 to 85% of DC energy is delivered to the grid as useable alternating current (AC). It is also assumed that 70% of this capacity will be coincidental with the system peak.

Duke Energy Carolinas made two significant investments to acquire and develop solar energy resource capabilities. First, Duke Energy Carolinas announced it will purchase the entire electricity output of the nation's largest photovoltaic solar farm to be built in Davidson County, North Carolina. Through a 20-year purchase power agreement with SunEdison, Duke Energy will purchase an estimated 21.5 MW (DC) of power from solar energy farms to be developed in Davidson County. The agreement with SunEdison represents the first signed contract for the acquisition of solar energy resources to meet the North Carolina's REPS requirements. In addition, Duke Energy Carolinas has proposed a plan to invest $100 million in solar energy developments at up to 850 North Carolina sites including homes, schools, stores and factories. The distributed generation solar proposal will produce an estimated 20 MW (DC) nameplate of installed capacity to customers who will be compensated based on the size of the installation and the amount of energy it produces. This proposal for solar energy development by Duke Energy Carolinas will allow the Company to evaluate the role of distributed generation on our system and gain experience with owning solar energy assets. These solar energy investments will provide resources for the compliance with the REPS solar energy carve-out requirements of 0.02% (two-hundredths of one percent) for 2010 as well as 0.07% (seven-hundredths of one percent) by 2012.

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. Duke Energy Carolinas has donated more than $2,000,000 to NC GreenPower, which has helped spur growth of renewable generation.

The South Carolina Public Service Commission recently approved Palmetto Clean Energy (PaCE) and associated tariffs. The mission of PaCE is to encourage renewable generation development from resources such as sun, wind, hydro, and organic matter by enabling South Carolina electric consumers, businesses, and organizations to help offset the cost to produce green energy. Duke Energy Carolinas supports PaCE by facilitating voluntary customer contributions to the program. PaCE will serve a similar role as NC GreenPower by encouraging the growth of renewable energy resources in South Carolina. PaCE is an investor owned utility program across South Carolina and includes Duke Energy Carolinas, Progress Energy Carolinas and South Carolina Electric and Gas.

In July, Duke Energy Carolinas and NC GreenPower created a Carbon Offset Program for North Carolina customers interested in "canceling out" the carbon dioxide produced from their daily activities. The Carbon Offset program will empower customers who seek to offset their carbon dioxide emissions from today's energy intensive lifestyle. Through the purchase of carbon offsets for $4 a month—which represents 500 pounds of carbon dioxide, the equivalent of 500-kilowatt hours of electricity—customers can cancel out their carbon dioxide emissions. Typical residential customers will need to purchase 2 blocks of carbon offsets their average monthly consumption. Duke Energy Carolinas will match the first block of energy purchased by customers in North Carolina up to $1,000,000 through 2009. Program funds will be used to support carbon offset programs such as reforestation and the capture of methane gas from landfills. NC GreenPower will administer the carbon offset program following guidelines developed by the Environmental Defense Fund.

Duke Energy Carolinas, other utilities, and stakeholders previously submitted comments that led to the development of Model Small Generator Interconnection and net metering standards in North Carolina. The intent of the standards is to 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. The North Carolina Utilities Commission recently issued revised interconnection standards to facilitate the interconnection of all state-jurisdictional generator interconnections with utilities in North Carolina. The Public Service Commission of South Carolina recently approved Net Metering provisions in South Carolina.

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 - 4 MW; Catawba County Blackburn Landfill facility - 3 MW; Greenville Gas Producers, the Enoree Landfill Gas Generating Facility– 3 MW; Northbrook Carolina Hydro (5 facilities) - 6 MW; Town of Lake Lure Hydro - 2 MW; 43 other hydroelectric and photovoltaic energy providers - 6 MW total. (See Appendix J for further details).

Duke Energy Carolinas also owns and operates 30 hydroelectric stations having a combined generating capacity of 3168 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. The Company surrendered the license for Dillsboro hydroelectric facility pursuant to the FERC rules. 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.

Duke Energy Carolinas continues to explore the feasibility of co-firing at existing plants to provide additional renewable energy resources. The Company completed two fuel assessments and issued a Request for Proposal for evaluation of re-powering the Dan River Steam Station Unit 3 with 100% biomass. Duke Energy Carolinas also issued a Request for Proposal for siting studies to evaluate the potential for co-firing at all of the Carolinas fossil units. A test burn is currently scheduled for Buck Steam station early in 2009. Based on the evaluation of these studies, Duke Energy Carolinas will determine the potential for co-firing biomass within the Carolinas. Additionally, the Company plans to evaluate biodiesel in place of fuel oil during start up of its Carolinas fossil units.

Duke Energy Carolinas continues to work 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 has developed a comprehensive technical and business model to determine the optimal technology installation when considering renewable energy production and the emerging agricultural carbon offset market. The team is currently seeking funding to pilot the technology and test the model.

Duke Energy Carolinas continues to be interested in the potential to develop wind resources off-shore and in western North Carolina. We continue to monitor wind energy activity in the eastern and western part of the state, development of local municipal wind ordinances, and stakeholder organizations such as the NC Wind Working Group.

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

- o 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[5].

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 has filed for approval in both North Carolina and South Carolina of a new approach to EE and DSM programs which will 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 currently provides full requirements wholesale power sales to Western Carolina University (WCU), the city of Highlands, and to customers served under Rate Schedule 10A. In addition, the Company has committed to serve the full requirements wholesale power needs of the City of Orangeburg, South Carolina, beginning in 2011. The Company is also committed to serve the supplemental power needs of three cooperatives that are also co-owners with Duke Energy Carolinas of the Catawba Nuclear Station. 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).

[5] 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 IRP.

In addition, Duke Energy Carolinas has committed to provide backstand service for NCEMC throughout the 20-year planning horizon up to the amount of their ownership entitlement in Catawba Nuclear Station. On October 1, 2008, the Saluda River ownership portion of Catawba will not be reflected in the forecast due to a sale of this interest to Duke Energy Carolinas and NCEMC, which will result in the elimination of any obligation for Duke Energy Carolinas to plan for Saluda River's load. NCEMC is purchasing a portion of Saluda's share of Catawba which will serve to increase the NCEMC total backstand obligation.

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 expired December 31, 2007. The second is a backstand agreement of up to 432 MW (depending on operation of the Catawba and McGuire facilities) that expired 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 480 MW by 2011 and approximately 600 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 - Note 1 City of Concord, NC Town of Dallas, NC Town of Forest City, NC Town of Kings Mountain, NC 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 year 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
Orangeburg	Full Requirements	Native Load Priority	December 31, 2018		191	193	195	197	199	201	203	205	208	210									
Blue Ridge EMC **See Note 1**	Full Requirements	Native Load Priority	December 31, 2021	196	201	206	210	214	217	220	225	230	235	238	242	245	249	253	256	260	264	268	272
Piedmont EMC **See Note 1**	Full Requirements	Native Load Priority	December 31, 2021	102	103	105	106	107	108	109	111	112	114	115	117	119	121	123	124	126	128	130	132
Rutherford EMC **See Note 1**	Partial Requirements	Native Load Priority	December 31, 2021	59	58	58	162	164	193	194	207	211	215	218	221	225	228	231	235	238	242	246	249
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 MWs over the past 10 years. In addition, Duke Energy Carolinas has contracts with a number of Qualifying Facilities. Table 2.6 shows both the purchased power capacity obtained through RFPs as well as the larger Qualifying Facility agreements. See Appendix J for additional information on all purchases from Qualifying Facilities.

Table 2.6
Wholesale Purchased Power Commitments

SUPPLIER	CITY	STATE	SUMMER FIRM CAPACITY (MW)	WINTER FIRM CAPACITY (MW)	CONTRACT START	CONTRACT EXPIRATION
Calpine Energy	Columbia	SC	520	520	1/1/2008	12/31/2008
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
Greenville Gas Producers, LLC	Greer	SC	3	3	8/1/08	Ongoing
Northbrook Carolina Hydro, LLC	Various	Both	6	6	12/4/06	Ongoing
Progress Ventures, Inc. Unit 1	Salisbury	NC	153	185	6/1/07	12/31/10
Progress Ventures, Inc. Unit 2	Salisbury	NC	153	185	1/1/06	12/31/10
Progress Ventures, Inc. 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
Sun Edison LLC	Salisbury	NC	16	16	TBD	12/31/2030
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 August 1, 2008)

	WINTER 08/09	SUMMER 08
Total Non-Utility Generation	1,193 MW	1,090 MW
Duke Energy Carolinas allocation of SEPA capacity	19 MW	19 MW
Total Firm Purchases	1,212 MW	1,109 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 to reduce SO_2 and NOx. Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) regulations were overturned in the courts in 2008. These regulations would have further reduced SO_2, NOx and mercury emissions. It is likely that new legislation or revised regulations will replace CAIR and CAMR, but it is too early to estimate the level of control or timing of the replacement programs.

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 enacted a renewable energy portfolio standard in 2007, and the first compliance plan will be filed in a separate document, but in the same docket as the IRP. 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 2008 Forecast includes projections of the energy needs of new and existing customers in Duke Energy Carolinas service territory. Certain wholesale customers have the option of obtaining all or a portion of their future energy needs from other suppliers. While this may reduce Duke Energy Carolinas obligation to serve those customers, Duke Energy Carolinas assumes for planning purposes that certain of its existing wholesale customer load (excluding Catawba owner loads as discussed below) will remain part of the load obligation.

The forecasts for 2008 through 2028 include the energy needs of the wholesale and retail customer classes as follows:

- Duke Energy Carolinas retail, including the retail load associated with Nantahala Power and Light (NP&L) area
- Duke Energy Carolinas wholesale customers under Schedule 10A
- NP&L area wholesale customers Western Carolina University and the Town of Highlands
- NCEMC load relating to ownership of Catawba
- Load equating to the portion of Catawba ownership related to the Saluda River Electric Cooperative Inc. (SR) until October 1, 2008
- Blue Ridge, Piedmont and Rutherford Electric Membership Cooperatives' supplemental load requirements starting in 2006
- Hourly electricity sale to NCEMC beginning in January 2009
- The city of Orangeburg supplemental load requirements starting in 2009
- Undesignated wholesale load of approximately 300 MWs in 2011 and 600 MWs in 2012 in recognition of potential wholesale load sales.

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

Per NCUC Rule R8-60 (i) (1) a description of the methods, models and assumptions used by the utility to prepare its peak load (MW) and energy sales (MWH) forecasts and the variables used in the models is provided on pages 4-6 of the Duke Energy Carolinas 2008 Forecast shown in Appendix B. Also, per Rule R8-60 (i) (1) (A) a forecast of customers by each customer class and a forecast of energy sales (KWH) by each customer class is provided on pages 9-14 and pages 19-23 of the 2008 Forecast Book.

The current 20-year forecast, which does not include the impact of new EE programs, projects 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 1.5 percent. If the impacts of new EE programs as shown in Appendix I are included, the average annual growth in summer peak demand is 1.5 percent, while winter peaks are forecasted to grow at an average annual rate of 1.2 percent. The forecast for average annual territorial energy need is 1.4 percent. The growth rates use projected 2008 information as the base year with a 18,011 MW summer peak, a 16,161 MW winter peak and a 94,282 GWH average annual territorial energy need.

Duke Energy Carolinas retail sales have grown at an average annual rate of 1.7 percent from 1992 to 2007. (Retail sales, excluding line losses, are approximately 83 percent of the total energy considered in the 2008 IRP.) This 15-year period of history reflects 10 years of strong load growth from 1992 to 2002 followed by five years of very little growth from 2002 to 2007. The following table shows historical and projected major customer class growth rates.

Table 3.1
Retail Load Growth (kWh sales)

Time Period	Total Retail	Residential	General Service	Industrial Textile	Industrial Non-Textile
1992 to 2007	1.7%	2.8%	3.6%	-5.2%	1.3%
1992 to 2002	2.0%	3.0%	4.2%	-3.2%	1.4%
2002 to 2007	1.0%	2.3%	2.5%	-9.2%	1.0%
2007 to 2028	1.0%	1.1%	1.8%	-5.4%	0.6%

A decline in the Industrial Textile class was the key contributor to the low load growth from 2002 to 2007, offset by growth in the Residential and General Service classes over the same period. Over the last 5 years, an average of approximately 50,000 new residential customers per year was added to the Duke Energy Carolinas service area.

Duke Energy Carolinas' total retail load growth over the planning horizon is driven by the expected growth in Residential and General Service classes. Sales to the Industrial Textile class are expected to decline, but not as much as in the last five years. The Industrial Non-Textile class is expected to show positive growth, particularly in the Automobile, Rubber & Plastics and Chemicals (excluding Man-Made Fibers). (Additional details on the current forecast can be found in the Duke Energy Carolinas Spring 2008 Forecast in Appendix B.)

A tabulation of the utility's forecasts for a 20- year period, including peak loads for summer and winter seasons of each year, annual energy forecasts and load duration curves is shown below. The load forecast for the 2008 IRP which does not include new EE programs is shown below (followed by the load duration curves for 2008, 2013, 2018 and 2023):

<u>Table 3.2</u>
Load Forecast without Energy Efficiency

YEAR[a,b,c,d,e]	SUMMER (MW)[f]	WINTER (MW)[f]	TERRITORIAL ENERGY (GWH)[f]
2009	18,400	16,407	95,552
2010	18,730	16,652	96,729
2011	19,384	17,205	99,640
2012	19,853	17,624	101,637
2013	20,017	17,756	102,144
2014	20,194	17,886	102,611
2015	20,471	18,062	103,717
2016	20,769	18,288	105,063
2017	21,054	18,514	106,311
2018	21,337	18,722	107,315
2019	21,625	18,935	108,680
2020	21,951	19,176	110,243
2021	22,271	19,392	112,127
2022	22,569	19,628	114,042
2023	22,884	19,865	116,005
2024	23,211	20,118	118,142
2025	23,547	20,393	120,336
2026	23,880	20,628	122,526
2027	24,223	20,884	124,729
2028	24,522	21,141	126,939

Note a: The MW (demand) forecasts above are the same as those shown on page 28 of the Duke Energy Carolinas Spring 2008 Forecast, but the peak forecasts vary from those shown on pages 24-27 of the Forecast, primarily because Spring 2008 Forecast Book's peak forecasts include the total resource needs for all Catawba Joint Owners. Does not include the undesignated wholesale load used for planning purposes.

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 October 1, 2008, 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 September 30, 2008.

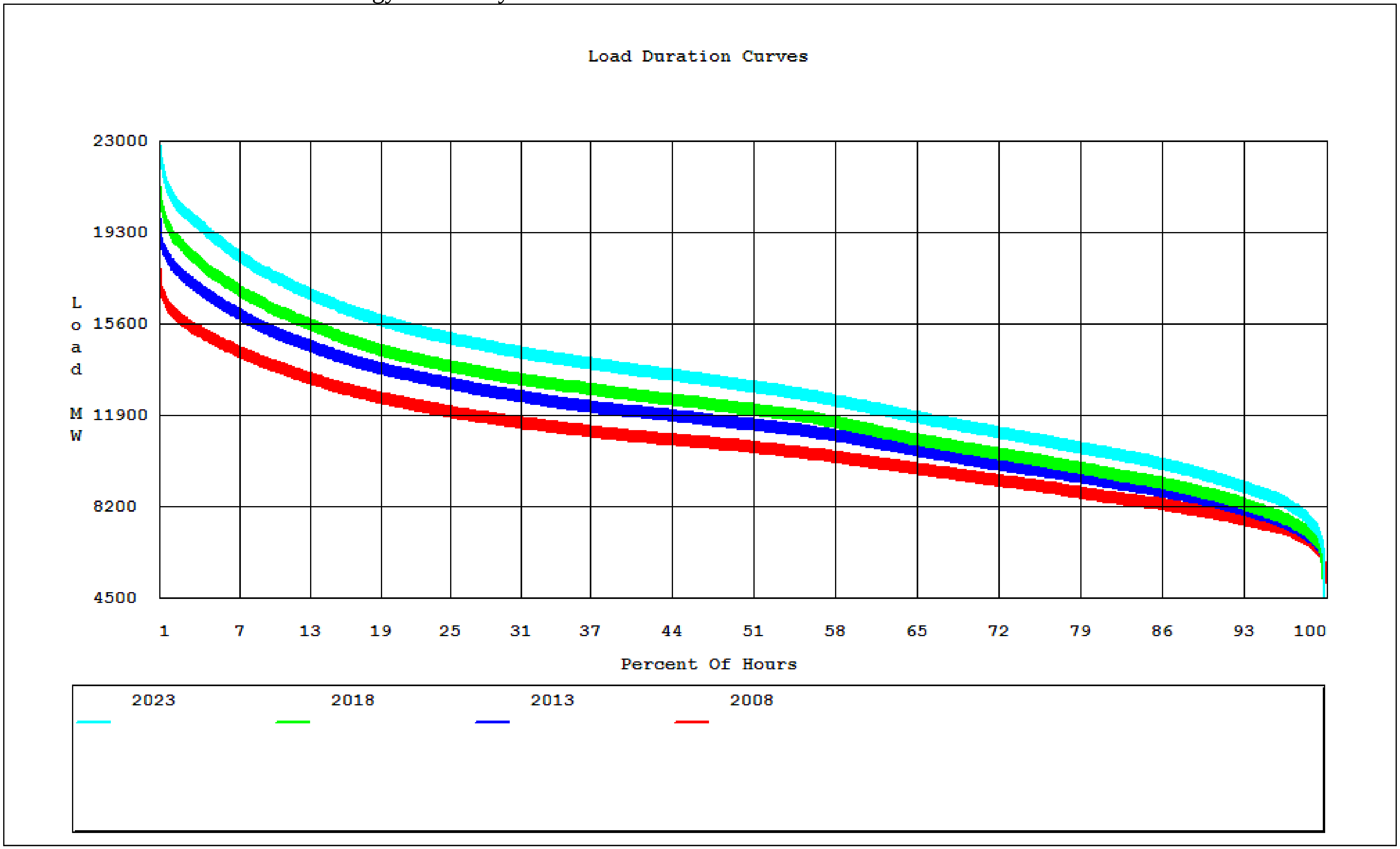
Note c: The load forecast includes Duke Energy Carolinas' contract to serve Blue Ridge, Piedmont and Rutherford Electric Membership Cooperatives' supplemental load requirements from 2006 through 2028. A new contract between Duke Energy Carolinas and NCEMC will provide additional hourly electricity sales 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 (1,039 MW at 2007 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 will the PMPA ownership interest in Catawba be included in the load forecast beginning in 2006, because PMPA also terminated its existing Interconnection Agreement with Duke Energy Carolinas effective January 1, 2006. Therefore, Duke Energy Carolinas is not responsible for providing reserves for the PMPA ownership interest in Catawba. These changes reduce the Duke Energy Carolinas load forecast by the forecasted PMPA load in the control area (478 MW at 2007 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).

Load Duration Curves without Energy Efficiency

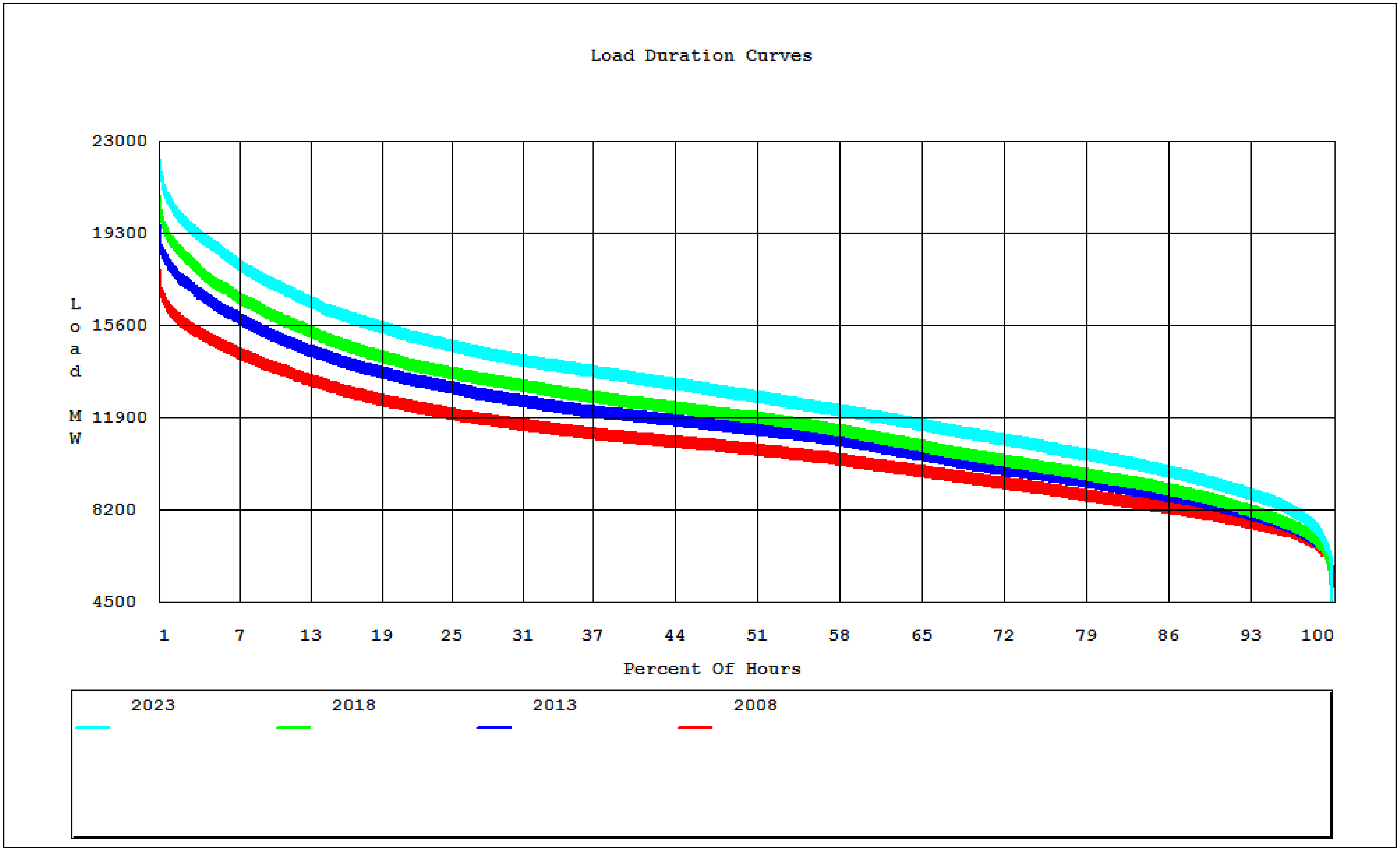


The load forecast for the 2008 IRP which includes the Wholesale Strategy and also includes new energy efficiency programs, as reflected in Section 4, is shown below (followed by the load duration curves for 2008, 2013, 2018 and 2023):

Table 3.3
Load Forecast with Energy Efficiency

YEAR[a,b,c,d,e]	SUMMER (MW)[f]	WINTER (MW)[f]	TERRITORIAL ENERGY (GWH)[f]
2009	18,362	16,402	95,455
2010	18,624	16,581	96,441
2011	19,214	17,063	99,167
2012	19,622	17,425	100,980
2013	19,722	17,494	101,304
2014	19,830	17,558	101,580
2015	20,044	17,664	102,502
2016	20,339	17,832	103,662
2017	20,701	17,997	104,729
2018	20,915	18,138	105,542
2019	20,983	18,281	106,722
2020	21,221	18,465	108,097
2021	21,919	18,622	109,899
2022	22,202	18,859	111,814
2023	22,528	19,096	113,778
2024	22,471	19,349	115,909
2025	22,775	19,626	118,109
2026	23,108	19,859	120,299
2027	23,869	20,114	122,503
2028	24,178	20,372	124,705

Load Duration Curves with Energy Efficiency



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
In March 2007, Duke Energy Carolinas received a CPCN for the 825 MW Cliffside 6 unit, which is scheduled to be on line in 2012. Duke Energy Carolinas received an air-quality permit from the North Carolina Division of Air Quality (NCDAQ) in January 2008. Various challenges to the air permit are ongoing. Construction began immediately following the issuance of the air permit.

Catawba Nuclear Station
On September 30, 2008, Duke Energy Carolinas completed the purchase of 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 own approximately 19 percent of the Catawba Nuclear Station, compared to the current ownership of 12.5 percent.

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 in June 2007.

Jocassee Unit 1 and 2 Runner upgrades
Capacity additions reflect an estimated 50 MW capacity up-rate at the Jocassee pumped storage facility from increased efficiency from the new runners to be installed in 2011.

Belews Creek Lower Pressure Rotor Upgrade
Capacity additions reflect an estimated 36 MW capacity up-rate at Belews Creek Steam Station due to increased efficiency from new low pressure turbine rotors on Units 1 and 2 to be installed in 2009.

Buck Combined Cycle Natural Gas Unit
A CPCN application was filed for adding approximately 600-800 MW of combined cycle generation at the Buck Steam Station in Salisbury, N.C. Hearings were held in March 2008 and approval was received in June 2008. The air permit was received in October 2008. Economic factors in 2008 have caused increased uncertainty with regard to forecasted load and near term capital expenditures. While current projections indicate there is still a capacity need in the 2011-2012 timeframe, the timing of the Buck simple cycle to combined cycle "phase-in" has been extended a year 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.

Dan River Combined Cycle Natural Gas Unit

A CPCN application was filed for adding approximately 600-800 MW of combined cycle generation at the Dan River Steam Station in Eden, N.C. Hearings were held in March 2008 and approval was received in June 2008. The air permit application was submitted in October 2008, with the final permit expected to be received by the end of 2009. Economic factors in 2008 have caused increased uncertainty with regard to forecasted load and near term capital expenditures. While current projections indicate there is still a capacity need in the 2011-2012 timeframe, the Dan River simple cycle to combined cycle "phase-in" has been changed to not phase-in the generation but continue with the combined cycle generation to be available by the summer of 2012.

Short term capacity needs to maintain an acceptable reserve margin can be met with any combination of built or purchased generation, purchase power agreements, or increased DSM. In addition, the timing and phase-in of the Buck and Dan River projects can continue to be optimized.

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 2008, the overall capability of the purchased power contracts is approximately 1109 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. There are two requirements related to the retirement of 800 MWs of older coal units. The first, a condition set fourth in the NCUC Order in Docket No. E-7, Sub 790, granting a CPCN to build Cliffside Unit 6, requires the retirement of the existing Cliffside Units 1-4 no later than the commercial operation date of the new unit, and retirement of 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[6]. The requirement to retire older coal is also set forth in the air permit for the new Cliffside unit, in addition to Cliffside Units 1-4, of 350 MWs of coal generation by 2015, an additional 200 MWs by 2016, and an additional 250 MWs by 2018. If the North Carolina Utilities Commission determines that the scheduled retirement of any unit identified for retirement pursuant to the Plan will have a material adverse impact of the reliability of electric generating

[6] Ref NCUC Docket No. E-7, Sub 790 Order Granting CPCN with Conditions, March 21, 2007

system, Duke may seek modification of the this plan. For planning purposes, the retirement dates for these 800 MWs of older coal is associated with the expected verification of realized EE load reductions, which is expected to occur earlier than the retirement dates set forth in the air permit.

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

Table 3.3
Projected Unit Retirements

STATION	CAPACITY IN MW	LOCATION	DECISION DATE	PLANT TYPE
Buck 4*	38	Salisbury, N.C.	6/30/2011	Conventional Coal
Buck 3*	75	Salisbury, N.C.	6/30/2012	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.	6/30/2012	Conventional Coal
Dan River 2*	67	Eden, N.C.	6/30/2012	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 is sufficient to provide reliable power supplies, based on the prevailing expectations of reasonable lead times for the development of new generation, siting of transmission facilities, and procurement of purchased capacity. As part of the Company's process for determining its target planning reserve margins, Duke Energy Carolinas reviews whether the current target planning reserve margin is adequate in the prior period. From July 2004 through July 2008, 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 July 2008.

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 available than traditional supply-side resources) in the plan due to the enactment of the REPS 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.

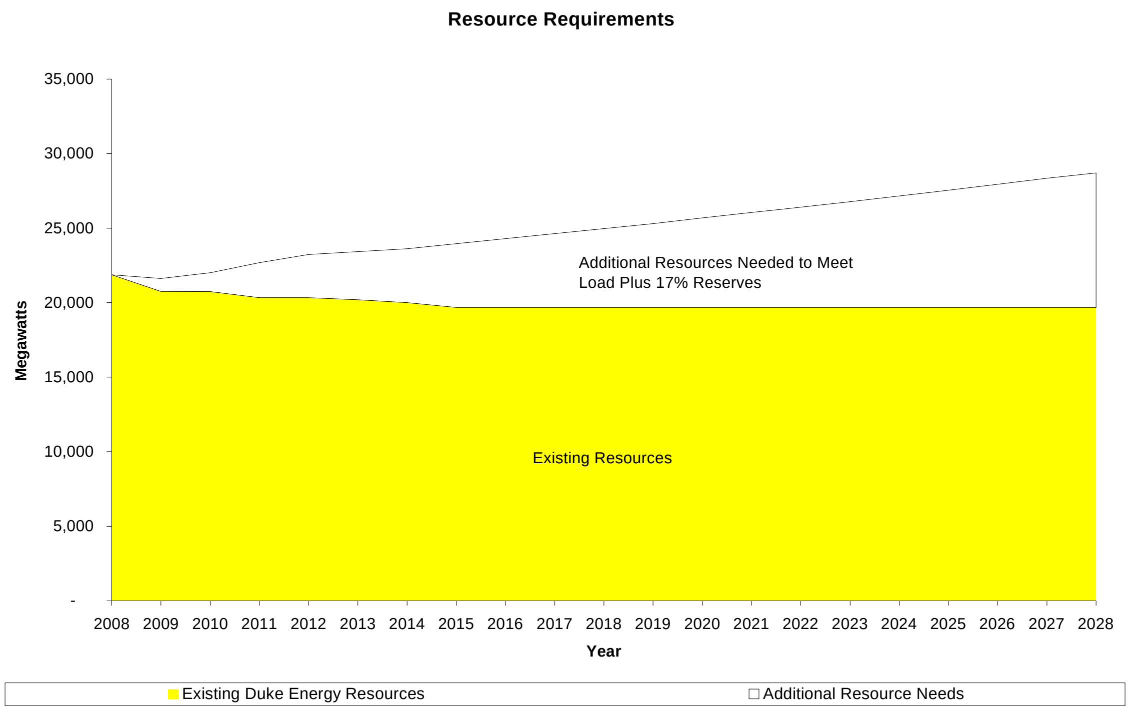
Duke Energy Carolinas also assesses its reserve margins on a short-term basis to determine whether to pursue additional capacity in the short-term power market. As each peak demand season approaches, the Company has a greater level of certainty regarding the customer load forecast and total system capability,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

Duke Energy Carolinas uses adjusted system capacity[7], 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 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 2008, existing resources, consisting of existing generation and purchased power to meet load requirements, total 21,870 MW. The load obligation plus the target planning reserve margin is 21,073 MW, indicating sufficient resources to meet Duke Energy Carolinas' obligation. 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 5,280 MW by 2018 and to 9,010 MW by 2028.

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



[7] Adjusted system capacity is calculated by adding the expected capacity of each generating unit plus firm purchased power capacity.

