The Duke Energy Carolinas Integrated Resource Plan (Annual Report)

September 1, 2010

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2010 Integrated Resource Plan – abbreviations

Carbon Dioxide	CO2
Central Electric Power Cooperative, Inc.	CEPCI
Certificate of Public Convenience and Necessity	CPCN
Clean Air Interstate Rule	CAIR
Clean Air Mercury Rule	CAMR
Coal Combustion Residuals	CCR
Combined Construction and Operating License	COL
Combined Cycle	CC
Combustion Turbines	CTs
Commercial Operation Date	COD
Compact Fluorescent Light bulbs	CFL
Demand Side Management	DSM
Direct Current	DC
Duke Energy Annual Plan	The Plan
Duke Energy Carolinas	DEC
Duke Energy Carolinas	The Company
Eastern Interconnection Planning Collaborative	EIPC
Electric Membership Corporation	EMC
Electric Power Research Institute	EPRI
Energy Efficiency	EE
Environmental Protection Agency	EPA
Federal Energy Regulatory Commission	FERC
Federal Loan Guarantee	FLG
Flue Gas Desulphurization	FGD
General Electric	GE
Greenhouse Gas	GHG
Heating, Ventilation and Air Conditioning	HVAC
Information Collection Request	ICR
Integrated Gasification Combined Cycle	IGCC
Integrated Resource Plan	IRP
Interruptible Service	IS
Load, Capacity, and Reserve Margin Table	LCR Table
Maximum Achievable Control Technology	MACT
Nantahala Power & Light	NP&L
National Ambient Air Quality Standards	NAAQS
National Pollutant Discharge Elimination System	NPDES
NC Department of Environment and Natural Resources	NCDENR
NC Green Power	NCGP
New Source Performance Standard	NSPS
Nitrogen Oxide	NOx
North American Electric Reliability Corp	NERC
North Carolina	NC
North Carolina Clean Smokestacks Act	NCCSA
North Carolina Division of Air Quality	NCDAQ
North Carolina Electric Membership Corporation	NCEMC
North Carolina Municipal Power Agency #1	NCMPA1
North Carolina Utility Commission	NCUC

2010 Integrated Resource Plan – abbreviations

North Carolina Utility Commission	The Commission
Notice of Proposed Rulemaking	NOPR
Nuclear Regulatory Commission	NRC
Palmetto Clean Energy	PaCE
Parts Per Billion	PPB
Photovoltaic	PV
Piedmont Municipal Power Agency	PMPA
Plug-In Electric Vehicles	PEV
Power Deliver	PD
Present Value Revenue Requirements	PVRR
Prevention of Significant Deterioration	PSD
Production Tax Credit	PTC
Public Service Commission of South Carolina	PSCSC
Purchase Power Agreement	PPA
Qualifying Facility	QF
Rate Impact Measure	RIM
Renewable Energy and Energy Efficiency Portfolio Standard	REPS
Renewable Energy Certificates	REC
Renewable Portfolio Standard	RPS
Request for Proposal	RFP
Resource Conservation Recovery Act	RCRA
Saluda River Electric Cooperative	SR
Selective Catalytic Reduction	SCR
SERC Reliability Corporation	SERC
South Carolina	SC
Southeastern Power Administration	SEPA
Standby Generation	SG
State Implementation Plan	SIP
Sulfur Dioxide	SO2
Technology Assessment Guide	TAG
Total Resource Cost	TRC
United States Department of Energy	USDOE
Utility Cost Test	UCT
Virginia/Carolinas	VACAR
Volt Ampere Reactive	VAR
Western Carolina University	WCU

FORWARD

This Integrated Resource Plan (IRP) is the second Duke Energy Carolinas biennial report under the revised Commission Rule R8-60. A cross reference identifying where each regulatory requirement can be found within this IRP is provided in Appendix M.

EXECUTIVE SUMMARY

Duke Energy Carolinas, LLC (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. Duke Energy Carolinas considers a diverse range of resources including renewable, nuclear, coal, gas, energy efficiency (EE), and demand-side management (DSM)[1] resources. The end result is the Company's IRP or Annual Plan.

Consistent with its responsibility to meet customer energy needs in a way that is affordable, reliable and clean, 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 considerations, 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 the operational flexibility to adjust to evolving economic, environmental, and operating circumstances in the future. As a result, the Company's plan is designed to be robust under many possible future scenarios.

Today's planning environment continues to present significant challenges from a fuel, regulatory and legislative perspective. For example, the 2010 Duke Energy Carolinas IRP reflects the impact of several significant changes from 2009, resulting in a different outlook than the 2009 plan. These changes include a 35% decrease in the fundamental natural gas price forecast, increased environmental pressure on coal fired generation, and the lack of clarity with regard to federal greenhouse gas emission legislation. In addition to these changes, the 2010 Duke Energy Carolinas IRP reflects the recent recession's continuing impact on near term power needs.

The fundamental price forecast for natural gas decreased primarily due to newly discovered domestic supplies of the fuel located in shale deposits. The potential of this new supply has lowered the projected fundamental natural gas price for the foreseeable future. As a result, the current plan calls for an increase in additional intermediate load natural gas combined cycle (CC) generation rather than natural gas combustion turbines (CTs), which are primarily used for peaking purposes.

Additionally, many environmental regulatory issues are converging as the Environmental Protection Agency (EPA) proposes new rules to regulate multiple areas related to coal generation resources. These new rules will increase the need for the installation of additional emission control technology or retirement of coal fired generation in the 2014 to 2018

[1] Throughout this IRP, the term EE will denote conservation programs while the term DSM will denote Demand Response programs, consistent with the language of N.C. Gen. Stat. 62-133.8 and 133.9.

timeframe. Specifically, the proposed EPA Clean Air Transport Rule is expected to replace the existing Nitrogen Oxide (NOx) and Sulfur Dioxide (SO2) Clean Air Interstate Rule (CAIR) by 2014; mercury control requirements are expected by 2015; a new ozone standard will put increased pressure on NOx control requirements by 2017; and new coal combustion byproducts handling requirements are expected by 2018. Given the known and anticipated emission control requirements, the Duke Energy Carolinas 2010 IRP incorporates a planning assumption, that all coal-fired generation where it is not economical to install a SO2 scrubber, will be retired by 2015. This planning assumption causes approximately 890 MWs of coal generation capacity to be retired earlier than it was in the 2009 Carolinas IRP.

The recession continues to impact the projected load forecast though 2015. With the addition of over 2000 MWs of additional coal and natural gas generation in the 2011-2012 timeframe, the projected reserve margins exceed the 17% planning reserve margin though 2014. The projected retirement of all non-scrubbed coal by 2015, however, causes the Company's projected reserve margin to quickly drop to target planning reserve margins.

In 2009, Duke Energy Carolinas planning assumed that federal greenhouse gas legislation, substantively similar to the Waxman/Markey legislation, would have been enacted. This legislation, however, has failed to gain enough support in Congress to become law, as have several other proposed bills relating to the regulation of greenhouse gas emissions. While lawmakers continue the debate, the EPA is also pursuing the regulation of CO2 emissions. In the 2010 IRP, the Company evaluated a range of CO2 prices in addition to potential Clean Energy Legislation that does not include a CO2 cap and trade mechanism.

Planning Process Results

Duke Energy Carolinas' generation resource needs increase significantly over the 20-year planning horizon. Cliffside Unit 6 and the Buck and Dan River natural gas combined cycle units, along with the EE and DSM programs, will fulfill these needs through 2016. Even if the Company fully realizes its goals for EE and DSM, the resource need grows to approximately 6000 MWs by 2030. This projected need is lower than in the 2009 Duke Energy Carolinas IRP due primarily to lower load projections and how demand response and energy efficiency savings projections were represented.

The 2010 Duke Energy Carolinas IRP outlines the Company's options and plan for meeting the projected long-term needs. The factors that influence resource needs are:

- Future load growth projections;
- The amount of EE and DSM that can be achieved;
- Reduction of available capacity and energy resources, for example, due to unit retirements and expiration of purchased power agreements (PPA); 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 over time.

The analysis of new nuclear capacity contained in the 2010 Duke Energy Carolinas IRP focuses on the impact of various uncertainties such as load variations, nuclear capital costs, greenhouse gas legislation, EPA regulations, fuel prices, and the availability of financing options such as federal loan guarantees (FLGs). The analysis continues to affirm the potential benefits of new greenhouse gas emission-free nuclear capacity in the 2020 timeframe under a carbon-constrained future. The Company continues to support the Nuclear Regulatory Commission's (NRC) evaluation of a Combined Construction and Operation License (COL) for the proposed Lee Nuclear Station in Cherokee County, South Carolina.

Both DSM and EE programs play important roles in the Company's development of a balanced, cost-effective portfolio. Renewable generation alternatives are necessary to meet North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) enacted in 2007. Energy savings resulting from EE programs may also be used in part to meet the REPS obligations and the Company has prepared a REPS Compliance Plan, pursuant to Commission Rule R8-67 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 sustainable strategy to ensure that the Company can meet customers' energy needs reliably and economically over the near and long term. 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 actions to be taken in the next year are summarized below:

- Continue to evaluate the probability, timing and impact of retirement of the 890 MWs of unscrubbed coal in the 2015 timeframe.

- Continue to execute the Company's EE plan which includes a portfolio of DSM and EE programs, and continue on-going collaborative work to develop and implement additional cost-effective EE and DSM products and services.
    - On February 9, 2010, the Commission approved Duke Energy Carolinas' energy efficiency plan in its O*rder Approving Agreement and Joint Stipulation of Settlement Subject o Certain Commission-Required Modification and Decisions on Contested Issues* in Docket No. E-7, Sub 831;
    - On January 20th, 2010, Duke Energy received approval of its modified save-a-watt mechanism through the Public Service Commission's decision in the South Carolina rate case (Docket No. 2009-226-E). Under the save-a-watt proposal, the Company will continue to expand its efforts of EE.

- Continue construction of the 825 MW Cliffside Unit 6, with the objective of bringing this additional capacity on line by 2012 at the existing Cliffside Steam Station.
    - As of June 2010, the project was 68% complete.

- Move forward with the construction of new combined-cycle/peaking generation.

- Buck Combined Cycle Project: Construction has begun and the project is scheduled to be operational by the end of 2011.
- Dan River Combined Cycle Project: Major equipment is being delivered and the site preparation is underway with construction scheduled to begin during the first quarter of 2011. The project is scheduled to be operational by the end of 2012.

- Continue to investigate the potential switch of fuel from coal to natural gas at the 370 MW Lee Steam Station. Lee Steam Station was originally designed to generate with natural gas or coal as a fuel source. For planning purposes, Lee Steam Station will be reflected in the 2010 Duke Energy Carolinas IRP as a retired coal station in the fourth quarter of 2014 and converted to natural gas by January 1, 2015. Preliminary engineering has been completed and more detailed project development and regulatory efforts will begin in 2011.

- Continue to pursue the option for new nuclear generating capacity in the 2020 timeframe.
  - The Company filed an application with the Nuclear Regulatory Commission (NRC) for a COL in December 2007. The Company plans to continue to support the NRC evaluation of the COL.
  - The Company continues to pursue project development and appropriate recovery and to evaluate the optimal time to file the Certificate of Public Convenience and Necessity (CPCN) in S.C and other needed regulatory approvals.
  - The Company will continue to pursue available federal, state and local tax incentives and favorable financing options at the federal and state level.
  - The Company will continue to assess opportunities to benefit from economies of scale and risk reduction in new resource decisions by considering the prospects for joint ownership and/or sales agreements for new nuclear generation resources.

- Continue to evaluate market options for traditional and renewable generation and enter into contracts as appropriate.
  - Purchased Power Agreements (PPAs) have been signed with developers of solar photovoltaic (PV), landfill gas, and thermal resources. Additionally, renewable energy certificate (REC) purchase agreements have been executed for purchases of unbundled RECs from wind, solar PV, solar thermal and hydroelectric facilities.
  - Duke Energy Carolina’s Distributed Generation Solar PV program is underway with a goal to install 10 MW Direct Current (DC) of PV generation that will be sited on customers’ property.

- Continue to pursue wholesale power sales agreements within the Duke Energy Balancing Authority Area.

- 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. To meet this obligation, the Company conducted an integrated resource planning process that serves as the basis for its 2010 IRP.

The planning process considers a wide range of assumptions and uncertainties and results in the development of an action plan that preserves the options necessary to meet customers' needs. The process and resulting conclusions are discussed in this document.

II. DUKE ENERGY CAROLINAS CURRENT STATE

Overview

Duke Energy Carolinas provides electric service to an approximately 24,000-square-mile service area in central and western North Carolina and western South Carolina. In addition to retail sales to approximately 2.41 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)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Residential	1,710	1,758	1,782	1,814	1841	1,874	1,909	1,952	2,052	2,059
Commercial	280	288	293	300	306	312	318	323	334	333
Industrial	8	8	8	8	8	8	7	7	7	7
Nantahala P&L	61	63	64	66	67	68	70	71	***	***
Other	10	11	11	11	12	13	13	13	14	14
Total	2,070	2,128	2,159	2,198	2,234	2,275	2,317	2,366	2,407	2,413
	(Number of customers is average of monthly figures)									
	***Nantahala Power &Light (NP&L) customer counts for 2008 & 2009 are included in the class customer counts									

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

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	Electric Operations									
Residential	22,334	22,719	23,898	23,356	24,542	25,460	25,147	26,782	27,335	27,273
Commercial	22,467	23,282	23,831	23,933	24,775	25,236	25,585	26,977	27,288	26,977
Industrial	29,632	26,784	26,141	24,645	25,085	25,361	24,396	23,829	22,634	19,204
Nantahala P&L	1,070	1,057	1,099	1,134	1,163	1,227	1,256	1,255	***	***
Other[a]	295	279	269	268	267	266	269	276	284	287
Total Retail Sales	75,797	74,121	75,238	73,336	75,832	77,550	76,653	79,119	77,541	73,741
Wholesale sales[b]	4,020	1,976	2,058	2,387	1,982	2,268	2,336	2,326	2,332	1,812
Total GWH Sold	79,817	76,097	77,296	75,723	77,814	79,818	78,989	81,445	79,873	75,553
	[a] Other = Municipal street lighting and traffic signals									
	[b] Wholesale sales include sales to NC and SC municipal customers , 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.									
	***NP&L sales for 2008 and 2009 are included in the class sales									

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:

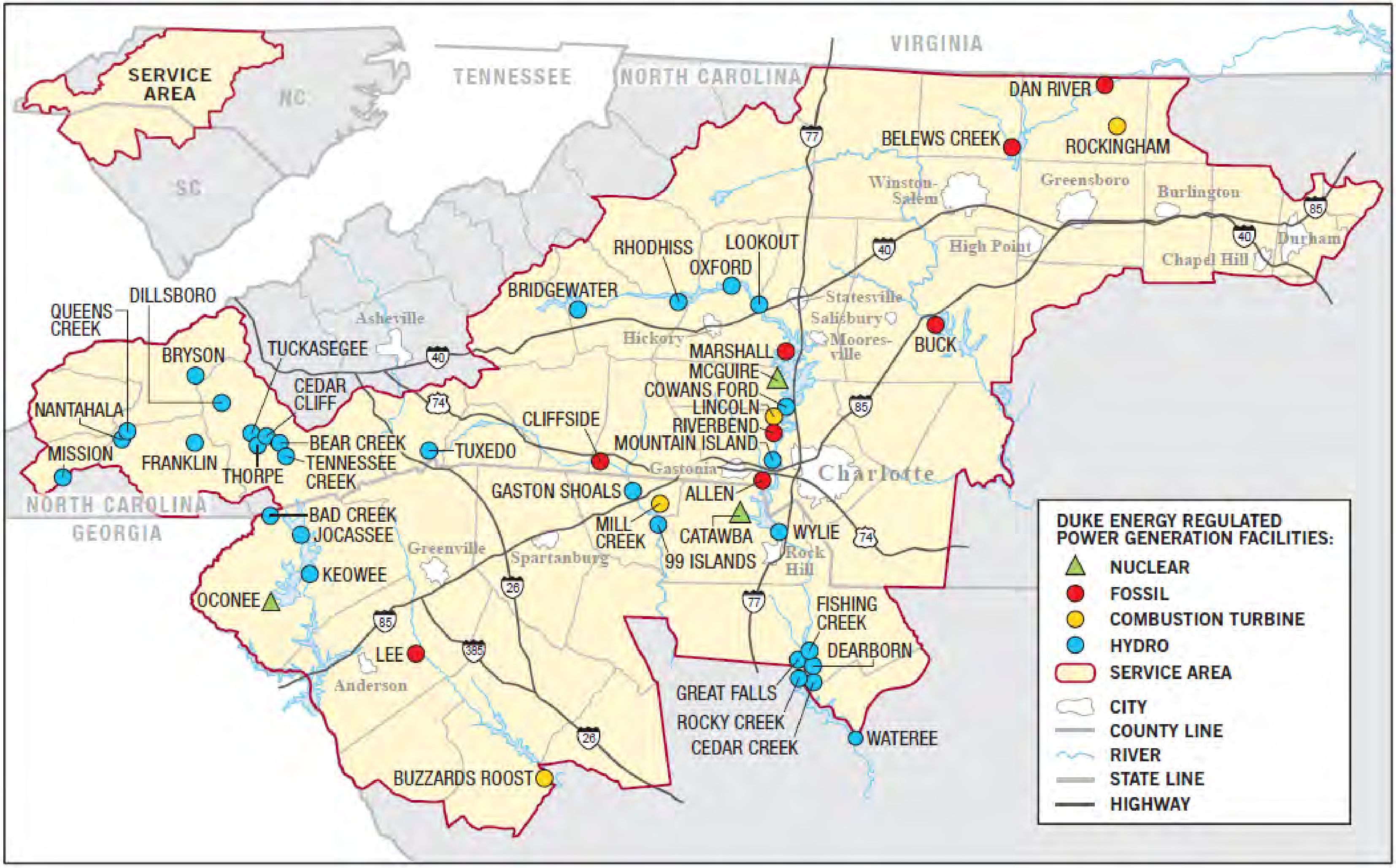
- Three nuclear generating stations with a combined net capacity of 6,996 MW (including all of Catawba Nuclear Station);
- Eight coal-fired stations with a combined capacity of 7,654 MW;
- 30 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 3,157 MW; and
- Eight combustion turbine stations with a combined capacity of 3,120 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 of the utilities that surround the Duke Energy Carolinas service area. There are 35 circuits connecting with eight different utilities: Progress Energy Carolinas, American Electric Power, Tennessee Valley Authority, Southern Company, Yadkin, Southeastern Power Administration (SEPA), South Carolina Electric and Gas, and Santee Cooper (also known as South Carolina Public Service Authority). These interconnections allow utilities to work together to provide an additional level of reliability. The strength of the system is also reinforced through coordination with other electric service providers in the Virginia-Carolinas (VACAR) subregion, SERC Reliability Corporation (SERC) (formerly Southeastern Electric Reliability Council), and North American Electric Reliability Corporation (NERC).

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

Duke Energy

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 10 years ahead 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. The annual screening uses methods that comply with SERC policy and NERC Reliability Standards and 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 optimization process. The Power Delivery optimization process evaluates problem-solution alternatives and their respective priority, scope, cost, and timing. The optimization process enables Power Delivery to produce a multi-year work plan and budget to fund a portfolio of projects which provides the greatest benefit for the dollars invested.

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). The Company performs studies to ensure transfer capability is acceptable to meet customers' expected use of the transmission system. The Power Delivery optimization process is also used to manage projects for improvement of transfer capability.

The 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. A full audit was completed in April 2008 and a "spot check" audit of selected standards was complete in August 2009. 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.

Transmission System Emerging Issues

Looking forward, several items that have the potential to impact the planning of the Duke Energy Carolinas Transmission System include:

- Proposed revisions to the NERC Transmission Planning standards that are in the balloting phase as of June 2010.

- The FERC Notice of Proposed Rulemaking (NOPR) on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities issued in June 2010 under Docket No. RM10-23-000.

- Increased interest in the integration of variable renewable resources (e.g., wind) into the grid. Examples of this include studies being done in the North Carolina Transmission Planning Collaborative in 2010 to assess the transmission impacts of significant off-shore wind development along the North Carolina coast.

- The Eastern Interconnection Planning Collaborative (EIPC) which is a new transmission study process that began in late 2009. The EIPC will:
    1. Provide a mechanism to aggregate existing regional transmission plans in the Eastern Interconnection and assess them on an Eastern Interconnection wide basis.
    2. Provide a framework to be able to perform technical analyses to inform state and federal government representatives and policy makers on important issues, such as future renewable resources and their impact on transmission infrastructure.

    As of late June 2010, the EIPC is in the process of finalizing a funding arrangement with the U.S. Department of Energy (DOE) to perform certain transmission assessments and studies over the next several years.

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 2009, Duke Energy Carolinas' nuclear and coal-fired generating units met the vast majority of customer needs by providing 53.8% and 44.4%, respectively, of Duke Energy Carolinas' energy from generation. Hydroelectric generation, CT generation, long term PPAs, and economical purchases from the wholesale market supplied the remainder.

The tables below list the Duke Energy Carolinas plants in service in North Carolina (NC) and South Carolina (SC) 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	162.0	167.0	Belmont, N.C.	Conventional Coal
Allen	2	162.0	167.0	Belmont, N.C.	Conventional Coal
Allen	3	261.0	270.0	Belmont, N.C.	Conventional Coal
Allen	4	276.0	282.0	Belmont, N.C.	Conventional Coal
Allen	5	266.0	275.0	Belmont, N.C.	Conventional Coal
Allen Steam Station		**1127.0**	**1161.0**		
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**	**2270.0**		
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		**7284.0 MW**	**7403.0 MW**		

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Buck	7C	25.0	30.0	Salisbury, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Buck	8C	25.0	30.0	Salisbury, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Buck	9C	12.0	15.0	Salisbury, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Buck Station CTs		**62.0**	**75.0**		
Dan River	4C	0.0	0.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Dan River	5C	24.0	31.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Dan River	6C	24.0	31.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Dan River Station CTs		**48.0**	**62.0**		
Lincoln	1	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	2	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	3	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	4	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	5	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	6	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	7	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	8	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	9	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	10	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	11	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	12	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	13	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	14	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	15	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	16	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Lincoln Station CTs		**1267.2**	**1488.0**		
Riverbend	8C	0.0	0.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	9C	22.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	10C	22.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	11C	20.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend Station CTs		**64.0**	**90.0**		
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		**2266.2 MW**	**2540.0 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	2	0	0	Whittier, N.C.	Hydro
Bryson City Hydro Station		**0.48**	**0.48**		
Cowans Ford	1	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	2	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	3	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	4	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford Hydro Station		**325.2**	**325.2**		

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Dillsboro	1	0	0	Dillsboro, N.C.	Hydro–Dam Removed
Dillsboro	2	0	0	Dillsboro, N.C.	Hydro–Dam Removed
Dillsboro Hydro Station		**0**	**0**		Hydro–Dam Removed
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		**27.9**	**27.9**		
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	0	Franklin, N.C.	Hydro
Franklin	2	0	0	Franklin, N.C.	Hydro
Franklin Hydro Station		**0**	**0**		
Mission	1	0	0	Murphy, N.C.	Hydro
Mission	2	0	0	Murphy, N.C.	Hydro
Mission	3	0.6	0.6	Murphy, N.C.	Hydro
Mission Hydro Station		**0.6**	**0.6**		
Nantahala	1	50.0	50.0	Topton, N.C.	Hydro
Nantahala Hydro Station		**50.0**	**50.0**		
Tennessee Creek	1	0	0	Tuckasegee, N.C.	Hydro
Tennessee Creek Hydro Station		**0**	**0**		

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
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		**605.1 MW**	**605.1 MW**		
TOTAL N.C. CAPABILITY		**12,355.3 MW**	**12,860.1 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	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	7C	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	8C	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	9C	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	10C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	11C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	12C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	13C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	14C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	15C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost Station CTs		**176.0**	**176.0**		
Lee	7C	41.0	41.0	Pelzer, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Lee	8C	41.0	41.0	Pelzer, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Lee Station CTs		**82.0**	**82.0**		
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

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
					Combustion Turbine
Mill Creek	6	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	7	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	8	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek Station CTs		**595.4**	**739.2**		
TOTAL S.C. COMB TURBINE		**853.4 MW**	**997.2 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		**730.0**	**730.0**		
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

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Fishing Creek	2	9.5	9.5	Great Falls, S.C.	Hydro
Fishing Creek	3	9.5	9.5	Great Falls, S.C.	Hydro
Fishing Creek	4	11.0	11.0	Great Falls, S.C.	Hydro
Fishing Creek	5	8.0	8.0	Great Falls, S.C.	Hydro
Fishing Creek Hydro Station		**49.0**	**49.0**		
Gaston Shoals	3	0	0	Blacksburg, S.C.	Hydro
Gaston Shoals	4	0	0	Blacksburg, S.C.	Hydro
Gaston Shoals	5	1.0	1.0	Blacksburg, S.C.	Hydro
Gaston Shoals	6	0	0	Blacksburg, S.C.	Hydro
Gaston Shoals Hydro Station		**1.0**	**1.0**		
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	0	0	Great Falls, S.C.	Hydro
Great Falls	4	0	0	Great Falls, S.C.	Hydro
Great Falls	5	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	6	0	0	Great Falls, S.C.	Hydro
Great Falls	7	0	0	Great Falls, S.C.	Hydro
Great Falls	8	0	0	Great Falls, S.C.	Hydro
Great Falls Hydro Station		**9.0**	**9.0**		
Rocky Creek	1	0	0	Great Falls, S.C.	Hydro
Rocky Creek	2	0	0	Great Falls, S.C.	Hydro
Rocky Creek	3	0	0	Great Falls, S.C.	Hydro
Rocky Creek	4	0	0	Great Falls, S.C.	Hydro
Rocky Creek	5	0	0	Great Falls, S.C.	Hydro
Rocky Creek	6	0	0	Great Falls, S.C.	Hydro
Rocky Creek	7	0	0	Great Falls, S.C.	Hydro
Rocky Creek	8	0	0	Great Falls, S.C.	Hydro
Rocky Creek Hydro Station		**0**	**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

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
99 Islands	4	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	5	0	0	Blacksburg, S.C.	Hydro
99 Islands	6	0	0	Blacksburg, S.C.	Hydro
99 Islands Hydro Station		**6.4**	**6.4**		
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		**461.4 MW**	**461.4 MW**		
TOTAL S.C. CAPABILITY		**8,570.8 MW**	**8,841.6 MW**		

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

NAME	SUMMER CAPACITY MW	WINTER CAPACITY MW
TOTAL DUKE ENERGY CAROLINAS GENERATING CAPABILITY	**20,926.1**	**21,701.7**

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 July 12, 2010.

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 currently used for peaking generation, but natural gas usage will expand when the Buck and Dan River Combined Cycle units are brought on-line.

Coal:
In recent years, Duke Energy Carolinas has burned approximately 19 million tons of coal annually. However, due to the current recession, the expected burn for 2010 is approximately 15 million tons of coal, and increasing as the economy recovers. 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 and internationally.

Although Central Appalachian coal market prices are well below the all-time highs experienced in 2008, projected market prices for two years out are 20 – 40% higher than those seen in 2006-2007, reflecting higher production costs combined with more balanced supply and demand. Increasingly strict federal safety regulations and surface mine permit requirements in Central Appalachia could result in lower production and corresponding higher prices (relative to other coal produced in other basins). For this reason, the Company is exploring means to develop greater supply and transportation flexibility in order to minimize the Company's dependency on Central Appalachian coals.

Natural Gas:
There has been an extraordinary transformative shift in natural gas fundamentals over the past few years. Natural gas has always exhibited a high degree of volatility due to the combination of its highly seasonal and weather dependent demand curve and long transportation hauls and storage limitations. This natural source of structural volatility, uncorrelated with the business cycle, made natural gas futures an attractive new investment class in the late 1990's, which added a new source of volatility. When oil prices began to climb in 2006, global liquefied natural gas (LNG) prices rose as well, thereby creating the impression that, due to our growing reliance upon LNC imports, the United States (US) market would be exposed to global price competition and its volatility for years to come. However, the promise of sustained high prices led to stepped up efforts to develop new domestic sources. Through trial and error, natural gas producers began to crack the code for finding and developing unconventional reservoirs like tight sands and shale. Through a variety of incremental improvements like horizontal boring, hydraulic fracturing and three-dimensional seismic imaging, the cost and yield curves for extraction from this unconventional gas source became more favorable. As incremental costs fell, improvements in resource characterization led to a dramatic rise in the estimated size of the reserve base. In June 2009, the US potential gas committee released their biennial report for 2008 in which the committee raised their estimates of the size of US gas reserves by 39% from their previous estimate.

The recession in 2008 cut industrial demand and the gas market has been forced to retrench in a low priced surplus market. While the market response has led to the dramatically lower wholesale prices and generally lower volatility, it hasn't been without controversy. There have been several high profile incidences involving unfinished wells, holding pond failures and methane migration into private water wells. Although rare, these incidents have stoked fears of contaminated water supplies and suspicions about the chemicals used in the fracturing process. The oil and gas industry has enjoyed certain exemptions from federal disclosure regarding the chemicals used in the fracturing process, but those exemptions are likely to change in the near future. The EPA is conducting a new study of the practices involved in shale development and new regulations are inevitable. Congress is also considering new legislation which will bring the industry under existing federal regulations contained in the Safe Drinking Water Act. This legislative and regulatory action will lead to higher costs, but at this point, there is no indication of any specific problem that cannot be addressed through better regulatory oversight and improved drilling and completion practices.

The size of the North American reserve base alone will have a dramatic impact on the US gas industry for decades and it will once again de-couple the US market from the broader global gas market. The impact on the electric utility sector will also be profound as this sector represents the single largest growth opportunity for the gas producers.

Nuclear Fuel:

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. Duke Energy Carolinas relies on long-term contracts to cover the largest portion of its forward requirements in each of the four industrial stages of the nuclear fuel cycle. By staggering long-term contracts over time, the Company's purchase price for deliveries within a given year consists of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. Diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply.

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 increase in the future. Although the costs of certain components of nuclear fuel are expected to increase in future years, nuclear fuel costs on a kWh basis will likely continue to be a fraction of the kWh cost of fossil fuel. Therefore, customers will continue to benefit from the Company's diverse generation mix and the strong performance of its nuclear fleet through lower fuel costs than would otherwise result absent the significant contribution of nuclear generation to meeting customers' demands.

Renewable Resources and Renewable Energy Initiatives

Duke Energy Carolinas' renewable strategy is primarily driven by the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard ("NC REPS"), a statutory requirement enacted in 2007 mandating that Duke Energy Carolinas and all other investor-owned utilities in the state to supply 12.5% of 2020 retail electricity sales (in North Carolina) from eligible renewable energy resources and/or energy efficiency savings by 2021. The prospect of future federal or additional state-level renewable energy legislation, such as in South Carolina, also influences this strategy.

To comply with NC REPS in the short and long term, the Company continues to build a balanced and diversified portfolio of cost-effective renewable energy resources through a combination of the following: (1) development of renewable energy resources owned and/or operated by Duke Energy Carolinas (2) PPAs from renewable power generation facilities; and (3) purchases of unbundled renewable energy certificates ("REC" or "RECs").

Available renewable resources in the Carolinas include:

- Hydro
- Wood Biomass Firing
- Landfill Gas
- On-Shore Wind (15% contribution to capacity on peak)
- Off-Shore Wind
- Solar PV (50% contribution to capacity on peak)
- Poultry Litter Biomass Firing
- Biogas
    - Poultry waste-derived biogas
    - Swine waste-derived biogas
    - Food waste-derived biogas

All renewable resources are premium resources relative to traditional fossil or nuclear generation. Among the different renewable resource types, however, there is tremendous variation in the levelized cost of energy (LCOE) and development potential in the Carolinas. At present, landfill gas represents one of the most cost-effective renewable resources available in the state. However, the future potential of this resource is limited by the number of landfills in the state. Wood-fired biomass also compares favorably to other resource options in terms of cost-effectiveness and achievable development potential. While we anticipate that wind resource costs would be reasonable if developed on a large scale, wind development in NC is inherently limited by the natural wind conditions of the state as well as by specific legal or operational constraints. For example, NC's Ridge Law prohibits large scale wind development in the mountains of western NC, where natural wind conditions are favorable.

Finally, while solar PV generation exists as a scalable renewable resource option, today it is simply not cost-competitive with wood biomass and would likely be constrained by scarce suitable acreage needed to support the solar farms and arrays necessary to attempt to match the capacity and output of a handful of biomass generation facilities.

With respect to Company-owned renewable energy resources, Duke Energy Carolinas has strategically pursued several resources, specifically solar PV, co-firing with woody biomass, hydro, and wind, as described below.

Solar PV

Duke Energy Carolinas' Solar PV Distributed Generation (10MW DC) Program, approved by the North Carolina Utilities Commission (NCUC) in 2009, is in its final phases of construction, and encompasses nineteen (19) customer and Duke Energy Carolinas owned sites, ranging from 50kW to 2,174kW. The program in its entirety is expected to be fully implemented by December 31, 2010.

Solar PV Distributed Generation Sites – Industrial and Commercial Duke Energy Carolinas				
Site Name	**City**	**State**	**KW (DC)**	**In-Service Date**
Highwoods	Greensboro	NC	1,495	
Food Lion	Salisbury	NC	1091	
Childress Klein	Charlotte	NC	532	
Nation Gypsum	Mt. Holly	NC	1,208	
McAlpine	Charlotte	NC	50	
Carrier Centers	Charlotte	NC	528	
Lincoln Charter School	Denver	NC	161	
Gaston County Schools	Lowell	NC	71	
City of Charlotte	Charlotte	NC	113	
EPA	Research Triangle Park	NC	109	
Freightliner	Barber	NC	371	
Siemens	Charlotte	NC	52	
Liberty Hardware	Winston Salem	NC	309	
Maple View Farm	Hillsborough	NC	180	
Childress Klein	Charlotte	NC	2,174	
Kimberly Clark	Hendersonville	NC	84	
TBB	High Point	NC	424	
Marshall Steam Station	Terrell	NC	900	
Habitat for Humanity	Charlotte	NC	105	
		Total	9,957	

Biomass

Company-owned woody biomass resources also play an important role in Duke Energy Carolinas' renewable compliance strategy. Woody biomass resources represent cost-effective renewable energy options with significant development potential in the

Carolinas. Unlike solar and wind resources, biomass resources can be dispatchable, like fossil resources, and offer baseload-type capacity. The Company's biomass strategy is a multi-year effort that began with smaller co-firing projects and will, if successful, build toward long-term repowering projects. At full implementation and build-out, Duke Energy Carolinas-owned "brownfield" biomass projects are expected to produce more than one million MWhs (and thus one million RECs) per year.

