CHAPTER 8

NEED FOR POWER

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NEED FOR POWER

8.0 INTRODUCTION

This chapter of the Environmental Report provides a discussion of the need for the baseload power that is expected to be generated by the proposed Lee Nuclear Station. As currently planned, the first unit of the proposed generation facility is expected to be operational between 2016 and 2018; the second unit is nominally planned to begin operation two years after the first unit. Such scheduling ensures that an adequate planning window exists between 2016 and 2018 in order to accommodate changes due to uncertainties in the Federal and State regulatory processes, construction schedule, availability of critical components, and market forces. Duke Energy is the owner, operator, and licensee of the Lee Nuclear Station.

Duke Energy is a regulated investor-owned utility in North Carolina and South Carolina with a designated franchise service area. As such, Duke Energy operates under statutes and utility commission rules and regulations in both States. Duke Energy has an obligation to provide reliable, economical electric service to its customers in North Carolina and South Carolina. Duke Energy plans and operates its North Carolina and South Carolina operations as a single system. Generating assets are dispatched to serve the needs of customers in both states regardless of the physical location of the asset.

As discussed below, Duke Energy is required to file an annual report in both States on Duke Energy's long-range plans for meeting the capacity and energy needs of its customers.

8.0.1 PLANNING PROCESS

In North Carolina, General Statutes 62-2 and 62-110.1 establish the policy of the State "to require energy planning … in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable…" and that "the (North Carolina Utilities Commission) shall ….keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including the probable future growth of the use of electricity, the probable needed generation reserves, the extent, size, mix, and general location of generating plants…." (Reference 1).

In North Carolina, that filing is an Annual Report filed in accordance with the North Carolina Utilities Commission (NCUC) Regulation R8-60[a] (Reference 2).

In South Carolina, the Code of Laws Section 58-37-40 (Reference 3) requires the filing of integrated resource plans, defined as:

a. On July 11, 2007, the NCUC issued an order revising Rule R8-60 to require the filing of Integrated Resource Plans in lieu of the Annual Report beginning in 2008. The revised rules require additional reporting on purchased power, demand-side management, wholesale sales of power, and alternative supply-side energy resources.

> "Integrated resource plan means a plan which contains the demand and energy forecast for at least a fifteen-year period, contains the supplier's or producer's program for meeting the requirements shown in its forecast in an economic and reliable manner, including both demand-side and supply-side options, with a brief description and summary cost-benefit analysis, if available, of each option which was considered, including those not selected, sets forth the supplier's or producer's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy service, and describes the external environmental and economic consequences of the plan to the extent practicable. For electrical utilities subject to the jurisdiction of the South Carolina Public Service Commission, this definition must be interpreted in a manner consistent with the integrated resource planning process adopted by the commission."

In South Carolina, the filing is made pursuant to Public Service Commission of South Carolina (PSCSC) Orders 91-1002, 93-845, and 98-502 (References 4, 5, and 6).

To satisfy both States' filing requirements, a single plan (the Integrated Resource Plan, or IRP) is filed with both States each year. Duke Energy filed the 2006 IRP (Reference 7) in North Carolina and South Carolina on September 1, 2006, and filed an updated plan on October 31, 2006, in NCUC Docket No. E-100, Sub 109, and PSCSC Docket No. 87-223-E. Duke Energy filed the 2007 IRP (Reference 8) in November 2007, in NCUC Docket No. E-100, Sub 114, and PSCSC Docket No. 87-223-E.

The IRP includes discussion of the:

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

NUREG-1555 states, "State or regional agencies may require the applicant to document a need for power or plan for future plant construction. The applicant may choose to rely on those documents rather than prepare a description of the power system of its own." The basic requirement for the reports to be acceptable under NUREG-1555 is that the reports be (1) systematic, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty. Since much of the need for power demonstration has evolved from the IRP process, an evaluation of the process, considering these four criteria, is presented in the following paragraphs.