Cumulative Resource Additions To Meet A 17 Percent Planning Reserve Margin

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Resource Need	0	870	1,270	2,340	2,890	3,220	3,630	4,270	4,620	4,950	5,280

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Resource Need	5,620	6,000	6,380	6,720	7,090	7,480	7,870	8,260	8,660	9,010

IV. RESOURCE ALTERNATIVES TO MEET FUTURE ENERGY NEEDS

Many potential resource options are available to meet future energy needs. They range from expanding EE and DSM resources 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 REPS 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.

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

EE and DSM Program Screening

The Company uses the DSMore model to evaluate the costs, benefits, and risks of DSM and EE programs and measures. DSMore is a financial analysis tool designed to estimate the value of a DSM/EE measure at an hourly level across distributions of weather and/or energy costs or prices. By examining projected program performance and cost effectiveness over a wide variety of weather and cost conditions, the Company is in a better position to measure the risks and benefits of employing DSM/EE measures versus traditional generation capacity additions, and further, to ensure that DSM resources are compared to supply side resources on a level playing field.

The analysis of energy efficiency cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the California Standard tests: Utility Cost Test ("UCT"), Rate Impact Measure ("RIM") Test, Total Resource Cost ("TRC") Test, Participant Test, and Societal Test. DSMore provides the results of those tests for any type of energy efficiency program (demand response and/or energy conservation).

The test results are also provided for a range of weather conditions, including normal weather, and under various cost and market price conditions. Because DSMore is designed to be able to analyze extreme conditions, it is possible to obtain a distribution of cost-effectiveness outcomes or expectations. Avoided costs for DSM/EE tend to increase with increasing market prices and/or more extreme weather conditions due to the covariance between load and costs/prices. Understanding the manner in which program cost-effectiveness varies under these conditions allows a more precise valuation of EE programs and DSM programs.

Generally, the DSMore model requires the user to input specific information regarding the measure or program to be analyzed as well as the cost and rate information of the utility. These inputs enable the user to then analyze the cost-effectiveness of the measure or program. The information required on a program or measure includes:

- Number of program participants, including free rider-ship or free drivers
- Projected program costs, contractor costs and/or administration
- Customer incentives, demand response credits or other incentives
- Measure life, incremental customer costs and/or annual maintenance costs
- Load impacts (kWh, kW and the hourly timing of reductions)
- Hours of interruption, magnitude of load reductions or load floors

The utility information required for the model includes:

- Discount rate
- Loss ratio, either for annual average losses or peak losses
- Rate structure, or tariff appropriate for a given customer class
- Avoided costs of energy, capacity, transmission & distribution
- Cost escalators

The Company develops the inputs for the program or measure using information on expected program costs, load impacts, customer incentives necessary to drive customers' participation, free rider expectations, and expected number of participants. This information is used in initial runs of the model to determine cost-effectiveness and whether adjustments need to be made to a program or measure in order for it to pass the Participant Test, the first critical test.

Inputs for each program or measure are derived from industry information such as EPRI, Energy Star, E-Source, other utility program information, as well as from external experts in the industry. Over time, as impact and process evaluations are performed on Duke Energy Carolinas program results, information and input specifically related to Duke Energy Carolinas customers will be identified and be used within future cost-effectiveness analyses.

The net present value of the financial stream of costs versus benefits is assessed, i.e., the costs to implement the measures are valued against the savings or avoided costs. The resultant benefit/cost ratios, or tests, provide a summary of the measure's cost-effectiveness relative to the benefits of its projected load impacts. As previously mentioned, the Participant Test is the first screen for a program or measure to make sure a program makes economic sense for the individual consumer. Duke Energy Carolinas also uses the Utility Cost Test ("UCT"), the Total Resource Cost Test ("TRC"), and the Ratepayer Impact Test ("RIM") Test for screening measures.

The Participant Test compares the benefits to the participant through bill savings and incentives from the utility, relative to the costs to the participant for implementing the measure. The costs can include capital cost as well as increased annual operating cost, if applicable.

The UCT compares utility benefits (avoided costs) relative to incurred utility costs to implement the program, and does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, including the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs, and load (line) losses.

The TRC test compares the total benefits to the utility and to participants relative to the costs to the utility to implement the program along with the costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the Participant Test, however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC.

The RIM Test, or non-participants test, indicates if rates increase or decrease over the long-run as a result of implementing the program.

The use of multiple tests can ensure the development of a reasonable set of DSM/EE programs, indicate the likelihood that customers will participate, and also protect against cross-subsidization.

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).

The collaborative efforts resulted in the Company's May 7, 2007 North Carolina DSM/EE filing[8] and September 28, 2007 South Carolina filing[9]. 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.

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 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.

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

The Duke Energy Carolinas' proposed EE plan complies with the requirement set forth in the Cliffside Unit 6 CPCN Order[10] to spend at least 1% of annual retail revenue requirement from the sale of electricity on future conservation and demand response programs each year, subject to appropriate 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 2,890 MW needed by 2012 by producing up to 1,256 MW 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 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.

[10] Ref NCUC Docket No. E-7, Sub 790 Order Granting CPCN with Conditions, March 21, 2007.

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, EE, and DSM programs is required over the next twenty years to meet customer demand reliably and cost-effectively.

The new pulverized coal units at Cliffside (Cliffside Unit 6) and the new combined cycle facilities at the Buck and Dan River Steam stations have received CPCNs from the NCUC and were incorporated in the base generation. In addition, Duke Energy Carolinas has included DSM/EE and renewable resources consistent with the Company's proposed energy efficiency plan and to meet the REPS. While near-term, there are no significant additional capacity needs beyond these committed and planned additions, the Company has capacity needs in 2011 and beyond. Decisions are necessary in the next year with regard to meeting these needs. Options include adding peaking capacity (either Duke Energy Carolinas' owned or by purchased power agreement) or nuclear uprates. The analysis demonstrates that nuclear uprates at an attractive price are beneficial. This option will be explored further over the next year.

The nuclear analysis focused on the impact of various uncertainties, such as nuclear capital costs, the impact of greenhouse gas legislation, and the availability of options such as federal loan guarantees that can help reduce the costs customers would pay for nuclear.

The IRP analysis included sensitivities on each of these uncertainties. With regard to nuclear capital costs, three costs were modeled. These costs, identified as low, mid, and high costs, are based on the latest information available for cost of the proposed Lee Nuclear Station.

With regard to the impact of greenhouse gas legislation, there is much uncertainty with regard to the level of greenhouse gas reduction that may be required by legislation and how the regulation could be administered. Due to this uncertainty, two reference cases were analyzed in this year's IRP process. The two cases are based on proposed greenhouse gas legislation that has been introduced in Congress in the past 3 years.

Lower Carbon Case: The prices used for the Lower Carbon case are based on the safety-valve allowance price trajectory contained in legislation (S. 1766) introduced in July of 2007 by Senators Bingaman and Specter. The legislation proposed a gradually declining economy-wide greenhouse gas emissions cap beginning in 2012 and ending in 2030 at 1990 emission levels. The Senate has taken no action on the proposal. In general terms this legislation would controll the nationwide growth of greenhouse gas emissions but did not result in net reductions of greenhouse gas emissions.

Higher Carbon Case: The prices used for the Higher Carbon case are based on the results of modeling of legislation (S. 2191) introduced in October of 2007 by Senators Lieberman and Warner. The legislation proposed a declining economy-wide greenhouse gas emissions cap beginning in 2012 and ending in 2050 at a level 70% below 2005 emission levels. The legislation was passed out of the Senate Committee on Environment and Public Works in December of 2007, and was subsequently defeated in a procedural vote on the Senate floor in June of 2008.

To put these cases in perspective the current President of the United States, George W. Bush, committed to reduce U.S. CO_2 emissions by 50% in 2050 at the 2008 G8 conference. Also, both 2008 presidential candidates have set forth energy plans that include plans for CO_2 legislation that would result in reductions between 65% and 80% by 2050.

With regard to nuclear financing options, this year's IRP incorporated tax and financing savings for the nuclear options. The Energy Policy Act of 2005 included incentives for new nuclear generation including production tax credits and federal loan guarantees. In addition, state and local incentives are available to support new nuclear development. Also, the impact of collecting construction financing costs prior to commercial operations, thereby lowering the ultimate cost to customers, was incorporated into the analysis. Such treatment is allowed in both North Carolina and South Carolina, but to different degrees. Depending on the assumptions related to tax and financing savings, the overall nuclear project cost can be reduced 13% to 32% over traditional utility tax and financing options. The nuclear cost, referenced as "traditional financing" in the 2008 IRP analyses included production tax credits, state and local incentives, and the ability to obtain construction financing cost prior to commercial operation, which lowers the total project cost approximately 13% over standard utility tax and financing options. The nuclear cost referenced as "favorable financing" in the 2008 IRP included the advantages included in traditional financing above, as well as the advantages from securing the federal loan guarantees, which lower the project cost by a total of 32%.

The results of the quantitative and qualitative analyses suggest that a combination of additional baseload, intermediate, and peaking generation, renewable resources, and EE and DSM programs are required over the next 20 years. The near-term resource needs can be met with new EE and DSM programs, completing construction of the Buck, Dan

River, and Cliffside Projects, as well as pursuing nuclear uprates and renewable resources.

With regard to the timeframe for new nuclear capacity, installation of one to two nuclear units in the 2018/2019 timeframe is the best option in the Higher Carbon scenario, as compared to meeting the generation need with natural gas generation. The selection of one or two nuclear units is dependent on the impact of greenhouse gas regulation, the commercial life of the nuclear asset, the ability to secure favorable financing and the installed price of the generation.

To demonstrate that the Company is planning adequately for customers, two portfolios, incorporating a lower and higher carbon future, were selected for the purposes of preparing the Load, Capacity, and Reserve Margin Table (LCR Table).

For the Lower Carbon scenario, the portfolio consisting of 3,992 MW[11] of new natural gas simple cycle capacity, 1,117 MW of new nuclear capacity, 1,016 MW of Demand-Side Management, 790 MW of Energy Efficiency, and 684 MW of renewable resources was selected. The portfolio for the Higher Carbon scenario was the same as the Lower Carbon scenario with the exception of the amount of new natural gas simple cycle capacity and purchase power agreements. In the Higher Carbon scenario, the amount of natural gas simple cycle capacity was reduced from 3,992 MW to 200 MW with a 2 year 632 MW purchase power agreement. The reason for the reduced capacity was due to projected lower energy demand in a Higher Carbon scenario. Both of these portfolios included the Cliffside Unit 6 and Buck and Dan River CT/CC Projects.

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. 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 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 DSM/EE programs, and continue on-going collaborative work to develop and implement additional DSM/EE products and services.
    - Duke Energy Carolinas filed its Energy Efficiency plan with the NCUC in May 2007.
    - The NCUC held evidentiary hearings regarding its proposed Energy Efficiency plan in July and August 2008.
    - Duke Energy Carolinas made an Energy Efficiency filing with the PSCSC in September 2007.

[11] The ultimate sizes of any generating unit may change somewhat depending on the vendor selected.

- The PSCSC held evidentiary hearings regarding its proposed Energy Efficiency plan in February 2008.
- No order has been received on the proposed plans as of the date of the finalization of this report.
- The Company will implement its Energy Efficiency plan upon commission approval.

- Continue construction of the 825 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 received an air-quality permit from the North Carolina Division of Air Quality (NCDAQ) in January 2008. Various challenges to the air permit are ongoing.
  - Construction began immediately following the issuance of the air permit.
- License and permit new combined-cycle/peaking generation.
  - Duke Energy Carolinas received the CPCNs from the NCUC for 1,240 MW (total) of combined-cycle generation at the Buck Steam Station and the Dan River Steam Station in June 2008.
  - The air permit application for the Buck combined cycle project was received in October 2008. Construction is expected to begin the first quarter of 2010.
  - The air permit application for the Dan River project is scheduled to be submitted by the fourth quarter of 2008, with the final permit expected to be received in the fourth quarter of 2009. Construction is expected to begin the first quarter of 2010.
  - Duke Energy Carolinas filed the preliminary information required by NCUC rules 120 days prior to filing a CPCN application to expand the existing Rockingham Combustion Turbine Station by 632 MWs. The Company has not decided whether this project will go forward but is ensuring the option is preserved to have peaking capacity on line in 2011 through this filing. Other options may also be used to address remaining 2011 needs.
- Continue to preserve the option to secure new nuclear generating capacity.
  - Duke Energy Carolina filed an application with the Nuclear Regulatory (NRC) for a Combined Construction and Operating License (COL) in December 2007, with the objective of potentially bringing a new plant on line during the next decade.
  - NCUC and PSCSC approved the Company's request for approval to continue nuclear project development cost expenditures.
  - Pursue available federal, state and local tax incentives and favorable financing options at the federal and state level.
  - Continue to assess opportunities to benefit form 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 renewable energy proposals was released in April 2007 which produced a proposed 1,942 megawatts of electricity from alternative sources from 26 different companies. Agreement has been reached with one solar and one landfill gas (methane) purchase power agreement and negotiations are still underway for other potential projects.
- Continue to monitor energy-related statutory and regulatory activities.

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.

The seasonal projections of load, capacity, and reserves of the selected plan are provided in tabular form below for both the Lower Carbon and Higher Carbon scenarios.

Summer Projections of Load, Capacity, and Reserves
for Duke Power and Nantahala Power and Light
2008 Annual Plan Lower Carbon Case

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Forecast																				
1 Duke System Peak	18,400	18,730	19,384	19,853	20,017	20,194	20,471	20,769	21,054	21,337	21,625	21,951	22,271	22,569	22,884	23,211	23,547	23,880	24,223	24,522
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	18,361	18,621	19,211	19,617	19,716	19,823	20,035	20,271	20,491	20,704	20,927	21,191	21,484	21,782	22,097	22,424	22,760	23,093	23,436	23,735
Cumulative System Capacity																				
3 Generating Capacity	20,043	20,068	20,053	20,439	21,781	21,777	21,581	21,095	20,962	20,829	20,829	20,829	20,829	20,829	20,829	20,829	20,829	20,829	20,829	20,829
4 Capacity Additions	36	9	424	1,749	138	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Capacity Derates	(11)	(23)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Capacity Retirements	0	0	(38)	(407)	(142)	(196)	(486)	(133)	(133)	0	0	0	0	0	0	0	0	0	0	0
7 Cumulative Generating Capacity	20,068	20,053	20,439	21,781	21,777	21,581	21,095	20,962	20,829	20,829	20,829	20,829	20,829	20,829	20,829	20,829	20,829	20,829	20,829	20,829
8 Cumulative Purchase Contracts	690	690	239	239	94	94	72	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	0	0	0	0	1,117	1,117	1,117	1,117	1,117	1,117	1,117	1,117	1,117	1,117	1,117
Peaking/Intermediate	0	0	600	0	0	632	1,264	1,896	1,896	1,896	1,896	1,896	1,896	1,896	2,528	2,528	3,160	3,792	3,792	3,992
Renewables	0	0	17	113	113	113	161	161	208	300	387	481	577	582	582	628	631	631	684	684
11 Cumulative Production Capacity	20,758	20,743	21,295	22,133	21,984	22,420	22,592	23,091	23,005	24,214	24,301	24,395	24,491	24,496	25,128	25,174	25,809	26,441	26,494	26,694
Reserves w/o DSM																				
12 Generating Reserves	2,396	2,122	2,085	2,516	2,268	2,597	2,557	2,820	2,514	3,511	3,374	3,204	3,007	2,714	3,031	2,750	3,049	3,348	3,058	2,959
13 % Reserve Margin	13.0%	11.4%	10.9%	12.8%	11.5%	13.1%	12.8%	13.9%	12.3%	17.0%	16.1%	15.1%	14.0%	12.5%	13.7%	12.3%	13.4%	14.5%	13.0%	12.5%
14 % Capacity Margin	11.5%	10.2%	9.8%	11.4%	10.3%	11.6%	11.3%	12.2%	10.9%	14.5%	13.9%	13.1%	12.3%	11.1%	12.1%	10.9%	11.8%	12.7%	11.5%	11.1%
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
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	21,519	21,641	22,311	23,149	23,000	23,436	23,608	24,107	24,021	25,230	25,316	25,410	25,507	25,512	26,144	26,190	26,825	27,457	27,510	27,710
Reserves w/DSM																				
17 Equivalent Reserves	3,157	3,020	3,100	3,531	3,284	3,613	3,573	3,836	3,530	4,526	4,390	4,220	4,023	3,730	4,047	3,766	4,065	4,364	4,074	3,975
18 % Reserve Margin	17.2%	16.2%	16.1%	18.0%	16.7%	18.2%	17.8%	18.9%	17.2%	21.9%	21.0%	19.9%	18.7%	17.1%	18.3%	16.8%	17.9%	18.9%	17.4%	16.7%
19 % Capacity Margin	14.7%	14.0%	13.9%	15.3%	14.3%	15.4%	15.1%	15.9%	14.7%	17.9%	17.3%	16.6%	15.8%	14.6%	15.5%	14.4%	15.2%	15.9%	14.8%	14.3%
Firm Wholesale Sales																				
Catawba Owner Load Following Agreement	23	23																		
Catawba Owner Backstand	73	73																		
20 Equivalent Reserves	3061	2924	3100	3531	3284	3613	3573	3836	3530	4526	4390	4220	4023	3730	4047	3766	4065	4364	4074	3975
21 % Reserve Margin	16.7%	15.7%	16.1%	18.0%	16.7%	18.2%	17.8%	18.9%	17.2%	21.9%	21.0%	19.9%	18.7%	17.1%	18.3%	16.8%	17.9%	18.9%	17.4%	16.7%
22 % Capacity Margin	14.2%	13.5%	13.9%	15.3%	14.3%	15.4%	15.1%	15.9%	14.7%	17.9%	17.3%	16.6%	15.8%	14.6%	15.5%	14.4%	15.2%	15.9%	14.8%	14.3%

Winter Projections of Load, Capacity, and Reserves
for Duke Power and Nantahala Power and Light
2008 Annual Plan Lower Carbon Case

	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	27/28
Forecast																				
1 Duke System Peak	16,407	16,652	17,205	17,624	17,756	17,886	18,062	18,288	18,514	18,722	18,935	19,176	19,392	19,628	19,865	20,118	20,393	20,628	20,884	21,141
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	16,402	16,581	17,063	17,424	17,494	17,558	17,663	17,831	17,995	18,137	18,279	18,462	18,621	18,857	19,094	19,347	19,622	19,857	20,113	20,370
Cumulative System Capacity																				
3 Generating Capacity	20,766	20,766	20,780	21,055	21,641	22,505	22,501	22,305	21,819	21,686	21,553	21,553	21,553	21,553	21,553	21,553	21,553	21,553	21,553	21,553
4 Capacity Additions	0	36	325	728	1,129	138	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Capacity Derates	0	(22)	(12)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Capacity Retirements	0	0	(38)	(142)	(265)	(142)	(196)	(486)	(133)	(133)	0	0	0	0	0	0	0	0	0	0
7 Cumulative Generating Capacity	20,766	20,780	21,055	21,641	22,505	22,501	22,305	21,819	21,686	21,553	21,553	21,553	21,553	21,553	21,553	21,553	21,553	21,553	21,553	21,553
8 Cumulative Purchase Contracts	794	794	246	246	94	94	72	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	0	0	0	0	0	1,117	1,117	1,117	1,117	1,117	1,117	1,117	1,117	1,117	1,117
Peaking/Intermediate	0	0	0	0	0	0	632	1,264	1,896	1,896	1,896	1,896	1,896	1,896	1,896	2,528	2,528	3,160	3,792	3,792
Renewables	0	0	17	17	113	113	113	161	161	208	300	387	481	577	582	582	628	631	631	684
11 Cumulative Production Capacity	21,560	21,574	21,318	21,904	22,712	22,708	23,122	23,316	23,815	23,729	24,937	25,024	25,118	25,215	25,220	25,852	25,898	26,533	27,165	27,218
Reserves w/o DSM																				
12 Generating Reserves	5,158	4,993	4,255	4,479	5,218	5,150	5,459	5,484	5,820	5,592	6,658	6,562	6,497	6,357	6,125	6,504	6,275	6,675	7,051	6,847
13 % Reserve Margin	31.4%	30.1%	24.9%	25.7%	29.8%	29.3%	30.9%	30.8%	32.3%	30.8%	36.4%	35.5%	34.9%	33.7%	32.1%	33.6%	32.0%	33.6%	35.1%	33.6%
14 % Capacity Margin	23.9%	23.1%	20.0%	20.5%	23.0%	22.7%	23.6%	23.5%	24.4%	23.6%	26.7%	26.2%	25.9%	25.2%	24.3%	25.2%	24.2%	25.2%	26.0%	25.2%
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
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	22,050	22,194	22,049	22,635	23,443	23,439	23,853	24,047	24,546	24,460	25,669	25,756	25,850	25,946	25,951	26,583	26,630	27,265	27,897	27,950
Reserves w/DSM																				
17 Equivalent Reserves	5,648	5,613	4,987	5,211	5,950	5,882	6,191	6,216	6,552	6,324	7,390	7,294	7,229	7,089	6,857	7,236	7,007	7,407	7,783	7,579
18 % Reserve Margin	34.4%	33.9%	29.2%	29.9%	34.0%	33.5%	35.0%	34.9%	36.4%	34.9%	40.4%	39.5%	38.8%	37.6%	35.9%	37.4%	35.7%	37.3%	38.7%	37.2%
19 % Capacity Margin	25.6%	25.3%	22.6%	23.0%	25.4%	25.1%	26.0%	25.8%	26.7%	25.9%	28.8%	28.3%	28.0%	27.3%	26.4%	27.2%	26.3%	27.2%	27.9%	27.1%
Firm Wholesale Sales																				
Catawba Owner Load Following Agreement	23	23																		
Catawba Owner Backstand	73	73																		
20 Equivalent Reserves	5552	5517	4987	5211	5950	5882	6191	6216	6552	6324	7390	7294	7229	7089	6857	7236	7007	7407	7783	7579
21 % Reserve Margin	33.8%	33.2%	29.2%	29.9%	34.0%	33.5%	35.0%	34.9%	36.4%	34.9%	40.4%	39.5%	38.8%	37.6%	35.9%	37.4%	35.7%	37.3%	38.7%	37.2%
22 % Capacity Margin	25.2%	24.9%	22.6%	23.0%	25.4%	25.1%	26.0%	25.8%	26.7%	25.9%	28.8%	28.3%	28.0%	27.3%	26.4%	27.2%	26.3%	27.2%	27.9%	27.1%

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 summe peak of that year. Capacity must be online by Dec 1 to be included in the available capacity for the winter pea of that year. Includes 103 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station les 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 thei interconnection agreement with Duke Energy Carolinas

4. Capacity Additions reflect an estimated 50 MW capacity uprate at the Jocassee pumped storage facility from increase efficiency from the new runners, 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
   The 150 MW addition in Catawba Nuclear Station resulting from the Saluda River acquisition was completed in September of 2008. However, there was no change to Catawba's capacity due to this acquition. Saluda River's portion of load associated with Catawba has historically been modeled within Duke Energy's load projections. Therefore Saluda's ownership in Catawba has also been included in the Existing Capacity for Load, Capacity and Reserves reporting
   Capacity Additions include Duke Energy Carolinas projects that have been approved by the NCUC (Cliffside 6 Buck and Dan River Combined Cycle facilities).
   Also included is a 197 MW capacity increase due to nuclear uprates at Catawba, McGuire, and Oconee; with 58 MW added by 2011 and 138 MW added by 2013.

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 Allen 1 - 5 followed by Cliffside 5

6. The 38 MW capacity retirement in summer 2011 represents the projected retirement date for Buck 4
   The 402 MW capacity retirement in summer 2012 represents the projected retirement dates for Buck 3 (75 MW) Dan River 1 and 2 (134 MW), and Cliffside units 1-4 (198 MW).
   The 142 MW capacity retirement in summer 2013 represents the projected retirement date for Dan River unit 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 (94 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 t 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 contrac which began in June 1998 and expires June 2013 and miscellaneous other QF projects totaling 22 MW
   C. Purchase of 153 MW from Rowan County Power, LLC, Unit 3 began June 1, 2004 and expires May 31, 2008
   D. Purchase of 151 MW from Rowan Unit 2 began January 1, 2006 and expires December 31, 2010
   E. Purchase of 153 MW from Rowan Unit 1 began June 1, 2007 and expires December 31, 2010
   F. 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 increase 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

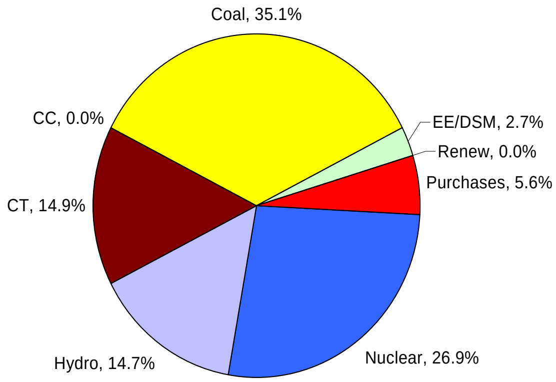
15. The Cumulative Demand Side Management capacity includes new Demand Side Management capacity representing placeholders for demand response and energy efficiency programs

20. Equivalent Reserves:

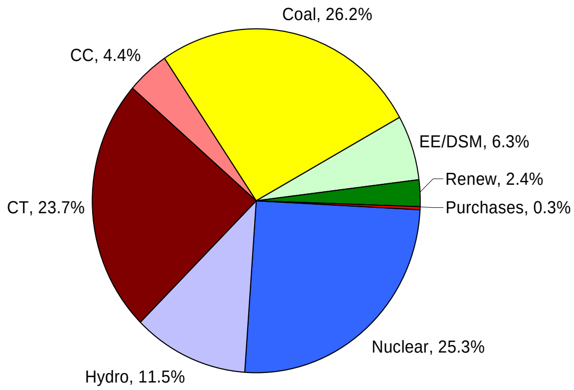
    Two firm wholesale agreements are effective between Duke Energy Carolinas and NCMPA1. The first is a 23 MW load following agreement that expires year-end 2010. The second is a backstand agreement of up to 432 MW (depending on operation of the Catawba and McGuire facilities) that was extended through 2010

The charts below show the changes in Duke Energy Carolinas' capacity mix and energy mix between 2008 and 2028 under Lower Carbon Case conditions. The relative shares of renewables, energy efficiency, and gas all increase, while the relative share of coal decreases.

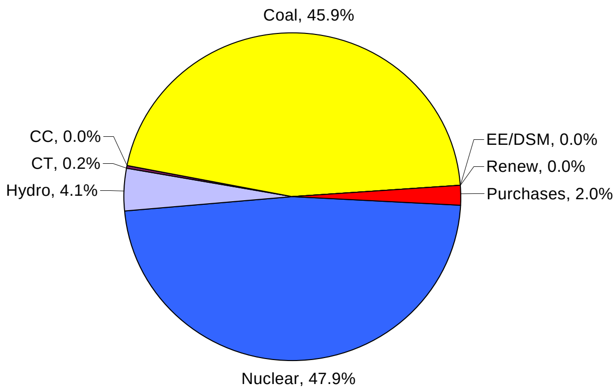
2008 Duke Energy Carolinas Capacity



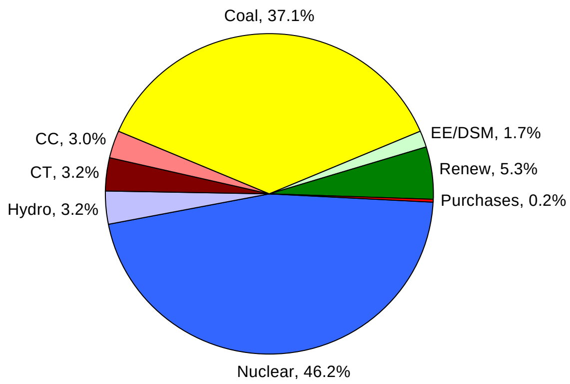
2028 Duke Energy Carolinas Capacity



2008 Duke Energy Carolinas Energy



2028 Duke Energy Carolinas Energy



The table below represents the annual incremental additions reflected in the LCR Table of the most robust Lower Carbon Case expansion plan. 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.