While the Company has not yet deployed woody biomass firing on a commercial-scale, Duke Energy Carolinas continues to conduct phased, internal technical assessments and economic evaluations regarding potential development of biomass resources through co-firing and repowering projects. For example, tests are underway to quantify the effects that co-firing biomass with coal has on operations and emissions of individual units at Buck Unit 6, located near Salisbury, North Carolina, and Lee Steam Station, located near Williamston, South Carolina. It is the Company's expectation that tests will demonstrate that brownfield biomass projects at existing sites are more cost-effective than new, "greenfield" projects of similar capacity.

The Company is also committed to biomass fuel supply procurement. To that end, Duke Energy Carolinas continues to explore various strategies, including: contracted supply arrangements with developers for such crops and trees as well as pilot-scale cultivation of perennial energy crops and trees planted and managed for biomass production.

Of note, in early 2010, when the Company filed Renewable Energy Facility Registration Statements for Lee Steam Station (Docket No. E-7, Sub 940) and for Buck (Docket E-7, Sub 939), several interest groups intervened in the proceeding, seeking to limit the interpretation of eligible wood fuels that would qualify as "biomass resources." At the time of submittal of this document, these registration statement proceedings were still pending before the NCUC. Should "biomass resources" be interpreted narrowly to exclude all other wood products except for "wood waste", Duke Energy Carolinas will not likely pursue its Company-owned biomass strategy to full implementation. Such an interpretation would have the effect of materially reducing the amount of available fuel and reduce (and in some cases completely eliminate) the economic benefit of the Company's planned investments of its customers. The Company would be required to pursue additional, less cost-competitive avenues for compliance with the statutory renewable requirements.

Hydro

Also within the category of Duke Energy-owned renewable resources, the Company continues to operate one of the largest fleets of hydroelectric power stations in the nation. While much of the Company's existing fleet of hydro plants does not qualify for compliance with Duke Energy Carolinas' obligations under NC REPS, certain existing assets do qualify based on recent NCUC rulings. Additionally, the Company continues to evaluate opportunities to add new hydro generation capacity to its fleet that would qualify as "renewable resources" under NC REPS.

Renewable Purchase Power Agreements

In a broad sense, the Company considers renewable energy resources in four categories: solar, swine waste, poultry waste, and so-called "general renewables" (all other renewable resources). This aligns with NC REPS, which requires certain amounts of renewable energy to come from solar, swine waste resources, poultry waste resources, and then the balance of the obligation is defined as "general renewable resources."

With respect to solar resources and general renewable resources, the Company has entered into several PPAs and unbundled REC purchases, including agreements for landfill gas, hydro, wind, solar PV, and solar thermal resources. Some of the REC purchase agreements have been executed under the Company's "standard offer" program, which was first initiated in January of 2009, with the intent to offer a streamlined process for contracting for renewable resources with smaller producers. Other agreements have been entered into on a negotiated basis outside of the standard offer parameters. Some of these negotiated agreements include agreements to purchase unbundled RECs, from both in-state and out-of-state renewable energy resources. The Company has found that wind RECs are available on the national market at very cost-effective prices and has purchased these resources, as permitted under NC REPS, to bring balance to the renewable portfolio.

The Company has yet to sign renewable PPAs for swine waste and poultry waste-to-energy resources. Nonetheless, the Company remains committed to procuring or developing these renewable resources, provided they are available and it is in the public interest to do so.

Swine Waste-to-Energy Resources

Duke Energy Carolinas has made reasonable efforts to meet the NC REPS swine waste set aside requirements, including but not limited to meeting with potential suppliers, evaluating bids received, and finding, engaging, and encouraging animal waste-to-energy developers to consider developing projects in the North Carolina market.

Duke Energy Carolinas' primary strategy for compliance is to jointly procure swine waste-to-energy resources with Progress Energy Carolinas, Inc., Dominion North Carolina Power, NCEMC, North Carolina Eastern Municipal Power Agency and NCMPA#1 (Joint Swine RFP). This joint business arrangement has received prior approval from the NCUC, and Duke Energy Carolinas and the other Power Suppliers have collectively undertaken a coordinated effort to procure energy and REC proposals from swine waste-to-energy generation providers and developers in North Carolina. The specific activities that have occurred to date, pursuant to the Commission's approval of the Joint Swine RFP are as follows:

a) Issued an RFP soliciting energy and/or REC proposals from swine waste to energy facilities. The RFP was posted locally as well as nationally, on the National Renewable Energy Laboratory website as well as the Electric Power Research Institute website;

b) Conducted economic analysis of proposals received and presented that analysis to the Other Power Suppliers;

c) Engaged a third-party consultant to conduct technical analysis of proposals received and rank proposals based on relative economic and technical viability; and

d) Generated short-list of cost-effective proposals and notified these developers of initiation of negotiations relating to power and REC purchase agreements with the individual Power Suppliers

In August 2010, the Power Suppliers commenced commercial negotiations with the short-listed developers and the parties will work towards the execution of substantive agreements with the subject developers.

Poultry Waste to Energy Resources

Duke Energy Carolinas intends to meet its NC REPS poultry waste set aside requirement through a combination of (1) bundled energy and REC PPAs with several poultry waste to energy suppliers, and (2) unbundled REC-only purchases. Duke Energy Carolinas continues to negotiate in good faith with all known poultry waste to energy suppliers. The Company concedes, however, that it has not reached agreement for poultry waste resources with any particular supplier due to several factors, including: (1) new market entrants make determination of prudent poultry waste to energy REC costs challenging; (2) de-risking large, twenty-year PPAs such that they do not put the Company at risk of exceeding the fixed cost caps specified in N.C. Gen. Stat. § 62-133.8(h) is a time-consuming and challenging endeavor for all parties; (3) changes in law (i.e., "Cleanfields Act" or Senate Bill 886) stand to alter the landscape of renewable resources that would qualify toward the poultry set-aside; and (4) prudency requires that the Company fully evaluate the costs and risk of all known suppliers of RECs that could be used to satisfy the poultry set-aside obligation. Duke Energy Carolinas will continue to use its best efforts to procure qualifying poultry waste resources to attempt to meet its respective share of the poultry waste set aside obligation in 2012.

The Company also continues to support numerous green power programs in the Carolinas. The North Carolina GreenPower (NCGP) Program and South Carolina's Palmetto Clean Energy (PaCE) Program are programs supporting renewable energy, with the mission to encourage renewable generation development from resources such as solar, wind, hydro, and organic matter by enabling electric consumers of the Carolinas, businesses, organizations, and others to help offset the cost of higher cost green energy production. Duke Energy Carolinas supports NCGP and PaCE by facilitating voluntary customer contributions to the program through the use of our customer support center and billing system. Also, at the request of Duke Energy Carolinas, NCGP created a Carbon Offset Program for North Carolina and South Carolina customers interested in "canceling out" the carbon dioxide produced from their daily activities. The Carbon Offset program empowers customers who seek to offset their carbon dioxide emissions from today's energy intensive lifestyle.

Current Energy Efficiency and Demand-Side Management Programs

In May 2007, Duke Energy Carolinas filed its application for approval of EE and DSM programs under its save-a-watt initiative. These programs were approved by the Commission in February 2009. The company began implementation of the programs in June 2009.

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-side management or demand response programs and certain rate structure programs). The following are the current EE and DSM programs in place in the Carolinas:

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 program is:

- **PowerManager -** 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.

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:

- **Interruptible Power Service (IS)** (North Carolina Only) **-** 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 (SG)** (North Carolina Only) **-** 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.

- **PowerShare®** is a non-residential curtailable program consisting of three options, an Emergency Option for curtailable load, an Emergency Option for load curtailment using on-site generators, 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.

- **Rates using price signals**
  - **Residential Time-of-Use (including a Residential Water Heating rate)**
    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 Optional Time-of-Use rates**
    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.

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**
  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. 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.

- **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 also helps 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.

- **Residential Energy Assessments**
  This program assists residential customers in assessing their energy usage and provides recommendations for more efficient use of energy in their homes. The program also helps identify those customers who could benefit most by investing in new demand-side management measures, undertaking more energy-efficient practices and participating in Duke Energy Carolinas programs. The types of available energy assessments and demand-side management products are as follows:
  - Mail-in Analysis. The customer provides information about their home, number of occupants, equipment, and energy usage on a mailed energy

profile survey, from which Duke Energy Carolinas will perform an energy use analysis and provide a Personalized Home Energy Report including specific energy-saving recommendations.

- Online Analysis. The customer provides information about their home, number of occupants, energy usage and equipment through an online energy profile survey. Duke Energy Carolinas will provide an Online Home Energy Audit including specific energy-saving recommendations.
- On-site Audit and Analysis. Duke Energy Carolinas will perform one on-site assessment of an owner-occupied home and its energy efficiency-related features during the life of this program.

- **Low Income Energy Efficiency and Weatherization Program**
  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.

- **Residential Smart $aver® Energy Efficient Products Program**
  The Smart $aver® Program provides 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 provides 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 provides incentives to customers, builders, and heating contractors (Heating Ventilation & Air Condition (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.

- **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

provides 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.

The projected impacts from these programs are included in this year's assessment of generation needs.

Additional Programs Being Considered

In addition to our current portfolio of programs, Duke Energy Carolinas is looking to add three additional concepts to our portfolio. These programs are similar to approved programs offered by Progress Energy Carolinas. The three additional programs are Tune and Seal, Direct Install Low Income and Appliance Recycle. A high-level overview is provided below.

- **Tune and Seal Program**
  Partnering with HVAC dealers, the program pays incentives to partially offset the cost of air conditioner and heat pump tune ups and duct sealing. This would be a new program and has not been offered in any of Duke's jurisdictions.

- **Direct Install Low Income Program**
  Program that targets low income neighborhoods providing high impact direct install measures (CFLs, pipe water heater wrap, low flow aerators and showerheads, HVAC filters and air infiltration sealing) and energy efficiency education.

- **Appliance Recycling Program**
  This is a program to incentivize households to turn in old inefficient refrigerators and freezers.

The following programs are proposed for pilot implementation and are currently pending approval by the NCUC.

- **Home Retrofit**
  This is a program to assist residential customers in assessing their energy usage, to provide recommendations for more efficient use of energy in their homes and to encourage the installation of energy efficient improvements by offsetting a portion of the cost of implementing the recommendations from the assessment.

- **Home Energy Comparison Report**
  Pilot will test the energy savings impact of providing periodic reports to targeted customers showing how their energy consumption compares to that of similar neighbors. To help identify more energy efficiency opportunities, and evaluate our existing programs, Duke Energy Carolinas has developed a diverse

stakeholder collaborative in its service territories.

Wholesale Power Sales Commitments

Duke Energy Carolinas currently provides requirements wholesale power sales to Western Carolina University (WCU), the City of Highlands, City of Concord, Town of Dallas, Forest City, Kings Mountain, Lockhart Power Company, Due West SC, and Prosperity, SC and starting in 2010 the City of Greenwood, SC. The Company is also committed to serve the power needs of three cooperatives (Blue Ridge Electric Membership Corporation (EMC), Piedmont EMC and Haywood EMC) and the supplemental needs of one other cooperative (Rutherford EMC). 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).

In 2005, Duke Energy Carolinas and NCMPA1 began a backstand agreement of up to 432 MW (depending on operation of the Catawba and McGuire facilities) that expired December 31, 2007. The parties have entered into a new agreement that extends through 2011.

In 2006, firm wholesale agreements became effective between Duke Energy Carolinas and three entities, Blue Ridge EMC, Piedmont EMC, and Rutherford EMC. Duke Energy Carolinas will supply their supplemental resource needs through 2021. This need grows to approximately 410 MW by 2011 and approximately 530 MW by 2021. The analyses in this IRP assumed that these contracts would be renewed or extended through the end of the planning horizon.

In addition, Duke Energy Carolinas has committed to provide backstand service for North Carolina EMC (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 (SR) ownership portion of Catawba ceased to be reflected in the forecast due to a sale of this interest to Duke Energy Carolinas and NCEMC, which resulted in the elimination of any obligation for Duke Energy Carolinas to plan for Saluda River's load. NCEMC purchased a portion of Saluda's share of Catawba which served to increase the NCEMC total backstand obligation.

Duke Energy Carolinas has entered into a firm shaped capacity sale with NCEMC that began on January 1, 2009, and expires on December 31, 2038. Initially, 72 MW is supplied on peak with the option to NCEMC to increase the peak purchase to 122 MW by 2020.

In 2009, the Company executed a firm PPA with Central Electric Power Cooperative, Inc. (Central) under which Duke Energy Carolinas will supply Central's supplemental resource needs of approximately 120 MW starting in 2013 and growing to 1000 MW by 2028. The analyses in this IRP assumed that this contract will be renewed or extended through the end of the planning horizon. Table 2.5 on the following page contains information concerning Duke Energy Carolinas' wholesale sales contracts.

Table 2.5

WHOLESALE CONTRACTS

Wholesale Customer	Contract Designation	Type	Contract Term	Commitment (MW) 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
NC/SC Municipalities		Native Load Priority	December 31,2018 with annual renewals. Can be terminated on one-year notice by either party after current contract term.	316	321	326	328	332	337	343	348	353	358
City of Concord, NC	Partial Requirements												
Town of Dallas, NC	Partial Requirements												
Town of Forest City, NC	Partial Requirements												
Town of Kings Mountain, NC	Partial Requirements												
Lockhart Power Company	Partial Requirements												
Town of Due West, SC	Partial Requirements												
Town of Prosperity, SC	Partial Requirements												
City of Greenwood, SC	Full Requirements												
See Note 1													
NP&L Wholesale		Native Load Priority	Annual renewals. Can be terminated on one-year notice by either party.	13	13	14	14	14	14	14	14	14	14
Town of Highlands, NC	Full Requirements												
Western Carolina University	Full Requirements												
See Note 1													
Blue Ridge EMC	Full Requirements	Native Load Priority	December 31, 2021	169	171	174	174	177	179	182	185	188	192
See Note 1													
Piedmont EMC	Full Requirements	Native Load Priority	December 31, 2021	87	89	90	91	92	94	95	97	99	101
See Note 1													
Rutherford EMC	Partial Requirements	Native Load Priority	December 31, 2021	47	153	156	183	186	200	203	207	211	216
See Note 1													
Haywood EMC	Full Requirements	Native Load Priority	December 31, 2021	20	20	21	21	21	22	22	23	23	23
See Note 1													
Central	Partial increasing to Full Requirements	Native Load Priority	January 1, 2013 through December 31, 2030	0	0	0	118	235	352	471	593	727	826
See Note 1													
NCEMC	Catawba Contract Backstand	Native Load Priority/ System Firm	Through Operating Life of Catawba and McGuire Nuclear Station	687	687	687	687	687	687	687	687	687	687
See Note 2													
NCMPA1	Generation Backstand	Native Load Priority	January 1, 2008 through December 31, 2011	73	73	0	0	0	0	0	0	0	0
NCEMC	Shaped Capacity Sale	Native Load Priority	January 1, 2009 through December 31, 2038	72	72	72	72	72	72	72	72	72	72

Note 1: The analyses in the Annual Plan assumed that the contracts will 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 (QF or QFs). Table 2.6 shows both the purchased power capacity obtained through RFPs as well as the larger QF agreements. See Appendix I for additional information on all purchases from QFs.

Table 2.6
Wholesale Purchased Power Commitments

SUPPLIER	CITY	STATE	SUMMER FIRM CAPACITY (MW)	WINTER FIRM CAPACITY (MW)	CONTRACT START	CONTRACT EXPIRATION
Catawba County	Newton	NC	3	3	8/23/99	8/22/14
Cherokee County Cogeneration Partners, L.P.	Gaffney	SC	88	95	7/1/96	6/30/13
Davidson Gas Producers, LLC	Lexington	NC	1	2	TBD	12/31/30
Gas Recovery Systems, LLC	Concord	NC	3	4	2/1/10	12/31/30
Gaston County	Dallas	NC	4	4	TBD	12/31/21
Greenville Gas Producers, LLC	Greer	SC	3	3	8/1/08	Ongoing
MP Durham, LLC	Durham	NC	3	3	9/18/09	12/31/29
Northbrook Carolina Hydro, LLC	Various	NC & SC	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	Ongoing
SunEd DEC1, LLC	Lexington	NC	16	16	12/1/09	12/31/2030

SUPPLIER	CITY	STATE	SUMMER FIRM CAPACITY (MW)	WINTER FIRM CAPACITY (MW)	CONTRACT START	CONTRACT EXPIRATION
Town of Lake Lure	Lake Lure	NC	2	2	2/21/06	2/20/11
WMRE Energy, LLC	Kernersville	NC	2	2	TBD	12/31/26
Misc. Small Hydro/Other	Various	Both	7	7	Various	Assumed Evergreen
Other – wholesale	Various	Both	169	169	Various	Various

Summary of Wholesale Purchased Power Commitments
(as of July 1, 2010)

	WINTER 10/11	SUMMER 10
Non-Utility Generation		
Traditional	675.0 MW	572.0 MW
Renewable *	10.8 MW	10.8 MW
Duke Energy Carolinas allocation of SEPA capacity	61.8 MW	61.8 MW
Other-Wholesale	107.1 MW	107.1 MW
Total Firm Purchases	854.7 MW	751.7 MW

Planning Philosophy with regard to Purchased Power

Opportunities for the purchase of wholesale power from suppliers and marketers are an important resource option for meeting the electricity needs of Duke Energy Carolinas' retail and wholesale customers. Duke Energy Carolinas has been active in the wholesale purchased power market since 1996 and during that time has entered into contracts totaling 2500 MWs to meet customer needs. The use of supply side requests for proposal (RFPs) continues to be an essential component of Duke Energy Carolinas' resource procurement strategy. In particular, the purchased power agreements that the Company has entered into have allowed customers to enjoy the benefits of discounted market capacity prices and have provided flexibility in meeting target planning reserve margin requirements.

The Company's approach to resource selection is as follows:

The IRP process is used to identify the type, size, and timing of the resource need. In selecting the optimal resource plan, Duke Energy Carolinas begins with an optimization model that selects the resource mix that minimizes the present value of revenue requirements (PVRR) for a given set of assumptions. The levelized cost method used for generation options serves as a proxy for either self-build or long-term purchased power opportunities. From the optimization step, several diverse portfolios of resources are selected for further detailed production costing modeling and ultimate selection of a resource plan for the IRP.

Once a resource need is identified, the Company determines the options to satisfy that need and determines the near-term and long-term actions necessary to secure the resource. The options could include a self-build Duke Energy Carolinas-owned resource, a Duke Energy Carolinas-owned acquired resource (new or existing), or a purchased power resource. The Company consistently has issued RFPs for peaking and intermediate resource needs. For example, following the identification of peaking and intermediate resource needs, the Company issued a RFP in May 2007 for conventional intermediate and peaking resource proposals of up to 800 MW beginning in the 2009-2010 timeframe and up to 2000 additional MW beginning in the 2013 timeframe. Potential bidders could submit bids for purchased power or for the acquisition of existing or new facilities. Ten bidders submitted a total of forty-five bids spanning time periods of two to thirty years. The bid evaluation considered price, operational flexibility, and location benefits. Ultimately, the Company determined that none of the proposed bids provided sufficient advantages to offset the multiple benefits of the proposed Buck and Dan River projects. The consideration of purchase power options was described in the Company's CPCN application for these facilities and addressed in testimony. The Commission issued the CPCNs for the Buck and Dan River projects in June 2008.

The Company also issued a RFP for renewable energy proposals in 2007. This RFP process produced proposals for approximately 1,900 megawatts of electricity from alternative sources from 26 different companies. The bids included wind, solar, biomass, biodiesel, landfill gas, hydro, and biogas projects. The Company entered into PPAs for a large solar project and several landfill gas facilities. In addition, the Company continues to receive unsolicited proposals for renewable purchased power resources and has entered into several PPAs as a result of unsolicited proposals.

The 2010 IRP plans included approximately 1,800 MWs of "New CT" capacity, in addition to existing and committed resources for the Cliffside Modernization project and Buck and Dan River combined cycle projects, as well as Lee Nuclear. The "New CT" resources reflect an identified need for peaking capacity that will be refined in future IRPs and could be met through new self-build capacity, purchased power, additional DSM or any combination of the three.

Although Duke Energy Carolinas evaluates the competitive wholesale market for peaking and intermediate resources, the Company's purchased power philosophy does not currently include soliciting purchased power bids for baseload capacity. Duke Energy Carolinas views baseload capacity as fundamentally different from peaking and intermediate capacity. Currently, there are two key concerns with relying upon the wholesale market for baseload capacity. First, generation outside the control area could be subject to interruption due to transmission issues more so than generation within the control area. Second, supplier default could jeopardize the ability to provide reliable service. The Company therefore believes that Duke Energy Carolinas-owned baseload resources are the most reliable means for Duke Energy Carolinas to meet its service obligations in a cost-effective and reliable manner.

In addition, the Company examines unsolicited bids for purchased power or resource acquisitions and is alert to opportunities to purchase power or resources.

Legislative and Regulatory Issues

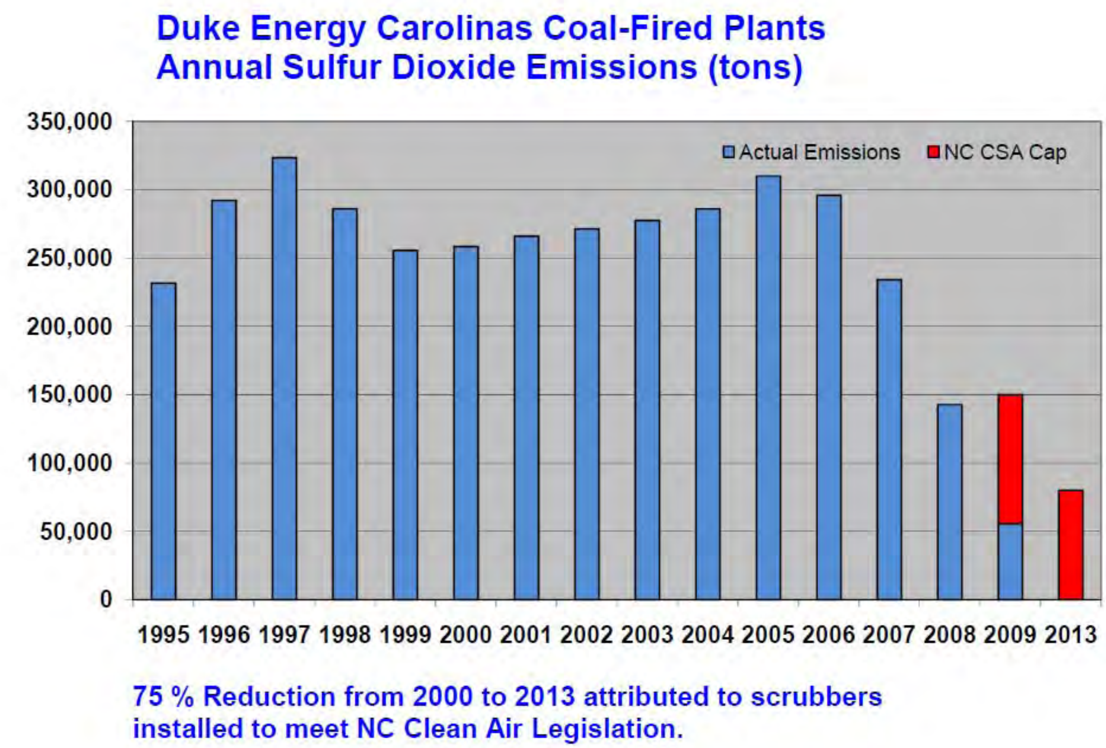
Duke Energy Carolinas, which is subject to the jurisdiction of federal agencies including the Federal Energy Regulatory Commission (FERC), EPA, and the NRC, as well as state commissions and agencies, is potentially impacted by state and federal legislative and regulatory actions. This section provides a high-level description of several issues Duke Energy Carolinas is actively monitoring or engaged in that could potentially influence choices for new generation.

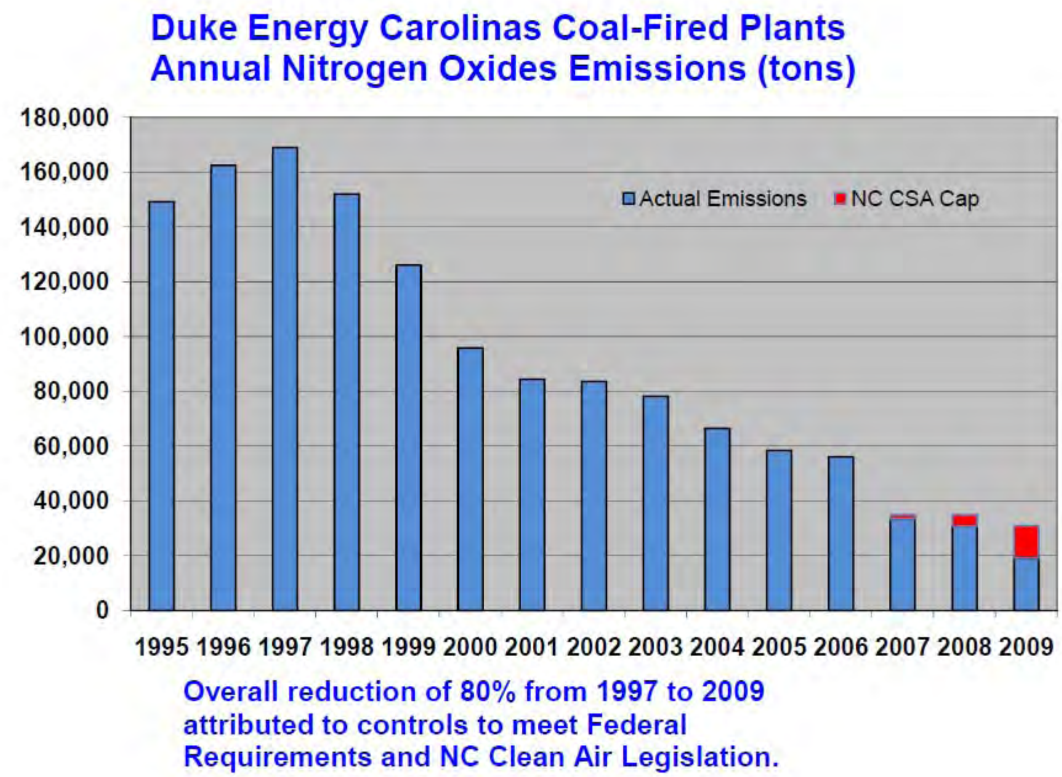
Air Quality

Duke Energy Carolinas is required to comply with numerous state and federal air emission regulations such as the Clean Air Interstate Rule (CAIR) NOx and SO2 cap-and-trade program, and the 2002 North Carolina Clean Smokestacks Act (NC CSA).

As a result of complying with the NC CSA, Duke Energy Carolinas will reduce SO2 emissions by approximately 75 percent by 2013 from 2000 levels. The law also required additional reductions in NOx emissions by 2007 and 2009, beyond those required by the CAIR rule, which Duke Energy Carolinas has achieved. This landmark legislation, which was passed by the North Carolina General Assembly in June of 2002, calls for some of the lowest state-mandated emission levels in the nation, and was passed with Duke Energy Carolinas' input and support.

The following graphs show Duke Energy Carolinas' NOx and SO2 emissions reductions to comply with the 2002 NC CSA requirements and actual emission through 2009.





In addition to current programs and regulatory requirements, several new regulations are in various stages of implementation and development that will impact operations for Duke Energy Carolinas in the coming years. Some of the major rules include:

Clean Air Interstate Rule (CAIR)

The EPA finalized its CAIR in May 2005. The CAIR limits total annual and summertime NO_X emissions and annual SO_2 emissions from electric generating facilities across the Eastern U.S. through a two-phased cap-and-trade program. Phase 1 began in 2009 for NO_X and in 2010 for SO_2. Phase 2 was scheduled to begin in 2015 for both NO_X and SO_2. In July 2008, the U.S. Court of Appeals for the District of Columbia (D.C. Circuit) issued its decision in *North Carolina v. EPA* vacating the CAIR. In December 2008, the D.C. Circuit issued a decision remanding the CAIR to the EPA, allowing CAIR to remain in effect as an interim solution until EPA develops new regulations. EPA announced in July 2010, plans to issue its Transport Rule to replace the CAIR. The rule which is expected to be finalized in June 2011 will begin to take effect very quickly, starting in 2012 in order to address new ozone National Ambient Air Quality Standard (NAAQS) requirements. The Transport Rule would reduce SO2 emissions by 71 percent and NO_X emissions by 52 percent from 2005 levels. The proposed rule includes EPA's preferred option to set pollution limits for the affected states and allows limited interstate trading to attain. EPA is also proposing the following alternatives to this option: (1) set state pollution limits while allowing intrastate trading only; and (2) set state pollution limits and specify the allowable emission limit for each power plant. Past and future developments related to the CAIR do not impact existing requirements that Duke Energy Carolinas reduce its SO2 and NOx emissions under the NC CSA.

Utility Boiler Maximum Achievable Control Technology (MACT)

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 (CAA) section 111(d). It also established a nationwide mercury cap-and-trade program covering existing and new coal-fired power units.

In February 2008, the D.C. Circuit Court of Appeals issued its opinion, vacating the CAMR. EPA has begun the process of developing a rule to replace the CAMR. The replacement rule, the Utility Boiler MACT will create emission limits for hazardous air pollutants (HAPs), including mercury. Duke Energy Carolinas is presently performing work as required by the EPA's Information Collection Request (ICR). The ICR requires collection of mercury and HAPs emissions data from numerous Duke Energy Carolinas facilities that will be used by EPA in developing the MACT rule. EPA expects to issue a proposed rule and finalize the MACT rule prior to the end of 2011. The Utility Boiler MACT rule is expected to require compliance with new emission limits by 2015. As with the Transport Rule, the impact on Duke Energy Carolinas plants by the MACT rule is not known at this time.

Both North Carolina and South Carolina issued final CAMR rules in early 2007. North Carolina included in its 2007 rule a requirement that Duke Energy Carolinas develop a mercury control plan for each coal fired unit in the state by 2013 and implement the plan by 2018. This regulation is not affected by the Court's invalidation of CAMR and will not be affected by EPA's Utility MACT rule.

National Ambient Air Quality Standards (NAAQS)

8 Hour Ozone Standard

On March 12, 2008 EPA revised the 8 hour ozone standard by lowering it from 84 to 75 parts per billion. In September of 2009, EPA announced a decision to reconsider the 75 ppb standard. The decision was in response to a court challenge from environmental groups and EPA's belief that a lower standard was justified. EPA issued a proposed rule on January 7, 2010 in which EPA proposed to replace the existing standard with a new standard between 60 and 70 parts per billion (ppb). EPA must finalize the rule in August 2010. EPA then has until August 2011 to finalize attainment designations. State Implementation Plans (SIP) will be due by the end of 2013, with attainment dates for most areas possibly in the 2016 to 2017 timeframe. Until the states develop implementation plans, only an estimate can be developed of the potential impact to Duke Energy Carolina's generation. A standard in the 60 – 70 ppb range is considered very stringent and will likely result in numerous non-attainment area designations.

SO2 Standards

In November 2009, EPA proposed a rule to replace the current 24-hour and annual primary SO_2 NAAQS with a 1-hour SO_2 standard. EPA finalized its new 1-hr standard of 75 ppb in June 2010. EPA will have 2 years (June 2012) to designate areas relative to their attainment status with the new standard. States with non-attainment areas will have until the February 2014 to submit their SIPs. In designating areas relative to their nonattainment status, EPA plans to use monitored air quality data for years 2009 – 2011 and dispersion modeling results. An area would be considered nonattainment if either monitoring or modeling indicates a violation of the standard. Initial attainment dates are expected to be the summer of 2017.

In addition, EPA is proposing to require states to relocate some existing monitors and to add some new monitors by January 2013. While these monitors will not be used by EPA to make the initial nonattainment designations, they will play a role in identifying possible future nonattainment areas. Based on EPA's schedule, 2016 would be the earliest year possible for having 3 years of available data from the new and relocated monitors needed to make nonattainment designations. Once again the potential station impacts and risk of violating the SO2 NAAQS standard are currently unknown.

Greenhouse Gas Regulation

On June 26, 2009, the U.S. House of Representatives passed H.R. 2454—the American Clean Energy and Security Act of 2009 (ACES). This legislation includes a GHG cap-and-trade program that covers approximately 85% of the GHG emissions in the U.S. economy, including emissions from the electric utility sector. On November 5, 2009, the U.S. Senate Environment and Public Works Committee passed and sent to the U.S. Senate floor S. 1733—the Clean Energy Jobs and American Power Act of 2009. No further Senate action has been taken on S. 1733 since passage out of committee. The debate over the structure of federal climate change legislation has shifted in recent months toward a utility-first approach where initially only GHG emissions from electric generation would be covered. The Senate adjourned for the August recess without taking action on climate change legislation. Although Duke Energy Carolinas believes it is likely that Congress will adopt mandatory GHG emission reduction legislation at some point, the timing and design details of any such legislation are highly uncertain at this time.

On December 7, 2009, the EPA finalized an Endangerment Finding for greenhouse gases under the CAA. The Endangerment Finding does not impose any regulatory requirements on industry, but was a necessary prerequisite for the EPA to be able to finalize its GHG emission standard for new motor vehicles, which it finalized on April 1, 2010. EPA's position is that implementation of the New Motor Vehicle Rule triggers Prevention of Significant Deterioration (PSD) permitting requirements for greenhouse gases for new and modified major stationary sources, including electric generating sources. On June 3, 2010 EPA finalized its Tailoring Rule that establishes a three-phase schedule for permitting of GHG emissions from stationary sources. The rule establishes January 2, 2011 as the beginning of the first phase of PSD permitting requirements for greenhouse gases.