The following discussion demonstrates that these filings are subject to review by each State's utility commissions, other regulatory authorities, and intervenors in both States. The 2006 IRP was approved by the NCUC on July 9, 2007. The 2006 and 2007 IRPs indicate the need for the

type of baseload power that this facility would provide, as well as demonstrate the economic and other considerations that make the proposed facility the best option to serve the projected electric power need. In addition, by virtue of the fact that the proposed facility is being constructed in South Carolina, that State also requires that Duke Energy obtain a Certificate of Environmental Compatibility and Public Convenience and Necessity for the facility (Reference 9). This filing, required before the construction of the proposed facility, requires that extensive data and information be filed by Duke Energy with the regulatory authorities sufficient to prove the need for the type and amount of generated power the facility is to produce as well as an economic and environmental justification for the proposed facility. The Order, issued by the PSCSC, is based on evidence provided by Duke Energy and intervenors, the SC Office of Regulatory Staff (charged with representing the public interest), and public input through the PSCSC hearing process.

As described below, the IRP process meets the NUREG-1555 criteria, and as such, will be extensively relied upon to develop the need for power in this chapter. In addition, where appropriate, the information provided from these documents will be augmented by data and modeling details not specified in these reports as well as supported by data from other independent sources.

8.0.2 THE IRP PROCESS IS SYSTEMATIC

Duke Energy must comply with an IRP process in both North Carolina and South Carolina. Consider first the IRP process in North Carolina. As defined by the NCUC (Reference 10), “the IRP Process is an overall planning strategy that examines conservation, load management, and other demand-side measures in addition to the use of utility-owned generating plants, non-utility generation, and other supply-side resources in order to determine the least cost way of providing electric service. The primary purpose of integrated resource planning is to integrate both demand-side and supply-side resource planning into one comprehensive procedure that weighs the cost and benefits of all reasonably available options in order to identify those options which are most cost-effective for the ratepayers consistent with the obligation to provide adequate, reliable service.”

In North Carolina, the rules governing this annual report (Reference 2) allow the NCUC Public Staff and any other intervenors to file a “report of its own as to any utility or may file an evaluation of or comments on the reports filed by the utilities, or both” and a hearing on the issues raised by the Public Staff, or any intervenor, may be scheduled by the NCUC for an evidentiary hearing. The NCUC is also required to conduct one or more public hearings in its analysis of the utilities’ long-range plans (Reference 1).

In South Carolina, the IRP must be submitted every three years and updated annually, and is subject to review by the PSCSC, its staff, and the state’s Office of Regulatory Staff (Reference 3). In addition to this IRP requirement in South Carolina, as provided by that State’s Code of Laws (Reference 3) and PSCSC Rules (Reference 11), Duke Energy must also obtain a Certificate of Environmental Compatibility and Public Convenience and Necessity prior to beginning construction of the Lee Nuclear Facility.

For additional information regarding the comprehensive nature of the IRP process and the related filings by Duke Energy, refer to Subsections 8.4.2 and 8.4.3 which describe the overall process in detail.

For an IRP, a systematic process can be characterized by four basic attributes listed below:

1. That the filing be required and subject to a specified filing process, including such conditions as timing and the review process;

2. That the filing be subject to laws, procedures, or agency rules requiring and specifying the documentation and data required, and that such documentation and data be sufficient and complete;

3. That the filing be subject to proper review and comment by both regulators or other industry experts; and,

4. That the filing be developed using approved and reviewed modeling tools.

As discussed above:

1. Both North Carolina and South Carolina have a process requiring utilities to develop and file an IRP each year;

2. For each State the process and content of the filing is outlined in the commission regulations (see Subsection 8.0.3 below);

3. For each State the process is subject to review by any party including the Office of Regulatory Staff (representing the public interest); and

4. The modeling tools used are subject to approval by each State utility commission.

On this basis, *the IRP process required of Duke Energy in both North Carolina and South Carolina can be defined as a systematic process*.