Year	Project	MW
2010	Renewable	17
2011	Nuclear Uprates	58
2011	PPA	600
2011	Buck Combined Cycle (Ph)	316
2012	Buck Combined Cycle (Ph)	304
2012	Dan River Combined Cycle	620
2012	Renewable	96
2012	Cliffside 6	825
2013	Nuclear Uprates	138
2014	New CT	632
2015	Renewable	48
2015	New CT	632
2016	New CT	632
2017	Renewable	47
2018	Renewable	92
2018	Lee Nuclear	1,117
2019	Renewable	87
2020	Renewable	94
2021	Renewable	96
2022	Renewable	5
2023	New CT	632
2024	Renewable	46
2025	Renewable	3
2025	New CT	632
2026	New CT	632
2027	Renewable	53
2028	New CT	200

Summer Projections of Load, Capacity, and Reserves
for Duke Power and Nantahala Power and Light
2008 Annual Plan Higher Carbon Case

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Forecast																				
1 Duke System Peak	18,400	18,730	19,384	19,853	19,617	19,588	19,646	19,766	19,870	19,967	20,064	20,191	20,364	20,514	20,675	20,844	21,018	21,119	21,224	21,286
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	18,361	18,621	19,211	19,617	19,316	19,217	19,210	19,268	19,307	19,334	19,366	19,431	19,577	19,727	19,888	20,057	20,231	20,332	20,437	20,499
Cumulative System Capacity																				
3 Generating Capacity	20,043	20,068	20,053	20,439	21,781	21,777	21,581	21,095	20,962	20,829	20,829	20,829	20,829	20,829	20,829	20,829	20,829	20,829	20,829	20,829
4 Capacity Additions	36	9	424	1,749	138	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Capacity Derates	(11)	(23)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Capacity Retirements	0	0	(38)	(407)	(142)	(196)	(486)	(133)	(133)	0	0	0	0	0	0	0	0	0	0	0
7 Cumulative Generating Capacity	20,068	20,053	20,439	21,781	21,777	21,581	21,095	20,962	20,829	20,829	20,829	20,829	20,829	20,829	20,829	20,829	20,829	20,829	20,829	20,829
8 Cumulative Purchase Contracts	690	690	239	239	94	94	72	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	0	0	0	0	1,117	1,117	1,117	1,117	1,117	1,117	1,117	1,117	1,117	1,117	1,117
Peaking/Intermediate	0	0	600	0	0	0	0	632	632	0	0	0	0	0	0	0	0	0	200	200
Renewables	0	0	17	113	113	113	161	161	208	300	387	481	577	582	582	628	631	631	684	684
11 Cumulative Production Capacity	20,758	20,743	21,295	22,133	21,984	21,788	21,328	21,827	21,741	22,318	22,405	22,499	22,595	22,600	22,600	22,646	22,649	22,649	22,902	22,902
Reserves w/o DSM																				
12 Generating Reserves	2,396	2,122	2,085	2,516	2,668	2,571	2,118	2,559	2,434	2,985	3,039	3,068	3,018	2,873	2,712	2,589	2,418	2,317	2,465	2,403
13 % Reserve Margin	13.0%	11.4%	10.9%	12.8%	13.8%	13.4%	11.0%	13.3%	12.6%	15.4%	15.7%	15.8%	15.4%	14.6%	13.6%	12.9%	12.0%	11.4%	12.1%	11.7%
14 % Capacity Margin	11.5%	10.2%	9.8%	11.4%	12.1%	11.8%	9.9%	11.7%	11.2%	13.4%	13.6%	13.6%	13.4%	12.7%	12.0%	11.4%	10.7%	10.2%	10.8%	10.5%
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
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	21,519	21,641	22,311	23,149	23,000	22,804	22,344	22,843	22,757	23,334	23,420	23,514	23,611	23,616	23,616	23,662	23,665	23,665	23,918	23,918
Reserves w/DSM																				
17 Equivalent Reserves	3,157	3,020	3,100	3,531	3,684	3,587	3,134	3,575	3,450	4,000	4,055	4,084	4,034	3,889	3,728	3,605	3,434	3,333	3,481	3,419
18 % Reserve Margin	17.2%	16.2%	16.1%	18.0%	19.1%	18.7%	16.3%	18.6%	17.9%	20.7%	20.9%	21.0%	20.6%	19.7%	18.7%	18.0%	17.0%	16.4%	17.0%	16.7%
19 % Capacity Margin	14.7%	14.0%	13.9%	15.3%	16.0%	15.7%	14.0%	15.6%	15.2%	17.1%	17.3%	17.4%	17.1%	16.5%	15.8%	15.2%	14.5%	14.1%	14.6%	14.3%
Firm Wholesale Sales																				
Catawba Owner Load Following Agreement	23	23																		
Catawba Owner Backstand	73	73																		
20 Equivalent Reserves	3061	2924	3100	3531	3684	3587	3134	3575	3450	4000	4055	4084	4034	3889	3728	3605	3434	3333	3481	3419
21 % Reserve Margin	16.7%	15.7%	16.1%	18.0%	19.1%	18.7%	16.3%	18.6%	17.9%	20.7%	20.9%	21.0%	20.6%	19.7%	18.7%	18.0%	17.0%	16.4%	17.0%	16.7%
22 % Capacity Margin	14.2%	13.5%	13.9%	15.3%	16.0%	15.7%	14.0%	15.6%	15.2%	17.1%	17.3%	17.4%	17.1%	16.5%	15.8%	15.2%	14.5%	14.1%	14.6%	14.3%

Winter Projections of Load, Capacity, and Reserves
for Duke Power and Nantahala Power and Light
2008 Annual Plan Higher Carbon Case

	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	27/28
Forecast																				
1 Duke System Peak	16,407	16,652	17,205	17,624	17,401	17,349	17,334	17,405	17,473	17,520	17,568	17,639	17,732	17,841	17,948	18,067	18,202	18,243	18,299	18,351
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	16,402	16,581	17,063	17,424	17,139	17,021	16,935	16,948	16,954	16,935	16,912	16,925	16,961	17,070	17,177	17,296	17,431	17,472	17,528	17,580
Cumulative System Capacity																				
3 Generating Capacity	20,766	20,766	20,780	21,055	21,641	22,505	22,501	22,305	21,819	21,686	21,553	21,553	21,553	21,553	21,553	21,553	21,553	21,553	21,553	21,553
4 Capacity Additions	0	36	325	728	1,129	138	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Capacity Derates	0	(22)	(12)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Capacity Retirements	0	0	(38)	(142)	(265)	(142)	(196)	(486)	(133)	(133)	0	0	0	0	0	0	0	0	0	0
7 Cumulative Generating Capacity	20,766	20,780	21,055	21,641	22,505	22,501	22,305	21,819	21,686	21,553	21,553	21,553	21,553	21,553	21,553	21,553	21,553	21,553	21,553	21,553
8 Cumulative Purchase Contracts	794	794	246	246	94	94	72	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	0	0	0	0	0	1,117	1,117	1,117	1,117	1,117	1,117	1,117	1,117	1,117	1,117
Peaking/Intermediate	0	0	0	0	0	0	0	0	632	632	0	0	0	0	0	0	0	0	0	200
Renewables	0	0	17	17	113	113	113	161	161	208	300	387	481	577	582	582	628	631	631	684
11 Cumulative Production Capacity	21,560	21,574	21,318	21,904	22,712	22,708	22,490	22,052	22,551	22,465	23,041	23,128	23,222	23,319	23,324	23,324	23,370	23,373	23,373	23,626
Reserves w/o DSM																				
12 Generating Reserves	5,158	4,993	4,255	4,479	5,573	5,687	5,555	5,103	5,597	5,530	6,129	6,203	6,261	6,248	6,146	6,027	5,938	5,900	5,844	6,045
13 % Reserve Margin	31.4%	30.1%	24.9%	25.7%	32.5%	33.4%	32.8%	30.1%	33.0%	32.7%	36.2%	36.6%	36.9%	36.6%	35.8%	34.8%	34.1%	33.8%	33.3%	34.4%
14 % Capacity Margin	23.9%	23.1%	20.0%	20.5%	24.5%	25.0%	24.7%	23.1%	24.8%	24.6%	26.6%	26.8%	27.0%	26.8%	26.4%	25.8%	25.4%	25.2%	25.0%	25.6%
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
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	22,050	22,194	22,049	22,635	23,443	23,439	23,221	22,783	23,282	23,196	23,773	23,860	23,954	24,050	24,055	24,055	24,102	24,105	24,105	24,358
Reserves w/DSM																				
17 Equivalent Reserves	5,648	5,613	4,987	5,211	6,305	6,419	6,287	5,835	6,329	6,262	6,861	6,935	6,993	6,980	6,878	6,759	6,670	6,632	6,576	6,777
18 % Reserve Margin	34.4%	33.9%	29.2%	29.9%	36.8%	37.7%	37.1%	34.4%	37.3%	37.0%	40.6%	41.0%	41.2%	40.9%	40.0%	39.1%	38.3%	38.0%	37.5%	38.6%
19 % Capacity Margin	25.6%	25.3%	22.6%	23.0%	26.9%	27.4%	27.1%	25.6%	27.2%	27.0%	28.9%	29.1%	29.2%	29.0%	28.6%	28.1%	27.7%	27.5%	27.3%	27.8%
Firm Wholesale Sales																				
Catawba Owner Load Following Agreement	23	23																		
Catawba Owner Backstand	73	73																		
20 Equivalent Reserves	5552	5517	4987	5211	6305	6419	6287	5835	6329	6262	6861	6935	6993	6980	6878	6759	6670	6632	6576	6777
21 % Reserve Margin	33.8%	33.2%	29.2%	29.9%	36.8%	37.7%	37.1%	34.4%	37.3%	37.0%	40.6%	41.0%	41.2%	40.9%	40.0%	39.1%	38.3%	38.0%	37.5%	38.6%
22 % Capacity Margin	25.2%	24.9%	22.6%	23.0%	26.9%	27.4%	27.1%	25.6%	27.2%	27.0%	28.9%	29.1%	29.2%	29.0%	28.6%	28.1%	27.7%	27.5%	27.3%	27.8%

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 summe peak of that year. Capacity must be online by Dec 1 to be included in the available capacity for the winter pea of that year. Includes 103 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station les 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 thei interconnection agreement with Duke Energy Carolinas

4. Capacity Additions reflect an estimated 50 MW capacity uprate at the Jocassee pumped storage facility from increase efficiency from the new runners, 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
   The 150 MW addition in Catawba Nuclear Station resulting from the Saluda River acquisition was completed in September of 2008. However, there was no change to Catawba's capacity due to this acquition. Saluda River's portion of load associated with Catawba has historically been modeled within Duke Energy's load projections. Therefore Saluda's ownership in Catawba has also been included in the Existing Capacity for Load, Capacity and Reserves reporting

   Capacity Additions include Duke Energy Carolinas projects that have been approved by the NCUC (Cliffside 6 Buck and Dan River Combined Cycle facilities).

   Also included is a 197 MW capacity increase due to nuclear uprates at Catawba, McGuire, and Oconee; with 58 MW added by 2011 and 138 MW added by 2013.

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 Allen 1 - 5 followed by Cliffside 5

6. The 38 MW capacity retirement in summer 2011 represents the projected retirement date for Buck 4
   The 402 MW capacity retirement in summer 2012 represents the projected retirement dates for Buck 3 (75 MW) Dan River 1 and 2 (134 MW), and Cliffside units 1-4 (198 MW).
   The 142 MW capacity retirement in summer 2013 represents the projected retirement date for Dan River unit 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 (94 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 contrac which began in June 1998 and expires June 2013 and miscellaneous other QF projects totaling 22 MW
   C. Purchase of 153 MW from Rowan County Power, LLC, Unit 3 began June 1, 2004 and expires May 31, 2008
   D. Purchase of 151 MW from Rowan Unit 2 began January 1, 2006 and expires December 31, 2010
   E. Purchase of 153 MW from Rowan Unit 1 began June 1, 2007 and expires December 31, 2010
   F. 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. The Cumulative Demand Side Management capacity includes new Demand Side Management capacity representing placeholders for demand response and energy efficiency programs

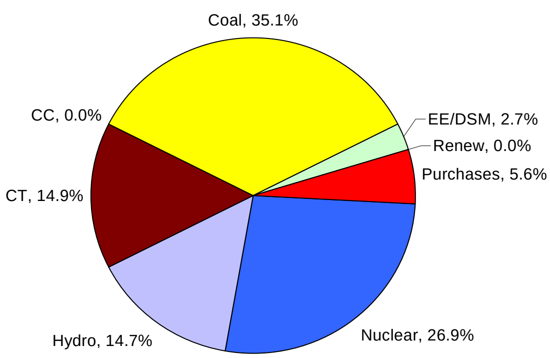
20. Equivalent Reserves:

    Two firm wholesale agreements are effective between Duke Energy Carolinas and NCMPA1. The first is a 23 MW load following agreement that expires year-end 2010. The second is a backstand agreement of up to 432 MW (depending on operation of the Catawba and McGuire facilities) that was extended through 2010

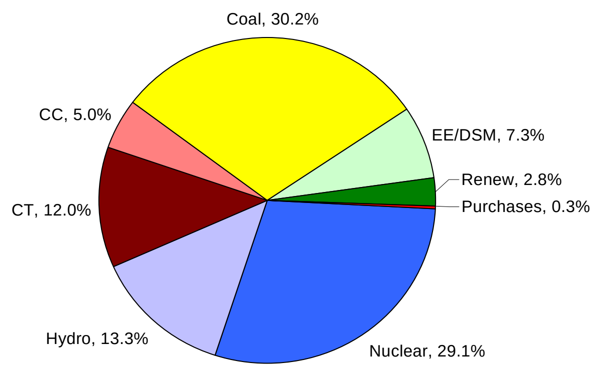
The charts below show the changes in Duke Energy Carolinas' capacity mix and energy mix between 2008 and 2028 under Higher Carbon Case conditions. The relative shares of renewables, energy efficiency, and gas all increase, while the relative share of coal decreases.

In the Higher Carbon 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.

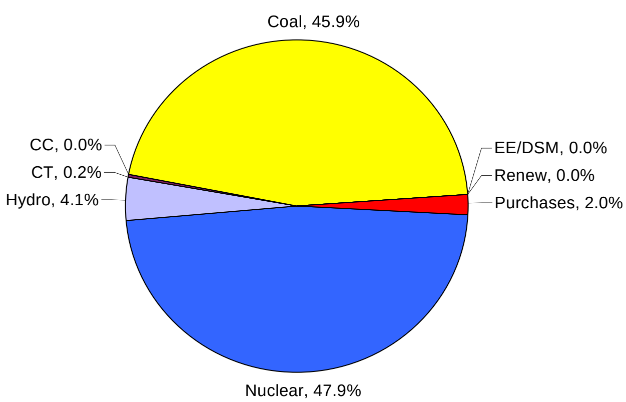
2008 Duke Energy Carolinas Capacity



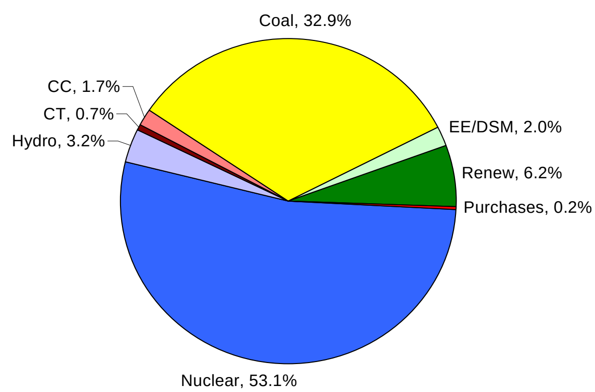
2028 Duke Energy Carolinas Capacity



2008 Duke Energy Carolinas Energy



2028 Duke Energy Carolinas Energy



The table below represents the annual incremental additions reflected in the LCR Table of the most robust Higher Carbon Case expansion plan. 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.

Year	Project	MW
2010	Renewable	17
2011	Nuclear Uprates	58
2011	PPA	600
2011	Buck Combined Cycle (Ph)	316
2012	Buck Combined Cycle (Ph)	304
2012	Dan River Combined Cycle	620
2012	Renewable	96
2012	Cliffside 6	825
2013	Nuclear Uprates	138
2015	Renewable	48
2016	CT PPA	632
2017	Renewable	47
2018	Renewable	92
2018	CT PPA Ends	(632)
2018	Lee Nuclear	1,117
2019	Renewable	87
2020	Renewable	94
2021	Renewable	96
2022	Renewable	5
2024	Renewable	46
2025	Renewable	3
2027	Renewable	53
2027	New CT	200

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

- 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:

- 1.5% average summer peak system demand growth over the next 20 years
- Generation reductions of more than 550 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
- Approximately 70 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

The IRP process evaluates demand-side (DSM/EE) and supply-side options to meet customer energy and capacity needs. DSM/EE options for consideration within the IRP are developed based on input from our collaborative partners and cost-effectiveness screening. Supply-side 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 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. For additional information on demand-side and supply-side options, 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:

- Base Load – 800MW Supercritical Pulverized Coal
- Base Load – 630 MW Integrated Gasification Combined Cycle (IGCC)
- Base Load – 2x1117MW Nuclear units (AP1000)
- Peaking/Intermediate – 4x160MW Combustion Turbines (7FA)
- Peaking/Intermediate –460 MW Unfired+120MW Duct Fired+40MW Inlet Chilled Natural Gas Combined Cycle
- Peaking/Intermediate –460 MW Unfired+40MW Inlet Chilled Natural Gas Combined Cycle
- Renewable – 20 MW Existing Unit Biomass Co-Firing
- Renewable – 50 MW Wind PPA - On-Shore
- Renewable – 3 MW Landfill Gas PPA
- Renewable – 16 MW Solar Photovoltaic PPA
- Renewable – 40 MW Biomass Firing PPA
- Renewable – 4.7 MW Hog Waste Digester PPA
- Renewable – 55 MW 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 200 MW, the model was allowed to select the sizes of the renewable PPAs needed to most economically meet an assumed renewable portfolio standard.

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. CPCNs have also been received for the phased combustion turbine to combined cycle additions at Buck and Dan River. The combustion turbine additions are reflected as committed resources in 2010 and 2011 and the combined cycle additions are reflected in 2011 and 2012 at Buck and Dan River respectively.

<u>Energy Efficiency and Demand-Side Management</u>
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 and EE programs evaluated were the same as filed in the 2007 IRP with the exception that the program start date was delayed until 2009.

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' proposed Energy Efficiency Plan as filed in NCUC Docket No. E-7, Sub 831, and PSC SC Docket No. 2007-358-E 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' proposed Energy Efficiency Plan for 2009 through 2012. From years 2013 through 2028 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 2013 and 2017, respectively, and their costs utilized the costs of Bundle 1 escalated at the rate of inflation.

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 decisions that are not needed in that timeframe. In particular, this year's analysis focused on nuclear need and timing. No alternative portfolios were developed for the peaking capacity needs in the 2013 to 2017 timeframe as Duke Energy Carolinas will have the opportunity to re-visit these needs in subsequent IRPs.

While potential new nuclear plant capacity could not go in service until 2018 at the earliest under the current planning assumptions, near-term decisions on 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 2018 to 2028. 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 2019. The use of a 2018 date is for modeling purposes only and the actual planned operational date may be delayed as additional information becomes available on critical issues such as enactment of carbon legislation.

The information as shown on the following pages outlines 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 and renewable portfolio standard requirements modeled after the NC REPS. In addition, each portfolio contains the addition of Cliffside Unit 6 in 2012, Buck CT/CC in 2010 and 2011 and Dan River CT/CC in 2011 and 2012 and the unit retirements shown in Table 3.3.

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:

- Lower carbon - Reference Case based on the Bingaman/Specter bill
- Higher carbon – Reference Case based on the Lieberman/Warner bill

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 scenarios:

- Load forecast variations
    - Increase relative to base forecast (+6% for peak demand and energy)
    - Decrease relative to base forecast (- 6% for peak demand and energy)

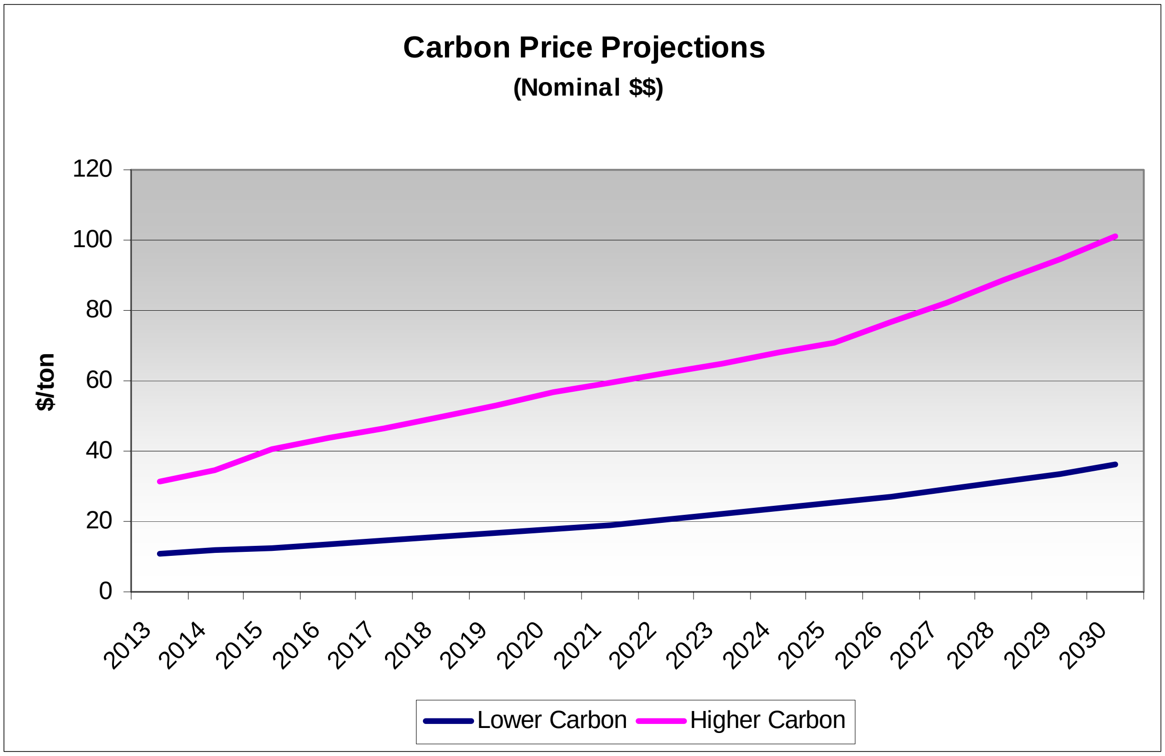
The sensitivities evaluated in each scenario were as follows:

- Construction cost sensitivity[1]
    - Costs to construct a new nuclear plant (+/- 6% higher than base case)
- Fuel price variability
    - Higher coal prices (45% higher than base case and 25% lower)
    - Higher natural gas prices (25% higher than base case and 25% lower)
- Emission allowance price variability
    - The Clean Air Mercury Rule (CAMR) was vacated in February 2008 and indications are it will be replaced with unit specific control requirements versus a cap and trade system under CAMR. For this reason mercury allowance values were removed from the analysis.
    - The Clean Air Interstate Rule (CAIR) was vacated in July 2008. At this time it is not clear what regulation or legislation will replace CAIR, but most likely it will be no less stringent than the current rule but just delayed. For the purpose of this analysis, it is assumed from a NOx and SO2 allowance perspective that CAIR is still in tact.
    - Alternative emission allowance prices for SO_2 and NOx based on a Higher Carbon Scenario.
    - The Lower Carbon case had CO_2 emission prices ranging from \$10/ton starting in 2013 to \$35/ton in 2030. The Higher Carbon case had CO_2 emission prices ranging from \$30/ton in 2013 to \$100/ton in 2030.
- In the Higher Carbon scenario, the base level of load was adjusted downward to reflect that some level of "price-induced" conservation may occur in a carbon-

[1] 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.

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 for the Lower and Higher Carbon scenarios.



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

Overall Requirements/Timing

- 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

Additional Requirements

- 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 (NC only)
    - 0.02% by 2010
    - 0.07% by 2012

- 0.14% by 2015
- 0.20% by 2018

- Hog waste requirement (NC only)
  - 0.07% by 2012
  - 0.14% by 2015
  - 0.20% by 2018
- Poultry waste requirement ((NC only - 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

The overall 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. The requirement that a certain percentage must come from Solar, Hog and Poultry waste was not applied to the South Carolina portion.

Six portfolios were analyzed including a combustion turbine/combined cycle portfolio (CT/CC), a "one" nuclear unit portfolio (1N), and a "two" unit nuclear portfolio (2N) with all three under the low and high carbon scenarios. An overview of the specifics of each portfolio is shown in Table A1 below.

In the 2N High Carbon portfolio, to manage the reserve margin, a purchase power agreement (PPA) was used for the 2016 peaking need and the remaining unscrubbed coal units were retired in 2020.

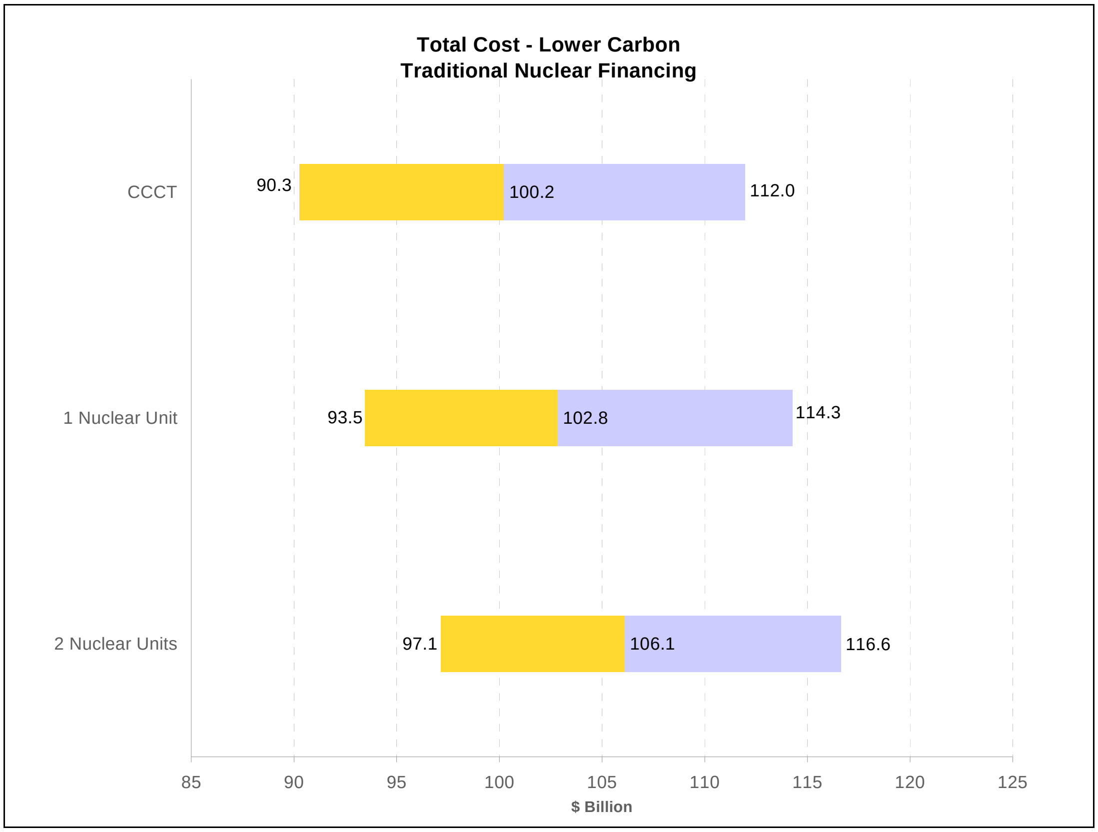
Table A1 – Portfolios Evaluated

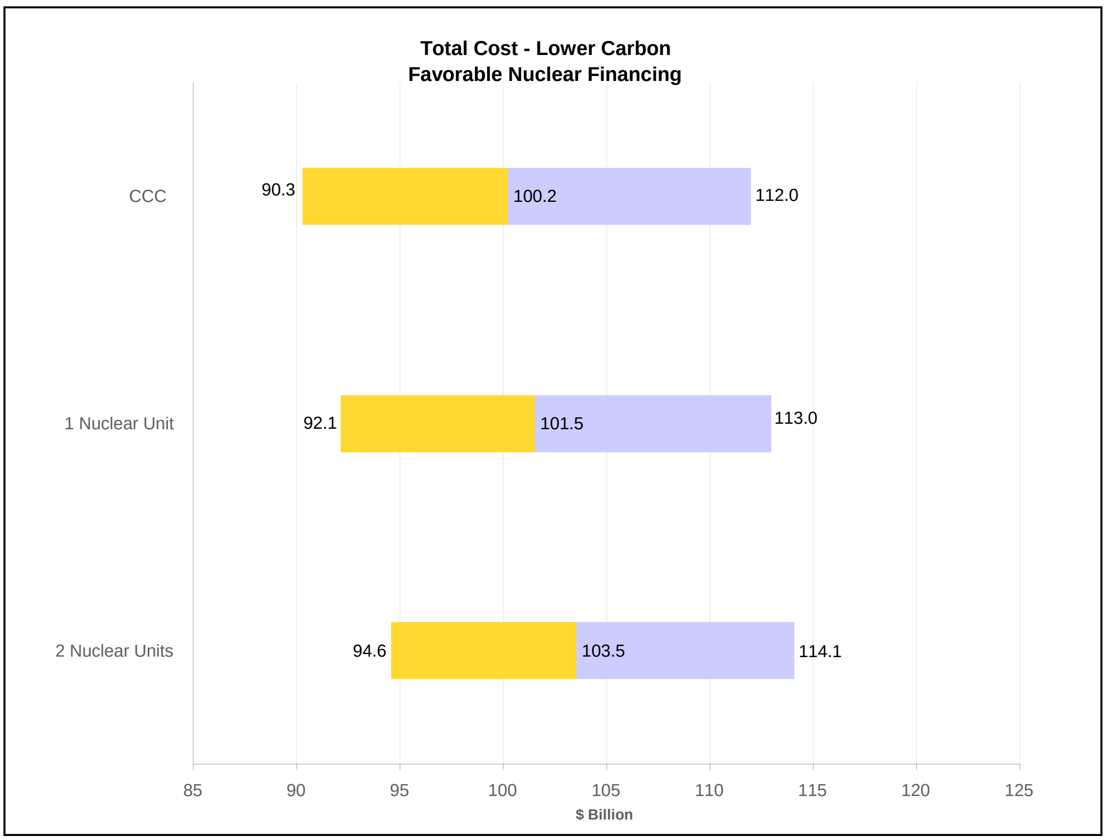
Year	Lower Carbon			Higher Carbon		
	CT/CC	1N	2N	CT/CC	1N	2N
2011	Nuclear Uprate	Nuclear Uprate	Nuclear Uprate	Nuclear Uprate	Nuclear Uprate	Nuclear Uprate
2012						
2013	Nuclear Uprate	Nuclear Uprate	Nuclear Uprate	Nuclear Uprate	Nuclear Uprate	Nuclear Uprate
2014	CT	CT	CT			
2015	CT	CT	CT			
2016	CT	CT	CT	CT	Start PPA	Start PPA
2017						
2018	CC	N	N	CC	End - PPA N	End - PPA N
2019			N			N
2020	CC					Retire
2021						
2022						
2023	CC	CT				
2024						
2025	CT	CT				
2026		CT	CT			
2027	CT				CT	
2028	CT	CT	CT	CT		
Total CT	3,250 MW	3,992 MW	2,878 MW	692 MW	200 MW	
Total CC	1,860 MW			620 MW		
Total N		1,117 MW	2,234 MW		1,117 MW	2,234 MW
Total N uprate	196 MW	196 MW	196 MW	196 MW	196 MW	196 MW
Total PPA					632 MW	632 MW
Total retire						626 MW

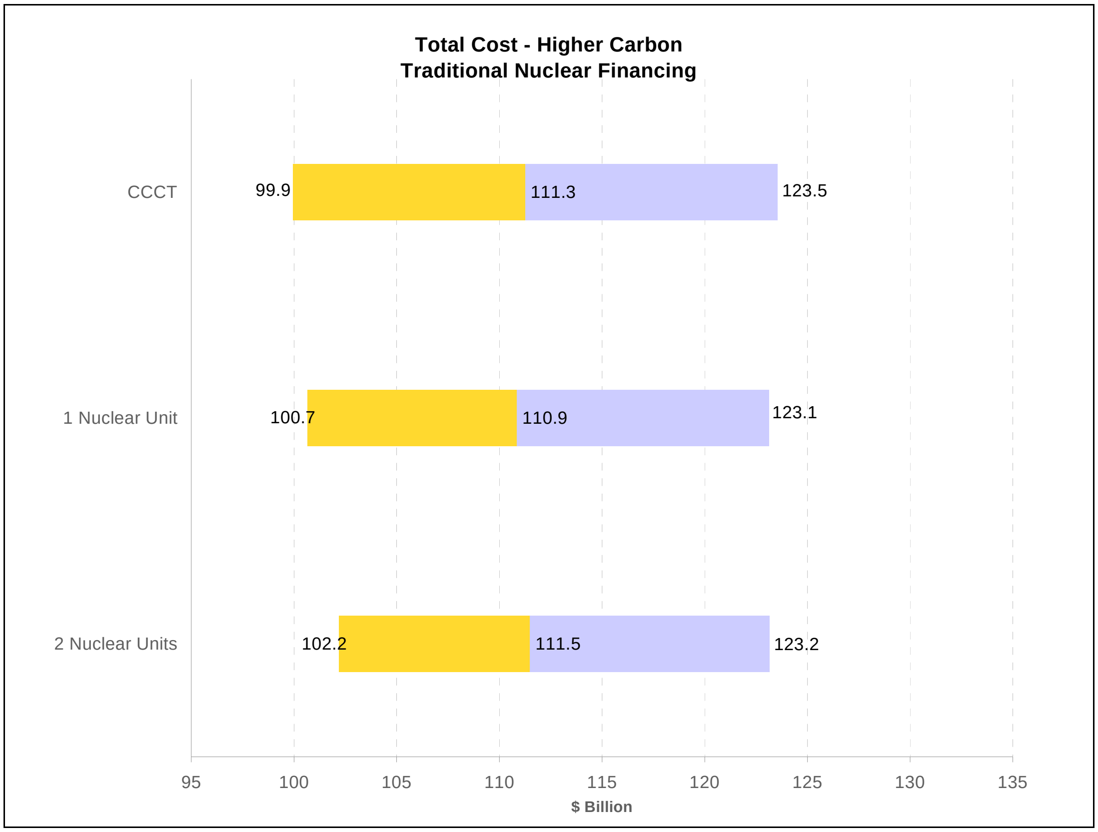
Quantitative Analysis Results

Yearly revenue requirements for various resource planning strategies were calculated based on production cost simulation and capital recovery over a 50-year analysis time frame. The charts below show the PVRRs for a wide range of sensitivities of each portfolio was compared to the PVRRs of other portfolios. The point near the middle of each bar where the color changes is the PVRR for base assumptions. The charts demonstrate how the portfolios perform under base assumptions as well as under a wide range of outcomes. In general, the preferred portfolio has a lower PVRR for base assumptions as well as a narrower range of PVRRs for sensitivities.