Water Quality and By-product Issues

CWA 316(b) Cooling Water Intake Structures

Federal regulations in Section 316(b) of the Clean Water Act may necessitate cooling water intake modifications for existing facilities to minimize impingement and entrainment of aquatic organisms. Most of Duke Energy Carolina's coal and nuclear generating stations are potentially affected sources under that rule.

EPA has announced plans to issue a proposed rule by November 2010 with a final rule not likely until mid-2012. With an assumed timeframe for compliance of 3 years, implementation of selected technology is possible in 2015.

Most likely regardless of water body type, performance standards to achieve 80% reduction of impinged fish and 80% reduction of fish entrainment will be required. Provided performance requirements can be met, retrofits may involve intake screen modifications only. However, failure to meet performance standards could require use of a closed-cycle cooling system.

Steam Electric Effluent Guidelines

In September 2009, EPA announced plans to revise the steam electric effluent guidelines. In order to assist with development of the revised regulation, EPA issued an Information Collection Request (ICR) to gather information and data from nearly all steam-electric generating facilities. The ICR was received in June 2010 and is required to be completed within 90 days. The regulation is to be technology-based, in that limits are based on the capability of technology. The primary focus of the revised regulation is on coal-fired generation, thus the major areas likely to be impacted are Flue Gas Desulfurization (FGD) wastewater treatment systems and ash handling systems. The EPA may set limits that dictate certain FGD wastewater treatment technologies for the industry and may require dry ash handling systems for both fly and bottom ash be installed. Following review of the ICR data, EPA plans to issue a draft rule in mid-2012 and a final rule in mid-2014. After the final rulemaking, effluent guideline requirements will be included in a station's National Pollutant Discharge Elimination System (NPDES) permit renewals. Thus requirements to comply with NPDES permit conditions may begin as early as 2017 for some facilities. The length of time allowed to comply will be determined through the permit renewal process.

Coal Combustion Byproducts

Following Tennessee Valley Authority's Kingston ash dike failure in December 2008, EPA began an effort to assess the integrity of ash dikes nationwide and to begin developing a rule to manage coal combustion byproducts (CCBs). CCBs include fly ash, bottom ash and FGD byproducts (gypsum). Since the 2008 dike failure, numerous ash dike inspections have been completed by EPA and an enormous amount of input has been received by EPA, as it developed proposed regulations. On June 21, 2010, EPA issued its proposed rule regarding CCBs. The EPA rule refers to these as coal combustion residuals (CCRs). The proposed rule offers two options 1) a hazardous waste classification under Resource Conservation and Recovery Act (RCRA) Subtitle C and 2) a non-hazardous waste classification under RCRA Subtitle D, along with dam safety and alternative rules. Both options would require strict new requirements regarding the handling, disposal and potential re-use ability of CCRs. The proposal will likely result in more conversions to dry handling of ash, more landfills, closure of existing ash ponds and the addition of new wastewater treatment systems. Final regulations are expected in mid-2011. EPA's regulatory classification of CCRs as hazardous or non-hazardous will be critical in developing plans for handling CCRs in the future. The impact to Duke Energy Carolinas of this regulation as proposed is still being assessed. Compliance with new regulations is projected to begin around 2017.

Renewable Portfolio Standard (RPS)

As noted above, the North Carolina General Assembly enacted NCREPS 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.

In 2009, the U.S. Senate Committee on Energy and Natural Resources issued the American Clean Energy Leadership Act of 2009. The legislation includes a national renewable portfolio standard (RPS) provision that begins at 3% in 2011 and increases to 15% in 2021. In the House, the H.R. 2454 climate change bill passed on June 26, 2009 includes a federal renewable portfolio standard provision that begins at 6% in 2012 and increases to 20% in 2021. These two RPS proposals likely define the boundaries of the debate and the requirements of any potential federal RPS requirement that might be enacted.

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.

Duke Energy Carolinas retail sales have grown at an average annual rate of 0.7 percent from 1994 to 2009. (Retail sales, excluding line losses, are approximately 83 percent of the total energy considered in the 2010 IRP in 2010.) 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	Commercial	Industrial Textile	Industrial Non-Textile
1994 to 2009	0.7%	2.3%	2.9%	-7.8%	-0.6%
1994 to 2004	1.3%	2.7%	3.7%	-5.3%	0.5%
2004 to 2009	-0.6%	1.6%	1.4%	-12.7%	-2.9%
2009 to 2030	1.5%	1.5%	2.1%	-4.6%	1.1%

A significant decline in the Industrial Textile class was the key contributor to the low load growth from 2004 to 2009, mostly offset by growth in the Residential and Commercial classes over the same period. Over the last 5 years, an average of approximately 43,000 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 Commercial classes. Over the forecast horizon, the industrial growth is projected to be relatively flat. Though growth is expected to be strong in rubber & plastics, autos and fabricated metals, other industries such as textiles, furniture and electronics are expected to decline.

Total Retail load growth summaries are not shown in the Duke Energy Carolinas Spring 2010 Forecast book in Appendix B. The Residential load growth summaries shown in Table 3.1 use the same history and forecast data for Residential Sales as on page 9 of the Forecast book. The Commercial load growth summaries use the same history and forecast data for Commercial Sales as on page 10 of the Forecast book. The Industrial Textile load growth summaries use the same history and forecast data for Textile Sales as on page 12 of the Forecast book. The Industrial Non-Textile load growth summaries use the same history and forecast data for Other Industrial Sales as on page 13 of the Forecast book.

Load Forecast

The spring 2010 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 2010 through 2030 include the energy needs of the wholesale and retail customer classes as follows:

- Duke Energy Carolinas retail, including the retail load associated with NP&L area
- Duke Energy Carolinas wholesale sales to NC and SC municipal customers
- NP&L area wholesale customers Western Carolina University and the Town of Highlands
- NCEMC load relating to ownership of Catawba
- Blue Ridge, Piedmont and Rutherford Electric Membership Cooperatives' supplemental load requirements starting in 2006
- Hourly electricity sale to NCEMC starting in January 2009
- Haywood EMC load requirements starting in January 2009
- The City of Greenwood SC load requirements starting in January 2010
- Central partial load requirements starting in 2013 (partial load requirements will increase until total load requirements met in 2019)
- Undesignated wholesale load of approximately 35 MWs in 2011 growing to 46 MWs in 2030.

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 2010 Forecast shown in Appendix B. Also, per

NCUC 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 2010 Forecast Book.

A tabulation of the utility's forecasts for a 20 year period, including peak loads for summer and winter seasons of each year and annual energy forecasts, both with and without the impact of energy efficiency is shown below in Tables 3.2 and 3.3.

The average annual energy and peak projections described below and summarized in Tables 3.2 and 3.3 differs from growth rates shown on pages 24-27 of the Forecast book. A comparison of the Forecast book (pages 24-27) and the forecast used for the IRP is given below:

- Both include Retail sales and wholesale sales under Schedule 10A and NP&L area wholesale sales for Western Carolina University and the Town of Highlands.

- The Forecast book (pages 24-27) includes the total resource needs of the four Catawba Joint Owners while the forecast used for the IRP includes only the following associated with the four Catawba Joint Owners; (1) NCEMC load relating to ownership of the Catawba Nuclear Station, Blue Ridge, Piedmont and Rutherford Electric Membership Cooperatives' supplemental load requirements starting in 2006, (2) Hourly electricity sale to NCEMC starting in January 2009, (3) Haywood EMC load requirements starting in January 2009 and (4) Central partial load requirements starting in 2013 with partial load requirements increasing until total load requirements met in 2019.

- The forecast used for the IRP also includes the City of Greenwood SC load requirements starting in January 2010 and the undesignated wholesale load of approximately 35 MWs in 2011 growing to 46 MWs in 2030. The Forecast book (pages 24-27) does not include these adjustments.

- The forecast used for the IRP is shown below with and without the impacts of energy efficiency while the Forecast book (pages 24-27) is shown only without the impacts of energy efficiency.

- For both forecasts, adjustments have been made for electric vehicles and the incandescent lighting ban.

The current 20-year forecast of the needs of the retail and wholesale customer classes, which does not include the impact of new energy efficiency programs, projects a 1.8 percent average annual growth in summer peak demand, while winter peaks are forecasted to grow at an average annual rate of 1.8 percent. The forecast for average annual territorial energy need is 2.0 percent. The growth rates use projected 2010 information as the base year with a 17,132 MW summer peak, a 16,390 MW winter peak and an 88,511 GWH average annual territorial energy need.

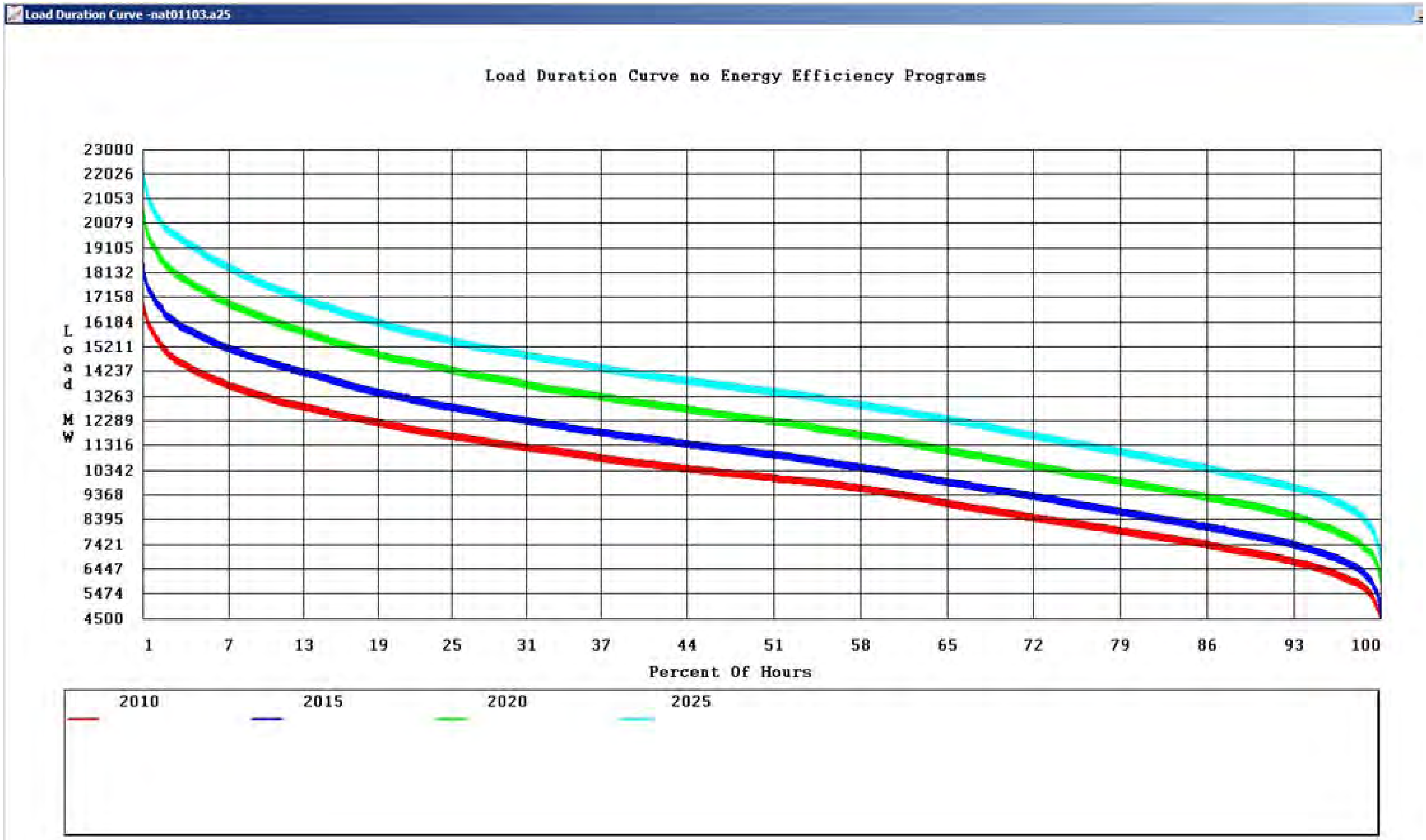
If the impacts of new energy efficiency programs are included, the average annual growth in summer peak demand is 1.7 percent, while winter peaks are forecasted to grow at an average annual rate of 1.6 percent. The forecast for average annual territorial energy need is 1.8 percent. The growth rates use projected 2010 information as the base year with a 17,117 MW summer peak, a 16,387 MW winter peak and a 88,395 GWH average annual territorial energy need.

The load forecast for the 2010 IRP which includes the undesignated wholesale load but does not include new energy efficiency programs is shown below in Table 3.2 followed by the load duration curves for 2010, 2015, 2020 and 2025 shown in Figure 3.1:

Table 3.2
Load Forecast without Energy Efficiency Programs

YEAR[a,b,c,d]	SUMMER (MW)[e]	WINTER (MW)[e]	TERRITORIAL ENERGY (GWH)[e]
2011	17,571	16,919	90,073
2012	17,840	17,186	91,770
2013	18,115	17,481	93,187
2014	18,481	17,839	95,159
2015	18,864	18,211	97,012
2016	19,307	18,624	99,381
2017	19,747	19,029	101,763
2018	20,212	19,455	104,334
2019	20,651	19,848	106,882
2020	21,031	20,189	109,265
2021	21,388	20,504	111,558
2022	21,698	20,795	113,455
2023	22,018	21,094	115,414
2024	22,343	21,396	117,431
2025	22,672	21,699	119,470
2026	23,010	22,011	121,614
2027	23,343	22,318	123,726
2028	23,689	22,633	125,924
2029	24,034	22,950	128,109
2030	24,384	23,270	130,332

Figure 3.1- Load Duration Curves without Energy Efficiency



The load forecast for the 2010 IRP which includes the undesignated wholesale load and also includes new energy efficiency programs, as reflected in Section 4, is shown below in Table 3.3 followed by the load duration curves for 2010, 2015, 2020 and 2025 shown in Figure 3.2:

Table 3.3
Load Forecast with Energy Efficiency Programs

YEAR[a,b,c,d]	**SUMMER (MW)**[e]	**WINTER (MW)**[e]	**TERRITORIAL ENERGY (GWH)**[e]
2011	17,529	16,885	89,739
2012	17,759	17,124	91,111
2013	17,974	17,328	92,046
2014	18,280	17,612	93,536
2015	18,605	17,930	94,907
2016	18,990	18,250	96,794
2017	19,351	18,636	98,693
2018	19,755	18,930	100,782
2019	20,155	19,311	102,849
2020	20,478	19,610	104,749
2021	20,754	19,754	106,560
2022	21,065	20,068	108,457
2023	21,385	20,367	110,416
2024	21,732	20,671	112,433
2025	22,060	21,030	114,472
2026	22,398	21,284	116,616
2027	22,710	21,533	118,728
2028	23,058	21,908	120,926
2029	23,401	22,223	123,111
2030	23,772	22,543	125,334

Note a: As part of the joint ownership arrangement for Catawba Nuclear Station, NCEMC and Saluda River (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 was not 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 resulted in termination September 30, 2008.

Note b: 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. Beginning in January 2009, one contract between Duke Energy Carolinas and NCEMC provides additional hourly electricity sales to NCEMC and another contract between Duke Energy Carolinas and Haywood EMC provides hourly electricity sales to

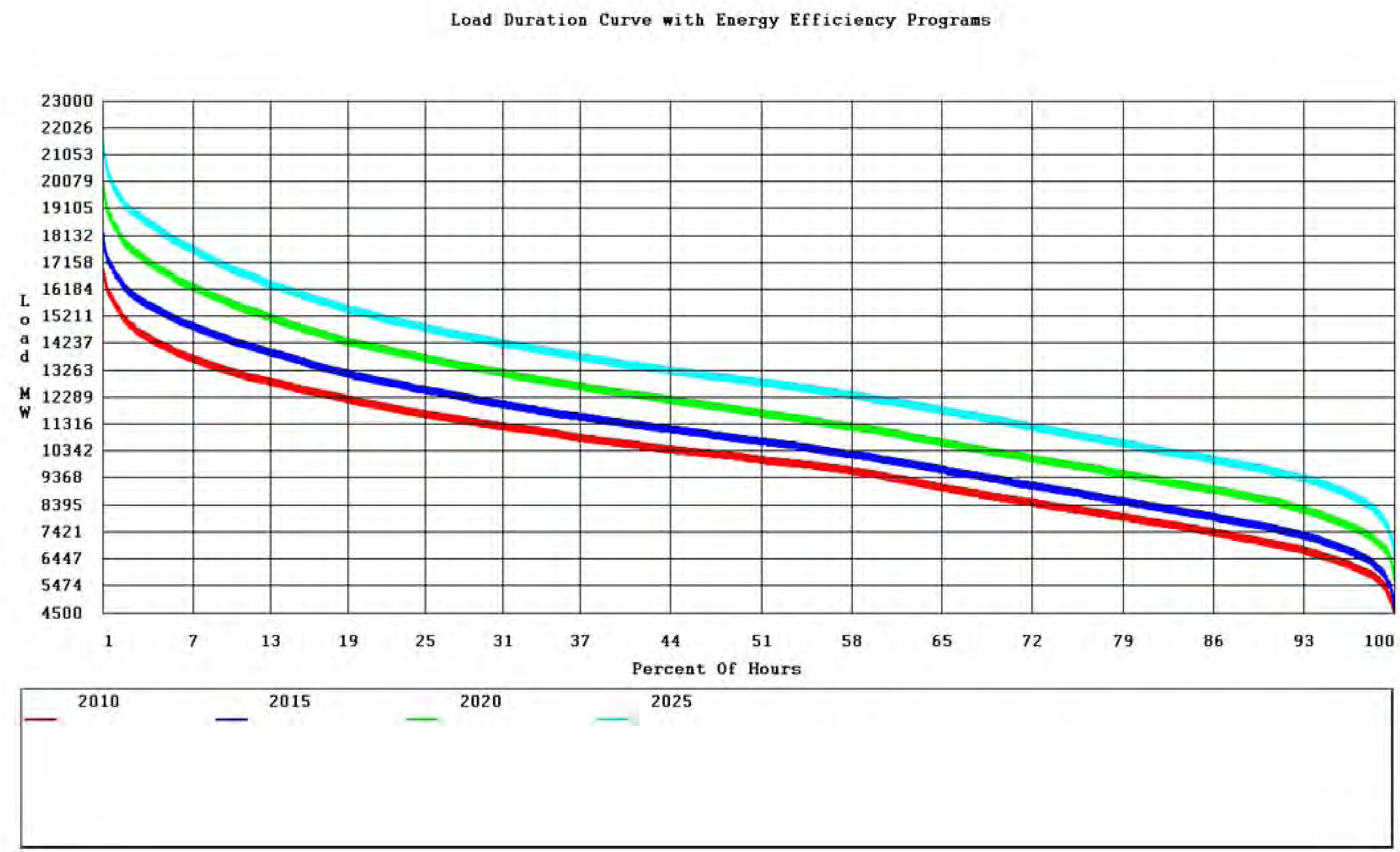
Haywood EMC. A new contract between Duke Energy Carolinas and the city of Greenwood SC will provide hourly electricity sales to Greenwood SC beginning in January 2010. A new agreement with Central provides for a seven year "step-in" to their full load requirement of approximately 900-1000 MWs such that Duke will only provide 15% of Central's total member cooperative load in Duke's Balancing Authority Area requirement in 2013. This will be followed by subsequent 15% annual increases in load over the following six years up to a total of 100%. Undesignated wholesale load of approximately 35 MWs in 2011 growing to 46 MWs in 2030 is also included in the summer peak numbers (with similar additions to winter peak and territorial energy).

Note c: 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 (927 MW at 2009 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 d: 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 (437 MW at 2009 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 e: 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).

Figure 3.2 - 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 need 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. As of June 2010 the project is over 68% complete.

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, which is scheduled to be available for the summer peak of 2012.

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
The Belews Creek Steam Lower Pressure Rotor upgrade was completed on Unit 1 in 2009 and on Unit 2 in the spring of 2010. The station is currently evaluating the efficiency gains based on summer time operation prior to reflecting increased capacity gains.

Buck Combined Cycle Natural Gas Unit
The CPCN was received June of 2008 and the air permit was received October 2008. The Buck combined cycle unit is scheduled to be operational by the end of 2011 and available by the summer of 2012. Construction is underway and the Project is currently over 20% complete.

Dan River Combined Cycle Natural Gas Unit
The CPCN was received in June of 2008 and the air permit application was received in August 2009. Activities to date include major equipment delivery and site preparation. Project construction is scheduled to begin the first quarter of 2011 and is scheduled to be operational by the end of 2012.

Riverbend, Buck, Dan River,and Buzzard's Roost Combustion Turbine De-rates
The available system capacity is reviewed every spring. In the 2009 review there were multiple de-rates among the old fleet combustion turbine fleet at Buck, Dan River and Riverbend totaling 124 MWs. Additional de-rates were identified during the 2010 review at Buzzard's Roost combustion turbine station totaling 20 MWs. These turbines were installed in the late 1960's and early 1970's and are approaching end of life, with

increasing difficulty in finding parts required for optimal operation.

Lee Steam Station Natural Gas Conversion

Lee Steam Station was originally designed to generate with natural gas or coal as a fuel source. Switching fuel sources from coal to natural gas could prove to be an economic solution to avoid adding costly pollution control equipment or replacing the 370 MW of capacity at an alternative site. For planning purposes Lee Steam Station will be retired as a coal station the fourth quarter of 2014 and converted to natural gas by January 1, 2015. Preliminary engineering has been completed and more detailed project development and regulatory efforts will begin in 2011.

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 3.4 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 forth 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[2]. 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 NCUC 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 system, Duke may seek modification of this plan. For planning purposes, the retirement dates for these 800 MWs of older coal are 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.

Additionally, multiple environmental regulatory issues are presently converging as the EPA has proposed new rules to regulate multiple areas relating to generation resources. These new rules, if implemented, will increase the need for the installation of additional control technology or retirement of coal fired generation in the 2014 to 2018 timeframe. Anticipating that there will be increased control requirements, the Carolinas 2010 IRP incorporates a planning assumption that all coal-fired generation that does not have an installed SO2 scrubber will be retired by 2015. This planning assumption accelerates the retirement of approximately 890 MWs of coal generation capacity as compared to the 2009 Carolinas IRP.

Table 3.4 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.

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

Table 3.4
Projected Unit Retirements

STATION	CAPACITY IN MW	LOCATION	DECISION DATE	PLANT TYPE
Buck 4*	38	Salisbury, N.C.	5/15/2011	Conventional Coal
Buck 3*	75	Salisbury, N.C.	5/15/2011	Conventional Coal
Cliffside 1*	38	Cliffside, N.C.	10/01/2011	Conventional Coal
Cliffside 2*	38	Cliffside, N.C.	10/01/2011	Conventional Coal
Cliffside 3*	61	Cliffside, N.C.	10/01/2011	Conventional Coal
Cliffside 4*	61	Cliffside, N.C.	10/01/2011	Conventional Coal
Dan River 1*	67	Eden, N.C.	5/15/2012	Conventional Coal
Dan River 2*	67	Eden, N.C.	3/01/2012	Conventional Coal
Dan River 3*	142	Eden, N.C.	10/01/2012	Conventional Coal
Buzzard Roost 6C**	22	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 7C**	22	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 8C**	22	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 9C**	22	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 10C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 11C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 12C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 13C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 14C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 15C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Riverbend 8C**	0	Mt. Holly, N.C.	6/01/2012	Combustion Turbine
Riverbend 9C**	22	Mt. Holly, N.C.	6/01/2012	Combustion Turbine
Riverbend 10C**	22	Mt. Holly, N.C.	6/01/2012	Combustion Turbine
Riverbend 11C**	20	Mt. Holly, N.C.	6/01/2012	Combustion Turbine
Buck 7C**	25	Spencer, N.C.	6/01/2012	Combustion Turbine
Buck 8C**	25	Spencer, N.C.	6/01/2012	Combustion Turbine
Buck 9C**	12	Spencer, N.C.	6/01/2012	Combustion Turbine
Dan River 4C**	0	Eden, N.C.	6/01/2012	Combustion Turbine
Dan River 5C**	24	Eden, N.C.	6/01/2012	Combustion Turbine
Dan River 6C**	24	Eden, N.C.	6/01/2013	Combustion Turbine
Riverbend 4*	94	Mt. Holly, N.C.	1/01/2015	Conventional Coal
Riverbend 5*	94	Mt. Holly, N.C.	1/01/2015	Conventional Coal
Riverbend 6***	133	Mt. Holly, N.C.	1/01/2015	Conventional Coal
Riverbend 7***	133	Mt. Holly, N.C.	1/01/2015	Conventional Coal
Buck 5***	128	Spencer, N.C.	1/01/2015	Conventional Coal
Buck 6***	128	Spencer, N.C.	1/01/2015	Conventional Coal
Lee 1***	100	Pelzer, S.C.	10/01/2014	Conventional Coal
Lee 2***	100	Pelzer, S.C.	10/01/2014	Conventional Coal
Lee 3***	170	Pelzer, S.C.	10/01/2014	Conventional Coal

Notes:

* 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.

** The old fleet combustion turbines retirement dates were accelerated based on derates in 2009, availability of replacement parts and the general condition of the remaining units.

*** For the 2010 IRP process, remaining coal units without scrubbers were assumed to be retired by 2015. Based on the continued increased regulatory scrutiny from an air, water and waste perspective, these units will likely either be required to install additional controls or retire. If final regulations or new legislation allows for latitude in the retirement date if a retirement commitment is made versus adding controls, the retirement date may be adjusted.

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 2005 through July 2009, 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 June 2010.

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 base load capacity such as 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[3], 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.

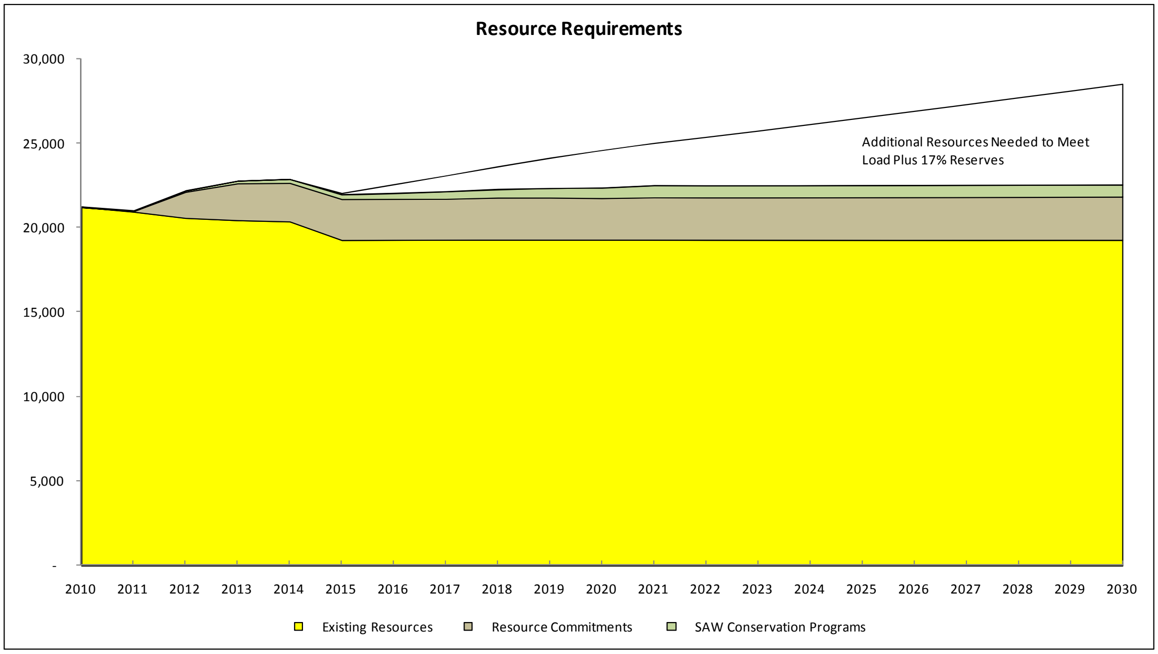
[3] Adjusted system capacity is calculated by adding the expected capacity of each generating unit plus firm purchased power capacity.

Load and Resource Balance

The following chart shows the existing resources and resource requirements needed to meet the load obligation, plus the 17 percent target planning reserve margin. Beginning in 2010, existing resources, consisting of existing generation and purchased power to meet load requirements, total 21,215 MW. The load obligation plus the target planning reserve margin is 20,027 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, and expirations of purchased-power contracts. The need grows to approximately 2,200 MW by 2020 and to 6,000 MW by 2030. Assumptions made in the development of this chart include:

1. Cliffside 6 is built by the summer of 2012 and therefore included in Resource Commitments
2. Coal retirements associated with the Cliffside Unit 6 ruling and permits, Buck 5&6, and Lee Steam Station are included (Buck and Lee retirements not included in the 2009 IRP)
3. Retirement of the old fleet combustion turbines
4. Conservation programs associated with the save-a-watt program are included
5. DSM programs associated with the save-a-watt program are included
6. Buck/Dan River combined cycle facilities are included in Resource Commitments (Not included in the 2009 IRP)
7. Renewable capacity is built or purchased to meet the NC REPS

Chart 3.1
Load and Resource Balance



Cumulative Resource Additions To Meet A 17 Percent Planning Reserve Margin (MWs)

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Resource Need	0	0	0	0	0	0	90	530	940	1350	1810

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Resource Need	2220	2500	2870	3240	3620	4000	4390	4770	5170	5560	5970

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 – 740 MW natural gas CT facility comprised of four units
- Peaking/Intermediate – 650 MW natural gas CC 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

- On Shore Wind (15% contribution to capacity on peak)
- Solar PV (50% contribution to capacity on peak)
- Biomass Firing
    - Woody Biomass Firing
    - Poultry Waste Firing
    - Hog Digester Biogas Firing
- Landfill Gas

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 RECS from out of state, as allowed in the legislation.

Future 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 and 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 and 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 UCT compares utility benefits (avoided costs) 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 RIM Test, or non-participants test, indicates if rates increase or decrease over the long-run as a result of implementing the program.
- 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 Participant Test evaluates programs from the perspective of the program's participants. The benefits include reductions in utility bills, incentives paid by the utility and any state, federal or local tax benefits received.
- The Societal Test evaluates programs from a broad societal prospective. It is identical to the TRC Test except the benefits includes externalities and the costs include negative externalities.

DSMore provides the results of those tests for any type of energy efficiency program (demand response and/or energy conservation).The use of multiple tests can ensure the development of a reasonable set of DSM and EE programs, indicate the likelihood that customers will participate, and also protect against cross-subsidization.

Energy Efficiency and Demand-Side Management Programs

Duke Energy Carolinas has made a strong commitment to EE and DSM. Duke Energy's save-a-watt approach fundamentally changes both the way these programs are perceived and the role of the Company in achieving results. The save-a-watt approach recognizes EE and DSM as a reliable, valuable resource that is an option in the portfolio available to meet customers' growing need for electricity along with coal, nuclear, natural gas, and renewable energy. These EE and DSM programs help customers meet their energy needs with less electricity, less cost and less environmental impact. The Company will manage EE and DSM to 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.

The EE and DSM plan will be updated annually based on the performance of programs, market conditions, economics, consumer demand, and avoided costs.

The Duke Energy Carolinas' approved EE plan also complies with the requirement set forth in the Cliffside Unit 6 CPCN Order[4] 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. The approved settlement will increase the Company's potential EE impacts significantly over the coming years, as used in the analysis for this IRP. However, pursuing EE and DSM initiatives will not meet all our growing demands for electricity. The Company still envisions the need to secure additional nuclear and gas generation as well as cost-effective renewable generation, but the save-a-watt approach could address approximately 40% of the 2016 new resource need.

Table 4.1 provides the base case projected load impacts of the EE and DSM through 2030. These were included in the base case IRP analysis. The forecasted energy efficiency savings through 2012 are consistent with Duke Energy Carolinas' North Carolina Settlement Energy Efficiency Plan for 2009 through 2012. The company assumes total efficiency savings will continue to grow on an annual basis through 2021, however the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan. The projected load impacts from the DSM programs are based upon the continuing as well as the new demand response programs.

Table 4.2 provides a high case scenario which uses the full target impacts of the save-a-watt bundle of programs for the first five years and then increases the load impacts at 1% of retail sales every year after that until the load impacts reach the economic potential identified by the 2007 market potential study. [5]

[4] Ref NCUC Docket No. E-7, Sub 790 Order Granting CPCN with Conditions, March 21, 2007.
[5] The load impacts in the high energy efficiency case have been reduced to account for the load reductions from the customer price response to the inclusion of higher projected electric rates for the cost of carbon compliance in the load forecast.

Table 4.1

Conservation and Demand Side Management Programs								
	Conservation		Demand Response Peak MW					Total
			Summer Peak MW					Summer Peak
	MWh	MW	IS	SG	PowerShare	PowerManager	Total	MW Impacts
2010	120,000	15	218	75	192	300	785	800
2011	330,000	42	218	75	347	321	961	1003
2012	660,000	81	218	75	494	380	1168	1249
2013	1,140,000	141	218	75	548	414	1255	1396
2014	1,620,000	201	218	75	548	426	1267	1468
2015	2,110,000	259	218	75	548	426	1267	1526
2016	2,590,000	317	218	75	548	426	1267	1584
2017	3,070,000	396	218	75	548	426	1267	1663
2018	3,550,000	457	218	75	548	426	1267	1724
2019	4,030,000	496	218	75	548	426	1267	1763
2020	4,520,000	553	218	75	548	426	1267	1820
2021	5,000,000	633	218	75	548	426	1267	1900
2022	5,000,000	633	218	75	548	426	1267	1900
2023	5,000,000	633	218	75	548	426	1267	1900
2024	5,000,000	633	218	75	548	426	1267	1900
2025	5,000,000	633	218	75	548	426	1267	1900
2026	5,000,000	633	218	75	548	426	1267	1900
2027	5,000,000	633	218	75	548	426	1267	1900
2028	5,000,000	633	218	75	548	426	1267	1900
2029	5,000,000	633	218	75	548	426	1267	1900
2030	5,000,000	633	218	75	548	426	1267	1900

Table 4.2

High EE Case Projected Load Impacts

Conservation and Demand Side Management Programs

	Conservation		Demand Response Peak MW					Total
			Summer Peak MW					Summer Peak
	MWh	MW	IS	SG	PowerShare	PowerManager	Total	MW Impacts
2010	140,000	18	245	84	215	318	862	880
2011	390,000	49	248	85	395	340	1068	1117
2012	770,000	95	249	86	565	402	1302	1397
2013	1,340,000	166	250	86	629	436	1401	1567
2014	1,910,000	236	251	86	630	450	1417	1653
2015	2,650,000	326	252	87	634	450	1424	1750
2016	3,390,000	415	254	87	637	451	1429	1845
2017	4,130,000	533	255	88	640	452	1434	1967
2018	4,870,000	626	256	88	642	454	1439	2066
2019	5,600,000	689	256	88	644	455	1444	2132
2020	6,340,000	777	257	88	646	457	1448	2225
2021	7,080,000	898	258	89	648	459	1453	2351
2022	7,820,000	990	259	89	650	461	1459	2449
2023	8,560,000	1,084	260	89	652	463	1464	2548
2024	9,300,000	1,137	260	90	654	466	1470	2606
2025	10,040,000	1,230	261	90	656	468	1475	2706
2026	10,780,000	1,321	262	90	658	471	1481	2802
2027	11,520,000	1,458	263	90	660	473	1487	2945
2028	12,260,000	1,547	264	91	662	476	1493	3040
2029	12,990,000	1,645	264	91	664	479	1499	3144
2030	13,730,000	1,683	265	91	666	482	1505	3188

DSM and EE Results to Date

DSM – Based on the adoption rate to date within the Power Manager and PowerShare® programs, the company is on track to meet the 2010 target of 492 MWs and is well positioned to meet the overall target of 1270 MWs by 2012.