8.0.3 THE IRP PROCESS IS COMPREHENSIVE

As discussed above, Duke Energy must comply with a very specific IRP process in both North Carolina and South Carolina. In North Carolina, the NCUC has adopted Commission Rule R8-60 (Reference 2) which requires an annual report, also referred to as the IRP filing, to be filed containing details with respect to Duke Energy's resource plan over a ten-year planning horizon. The information in this plan includes:

1. A tabulation of summer and winter peak loads, annual energy forecast, generating capability, and reserve margins for each year, and a description of the methods and assumptions used by the utility to prepare its forecast;

2. A list of existing plants in service with capacity, plant type, and location;

3. A list of generating units under construction or planned at plant locations for which property has been acquired, for which certificates have been received, or for which applications have been filed with location, capacity, plant type, and proposed date of operation included;

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

5. A list of units to be retired from service with location, capacity and expected date of retirement from the system;

6. A list of units for which there are specific plans for life extension, refurbishment or upgrading. The reporting utility shall also provide the expected (or actual) date removed from service, general location, capacity rating upon return to service, expected return to service date, and a general description of work to be performed;

7. A list of transmission lines and other associated facilities (161 kV or over) which are under construction or for which there are specific plans including the capacity and voltage levels, location, and schedules for completion and operation;

8. 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;

9. A list of demand-side options reflected in the resource plan;

10. A list of wholesale purchase power commitments reflected in the resource plan; and,

11. A list of wholesale power sales commitments reflected in the resource plan.

Similarly, in South Carolina, Duke Energy must file an IRP as directed by the Code of Laws (Reference 3) in that State which requires that the filing:

1. Contain demand and energy forecast for at least a fifteen-year period,

2. Contain the supplier's or producer's program for meeting the requirements shown in its forecast in an economic and reliable manner,

3. Include both demand-side and supply-side options,

4. Include a brief description and summary cost-benefit analysis of each option considered, including those not selected,

5. Set forth the supplier's or producer's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy service,

6. Describe the external environmental and economic consequences of the plan to the extent practicable, and

7. Be presented in a manner consistent with the integrated resource planning process adopted by the PSCSC.

The 2007 IRP submitted to both North Carolina and South Carolina considered 88 supply-side options, several hundred demand-side options, and considered multiple sensitivities (or risk analysis, discussed in more detail below) around the various possible resource scenarios. For additional information regarding the comprehensive nature of the IRP process and the related filings by Duke Energy, refer to Subsections 8.4.2 and 8.4.3 which describe the overall modeling, planning and screening process in detail.

Based on this review of the filing requirements and how Duke Energy develops its IRP, *the IRP process required of Duke Energy in both North Carolina and South Carolina can be defined as comprehensive.*

8.0.4 THE IRP PROCESS IS SUBJECT TO CONFIRMATION

As noted above, in North Carolina, the statutes and rules governing the development of the IRP allow the NCUC Public Staff (the NCUC Public Staff is charged with representing the interests of the North Carolina electric consumers), and any other intervenors, to comment on the IRP or file an alternative plan. In addition, a public hearing is required and the Commission may convene an evidentiary hearing on the IRP. In the IRP hearing, evidence or comments may be presented by Duke Energy, the Public Staff, intervenors, and the public at large. The NCUC will issue an order based on the evidence presented by the parties to the proceeding.

For example, in the 2005 IRP proceeding in North Carolina, in addition to the Public Staff and electric utilities, there were interventions by seven other parties. There were also three public hearings (in Raleigh, Greenville and Asheville North Carolina) where 76 members of the public at large testified before the Commission. The issues presented at the evidentiary hearings in this case included:

- The validity of the utility's load forecasting methods,
- Whether the companies are employing and developing adequate demand-side management (DSM) and displacing the need for additional generating assets,
- The potential opportunities for cost-effective energy efficiency and conservation measures,
- The degree to which utility programs can effectively reduce consumption, including information on the amount of customer education needed, and financial incentives employed by the companies to encourage customer energy efficiency measures, and what funding mechanisms could be employed to implement specific energy efficiency measures.