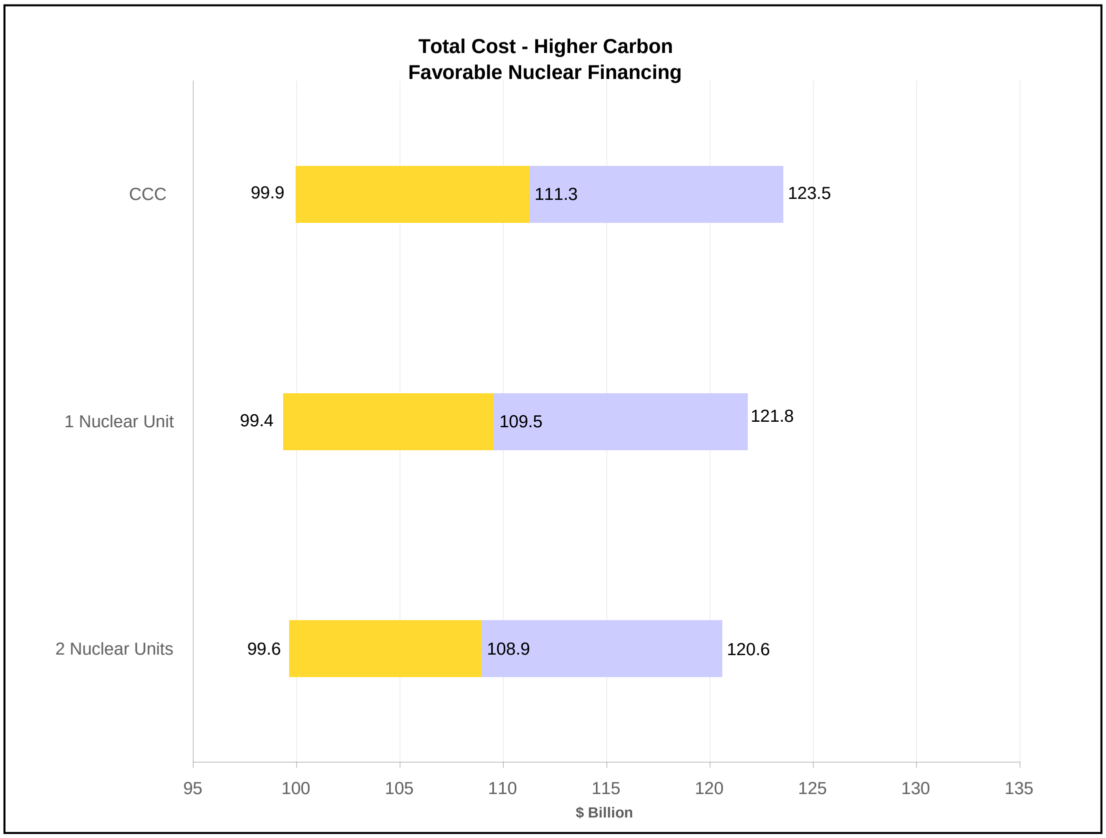
The charts below represent the range of system revenue requirements under each portfolio when load, fuel cost, and equipment cost is varied. Due to magnitude of the financial impact that favorable financing can have on the nuclear options, results are shown with traditional financing and with favorable financing. The upper ranges for the CT/CC and 1N portfolios represent the high coal cost sensitivity, where the upper range for the 2N portfolios represent the higher load sensitivity. The lower range for all cases represents the lower load sensitivity.


Total Cost - Lower Carbon
Traditional Nuclear Financing
CCCT
1 Nuclear Unit
2 Nuclear Units
90.3
100.2
112.0
93.5
102.8
114.3
97.1
106.1
116.6
85
90
95
100
105
110
115
120
125
$ Billion


Total Cost - Lower Carbon
Favorable Nuclear Financing
CCC
1 Nuclear Unit
2 Nuclear Units
90.3
100.2
112.0
92.1
101.5
113.0
94.6
103.5
114.1
85
90
95
100
105
110
115
120
125
$ Billion



Total Cost - Higher Carbon
Traditional Nuclear Financing
CCCT
99.9
111.3
123.5
1 Nuclear Unit
100.7
110.9
123.1
2 Nuclear Units
102.2
111.5
123.2
95
100
105
110
115
120
125
130
135
$ Billion



Total Cost - Higher Carbon
Favorable Nuclear Financing
CCC
99.9
111.3
123.5
1 Nuclear Unit
99.4
109.5
121.8
2 Nuclear Units
99.6
108.9
120.6
95
100
105
110
115
120
125
130
135
$ Billion

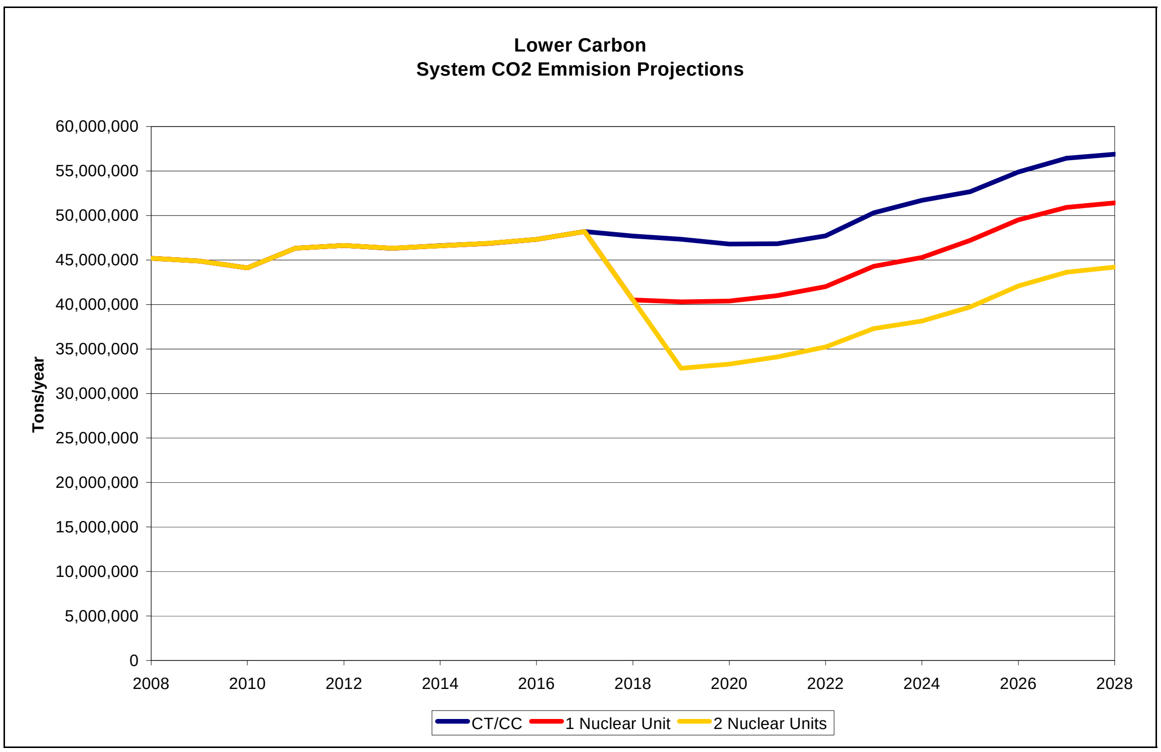
Quantitative Analysis Summary

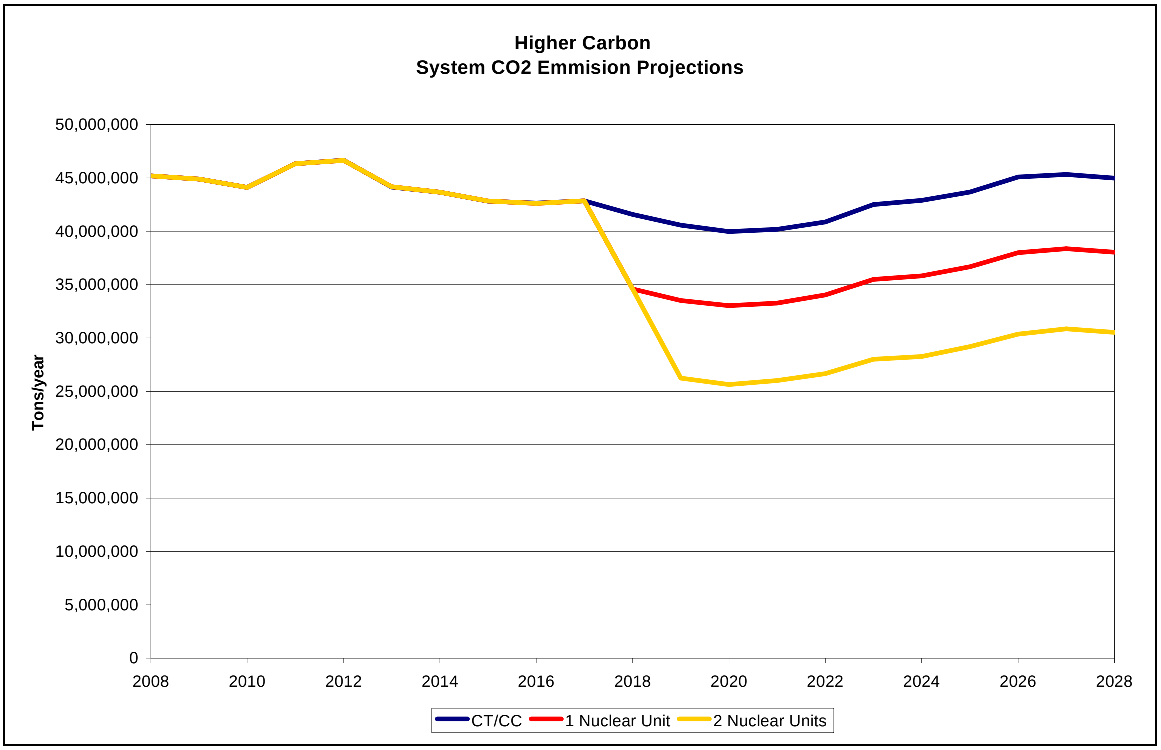
Table A2 - Comparison of Nuclear Portfolios to the Combustion Turbine/Combined Cycle Portfolio

Mid Case Estimate – 40 year nuclear life (2058)				
	Lower Carbon CT/CC Portfolio $100.2 Billion		Higher Carbon CT/CC Portfolio $111.2 Billion	
Nuclear Options	Traditional Financing	Favorable Financing	Traditional Financing	Favorable Financing
Own 1 Unit of a 2 Unit Plant	$2.6 billion (higher)	$ 1.3 billion (higher)	$0.5 billion (lower)	$1.7 billion (lower)
2 Units	$5.9 billion (higher)	$3.3 billion (higher)	$0.2 billion (higher)	$2.3billion (lower)

The values in Table A2 represent the base cost of each portfolio. These values indicate that the nuclear options are preferred in the Higher Carbon cases.

The major benefit of having additional nuclear generation is the lower system CO_2 footprint and the associated economic benefit. The projected CO_2 emissions under the Lower and Higher Carbon scenarios are shown below. A review of these projections show to make real system reductions in CO_2 emissions additional nuclear generation is needed.





Other scenarios were evaluated including the potential impact of plug-in hybrid electric vehicles, the impact of non-firm energy sales, and the impact of the 60 to 80 year asset life of nuclear versus a combined cycle facility with an estimate 30 year life. These were all advantages to the nuclear portfolios that are not captured in the cost above.

The value of nuclear having NOx and SO_2 free generation and the lower volatility of nuclear fuels was incorporated into the economic analysis above. However, the value could be even higher, based on the volatility of the coal and gas markets have experienced during the past year. Also, the value of NOx and SO_2 were based on regulations today and future more stringent regulations will only increase the value of reduction of these emissions.

The biggest risks to the nuclear portfolios are the time required to license and construct a nuclear unit, potential for even lower demand than currently estimated, and the ability to secure favorable financing.

In summary, the results of the quantitative analyses indicate that it is prudent for Duke Energy Carolinas to continue to preserve the option to build new nuclear capacity in the 2018 timeframe. The advantages of favorable financing and co-ownership are evident in the analysis above. Duke Energy Carolinas is aggressively pursuing favorable financing options and continues to seek potential co-owners for this generation.

The overall conclusions of the quantitative analysis are 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)
- There is a peaking need in 2014 to 2016 timeframe to maintain the 17% reserve margin. Over the next year, the Company will verify and explore options to meet the need.
- The analysis demonstrates that the nuclear option in a higher carbon scenario is an attractive option.
  - Continuing to preserve the option to secure new nuclear generation is prudent.
  - Favorable financing is very important to the project cost when compared to other generation options.
  - Co-ownership is beneficial from a generation and risk perspective.

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, 3,992 MW of new CT capacity in a Lower Carbon scenario reduced to 200 MW of new CT capacity in a Higher Carbon scenario, 196 MW of nuclear uprates and 684 MW of renewables.

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.

Duke Energy Carolinas
Spring 2008 Forecast

Sales

Rates Billed

Peaks

2008-2023

October 17, 2008

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Regular Sales and System Peak Summer (2008 Forecast vs. 2009 Forecast)

Regular sales includes total Retail and Full/Partial Requirements Wholesale sales (as defined on page 7). The system peak summer demand includes all MW demands associated with Retail classes, Schedule 10A Resale and the total resource needs of the Catawba Joint Owners (as defined on page 15).

Growth Statistics from 2008 to 2009				
	Forecasted 2008	Forecasted 2009	Growth	
Item	**Amount**	**Amount**	**Amount**	**%**
Regular Sales	82,112 GWH	82,727 GWH	615 GWH	0.7%
System Peak Summer	20,905 MW	21,225 MW	321 MW	1.5%

Regular Sales Outlook for the Forecast Horizon (2007 – 2023)

Total Regular sales are expected to grow at an average annual rate of 1.1% from 2007 through 2023. Growth rates for all retail classes of sales are less than the growth projections in the Fall 2007 forecast due to a slower growing economy and the expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007. The Full/Partial Requirements Wholesale class forecast will increase due to a change in an agreement between Duke Energy Carolinas (DEC) and Piedmont Electric Membership Corporation (PEMC). From January 2008 forward, DEC will provide all of the supplemental requirements of PEMC. In the 2007 forecast, DEC was to provide only a portion of the supplemental requirements of PEMC from 2007 to 2010 and all of the supplemental requirements from 2011 forward.

Comparison of Regular Sales Growth Statistics Spring 2008 Forecast vs. Fall 2007 Forecast					
	Spring 2008 Forecast Annual Growth (2007-2023)		Fall 2007 Forecast Annual Growth (2007-2023)		Average Annual Difference [1]
Item	**Amount**	**%**	**Amount**	**%**	
Regular Sales:					
Residential	264 GWH	0.9%	390 GWH	1.3%	-126 GWH
Commercial	531 GWH	1.7%	691 GWH	2.1%	-160 GWH
Industrial (total)	-120 GWH	-0.5%	-43 GWH	-0.2%	-76 GWH
Textile	-213 GWH	-6.4%	-206 GWH	-6.0%	-7 GWH
Other Industrial	94 GWH	0.5%	163 GWH	0.8%	-69 GWH
Other [2]	4 GWH	1.3%	4 GWH	1.2%	0 GWH
Full/Partial Wholesale [3]	292 GWH	8.5%	317 GWH	8.9%	-25 GWH
Total Regular	972 GWH	1.1%	1,358 GWH	1.5%	-386 GWH

[1] *Average annual differences may not match due to rounding*
[2] *Other sales consist of Street and Public Lighting and Traffic Signal GWH sales.*
[3] *Full/Partial Wholesale sales include Schedele 10A sales and supplemental sales to the NC EMCs.*

System Peak Outlook for the Forecast Horizon (2007 – 2023)

System peak hour demands are forecasted on a summer and winter basis. The system peak summer demand on the Duke Energy Carolinas is expected to grow at an average annual rate of 1.4% from 2007 through 2023. The system peak winter demand is expected to grow at an average annual rate of 1.3% from 2007 through 2023.

Comparison of System Peak Demand Growth Statistics Spring 2008 Forecast vs. Fall 2007 Forecast					
	Spring 2008 Forecast Annual Growth (2007-2023)		Fall 2007 Forecast Annual Growth (2007-2023)		Average Annual Difference [1]
Item	**Amount**	**%**	**Amount**	**%**	
System Peaks					
Summer	330 MW	1.4%	426 MW	1.8%	-96 MW
Winter	252 MW	1.3%	327 MW	1.6%	-75 MW

Other Forecasts

- The number of rates billed is forecasted for the Residential, Commercial and Industrial classes of Duke Energy Carolinas. The total number of rates billed is expected to grow at 1.7% annually over the forecast horizon.

- The total annual energy requirements of the Catawba Joint Owners are forecasted to grow at 2.1% annually over the forecast horizon.

- Territorial energy requirements are forecasted to grow from 104,735 GWH in 2008 to 124,825 GWH in 2023, for an average annual growth rate of 1.2%.

General forecasting methodology for Duke Energy Carolinas energy and demand forecasts for Spring 2008

Duke Energy Carolinas' Spring 2008 forecasts represent projections of the energy and peak demand needs for its service area, which is located within the states of North and South Carolina, including the major urban areas of Charlotte, Greensboro and Winston-Salem in North Carolina and Spartanburg and Greenville in South Carolina. The forecasts cover the time period of 2008 – 2023 and represent the energy and peak demand needs for the Duke Energy Carolinas system comprised of the following customer classes and other utility/wholesale entities:

- Residential
- Commercial
- Textiles
- Other Industrial
- Other Retail
- Duke Energy Carolinas full /partial requirements wholesale
- Catawba Joint Owners' energy requirements
- Territorial energy requirements

Energy use is dependent upon key economic factors such as income, energy prices and employment along with weather. The general framework of the Company's forecast methodology begins with forecasts of regional economic activity, demographic trends and expected long-term weather. The economic forecasts used in the Spring 2008 forecasts are obtained from Moody's Economy.com, a nationally recognized economic forecasting firm, and include economic forecasts for the two states of North Carolina and South Carolina. These economic forecasts represent long-term projections of numerous economic concepts including the following:

- Total gross state product (GSP) in NC and SC
- Non-manufacturing GSP in NC and SC
- Non-manufacturing employment in NC and SC
- Manufacturing GSP in NC and SC by industry group, e.g., textiles
- Employment in NC and SC by industry group
- Total personal income

Total population forecasts are obtained from the two states' demographic offices for each county in each state which are then used to derive the total population forecast for the 51 counties that the Company serves in the Carolinas.

General forecasting methodology (continued)

A projection of weather variables, cooling degree days (CDD) and heating degree days (HDD), are made for the forecast period by examining long-term historical weather. For the Spring 2008 forecasts, a 10 year simple average of CDD and HDD were used.

Other factors influencing the forecasts are identified and quantified such as changes in wholesale power contracts, historical billing days and other demographic trends including housing square footage, etc.

Energy forecasts for all of the Company's retail customers are developed at a customer class level, i.e., residential, commercial, textile, other industrial and street lighting along with forecasts for its wholesale customers. Econometric models incorporating the use of industry-standard linear regression techniques were developed utilizing a number of key drivers of energy usage as outlined above. The following provides information about the models.

Residential Class:
The Company's residential class sales forecast is comprised of two separate and independent forecasts. The first is the number of residential rates billed which is driven by population projections of the counties in which the Company provides electric service. The second forecast is energy usage per rate billed which is driven primarily by weather, regional economic and demographic trends, electric price and appliance efficiencies. The total residential sales forecast is derived by multiplying the two forecasts together.

Commercial Class:
Commercial electricity usage changes with the level of regional economic activity and the impact of weather.

Textile Class:
The level of electricity consumption by Duke Energy Carolinas' textile group is very dependent on foreign competition. Usage is also impacted by the level of textile manufacturing output, exchange rates, electric prices and weather.

Other Industrial Class:
Electricity usage for Duke's other industrial customers was forecasted by 16 groups according to the 3 digit NAICS classification and then aggregated to provide the overall other industrial sales forecast. Usage is driven primarily by regional manufacturing output at a 3 digit NAICS level, electric prices and weather.

Other Retail Class:
This class in comprised of public street lighting and traffic signals within the Company's service area. The level of electricity usage is impacted not only by economic growth but also by advances in lighting efficiencies.

General forecasting methodology (continued)

Full / Partial Requirements Wholesale:
Duke Energy Carolinas provides electricity on a contract basis to numerous wholesale customers. The forecast of wholesale sales for this group is developed in two parts: 1) sales provided under the Company's Schedule 10A and driven primarily by regional economic and demographic trends and 2) special contracted sales agreements with other wholesale customers including adjustments for any known or anticipated changes in wholesale contracts.

Catawba Joint Owners:
Their forecast of electricity consumption is driven primarily by regional economic and demographic trends.

Territorial Energy:
Territorial energy is the summation of all the Company's retail sales, full/partial requirement wholesale sales, Nantahala Power & Light's retail and wholesale sales, the Catawba Joint Owners' loads, line losses and company use.

Additional adjustments were made to the energy forecasts to account for proposed energy efficiency programs and the expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007.

Similarly, Duke Energy Carolinas' forecasts of its annual summer and winter peak demand forecasts uses econometric linear regression models that relate historical annual summer/winter peak demands to key drivers including daily temperature variables (such as daily sum of heating degree hours from 7 to 8AM in the winter with a base of 60 degrees and the daily sum of cooling degree hours from 1 to 5PM in the summer with a base of 69 degrees) and the monthly electricity usage of the entity to be forecasted.

Additional adjustments were made to the peak forecasts to account for the expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007. These peak forecasts do not include adjustments for proposed energy efficiency programs.

Billed Sales and Other Energy Requirements

Regular Sales, which includes billed sales to Retail and Full/Partial Requirements Wholesale classes, are expected to grow at 972 GWH per year or 1.1% over the forecast horizon. Retail sales include GWH sales billed to the Residential, Commercial, Industrial, Street and Public Lighting, and Traffic Signal Service classes. Full/Partial Requirements Wholesale sales include GWH sales billed to municipalities and public utility companies that purchase their full power requirements from the Company, except for power supplied by parallel operation of generation facilities, plus in the forecast period, supplemental sales to specified EMCs in North Carolina.

Regular Sales

Regular Sales, as defined here, include Nantahala Power & Light's ("NP&L") retail and wholesale GWH sales.

Additional adjustments were made to the Regular Sales forecasts to account for proposed energy efficiency programs and the expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007.

Points of Interest

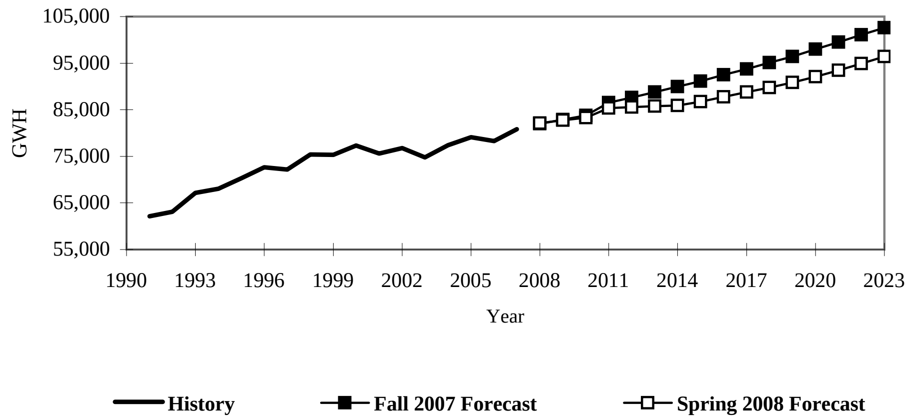
• The **Residential** class continues to show positive growth, driven by steady gains in population within the Duke Energy Carolinas service area. The resulting annual growth in Residential billed sales is expected to average 0.9% over the forecast horizon.

• The **Commercial** class is projected to be the fastest growing retail class, with billed sales growing at 1.7% per year over the next fifteen years. Three sectors that contributed greatly to total Commercial sales growth from 2006 to 2007 were: Offices (314 GWH growth), Utilities (140 GWH growth) and Medical (85 GWH growth).

• The **Industrial** class continues to struggle due to Textiles. Over the forecast horizon, the closing of Textile plants is expected to continue. In the Other Industrial class, however, several sectors are expected to show strong growth. These include: Autos, Rubber & Plastics and Chemicals (excluding Man-Made Fibers). As a result, Total Industrial sales are expected to decline slightly over the forecast horizon.

• The **Full/Partial Requirements Wholesale** class is expected to grow at 8.5% annually over the forecast horizon, primarily due to the forecasted supplemental sales to specified EMCs in North Carolina.

Regular Billed Sales *(Sum of Retail and Full/Partial Wholesale classes)*



HISTORY

Year	Actual GWH	Growth GWH	Growth %
1998	75,380	3,177	4.4
1999	75,307	-73	-0.1
2000	77,298	1,990	2.6
2001	75,605	-1,692	-2.2
2002	76,769	1,164	1.5
2003	74,784	-1,984	-2.6
2004	77,374	2,590	3.5
2005	79,130	1,756	2.3
2006	78,291	-840	-1.1
2007	80,855	2,564	3.3

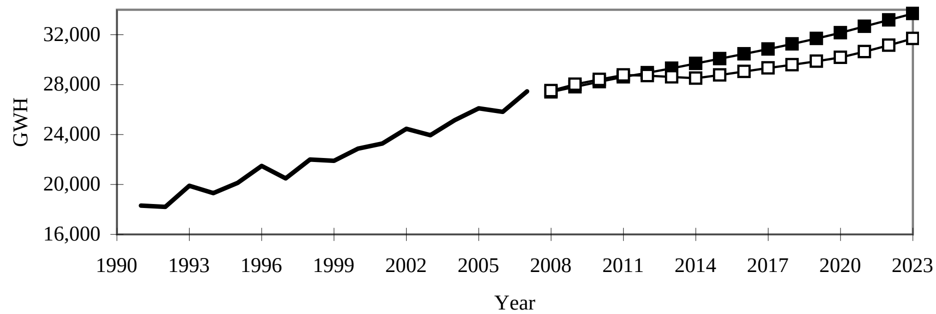
AVERAGE ANNUAL GROWTH

	GWH Per Year	% Per Year
History (2002 to 2007)	817	1.0
History (1992 to 2007)	1183	1.7
Spring 2008 Forecast (2007 to 2023)	972	1.1
Fall 2007 Forecast (2007 to 2023)	1358	1.5

SPRING 2008 FORECAST / FALL 2007 FORECAST

Year	GWH	Growth GWH	Growth %	Fall 2007 GWH	Difference from Fall 2007 GWH	Difference from Fall 2007 %
2008	82,112	1,257	1.6	81,996	115	0.1
2009	82,727	615	0.7	82,884	-157	-0.2
2010	83,317	590	0.7	83,746	-430	-0.5
2011	85,380	2,064	2.5	86,509	-1,128	-1.3
2012	85,534	153	0.2	87,624	-2,090	-2.4
2013	85,758	224	0.3	88,809	-3,051	-3.4
2014	85,928	171	0.2	89,953	-4,024	-4.5
2015	86,753	825	1.0	91,128	-4,375	-4.8
2016	87,792	1,038	1.2	92,482	-4,690	-5.1
2017	88,761	970	1.1	93,756	-4,995	-5.3
2018	89,762	1,000	1.1	95,078	-5,316	-5.6
2019	90,837	1,075	1.2	96,435	-5,598	-5.8
2020	92,087	1,250	1.4	98,021	-5,935	-6.1
2021	93,455	1,369	1.5	99,528	-6,073	-6.1
2022	94,911	1,456	1.6	101,054	-6,143	-6.1
2023	96,403	1,492	1.6	102,585	-6,182	-6.0

Residential Billed Sales



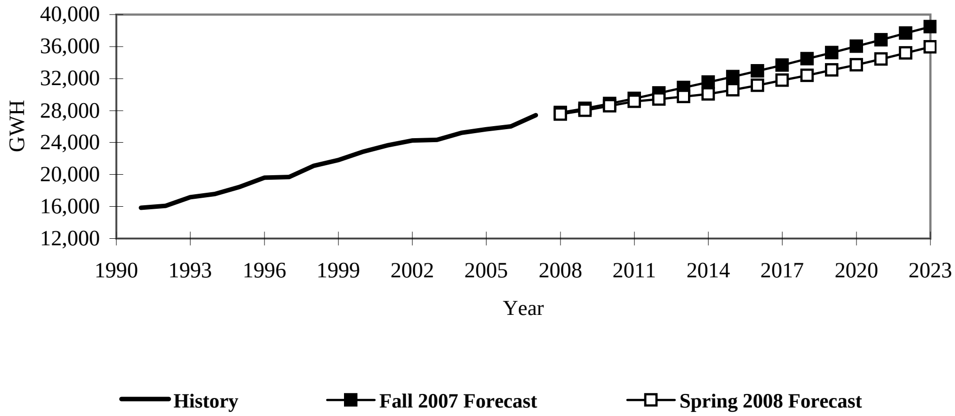
HISTORY | **AVERAGE ANNUAL GROWTH**

Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
1998	22,001	1,519	7.4			
1999	21,897	-104	-0.5			
2000	22,884	987	4.5			
2001	23,272	388	1.7			
2002	24,466	1,194	5.1			
2003	23,947	-519	-2.1	History (2002 to 2007)	599	2.3
2004	25,150	1,203	5.0	History (1992 to 2007)	617	2.8
2005	26,108	958	3.8			
2006	25,816	-292	-1.1	Spring 2008 Forecast (2007 to 2023)	264	0.9
2007	27,459	1,643	6.4	Fall 2007 Forecast (2007 to 2023)	390	1.3

SPRING 2008 FORECAST | **FALL 2007 FORECAST**

Year	GWH	Growth GWH	Growth %	GWH	Difference from Fall 2007 GWH	Difference from Fall 2007 %
2008	27,518	59	0.2	27,416	102	0.4
2009	28,015	497	1.8	27,829	186	0.7
2010	28,402	387	1.4	28,221	181	0.6
2011	28,782	380	1.3	28,614	168	0.6
2012	28,713	-69	-0.2	28,945	-231	-0.8
2013	28,628	-86	-0.3	29,305	-677	-2.3
2014	28,514	-114	-0.4	29,684	-1,170	-3.9
2015	28,778	264	0.9	30,070	-1,292	-4.3
2016	29,053	275	1.0	30,458	-1,405	-4.6
2017	29,333	280	1.0	30,853	-1,520	-4.9
2018	29,595	262	0.9	31,262	-1,667	-5.3
2019	29,880	284	1.0	31,687	-1,807	-5.7
2020	30,167	287	1.0	32,164	-1,997	-6.2
2021	30,636	469	1.6	32,675	-2,039	-6.2
2022	31,157	521	1.7	33,181	-2,023	-6.1
2023	31,684	527	1.7	33,695	-2,010	-6.0