EE - The Company has experienced a strong response to its EE programs and is on track to meet the 2010 conservation target of 120,000 MWhrs.

Programs Evaluated but Rejected

Duke Energy Carolinas has not rejected any programs as a result of EE and DSM program screening.

Looking to the Future

Smart Grid – Duke Energy is pursuing implementation of Smart Grid throughout the enterprise. The recent $200 million grant that was awarded to Duke Energy from the US DOE helps further that goal. In order to meet DSM goals and support plug-in electric vehicles (“PEV”), the development of the Smart Grid initiatives will be an integral part of this process. The NCUC proposed a requirement to include Smart Grid impacts in the IRP for North Carolina electric utilities (including Duke Energy Carolinas) in Docket E-100, Sub 126. Duke Energy Carolinas filed joint comments along with Dominion-North Carolina Power on February 26, 2010, in which the two utilities supported the inclusion of the impact of Smart Grid to the resource plan, but emphasized that the purpose of including utilities’ Smart Grid plans in the IRP filing is to ensure that the resource plan reflects the potential impact of the Smart Grid. Additionally, the two utilities also advocated that the Smart Grid should be treated similarly to how energy efficiency and demand side management resources are incorporated into the IRP. Progress Energy later joined Duke Energy Carolinas and Dominion-North Carolina Power in reply comments filed before the Commission on March 26, 2010, further emphasizing these points.

V. SUSTAINABILITY

Balancing the need for affordable, reliable and cleaner energy for the 21st century represents an important leadership opportunity for the Company and the country. Despite the complexity of the challenge, Duke Energy Carolinas believes its commitment to sustainability – doing business in a way that's good for people, planet and profits – is helping the Company make decisions that are good for today, and even better for tomorrow.

Stakeholder input is a hallmark of sustainability. Duke Energy Carolinas serves diverse stakeholders with diverse priorities – from investors to environmental interest groups and from industrial customers who compete globally to communities where the Company is a large employer and a contributor to the tax base.

To gain stakeholder feedback on what is important in our resource planning, members of the Carolinas Energy Efficiency Planning Collaborative were surveyed. Members of this collaborative represent industry, environmental, academia, and governmental interests. Though the survey sample size was small and the results varied between stakeholders on specific questions, there was agreement that a balanced portfolio of nuclear, natural gas, energy efficiency, and renewables was favorable. Also, important aspects of resource planning are the lowest cost to customers, followed by the lowest environmental footprint.

To ensure the Company's plan is consistent with our commitment to sustainability, Duke Energy Carolinas evaluated portfolios based on the following criteria: affordability, reliability, environmental impacts (air, water, waste and land), and job potential. The most sustainable portfolio for new generation was a balanced portfolio consisting of a mix of nuclear generation, natural gas generation, renewables generation and energy efficiency. The exact amount of each will change as the Company learns more about how much energy efficiency and renewables can be implemented cost effectively.

Both the survey and the Company's evaluation of portfolios support a diversified portfolio to meet customer electricity needs in a sustainable way.

An overview of survey results and the evaluation of portfolios are shown in Appendix A.

VI. OVERALL PLANNING PROCESS CONCLUSIONS

Duke Energy Carolinas' Resource Planning process provides a framework for the Company to access, 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 simulation models.

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 unit at Cliffside (Unit 6) is assumed to be in service in 2012, annually providing 5700 GWh of baseload energy. Project implementation is underway for the new combined cycle facilities at Buck and Dan River and is assumed operational in late 2011 and late 2012, respectively. In addition, Duke Energy Carolinas has included DSM, EE and renewable resources consistent with the Company's energy efficiency plan approved in North and South Carolina and to meet the North Carolina REPS. For planning purposes, approximately 5% of retail sales in South Carolina would come from renewable energy, phased in from 2015 to 2026. Approximately 200 MWs of nuclear up-rates were demonstrated to be cost effective in the 2010 IRP and specific projects are being developed to be implemented in the 2011-2019 timeframe. For planning purposes, Lee Steam Station will be retired from coal fired generation and converted to natural gas generation starting 2015. While near-term, there are no significant additional capacity needs beyond these committed and planned additions, the Company has capacity needs in 2017 and beyond.

The analysis of new nuclear capacity contained in the 2010 Carolinas IRP focuses on the impact of various uncertainties such as load variations, nuclear capital costs, greenhouse gas legislation, EPA regulations, fuel prices, and the availability of financing options such as federal loan guarantees (FLG). FLGs would significantly reduce the financing cost of new nuclear capacity and, therefore, further benefit customers.

The IRP analysis included sensitivities on each of the uncertainties described below:

Load Variations: The base case load forecast incorporates the impact of the current recession, projected EE achievements, demand destruction associated with the implementation of carbon legislation, new wholesale sales opportunities, and the impact associated with future plug-in hybrid vehicles. The high and low load forecast sensitivities were developed to reflect a 95% confidence interval.

Nuclear Capital Costs: The nuclear capital cost was varied on the low end to reflect the impact of minimal project contingency and varied on the high side to reflect increased labor and material cost.

Greenhouse Gas Legislation: The 2010 fundamental CO2 allowance price forecast was lower primarily due to projection of lower natural gas prices, increased coal retirements, lower loads and increased projections with regards the ability to use to international and domestic offsets to meet CO2 reduction mandates. For the 2010 IRP a range of CO2 prices was evaluated based on various legislative cap and trade proposals, in addition to potential Clean Energy legislation that does not have a CO2 cap and trade mechanism, but relied upon a federal RPS.

Fuel Prices: The base case natural gas and coal price projections were based on Duke Energy's fundamental price forecasts, which are updated annually. A high cost fuel scenario was evaluated which reflects the impact of increased demand on natural gas and regulatory challenges to the coal mining industry. The lower cost fuel scenario represents a larger supply of domestic natural gas than currently assumed and a lower demand on coal.

Nuclear Financing Options: The nuclear cost referenced as "traditional financing" in the 2010 Annual Plan includes state incentives, local incentives, and the ability to obtain construction financing cost prior to commercial operation. The nuclear cost referenced as "favorable financing" includes both Production Tax Credits (PTCs) and FLGs. These credits were evaluated as sensitivities because we currently do not qualify for these programs. However, it is important to continue to include these benefits as sensitivities because it demonstrates how much it could lower the cost to customer, should we qualify. There is legislative support for expanding these programs in the future.

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, completion of various fossil and hydro unit uprates, as well as pursuing nuclear uprates and renewable resources. The analysis continues to affirm the potential benefits of new nuclear capacity in the 2020 timeframe in a carbon-constrained future. The Company will continue to pursue a COL from the NRC.

To demonstrate that the Company is planning adequately for customers, a portfolio incorporating the impact of impending carbon legislation was selected for the purposes of preparing the Load, Capacity, and Reserve Margin Table (LCR Table).

This portfolio consisted of 1,780 MW[6] of new natural gas simple cycle capacity, 1,300 MW of combined cycle capacity, 2,234 MW of new nuclear capacity, 1,267 MW of DSM, 633 MW of EE, and 520 MW of renewable resources. The portfolio included the Cliffside Unit 6, Buck CC, and Dan River CC projects.

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

However, significant challenges remain such as obtaining the necessary regulatory approvals to implement future 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 qualitative 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 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.

Summer Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2010 Annual Plan

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Load Forecast										
1 Duke System Peak	17,571	17,840	18,115	18,481	18,864	19,307	19,747	20,212	20,651	21,031
Reductions to Load Forecast										
2 New EE Programs	(42)	(81)	(141)	(201)	(259)	(317)	(396)	(457)	(496)	(553)
3 Adjusted Duke System Peak	**17,529**	**17,759**	**17,974**	**18,280**	**18,605**	**18,990**	**19,351**	**19,755**	**20,155**	**20,478**
Cumulative System Capacity										
4 Generating Capacity	19,817	19,756	20,564	21,064	21,082	20,372	20,382	20,409	20,489	20,519
5 Capacity Additions	64	1,465	666	18	370	10	27	81	30	0
6 Capacity Derates	(12)	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	(113)	(658)	(166)	0	(1,080)	0	0	0	0	0
8 Cumulative Generating Capacity	19,756	20,564	21,064	21,082	20,372	20,382	20,409	20,489	20,519	20,519
Purchase Contracts										
9 Cumulative Purchase Contracts	270	270	211	123	100	100	100	100	100	97
Sales Contracts										
10 Catawba Owner Backstand	(73)									
11 Catawba Owner Load Following Agreement										
12 Cumulative Future Resource Additions										
Base Load	0	0	0	0	0	0	0	0	0	0
Peaking/Intermediate	0	0	0	0	0	0	740	740	1,480	1,480
Renewables	36	125	154	259	378	379	380	450	453	424
13 Cumulative Production Capacity	**19,989**	**20,958**	**21,429**	**21,465**	**20,851**	**20,861**	**21,629**	**21,780**	**22,553**	**22,521**
Reserves w/o Demand-Side Management										
14 Generating Reserves	2,460	3,199	3,455	3,185	2,246	1,871	2,278	2,025	2,398	2,043
15 % Reserve Margin	**14.0%**	**18.0%**	**19.2%**	**17.4%**	**12.1%**	**9.9%**	**11.8%**	**10.2%**	**11.9%**	**10.0%**
16 % Capacity Margin	12.3%	15.3%	16.1%	14.8%	10.8%	9.0%	10.5%	9.3%	10.6%	9.1%
Demand-Side Management										
17 Cumulative DSM Capacity	961	1,168	1,255	1,267	1,267	1,267	1,267	1,267	1,267	1,267
IS / SG	293	293	293	293	293	293	293	293	293	293
Power Share / Power Manager	668	875	962	974	974	974	974	974	974	974
18 Cumulative Equivalent Capacity	20,950	22,126	22,684	22,732	22,118	22,129	22,897	23,047	23,820	23,789
Reserves w/ DSM										
19 Generating Reserves	3,421	4,367	4,710	4,452	3,513	3,139	3,546	3,292	3,665	3,311
20 % Reserve Margin	**19.5%**	**24.6%**	**26.2%**	**24.4%**	**18.9%**	**16.5%**	**18.3%**	**16.7%**	**18.2%**	**16.2%**
21 % Capacity Margin	16.3%	19.7%	20.8%	19.6%	15.9%	14.2%	15.5%	14.3%	15.4%	13.9%

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Forecast										
1 Duke System Peak	21,388	21,698	22,018	22,343	22,672	23,010	23,343	23,689	24,034	24,384
Reductions to Load Forecast										
2 New EE Programs	(633)	(633)	(633)	(633)	(633)	(633)	(633)	(633)	(633)	(633)
3 Adjusted Duke System Peak	**20,755**	**21,065**	**21,385**	**21,710**	**22,039**	**22,377**	**22,710**	**23,056**	**23,401**	**23,751**
Cumulative System Capacity										
4 Generating Capacity	20,519	20,519	20,519	20,519	20,519	20,519	20,519	20,519	20,519	20,519
5 Capacity Additions	0	0	0	0	0	0	0	0	0	0
6 Capacity Derates	0	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	0	0	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	20,519	20,519	20,519	20,519	20,519	20,519	20,519	20,519	20,519	20,519
Purchase Contracts										
9 Cumulative Purchase Contracts	96	87	87	87	87	87	87	87	87	87
Sales Contracts										
10 Catawba Owner Backstand										
11 Catawba Owner Load Following Agreement										
12 Cumulative Future Resource Additions										
Base Load	1,117	1,117	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234
Peaking/Intermediate	1,480	1,480	1,480	1,480	1,480	1,480	2,130	2,130	2,780	3,080
Renewables	471	474	472	477	483	490	497	505	512	520
13 Cumulative Production Capacity	**23,684**	**23,678**	**24,793**	**24,798**	**24,804**	**24,811**	**25,468**	**25,476**	**26,133**	**26,441**
Reserves w/o Demand-Side Management										
14 Generating Reserves	2,929	2,613	3,408	3,088	2,765	2,434	2,758	2,420	2,732	2,690
15 % Reserve Margin	**14.1%**	**12.4%**	**15.9%**	**14.2%**	**12.5%**	**10.9%**	**12.1%**	**10.5%**	**11.7%**	**11.3%**
16 % Capacity Margin	12.4%	11.0%	13.7%	12.5%	11.1%	9.8%	10.8%	9.5%	10.5%	10.2%
Demand-Side Management										
17 Cumulative DSM Capacity	1,267	1,267	1,267	1,267	1,267	1,267	1,267	1,267	1,267	1,267
IS / SG	293	293	293	293	293	293	293	293	293	293
Power Share / Power Manager	974	974	974	974	974	974	974	974	974	974
18 Cumulative Equivalent Capacity	24,952	24,946	26,061	26,066	26,071	26,078	26,736	26,743	27,401	27,709
Reserves w/ DSM										
19 Generating Reserves	4,197	3,881	4,676	4,356	4,032	3,701	4,026	3,687	4,000	3,958
20 % Reserve Margin	**20.2%**	**18.4%**	**21.9%**	**20.1%**	**18.3%**	**16.5%**	**17.7%**	**16.0%**	**17.1%**	**16.7%**
21 % Capacity Margin	16.8%	15.6%	17.9%	16.7%	15.5%	14.2%	15.1%	13.8%	14.6%	14.3%

Winter Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2010 Annual Plan

	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	2018	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
Load Forecast																					
1 Duke System Peak	16,919	17,186	17,481	17,839	18,211	18,624	19,029	19,455	20,212	19,848	20,189	20,504	20,795	21,094	21,396	21,699	22,011	22,318	22,633	22,950	23,270
Reductions to Load Forecast																					
2 New EE Programs	(34)	(62)	(153)	(227)	(281)	(374)	(393)	(525)	(457)	(537)	(579)	(750)	(727)	(727)	(727)	(727)	(727)	(727)	(727)	(727)	(727)
3 Adjusted Duke System Peak	**16,885**	**17,124**	**17,328**	**17,612**	**17,930**	**18,250**	**18,636**	**18,930**	**19,755**	**19,311**	**19,610**	**19,754**	**20,068**	**20,367**	**20,669**	**20,972**	**21,284**	**21,591**	**21,906**	**22,223**	**22,543**
Cumulative System Capacity																					
4 Generating Capacity	20,567	20,567	20,928	21,791	21,814	21,462	21,122	21,131	20,409	21,158	21,239	21,269	21,269	21,269	21,269	21,269	21,269	21,269	21,269	21,269	21,269
5 Capacity Additions	0	684	1,465	46	18	370	10	27	0	81	30	0	0	0	0	0	0	0	0	0	0
6 Capacity Derates	0	(12)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	0	(311)	(602)	(24)	(370)	(710)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	20,567	20,928	21,791	21,814	21,462	21,122	21,131	21,158	20,409	21,239	21,269	21,269	21,269	21,269	21,269	21,269	21,269	21,269	21,269	21,269	21,269
Purchase Contracts																					
9 Cumulative Purchase Contracts	277	277	218	123	100	100	100	100	100	100	97	96	87	87	87	87	87	87	87	87	87
Sales Contracts																					
10 Catawba Owner Backstand	(73)	(73)																			
11 Catawba Owner Load Following Agreement	(50)																				
12 Cumulative Future Resource Additions																					
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	1,117	1,117	2,234	2,234	2,234	2,234	2,234	2,234	2,234
Peaking/Intermediate	0	0	0	0	0	0	0	740	740	740	1,480	1,480	1,480	1,480	1,480	1,480	1,480	1,480	2,130	2,130	2,780
Renewables	12	36	125	154	259	378	379	380	450	450	453	424	471	474	472	477	483	490	497	505	512
13 Cumulative Production Capacity	**20,733**	**21,168**	**22,134**	**22,091**	**21,822**	**21,600**	**21,611**	**22,379**	**21,699**	**22,529**	**23,299**	**23,270**	**24,425**	**24,428**	**25,543**	**25,548**	**25,553**	**25,560**	**26,218**	**26,225**	**26,883**
Reserves w/o Demand-Side Management																					
14 Generating Reserves	3,848	4,044	4,806	4,479	3,892	3,350	2,975	3,449	1,944	3,218	3,689	3,516	4,357	4,061	4,874	4,576	4,269	3,969	4,312	4,002	4,340
15 % Reserve Margin	**22.8%**	**23.6%**	**27.7%**	**25.4%**	**21.7%**	**18.4%**	**16.0%**	**18.2%**	**9.8%**	**16.7%**	**18.8%**	**17.8%**	**21.7%**	**19.9%**	**23.6%**	**21.8%**	**20.1%**	**18.4%**	**19.7%**	**18.0%**	**19.3%**
16 % Capacity Margin	18.6%	19.1%	21.7%	20.3%	17.8%	15.5%	13.8%	15.4%	9.0%	14.3%	15.8%	15.1%	17.8%	16.6%	19.1%	17.9%	16.7%	15.5%	16.4%	15.3%	16.1%
Demand-Side Management																					
17 Cumulative DSM Capacity	640	788	841	841	841	841	841	841	1,267	841	841	841	841	841	841	841	841	841	841	841	841
IS / SG	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293
Power Share / Power Manager	347	494	548	548	548	548	548	548	974	548	548	548	548	548	548	548	548	548	548	548	548
18 Cumulative Equivalent Capacity	21,373	21,955	22,975	22,932	22,663	22,442	22,452	23,220	22,966	23,371	24,141	24,111	25,266	25,269	26,384	26,389	26,395	26,402	27,059	27,067	27,724
Reserves w/ DSM																					
19 Generating Reserves	4,488	4,831	5,647	5,320	4,733	4,192	3,816	4,290	3,211	4,060	4,531	4,357	5,198	4,902	5,715	5,417	5,111	4,811	5,153	4,844	5,181
20 % Reserve Margin	**26.6%**	**28.2%**	**32.6%**	**30.2%**	**26.4%**	**23.0%**	**20.5%**	**22.7%**	**16.3%**	**21.0%**	**23.1%**	**22.1%**	**25.9%**	**24.1%**	**27.7%**	**25.8%**	**24.0%**	**22.3%**	**23.5%**	**21.8%**	**23.0%**
21 % Capacity Margin	21.0%	22.0%	24.6%	23.2%	20.9%	18.7%	17.0%	18.5%	14.0%	17.4%	18.8%	18.1%	20.6%	19.4%	21.7%	20.5%	19.4%	18.2%	19.0%	17.9%	18.7%

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 in 1998.

4. Generating Capacity must be online by June 1 to be included in the available capacity for the summer peak of that year. Capacity must be online by Dec 1 to be included in the available capacity for the winter peak of that year. Includes 91 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for NCMPA1 firm capacity sale.
   Generating Capacity also reflects a 277 MW reduction in Catawba Nuclear Station to account for PMPAs termination of their interconnection agreement with Duke Energy Carolinas.

5. Capacity Additions reflect an estimated 50 MW capacity uprate at the Jocassee pumped storage facility from increased efficiency from the new runners by the summer of 2011 and an 8.75 MW increase in capacity at Bridgewater Hydro by summer 2012. 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).
   Capacity Additions include the conversion of Lee Steam Station from coal to natural gas in 2015.
   Capacity Additions include Duke Energy Carolinas hydro units scheduled to be repaired and returned to service. These units are returned to service in the 2011-2017 timeframe and total 34 MW.
   Also included is a 205 MW capacity increase due to nuclear uprates at Catawba, McGuire, and Oconee. Timing of these uprates is shown from 2012-2019

6. The expected Capacity Derates reflect the impact of parasitic loads from planned scrubber additions to Cliffside 5.

7. The 113 MW capacity retirement in summer 2011 represents the projected retirement dates for Buck Units 3-4.
   The 658 MW capacity retirement in summer 2012 represents the projected retirement date for Dan River Steam Station units 1 and 2 (134 MW), Cliffside Steam Station units 1-4 (198 MW), and 326 MWs of old fleet CT retirements.
   The 166 MW capacity retirement in summer 2013 represents the projected retirement date for Dan River Steam Station unit 3 (142 MW) and 24 MWs of old fleet CT retirements.
   The 1080 MW capacity retirement in summer 2015 represents the projected retirement date for Lee Steam Station (370 MW), Buck Steam Station units 5 and 6 (256 MW) and Riverbend Steam Station units 4-7 (454 MW).
   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.

10-11. Two firm wholesale agreements are effective between Duke Energy Carolinas and NCMPA1. The first is a 50 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 2011.

9. 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 certain wholesale customers who continue to be served by Duke.
   B. Purchased capacity from PURPA Qualifying Facilities includes the 88 MW Cherokee County Cogeneration Partners contract which began in June 1998 and expires June 2013 and miscellaneous other QF projects totaling 36 MW.

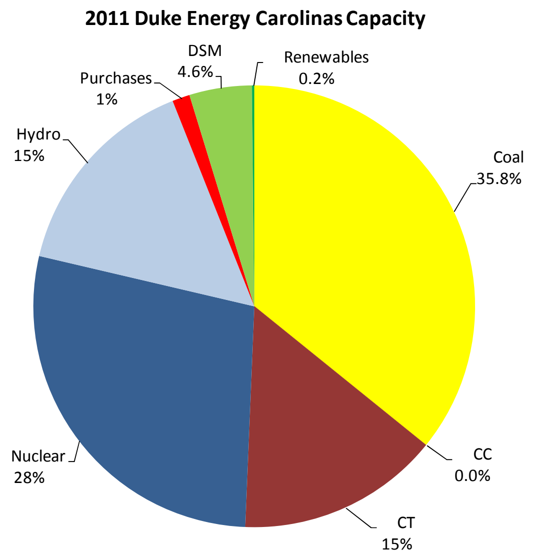
12. Cumulative Future Resource Additions represent a combination of new capacity resources or capability increases from the most robust plan.

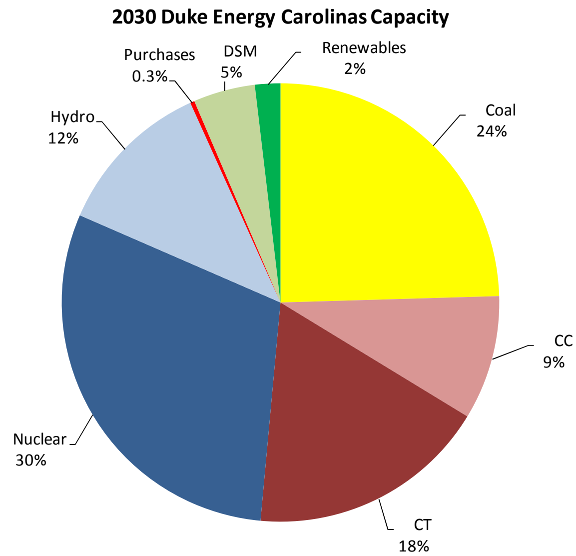
15. Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand

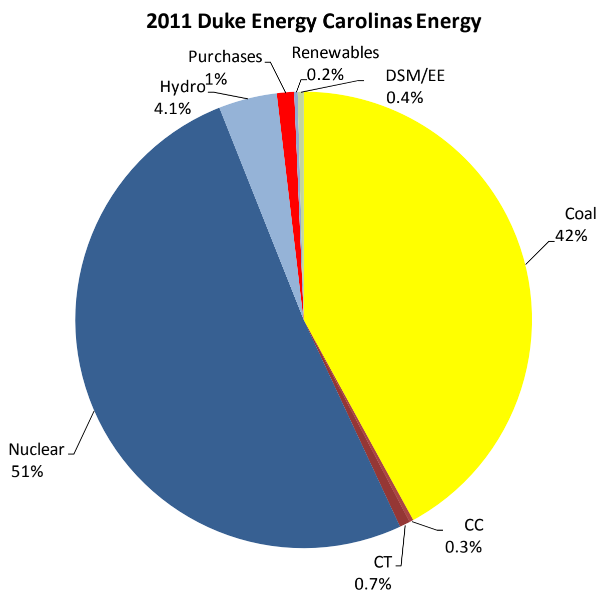
16. Capacity Margin = (Cumulative Capacity - System Peak Demand)/Cumulative Capacity

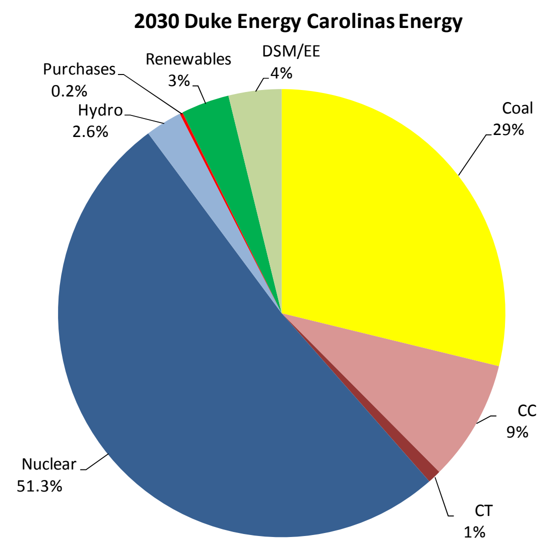
17. The Cumulative Demand Side Management capacity includes new Demand Side Management capacity representing placeholders for demand response and energy efficiency programs.

The charts below show the changes in Duke Energy Carolinas' capacity mix and energy mix between 2011 and 2030. The relative shares of renewables, energy efficiency, and gas all increase, while the relative share of coal decreases.

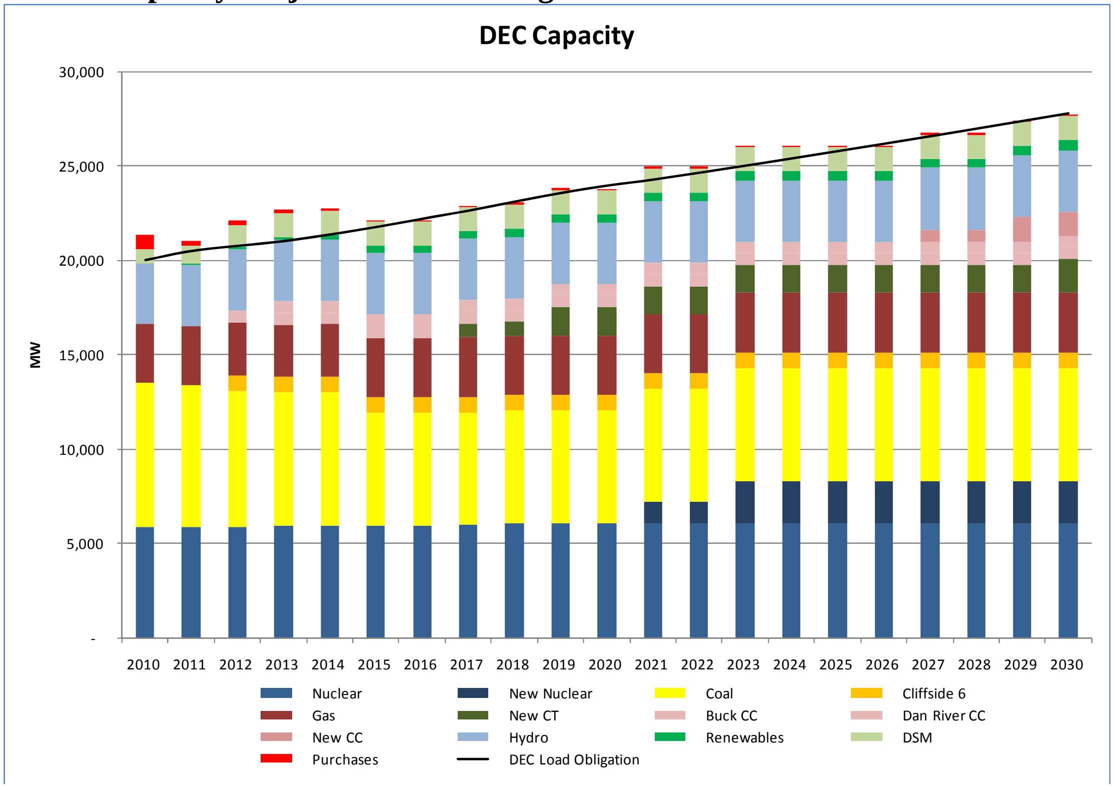




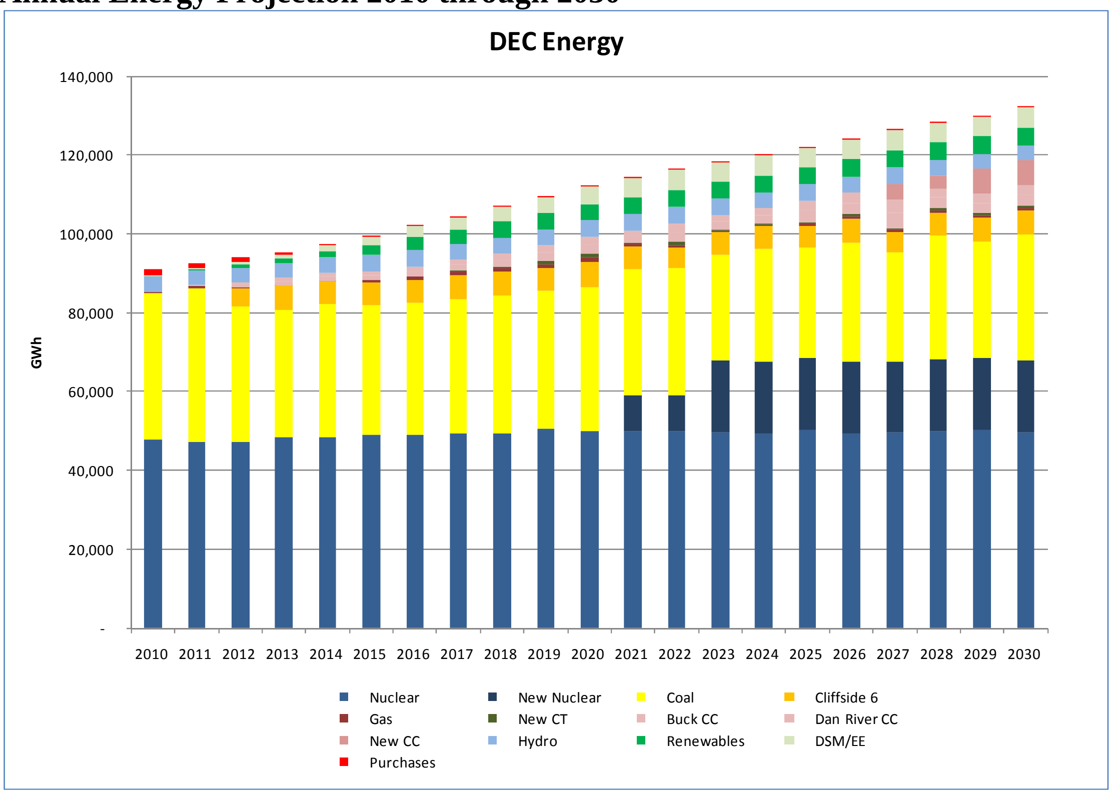




Annual Capacity Projection 2010 through 2030



Annual Energy Projection 2010 through 2030



The table below represents the annual incremental additions reflected in the LCR Table of the most robust expansion plan. The plan contains the addition of Cliffside Unit 6 in 2012, the unit retirements shown in Table 3.3 and the impact of EE and DSM programs.

Year	Month	Project	MW
2011	6	Jocasee Uprates	50
2011	10	Buck Combined Cycle	620
2012	4	Cliffside 6	825
2012	6	Bridgewater Hydro	8.75
2012	6	Nuclear Uprates	10
2012	10	Dan River Combined Cycle	620
2013	6	Nuclear Uprates	45
2014	6	Nuclear Uprates	18
2017	6	Nuclear Uprates	21
2017	6	New CT	740
2018	6	Nuclear Uprates	81
2019	6	Nuclear Uprates	30
2019	6	New CT	740
2021	6	New Nuclear	1117
2023	6	New Nuclear	1117
2027	6	New CC	650
2029	6	New CC	650
2030	6	New CT	300

Renewables								
	MW Contribution to Summer Peak				MW Nameplate			
Year	Wind	Solar	Biomass	Total	Wind	Solar	Biomass	Total
2010	0.0	5	7	12	0	11	7	18
2011	0.0	13	23	36	0	27	23	49
2012	0.0	16	108	125	0	33	108	141
2013	0.5	16	137	154	3	33	137	173
2014	0.4	25	234	259	2	50	234	287
2015	0.4	30	348	378	3	59	348	410
2016	0.4	30	349	379	3	59	349	411
2017	0.5	30	350	380	3	59	350	413
2018	0.7	34	416	450	5	67	416	487
2019	0.7	34	419	453	5	68	419	491
2020	10	34	381	424	66	68	381	514
2021	20	34	417	471	133	68	417	618
2022	20	34	420	474	133	69	420	622
2023	20	35	418	472	134	69	418	621
2024	20	35	422	477	134	70	422	627
2025	20	35	427	483	135	70	427	632
2026	21	35	434	490	137	71	434	642
2027	21	36	440	497	140	72	440	652
2028	21	36	447	505	142	73	447	662
2029	22	37	454	512	145	74	454	672
2030	22	37	461	520	147	74	461	683

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:

- 1.8% average summer peak system demand growth over the next 20 years without impacts of new energy efficiency programs
- Generation retirements of approximately 350 MW of old fleet combustion turbines by 2013
- Generation retirements of approximately 1,040 MW of older coal units associated with the addition of Cliffside Unit 6.
- Generation retirements of approximately 630 MW of remaining coal units without scrubbers by 2015
- 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 EE, DSM 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). 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.