Commercial Billed Sales



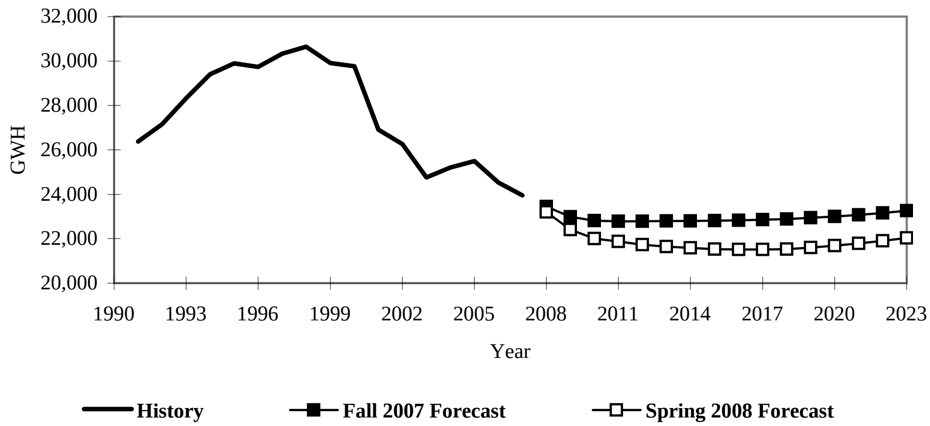
HISTORY | **AVERAGE ANNUAL GROWTH**

Year	Actual GWH	GWH	Growth %		GWH Per Year	% Per Year
1998	21,093	1,407	7.1			
1999	21,807	714	3.4			
2000	22,845	1,038	4.8			
2001	23,666	821	3.6			
2002	24,242	576	2.4			
2003	24,355	113	0.5	History (2002 to 2007)	638	2.5
2004	25,204	849	3.5	History (1992 to 2007)	758	3.6
2005	25,679	475	1.9			
2006	26,030	352	1.4	Spring 2008 Forecast (2007 to 2023)	531	1.7
2007	27,433	1,402	5.4	Fall 2007 Forecast (2007 to 2023)	691	2.1

SPRING 2008 FORECAST | **FALL 2007 FORECAST**

		Growth			Difference from Fall 2007	
Year	GWH	GWH	%	GWH	GWH	%
2008	27,546	113	0.4	27,741	-195	-0.7
2009	28,021	476	1.7	28,263	-241	-0.9
2010	28,566	545	1.9	28,851	-285	-1.0
2011	29,127	561	2.0	29,485	-358	-1.2
2012	29,437	310	1.1	30,172	-736	-2.4
2013	29,761	325	1.1	30,867	-1,105	-3.6
2014	30,061	300	1.0	31,539	-1,477	-4.7
2015	30,593	532	1.8	32,222	-1,629	-5.1
2016	31,156	563	1.8	32,934	-1,778	-5.4
2017	31,770	613	2.0	33,690	-1,920	-5.7
2018	32,403	633	2.0	34,463	-2,060	-6.0
2019	33,061	658	2.0	35,242	-2,182	-6.2
2020	33,721	661	2.0	36,039	-2,318	-6.4
2021	34,437	716	2.1	36,853	-2,416	-6.6
2022	35,177	740	2.1	37,666	-2,488	-6.6
2023	35,937	759	2.2	38,496	-2,560	-6.6

Total Industrial Billed Sales *(includes Textile and Other Industrial)*



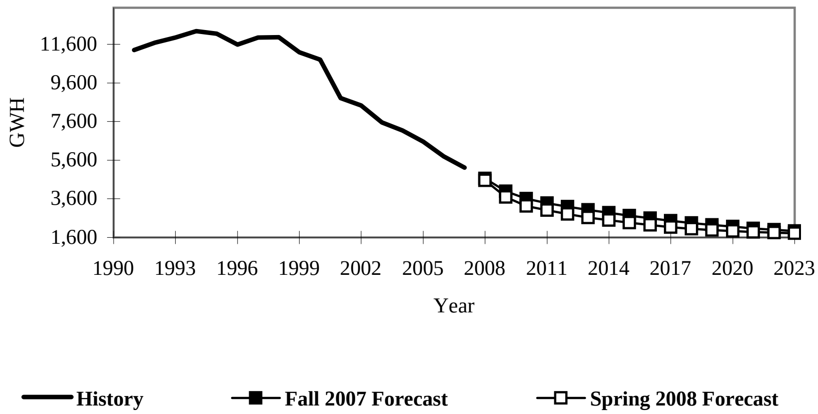
HISTORY | **AVERAGE ANNUAL GROWTH**

Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
1998	30,649	319	1.1			
1999	29,905	-745	-2.4			
2000	29,772	-133	-0.4			
2001	26,902	-2,869	-9.6			
2002	26,259	-643	-2.4			
2003	24,764	-1,496	-5.7	History (2002 to 2007)	-462	-1.8
2004	25,209	445	1.8	History (1992 to 2007)	-214	-0.8
2005	25,495	286	1.1			
2006	24,535	-960	-3.8	Spring 2008 Forecast (2007 to 2023)	-120	-0.5
2007	23,948	-587	-2.4	Fall 2007 Forecast (2007 to 2023)	-43	-0.2

SPRING 2008 FORECAST | **FALL 2007 FORECAST**

Year	GWH	Growth GWH	Growth %	GWH	Difference from Fall 2007 GWH	Difference from Fall 2007 %
2008	23,195	-753	-3.1	23,449	-254	-1.1
2009	22,414	-781	-3.4	22,983	-569	-2.5
2010	22,004	-411	-1.8	22,813	-809	-3.5
2011	21,873	-131	-0.6	22,784	-911	-4.0
2012	21,737	-136	-0.6	22,785	-1,048	-4.6
2013	21,644	-93	-0.4	22,793	-1,149	-5.0
2014	21,585	-59	-0.3	22,795	-1,210	-5.3
2015	21,535	-49	-0.2	22,809	-1,274	-5.6
2016	21,517	-18	-0.1	22,829	-1,311	-5.7
2017	21,512	-5	0.0	22,857	-1,344	-5.9
2018	21,536	23	0.1	22,890	-1,355	-5.9
2019	21,595	59	0.3	22,936	-1,341	-5.8
2020	21,686	91	0.4	23,001	-1,315	-5.7
2021	21,792	106	0.5	23,073	-1,281	-5.6
2022	21,906	114	0.5	23,159	-1,253	-5.4
2023	22,031	125	0.6	23,255	-1,224	-5.3

Textile Billed Sales



HISTORY

Year	Actual GWH	Growth GWH	Growth %
1998	11,976	26	0.2
1999	11,196	-780	-6.5
2000	10,814	-382	-3.4
2001	8,825	-1,989	-18.4
2002	8,443	-382	-4.3
2003	7,562	-881	-10.4
2004	7,147	-415	-5.5
2005	6,561	-586	-8.2
2006	5,791	-770	-11.7
2007	5,224	-567	-9.8

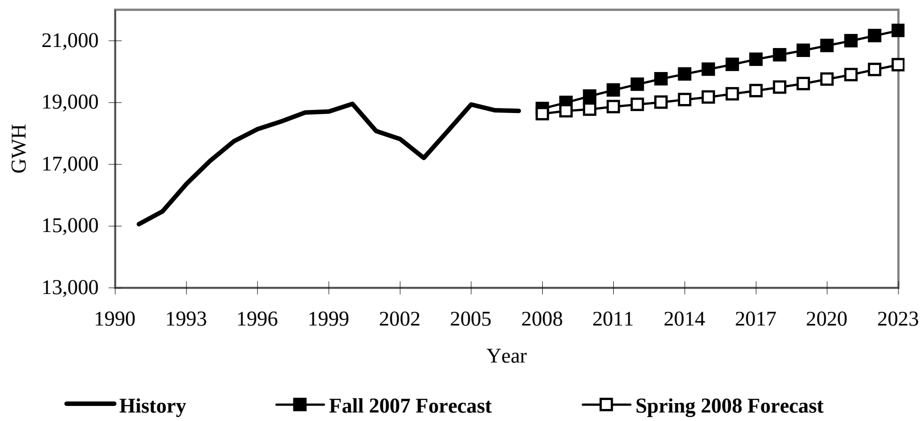
AVERAGE ANNUAL GROWTH

	GWH Per Year	% Per Year
History (2002 to 2007)	-644	-9.2
History (1992 to 2007)	-431	-5.2
Spring 2008 Forecast (2007 to 2023)	-213	-6.4
Fall 2007 Forecast (2007 to 2023)	-206	-6.0

SPRING 2008 FORECAST / FALL 2007 FORECAST

Year	Spring 2008 GWH	Growth GWH	Growth %	Fall 2007 GWH	Difference from Fall 2007 GWH	Difference from Fall 2007 %
2008	4,556	-668	-12.8	4,648	-92	-2.0
2009	3,685	-871	-19.1	3,982	-297	-7.5
2010	3,230	-455	-12.4	3,607	-378	-10.5
2011	3,012	-218	-6.7	3,383	-372	-11.0
2012	2,804	-208	-6.9	3,197	-393	-12.3
2013	2,635	-169	-6.0	3,032	-396	-13.1
2014	2,491	-144	-5.5	2,874	-383	-13.3
2015	2,360	-131	-5.3	2,731	-371	-13.6
2016	2,243	-117	-5.0	2,595	-352	-13.6
2017	2,132	-111	-4.9	2,463	-331	-13.4
2018	2,046	-86	-4.0	2,347	-301	-12.8
2019	1,983	-63	-3.1	2,248	-265	-11.8
2020	1,934	-49	-2.5	2,159	-225	-10.4
2021	1,889	-45	-2.3	2,073	-183	-8.8
2022	1,846	-44	-2.3	1,996	-150	-7.5
2023	1,810	-36	-2.0	1,926	-116	-6.0

Other Industrial Billed Sales



HISTORY

Year	Actual GWH	Growth GWH	Growth %
1998	18,673	293	1.6
1999	18,709	35	0.2
2000	18,957	249	1.3
2001	18,077	-880	-4.6
2002	17,816	-261	-1.4
2003	17,202	-614	-3.4
2004	18,063	861	5.0
2005	18,934	872	4.8
2006	18,744	-191	-1.0
2007	18,724	-20	-0.1

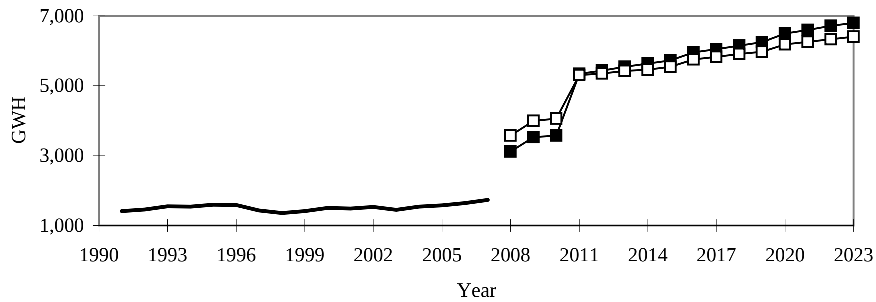
AVERAGE ANNUAL GROWTH

	GWH Per Year	% Per Year
History (2002 to 2007)	182	1.0
History (1992 to 2007)	217	1.3
Spring 2008 Forecast (2007 to 2023)	94	0.5
Fall 2007 Forecast (2007 to 2023)	163	0.8

SPRING 2008 FORECAST / FALL 2007 FORECAST

	SPRING 2008 FORECAST	Growth		FALL 2007 FORECAST	Difference from Fall 2007	
Year	GWH	GWH	%	GWH	GWH	%
2008	18,639	-85	-0.5	18,801	-162	-0.9
2009	18,730	90	0.5	19,001	-272	-1.4
2010	18,774	44	0.2	19,205	-432	-2.2
2011	18,861	87	0.5	19,400	-540	-2.8
2012	18,933	72	0.4	19,588	-655	-3.3
2013	19,008	75	0.4	19,761	-753	-3.8
2014	19,094	85	0.4	19,920	-827	-4.2
2015	19,175	81	0.4	20,077	-902	-4.5
2016	19,275	100	0.5	20,234	-959	-4.7
2017	19,380	106	0.5	20,394	-1,014	-5.0
2018	19,490	109	0.6	20,543	-1,053	-5.1
2019	19,612	122	0.6	20,688	-1,076	-5.2
2020	19,751	139	0.7	20,841	-1,090	-5.2
2021	19,903	151	0.8	21,000	-1,097	-5.2
2022	20,060	158	0.8	21,163	-1,103	-5.2
2023	20,221	161	0.8	21,329	-1,107	-5.2

Full / Partial Requirements Wholesale Billed Sales [1,2]



HISTORY / AVERAGE ANNUAL GROWTH

Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
1998	1,359	-76	-5.3			
1999	1,412	53	3.9			
2000	1,500	88	6.3			
2001	1,484	-16	-1.1			
2002	1,530	47	3.1			
2003	1,448	-82	-5.4	History (2002 to 2007)	41	2.6
2004	1,542	93	6.4	History (1992 to 2007)	19	1.2
2005	1,580	38	2.5			
2006	1,638	58	3.7	Spring 2008 Forecast (2007 to 2023)	292	8.5
2007	1,736	98	6.0	Fall 2007 Forecast (2007 to 2023)	317	8.9

SPRING 2008 FORECAST / FALL 2007 FORECAST

Year	GWH	Growth GWH	Growth %	GWH	Difference from Fall 2007 GWH	Difference from Fall 2007 %
2008	3,574	1,838	105.9	3,115	460	14.8
2009	3,995	420	11.8	3,529	466	13.2
2010	4,059	65	1.6	3,577	482	13.5
2011	5,309	1,250	30.8	5,337	-28	-0.5
2012	5,353	44	0.8	5,429	-76	-1.4
2013	5,426	74	1.4	5,548	-122	-2.2
2014	5,466	39	0.7	5,635	-169	-3.0
2015	5,539	74	1.3	5,722	-183	-3.2
2016	5,753	214	3.9	5,952	-199	-3.3
2017	5,830	77	1.3	6,044	-214	-3.5
2018	5,907	77	1.3	6,144	-238	-3.9
2019	5,976	69	1.2	6,248	-271	-4.3
2020	6,183	207	3.5	6,492	-309	-4.8
2021	6,256	73	1.2	6,598	-342	-5.2
2022	6,332	76	1.2	6,716	-384	-5.7
2023	6,409	77	1.2	6,802	-393	-5.8

1 Schedule 10A Resale Sales does not include SEPA allocation

Duke Energy Carolinas owns 12.5% of the capacity of the Catawba Nuclear Station Units 1 and 2.

The remaining 87.5% is owned by the North Carolina Municipal Power Agency #1 (37.5%), Piedmont Municipal Power Agency (12.5%), North Carolina Electric Membership Corporation (28.1%) and Saluda River Electric Cooperative, Inc. (9.4%).

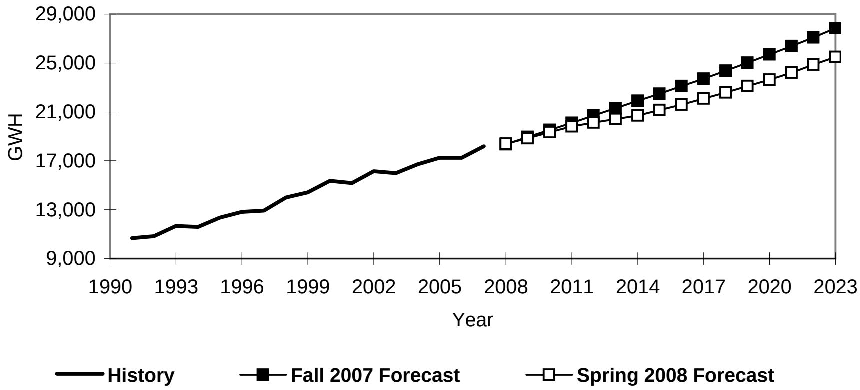
(In December 2006 Duke Energy Carolinas and North Carolina Electric Membership Corporation announced agreements to buy Saluda River Electric Cooperative, Inc.'s ownership interest in unit 1 of the Catawba Nuclear Station. Duke Energy Carolinas will then own 19.3% of the capacity of the Catawba Nuclear Station Units 1 and 2 and North Carolina Electric Membership Corporation will own 30.7% of the capacity of the Catawba Nuclear Station Units 1 and 2.)

In addition to the power supplied from the ownership share in the Catawba stations, each Catawba Joint Owner must purchase supplemental power to meet its total energy requirements.The Catawba forecast represents the total energy requirements of the Catawba Joint Owners.

Total Catawba electric energy requirements are expected to increase at an average annual growth of 455 GWH per year and a growth rate of 2.1 % per year over the period from 2007-2023.

Additional adjustments were made to the Catawba Sales forecasts to account for the expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007.

Catawba Total Delivered Energy Requirements [1]



HISTORY

AVERAGE ANNUAL GROWTH

YEAR	Actual GWH	GROWTH GWH	GROWTH %		GWH Per Year	% Per Year
1998	14,000	1,064	8.2			
1999	14,413	413	2.9			
2000	15,354	941	6.5			
2001	15,184	-170	-1.1			
2002	16,151	967	6.4			
2003	15,986	-165	-1.0	History (2002 to 2007)	410	2.4
2004	16,711	725	4.5	History (1992 to 2007)	492	3.5
2005	17,237	527	3.2			
2006	17,246	9	0.0	Spring 2008 Forecast (2007 to 2023)	455	2.1
2007	18,200	954	5.5	Fall 2007 Forecast (2007 to 2023)	603	2.7

SPRING 2008 FORECAST

FALL 2007 FORECAST

Year	GWH	Growth GWH	Growth %	GWH	Difference from Fall 2007 GWH	Difference from Fall 2007 %
2008	18,392	192	1.1	18,339	53	0.3
2009	18,841	450	2.4	18,942	-101	-0.5
2010	19,351	510	2.7	19,523	-172	-0.9
2011	19,811	460	2.4	20,109	-298	-1.5
2012	20,114	303	1.5	20,712	-598	-2.9
2013	20,412	299	1.5	21,311	-899	-4.2
2014	20,697	285	1.4	21,902	-1,205	-5.5
2015	21,138	440	2.1	22,494	-1,357	-6.0
2016	21,598	461	2.2	23,099	-1,500	-6.5
2017	22,085	487	2.3	23,722	-1,637	-6.9
2018	22,588	503	2.3	24,368	-1,779	-7.3
2019	23,104	516	2.3	25,026	-1,923	-7.7
2020	23,628	524	2.3	25,693	-2,065	-8.0
2021	24,222	594	2.5	26,379	-2,157	-8.2
2022	24,852	630	2.6	27,097	-2,245	-8.3
2023	25,483	631	2.5	27,842	-2,358	-8.5

1 Total Delivery for Catawba Joint Owners includes SEPA allocations.

Territorial energy requirements consist of:

- Regular Sales (excluding supplemental sales to NC EMCs)
- Catawba Joint Owner energy requirements
- Southeastern Power Administration ("SEPA") energy allocations that are wheeled to municipal and cooperative electric systems within the Duke Energy Carolinas' service area
- Duke Energy Carolinas company use
- System losses and unbilled energy

Territorial energy requirements are forecasted to grow 1.2% per year from 2008 to 2023. All values below are expressed in GWH.

Territorial Energy

Year	Regular Sales [1]	Catawba (Less SEPA) Total [2]	SEPA [3]	Company Use [4]	Losses & Unbilled [6 & 7]	Territorial Energy
2008	80,190	18,092	311	212	5,931	104,735
2009	80,416	18,541	311	214	5,966	105,449
2010	80,977	19,051	311	215	6,020	106,573
2011	81,825	19,511	311	215	6,094	107,956
2012	81,968	19,814	311	215	6,112	108,420
2013	82,153	20,112	311	215	6,134	108,925
2014	82,319	20,397	311	215	6,153	109,395
2015	83,105	20,837	311	215	6,219	110,687
2016	83,964	21,298	311	215	6,290	112,078
2017	84,893	21,785	311	215	6,367	113,570
2018	85,852	22,288	311	215	6,446	115,112
2019	86,894	22,803	311	215	6,530	116,753
2020	87,971	23,328	311	215	6,617	118,441
2021	89,302	23,922	311	215	6,723	120,473
2022	90,717	24,552	311	215	6,834	122,629
2023	92,168	25,183	311	215	6,948	124,825

[1] Regular Sales represents total electricity used by Duke Energy Carolinas Retail and Schedule 10A Resale classes. Supplemental sales to NC EMCs are not included in this column.

[2] Catawba Total represents Catawba Joint Owner electricity requirements less their SEPA allocations.

[3] SEPA represents hydro energy allocated to the municipalities and co-operatives and wheeled by Duke Energy Carolinas.

[4] Company Use represents electricity used by Duke Energy Carolinas offices and facilities.

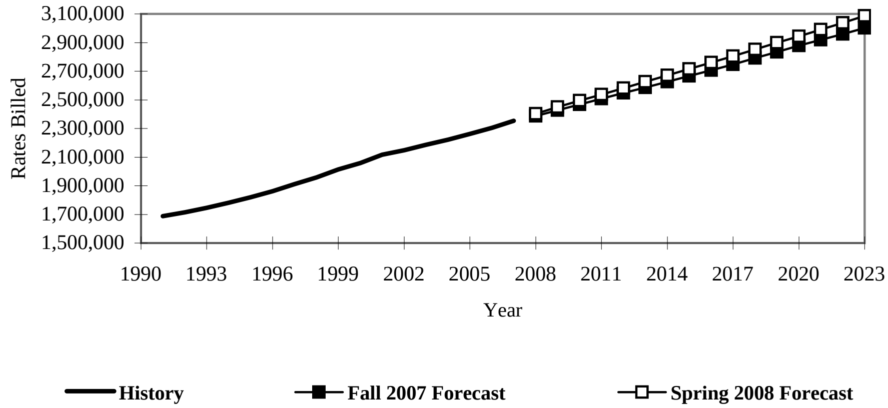
[6] Losses represent electricity line losses from generation sources to customer meters. .

[7] Unbilled Sales represent the adjustment made to create calendar period sales from billing period sales.

Number of Rates Billed

Total Rates Billed

(Sum of Major Retail Classes: Residential, Commercial and Industrial)



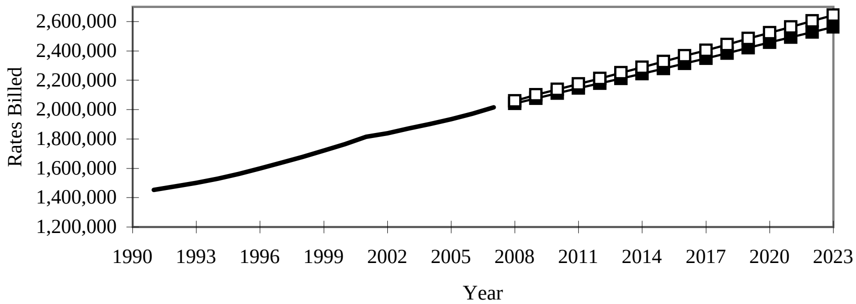
HISTORY | **AVERAGE ANNUAL GROWTH**

Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
1998	1,959,000	48,523	2.5			
1999	2,013,039	54,039	2.8			
2000	2,059,152	46,113	2.3			
2001	2,117,432	58,280	2.8			
2002	2,148,117	30,685	1.4			
2003	2,186,825	38,708	1.8	History (2002 to 2007)	41,192	1.8
2004	2,221,590	34,766	1.6	History (1992 to 2007)	42,563	2.1
2005	2,261,639	40,049	1.8			
2006	2,304,050	42,411	1.9	Spring 2008 Forecast (2007 to 2023)	45,718	1.7
2007	2,354,078	50,028	2.2	Fall 2007 Forecast (2007 to 2023)	40,456	1.5

SPRING 2008 FORECAST | **FALL 2007 FORECAST**

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	Difference from Fall 2007 Rates Billed	%
2008	2,403,353	49,275	2.1	2,387,053	16,300	0.7
2009	2,449,915	46,562	1.9	2,427,846	22,069	0.9
2010	2,493,744	43,830	1.8	2,468,613	25,132	1.0
2011	2,537,538	43,794	1.8	2,508,178	29,361	1.2
2012	2,581,523	43,985	1.7	2,547,364	34,159	1.3
2013	2,625,671	44,148	1.7	2,586,502	39,169	1.5
2014	2,669,991	44,320	1.7	2,625,849	44,142	1.7
2015	2,714,714	44,723	1.7	2,665,595	49,119	1.8
2016	2,760,179	45,465	1.7	2,706,348	53,831	2.0
2017	2,805,941	45,762	1.7	2,747,972	57,969	2.1
2018	2,851,869	45,928	1.6	2,790,684	61,184	2.2
2019	2,897,957	46,089	1.6	2,834,411	63,546	2.2
2020	2,944,341	46,383	1.6	2,877,897	66,443	2.3
2021	2,991,211	46,871	1.6	2,918,961	72,250	2.5
2022	3,038,313	47,101	1.6	2,959,767	78,546	2.7
2023	3,085,561	47,248	1.6	3,001,373	84,188	2.8

Residential Rates Billed



HISTORY

Year	Actual Rates Billed	Growth Rates Billed	%
1998	1,677,935	40,651	2.5
1999	1,722,110	44,175	2.6
2000	1,764,183	42,073	2.4
2001	1,813,867	49,684	2.8
2002	1,839,689	25,822	1.4
2003	1,872,484	32,795	1.8
2004	1,901,335	28,851	1.5
2005	1,935,320	33,985	1.8
2006	1,971,673	36,353	1.9
2007	2,016,104	44,431	2.3

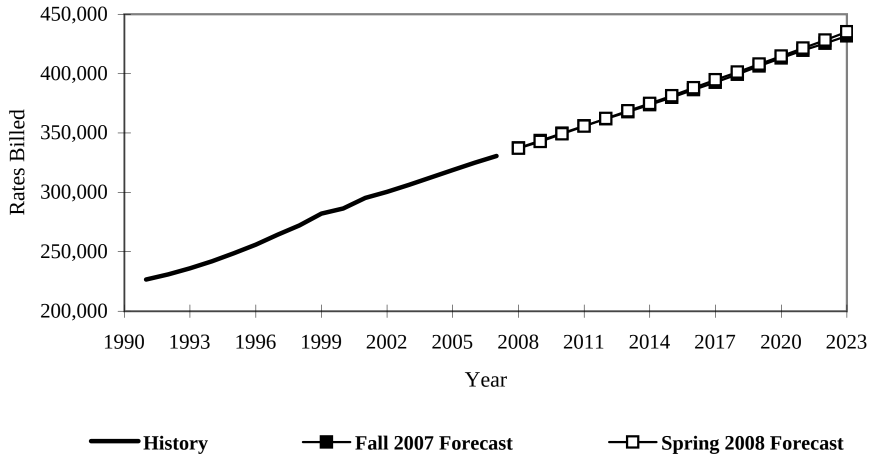
AVERAGE ANNUAL GROWTH

	Rates Billed Per Year	% Per Year
History (2002 to 2007)	35,283	1.8
History (1992 to 2007)	36,000	2.1
Spring 2008 Forecast (2007 to 2023)	39,225	1.7
Fall 2007 Forecast (2007 to 2023)	34,180	1.5

SPRING 2008 FORECAST / FALL 2007 FORECAST

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	Difference from Fall 2007 Rates Billed	%
2008	2,059,106	43,002	2.1	2,042,391	16,715	0.8
2009	2,099,931	40,825	2.0	2,077,097	22,834	1.1
2010	2,137,361	37,430	1.8	2,111,749	25,612	1.2
2011	2,174,822	37,461	1.8	2,145,235	29,586	1.4
2012	2,212,456	37,635	1.7	2,178,355	34,101	1.6
2013	2,250,240	37,783	1.7	2,211,642	38,597	1.7
2014	2,288,171	37,931	1.7	2,245,006	43,165	1.9
2015	2,326,454	38,283	1.7	2,278,635	47,819	2.1
2016	2,365,368	38,914	1.7	2,313,135	52,233	2.3
2017	2,404,524	39,156	1.7	2,348,349	56,175	2.4
2018	2,443,820	39,296	1.6	2,384,439	59,381	2.5
2019	2,483,250	39,430	1.6	2,421,341	61,910	2.6
2020	2,522,929	39,679	1.6	2,458,016	64,913	2.6
2021	2,563,017	40,088	1.6	2,492,730	70,287	2.8
2022	2,603,295	40,279	1.6	2,527,472	75,823	3.0
2023	2,643,698	40,403	1.6	2,562,977	80,721	3.1

Commercial Rates Billed



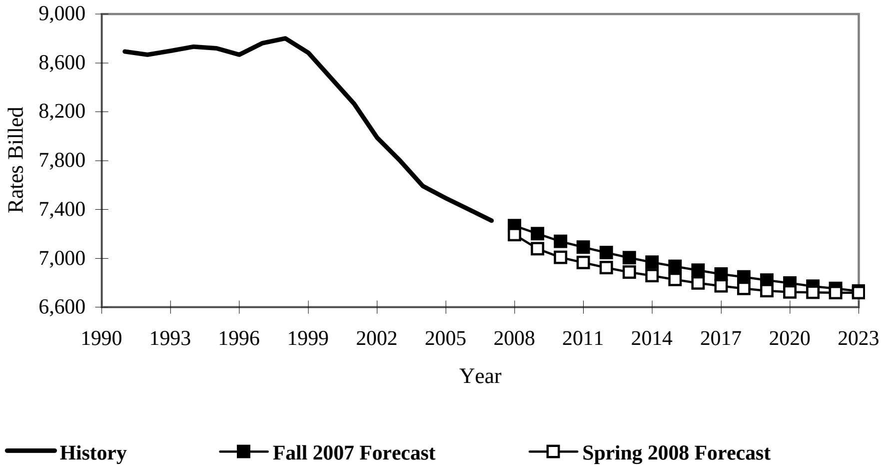
HISTORY | **AVERAGE ANNUAL GROWTH**

Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
1998	272,265	7,834	3.0			
1999	282,248	9,983	3.7			
2000	286,495	4,247	1.5			
2001	295,300	8,805	3.1			
2002	300,440	5,140	1.7			
2003	306,540	6,101	2.0	History (2002 to 2007)	6,045	1.9
2004	312,665	6,125	2.0	History (1992 to 2007)	6,653	2.4
2005	318,827	6,162	2.0			
2006	324,977	6,150	1.9	Spring 2008 Forecast (2007 to 2023)	6,530	1.7
2007	330,666	5,689	1.8	Fall 2007 Forecast (2007 to 2023)	6,312	1.7

SPRING 2008 FORECAST | **FALL 2007 FORECAST**

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	Difference from Fall 2007 Rates Billed	%
2008	337,056	6,390	1.9	337,397	-341	-0.1
2009	342,907	5,851	1.7	343,548	-641	-0.2
2010	349,377	6,470	1.9	349,728	-351	-0.1
2011	355,753	6,377	1.8	355,853	-100	0.0
2012	362,144	6,391	1.8	361,964	180	0.0
2013	368,545	6,401	1.8	367,856	689	0.2
2014	374,964	6,419	1.7	373,876	1,088	0.3
2015	381,435	6,471	1.7	380,027	1,409	0.4
2016	388,013	6,578	1.7	386,311	1,702	0.4
2017	394,643	6,630	1.7	392,752	1,891	0.5
2018	401,297	6,653	1.7	399,400	1,897	0.5
2019	407,973	6,676	1.7	406,250	1,723	0.4
2020	414,688	6,715	1.6	413,085	1,603	0.4
2021	421,474	6,786	1.6	419,460	2,014	0.5
2022	428,299	6,825	1.6	425,543	2,756	0.6
2023	435,146	6,847	1.6	431,664	3,481	0.8