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 – 800 MW Supercritical Pulverized Coal
- Base Load – 630 MW Integrated Gasification Combined Cycle (IGCC)
- Base Load – 2,234 MW (2x1,117 MW) Nuclear units (AP1000)
- Peaking/Intermediate – 740 MW (4x185 MW) CT
- Peaking/Intermediate – 650 MW (460 MW Unfired + 150MW Duct Fired + 40MW Inlet Chilled) Natural Gas CC
- Renewable – Existing Unit Biomass Co-Firing
- Renewable – Wind PPA On-Shore
- Renewable – Wind PPA Off-Shore
- Renewable – Landfill Gas PPA
- Renewable – Solar Photovoltaic PPA
- Renewable – Biomass Firing PPA
- Renewable – Hog Waste Digester PPA
- Renewable – 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.

Energy Efficiency and Demand-Side Management

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

The costs and impacts included in Duke Energy Carolinas' approved Energy Efficiency Plan settlement in NCUC Docket No. E-7, Sub 831 was modeled and the assumptions were made that these costs and impacts would continue throughout the planning period.

The forecasted energy efficiency savings through 2012 are consistent with Duke Energy Carolinas' North Carolina Settlement Energy Efficiency Plan for 2009 through 2012. The company assumes total efficiency savings will continue to grow on an annual basis through 2021, however the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan.

The demand response programs dispatch method was enhanced to more accurately reflect the resources' potential benefits. The dispatch price of the program is tied to the cost of natural gas using a heatrate and variable O&M cost. This change resulted in increased operation of the demand response programs in the production cost simulation runs.

Develop Theoretical Portfolio Configurations

A 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 set of basic inputs which were varied 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 set of basic 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/reactive power support, spinning reserve (10 to 15-minute start-up) and other requirements as a result of Virginia-Carolinas (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 optimal timing of combustion turbine, combined cycle, and nuclear additions in the 2015 – 2030 timeframe.

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 combined cycle in 2012 and Dan River combined cycle in 2013 and the unit retirements shown in Table 3.4.

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

<u>Overall Requirements/Timing</u>

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

<u>Additional Requirements</u>

- Up to 25% from EE through 2020
- Up to 40% from EE starting in 2021
- Up to 25% of the requirements can be met with 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 – using Duke Energy Carolinas' share of total North Carolina load which is approximately 42%)
  - 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 retail loads and legacy Schedule 10A customers served by Duke Energy Carolinas. The requirement that a certain percentage must come from Solar, Hog and Poultry waste was not applied to the South Carolina portion.

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, five main scenarios were chosen to illustrate the impacts of key risks and decisions. Three of these scenarios fall into the Reference CO2 Case and two fall into the Clean Energy Legislation Case.

- Reference Case: Cap and trade program with CO_2 prices based on the Waxman/Markey legislation delayed three years to start in 2015.
- Clean Energy Legislation: In addition to evaluating potential CO_2 cap and trade options, the impact of proposed Clean Energy legislation without a price on CO_2 emissions were also evaluated. Assumptions used in this analysis include:
    - Based on the proposed Lugar and Graham Clean Energy Legislation.
    - 15% of retail sales by 2015 must be clean energy, increasing to 30% by 2030.
    - Clean energy is renewable resources, energy efficiency, nuclear, or alternative compliance payment.
    - Portfolios based on this legislation include the high energy efficiency impacts as described below and an additional 1,000 MW of wind and solar PPA brought on in between 2015 and 2020.

The five portfolios that were analyzed are shown below:

Reference CO_2 Case Scenarios:

1. Natural Gas – Combustion turbine/combined cycle portfolio (CT/CC)
2. 2021-2023 – Two unit nuclear portfolio (2N 2021-2023)
3. 2026-2028 – Two unit nuclear portfolio (2N 2026-2028)

Clean Energy Legislation Scenarios:

4. Clean Energy Gas – CT/CC portfolio with the Clean Energy Legislation assumptions
5. Clean Energy Nuclear – One nuclear unit in 2022 portfolio with the Clean Energy Legislation assumptions

An overview of the specifics of each portfolio is shown in Table A1 below.

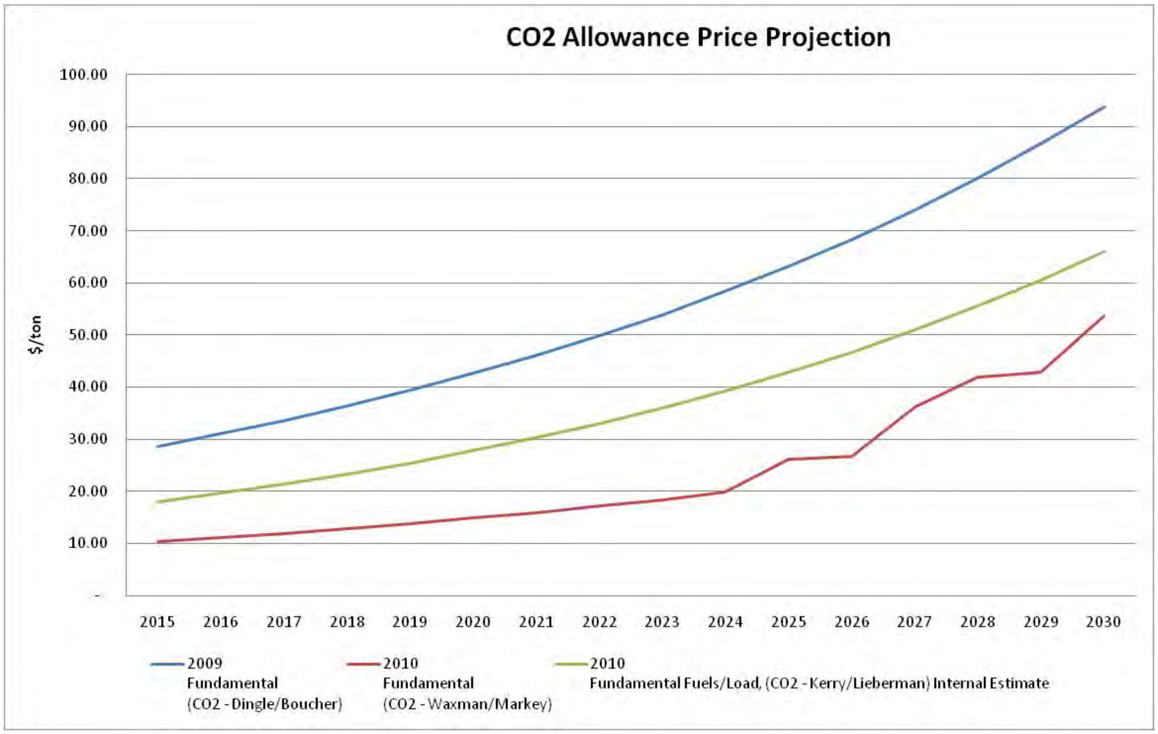
The sensitivities chosen to be performed for these scenarios were those representing the highest risks going forward. The following sensitivities were evaluated in the Reference Case scenarios:

- Load forecast variations
  - Increase relative to base forecast (+10% for peak demand and energy by 2030)
  - Decrease relative to base forecast (- 10% for peak demand and energy by 2030)
- Construction cost sensitivity[7]
  - Costs to construct a new nuclear plant (+20/- 10% higher than base case)
- Fuel price variability
  - Higher Fuel Prices (coal prices 50% higher, natural gas prices 35% higher)
  - Lower Fuel Prices (coal prices 20% lower, natural gas prices 25% lower)
- Emission allowance price variability
  - The NO_x and SO_2 allowance prices were based on an intrastate trading program which was one option allowed under the proposed EPA Clean Air Transport rule.
- The Carbon reference case had CO_2 emission prices ranging from $10/ton starting in 2015 to $54/ton in 2030 based on the proposed Waxman/Markey legislation. Sensitivities were performed based on the proposed Kerry/Lieberman legislation and the 2009 fundamental CO_2 price.
- High Energy Efficiency – This sensitivity includes the full target impacts of the save-a-watt bundle of programs for the first five years and then increases the load impacts at 1% of retail sales every year after that until the load impacts reach the economic potential identified by the 2007 market potential study. When fully implemented this increased energy efficiency resulted in approximately a 13% decrease in retail sales.

[7] 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.

Chart A1 shows the CO_2 prices utilized in the analysis.

Chart A1



An overview of the specifics of each portfolio is shown in Table A1 below.

Table A1 – Portfolios Evaluated

Year	Portfolio				
	CT/CC	2N 2021-2023	2N 2026-2028	Clean Energy Gas	Clean Energy Nuclear
2011					
2012					
2013					
2014					
2015					
2016					
2017	CC	CT	CT		
2018					
2019	CT	CT	CT	CC	CC
2020				CT	CT
2021	CC	N	CC		
2022					N
2023	CC	N	CC	CC	
2024					
2025	CC		CT (PPA)		
2026	CC		N	CC	
2027		CC			
2028	CT		N	CT	CT
2029		CC			
2030	CT	CT	CT	CT	CT
Total CT	2,050 MW	1,780 MW	1,780 MW	1,690 MW	1,880 MW
Total CC	3,250 MW	1,300 MW	1,300 MW	1,950 MW	650 MW
Total Nuclear		2,234 MW	2,234 MW		1,117 MW
Total Nuclear Uprate	204 MW	204 MW	204 MW	204 MW	204 MW
Total retire	2,017 MW	2,017 MW	2,017 MW	2,017 MW	2,017 MW

Quantitative Analysis Results

The quantitative analysis focused on critical variables that impact the need for and timing of new nuclear generation. Three potential resource planning strategies were tested under base assumption and variations in CO2 price, fuel costs, load/energy efficiency, and nuclear capital costs. These three potential resource planning strategies are:

- No new nuclear capacity (the CT/CC portfolio)
- Full ownership of new nuclear capacity (the 2 Nuclear Units portfolio)
- Shared ownership of new nuclear capacity (the 1 Nuclear Unit portfolio).

For the base case and each sensitivity, the PVRR was calculated for each portfolio. The revenue requirement calculation estimates the costs to customers for the Company to recover system production costs and new capital incurred. A 50-year analysis time frame was used to fully capture the long-term impact of nuclear generation added late in the 20 year planning horizon. Table A2 below represents a comparison of the Natural Gas portfolio with a full ownership nuclear portfolio (1 unit in 2021 & 2 unit in 2023) over a range of sensitivities and timing of new nuclear generation. The green block represents the lowest PVRR between the two options and the value contained within the block is the PVRR savings in $billions between the two cases.

Table A2
Comparison of Nuclear Portfolios to the CT/CC Portfolio
(Cost are represented in $billions)

	Reference Case	**CO2 Price Sensitivity**		**Fuel Sensitivity**	
Portfolio		Kerry/ Lieberman	2009 Fundamental	High Fuel Cost	Low Fuel Cost
2 Nuclear Units (2021-2023)	(1.8)	(2.8)	(5.0)	(5.5)	
Natural Gas					(0.6)
	Load Sensitivity			**Nuclear Capital Cost Sensitivity**	
	High Load	Low Load	High DSM	20% Increase	10% Decrease
2 Nuclear Units (2021-2023)	(1.9)	(1.2)	(1.6)		(2.9)
Natural Gas				(0.5)	
Favorable Financing		**Clean Energy Bill**		**Timing**	
Portfolio	FLG & PTCs	Portfolio		Portfolio	
2 Nuclear Units (2021-2023)	(4.4)	1 Nuclear Unit (2021)	(0.7)	2 Nuclear Units (2026-2028)	(1.9)
Natural Gas		Natural Gas		Natural Gas	

The 2 Nuclear Unit portfolios resulted in a lower cost to customer in every case with the exception of increased nuclear capital cost and lower fuel cost. (Note that in the Clean Energy Bill sensitivity, the 1 Nuclear Unit portfolio was best.) In each of the other sensitivities where the 2 Nuclear Unit portfolio was lowest cost, the savings associated with the 1 Nuclear Unit portfolio was approximately half of the savings of the 2 Nuclear Unit portfolio. The cost effectiveness of new nuclear generation in 2026-2028 timeframe was approximately the same as installation in 2021-2023 under base assumptions. However, if fuel prices or CO2 prices are higher than the fundamental assumptions or if Clean Energy legislation is passed, nuclear generation in the 2021 timeframe is the preferred portfolio.

In order to test if compliance with a standard, resulting from Clean Energy Legislation, could be achieved without new nuclear generation, an assumption was made that the standard would result in higher energy efficiency and renewable generation than included in the base case. Therefore the Clean Energy Legislation portfolios (both the nuclear and natural gas portfolios) incorporated the impact of the high energy efficiency assumptions outlined in Table 4.2 and over 1000 MWs of additional renewable generation. In the natural gas portfolio the alternative compliance payment was required in multiple years to meet the legislative targets which decreased the cost effectiveness of the portfolio. If the increased amount of energy efficiency and renewables is not achieved, this would support the addition of additional nuclear generation to meet the Clean Energy standard.

Based on the quantitative analysis, the optimal plan includes two new nuclear units in the 2020 timeframe. A potentially attractive means of securing new nuclear generation is regional nuclear development where two or more partners plan collaboratively to stage multiple nuclear stations over a period of years and each partner would own a portion of each station. Several advantages to a regional nuclear approach are:

- Load Growth: Smaller blocks of base load generation brought on-line over a period of years would more closely match projected load growth.
- Financial: The substantial capital cost would be phased in over a longer period of time and would spread the risk if there were cost increases.
- Regulatory Uncertainty: The optimal amount and timing of additional nuclear generation will depend on the outcome of final legislation. Using a regional approach would allow utilities to better optimize their portfolios as legislation or regulation change over time.

Duke Energy supports this concept and continues to explore regional nuclear opportunities.

Sustainability Evaluation

To gain insights on what is important to stakeholders in resource planning, members of the Carolinas Energy Efficiency Planning Collaborative were surveyed. Members of this collaborative represent industry, environmental, academia, and governmental interests. The respondent size was small and opinions varied among specific topics; however the following statements represent the majority opinions of our stakeholders:

- Long-range planning: The lowest cost to customers was a very important aspect of long-range planning. Also, a balanced portfolio including new nuclear, energy efficiency, renewables and natural gas generation was the portfolio type Duke Energy Carolinas should aspire to achieve.

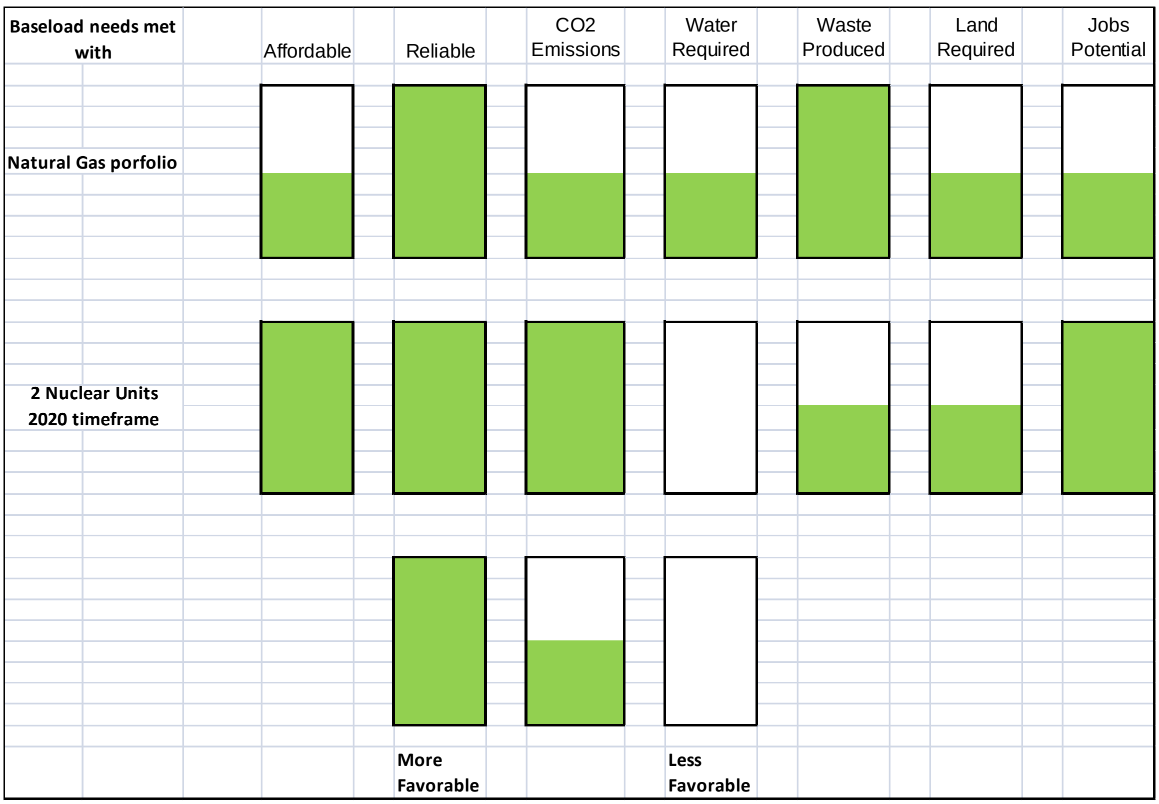
- Load Demand: Energy efficiency will have the largest impact on future load demand.

- Environmental: From an environmental perspective, air and $CO2$ emissions are the most important consideration for future planning.

- Renewables and Energy Efficiency: Government should provide financial incentives for the development of renewables and energy efficiency for a defined period of time (until technology has been proven).

A relative ranking of affordability, reliability, job potential and environmental impacts was developed for the natural gas and the nuclear portfolios. The portfolios were reviewed based on supply side options to meet customer needs from the standpoint of key sustainability criteria. The same amount of energy efficiency and renewables were included in both portfolios, so this is essentially a sustainability comparison between meeting future base load needs with natural gas or nuclear. Table A3 illustrates how each portfolio performed under this criterion.

Table A3



A review of the relative ranking of the portfolios in Table A3 illustrates that a balanced portfolio with the inclusion of new nuclear to meet base load needs, natural gas, renewables, and energy efficiency ranked most favorably with regard to lowest cost to customers and lowest carbon footprint.

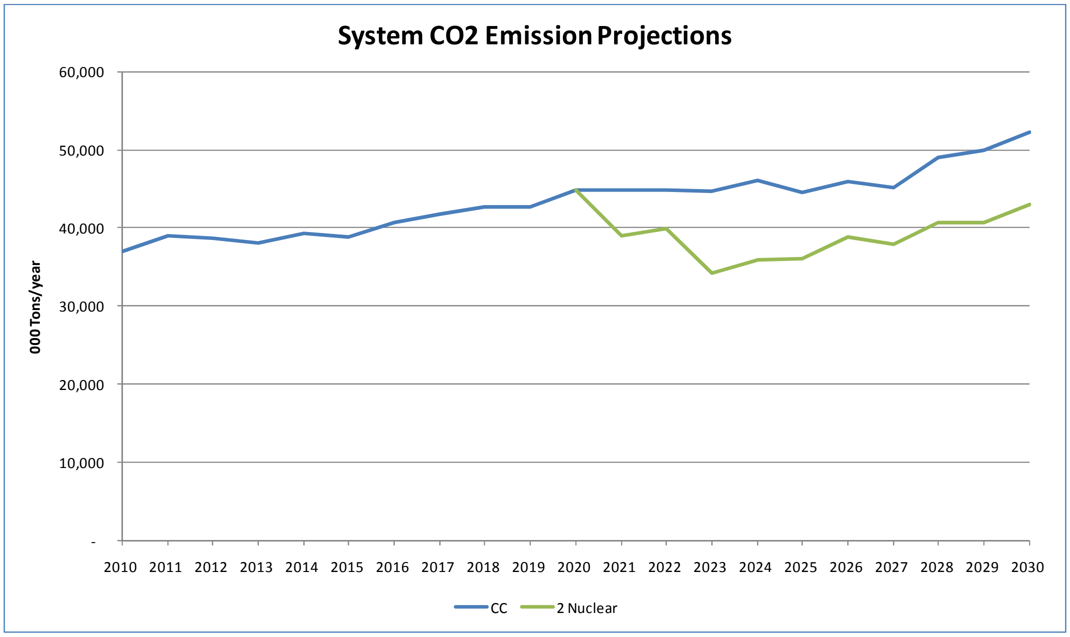
Several key insights from the survey are that cost to customers, carbon footprint, and maintaining a balanced portfolio consisting of a mix of new nuclear, natural gas generation, renewables, and energy efficiency are very important aspects in the development of the resource plan.

Both the survey and the relative ranking support a diversified portfolio to meet customer electricity needs in a sustainable way.

Quantitative Analysis Summary

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 CT/CC and the 2Nuclear scenarios are shown in Chart A4 below. A review of these projections show to make real system reductions in CO_2 emissions additional nuclear generation is needed.

Chart A4



The biggest risks to the nuclear portfolios are the time required to license and construct a nuclear unit, uncertainty regarding GHG regulation/legislation, potential for even lower demand than currently estimated, capital cost to build, and the ability to secure favorable financing. However, in a carbon constrained future, new nuclear generation must be in the generation mix to reduce the carbon footprint.

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 2021 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
  - The screening analysis shows that portfolios with the new EE and DSM were lower cost than those without and EE and DSM.
  - The high energy efficiency sensitivity is cost effective if there is an equal participation between residential and non-residential customers. If a significant number of non-residential customers opt out, then the high EE case may no longer be cost effective.
- Significant renewable resources will be needed to meet the new NC REPS (and potentially a federal standard)
- There is a capacity need in 2017 to 2020 timeframe to maintain the 17% reserve margin.
- The analysis demonstrates that the nuclear option 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:

- 1,267 MW equivalent of incremental capacity under the new save-a-watt demand-side management programs
- 633 MW of new energy efficiency (reduction to system peak load)
- 2,234 MW of new nuclear capacity
- 1,300 MW of new CC capacity
- 1,780 MW of new CT capacity
- 204 MW of nuclear uprates
- 520 MW of renewables (683 MWs nameplate)

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 2010 Forecast

Sales

Rates Billed

Peaks

2010-2025

July 20, 2010

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Regular Sales and System Peak Summer (2009 Forecast vs. 2010 Forecast)

Regular sales include 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 2010 to 2011				
	Forecasted 2010	**Forecasted 2011**	**Growth**	
Item	**Amount**	**Amount**	**Amount**	**%**
Regular Sales	77,957 GWH	79,398 GWH	1,441 GWH	1.8%
System Peak Summer	20,015 MW	20,292 MW	277 MW	1.4%

Regular Sales Outlook for the Forecast Horizon (2009 – 2025)

Total Regular sales are expected to grow at an average annual rate of 1.7% from 2009 through 2025. Growth rates for most retail classes of sales are greater than the growth projections in the Fall 2009 forecast primarily due to a recovering economy. Adjustments were made to the energy forecasts for the Fall 2009 Forecasts and the Spring 2010 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. Additional adjustments to the Spring 2010 Forecast include sales reductions associated with price increases due to a Carbon Tax starting in 2015 and sales additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011. The Full/Partial Requirements Wholesale class forecast will increase due to new sales contracts with Haywood EMC starting in 2009 and the city of Greenwood SC starting in 2010 and the Central Electric Power Cooperative, Inc. (CEPCI) starting in 2013. One customer of the Full/Partial Requirements Wholesale class, Clemson University, moved from this class to the Duke Carolinas Retail class starting in 2009.

Comparison of Regular Sales Growth Statistics Spring 2010 Forecast vs. Fall 2009 Forecast					
	Spring 2010 Forecast Annual Growth (2009-2025)		Fall 2009 Forecast Annual Growth (2009-2025)		Average Annual Difference [1]
Item	**Amount**	**%**	**Amount**	**%**	
Regular Sales:					
Residential	397 GWH	1.3%	401 GWH	1.3%	-4 GWH
Commercial	618 GWH	2.0%	607 GWH	1.9%	11 GWH
Industrial (total)	55 GWH	0.3%	-27 GWH	-0.1%	82 GWH
Textile	-121 GWH	-4.7%	-161 GWH	-7.5%	40 GWH
Other Industrial	177 GWH	1.0%	134 GWH	0.8%	42 GWH
Other [2]	5 GWH	1.5%	5 GWH	1.5%	0 GWH
Full/Partial Wholesale [3]	462 GWH	7.0%	191 GWH	3.8%	271 GWH
Total Regular	1,537 GWH	1.7%	1,177 GWH	1.4%	360 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 Schedule 10A sales , supplemental sales to the NC EMCs and sales to the city of Greenwood SC and sales to CEPCI.*

System Peak Outlook for the Forecast Horizon (2009 – 2025)

System peak hour demands are forecasted on a summer and winter basis. Adjustments were made to the peak forecasts for the Fall 2009 Forecasts and the Spring 2010 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.** Additional adjustments to the Spring 2010 Forecast include peak reductions associated with price increases due to a Carbon Tax starting in 2015 and peak additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011. The system peak summer demand on the Duke Energy Carolinas is expected to grow at an average annual rate of 1.4% from 2009 through 2025. The system peak winter demand is expected to grow at an average annual rate of 1.5% from 2009 through 2025.

Comparison of System Peak Demand Growth Statistics Spring 2010 Forecast vs. Fall 2009 Forecast					
	Spring 2010 Forecast Annual Growth (2009-2025)		Fall 2009 Forecast Annual Growth (2009-2025)		Average Annual Difference [1]
Item	**Amount**	**%**	**Amount**	**%**	
System Peaks					
Summer	317 MW	1.4%	330 MW	1.5%	-13 MW
Winter	306 MW	1.5%	271 MW	1.3%	35 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 1.3% annually over the forecast horizon.

- The total annual energy requirements of the Catawba Joint Owners are forecasted to grow at 1.5% annually over the forecast horizon.

- Territorial energy requirements are forecasted to grow from 99,211 GWH in 2010 to 123,508 GWH in 2025, for an average annual growth rate of 1.5%.

General forecasting methodology for Duke Energy Carolinas energy and demand forecasts for Spring 2010

Duke Energy Carolinas' Spring 2010 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 2010 – 2025 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 2010 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 real gross state product (GSP) in NC and SC
- Non-manufacturing real GSP in NC and SC
- Non-manufacturing employment in NC and SC
- Manufacturing real GSP in NC and SC by industry group, e.g., textiles
- Employment in NC and SC by industry group
- Total real 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) is made for the forecast period by examining long-term historical weather. For the Spring 2010 forecasts, a 10-year simple average of CDD and HDD was 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 15 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.

Adjustments were made to the energy forecasts for the Fall 2009 Forecasts and the Spring 2010 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. Additional adjustments to the Spring 2010 Forecast include sales reductions associated with price increases due to a Carbon Tax starting in 2015 and sales additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011.

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.

Adjustments were made to the peak forecasts for the Fall 2009 Forecasts and the Spring 2010 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.** Additional adjustments to the Spring 2010 Forecast include peak reductions associated with price increases due to a Carbon Tax starting in 2015 and peak additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011.

Billed Sales and Other Energy Requirements

Regular Sales, which include billed sales to Retail and Full/Partial Requirements Wholesale classes, are expected to grow at 1537 GWH per year or 1.7% 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 and sales to the city of Greenwood, SC and sales to the Central Electric Power Cooperative, Inc.(CEPCI).

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

Adjustments were made to the energy forecasts for the Fall 2009 Forecasts and the Spring 2010 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. Additional adjustments to the Spring 2010 Forecast include sales reductions associated with price increases due to a Carbon Tax starting in 2015 and sales additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011.

Points of Interest

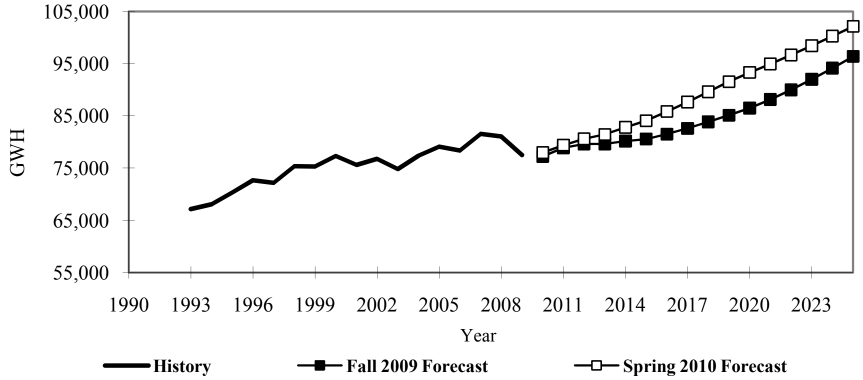
• The **Residential** class continues to show positive growth, driven by steady gains in population within the Duke Energy Carolinas service area. The resulting annual growth in Residential billed sales is expected to average 1.3% over the forecast horizon.

• The **Commercial** class is projected to be the fastest growing retail class, with billed sales growing at 2.0% per year over the next fifteen years. Three sectors that are 45% of Commercial Class weather normalized sales in 2009 are Offices, which include banking (20%), Retail (13%) and Education (12%). Growth in weather normalized sales from 2008 to 2009 were positive for Offices (37 GWH) and Education (114 GWH) but negative for Retail (-144 GWH).

• The **Industrial** class continues to struggle due to Textile closings and the economic downturn. Over the forecast horizon, the industrial growth is projected to be relatively flat. Though growth is expected to be strong in rubber & plastics, autos and fabricated metals, other industries such as textiles, furniture and electronics are expected to decline. Overall, Total Industrial sales are expected to grow 0.3% over the forecast horizon.

• The **Full/Partial Requirements Wholesale** class is expected to grow at 7.0% annually over the forecast horizon, primarily due to the forecasted supplemental sales to specified EMCs in North Carolina and sales to CEPCI in South Carolina.