Total Industrial Rates Billed *(Includes Textile and Other Industrial)*



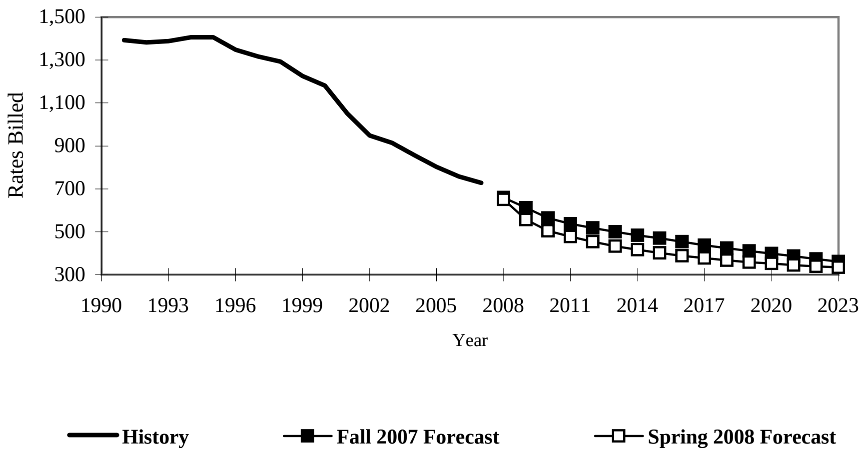
HISTORY **AVERAGE ANNUAL GROWTH**

Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
1998	8,800	38	0.4			
1999	8,681	-119	-1.3			
2000	8,474	-207	-2.4			
2001	8,265	-210	-2.5			
2002	7,989	-276	-3.3			
2003	7,801	-188	-2.3	History (2002 to 2007)	-136	-1.8
2004	7,591	-210	-2.7	History (1992 to 2007)	-91	-1.1
2005	7,492	-99	-1.3			
2006	7,401	-91	-1.2	Spring 2008 Forecast (2007 to 2023)	-37	-0.5
2007	7,309	-92	-1.2	Fall 2007 Forecast (2007 to 2023)	-36	-0.5

SPRING 2008 FORECAST **FALL 2007 FORECAST**

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	Difference from Fall 2007 Rates Billed	%
2008	7,192	-117	-1.6	7,265	-73	-1.0
2009	7,078	-114	-1.6	7,201	-123	-1.7
2010	7,007	-71	-1.0	7,136	-129	-1.8
2011	6,964	-43	-0.6	7,089	-126	-1.8
2012	6,923	-41	-0.6	7,045	-122	-1.7
2013	6,887	-36	-0.5	7,003	-116	-1.7
2014	6,856	-31	-0.5	6,967	-111	-1.6
2015	6,825	-31	-0.5	6,933	-108	-1.6
2016	6,798	-27	-0.4	6,902	-104	-1.5
2017	6,774	-24	-0.4	6,871	-97	-1.4
2018	6,752	-22	-0.3	6,845	-93	-1.4
2019	6,734	-18	-0.3	6,821	-86	-1.3
2020	6,724	-11	-0.2	6,796	-73	-1.1
2021	6,720	-3	0.0	6,772	-51	-0.8
2022	6,718	-2	0.0	6,752	-34	-0.5
2023	6,717	-1	0.0	6,732	-15	-0.2

Textile Rates Billed



HISTORY

Year	Actual Rates Billed	Growth Rates Billed	%
1998	1,293	-24	-1.9
1999	1,226	-67	-5.2
2000	1,181	-45	-3.7
2001	1,052	-129	-10.9
2002	949	-103	-9.8
2003	914	-35	-3.6
2004	857	-57	-6.2
2005	802	-56	-6.5
2006	757	-45	-5.6
2007	728	-29	-3.8

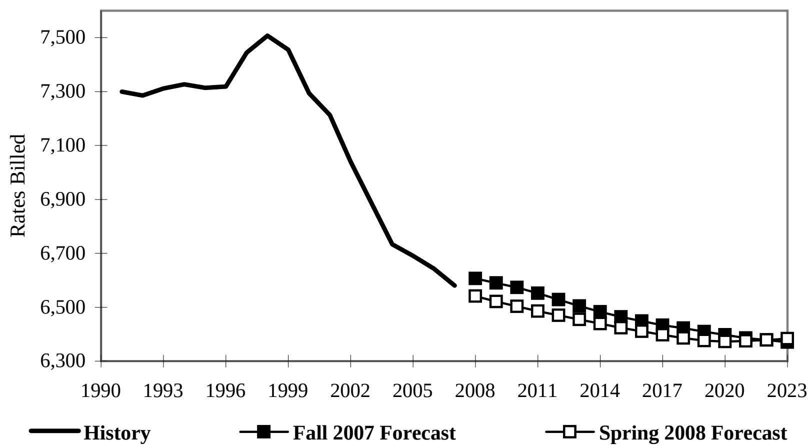
AVERAGE ANNUAL GROWTH

	Rates Billed Per Year	% Per Year
History (2002 to 2007)	-44	-5.2
History (1992 to 2007)	-44	-4.2
Spring 2008 Forecast (2007 to 2023)	-25	-4.8
Fall 2007 Forecast (2007 to 2023)	-23	-4.3

SPRING 2008 FORECAST / FALL 2007 FORECAST

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	Difference from Fall 2007 Rates Billed	%
2008	651	-77	-10.6	659	-8	-1.2
2009	557	-94	-14.4	611	-54	-8.9
2010	504	-53	-9.5	563	-59	-10.5
2011	478	-26	-5.2	538	-60	-11.1
2012	453	-25	-5.2	517	-64	-12.4
2013	433	-20	-4.4	500	-67	-13.4
2014	417	-16	-3.7	484	-67	-13.9
2015	401	-16	-3.8	470	-69	-14.6
2016	388	-13	-3.2	454	-66	-14.6
2017	377	-11	-2.8	438	-61	-13.9
2018	367	-10	-2.7	423	-56	-13.3
2019	358	-9	-2.4	411	-52	-12.8
2020	352	-7	-1.8	398	-47	-11.7
2021	345	-6	-1.8	386	-40	-10.5
2022	339	-6	-1.8	374	-34	-9.2
2023	334	-5	-1.5	362	-28	-7.7

Other Industrial Rates Billed



HISTORY **AVERAGE ANNUAL GROWTH**

Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
1998	7,507	62	0.8			
1999	7,455	-52	-0.7			
2000	7,293	-162	-2.2			
2001	7,213	-81	-1.1			
2002	7,040	-173	-2.4			
2003	6,887	-153	-2.2	History (2002 to 2007)	-92	-1.3
2004	6,733	-154	-2.2	History (1992 to 2007)	-47	-0.7
2005	6,690	-43	-0.6			
2006	6,644	-47	-0.7	Spring 2008 Forecast (2007 to 2023)	-12	-0.2
2007	6,581	-63	-0.9	Fall 2007 Forecast (2007 to 2023)	-13	-0.2

SPRING 2008 FORECAST **FALL 2007 FORECAST**

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	Difference from Fall 2007 Rates Billed	%
2008	6,541	-40	-0.6	6,607	-66	-1.0
2009	6,521	-20	-0.3	6,590	-69	-1.0
2010	6,503	-18	-0.3	6,573	-70	-1.1
2011	6,486	-17	-0.3	6,552	-66	-1.0
2012	6,470	-16	-0.2	6,528	-58	-0.9
2013	6,454	-16	-0.2	6,504	-50	-0.8
2014	6,439	-15	-0.2	6,483	-44	-0.7
2015	6,424	-15	-0.2	6,464	-40	-0.6
2016	6,410	-14	-0.2	6,448	-38	-0.6
2017	6,397	-13	-0.2	6,433	-36	-0.6
2018	6,385	-12	-0.2	6,422	-37	-0.6
2019	6,376	-9	-0.1	6,410	-34	-0.5
2020	6,372	-4	-0.1	6,398	-26	-0.4
2021	6,375	3	0.0	6,386	-11	-0.2
2022	6,379	4	0.1	6,379	0	0.0
2023	6,383	4	0.1	6,370	13	0.2

System Peaks

The Summer peak forecast represents the maximum coincidental demand during the summer season on the Duke Energy Carolinas system. It includes all Retail classes, Schedule 10A Resale, and total resource needs for Catawba Joint Owners plus the contribution to total peak associated with Nantahala Power and Light. The peak forecast excludes the demand portion of contract sales to other utilities, and sales to Seneca and Greenwood. It is expressed in MW at the point of generation and includes losses.

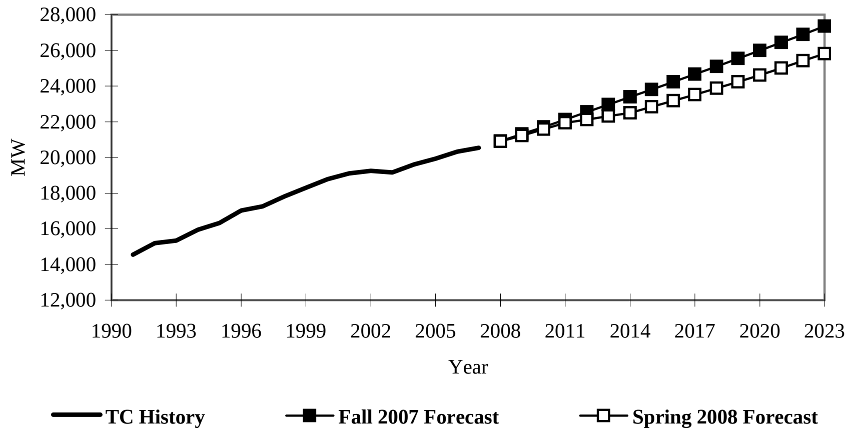
Additional adjustments were made to the peak forecasts to account for the expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007. These peak forecasts do not include adjustments for proposed energy efficiency programs.

The last Summer peak occurred on Wednesday, August 8, 2007 at 4 p.m. An actual peak of 21,418 MW was achieved at a time when the temperature was 100 degrees (for the Spring 2008 Forecast the expected temperature at the time of summer peak is 94 degrees).

Growth Forecasts

The new forecast projects an incremental growth of 330 MW or 1.4% per year for 2007-2023. The previous forecast growth was 426 MW or 1.8% per year for 2007-2023.

System Summer MW



HISTORY / **AVERAGE ANNUAL GROWTH**

Year	Weather Normalized MW	Growth MW	Growth %		MW Per Year	% Per Year
1998	17,813	562	3.3			
1999	18,292	479	2.7			
2000	18,780	488	2.7			
2001	19,111	331	1.8			
2002	19,238	127	0.7			
2003	19,159	-79	-0.4	History (2002 to 2007)	259	1.3
2004	19,614	455	2.4	History (1992 to 2007)	356	2.0
2005	19,936	322	1.6			
2006	20,314	378	1.9	Spring 2008 Forecast (2007 to 2023)	330	1.4
2007	20,535	221	1.1	Fall 2007 Forecast (2007 to 2023)	426	1.8

SPRING 2008 FORECAST / **FALL 2007 FORECAST**

Year	MW	Growth MW	Growth %	MW	Difference from Fall 2007 MW	Difference from Fall 2007 %
2008	20,905	369	1.8	20,911	-6	0.0
2009	21,225	321	1.5	21,304	-78	-0.4
2010	21,577	352	1.7	21,706	-129	-0.6
2011	21,935	358	1.7	22,120	-185	-0.8
2012	22,125	190	0.9	22,543	-418	-1.9
2013	22,315	190	0.9	22,965	-650	-2.8
2014	22,499	183	0.8	23,384	-885	-3.8
2015	22,831	332	1.5	23,804	-974	-4.1
2016	23,172	342	1.5	24,230	-1,057	-4.4
2017	23,522	349	1.5	24,662	-1,141	-4.6
2018	23,876	355	1.5	25,101	-1,225	-4.9
2019	24,238	362	1.5	25,544	-1,306	-5.1
2020	24,603	365	1.5	25,989	-1,386	-5.3
2021	25,007	404	1.6	26,435	-1,428	-5.4
2022	25,408	401	1.6	26,887	-1,479	-5.5
2023	25,812	404	1.6	27,346	-1,534	-5.6

The Winter peak forecast represents the maximum coincidental demand during the winter season on the Duke Energy Carolinas' system. It includes all Retail classes, Schedule 10A Resale, and total resource needs for Catawba Joint Owners plus the contribution to total peak associated with Nantahala Power and Light. The peak forecast excludes the demand portion of contract sales to other utilities, and sales to Seneca and Greenwood. It is expressed in MW at the point of generation and includes losses.

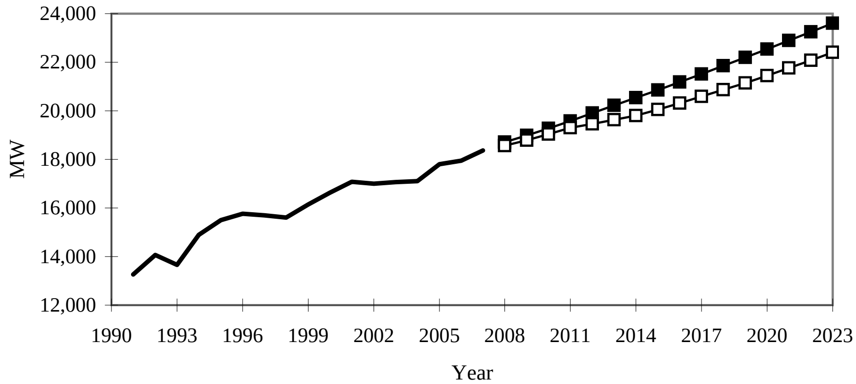
Additional adjustments were made to the peak forecasts to account for the expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007. These peak forecasts do not include adjustments for proposed energy efficiency programs.

The last Winter peak occurred on Friday, January 25, 2008 at 8 a.m. with an actual peak of 18,327 MW. This was achieved at a time when the temperature was 19 degrees (for the Spring 2008 Forecast the expected temperature at the time of winter peak is 18 degrees).

Growth Forecasts

The new Forecast projects an incremental growth of 252 MW or 1.3% per year from 2007-2023. The previous forecast growth was 327 MW or 1.6% per year from 2007-2023.

System Winter MW



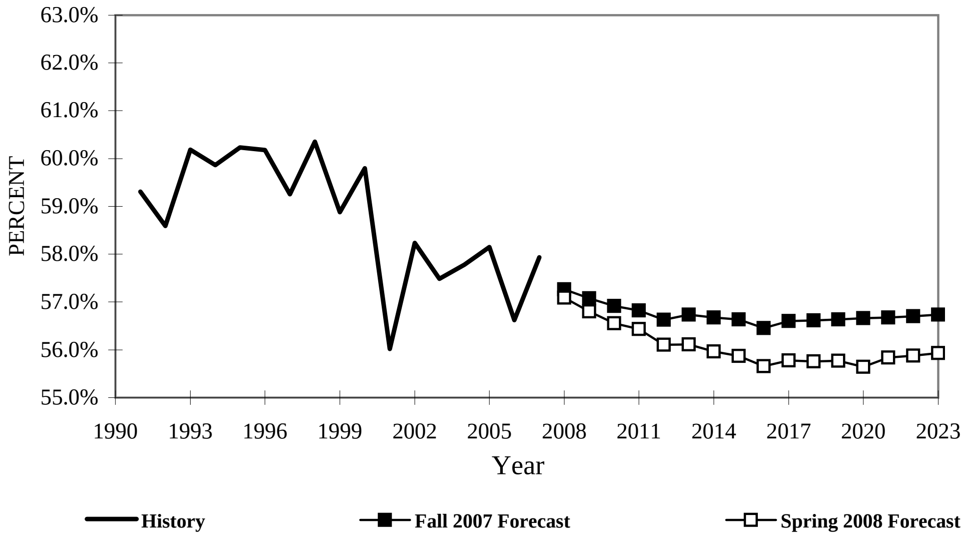
HISTORY / AVERAGE ANNUAL GROWTH

Year	Weather Normalized MW	Growth MW	Growth %		MW Per Year	% Per Year
1998	15,604	-94	-0.6			
1999	16,150	546	3.5			
2000	16,631	481	3.0			
2001	17,078	447	2.7			
2002	17,000	-78	-0.5			
2003	17,062	62	0.4	History (2002 to 2007)	273	1.6
2004	17,102	40	0.2	History (1992 to 2007)	286	1.8
2005	17,806	703	4.1			
2006	17,943	137	0.8	Spring 2008 Forecast (2007 to 2023)	252	1.3
2007	18,366	423	2.4	Fall 2007 Forecast (2007 to 2023)	327	1.6

SPRING 2008 FORECAST / FALL 2007 FORECAST

Year	MW	Growth MW	Growth %	MW	Difference from Fall 2007 MW	Difference from Fall 2007 %
2008	18,566	200	1.1	18,711	-145	-0.8
2009	18,787	221	1.2	18,982	-196	-1.0
2010	19,039	252	1.3	19,274	-236	-1.2
2011	19,301	262	1.4	19,583	-282	-1.4
2012	19,466	165	0.9	19,903	-437	-2.2
2013	19,636	170	0.9	20,223	-587	-2.9
2014	19,802	166	0.8	20,538	-737	-3.6
2015	20,053	251	1.3	20,857	-804	-3.9
2016	20,314	261	1.3	21,181	-867	-4.1
2017	20,586	272	1.3	21,513	-928	-4.3
2018	20,863	278	1.3	21,853	-990	-4.5
2019	21,151	288	1.4	22,198	-1,047	-4.7
2020	21,443	292	1.4	22,544	-1,101	-4.9
2021	21,763	320	1.5	22,891	-1,128	-4.9
2022	22,082	319	1.5	23,244	-1,162	-5.0
2023	22,406	323	1.5	23,604	-1,198	-5.1

The system load factor represents the relationship between annual energy and the maximum demand for the Duke Energy Carolinas' system. It is measured at generation level and excludes off-system sales and peaks.



APPENDIX C: 2007 FERC Form 715

The 2008 FERC Form 715 filed April 2008 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. The Company has sought authorization to cancel the current DSM/EE programs in the proceeding on Duke Energy Carolinas new energy efficiency plan, however the rate options discussed below will continue. 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 if the programs were to be continued and activation history.

Current Energy Efficiency and Demand-Side Management Programs

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.

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.

Existing EE and DSM Program Details

Projected MW Demand Response Impacts - Summer

Year	Load Control AC	Load Control WH	Interruptible IS	Interruptible SG	Total	Total Peak Impacts
2008	236	4	277	84	602	603
2009	223	4	248	85	560	561
2010	210	4	219	86	519	520
2011	198	3	190	87	479	480
2012	188	3	161	89	441	442
2013	177	3	132	90	402	403
2014	167	3	132	91	392	393
2015	157	2	132	92	384	385
2016	148	2	132	93	376	377
2017	140	2	132	94	368	369
2018	132	2	132	95	361	362
2019	124	2	132	96	354	355
2020	117	1	132	97	347	348
2021	110	1	132	98	342	343
2022	104	1	132	99	336	337
2023	98	1	132	100	331	332
2024	92	1	132	101	326	327
2025	87	1	132	103	322	323
2026	82	1	132	104	318	319
2027	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
9/07 – 9/08	Air Conditioners				
	Water Heaters				
	Standby Generators				
	Interruptible Service	Communication Test	N/A	N/A	5/6/2008
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
		Communication 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	Communication 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	Communication 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 Update

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 final air permit was issued January 29, 2008. A number of conditions were a part of the CPCN and final air permit including:

1) 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)
2) Retiring older coal generation under the following requirement.
    a. Retire Cliffside Units 1-4 no later than the commercial operation date of the new unit.
    b. Retire on a MW for MW basis, in addition to Cliffside 1-4, load reductions achieved through energy efficiency programs achieved through the 1% of annual retail revenues comment to DSM/EE programs.
    c. In addition to Cliffside Units 1-4, retire 350 MW of coal generation by 2015, an additional 200 MWs by 2016, and an additional 250 MW by 2018.
        i. The MW in c) is not additive with MW identified in b)

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 were filed monthly through February 2008 and will be filed annually from this date to the end of the project.

On-site construction has begun, and the on-going legal challenges and their status are outlined in Appendix M. After final equipment selection and detailed engineering completed, Cliffside 6 is expected to have a net output of 825 MWs versus the 800 MWs used in previous IRPs. The unit is scheduled to be on line by the summer peak of 2012.

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. New powerhouse and generation equipment will be installed 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 in June 2007. Construction began in July 2008 with an expected release to dispatch date of June 2010.

2008 CPCN Proceedings

Buck Combined Cycle Natural Gas Unit

A CPCN application was filed for adding approximately 600-800 MW of combined cycle generation at the Buck Steam Station in Salisbury, N.C. Hearings were held in March 2008 and approval was received in June 2008. The air permit application was received in October 2008. Economic factors in 2008 have caused increased uncertainty with regard to forecasted load and near term capital expenditures. While current projections indicate there is still a capacity need in the 2011-2012 timeframe, the timing of the Buck simple cycle to combined cycle “phase-in” has been extended a year 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.

Dan River Combined Cycle Natural Gas Unit

A CPCN application was filed for adding approximately 600-800 MW of combined cycle generation at the Dan River Steam Station in Eden, N.C. Hearings were held in March 2008 and approval was received in June 2008. The air permit application was submitted in October 2008, with the final permit expected to be received by the end of 2009. Economic factors in 2008 have caused increased uncertainty with regard to forecasted load and near term capital expenditures. While current projections indicate there is still a capacity need in the 2011-2012 timeframe, the Dan River simple cycle to combined cycle “phase-in” has been changed to not phase-in the generation but continue with the combined cycle generation to be available by the summer of 2012.

Short term capacity needs to maintain an acceptable reserve margin can be met with any combination of built or purchased generation, purchase power agreements, or increased DSM. In addition, the timing and phase-in of the Buck and Dan River projects can continue to be optimized.

Pending CPCN Proceedings

Rockingham Combustion Turbine Expansion

There is a potential need for an additional capacity in 2011. In order to be in position to meet this need, Duke Energy Carolinas filed on July 31, 2008 the preliminary information required pursuant to Rule R8-61 120 days in advance of a CPCN application to expand the existing Rockingham Combustion Turbine facility with four additional combustion turbines. Multiple options to meet this need are being considered but the filing of the preliminary information pursuant to Rule R8-61 preserves the self-build option.

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 from the NRC. The Westinghouse Advanced Passive 1000 reactor technology was selected for the application after an extensive review of multiple technologies.

In 2006, a site in Cherokee County, S.C. was selected for the project. Site characterization work is now complete.   The Lee Nuclear COL application was submitted to the NRC on December 13, 2007. The NRC's sufficiency review concluded with acceptance and docketing of the application on February 25, 2008. Subsequently, on April 2, 2008, the NRC published a schedule for the full review of the application, indicating scheduled completion of the environmental review in March 2010 and scheduled completion of the safety review in February 2011. Issuance of the combined license is scheduled to occur following the conclusion of public hearings. The typical planning assumption for public hearings is 12 months, which would result in issuance of a license in early 2012. In September 2008, the Atomic Safety and Licensing Board of the NRC issued a decision dismissing in its entirety the only petition to intervene challenging the Lee COL application, filed by the Blue Ridge Environmental Defense League (BREDL). BREDL did not appeal this Board decision dismissing its petition to intervene and proposed contentions. Consequently, the 12 month period allotted in the NRC schedule for a contested hearing is unnecessary at this time.

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.

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:

Pleasant Garden Tie to Asheboro Switchyard – 230kV

- County location of end point(s): Guilford County
- Approximate length: 0.05 miles
- Typical right-of-way width for proposed type of line: 150 feet
- Typical tower height for proposed type of line: 150 feet
- Number of circuits: 1
- Operating voltage: 230 KV
- Design capacity: 1100 MVS
- Estimated date for starting construction: 5/12/2010
- Estimated in-service date: 6/1/2011

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, 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. As discussed in last year's filing, the rapidly escalating prices in these markets has continued often making 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.

As described in the 2007 filing where it outlined the fact that in developing the 2006 IRP, a list of eighty-eight supply-side resources was compiled of potential alternatives for the IRP process, this learning and experience from the 2006 analyses allowed a more focused approach to resource screening that carries forward 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. As was shown 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. As in the 2007 IRP analyses, the elimination of some of these variations allowed more time to concentrate on ensuring consistency of treatment across the technologies. This approach also allows the Company to examine renewable technologies such as wind, biomass, hydro, animal waste, and solar in more depth.

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 supply-side utility scale. Small-scale substation pilots are being studied to assist in increasing distribution system reliability.

- 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. The capacity and energy available from CAES is also very site geologically specific. 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. Fuel gas (hydrogen) purity, 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

Peak / Intermediate Technologies
4-160 MW Combustion Turbines – GE 7FA
460 MW Unfired + 40 MW Inlet Chilling Combined Cycle – 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.

Renewable technologies were screened within their own category, rather than being screened together with conventional technologies within the baseload or peaking/intermediate categories in order to identify the most attractive options to satisfy the NC REPS requirement.

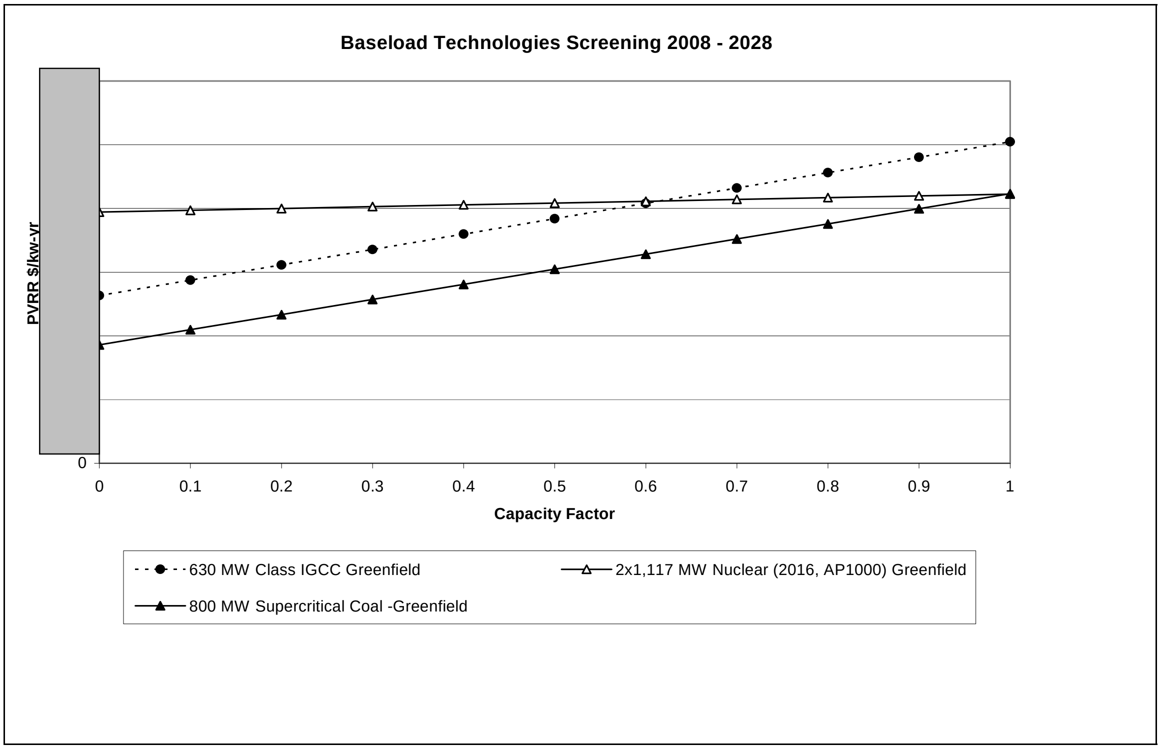
The screening includes the impacts of the traditional regulated emissions of SO_2 and NOx generally associated with the Clean Air Act Amendments of 1990, the recently overturned Clean Air Interstate Rule, and the 2002 North Carolina Clean Smokestacks Act along with consideration of the Lower Carbon scenario CO_2 regulations and a Renewable Portfolio Standard. The impact of the Higher Carbon scenario is also shown for comparison purposes in the composite bus bar chart. These scenarios are discussed in more detail in Appendix A.

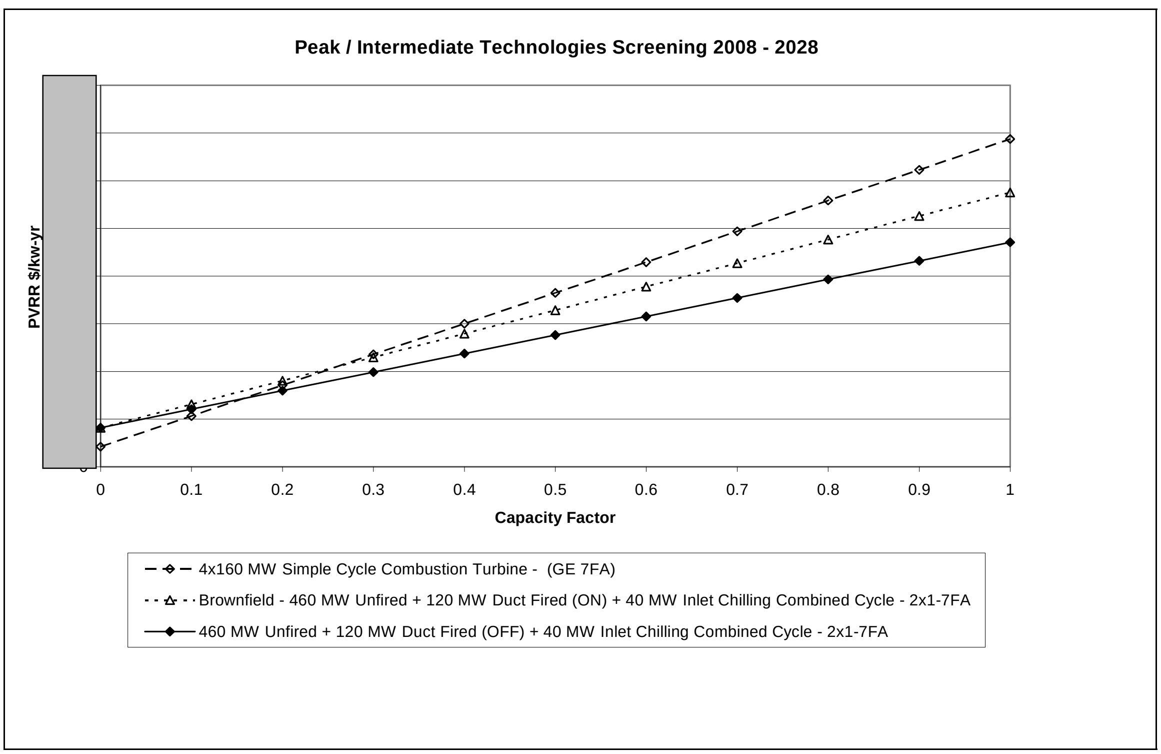
The following sets of estimated Levelized Busbar Cost[2] charts provide an economic comparison of the technologies in their respective categories. Busbar charts comparisons involving some renewable resources, particularly wind and solar resources, can be somewhat misleading because these resources do not contribute their full installed capacity at the time of the system peak[3]. 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. Also, the capacity (MW size) of the Baseload and Peak/Intermediate technology categories are listed in the chart legends, and tabular listings below. The expected energy (MWh) at any given capacity factor (whether along a continuous line, or a specific point) may be determined by the following formula: Expected Energy (MWh) = 8,760 x Capacity (MW size) x Capacity Factor (%/100).

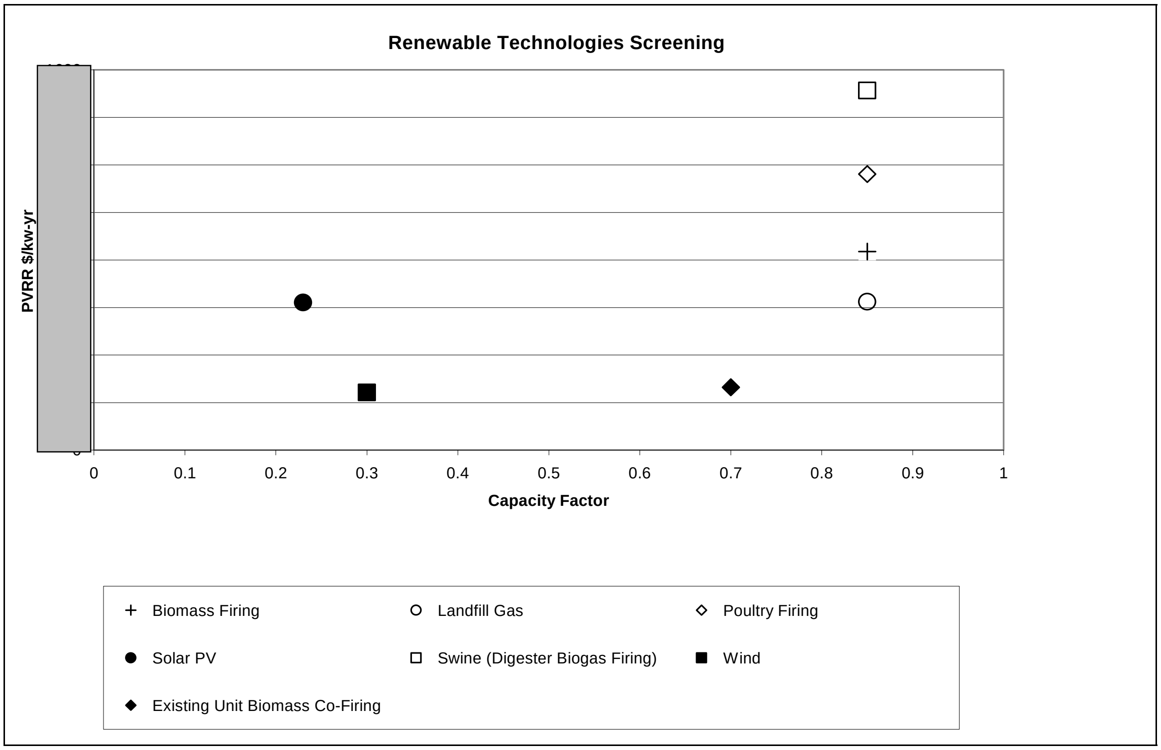
[2] While these estimated levelized busbar costs provide a reasonable basis for initial screening of technologies, simple busbar cost information has limitations. In isolation, busbar cost information has limited applicability in decision-making because it is highly dependent on the circumstances being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

[3] For purposes of this IRP, 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.

Busbar Charts by Technology Category – Lower Carbon Scenario







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.

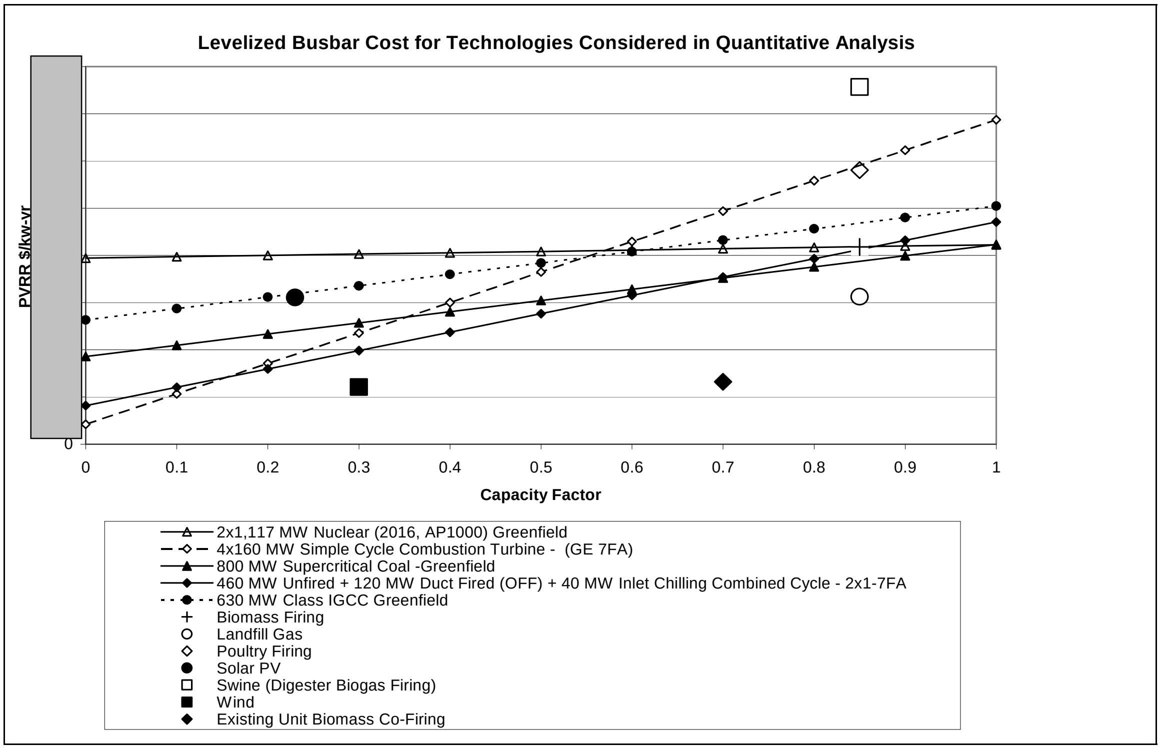
The following technologies were selected for the quantitative analysis:

- Base Load – 800MW Supercritical Pulverized Coal
- Base Load – 630 MW IGCC
- Base Load – 2x1,117MW Nuclear units (AP1000)
- Peaking/Intermediate – 4x160MW Combustion Turbines (7FA)
- Peaking/Intermediate –460 MW Unfired+120MW Duct Fired+40MW Inlet Chilled N. Gas Combined Cycle
- Peaking/Intermediate –460 MW Unfired+40MW Inlet Chilled N. Gas Combined Cycle
- Renewable – 20 MW Existing Unit Biomass Co-Firing
- Renewable – 50 MW Wind PPA - On-Shore
- Renewable – 3 MW Landfill Gas PPA
- Renewable – 16 MW Solar Photovoltaic PPA
- Renewable – 40 MW Biomass Firing PPA

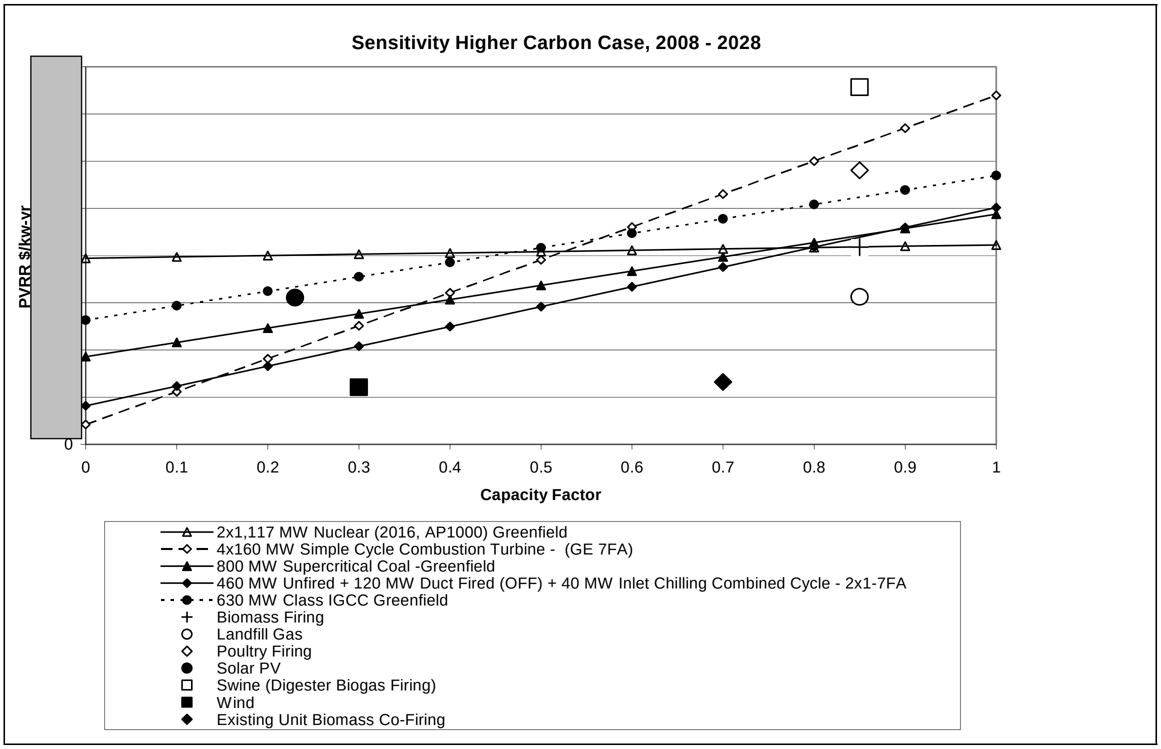
- Renewable – 4.7 MW Hog Waste Digester PPA
- Renewable – 55 MW Poultry Waste PPA

The chart below show the technologies that were the "best" from each of the three general categories screened on one chart.

Composite Busbar Chart - Lower Carbon Scenario



Composite Busbar Chart - Higher Carbon Scenario



Review of the Composite Busbar charts highlights the benefits to nuclear compared to other baseload technologies as CO2 prices increase.

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).

The collaborative efforts resulted in the Company's May 7, 2007 North Carolina DSM/EE filing[4] and September 28, 2007 South Carolina filing[5]. Future Measurement

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

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 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.

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 its 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.

Advanced Power Manager Program (Demand Response)
This is a potential 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.

Efficiency Savings Plan (Conservation)
This is a potential 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 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	Total	Residential	Non-Residential	Total EE	Power Share	Power Manager	Total DR	Total MW Impacts
2008	70,821	27,029	97,850	32	7	39	517	244	761	800
2009	209,388	79,273	288,661	90	21	110	653	244	898	1008
2010	339,285	134,217	473,502	141	35	176	771	244	1016	1192
2011	464,162	192,879	657,041	189	51	239	771	244	1016	1255
2012	593,071	247,024	840,096	241	65	306	771	244	1016	1321
2013	731,647	299,266	1,030,913	299	78	377	771	244	1016	1393
2014	861,545	354,227	1,215,771	350	93	443	771	244	1016	1458
2015	987,871	413,472	1,401,343	398	108	506	771	244	1016	1522
2016	1,115,335	467,047	1,582,382	450	122	572	771	244	1016	1588
2017	1,253,903	519,262	1,773,164	508	136	644	771	244	1016	1659
2018	1,383,795	574,222	1,958,017	559	150	709	771	244	1016	1725
2019	1,511,583	634,047	2,145,630	607	166	773	771	244	1016	1788
2020	1,566,746	660,015	2,226,761	628	172	800	771	244	1016	1816
2021	1,566,755	660,015	2,226,770	628	172	800	771	244	1016	1816
2022	1,566,774	660,027	2,226,801	628	172	800	771	244	1016	1816
2023	1,571,129	661,730	2,232,859	628	172	800	771	244	1016	1816
2024	1,566,755	660,013	2,226,768	628	172	800	771	244	1016	1816
2025	1,566,756	660,031	2,226,787	628	172	800	771	244	1016	1816
2026	1,566,746	660,015	2,226,761	628	172	800	771	244	1016	1816
2027	1,571,128	661,726	2,232,855	628	172	800	771	244	1016	1816
2028	1,566,747	659,986	2,226,733	628	172	800	771	244	1016	1816
2029	1,566,751	660,031	2,226,782	628	172	800	771	244	1016	1816
2030	1,566,755	660,013	2,226,768	628	172	800	771	244	1016	1816
2031	1,571,112	661,714	2,232,826	628	172	800	771	244	1016	1816
2032	1,566,755	660,015	2,226,770	628	172	800	771	244	1016	1816

Proposed Programs

Energy Efficiency Education Program for Schools

	UCT	TRC	RIM	Participant
Avoided T&D	$8,400,366	$8,400,366	$8,400,366	$0
Cost-Based Avoided Production	$34,532,156	$34,532,156	$34,532,156	$0
Cost-Based Avoided Capacity	$11,062,825	$11,062,825	$11,062,825	$0
Lost Revenue	$0	$0	$0	$62,325,574
Net Lost Revenue	$0	$0	$48,193,841	$0
Administration Costs	$6,401,094	$6,401,094	$6,401,094	$0
Implementation Costs	$9,601,641	$9,601,641	$9,601,641	$0
Incentives	$0	$0	$0	$0
Other Utility Costs	$1,400,712	$1,400,712	$1,400,712	$0
Participant Costs	$0	$0	$0	$0
Total Benefits	$53,995,346	$53,995,346	$53,995,346	$62,325,574
Total Costs	$17,403,447	$17,403,447	$65,597,288	$0
Benefit/Cost Ratios	**3.10**	**3.10**	**0.82**	

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

Proposed Programs

Low Income Services				
	UCT	**TRC**	**RIM**	**Participant**
Avoided T&D	$4,008,340	$4,008,340	$4,008,340	$0
Cost-Based Avoided Production	$17,509,853	$17,509,853	$17,509,853	$0
Cost-Based Avoided Capacity	$3,140,121	$3,140,121	$3,140,121	$0
Lost Revenue	$0	$0	$0	$31,684,787
Net Lost Revenue	$0	$0	$24,499,283	$0
Administration Costs	$3,609,236	$3,609,236	$3,609,236	$0
Implementation Costs	$5,413,854	$5,413,854	$5,413,854	$0
Incentives	$0	$0	$0	$0
Other Utility Costs	$3,384,615	$3,384,615	$3,384,615	$0
Participant Costs	$0	$0	$0	$0
Total Benefits	$24,658,314	$24,658,314	$24,658,314	$31,684,787
Total Costs	$12,407,705	$12,407,705	$36,906,987	$0
Benefit/Cost Ratios	**1.99**	**1.99**	**0.67**	

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

Proposed Programs

Power Manager				
	UCT	TRC	RIM	Participant
Avoided T&D	$50,465,877	$50,465,877	$50,465,877	$0
Cost-Based Avoided Production	$109,008,979	$109,008,979	$109,008,979	$0
Cost-Based Avoided Capacity	$106,920,781	$106,920,781	$106,920,781	$0
Lost Revenue	$0	$0	$0	$0
Net Lost Revenue	$0	$0	$0	$0
Administration Costs	$734,839	$734,839	$734,839	$0
Implementation Costs	$1,102,259	$1,102,259	$1,102,259	$0
Incentives	$33,450,743	$0	$33,450,743	$33,450,743
Other Utility Costs	$0	$0	$0	$0
Participant Costs	$0	$0	$0	$0
Total Benefits	$266,395,637	$266,395,637	$266,395,637	$33,450,743
Total Costs	$35,287,841	$1,837,098	$35,287,841	$0
Benefit/Cost Ratios	**7.55**	**145.01**	**7.55**	

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

Proposed Programs

Residential Energy Assessments				
	UCT	**TRC**	**RIM**	**Participant**
Avoided T&D	$3,700,754	$3,700,754	$3,700,754	$0
Cost-Based Avoided Production	$15,156,841	$15,156,841	$15,156,841	$0
Cost-Based Avoided Capacity	$3,414,998	$3,414,998	$3,414,998	$0
Lost Revenue	$0	$0	$0	$27,480,998
Net Lost Revenue	$0	$0	$21,250,411	$0
Administration Costs	$3,456,959	$3,456,959	$3,456,959	$0
Implementation Costs	$5,185,439	$5,185,439	$5,185,439	$0
Incentives	$0	$0	$0	$0
Other Utility Costs	$72,910	$72,910	$72,910	$0
Participant Costs	$0	$0	$0	$0
Total Benefits	$22,272,593	$22,272,593	$22,272,593	$27,480,998
Total Costs	$8,715,308	$8,715,308	$29,965,719	$0
Benefit/Cost Ratios	**2.56**	**2.56**	**0.74**	

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

Proposed Programs

PowerShare®				
	UCT	**TRC**	**RIM**	**Participant**
Avoided T&D	$164,879,815	$164,879,815	$164,879,815	$0
Cost-Based Avoided Production	$382,500,957	$382,500,957	$382,500,957	$0
Cost-Based Avoided Capacity	$395,455,252	$395,455,252	$395,455,252	$0
Lost Revenue	$0	$0	$0	$0
Net Lost Revenue	$0	$0	$0	$0
Administration Costs	$1,513,125	$1,513,125	$1,513,125	$0
Implementation Costs	$2,269,687	$2,269,687	$2,269,687	$0
Incentives	$218,997,082	$0	$218,997,082	$218,997,082
Other Utility Costs	$0	$0	$0	$0
Participant Costs	$0	$3,813,254	$0	$3,813,254
Total Benefits	$942,836,024	$942,836,024	$942,836,024	$218,997,082
Total Costs	$222,779,894	$7,596,067	$222,779,894	$3,813,254
Benefit/Cost Ratios	**4.23**	**124.12**	**4.23**	**57.43**

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

Proposed Programs

Smart $aver® for Non-Residential Customers				
	UCT	TRC	RIM	Participant
Avoided T&D	$14,608,395	$14,608,395	$14,608,395	$0
Cost-Based Avoided Production	$45,703,826	$45,703,826	$45,703,826	$0
Cost-Based Avoided Capacity	$20,570,690	$20,570,690	$20,570,690	$0
Lost Revenue	$0	$0	$0	$62,637,867
Net Lost Revenue	$0	$0	$44,141,650	$0
Administration Costs	$3,302,119	$3,302,119	$3,302,119	$0
Implementation Costs	$4,953,179	$4,953,179	$4,953,179	$0
Incentives	$15,847,000	$0	$15,847,000	$15,847,000
Other Utility Costs	$4,284,675	$4,284,675	$4,284,675	$0
Participant Costs	$0	$32,523,521	$0	$32,523,521
Total Benefits	$80,882,910	$80,882,910	$80,882,910	$78,484,867
Total Costs	$28,386,973	$45,063,494	$72,528,623	$32,523,521
Benefit/Cost Ratios	**2.85**	**1.79**	**1.12**	**2.41**

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 July 11, 2007, in Docket No. E-100, Sub 111, 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 electricity to Duke Energy Carolinas)					
Name	**City**	**State**	**Nameplate KW**	**Primary Fuel Type**	**Part of Total Supply Resources [1]**
Advantage Investment Group, LLC	Spencer Mtn	NC	640	Hydroelectric	Yes
Alamance Hydro, LLC	Glen Raven	NC	240	Hydroelectric	Yes
Barbara Ann Evans - Caroleen Mills	Caroleen	NC	324	Hydroelectric	Yes
Byron P. Matthews	Chapel Hill	NC	3	Photovoltaic	Yes
Catawba County - Blackburn Landfill	Newton	NC	4,000	Landfill Gas	Yes
Cliffside Mills, LLC	Cliffside	NC	1,600	Hydroelectric	Yes
David K. Birkhead	Hillsborough	NC	2	Photovoltaic	Yes
David Ringenburg	Chapel Hill	NC	7	Photovoltaic	Yes
David E. Shi	Brevard	NC	3	Photovoltaic	Yes
David M. Thomas	Lenoir	NC	6	Photovoltaic	Yes
David Wiener dba JZ Solar Electric	Chapel Hill	NC	3	Photovoltaic	Yes
Decision Support Management LLC	Matthews	NC	30	Photovoltaic	Yes
Delta Products Corporation	RTP	NC	30	Photovoltaic	Yes
Diann M. Barbacci	Kernersville	NC	2	Photovoltaic	Yes
Everrett Williams	Robbinsville	NC	4	Hydroelectric	Yes
Frances L. Thompson	Hickory	NC	4	Photovoltaic	Yes
Gwenyth T. Reid	Hillsborough	NC	4	Photovoltaic	Yes
Haneline Power, LLC	Millersville	NC	365	Hydroelectric	Yes
Hardins Resources Company	Hardins	NC	820	Hydroelectric	Yes
Haw River Hydro Company	Saxapahaw	NC	1,500	Hydroelectric	Yes
Hayden-Harman Foundation	Burlington	NC	2	Photovoltaic	Yes
Hendrik J. Roddenburg	Chapel Hill	NC	3	Photovoltaic	Yes
Holzworth Holdings, Inc.	Durham	NC	3	Photovoltaic	Yes
Jafasa Farms - Residence	Mills River	NC	6	Photovoltaic	Yes
Jafasa Farms - Greenhouse	Mills River	NC	6	Photovoltaic	Yes
James B. Sherman	Chapel Hill	NC	5	Photovoltaic	Yes
Jerome Levit	Graham	NC	2	Photovoltaic	Yes
Jim and Linda Alexander	Chapel Hill	NC	4	Photovoltaic	Yes
John H. DiLiberti	Hillsborough	NC	9	Photovoltaic	Yes
Mark A. Powers	Chapel Hill	NC	2	Photovoltaic	Yes
Mayo Hydropower, LLC - Avalon Dam	Mayodan	NC	1,275	Hydroelectric	Yes
Mayo Hydropower, LLC - Mayo Dam	Mayodan	NC	950	Hydroelectric	Yes
MegaWatt Solar	Hillsborough	NC	5	Photovoltaic	Yes
Mill Shoals Hydro Co - High Shoals Hydro	High Shoals	NC	1,800	Hydroelectric	Yes
Northbrook Carolina Hydro, LLC-Turner Shoals Hydro	Mill Springs	NC	5,500	Hydroelectric	Yes
Pacifica Master Homeowners' Association	Carrboro	NC	5	Photovoltaic	Yes
Paul G. Keller DBA Futility	Chapel Hill	NC	3	Photovoltaic	Yes
Phillip B. Caldwell	Brevard	NC	3	Photovoltaic	Yes
Pickens Mill Hydro, LLC - Stice Shoals Hydro	Shelby	NC	600	Hydroelectric	Yes
Pippin Home Designs	Sherrills Ford	NC	2	Photovoltaic	Yes
Rebecca T. Cobey	Chapel Hill	NC	1	Photovoltaic	Yes
Salem Energy Systems	Winston-Salem	NC	4,270	Landfill Gas	Yes
Shawn L. Slome	Chapel Hill	NC	2	Photovoltaic	Yes
South Yadkin Power, Inc	Cooleemee	NC	1,400	Hydroelectric	Yes
Spray Cotton Mills	Eden	NC	500	Hydroelectric	Yes
Stephen C. Graf	Cedar Grove	NC	5	Photovoltaic	Yes
Steve Mason Enterprises-Long Shoals Hydro	Long Shoals	NC	900	Hydroelectric	Yes
Strates Inc. DBA Westtown Eatery & Express	Winston-Salem	NC	6	Photovoltaic	Yes
The Rocket Shop, LLC	Durham	NC	2	Photovoltaic	Yes
Timothy R. Martin	Browns Summit	NC	3	Photovoltaic	Yes
Town of Chapel Hill	Chapel Hill	NC	4	Photovoltaic	Yes

PURPA QUALIFYING FACILITIES (Selling electricity to Duke Energy Carolinas)

Name	City	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources [1]
Town of Lake Lure	Lake Lure	NC	3,600	Hydroelectric	Yes
W. Jefferson Holt DBA Holt Family Farm Power	Chapel Hill	NC	9	Photovoltaic	Yes
Yves Naar	Brevard	NC	4	Photovoltaic	Yes
Walter C. McGervey	Statesville	NC	1	Photovoltaic	Yes
Aquenergy Systems Inc	Piedmont	SC	1,050	Hydroelectric	Yes
Aquenergy Systems Inc	Ware Shoals	SC	6,300	Hydroelectric	Yes
Cherokee County Cogeneration Partners	Gaffney	SC	100,000	Natural gas	Yes
Converse Energy Inc	Converse	SC	1,250	Hydroelectric	Yes
Greenville Gas Producers, LLC	Greenville	SC	3,200	Landfill Gas	Yes
Northbrook Carolina Hydro, LLC - Boyds Mill Hydro	Ware Shoals	SC	1,500	Hydroelectric	Yes
Northbrook Carolina Hydro, LLC - Hollidays Bridge Hydro	Belton	SC	3,500	Hydroelectric	Yes
Northbrook Carolina Hydro, LLC - Saluda Hydro	Greenville	SC	2,400	Hydroelectric	Yes
Pacolet River Power Co	Clifton	SC	800	Hydroelectric	Yes
Pelzer Hydro Co - Upper Hydro	Pelzer	SC	2,020	Hydroelectric	Yes
Pelzer Hydro Co - Lower Hydro	Williamston	SC	3,300	Hydroelectric	Yes

[1] Nameplate rating generally exceeds the contract capacity

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
Broad River Energy Center, LLC	Gaffney	SC	875,000	Natural gas	No

[1] Nameplate rating generally exceeds the contract capacity

CUSTOMER-OWNED STANDBY GENERATION				
County	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources[1]
Belmont	NC	350	Unknown	Yes
Belmont	NC	350	Unknown	Yes
Belmont	NC	500	Unknown	Yes
Bessemer City	NC	440	Unknown	Yes
Brevard	NC	1,000	Unknown	Yes
Burlington	NC	550	Unknown	Yes
Burlington	NC	600	Unknown	Yes
Burlington	NC	650	Unknown	Yes
Burlington	NC	225	Unknown	Yes
Burlington	NC	200	Unknown	Yes
Burlington	NC	1,150	Unknown	Yes
Butner	NC	1,250	Unknown	Yes
Butner	NC	750	Unknown	Yes
Carrboro	NC	1,135	Unknown	Yes
Carrboro	NC	2,000	Unknown	Yes
Carrboro	NC	500	Unknown	Yes
Chapel Hill	NC	500	Unknown	Yes
Charlotte	NC	1,750	Unknown	Yes
Charlotte	NC	1,200	Unknown	Yes
Charlotte	NC	1,250	Unknown	Yes
Charlotte	NC	1,200	Unknown	Yes
Charlotte	NC	2,250	Unknown	Yes
Charlotte	NC	420	Unknown	Yes
Charlotte	NC	1,135	Unknown	Yes
Charlotte	NC	1,135	Unknown	Yes
Charlotte	NC	1,500	Unknown	Yes
Charlotte	NC	10,000	Unknown	Yes
Charlotte	NC	200	Unknown	Yes
Charlotte	NC	2,200	Unknown	Yes
Charlotte	NC	700	Unknown	Yes
Charlotte	NC	5,600	Unknown	Yes
Charlotte	NC	4,000	Unknown	Yes
Concord	NC	680	Unknown	Yes
Danbury	NC	400	Unknown	Yes
Durham	NC	1,600	Unknown	Yes
Durham	NC	1,300	Unknown	Yes
Durham	NC	2,500	Unknown	Yes
Durham	NC	1,100	Unknown	Yes
Durham	NC	1,400	Unknown	Yes
Durham	NC	1,600	Unknown	Yes
Durham	NC	1,500	Unknown	Yes
Durham	NC	2,250	Unknown	Yes
Durham	NC	4,500	Unknown	Yes
Durham	NC	6,400	Unknown	Yes
Eden	NC	1,700	Unknown	Yes
Elkin	NC	400	Unknown	Yes
Elkin	NC	500	Unknown	Yes

CUSTOMER-OWNED STANDBY GENERATION				
County	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources[1]
Gastonia	NC	910	Unknown	Yes
Gastonia	NC	680	Unknown	Yes
Gastonia	NC	12,500	Unknown	Yes
Graham	NC	800	Unknown	Yes
Greensboro	NC	1,350	Unknown	Yes
Greensboro	NC	125	Unknown	Yes
Greensboro	NC	1,000	Unknown	Yes
Greensboro	NC	1,500	Unknown	Yes
Greensboro	NC	2,000	Unknown	Yes
Greensboro	NC	250	Unknown	Yes
Greensboro	NC	750	Unknown	Yes
Greensboro	NC	1,280	Unknown	Yes
Greensboro	NC	700	Unknown	Yes
Hendersonville	NC	1,000	Unknown	Yes
Hendersonville	NC	500	Unknown	Yes
Hendersonville	NC	1,000	Unknown	Yes
Hickory	NC	1,500	Unknown	Yes
Hickory	NC	750	Unknown	Yes
Hickory	NC	1,000	Unknown	Yes
Hickory	NC	1,500	Unknown	Yes
Hickory	NC	1,040	Unknown	Yes
Hickory	NC	500	Unknown	Yes
Huntersville	NC	2,950	Unknown	Yes
Huntersville	NC	775	Unknown	Yes
Huntersville	NC	3,200	Unknown	Yes
Indian Trail	NC	900	Unknown	Yes
King	NC	800	Unknown	Yes
Lexington	NC	750	Unknown	Yes
Lexington	NC	2,950	Unknown	Yes
Lincolnton	NC	300	Unknown	Yes
Marion	NC	650	Unknown	Yes
Matthews	NC	1,450	Unknown	Yes
Mebane	NC	400	Unknown	Yes
Monroe	NC	400	Unknown	Yes
Mooresville	NC	750	Unknown	Yes
Morganton	NC	200	Unknown	Yes
Mt. Airy	NC	600	Unknown	Yes
Mt. Airy	NC	750	Unknown	Yes
Mt. Holly	NC	210	Unknown	Yes
N. Wilkesboro	NC	600	Unknown	Yes
N. Wilkesboro	NC	155	Unknown	Yes
North Wilkesboro	NC	1,250	Unknown	Yes
Pfafftown	NC	4,000	Unknown	Yes
Reidsville	NC	750	Unknown	Yes
RTP	NC	1,000	Unknown	Yes
RTP	NC	350	Unknown	Yes
RTP	NC	750	Unknown	Yes