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



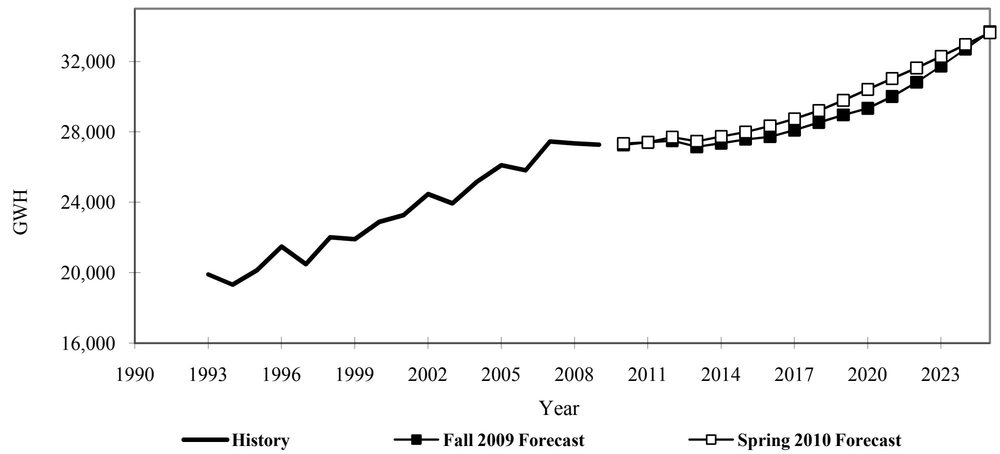
HISTORY / AVERAGE ANNUAL GROWTH

Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
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	History (2004 to 2009)	31	0.0
2006	78,347	-784	-1.0	History (1994 to 2009)	631	0.9
2007	81,572	3,225	4.1			
2008	81,066	-505	-0.6	Spring 2010 Forecast (2009 to 2025)	1537	1.7
2009	77,528	-3,538	-4.4	Fall 2009 Forecast (2009 to 2025)	1177	1.4

SPRING 2010 FORECAST / FALL 2009 FORECAST

Year	GWH	Growth GWH	Growth %	GWH	Difference from Fall 2009 GWH	Difference from Fall 2009 %
2010	77,957	429	0.6	77,213	744	1.0
2011	79,398	1,441	1.8	78,858	540	0.7
2012	80,601	1,203	1.5	79,607	994	1.2
2013	81,432	831	1.0	79,619	1,813	2.3
2014	82,795	1,363	1.7	80,176	2,619	3.3
2015	84,073	1,278	1.5	80,561	3,512	4.4
2016	85,838	1,765	2.1	81,504	4,334	5.3
2017	87,633	1,795	2.1	82,599	5,034	6.1
2018	89,603	1,970	2.2	83,846	5,758	6.9
2019	91,545	1,942	2.2	85,111	6,434	7.6
2020	93,306	1,761	1.9	86,494	6,813	7.9
2021	94,940	1,634	1.8	88,133	6,807	7.7
2022	96,650	1,709	1.8	89,977	6,673	7.4
2023	98,430	1,781	1.8	91,993	6,437	7.0
2024	100,268	1,838	1.9	94,138	6,130	6.5
2025	102,126	1,858	1.9	96,363	5,762	6.0

Residential Billed Sales



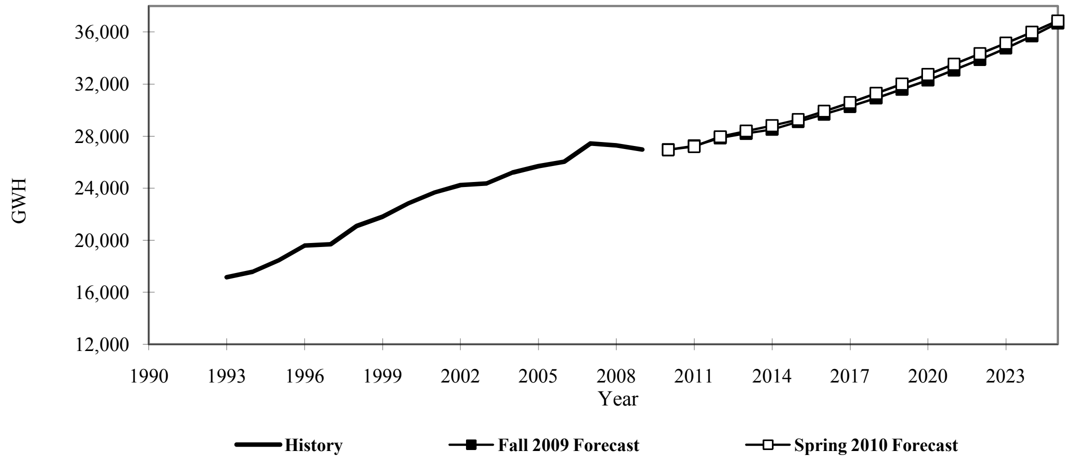
HISTORY | **AVERAGE ANNUAL GROWTH**

Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
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			
2004	25,150	1,203	5.0			
2005	26,108	958	3.8	History (2004 to 2009)	424	1.6
2006	25,816	-292	-1.1	History (1994 to 2009)	531	2.3
2007	27,459	1,643	6.4			
2008	27,335	-124	-0.5	Spring 2010 Forecast (2009 to 2025)	397	1.3
2009	27,273	-62	-0.2	Fall 2009 Forecast (2009 to 2025)	401	1.3

SPRING 2010 FORECAST | **FALL 2009 FORECAST**

Year	GWH	Growth GWH	Growth %	GWH	Difference from Fall 2009 GWH	Difference from Fall 2009 %
2010	27,337	64	0.2	27,260	76	0.3
2011	27,402	66	0.2	27,406	-3	0.0
2012	27,694	292	1.1	27,496	198	0.7
2013	27,466	-228	-0.8	27,148	318	1.2
2014	27,735	268	1.0	27,344	391	1.4
2015	27,988	253	0.9	27,575	412	1.5
2016	28,340	353	1.3	27,724	617	2.2
2017	28,733	392	1.4	28,092	640	2.3
2018	29,205	472	1.6	28,533	672	2.4
2019	29,790	585	2.0	28,960	830	2.9
2020	30,411	621	2.1	29,334	1,076	3.7
2021	31,029	618	2.0	30,005	1,024	3.4
2022	31,630	600	1.9	30,814	816	2.6
2023	32,282	652	2.1	31,733	549	1.7
2024	32,966	684	2.1	32,704	263	0.8
2025	33,631	665	2.0	33,693	-62	-0.2

Commercial Billed Sales



HISTORY

Year	Actual GWH	Growth GWH	Growth %
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
2004	25,204	849	3.5
2005	25,679	475	1.9
2006	26,030	352	1.4
2007	27,433	1,402	5.4
2008	27,288	-145	-0.5
2009	26,977	-311	-1.1

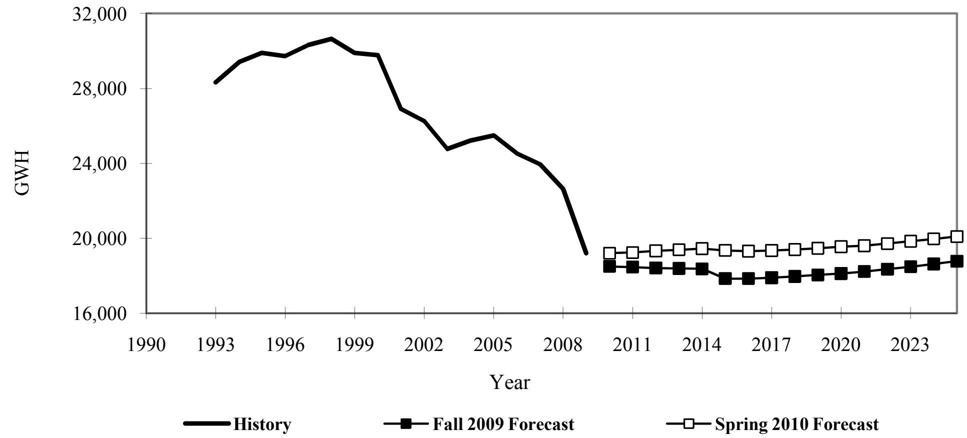
AVERAGE ANNUAL GROWTH

	GWH Per Year	% Per Year
History (2004 to 2009)	355	1.4
History (1994 to 2009)	627	2.9
Spring 2010 Forecast (2009 to 2025)	618	2.0
Fall 2009 Forecast (2009 to 2025)	607	1.9

SPRING 2010 FORECAST / FALL 2009 FORECAST

Year	GWH	Growth GWH	Growth %	Fall 2009 GWH	Difference from Fall 2009 GWH	Difference from Fall 2009 %
2010	26,946	-31	-0.1	26,951	-5	0.0
2011	27,198	252	0.9	27,246	-48	-0.2
2012	27,953	755	2.8	27,868	85	0.3
2013	28,389	436	1.6	28,199	190	0.7
2014	28,805	416	1.5	28,511	294	1.0
2015	29,279	473	1.6	29,102	177	0.6
2016	29,918	639	2.2	29,676	242	0.8
2017	30,576	658	2.2	30,274	302	1.0
2018	31,279	703	2.3	30,923	356	1.2
2019	31,993	713	2.3	31,593	400	1.3
2020	32,731	738	2.3	32,300	431	1.3
2021	33,522	791	2.4	33,070	451	1.4
2022	34,331	810	2.4	33,889	442	1.3
2023	35,149	818	2.4	34,764	386	1.1
2024	35,985	836	2.4	35,694	291	0.8
2025	36,862	877	2.4	36,687	174	0.5

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



HISTORY

Year	Actual GWH	Growth GWH	Growth %
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
2004	25,209	445	1.8
2005	25,495	286	1.1
2006	24,535	-960	-3.8
2007	23,948	-587	-2.4
2008	22,634	-1,314	-5.5
2009	19,204	-3,430	-15.2

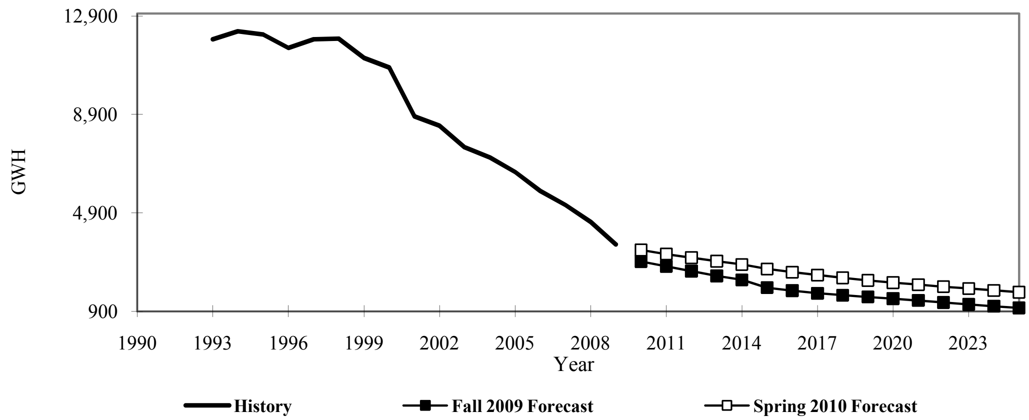
AVERAGE ANNUAL GROWTH

	GWH Per Year	% Per Year
History (2004 to 2009)	-1201	-5.3
History (1994 to 2009)	-680	-2.8
Spring 2010 Forecast (2009 to 2025)	55	0.3
Fall 2009 Forecast (2009 to 2025)	-27	-0.1

SPRING 2010 FORECAST / FALL 2009 FORECAST

Year	GWH	Growth GWH	Growth %	Fall 2009 GWH	Difference from Fall 2009 GWH	Difference from Fall 2009 %
2010	19,202	-2	0.0	18,497	705	3.8
2011	19,237	35	0.2	18,464	773	4.2
2012	19,328	91	0.5	18,413	914	5.0
2013	19,384	56	0.3	18,388	996	5.4
2014	19,448	64	0.3	18,365	1,083	5.9
2015	19,350	-97	-0.5	17,848	1,502	8.4
2016	19,309	-41	-0.2	17,849	1,461	8.2
2017	19,347	37	0.2	17,894	1,453	8.1
2018	19,395	48	0.2	17,961	1,434	8.0
2019	19,466	71	0.4	18,040	1,425	7.9
2020	19,550	85	0.4	18,116	1,435	7.9
2021	19,599	48	0.2	18,225	1,374	7.5
2022	19,715	117	0.6	18,348	1,367	7.5
2023	19,840	125	0.6	18,479	1,361	7.4
2024	19,964	124	0.6	18,626	1,338	7.2
2025	20,092	127	0.6	18,777	1,315	7.0

Textile Billed Sales



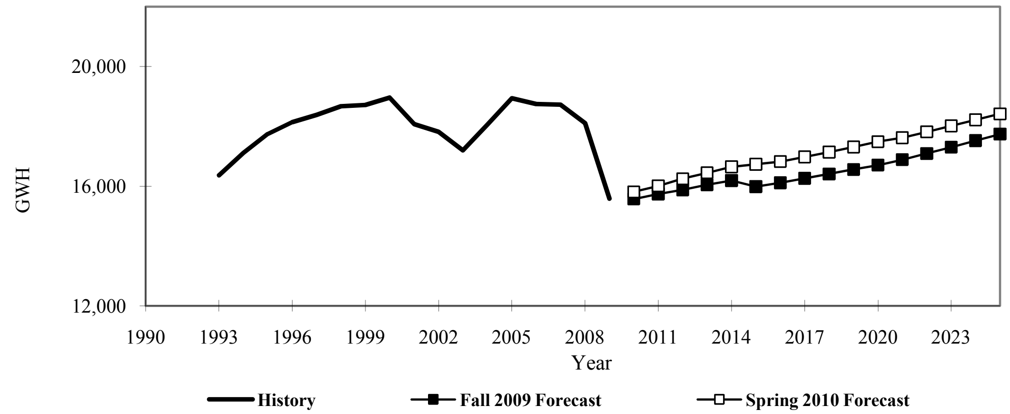
HISTORY / AVERAGE ANNUAL GROWTH

Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
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	History (2004 to 2009)	-706	-12.7
2006	5,791	-770	-11.7	History (1994 to 2009)	-578	-7.8
2007	5,224	-567	-9.8			
2008	4,524	-700	-13.4	Spring 2010 Forecast (2009 to 2025)	-121	-4.7
2009	3,616	-908	-20.1	Fall 2009 Forecast (2009 to 2025)	-161	-7.5

SPRING 2010 FORECAST / FALL 2009 FORECAST

Year	GWH	Growth GWH	Growth %	GWH	Difference from Fall 2009 GWH	Difference from Fall 2009 %
2010	3,393	-223	-6.2	2,925	468	16.0
2011	3,227	-166	-4.9	2,726	501	18.4
2012	3,080	-147	-4.6	2,533	546	21.6
2013	2,937	-143	-4.6	2,340	597	25.5
2014	2,801	-136	-4.6	2,177	624	28.7
2015	2,619	-182	-6.5	1,863	756	40.6
2016	2,489	-130	-4.9	1,738	751	43.2
2017	2,370	-119	-4.8	1,632	738	45.2
2018	2,259	-112	-4.7	1,552	706	45.5
2019	2,156	-102	-4.5	1,483	673	45.4
2020	2,065	-92	-4.3	1,413	651	46.1
2021	1,981	-84	-4.0	1,340	641	47.8
2022	1,901	-80	-4.0	1,258	644	51.2
2023	1,826	-76	-4.0	1,177	648	55.1
2024	1,748	-77	-4.2	1,105	643	58.2
2025	1,674	-74	-4.2	1,037	637	61.4

Other Industrial Billed Sales



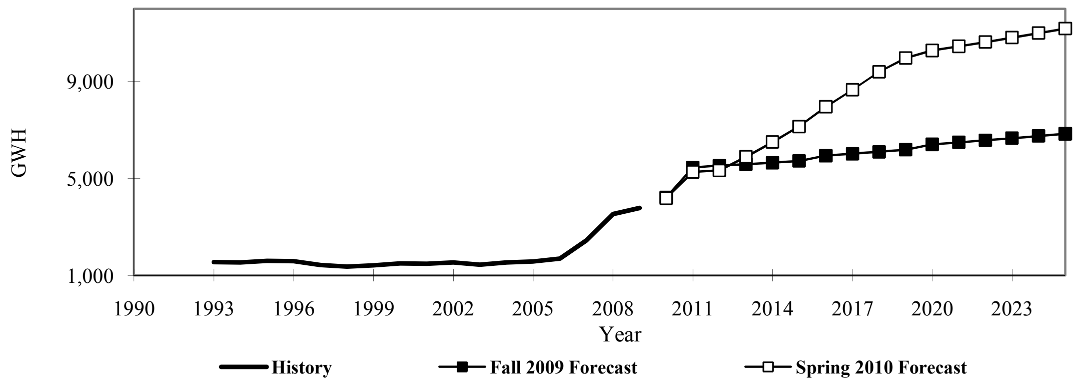
HISTORY | **AVERAGE ANNUAL GROWTH**

Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
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	History (2004 to 2009)	-495	-2.9
2006	18,744	-191	-1.0	History (1994 to 2009)	-102	-0.6
2007	18,724	-20	-0.1			
2008	18,110	-614	-3.3	Spring 2010 Forecast (2009 to 2025)	177	1.0
2009	15,588	-2,522	-13.9	Fall 2009 Forecast (2009 to 2025)	134	0.8

SPRING 2010 FORECAST | **FALL 2009 FORECAST**

Year	GWH	Growth GWH	Growth %	GWH	Difference from Fall 2009 GWH	Difference from Fall 2009 %
2010	15,809	221	1.4	15,573	236	1.5
2011	16,010	201	1.3	15,738	272	1.7
2012	16,248	238	1.5	15,880	368	2.3
2013	16,446	199	1.2	16,048	398	2.5
2014	16,647	200	1.2	16,188	458	2.8
2015	16,732	85	0.5	15,986	746	4.7
2016	16,820	88	0.5	16,111	709	4.4
2017	16,976	156	0.9	16,261	715	4.4
2018	17,136	160	0.9	16,408	728	4.4
2019	17,309	173	1.0	16,557	752	4.5
2020	17,486	176	1.0	16,703	783	4.7
2021	17,618	132	0.8	16,885	733	4.3
2022	17,814	196	1.1	17,090	724	4.2
2023	18,015	200	1.1	17,302	713	4.1
2024	18,216	201	1.1	17,521	695	4.0
2025	18,417	201	1.1	17,740	678	3.8

Full / Partial Requirements Wholesale Billed Sales [1]



HISTORY

AVERAGE ANNUAL GROWTH

Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
2000	1,500	88	6.3			
2001	1,484	-16	-1.1			
2002	1,530	47	3.1			
2003	1,448	-82	-5.4			
2004	1,542	93	6.4			
2005	1,580	38	2.5	History (2004 to 2009)	449	19.7
2006	1,694	114	7.2	History (1994 to 2009)	150	6.2
2007	2,454	760	44.8			
2008	3,525	1,072	43.7	Spring 2010 Forecast (2009 to 2025)	462	7.0
2009	3,788	262	7.4	Fall 2009 Forecast (2009 to 2025)	191	3.8

SPRING 2010 FORECAST

FALL 2009 FORECAST

Year	GWH	Growth GWH	Growth %	GWH	Difference from Fall 2009 GWH	Difference from Fall 2009 %
2010	4,183	395	10.4	4,214	-31	-0.7
2011	5,269	1,086	26.0	5,449	-180	-3.3
2012	5,330	61	1.2	5,531	-201	-3.6
2013	5,891	561	10.5	5,580	311	5.6
2014	6,501	610	10.4	5,648	853	15.1
2015	7,144	643	9.9	5,722	1,422	24.9
2016	7,954	809	11.3	5,937	2,017	34.0
2017	8,656	702	8.8	6,016	2,640	43.9
2018	9,397	741	8.6	6,100	3,297	54.0
2019	9,964	567	6.0	6,184	3,780	61.1
2020	10,276	312	3.1	6,405	3,872	60.4
2021	10,448	171	1.7	6,488	3,960	61.0
2022	10,625	178	1.7	6,576	4,049	61.6
2023	10,806	180	1.7	6,663	4,143	62.2
2024	10,994	188	1.7	6,754	4,240	62.8
2025	11,177	183	1.7	6,841	4,336	63.4

1 Full/Partial Requirements Wholesale Billed sales include sales to Schedule 10A Resale: cities of Concord NC, Dallas NC, Forest City NC, Kings Mountain NC, Due West SC, Prosperity SC and to Electric Company Lockhart SC. Wholesale sales also include sales to Western Carolina University and a town of Highlands; supplemental sales to Piedmont EMC, Blue Ridge EMC, Rutherfordton EMC and Haywood EMC, city of Greenwood and CEPCI, plus, a sale of electricity from Duke Energy to NCEMC.
2 Schedule 10A Resale Sales do not include SEPA allocation.
3 Wholesale sales include Wholesale CFL adjustments.

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%).

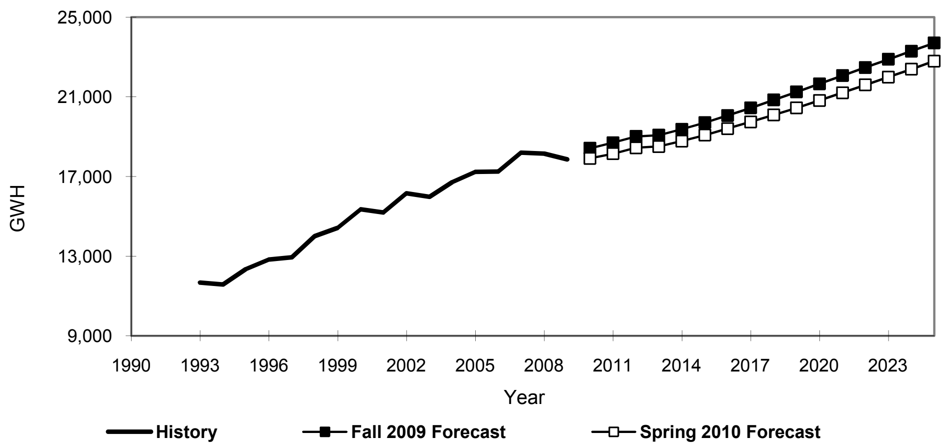
(In December 2006 Duke Energy Carolinas and North Carolina Electric Membership Corporation announced agreements to buy Saluda River Electric Cooperative, Inc.'s ownership interest in unit 1 of the Catawba Nuclear Station. Duke Energy Carolinas will then own 19.3% of the capacity of the Catawba Nuclear 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. This agreement was completed in September of 2008.)

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 308 GWH per year and a growth rate of 1.5 % per year over the period from 2009-2025.

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
2000	15,354	941	6.5			
2001	15,184	-170	-1.1			
2002	16,151	967	6.4			
2003	15,986	-165	-1.0			
2004	16,711	725	4.5			
2005	17,237	527	3.2	History (2004 to 2009)	231	1.3
2006	17,246	9	0.0	History (1994 to 2009)	419	2.9
2007	18,200	954	5.5			
2008	18,140	-60	-0.3	Spring 2010 Forecast (2009 to 2025)	308	1.5
2009	17,864	-276	-1.5	Fall 2009 Forecast (2009 to 2025)	365	1.8

SPRING 2010 FORECAST | **FALL 2009 FORECAST**

Year	GWH	Growth GWH	Growth %	GWH	Difference from Fall 2009 GWH	Difference from Fall 2009 %
2010	17,908	44	0.2	18,419	-511	-2.8
2011	18,145	237	1.3	18,701	-555	-3.0
2012	18,443	298	1.6	19,008	-565	-3.0
2013	18,504	61	0.3	19,077	-573	-3.0
2014	18,780	277	1.5	19,370	-590	-3.0
2015	19,076	296	1.6	19,703	-627	-3.2
2016	19,405	329	1.7	20,060	-655	-3.3
2017	19,739	334	1.7	20,441	-702	-3.4
2018	20,086	348	1.8	20,843	-757	-3.6
2019	20,444	358	1.8	21,247	-803	-3.8
2020	20,820	376	1.8	21,655	-835	-3.9
2021	21,202	382	1.8	22,063	-861	-3.9
2022	21,597	395	1.9	22,473	-876	-3.9
2023	21,988	391	1.8	22,882	-895	-3.9
2024	22,386	398	1.8	23,294	-908	-3.9
2025	22,799	412	1.8	23,707	-908	-3.8

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 1.5% per year from 2010 to 2025. All values below are expressed in GWH.

Territorial Energy

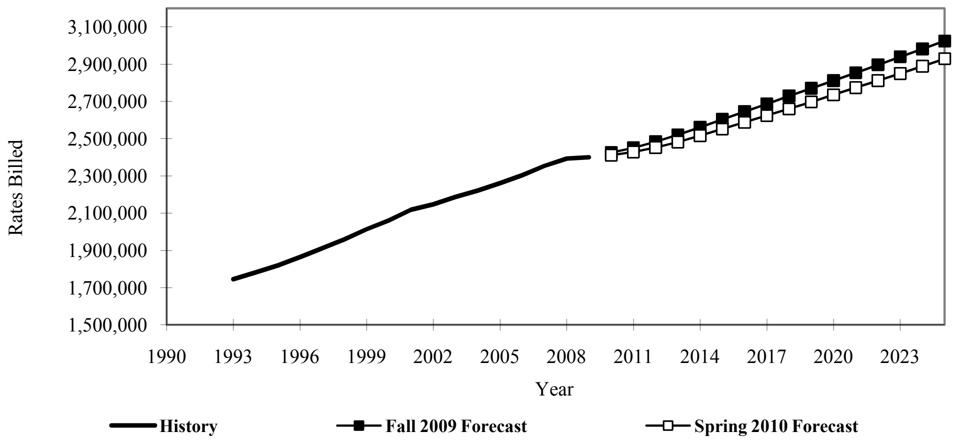
Year	Regular Sales [1]	Catawba (Less SEPA) Total [2]	SEPA [3]	Company Use [4]	Losses & Unbilled [5 & 6]	Territorial Energy
2010	75,706	17,608	329	220	5,349	99,211
2011	76,095	17,845	329	220	5,395	99,884
2012	77,278	18,143	329	220	5,529	101,499
2013	77,593	18,203	329	221	5,622	101,968
2014	78,366	18,480	329	221	5,744	103,139
2015	79,042	18,776	329	221	5,831	104,198
2016	80,041	19,105	329	221	5,940	105,635
2017	81,179	19,439	329	221	6,055	107,222
2018	82,451	19,786	329	221	6,170	108,958
2019	83,869	20,144	329	221	6,293	110,857
2020	85,362	20,520	329	221	6,418	112,851
2021	86,868	20,902	329	221	6,542	114,862
2022	88,444	21,297	329	221	6,644	116,934
2023	90,088	21,688	329	221	6,746	119,072
2024	91,781	22,086	329	221	6,852	121,269
2025	93,501	22,498	329	221	6,959	123,508

[1] Regular Sales represents total electricity used by Duke Energy Carolinas Retail and Schedule 10A Resale classes and the city of Greenwood SC. Supplemental sales to NC EMCs and CEPCI 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 (Catawba, Schedule 10A and city of Greenwood) and wheeled by Duke Energy Carolinas.
[4] Company Use represents electricity used by Duke Energy Carolinas offices and facilities.
[5] Losses represent electricity line losses from generation sources to customer meters.
[6] Unbilled Sales represent the adjustment made to create calendar period sales from billing period sales.

Number of Rates Billed

Total Rates Billed

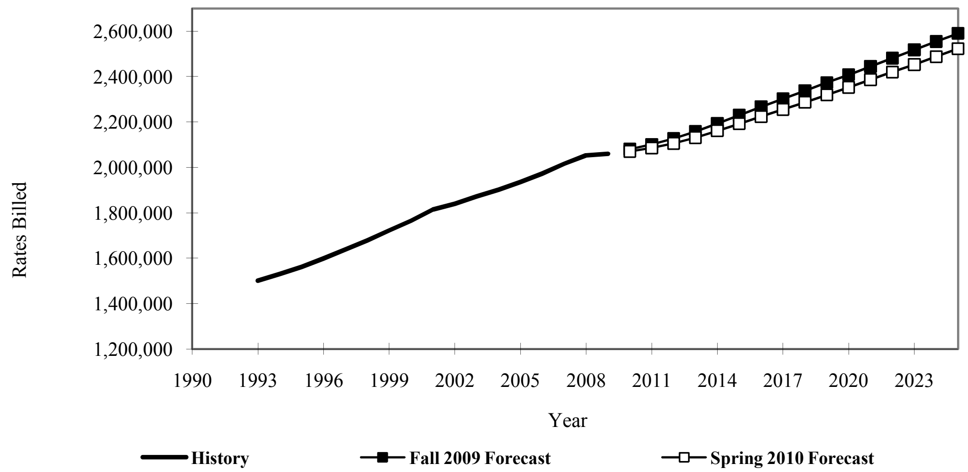
(Sum of Major Retail Classes: Residential, Commercial and Industrial)



HISTORY				AVERAGE ANNUAL GROWTH		
Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
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			
2004	2,221,590	34,766	1.6			
2005	2,261,639	40,049	1.8	History (2004 to 2009)	35,554	1.6
2006	2,304,050	42,411	1.9	History (1994 to 2009)	41,232	2.0
2007	2,354,078	50,028	2.2			
2008	2,393,426	39,348	1.7	Spring 2010 Forecast (2009 to 2025)	33,119	1.3
2009	2,399,359	5,933	0.2	Fall 2009 Forecast (2009 to 2025)	39,041	1.5

SPRING 2010 FORECAST				FALL 2009 FORECAST		
		Growth			Difference from Fall 2009	
Year	Rates Billed	Rates Billed	%	Rates Billed	Rates Billed	%
2010	2,411,449	12,091	0.5	2,424,713	-13,264	-0.5
2011	2,428,745	17,296	0.7	2,451,540	-22,795	-0.9
2012	2,452,181	23,437	1.0	2,483,224	-31,042	-1.3
2013	2,481,693	29,511	1.2	2,520,470	-38,778	-1.5
2014	2,516,311	34,618	1.4	2,561,233	-44,922	-1.8
2015	2,551,480	35,169	1.4	2,603,535	-52,055	-2.0
2016	2,587,657	36,177	1.4	2,645,629	-57,972	-2.2
2017	2,623,816	36,159	1.4	2,686,855	-63,038	-2.3
2018	2,659,839	36,023	1.4	2,728,805	-68,966	-2.5
2019	2,696,933	37,094	1.4	2,770,281	-73,348	-2.6
2020	2,735,139	38,207	1.4	2,811,318	-76,179	-2.7
2021	2,773,774	38,635	1.4	2,853,567	-79,793	-2.8
2022	2,811,451	37,677	1.4	2,896,175	-84,724	-2.9
2023	2,849,237	37,786	1.3	2,939,121	-89,885	-3.1
2024	2,888,871	39,634	1.4	2,981,697	-92,826	-3.1
2025	2,929,257	40,386	1.4	3,024,016	-94,759	-3.1

Residential Rates Billed



HISTORY

Year	Actual Rates Billed	Growth Rates Billed	%
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
2008	2,052,252	36,149	1.8
2009	2,059,394	7,142	0.3

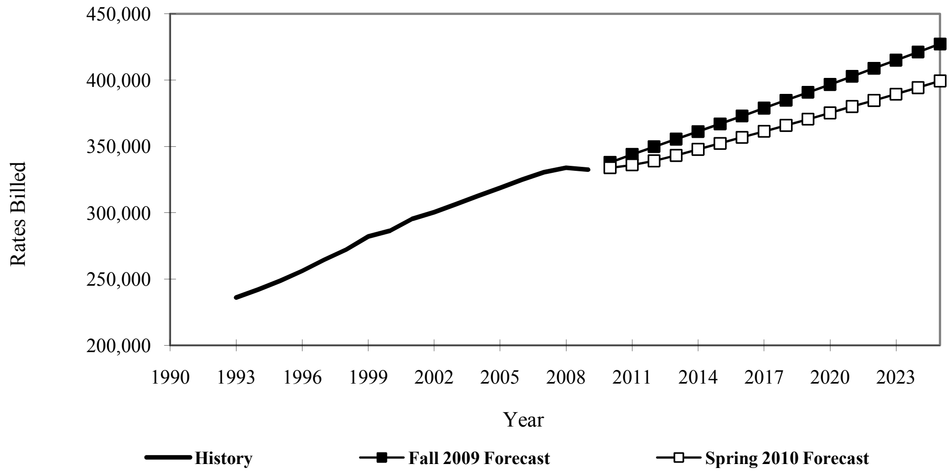
AVERAGE ANNUAL GROWTH

	Rates Billed Per Year	% Per Year
History (2004 to 2009)	31,612	1.6
History (1994 to 2009)	35,292	2.0
Spring 2010 Forecast (2009 to 2025)	28,966	1.3
Fall 2009 Forecast (2009 to 2025)	33,176	1.4

SPRING 2010 FORECAST / FALL 2009 FORECAST

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	Difference from Fall 2009 Rates Billed	%
2010	2,070,183	10,789	0.5	2,080,010	-9,827	-0.5
2011	2,085,384	15,201	0.7	2,100,802	-15,418	-0.7
2012	2,105,803	20,419	1.0	2,126,672	-20,868	-1.0
2013	2,131,238	25,434	1.2	2,158,355	-27,118	-1.3
2014	2,161,270	30,033	1.4	2,193,441	-32,171	-1.5
2015	2,191,961	30,691	1.4	2,229,979	-38,018	-1.7
2016	2,223,590	31,628	1.4	2,266,192	-42,602	-1.9
2017	2,255,247	31,658	1.4	2,301,510	-46,263	-2.0
2018	2,286,808	31,560	1.4	2,337,546	-50,738	-2.2
2019	2,319,292	32,484	1.4	2,373,086	-53,794	-2.3
2020	2,352,751	33,459	1.4	2,408,137	-55,386	-2.3
2021	2,386,605	33,854	1.4	2,444,313	-57,709	-2.4
2022	2,419,649	33,044	1.4	2,480,814	-61,166	-2.5
2023	2,452,772	33,124	1.4	2,517,633	-64,861	-2.6
2024	2,487,476	34,704	1.4	2,554,066	-66,589	-2.6
2025	2,522,854	35,378	1.4	2,590,209	-67,355	-2.6

Commercial Rates Billed



HISTORY

Year	Actual Rates Billed	Growth Rates Billed	%
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
2004	312,665	6,125	2.0
2005	318,827	6,162	2.0
2006	324,977	6,150	1.9
2007	330,666	5,689	1.8
2008	333,873	3,208	1.0
2009	332,593	-1,280	-0.4

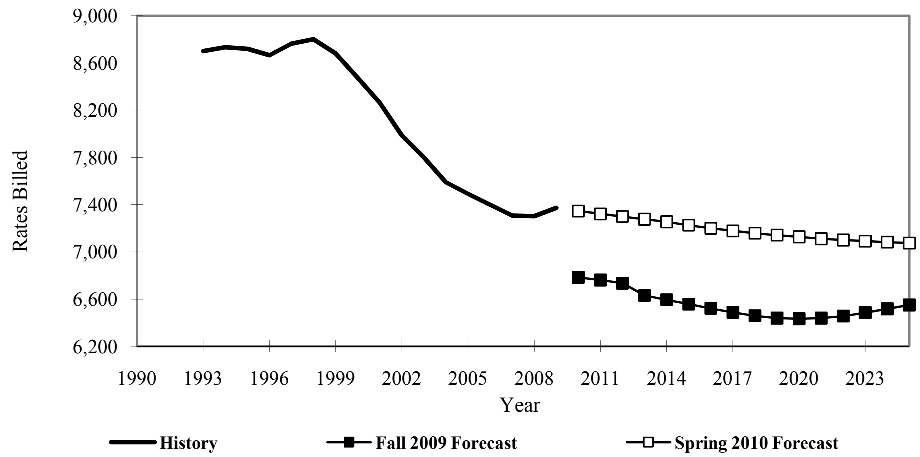
AVERAGE ANNUAL GROWTH

	Rates Billed Per Year	% Per Year
History (2004 to 2009)	3,986	1.2
History (1994 to 2009)	6,031	2.1
Spring 2010 Forecast (2009 to 2025)	4,171	1.1
Fall 2009 Forecast (2009 to 2025)	5,916	1.6

SPRING 2010 FORECAST / FALL 2009 FORECAST

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	Difference from Fall 2009 Rates Billed	%
2010	333,921	1,328	0.4	337,920	-3,999	-1.2
2011	336,039	2,118	0.6	343,977	-7,938	-2.3
2012	339,079	3,040	0.9	349,819	-10,740	-3.1
2013	343,178	4,099	1.2	355,484	-12,306	-3.5
2014	347,785	4,607	1.3	361,197	-13,411	-3.7
2015	352,292	4,507	1.3	366,998	-14,706	-4.0
2016	356,868	4,576	1.3	372,916	-16,048	-4.3
2017	361,391	4,524	1.3	378,856	-17,465	-4.6
2018	365,873	4,481	1.2	384,800	-18,927	-4.9
2019	370,499	4,626	1.3	390,755	-20,256	-5.2
2020	375,261	4,762	1.3	396,748	-21,486	-5.4
2021	380,058	4,797	1.3	402,814	-22,756	-5.6
2022	384,701	4,643	1.2	408,904	-24,203	-5.9
2023	389,373	4,671	1.2	415,002	-25,630	-6.2
2024	394,312	4,939	1.3	421,113	-26,801	-6.4
2025	399,327	5,015	1.3	427,255	-27,928	-6.5

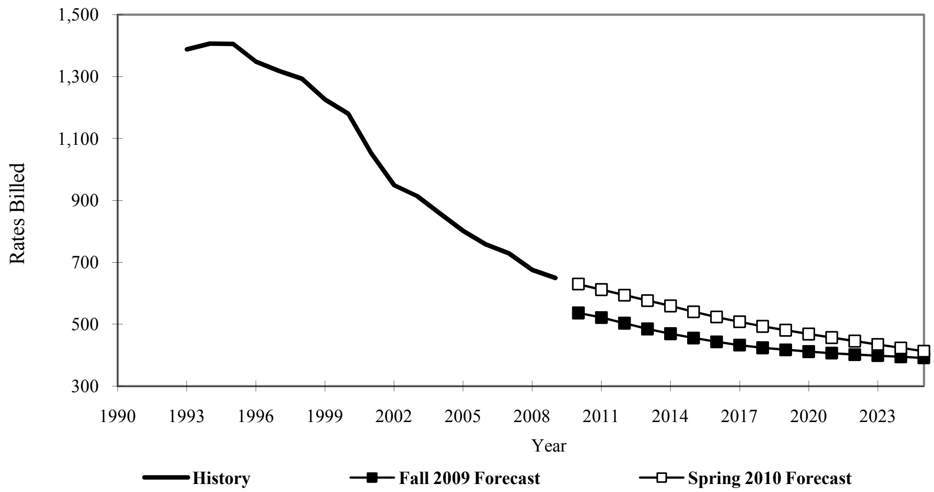
Total Industrial Rates Billed *(Includes Textile and Other Industrial)*



HISTORY				AVERAGE ANNUAL GROWTH		
Year	**Actual Rates Billed**	**Growth Rates Billed**	**%**		**Rates Billed Per Year**	**% Per Year**
2000	8,474	-207	-2.4			
2001	8,265	-210	-2.5			
2002	7,989	-276	-3.3			
2003	7,801	-188	-2.3			
2004	7,591	-210	-2.7			
2005	7,492	-99	-1.3	History (2004 to 2009)	-44	-0.6
2006	7,401	-91	-1.2	History (1994 to 2009)	-91	-1.1
2007	7,309	-92	-1.2			
2008	7,301	-8	-0.1	Spring 2010 Forecast (2009 to 2025)	-19	-0.3
2009	7,372	71	1.0	Fall 2009 Forecast (2009 to 2025)	-51	-0.7

SPRING 2010 FORECAST				FALL 2009 FORECAST		
		Growth			**Difference from Fall 2009**	
Year	**Rates Billed**	**Rates Billed**	**%**	**Rates Billed**	**Rates Billed**	**%**
2010	7,346	-26	-0.4	6,783	563	8.3
2011	7,322	-24	-0.3	6,761	560	8.3
2012	7,299	-23	-0.3	6,733	566	8.4
2013	7,277	-22	-0.3	6,631	646	9.7
2014	7,255	-22	-0.3	6,595	660	10.0
2015	7,226	-29	-0.4	6,557	669	10.2
2016	7,200	-27	-0.4	6,522	678	10.4
2017	7,178	-22	-0.3	6,488	690	10.6
2018	7,159	-19	-0.3	6,459	699	10.8
2019	7,142	-17	-0.2	6,440	702	10.9
2020	7,127	-15	-0.2	6,434	693	10.8
2021	7,112	-16	-0.2	6,440	672	10.4
2022	7,101	-11	-0.2	6,457	644	10.0
2023	7,091	-9	-0.1	6,486	606	9.3
2024	7,083	-9	-0.1	6,519	564	8.7
2025	7,075	-7	-0.1	6,551	524	8.0

Textile Rates Billed



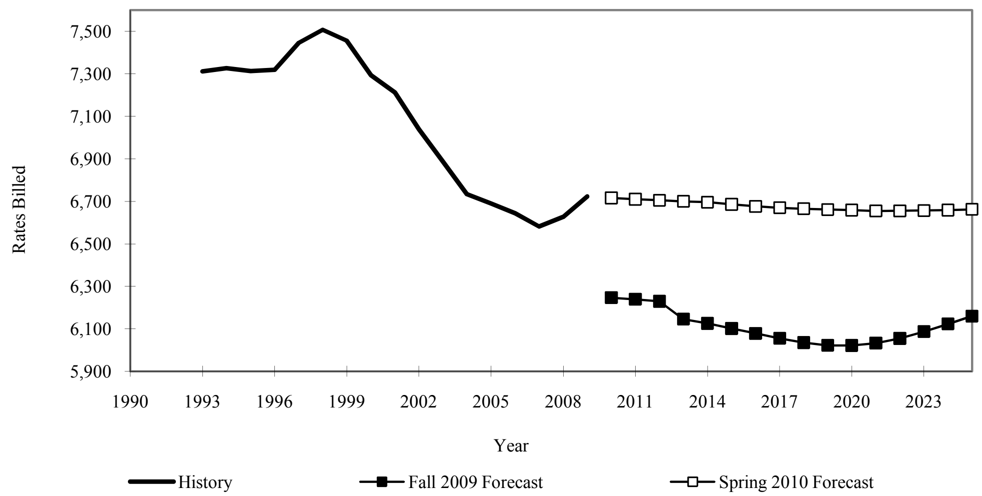
HISTORY / **AVERAGE ANNUAL GROWTH**

Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
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	History (2004 to 2009)	-42	-5.4
2006	757	-45	-5.6	History (1994 to 2009)	-51	-5.0
2007	728	-29	-3.8			
2008	675	-53	-7.3	Spring 2010 Forecast (2009 to 2025)	-15	-2.8
2009	649	-26	-3.9	Fall 2009 Forecast (2009 to 2025)	-16	-3.1

SPRING 2010 FORECAST / **FALL 2009 FORECAST**

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	Difference from Fall 2009 Rates Billed	%
2010	630	-19	-3.0	536	94	17.4
2011	612	-18	-2.9	522	90	17.2
2012	594	-18	-2.9	503	90	18.0
2013	576	-17	-2.9	485	92	18.9
2014	559	-17	-3.0	469	90	19.1
2015	540	-19	-3.4	455	85	18.6
2016	523	-17	-3.1	443	80	18.1
2017	508	-15	-3.0	432	75	17.5
2018	493	-15	-2.9	424	70	16.4
2019	480	-13	-2.6	417	63	15.2
2020	468	-12	-2.5	412	57	13.8
2021	457	-12	-2.5	407	50	12.3
2022	445	-11	-2.5	402	44	10.9
2023	434	-11	-2.5	398	36	9.1
2024	424	-11	-2.5	395	29	7.2
2025	413	-11	-2.5	391	22	5.6

Other Industrial Rates Billed



HISTORY				**AVERAGE ANNUAL GROWTH**		
Year	**Actual Rates Billed**	**Growth Rates Billed**	**%**		**Rates Billed Per Year**	**% Per Year**
2000	7,293	-162	-2.2			
2001	7,213	-81	-1.1			
2002	7,040	-173	-2.4			
2003	6,887	-153	-2.2			
2004	6,733	-154	-2.2			
2005	6,690	-43	-0.6	History (2004 to 2009)	-2	0.0
2006	6,644	-47	-0.7	History (1994 to 2009)	-40	-0.6
2007	6,581	-63	-0.9			
2008	6,626	45	0.7	Spring 2010 Forecast (2009 to 2025)	-4	-0.1
2009	6,723	97	1.5	Fall 2009 Forecast (2009 to 2025)	-35	-0.5

SPRING 2010 FORECAST				**FALL 2009 FORECAST**		
		Growth			**Difference from Fall 2009**	
Year	**Rates Billed**	**Rates Billed**	**%**	**Rates Billed**	**Rates Billed**	**%**
2010	6,716	-7	-0.1	6,247	469	7.5
2011	6,710	-6	-0.1	6,240	470	7.5
2012	6,705	-5	-0.1	6,230	475	7.6
2013	6,700	-5	-0.1	6,146	554	9.0
2014	6,696	-4	-0.1	6,126	570	9.3
2015	6,686	-10	-0.1	6,102	584	9.6
2016	6,676	-10	-0.1	6,079	598	9.8
2017	6,670	-6	-0.1	6,056	614	10.1
2018	6,665	-5	-0.1	6,036	630	10.4
2019	6,662	-4	-0.1	6,023	639	10.6
2020	6,659	-3	0.0	6,022	637	10.6
2021	6,655	-4	-0.1	6,033	622	10.3
2022	6,655	1	0.0	6,055	600	9.9
2023	6,657	2	0.0	6,088	569	9.4
2024	6,659	2	0.0	6,124	536	8.7
2025	6,663	3	0.1	6,160	503	8.2

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.

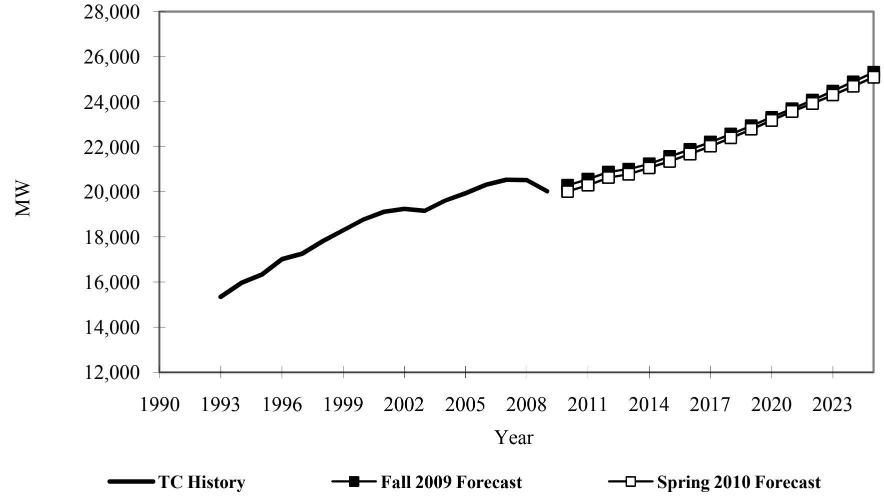
Adjustments were made to the peak forecasts for the Fall 2009 Forecasts and the Spring 2010 Forecasts to account for the expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007. **These peak forecasts do not include adjustments for proposed energy efficiency programs.** Additional adjustments to the Spring 2010 Forecast include peak reductions associated with price increases due to a Carbon Tax starting in 2015 and peak additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011.

The last Summer peak occurred on Monday, August 10, 2009 at 4 p.m. An actual peak of 19,637 MW was achieved at a time when the temperature was 96 degrees (for the Spring 2010 Forecast the expected temperature at the time of summer peak is 94.7 degrees).

Growth Forecasts

The new forecast projects an incremental growth of 317 MW or 1.4% per year for 2009-2025. The previous forecast growth was 330 MW or 1.5% per year for 2009-2025.

System Summer MW



HISTORY / **AVERAGE ANNUAL GROWTH**

Year	Weather Normalized MW	Growth MW	Growth %		MW Per Year	% Per Year
2000	18,780	488	2.7			
2001	19,111	331	1.8			
2002	19,238	127	0.7			
2003	19,159	-79	-0.4			
2004	19,614	455	2.4			
2005	19,936	322	1.6	History (2004 to 2009)	82	0.4
2006	20,314	378	1.9	History (1994 to 2009)	271	1.5
2007	20,535	221	1.1			
2008	20,522	-13	-0.1	Spring 2010 Forecast (2009 to 2025)	317	1.4
2009	20,023	-499	-2.4	Fall 2009 Forecast (2009 to 2025)	330	1.5

SPRING 2010 FORECAST / **FALL 2009 FORECAST**

Year	MW	Growth MW	Growth %	MW	Difference from Fall 2009 MW	Difference from Fall 2009 %
2010	20,015	-8	0.0	20,294	-279	-1.4
2011	20,292	277	1.4	20,563	-271	-1.3
2012	20,633	341	1.7	20,879	-246	-1.2
2013	20,786	153	0.7	21,006	-220	-1.0
2014	21,062	277	1.3	21,246	-183	-0.9
2015	21,351	289	1.4	21,563	-212	-1.0
2016	21,680	329	1.5	21,882	-202	-0.9
2017	22,027	347	1.6	22,211	-184	-0.8
2018	22,393	367	1.7	22,564	-171	-0.8
2019	22,776	383	1.7	22,931	-155	-0.7
2020	23,169	393	1.7	23,304	-135	-0.6
2021	23,566	397	1.7	23,685	-119	-0.5
2022	23,923	357	1.5	24,070	-147	-0.6
2023	24,295	372	1.6	24,470	-175	-0.7
2024	24,684	389	1.6	24,883	-198	-0.8
2025	25,087	403	1.6	25,297	-210	-0.8

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.

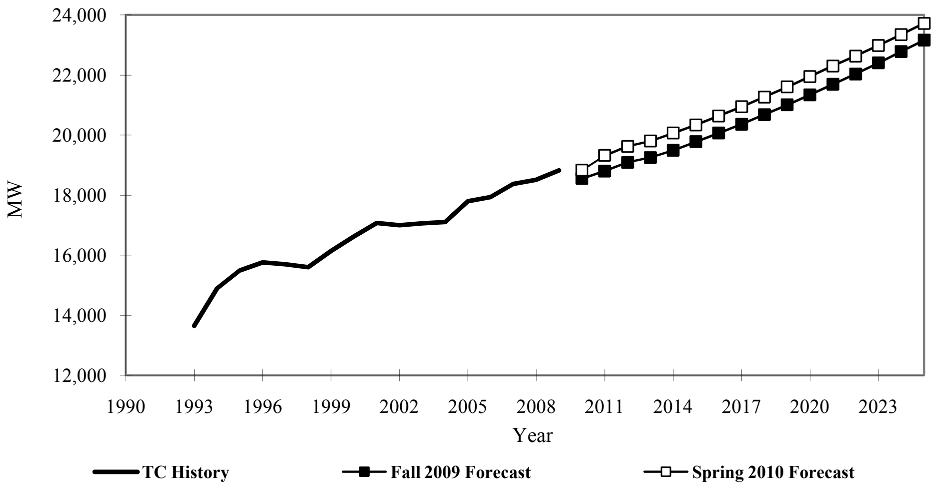
Adjustments were made to the peak forecasts for the Fall 2009 Forecasts and the Spring 2010 Forecasts to account for the expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007. **These peak forecasts do not include adjustments for proposed energy efficiency programs.** Additional adjustments to the Spring 2010 Forecast include peak reductions associated with price increases due to a Carbon Tax starting in 2015 and peak additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011.

The last Winter peak occurred on Monday, January 11, 2010 at 8 a.m. with an actual peak of 19,388 MW. This was achieved at a time when the temperature was 18 degrees (for the Spring 2010 Forecast the expected temperature at the time of winter peak is 18.0 degrees).

Growth Forecasts

The new Forecast projects an incremental growth of 306 MW or 1.5% per year from 2009-2025. The previous forecast growth was 271 MW or 1.3% per year from 2009-2025.

System Winter MW

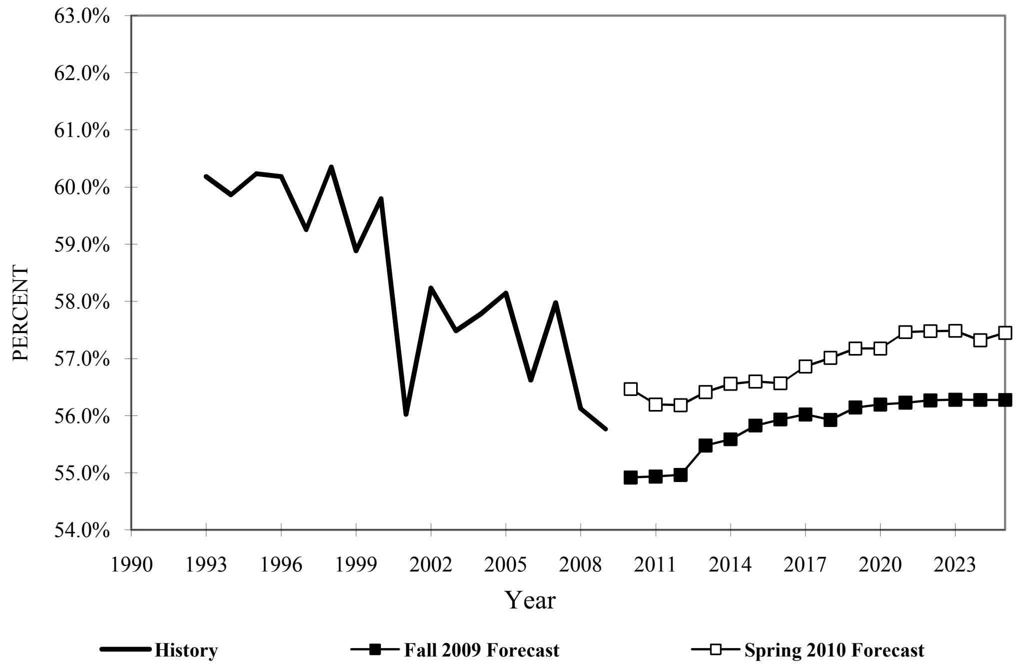


HISTORY				AVERAGE ANNUAL GROWTH		
Year	Weather Normalized MW	Growth MW	Growth %		MW Per Year	% Per Year
2000	16,631	481	3.0			
2001	17,078	447	2.7			
2002	17,000	-78	-0.5			
2003	17,062	62	0.4			
2004	17,102	40	0.2			
2005	17,806	703	4.1	History (2004 to 2009)	345	1.9
2006	17,943	137	0.8	History (1994 to 2009)	262	1.6
2007	18,376	433	2.4			
2008	18,519	143	0.8	Spring 2010 Forecast (2009 to 2025)	306	1.5
2009	18,828	309	1.7	Fall 2009 Forecast (2009 to 2025)	271	1.3

SPRING 2010 FORECAST				FALL 2009 FORECAST		
Year	MW	Growth MW	Growth %	MW	Difference from Fall 2009 MW	Difference from Fall 2009 %
2010	18,833	5	0.0	18,554	279	1.5
2011	19,324	491	2.6	18,808	515	2.7
2012	19,627	303	1.6	19,092	534	2.8
2013	19,806	179	0.9	19,257	549	2.9
2014	20,069	264	1.3	19,496	573	2.9
2015	20,342	272	1.4	19,782	560	2.8
2016	20,639	297	1.5	20,070	569	2.8
2017	20,947	308	1.5	20,365	581	2.9
2018	21,270	323	1.5	20,681	589	2.8
2019	21,606	336	1.6	21,010	596	2.8
2020	21,952	346	1.6	21,346	607	2.8
2021	22,305	353	1.6	21,689	616	2.8
2022	22,637	332	1.5	22,041	597	2.7
2023	22,985	348	1.5	22,406	578	2.6
2024	23,347	363	1.6	22,784	563	2.5
2025	23,724	376	1.6	23,165	559	2.4

Load Factor

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: 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 renewable resource providers, the Electric Power Research Institute (EPRI) Technology Assessment Guide (TAG®), and studies performed by and/or information gathered from entities such as the DOE, General Electric (GE), 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 estimated 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 this is very difficult to maintain. 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 previous IRP filings, where it outlined that in developing the 2006 IRP a list of eighty-eight supply-side resources was compiled of potential alternatives for the IRP process, the 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 screening analyses, the largest sizes of each technology were the lowest cost due to economies of scale, and the estimated cost differences caused by the other variations were generally minor. As in previous IRP analyses, the elimination of some of these variations allowed more time to concentrate on ensuring consistency of treatment across the technologies.

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

Conventional Technologies (technologies in common use):

Base Load Technologies
800 MW class Supercritical Coal (Greenfield)
2 - 1117 MW Nuclear units, AP1000 (priced as a set of 2 units on a common site)

Peak / Intermediate Technologies
4 - 204 MW CTs – GE 7FA .05 (priced as a set of 4 units on a common site)
480 MW Unfired + 45 MW Inlet Evaporative Cooler CC – 7FA.05
480MW Unfired + 125 MW Duct Fired + 45 MW Inlet Evaporative Cooler CC – 7FA.05

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

Base Load Technologies
630 MW class IGCC (Brownfield)

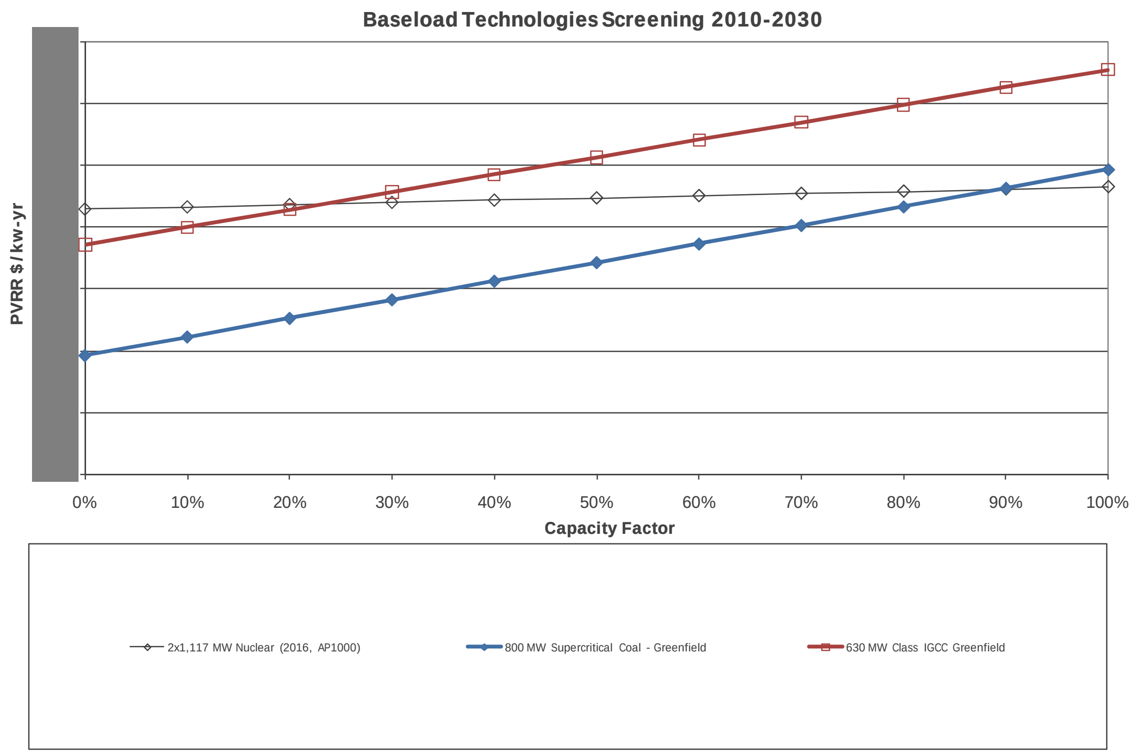
Renewable Technologies
On-Shore Wind 100 MW
Solar PV 80 MW
Biomass Firing
    Woody Biomass Firing 75 MW
    Hog Digester Biogas Firing 15 MW
    Poultry Waste Firing 15MW
Landfill Gas 15MW

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 renewable 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 CAA Amendments of 1990, the recently overturned CAIR, and the 2002 NC CSA along with consideration of multiple CO2 scenarios and a RPS (at the time of the this analysis, the EPA's recently released draft of the Clean Air Transport Rule (CATR) was still being evaluated). The impact of two CO2 scenarios is also shown for comparison purposes in the composite bus bar chart. These scenarios are discussed in more detail in Appendix A.

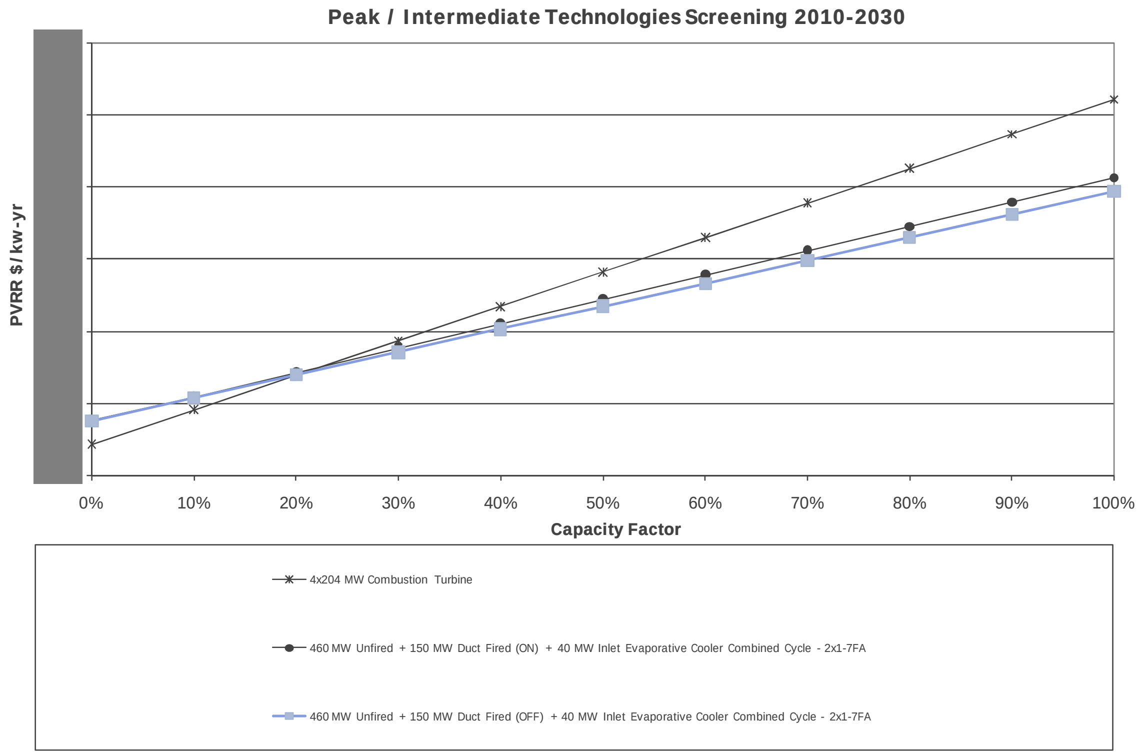
The following sets of estimated Levelized Busbar Cost[8] charts provide an economic comparison of the technologies in their respective categories. Busbar charts comparisons involving some renewable resources, particularly wind and solar resources, can be somewhat misleading because these resources do not contribute their full installed capacity at the time of the system peak[9]. 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. 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).

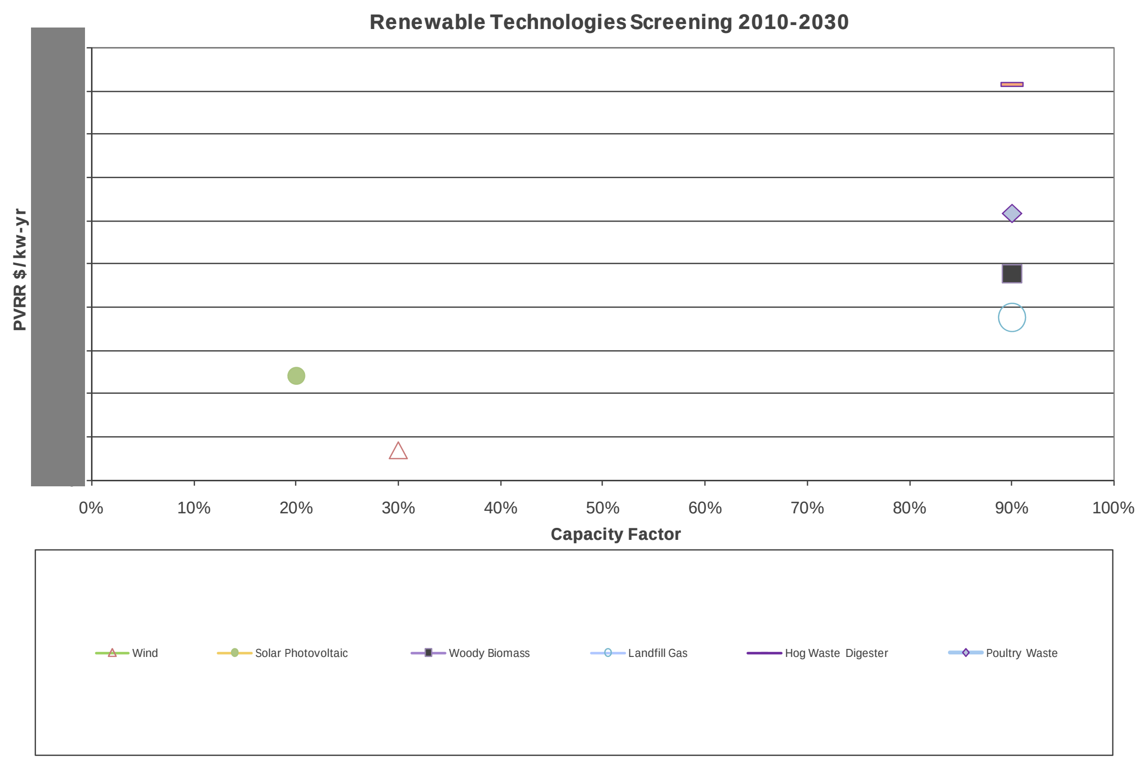
Busbar Charts by Technology Category – Base 2010 Fundamentals Carbon Scenario



[8] 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.

[9] 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 50% of installed capacity at the time of peak.





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.

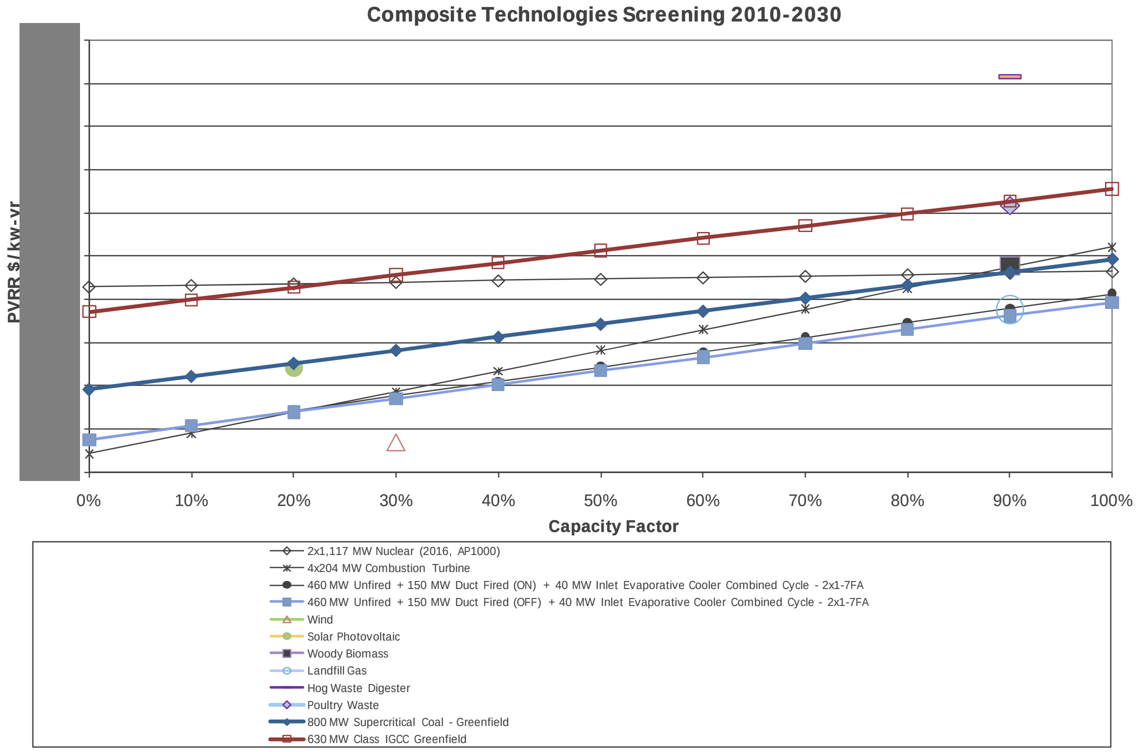
CC generation was included in the peaking intermediate screening curves for comparison purposes. However, based on the screen results, CC generation would be cost effective as a base load technology.

The following technologies were selected for the quantitative analysis:

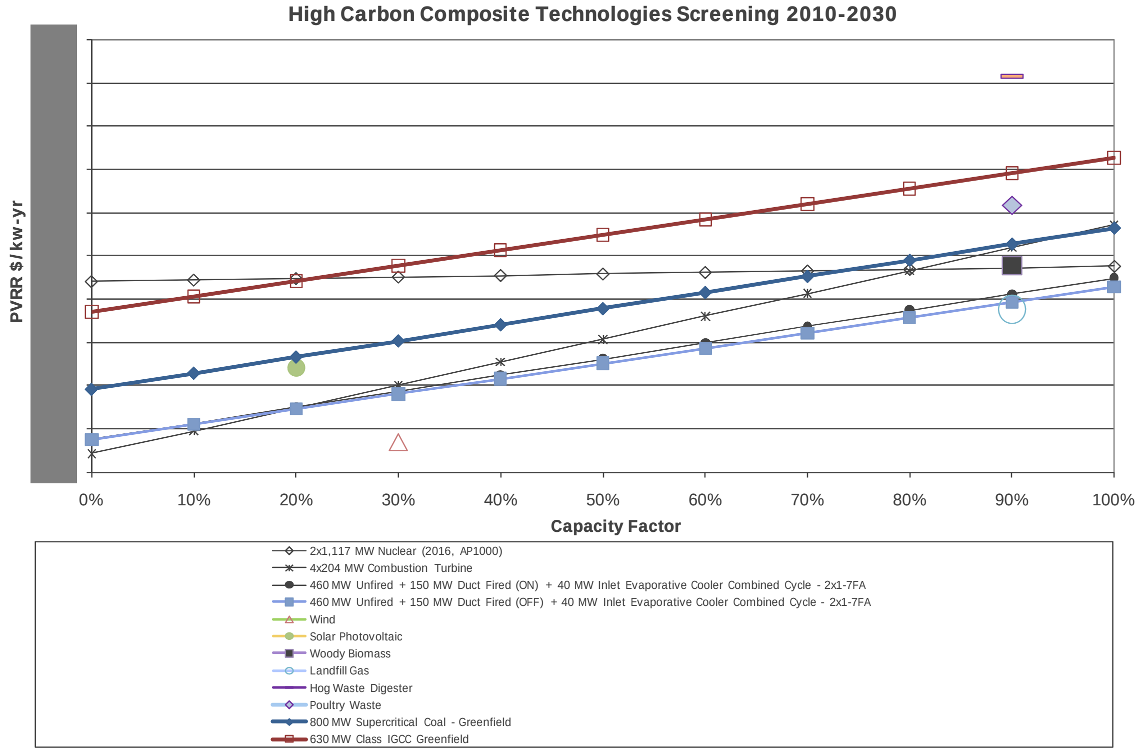
- Base Load – 800MW Supercritical Pulverized Coal
- Base Load – 630 MW IGCC
- Base Load – 2x1,117MW Nuclear units (AP1000)
- Peaking/Intermediate – 4x204MW CTs (7FA.05)
- Base Load/Intermediate/Peaking –480 MW Unfired + 125MW Duct Fired + 45MW Inlet Evaporative Cooler N. Gas CC
- Base Load/Intermediate/Peaking –480 MW Unfired+45MW Inlet Evaporative Cooler CC
- Renewable – 75 MW Woody Biomass Firing
- Renewable – 100 MW Wind - On-Shore
- Renewable – 15 MW Landfill Gas
- Renewable – 80 MW Solar PV
- Renewable – 15 MW Poultry Waste Firing
- Renewable – 15 MW Hog Waste Digester

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

Composite Busbar Chart – Base/2010 Fundamentals Carbon Scenario



Composite Busbar Chart - Higher Carbon Scenario (Based on 2009 fundamentals)



Review of the Composite Busbar charts highlights the benefits to nuclear and combined cycle generation compared to other baseload/intermediate technologies as CO2 prices increase.