CUSTOMER-OWNED STANDBY GENERATION				
County	**State**	**Nameplate KW**	**Primary Fuel Type**	**Part of Total Supply Resources[1]**
Rural Hall	NC	1,050	Unknown	Yes
Rutherfordton	NC	800	Unknown	Yes
Salisbury	NC	1,500	Unknown	Yes
Shelby	NC	4,480	Unknown	Yes
Valdese	NC	600	Unknown	Yes
Valdese	NC	800	Unknown	Yes
Welcome	NC	300	Unknown	Yes
Wilkesboro	NC	750	Unknown	Yes
Winston	NC	750	Unknown	Yes
Winston Salem	NC	1,800	Unknown	Yes
Winston Salem	NC	3,360	Unknown	Yes
Winston Salem	NC	1,250	Unknown	Yes
Winston Salem	NC	3,000	Unknown	Yes
Winston Salem	NC	2,000	Unknown	Yes
Winston Salem	NC	3,000	Unknown	Yes
Winston-Salem	NC	500	Unknown	Yes
Winston-Salem	NC	3,200	Unknown	Yes
Winston-Salem	NC	400	Unknown	Yes
Winston-Salem	NC	3,750	Unknown	Yes
Yadkinville	NC	500	Unknown	Yes
Yadkinville	NC	1,200	Unknown	Yes
Anderson	SC	2,250	Unknown	Yes
Anderson	SC	1,500	Unknown	Yes
Bullock Creek	SC	275	Unknown	Yes
Clinton	SC	447	Unknown	Yes
Clover	SC	625	Unknown	Yes
Clover	SC	75	Unknown	Yes
Duncan	SC	600	Unknown	Yes
Fort Mill	SC	1,600	Unknown	Yes
Gaffney	SC	1,200	Unknown	Yes
Greenville	SC	3,650	Unknown	Yes
Greenville	SC	2,500	Unknown	Yes
Greenville	SC	300	Unknown	Yes
Greenville	SC	500	Unknown	Yes
Greenville	SC	1,500	Unknown	Yes
Greenwood	SC	2,400	Unknown	Yes
Greenwood	SC	600	Unknown	Yes
Greer	SC	125	Unknown	Yes
Greer	SC	2,750	Unknown	Yes
Inman	SC	165	Unknown	Yes
Kershaw	SC	165	Unknown	Yes
Kershaw	SC	1,500	Unknown	Yes
Lancaster	SC	1,500	Unknown	Yes
Lancaster	SC	1,000	Unknown	Yes
Lancaster	SC	300	Unknown	Yes
Lyman	SC	1,000	Unknown	Yes
Mt. Holly	SC	265	Unknown	Yes

CUSTOMER-OWNED STANDBY GENERATION				
County	**State**	**Nameplate KW**	**Primary Fuel Type**	**Part of Total Supply Resources[1]**
Simpsonville	SC	900	Unknown	Yes
Simpsonville	SC	458	Unknown	Yes
Spartanburg	SC	600	Unknown	Yes
Spartanburg	SC	450	Unknown	Yes
Spartanburg	SC	2,900	Unknown	Yes
Spartanburg	SC	2,700	Unknown	Yes
Spartanburg	SC	1,250	Unknown	Yes
Spartanburg	SC	1,600	Unknown	Yes
Taylor	SC	350	Unknown	Yes
Van Wyck	SC	450	Unknown	Yes
Van Wyck	SC	365	Unknown	Yes
Walhalla	SC	350	Unknown	Yes

[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[1]**
Burke	NC	800	Diesel	No
Cabarrus	NC	32,000	Diesel	No
Catawba	NC	250	Coal, Wood Cogen	No
Catawba	NC	8,050	Diesel	No
Cleveland	NC	5,025	Diesel	No
Cleveland	NC	4,500	Diesel	No
Cleveland	NC	2,000	Diesel	No
Cherokee	NC	8	Photovoltaic	No
Durham	NC	2	Photovoltaic	No
Durham	NC	2	Photovoltaic	No
Durham	NC	1	Photovoltaic	No
Durham	NC	3	Photovoltaic	No
Durham	NC	2	Photovoltaic	No
Durham	NC	3	Photovoltaic	No
Forsyth	NC	8,400	Coal, Wood Cogen	No
Forsyth	NC	15	Photovoltaic	No
Forsyth	NC	4	Photovoltaic	No
Gaston	NC	1,056	Hydroelectric	No
Guilford	NC	3	Photovoltaic	No
Guilford	NC	3	Photovoltaic	No
Guilford	NC	2,000	Diesel	No
Guilford	NC	900	Diesel	No
Guilford	NC	2,000	Diesel	No
Guilford	NC	2	Photovoltaic	No
Guilford	NC	2	Photovoltaic	No
Guilford	NC	3	Photovoltaic	No
Iredell	NC	1,050	Diesel	No
Iredell	NC	8	Photovoltaic	No
Mecklenburg	NC	4	Photovoltaic	No
Mecklenburg	NC	4	Photovoltaic	No
Mecklenburg	NC	3	Photovoltaic	No
Orange	NC	4	Photovoltaic	No
Orange	NC	1	Photovoltaic	No
Orange	NC	2	Photovoltaic	No
Orange	NC	1	Photovoltaic	No
Orange	NC	2	Photovoltaic	No
Orange	NC	28,000	Coal Cogen	No
Orange	NC	2	Photovoltaic	No

CUSTOMER-OWNED SELF-GENERATION				
County	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources[1]
Randolph	NC	2	Photovoltaic	No
Randolph	NC	2	Photovoltaic	No
Rockingham	NC	5,480	Coal Cogen	No
Rockingham	NC	2	Photovoltaic	No
Rowan	NC	8	Photovoltaic/Wind	No
Rowan	NC	2	Photovoltaic	No
Rutherford	NC	6,400	Diesel	No
Rutherford	NC	4,800	Diesel	No
Rutherford	NC	750	Diesel	No
Rutherford	NC	1,000	Diesel	No
Rutherford	NC	350	Diesel	No
Surry	NC	2,500	Unknown	No
Transylvania	NC	2	Photovoltaic	No
Transylvania	NC	3	Photovoltaic	No
Union	NC	12,500	Diesel	No
Union	NC	7,400	Diesel	No
Union	NC	4,950	Diesel	No
Union	NC	4,200	Diesel	No
Union	NC	1,600	Diesel	No
Union	NC	1,600	Diesel	No
Union	NC	1,600	Diesel	No
Yadkin	NC	7	Photovoltaic	No
Abbeville	SC	3,250	Hydroelectric	No
Abbeville	SC	2,865	Diesel	No
Cherokee	SC	8,000	Diesel	No
Cherokee	SC	4,140	Hydroelectric	No
Greenville	SC	4,550	Diesel Cogen	No
Greenville	SC	5,000	Natural Gas, Landfill Gas	No
Greenville	SC	100	Photovoltaic	No
Greenville	SC	370	Digester Gas	No
Greenville	SC	250	Unknown	No
Laurens	SC	2,150	Diesel	No
Laurens	SC	4,000	Diesel	No
Oconee	SC	700	Hydroelectric	No
Oconee	SC	9,175	Diesel	No
Oconee	SC	2,865	Diesel	No
Pickens	SC	2,865	Diesel	No
Pickens	SC	6,400	Diesel	No
Spartanburg	SC	1,000	Hydroelectric	No
Greenville	SC	2,550	Diesel	No
Union	SC	15,900	Hydroelectric	No
Union	SC	6,000	Diesel	No
Union	SC	5,730	Diesel	No

CUSTOMER-OWNED SELF-GENERATION				
County	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources[1]
York	SC	42,500	Coal, Wood Cogen	No
York	SC	3,000	Diesel	No
York	SC	2	Photovoltaic	No
York	SC	2,865	Diesel	No
York	SC	2,865	Diesel	No

[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
Alamance	NC	300	Diesel	No
Burke	NC	2,000	Diesel	No
Durham	NC	1,750	Diesel	No
Granville	NC	1,750	Diesel	No
Guilford	NC	300	Diesel	No
Guilford	NC	150	Diesel	No
Guilford	NC	60	Diesel	No
Guilford	NC	175	Diesel	No
Guilford	NC	2,000	Diesel	No
Guilford	NC	1,750	Diesel	No
Mecklenburg	NC	1,500	Diesel	No
Mecklenburg	NC	500	Diesel	No
Mecklenburg	NC	150	Diesel	No
Mecklenburg	NC	1,000	Diesel	No
Mecklenburg	NC	1,750	Diesel	No
Mecklenburg	NC	200	Diesel	No
Mecklenburg	NC	400	Diesel	No
Surry	NC	125	Diesel	No
Wilkes	NC	2,000	Diesel	No
Greenville	SC	500	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	/ /	End of 2007/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	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	8,229.34		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	/ /	End of 2007/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	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	8,229.34		159

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/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.
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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	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (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	2,920.72		
31	100 KV Lines		100.00	100.00	Pole	585.12		
32	100 KV Lines		100.00	100.00	Underground	1.06		
33								
34	TOTAL 100 - 138 KV LINES					3,556.74		2
35								
36					TOTAL	8,229.34		159

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/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.
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3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	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	192.19		
6	44 KV Lines		44.00	44.00	Pole	2,171.33		
7	44 KV Lines		44.00	44.00	Underground	0.17		1
8								
9	TOTAL 44 KV LINES					2,363.69		1
10								
11	33 KV Lines		33.00	33.00	Pole	14.65		
12	24 KV Lines		24.00	24.00	Pole	85.03		
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					127.09		2
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	8,229.34		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	/ /	End of 2007/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	99,253,539	119,609,441					13
	20,355,902	99,253,539	119,609,441					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
	147,449,461	1,044,967,887	1,192,417,348	643,080	8,500,284		9,143,364	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS (Continued)

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
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
	147,449,461	1,044,967,887	1,192,417,348	643,080	8,500,284		9,143,364	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	/ /	End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

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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
	40,059,448	214,079,209	254,138,657					13
	40,059,448	214,079,209	254,138,657					14
								15
795								16
636								17
795								18
636								19
397.5								20
795								21
636								22
795								23
795								24
	2,374,207	51,523,767	53,897,974					25
	2,374,207	51,523,767	53,897,974					26
								27
477								28
								29
								30
								31
								32
	58,002,252	470,630,816	528,633,068					33
	58,002,252	470,630,816	528,633,068					34
								35
	147,449,461	1,044,967,887	1,192,417,348	643,080	8,500,284		9,143,364	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	/ /	End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

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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.
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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.
								1
	4,446,142	20,181,665	24,627,807					2
	4,446,142	20,181,665	24,627,807					3
								4
								5
								6
								7
	21,595,572	185,165,676	206,761,248					8
	21,595,572	185,165,676	206,761,248					9
								10
								11
								12
								13
								14
								15
	615,938	4,133,215	4,749,153					16
	615,938	4,133,215	4,749,153					17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
				643,080	8,500,284		9,143,364	33
								34
								35
	147,449,461	1,044,967,887	1,192,417,348	643,080	8,500,284		9,143,364	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	/ /	2007/Q4

FOOTNOTE DATA

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	/ /	End of 2007/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	OH Construction: New Lines						
2	Lunsford Road Retail Tap		5.50	Pole	8.00	1	
3	Mar Don Retail Tap		0.07	Pole	43.00	1	
4	North Gordonton Retail Tap		0.01			1	
5	Kingsgate Retail Tap		0.09	Pole	11.00	1	
6	Liberty Denim Retail Tap		0.06	Pole	33.00	1	
7	Broad River Delivery 17 Tap		0.10	Pole	30.00	1	
8	Pinch Gut Creek Retail Tap		3.71	Pole	9.00	1	
9	National Gypsum Tap		0.09	Pole	11.00	1	
10	North Lincoln Retail Tap		0.03	Pole	33.00	1	
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23	OH Lines: Major Rebuild						
24	Cliffside Steam Station	Tiger Tie	5.89		8.00	1	
25	North Greensboro Tie	Dan River Steam Station	3.70		8.00	1	
26	Woodruff Tie	Perrin Bent	0.59		12.00	1	
27	Nantahala	Robbinsville	8.19			1	
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		28.03		206.00	13	

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	/ /	End of 2007/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
556.5	ACSR		100	1,056,458	1,456,828	892,894		3,406,180	2
954.0	ACSR		100	60,741	101,962	62,493		225,196	3
477.0	ACSR		100			264,405		264,405	4
556.5	ACSR		100		80,771	49,506		130,277	5
556.5	ACSR		100	2,952	74,881	45,894		123,727	6
556.5	ACSR		100		94,894	58,160		153,054	7
556.5	ACSR		100	11,326	867,977	531,986		1,411,289	8
556.5	ACSR		44		29,132	17,855		46,987	9
556.5	ACSR		44	9,369	12,534	7,682		29,585	10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
556.5	ACSR		100		2,137,896	1,310,323		3,448,219	24
556.5	ACSR		44	357,212	712,167	436,490		1,505,869	25
556.5	ACSR		44		286,877	175,828		462,705	26
795.0	ACSR		161	295,703		19,485,620		19,781,323	27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				1,793,761	5,855,919	23,339,136		30,988,816	44

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	/ /	2007/Q4

FOOTNOTE DATA

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

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: l
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 3 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 3 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 4 Column: d
No Structures used in the new line

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: m
All or portion of cost is in account 106, cost is prorated where necessary

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: l
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.: 7 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 7 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

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

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

Schedule Page: 424 Line No.: 10 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

Name of Respondent Duke Energy Carolinas, LLC	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2007/Q4

FOOTNOTE DATA

Schedule Page: 424 Line No.: 25 Column: l
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 25 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 25 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

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

Schedule Page: 424 Line No.: 26 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 26 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 27 Column: d
No structures used in the new line

Schedule Page: 424 Line No.: 27 Column: l
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 27 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 IRP 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 May 1, 2008 is:

Rider EC:

62 MW for North Carolina
28 MW for South Carolina

Rider ER:

2.5   MW for North Carolina
1   MW for South Carolina

APPENDIX M: LEGISLATIVE AND REGULATORY ISSUES

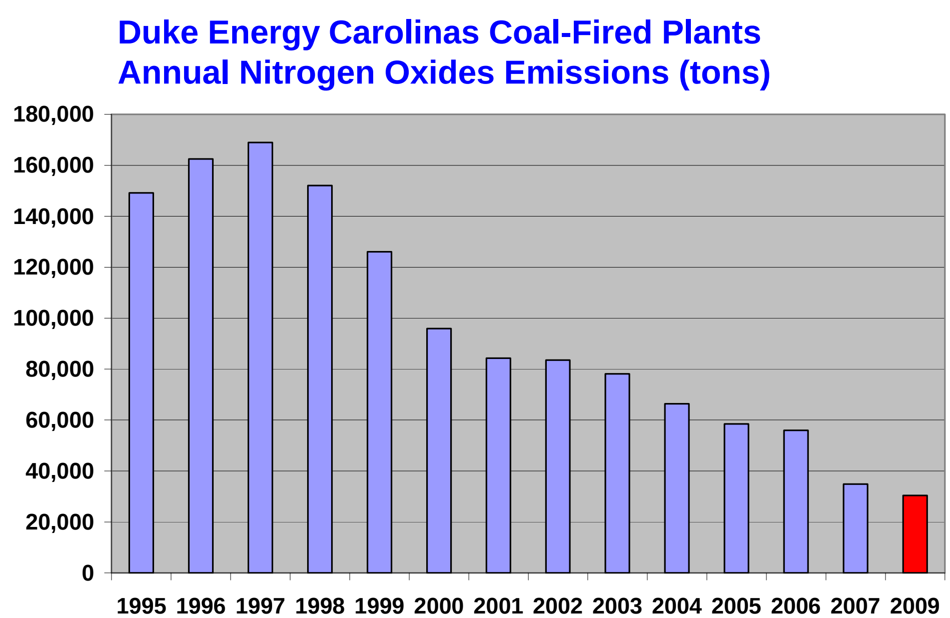
Duke Energy Carolinas is subject to the jurisdiction of federal agencies including the FERC, EPA, and the NRC, as well as state commissions and agencies. In addition, state and federal policy actions have potential impacts on the Company. This section provides a high-level description of several issues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

Air Quality

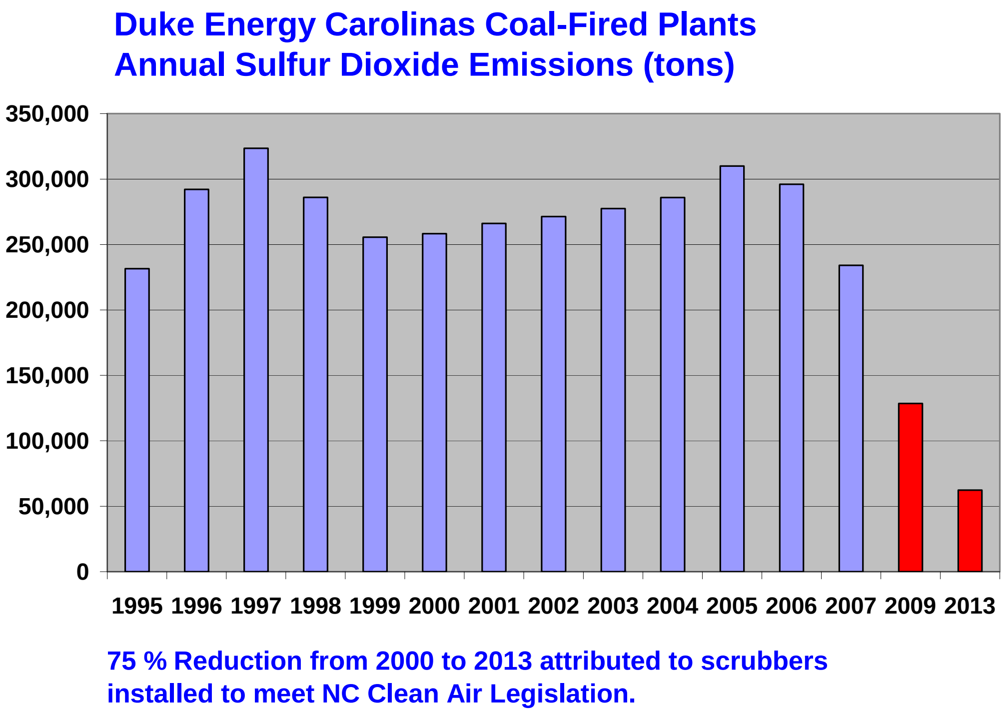
Duke Energy Carolinas is required to comply with federal regulations such as the Clean Air Act's Nitrogen Oxide (NOx) State Implementation Plan (SIP) Call, the 1990 CAAA Title IV SO2 requirements and the 2002 North Carolina Clean Smokestacks Act.

As a result of the North Carolina Clean Smokestacks Act, Duke Energy Carolinas will reduce sulfur dioxide (SO_2) emissions by about 75 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 controls to meet Federal Requirements and NC Clean Air Legislation.



Clean Air Interstate Rule (CAIR)

The EPA finalized its CAIR in May 2005. The CAIR was to have limited total annual and summertime NOx emissions and annual SO2 emissions from electric generating facilities across the Eastern U.S. through a two-phased cap-and-trade program. Phase 1 was to begin in 2009 for NOx and in 2010 for SO2. Phase 2 was to begin in 2015 for both NOx and SO2. On July 11, 2008, the U.S. Court of Appeals for the District of Columbia issued its decision in North Carolina v. EPA No. 05-1244 vacating the CAIR. EPA has until August 25th to appeal the decision. The D.C. Circuit's decision creates uncertainty regarding future SO2 and NOx emission reductions requirements and their timing. While it is fairly certain that there will be a delay in the timing of federal requirements to reduce emissions, it is expected that electric sector emission reductions at least as stringent as those imposed by CAIR will be required in the near future, through new federal rules and/or individual state requirements. The decision does not impact existing requirement that Duke Energy reduce its SO2 and NOx emissions under North Carolina clean air legislation.

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, better known as the Clean Air Mercury Rule (CAMR). The rule established mercury emission-rate limits for new coal-fired steam generating units, as defined in Clean Air Act section 111(d). It also established a nationwide mercury cap-and-trade program covering existing and new coal-fired power units. Both North Carolina and South Carolina issued final CAMR rules in early 2007.

On February 8, 2008 the U.S. Court of Appeals for the District of Columbia issued its opinion in New Jersey v. EPA, No. 05-1097 vacating the CAMR. Requests for rehearing were denied. In September 2008 the Utility Air Regulatory Group asked the U.S. Supreme Court to review the D.C. Circuit's decision. The D.C. Circuit's decision creates uncertainty regarding future mercury emission reduction requirements and their timing, but makes it fairly certain that there will be a delay in the implementation of federal mercury requirements for existing coal-fired power plants. At this point, Duke Energy is unable to estimate the costs to comply with any future mercury regulations that might result from the DC Circuit's decision.

North Carolina included in its 2007 mercury rule a requirement that Duke Energy (and Progress Energy) develop a mercury control plan for each coal fired unit in the state by 2013 and implement the plan by 2018. This regulation will remain in effect regardless of CAMR. Based on current plans that include retirement of 1000 MW of older coal-fired capacity, Buck Units 5 & 6 are the only units in North Carolina that would be in operation in 2018 that do not have any plans for mercury control. All other units that will be in operation will have wet Flue Gas Desulphurization (FGD) systems with or without Selective Catalytic Reduction (SCR). A plan for mercury control for Buck will be developed by 2013. The NC regulation will allow offsetting the mercury control requirement at Buck by enhancing mercury control at another unit that has wet FGD.

8 Hour Ozone Standard

The North Carolina Department of Air Quality (NCDAQ) has developed 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 is expected to enhance the ability to capture mercury in the scrubber.

The 8 hour ozone standard was lowered from 84 ppb to 75 ppb March 12, 2008. It is estimated that it will take states approximately two to three years to develop a SIP for compliance and an additional three years to have any additional controls in place. It is not known at this time if additional NOx controls will be required on Duke Energy Carolinas units.

Cliffside

The final air permit was issued January 29, 2008 and construction has begun. On March 18, 2008, Appalachian Voices filed a contested case petition with the Office of Administrative Hearings challenging the Cliffside air permit and seeking a stay. On

March 19, NC WARN also filed a contested case petition also seeking a stay. On March 27, the Southern Environmental Law Center, on behalf of several environmental organizations, filed another contested case petition. On March 28, several Riverkeeper organizations filed a contested case petition. Duke Energy has been allowed to intervene in all four cases, which have been consolidated. Duke Energy and the state of NC has filed a motion to dismiss the contested case with hearing expected fourth quarter 2008.

On May 6, 2008 the Southern Environmental Law Center, on behalf of National Parks Conservation Association, Natural Resources Defense Council, Sierra Club, Southern Alliance for Clean Energy and Environmental Defense Fund ("Citizen Groups"), sent Duke a 60-day notice letter indicating its intent to sue Duke in federal district court for alleged violations of the Clean Air Act. These Citizen Groups allege that DE Carolinas violated section 7412(g)(2) of title 42 of the United States Code when it commenced construction of Cliffside Unit 6 at Cliffside Steam Station without obtaining a determination that the maximum achievable control technology ("MACT") emission limits will be met for all prospective emissions at that plant. The Citizen's Groups claim the right to injunctive relief against further construction at the plant as well as civil penalties in the amount of up to $32,500 per day for each alleged violation. Section 304 of the Clean Air Act authorizes citizen suits to enforce the Act's provisions. Duke Energy Carolinas denies any such violation and intends to vigorously defend any potential suit commenced by the Citizen Groups. On June 2, 2008, in response to the Citizen Groups' 60-day notice letter, the NC Division of Air Quality ("DAQ") sent Duke a letter requesting that Duke volunteer to undergo a MACT determination to establish that Cliffside Unit 6 has the maximum controls for hazardous air pollutants required by the Clean Air. Duke Energy Carolinas submitted a MACT assessment document to the NC DAQ on July 3, 2008.

Global Climate Change

While current U.S. policy calls for reducing the greenhouse gas emissions intensity of the economy through voluntary measures, significant debate has begun at the federal level over the possible adoption of a mandatory reduction program. About a dozen bills have been introduced in the current session of Congress calling for mandatory limits on U.S. greenhouse gas emissions, most through the enactment of a cap-and-trade program. Despite the increased activity, however, it remains unclear as to when Congress will eventually pass legislation mandating reductions in greenhouse gas emissions, or the requirements of legislation that is enacted.

The U.S. EPA, in response to a 2006 Supreme Court decision, has issued an advanced notice of proposed rulemaking that seeks comment on alternative ways in which EPA could regulate greenhouse gas emissions. It is unclear how the EPA process will proceed, but it is possible that it could eventually lead to the regulation of greenhouse gas emissions from the electric utility sector.

Duke Energy 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 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 renewable portfolio standard was introduced, debated and defeated in the U.S. Congress during the 110th Congressional session. Renewable energy mandates are anticipated to be debated in the future as a part of comprehensive climate change legislation.

Duke Energy remains an active participant in discussions and continues to educate members of Congress on the economic consequences of enacting a one-size-fits-all approach for renewable energy development. Duke Energy believes that appropriate resource management is better left to the discretion of individual 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 – Requires 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.

Energy Independence and Security Act of 2007

The new Federal legislation passed in December 2007 included provisions on energy efficiency standards for appliances and lighting. The legislation effectively bans the sale of most incandescent light bulbs in a phased-in process from 2012 to 2014. It also requires greater efficiency for light bulbs by the year 2020.

The Company's electric load forecast has incorporated projected reductions in electricity sales to reflect these new provisions.

Hydroelectric Relicensing

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); and
- Nantahala Project.

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." These annual licenses remain in effect.

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.” This annual license remains in effect.

On March 23, 2007, FERC issued a notice of authorization for continued project operation for the East Fork and West Fork projects, 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.” These annual licenses remain in effect.

On July 19, 2007 FERC issued its Order Accepting Surrender and Dismissing Application for Subsequent License for the Dillsboro Project. On April 22, 2008, following requests for rehearing, FERC issued its Order on Rehearing and Clarification, affirming its July 2007 surrender order. On June 20, 2008 Jackson County, North Carolina, The Town of Franklin, North Carolina, and The Friends of Lake Glenville, Association, Inc. filed in the D.C. Circuit Court of Appeals a petition for review of both orders pertaining to Duke's Dillsboro Hydroelectric Project. Duke Energy Carolinas has moved to intervene.

In August, 2006, Duke Energy Carolinas filed an Application for a New License for the Catawba-Wateree Hydroelectric Project two 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.

Fish Passage Accord - Catawba-Wateree Hydro Relicensing

On May 14, 2008, the final party signed the Santee River Basin Fish Passage Accord (Accord), resolving a very important hydro relicensing issue for Duke's Catawba-Wateree Project and for multiple hydro projects owned by South Carolina Electric & Gas (SCE&G) in the Broad and Saluda River basins, all of which are part of the larger Santee River Basin. In addition to Duke Energy Carolinas and SCE&G, other parties to the

Accord include the North Carolina Wildlife Resources Commission (NCWRC), South Carolina Department of Natural Resources (SCDNR) and the United States Fish and Wildlife Service (USFWS). The Accord provides a cooperative program of additional study, fish stocking and selected fish passage facility construction aimed at enhancing and restoring populations of diadromous fish (i.e., fish such as American shad, blueback herring, sturgeon and eels that live part of their lives in the ocean and part in freshwater and whose life cycle can be impacted by migration barriers such as dams). Diadromous fish passage is typically one of the most costly issues associated with relicensing of hydro projects. Duke Energy Carolinas and SCE&G will jointly fund a 10-year program of studies and fish stocking efforts and will work with the resource agencies to evaluate study results and stocking efforts to improve efficiency of necessary future investments. Agreement by the USFWS to the flow and lake level requirements identified in the Comprehensive Relicensing Agreement (CRA) reduces Duke Energy Carolinas risks related to the scope of the fish passage facility construction during the next license period.

The term of a new FERC license for a hydropower facility ranges 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 of a license application.

Generating Units with Plans for Life Extension

STATION	LICENSE APPLICATION FILED	PRESENT LICENSE EXPIRATION DATE
Bryson Project No. 2601	7/22/2003	Good until license renewed
Franklin Project No. 2603	7/22/2003	Good until license renewed
Mission Project No. 2619	7/22/2003	Good until license renewed
East Fork Project No. 2698	1/26/2004	Good until license renewed
West Fork Project No. 2686	1/26/2004	Good until license renewed
Nantahala Project No. 2692	2/20/2004	Good until license renewed
Catawba-Wateree Project No. 2232	8/29/2006	Good until license renewed

SC v. NC Equitable Apportionment suit before the Supreme Court

On June 7, 2007, South Carolina filed an action under the Supreme Court's original jurisdiction seeking equitable apportionment of water from the Catawba River, seeking a determination that North Carolina's Interbasin Transfer law is unconstitutional and seeking a preliminary injunction to prevent any Interbasin Transfers after June 7. To protect its interests in its several reservoirs, Duke filed a motion to intervene and an answer on November 30, 2007. Two other entities, the City of Charlotte and the Catawba River Water Supply Project, also moved to intervene. On May 29, 2008 the Special Master issued an order granting intervention to all three parties. Discovery is expected to commence shortly and to take at least a year for the first phase of the case. A trial on the merits is not expected for several years.

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. Subsequent studies have been performed and reports published with updates to the Collaborative Plan. The latest full report, the NCTPC 2007 Collaborative Transmission Plan Report, was published on January 16, 2008 with a supplemental 2007 report published on May 16, 2008. The purpose of the supplemental analysis was to address two major Progress Energy upgrades in their eastern N.C. service area driven by OATT requests and to evaluate the impact of changes in resource plans for the Progress Energy western N.C. service area. These were significant changes that occurred late in the process of the original 2007 study and could not be incorporated in that analysis due to time constraints.

The updated 2007 Collaborative Plan is composed of 17 major transmission projects, representing more than $400 million in investments over the next decade. Major projects are defined as those requiring investments of more than $10 million. The major transmission projects identified in the updated 2007 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 (IE) to serve as its transmission coordinator and an Independent Monitor (IM) 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

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.

Duke Energy Carolinas is nearing the end of the two year initial period and has discussed the contract with MISO and our transmission customers. Duke Energy Carolinas has made a decision to continue the IE and IM contracts. However, MISO will no longer coordinate transmission planning. Coordinated transmission planning is now achieved by participation in the NC Planning Collaborative.

APPENDIX N: CROSS-REFERENCE OF IRP REQUIREMENTS

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

Requirement	Location	Reference
Forecast of Load, Supply-side Resources, and Demand-Side Resources. • 10 year history of customers & energy sales • 15 year forecast w & w/o energy efficiency • Description of supply-side resources	 Sect III Sect III Sect IV, App I	 NC R8-60 h (i) 1A NC R8-60 h(i) 1B NC R8-60 h(i) 1C
Generating Facilities • Existing Generation • Planned Generation • Non Utility Generation • Proposed Generation Units at Locations not known • Generating Units Projected to be Retired • Generating Units with plan for life extension	 Sect II Sect III, App E App J Sect V, App F Sect III N/A	 NC R8-60 h (i) 2A(i-vi) NC R8-60 h (i) 2B(i-iv) NC R8-60 h (i) 2C
Reserve Margin	Sect III	NC R8-60 h (i) 3
Wholesale Contract for the Purchase and Sale of Power • Wholesale Purchase Power Contract • Request for Proposal • Wholesale power sales contracts	 Sect II Sect II Sect II	 NC R8-60 h (i) 4A NC R8-60 h (i) 4B NC R8-60 h (i) 4C
Transmission Facilities , planned & under construction Transmissions System Adequacy FERC Form 1 (pages 422-425) FERC Form 715	App G Sect II App K App C	NC R8-60 h (i) 5
Energy Efficiency and Demand Side Management • Existing Programs • Future Programs • Rejected Programs • Consumer Education Programs	 Sect II, App D Sect III App I App I	 NC R8-60 h (i) 6A NC R8-60 h (i) 6B NC R8-60 h (i) 6C NC R8-60 h (i) 6D
Assessment of Alternative Supply-Side Energy Resource • Current and Future Alternative Supply-Side • Rejected Alternative Supply-Side Energy Resource	 App I App I	 NC R8-60 h (i) 7A NC R8-60 h (i) 7B
Evaluation of Resource Options (Quantitative Analysis)	 App A	NC R8-60 h (i) 8
Cost benefit analysis of each option Levelized Bus-bar Costs	 App I	 NC R8-60 h (i) 9
Other Information (economic development)	App L	
Legislative and Regulatory Issues	App M	
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	Sec I, V, App A	
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	Sec V, App A	