It should be noted that the specific technologies screened and ultimately included in the quantitative analyses are general place-holders meant to be representative of a particular technology type. Exact cost and performance of any technology ultimately selected for implementation will depend on many variables not explicitly addressed in this general IRP type analyses. These variables may include, but may not be limited to the following: technology vendor/supplier selected; specific machine, number of machines, and/or individual machines sizes and models selected and/or available; specific site parameters, including extent of existing infrastructure; site specific permitting requirements; economic market conditions at the time of contract(s) negotiations and/or contract(s) award; etc.

Appendix D: Demand Side Management Activation History

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
9/09 – 6/10	Air Conditioners	Cycling Event	44 MW	Verifying	6/14/2010
		Cycling Event	50 MW	Verifying	6/15/2010
		Cycling Event	95 MW	Verifying	6/23/2010
	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	6/8/2010
	PowerShare Voluntary	Economic Event			6/15/2010
		Economic Event			6/23/2010
	Water Heaters				
9/08 -9/09	Air Conditioners	Cycling Event		30 MW	8/10/2009
		SOC Full Shed Test	N/A	N/A	8/11/2009
	Water Heaters				
	Standby Generators				
	Interruptible Service	Communication Test	N/A	N/A	5/6/2009
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

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
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
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

Time Frame	**Program**	**Times Activated**	**Reduction Expected**	**Reduction Achieved**	**Activation Date**
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
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

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
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: 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 12 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 F: 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 – 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 J 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

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 MVA
- Estimated date for starting construction: 10/1/2010
- Estimated in-service date: 6/1/2011

APPENDIX G: 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 H: 2010 FERC Form 715

The 2010 FERC Form 715 filed April 2010 is confidential and filed under seal.

APPENDIX I: 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)					
Supplier	**City**	**State**	**Nameplate KW**	**Primary Fuel Type**	**Part of Total Supply Resources** [1]
203 Neotrantor LLC	Hendersonville	NC	9	Photovoltaic	Yes
Advantage Investment Group, LLC	Spencer Mountain	NC	640	Hydroelectric	Yes
AKS Real Estate Holdings, LLC	Chapel Hill	NC	3	Photovoltaic	Yes
Alamance Hydro, LLC	Glen Raven	NC	240	Hydroelectric	Yes
Amelia M. Collins	Chapel Hill	NC	4	Photovoltaic	Yes
Andrews Truss Inc.	Andrews	NC	10	Photovoltaic	Yes
Anna L. Reilly	Winston-Salem	NC	4	Photovoltaic	Yes
Barbara Ann Evans	Caroleen	NC	324	Hydroelectric	Yes
Berjouhi Keshguerian	High Point	NC	4	Photovoltaic	Yes
Bernd Schneitler	Pilot Mountain	NC	10	Photovoltaic	Yes
Biomerieux, Inc.	Durham	NC	124	Photovoltaic	Yes
Black Hawk, Inc.	Hendersonville	NC	9	Photovoltaic	Yes
Bruce Marotta	Durham	NC	4	Photovoltaic	Yes
Byron Matthews	Chapel Hill	NC	3	Photovoltaic	Yes
Catawba County - Blackburn Landfill	Newton	NC	4,000	Landfill Gas	Yes
Chapel Hill Tire Company	Carrboro	NC	16	Photovoltaic	Yes
Cliffside Mills, LLC	Cliffside	NC	1,600	Hydroelectric	Yes
David A. Ringenburg	Chapel Hill	NC	8	Photovoltaic	Yes
David Birkhead	Hillsborough	NC	2	Photovoltaic	Yes
David Boyer	Sandy Ridge	NC	4	Photovoltaic	Yes
David E. Shi	Brevard	NC	3	Photovoltaic	Yes
David H. Newman	Greensboro	NC	6	Photovoltaic	Yes
David M. Thomas	Lenoir	NC	6	Photovoltaic	Yes
David W. Walters	Sylva	NC	5	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

Supplier	City	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources
Diann M. Barbacci	Kernersville	NC	2	Photovoltaic	Yes
Dirk J. Spruyt	Chapel Hill	NC	4	Photovoltaic	Yes
Dr. James David Branch	Winston-Salem	NC	11	Photovoltaic	Yes
Edward W. Witkin	Chapel Hill	NC	6	Photovoltaic	Yes
Ernest E. McConnell	Raleigh	NC	3	Photovoltaic	Yes
Everett Williams	Robbinsville	NC	4	Micro-hydro	Yes
Fogleman Construction, Inc.	Graham	NC	3	Photovoltaic	Yes
Frances L. Thompson	Hickory	NC	5	Photovoltaic	Yes
Gail D. Schmidt	Tryon	NC	3	Photovoltaic	Yes
Gas Recovery Systems, LLC	Concord	NC	5,000	Landfill Gas	Yes
George F. Fralick	Edneyville	NC	3	Photovoltaic	Yes
Gerald W. Meisner & Harol M. Hoffman	Greensboro	NC	4	Photovoltaic	Yes
Gerry Priebe	Bryson City	NC	7	Photovoltaic	Yes
Gwenyth T. Reid	Hillsborough	NC	4	Photovoltaic	Yes
H. Malcolm Hardy	Chapel Hill	NC	3	Photovoltaic	Yes
Haneline Power, LLC	Millersville	NC	365	Hydroelectric	Yes
Hardins Resources Company	Hardens	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
Henry J. Becker	Chapel Hill	NC	7	Photovoltaic	Yes
Holzworth Holdings, Inc.	Durham	NC	3	Photovoltaic	Yes
Innovative Solar Solutions	Charlotte	NC	4	Photovoltaic	Yes
Irvine River Company	Eden	NC	500	Hydroelectric	Yes
Jafasa Farms - Residence	Horseshoe	NC	6	Photovoltaic	Yes
Jafasa Farms - Greenhouse	Horseshoe	NC	6	Photovoltaic	Yes
James B. Sherman	Chapel Hill	NC	5	Photovoltaic	Yes
James J. Boyle	Durham	NC	4	Photovoltaic	Yes
James Lee Johnson	Matthews	NC	2	Photovoltaic	Yes

Supplier	City	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources [1]
James Richard Trevathan	Highlands	NC	3	Photovoltaic	Yes
Jeffery L. Pardue	Wilkesboro	NC	4	Photovoltaic	Yes
Jerome Levit	Graham	NC	2	Photovoltaic	Yes
Jim and Linda Alexander	Chapel Hill	NC	4	Photovoltaic	Yes
Joel L. Hager	Salisbury	NC	4	Photovoltaic	Yes
John B. Robbins	Concord	NC	10	Photovoltaic	Yes
John H. DiLiberti	Hillsborough	NC	10	Photovoltaic	Yes
Keith Adam Smith	Nebo	NC	2	Photovoltaic	Yes
KMBA, LLC	Charlotte	NC	9	Photovoltaic	Yes
Laura J. Ballance	Durham	NC	7	Photovoltaic	Yes
Leon's Beauty School, Inc.	Greensboro	NC	35	Photovoltaic	Yes
Marilyn M. Norfolk	Chapel Hill	NC	5	Photovoltaic	Yes
Mark A. Powers	Chapel Hill	NC	2	Photovoltaic	Yes
Mark S. Trustin Attorney At Law	Durham	NC	3	Photovoltaic	Yes
Mary Karen Nicholson	Mebane	NC	2	Photovoltaic	Yes
Matthew T. Ewers	Charlotte	NC	3	Photovoltaic	Yes
Mayo Hydropower, LLC	Mayodan	NC	951	Hydroelectric	Yes
Mayo Hydropower, LLC	Mayodan	NC	1,275	Hydroelectric	Yes
Megawatt Solar, Inc.	Hillsborough	NC	5	Photovoltaic	Yes
Michael G. Hitchcock	Yadkinville	NC	8	Photovoltaic	Yes
Mill Shoals Hydro Company, Inc.	High Shoals	NC	1,800	Hydroelectric	Yes
MP Durham, LLC	Durham	NC	3,180	Landfill Gas	Yes
Northbrook Carolina Hydro, L.L.C. - Turner Shoals	Mill Spring	NC	5,500	Hydroelectric	Yes
Oakdale Holding, LLC	Hillsborough	NC	18	Photovoltaic	Yes
Oenophilia	Hillsborough	NC	18	Photovoltaic	Yes
Optima Engineering	Charlotte	NC	8	Photovoltaic	Yes
Pacifica Master Homeowners' Association	Carrboro	NC	5	Photovoltaic	Yes
Paul C. Kuo	Chapel Hill	NC	3	Photovoltaic	Yes
Paul G. Keller DBA Futility	Chapel Hill	NC	4	Photovoltaic	Yes

Supplier	City	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources [1]
Peter J. Jarosak	Greensboro	NC	3	Photovoltaic	Yes
Philip E. Miner	Ellenboro	NC	5	Photovoltaic	Yes
Phillip B. Caldwell	Brevard	NC	3	Photovoltaic	Yes
Pickens Mill Hydro, LLC	Charlotte	NC	600	Hydroelectric	Yes
Pippin Home Designs	Sherrills Ford	NC	4	Photovoltaic	Yes
R. Lawrence Ashe, Jr.	Glenville	NC	4	Photovoltaic	Yes
Rajah Y. Chacko	Charlotte	NC	3	Photovoltaic	Yes
Rajendra Morey	Durham	NC	7	Photovoltaic	Yes
Ramona L. Sherwood	Charlotte	NC	4	Photovoltaic	Yes
RayLen Vineyards, Inc.	Mocksville	NC	10	Photovoltaic	Yes
Rebecca G. Laskody	Chapel Hill	NC	3	Photovoltaic	Yes
Rebecca T. Cobey	Chapel Hill	NC	2	Photovoltaic	Yes
Ron B. Rozzelle	Graham	NC	6	Photovoltaic	Yes
Ronald R. Butters	Durham	NC	5	Photovoltaic	Yes
Russell Von Stein	Brevard	NC	3	Photovoltaic	Yes
Salem Energy Systems, L.L.C.	Winston-Salem	NC	4,750	Landfill Gas	Yes
Samuel B. Moore	Elon	NC	2	Photovoltaic	Yes
Samuel C. Province	Vale	NC	10	Photovoltaic	Yes
SanDan Farm	McLeansville	NC	24	Photovoltaic	Yes
Scot Friedman	Greensboro	NC	5	Photovoltaic	Yes
Shawn L. Slome	Chapel Hill	NC	2	Photovoltaic	Yes
Sheldon R. Pinnell	Durham	NC		Photovoltaic	Yes
South Yadkin Power, Inc.	Greensboro	NC	1,500	Hydroelectric	Yes
Stanley D. Chamberlain	Chapel Hill	NC	9	Photovoltaic	Yes
Stephen C. Graf	Cedar Grove	NC	5	Photovoltaic	Yes
Steve Mason Enterprises Inc	Gastonia	NC	750	Hydroelectric	Yes
Stewart Bible	Durham	NC	2	Photovoltaic	Yes
Strates Inc. DBA Westtown Eatery & Express	Winston-Salem	NC	6	Photovoltaic	Yes
Sun Capital, Inc	Summerfield	NC	21	Photovoltaic	Yes

Supplier	City	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources [1]
SunE DEC1, LLC	Lexington	NC	15,500	Photovoltaic	Yes
Susan Bishop McCracken	Franklin	NC	6	Photovoltaic	Yes
T.S. Designs	Burlington	NC	9	Photovoltaic	Yes
The Rocket Shop, LLC	Durham	NC	2	Photovoltaic	Yes
Theresa S. Greene	Burlington	NC	2	Photovoltaic	Yes
Thomas Christopher	Concord	NC	4	Photovoltaic	Yes
Thomas Knox Worde	Bryson City	NC	3	Photovoltaic	Yes
Timberlyne Legion, LLC	Chapel Hill	NC	9	Photovoltaic	Yes
Timberlyne Professional Center, LLC	Chapel Hill	NC	9	Photovoltaic	Yes
Toben Properties, LLC	Chapel Hill	NC	5	Photovoltaic	Yes
Town of Chapel Hill	Chapel Hill	NC	4	Photovoltaic	Yes
Town of Lake Lure	Lake Lure	NC	3,600	Hydroelectric	Yes
W. B. Moore Company of Charlotte	Charlotte	NC	27	Photovoltaic	Yes
W. Jefferson Holt DBA Holt Family Farm Power	Chapel Hill	NC	9	Photovoltaic	Yes
Wallace and Graham, PA	Salisbury	NC	150	Photovoltaic	Yes
Walter C. McGervey	Statesville	NC	1	Photovoltaic	Yes
White Oak of Saluda, LLC	Saluda	NC	5	Photovoltaic	Yes
William Terry Baker	Carrboro	NC	4	Photovoltaic	Yes
Yves Naar	Brevard	NC	4	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, L.P.	Gaffney	SC	100,000	Natural Gas	Yes
Clark H. Mizell	Gray Court	SC	6	Photovoltaic	Yes
Converse Energy Incorporated	Converse	SC	1,250	Hydroelectric	Yes
Greenville Gas Producers, LLC	Enoree	SC	3,200	Landfill Gas	Yes
Inman Mills	Enoree	SC	1,600	Hydroelectric	Yes
Jody Fine	Ware Shoals	SC	2	Photovoltaic	Yes
Lamar Bailes	Walhalla	SC	5	Photovoltaic	Yes
Lawrence B. Miller	Anderson	SC	3	Photovoltaic	Yes
Northbrook Carolina Hydro, L.L.C. - Boyd's Mill	Ware Shoals	SC	1,500	Hydroelectric	Yes

Supplier	City	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources [1]
Northbrook Carolina Hydro, L.L.C. - Hollidays Bridge	Belton	SC	3,500	Hydroelectric	Yes
Northbrook Carolina Hydro, L.L.C. - Saluda	Greenville	SC	2,400	Hydroelectric	Yes
Pelzer Hydro Company, Inc.	Pelzer	SC	2,020	Hydroelectric	Yes
Pelzer Hydro Company, Inc.	Pelzer	SC	3,300	Hydroelectric	Yes
Thomas W. Bates	Simpsonville	SC	5	Photovoltaic	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	459,000	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				
City	**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	400	Unknown	Yes
Charlotte	NC	1,750	Unknown	Yes
Charlotte	NC	1200	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	1600	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

City	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources[1]
Durham	NC	6,400	Unknown	Yes
Durham	NC	1,825	Unknown	Yes
Eden	NC	1,700	Unknown	Yes
Elkin	NC	400	Unknown	Yes
Elkin	NC	500	Unknown	Yes
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
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	265	Unknown	Yes
Mt. Holly	NC	210	Unknown	Yes

City	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources[1]
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
Research Triangle	NC	1,000	Unknown	Yes
Research Triangle	NC	350	Unknown	Yes
Research Triangle	NC	750	Unknown	Yes
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-Salem	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

City	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources[1]
Greer	SC	2,750	Unknown	Yes
Inman	SC	165	Unknown	Yes
Kershaw	SC	165	Unknown	Yes
Kershaw	SC	1,500	Unknown	Yes
Lancaster	SC	1,000	Unknown	Yes
Lancaster	SC	1,500	Unknown	Yes
Lancaster	SC	300	Unknown	Yes
Lyman	SC	1,000	Unknown	Yes
Mt. Holly	SC	265	Unknown	Yes
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]**
Alamance	NC	30	Photovoltaic	No
Alamance	NC	2	Photovoltaic	No
Alamance	NC	3	Photovoltaic	No
Alamance	NC	2	Photovoltaic	No
Alamance	NC	2	Photovoltaic	No
Alamance	NC	3	Photovoltaic	No
Alamance	NC	3	Photovoltaic	No
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
Cleveland	NC	1	Wind Turbine	No
Cherokee	NC	8	Photovoltaic	No
Davidson	NC	4	Photovoltaic	No
Durham	NC	2	Photovoltaic	No
Durham	NC	30	Photovoltaic	No
Durham	NC	2	Photovoltaic	No
Durham	NC	2	Photovoltaic	No
Durham	NC	75	Photovoltaic	No
Durham	NC	30	Photovoltaic	No
Durham	NC	1	Photovoltaic	No
Durham	NC	3	Photovoltaic	No
Durham	NC	3	Photovoltaic	No
Durham	NC	3	Photovoltaic	No
Durham	NC	4	Photovoltaic	No
Durham	NC	1	Photovoltaic	No
Durham	NC	2	Photovoltaic	No
Durham	NC	3	Photovoltaic	No
Durham	NC	52	Photovoltaic	No
Durham	NC	53	Photovoltaic	No
Forsyth	NC	3	Photovoltaic	No
Forsyth	NC	8,400	Coal, Wood Cogen	No
Forsyth	NC	3	Photovoltaic	No
Forsyth	NC	4	Photovoltaic	No
Forsyth	NC	15	Photovoltaic	No
Forsyth	NC	3	Photovoltaic	No
Forsyth	NC	3	Photovoltaic	No
Forsyth	NC	4	Photovoltaic	No
Gaston	NC	1,056	Hydroelectric	No
Guilford	NC	3	Photovoltaic	No
Guilford	NC	3	Photovoltaic	No

County	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources[1]
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
Guilford	NC	1	Photovoltaic	No
Guilford	NC	3	Photovoltaic	No
Henderson	NC	1	Wind Turbine	No
Henderson	NC	4	Photovoltaic	No
Iredell	NC	1,050	Diesel	No
Iredell	NC	8	Photovoltaic	No
Jackson	NC	4	Photovoltaic	No
Macon	NC	3	Photovoltaic	No
McDowell	NC	1	Photovoltaic	No
McDowell	NC	1	Photovoltaic	No
Mecklenburg	NC	4	Photovoltaic	No
Mecklenburg	NC	31	Photovoltaic	No
Mecklenburg	NC	1	Photovoltaic	No
Mecklenburg	NC	4	Photovoltaic	No
Mecklenburg	NC	12	Photovoltaic	No
Mecklenburg	NC	3	Photovoltaic	No
Mecklenburg	NC	2	Photovoltaic	No
Mecklenburg	NC	5	Photovoltaic	No
Orange	NC	1	Photovoltaic	No
Orange	NC	3	Photovoltaic	No
Orange	NC	4	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
Polk	NC	2	Photovoltaic	No
Randolph	NC	2	Photovoltaic	No
Randolph	NC	2	Photovoltaic	No
Rockingham	NC	5,480	Coal Cogen	No
Rockingham	NC	2	Photovoltaic	No
Rockingham	NC	3	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

County	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources[1]
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
Union	NC	7	Photovoltaic	No
Wilkes	NC	2	Photovoltaic	No
Wilkes	NC	3	Photovoltaic	No
Yadkin	NC	7	Photovoltaic	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	10,000	Natural Gas, Landfill Gas	No
Greenville	SC	2	Photovoltaic	No
Greenville	SC	4,550	Diesel Cogen	No
Greenville	SC	2	Photovoltaic	No
Greenville	SC	2	Photovoltaic	No
Greenville	SC	3	Photovoltaic	No
Greenville	SC	30	Photovoltaic	No
Greenville	SC	100	Photovoltaic	No
Greenville	SC	5	Photovoltaic	No
Greenville	SC	2	Photovoltaic	No
Greenville	SC	1	Photovoltaic	No
Greenville	SC	5	Photovoltaic	No
Greenville	SC	4	Photovoltaic	No
Greenville	SC	4	Photovoltaic	No
Greenville	SC	2	Photovoltaic	No
Greenville	SC	250	Unknown	No
Greenville	SC	6	Photovoltaic	No
Greenville	SC	370	Digester Gas	No
Greenville	SC	2	Photovoltaic	No
Laurens	SC	2,150	Diesel	No
Laurens	SC	6	Photovoltaic	No
Laurens	SC	4,000	Diesel	No
Oconee	SC	700	Hydroelectric	No
Oconee	SC	9,175	Diesel	No
Oconee	SC	10	Photovoltaic	No

County	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources[1]
Oconee	SC	2,865	Diesel	No
Pickens	SC	11	Photovoltaic	No
Pickens	SC	6,400	Diesel	No
Pickens	SC	1	Photovoltaic	No
Pickens	SC	4	Photovoltaic	No
Pickens	SC	16	Photovoltaic	No
Pickens	SC	2,865	Diesel	No
Spartanburg	SC	3	Photovoltaic	No
Spartanburg	SC	4	Photovoltaic	No
Spartanburg	SC	5	Photovoltaic	No
Spartanburg	SC	4	Photovoltaic	No
Spartanburg	SC	1,000	Hydroelectric	No
Spartanburg	SC	4	Photovoltaic	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
York	SC	42,500	Coal, Wood Cogen	No
York	SC	3	Photovoltaic	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
Forsyth	NC	2,400	Diesel	No
Granville	NC	1,750	Diesel	No
Guilford	NC	150	Diesel	No
Guilford	NC	150	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
Anderson	SC	300	Diesel	No
Greenville	SC	500	Diesel	No
Greenville	SC	1,000	Diesel	No

APPENDIX J: FERC FORM 1 PAGES

Following are Duke Energy Carolinas' 2009 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 2009/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 Station	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 Station	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	8,246.43		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 2009/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)			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)	
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	99,565,715	119,921,617					13
	20,355,902	99,565,715	119,921,617					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
	154,448,544	1,166,172,306	1,320,620,850	867,665	11,321,274		12,188,939	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 2009/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 (Roxboro)	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 Station	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	8,246.43		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 2009/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954								1
795								2
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
	154,448,544	1,166,172,306	1,320,620,850	867,665	11,321,274		12,188,939	36

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 2009/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	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 Tie	Marble Tie	161.00	161.00	Tower	16.85		2
18	Nantahala Hydro	Santeetlah Plt Robbinsville	161.00	161.00	Tower	18.88		2
19	Tuckaseegee Tie	West Mill Tie	161.00	161.00	Tower & Pole	10.42		2
20	Tuckasegee Tie	Thorpe Hydro	161.00	161.00	Tower & Pole	3.25		1
21	Wesbter Tie	Lake Emory S. S.	161.00	161.00	Tower	11.93		1
22	West Mill Tie	Lake Emory S. S.	161.00	161.00	Tower	6.78		1
23	West Mill Tie	Nantahala Tie	161.00	161.00	Tower	13.08		1
24								
25	TOTAL 161 KV LINES					93.85		11
26								
27	Dan River Steam	Appalachian Power	138.00	138.00	Tower & Pole	6.53		1
28	115 KV Lines		115.00	115.00	Tower & Pole	43.37		1
29	100 KV Lines		100.00	100.00	Tower	2,897.53		
30	100 KV Lines		100.00	100.00	Pole	624.24		
31			100.00	100.00	Underground	1.40		
32								
33	TOTAL 100 - 138 KV LINES					3,573.07		2
34								
35	66 KV Lines		66.00	66.00	Pole	117.24		1
36					TOTAL	8,246.43		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 2009/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								
2	TOTAL 66 KV LINES					117.24		1
3								
4	44 KV Lines		44.00	44.00	Tower	183.05		
5	44 KV Lines		44.00	44.00	Pole	2,181.68		
6	44 KV Lines		44.00	44.00	Underground	0.34		1
7								
8	TOTAL 44 KV LINES					2,365.07		1
9								
10	33 KV Lines		33.00	33.00	Pole	14.65		
11	24 KV Lines		24.00	24.00	Pole	84.64		
12	24 KV Lines		24.00	24.00	Underground	0.44		1
13	12 KV Lines		12.00	12.00	Tower & Pole	25.67		
14	12 KV Lines		12.00	12.00	Underground	0.22		1
15								
16	TOTAL 13-33 KV LINES					125.62		2
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	8,246.43		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 2009/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)			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
795								4
795								5
954								6
2515								7
954								8
1272								9
954								10
954								11
954								12
	39,794,904	217,770,449	257,565,353					13
	39,794,904	217,770,449	257,565,353					14
								15
795								16
795								17
636								18
795								19
397.5								20
636								21
795								22
795								23
	2,387,306	73,827,008	76,214,314					24
	2,387,306	73,827,008	76,214,314					25
								26
477								27
								28
								29
								30
								31
	64,348,200	524,612,413	588,960,613					32
	64,348,200	524,612,413	588,960,613					33
								34
								35
	154,448,544	1,166,172,306	1,320,620,850	867,665	11,321,274		12,188,939	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 2009/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)			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)	
	4,460,895	20,991,343	25,452,238					1
	4,460,895	20,991,343	25,452,238					2
								3
								4
								5
								6
	22,521,643	225,110,537	247,632,180					7
	22,521,643	225,110,537	247,632,180					8
								9
								10
								11
								12
								13
								14
	579,694	4,294,841	4,874,535	867,665	11,321,274		12,188,939	15
	579,694	4,294,841	4,874,535	867,665	11,321,274		12,188,939	16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	154,448,544	1,166,172,306	1,320,620,850	867,665	11,321,274		12,188,939	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 2009/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	Overhead : New Line						
2	Leafcrest Retail Tap		0.21	Pole	5.00	1	
3	Pioneer Avenue Retail Tap		0.05	Pole	80.00	1	
4	Goodwill Church Rd Ret Tap		4.49	Pole	9.00	1	
5	Galenor Design LLC Tap		0.49		14.00	2	
6	Newton City Delivery #3 Tap		0.10	Pole	30.00	1	
7	Energy United Del 44 Tap		0.17		12.00	1	
8	White Plains Retail Tap		0.75	Pole	11.00	1	
9	Bell Town Retail Tap		1.54	Pole	9.00	1	
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23	Overhead : Major Rebuild						
24	Concord Main	Philip Morris Tap	0.48		44.00	2	
25	Little Rock Tap	Little Rock Retail	0.81	Pole	22.00	2	
26	Energy United Delivery 6 Tap	Conely Tap	4.83		8.00	2	
27	Sun Edison Tap	Buck Tie	5.94		3.00	1	
28	Buzzard Roost Tap	Bush River Tie	4.74		9.00	2	
29	Reedy River Tie	Scuffletown Retail Tap	5.18		11.00	2	
30	Nantahala Hydro	Santeetlah Hydro	18.88		4.00	1	
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		48.66		271.00	21	

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 2009/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 KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
556.5	ACSR		100		22,255	13,641		35,896	2
336.4	ACSR		100		122,117	74,845		196,962	3
556.5	ACSR		100	1,135,493	1,560,595	956,494		3,652,582	4
556.5	ACSR		100		350,888	72,699		423,587	5
556.5	ACSR		100		164,091	100,572		264,663	6
954.0	ACSR		100	5,579	225,674	138,316		369,569	7
556.5	ACSR		100	258,546	639,313	391,836		1,289,695	8
556.5	ACSR		100	368,115	564,903	346,231		1,279,249	9
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
477.0	ACSR		100		1,720,410	1,054,444		2,774,854	24
556.5	ACSR		100	44,097	1,245,222	763,201		2,052,520	25
1272.0	ACSR		100		1,747,086	1,070,795		2,817,881	26
336.4	ACSR		100		1,191,984	730,571		1,922,555	27
556.5	ACSR		100		1,317,305	807,380		2,124,685	28
954.0	ACSR		100	1,402,004	1,799,493	1,102,915		4,304,412	29
795.0	ACSR		161		13,933,839	8,540,095		22,473,934	30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
					3,213,834	26,605,175	16,164,035		45,983,044	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	/ /	2009/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.: 29 Column: h

Number of Circuits - 1 & 2

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: 422.3 Line No.: 4 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.: 10 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.: 13 Column: h

Number of Circuits - 1 & 2

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 2009/Q4

FOOTNOTE DATA

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: 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: l
All or portion of cost is in account 106, cost is prorated where necessary
Schedule Page: 424 Line No.: 4 Column: m
All or portion of cost is in account 106, cost is prorated where necessary
Schedule Page: 424 Line No.: 4 Column: n
All or portion of cost is in account 106, cost is prorated where necessary
Schedule Page: 424 Line No.: 5 Column: d
Towers & Poles used in the new line
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: d
Towers & Poles used in the new line
Schedule Page: 424 Line No.: 7 Column: l
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: l
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.: 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: 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

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Duke Energy Carolinas, LLC	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2009/Q4

FOOTNOTE DATA

Schedule Page: 424 Line No.: 26 Column: m
All or portion fo 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
Towers & Poles used in the new line

Schedule Page: 424 Line No.: 27 Column: m
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

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

Schedule Page: 424 Line No.: 28 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 28 Column: n
All or portion of cost in in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 29 Column: d
Towers & Poles used in the new line

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

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

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

Schedule Page: 424 Line No.: 30 Column: d
Towers & Poles used in the new line

Schedule Page: 424 Line No.: 30 Column: m
All or portion of cost is in account 106, cost is prorated where necessary

Schedule Page: 424 Line No.: 30 Column: n
All or portion of cost is in account 106, cost is prorated where necessary

APPENDIX K: 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 July, 2010 is:

Rider EC:

79 MW for North Carolina
3 MW for South Carolina

Rider ER:

No customers currently enrolled.

APPENDIX L: WHOLESALE PROJECTIONS FROM EXISTING AND POTENTIAL CUSTOMERS

Table L1 below provides the historical and projected growth in peak loads for the Company's wholesale customers. The wholesale customer growth rates vary and none are the same as the historical growth rate in Duke load. With respect to wholesale sales contracts, econometric forecasting models are developed for each wholesale customer in a process similar to that used for retail to produce MWH sales forecasts. Where contracts are in place, the wholesale forecasts are incorporated into the final forecasts based on dates of service specified in the contracts. Duke Energy Carolinas historical growth rates is 0.4% per year from 2004 to 2009 as referenced in the Duke Energy Carolinas Spring 2010 Forecast located in Appendix B (pg 25). Therefore, just as historical wholesale load growth rates have been different than Duke's load growth, so too, will the projected growth rates for current wholesale customers be different. Load growth rates can be influenced by changes and/or differences in population, employment, industrial output, customer growth, and customer mix. Each of the wholesale customers is different in composition than Duke Energy Carolinas' retail load in all of these areas so that different growth rates are to be expected.

It is important to note that the growth rates for Central and NCEMC Supplemental Requirements) are primarily driven by terms of the contract. The Central Sale provides for a seven year "step-in" to Central's full load requirement such that the Company will provide 15% of Central's total member cooperative load in Duke's Balancing Authority Area requirement in 2013. This initial load requirement will be followed by subsequent 15% annual increases in load over the following six years up to a total of 100%. The NCEMC Supplemental Requirements sale is essentially a fixed quantity of capacity and energy specified by the contract. The contract also provides NCEMC with an option to increase the amount of capacity by 25 MWs for specific years of the contract. Therefore, the growth rates for those wholesale customers do not reflect their underlying economic conditions and as a result are not useful data.

The wholesale load shown in Table L1 is gross loads whereas the wholesale sales contracts shown in Table 2.5 net out resources provided by the buyer.

TABLE L1

	Duke Carolinas Historical and Projected Wholesale Load
	[redacted]
History	
1999	
2000	
2001	
2002	
2003	
2004	
2005	
2006	
2007	
2008	
2009	
Forecast	
2010	
2011	
2012	
2013	
2014	
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	
2024	
2025	
2026	
2027	
2028	
2029	
2030	
Growth Rate	
Growth Rate	

The potential customers below were identified as undesignated wholesale load in the analysis. Each of the potential customers identified in Table L2 below have a reasonable expectation to be signed in 2010, however until a greater probability can be assigned to that expectation, it would be premature to classify these potential obligations as firm commitments of the company. For this reason they are included in the undesignated load classification.

Table L2

Undesignated Wholesale MW Projections																				
Gross Load (MW)																				
Deal Name	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
[redacted]																				

APPENDIX M: 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 IRP.

Requirement	Location	Reference	Updated
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 II Sect III Sect III, IV, & App C	NC R8-60 h (i) 1(i) NC R8-60 h(i) 1(ii) NC R8-60 h(i) 1(iii)	Yes Yes Yes
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, IV App I Sect VI, App E Sect III N/A	NC R8-60 h (i) 2(i)(a-f) NC R8-60 h (i) 2(ii)(a-d) NC R8-60 h (i) 2(iii)	Yes Yes Yes Yes Yes
Reserve Margin	Sect III	NC R8-60 h (i) 3	Yes
Wholesale Contract for the Purchase and Sale of Power • Wholesale Purchase Power Contract • Request for Proposal • Wholesale power sales contracts • Wholesale projections (existing and undesignated)	Sect II Sect II Sect II App L	NC R8-60 h (i) 4(i) NC R8-60 h (i) 4(ii) NC R8-60 h (i) 4(iii) NCUC 09 IRP req (6)	Yes Yes Yes Yes
Transmission Facilities , planned & under construction Transmissions System Adequacy FERC Form 1 (pages 422-425) FERC Form 715	App F & G Sect II App J App H	NC R8-60 h (i) 5	Yes Yes Yes Yes
Energy Efficiency and Demand Side Management • Existing Programs • Future Programs • Rejected Programs • Consumer Education Programs • DSM projected reliance	Sect II, App D Sect III, IV Sect IV Sect II, IV App A	NC R8-60 h (i) 6(i) NC R8-60 h (i) 6(ii) NC R8-60 h (i) 6(iii) NC R8-60 h (i) 6(iv) NCUC 09 IRP req (7)	Yes Yes Yes Yes Yes
Assessment of Alternative Supply-Side Energy Resource • Current and Future Alternative Supply-Side • Rejected Alternative Supply-Side Energy Resource	App C App C	NC R8-60 h (i) 7(i) NC R8-60 h (i) 7(ii)	Yes Yes
Evaluation of Resource Options (Quantitative Analysis)	App A	NC R8-60 h (i) 8	Yes
Cost benefit analysis of each option Levelized Bus-bar Costs	App C	NC R8-60 h (i) 9	Yes
Other Information (economic development)	App K		Yes
Legislative and Regulatory Issues	Sect II		Yes
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	Sect I, VI, & App A		Yes
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	Sect VI, App A		Yes