In South Carolina, Duke Energy is required to submit the IRP each year. The PSCSC may choose to hold a public hearing on the submittal or simply docket the submittal.

After the various public and evidentiary hearings, the NCUC approved Duke Energy's 2005 IRP (Reference 12). Duke Energy's 2006 IRP was approved by the NCUC without an evidentiary hearing (Reference 13). The 2007 IRP was filed with the commissions in both North Carolina and South Carolina in November 2007 and review is pending in both States. The filing is now available for review by any interested party (The 2007 IRP can be found on the NCUC website,

www.ncuc.commerce.state.nc.us, in Docket No. E-100, Sub 114 or the PSCSC website, www.psc.sc.gov, in Docket No. 87-223-E.) .

As evidenced by the IRP review process and procedures in both States, and as demonstrated most recently in North Carolina, the IRP process is subject to confirmation.

8.0.5 THE IRP PROCESS IS RESPONSIVE TO FORECASTING UNCERTAINTY

Subsection 8.2.1 discusses how the model incorporates uncertainty. Consistent with the responsibility to meet customer energy needs in a reliable, economical manner, Duke Energy's resource planning approach includes both quantitative analysis and qualitative considerations. A quantitative analysis can provide insights on future risks and uncertainties associated with fuel prices, load growth rates, capital and operating costs and other variables. Qualitative perspectives such as the importance of fuel diversity, Duke Energy's environmental profile, the stage of technology deployment, and regional economic development are also important factors to consider as long-term decisions are made regarding new resources.

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

In the 2007 IRP process, Duke Energy considered three load forecasts. These load forecasts comprise high, normal, and low load forecasts with the extremes at the 95% and 5% confidence limits. These limits are more stringent than the 75% and 25% confidence limits referenced in the NUREG-1555 guidelines (NUREG-1555, pg 8.2.1-2). Potential resource portfolios are tested not only against these load forecast variations, but also against numerous other variable sensitivities including: fuel costs; construction costs; load forecasts; and, potential carbon taxes. Duke Energy's 2007 IRP (Reference 8), Appendix A, provides a thorough review of all of the generation scenario models and the risk analysis related to these modeling runs.

In summary, *Duke Energy's IRP properly incorporates forcasting uncertainty and does so in a fashion even more stringent than that suggested by NUREG-1555.*

Based on the discussion above and information contained in subsequent sections of this chapter, Duke Energy believes that its IRP and treatment of this report in both North Carolina and South Carolina by the NCUC and PSCSC satisfies the criteria discussed in NUREG-1555 for establishing a need for the power that will be generated by the Lee Nuclear Station. Duke Energy has chosen to provide information outlined in NUREG-1555 to enable the NRC to make its own need for power determination, if appropriate.

The remainder of this chapter is organized in the following manner. Section 8.1 provides a description of Duke Energy's relevant service area and provides some basic information about the customers in this area. Section 8.2 provides a description and evaluation of Duke Energy's forecast that demonstrates the need for the baseload power to be supplied by the Lee Nuclear Station. Section 8.3 discusses Duke Energy's current and planned generating and other energy supply resources. Finally, Section 8.4 provides an overall examination and evaluation of the forecast electric demand and reserves, as compared to the planned resource additions, and in doing so, provides evidence supporting the need for baseload power from the Lee Nuclear Station.

8.0.6 REFERENCES

1. North Carolina General Statutes, Chapter 62, Public Utilities, http://www.ncga.state.nc.us/gascripts/Statutes/StatutesTOC.pl?Chapter=0062

2. North Carolina Utilities Commission, Rules and Regulations, Chapter 8, Electric Light and Power, http://www.ncuc.commerce.state.nc.us/ncrules/Chapter08.pdf

3. South Carolina, Code of Laws, Title 58, Public Utilities, Services and Carriers, http://www.scstatehouse.net/code/titl58.htm

4. Public Service Commission of South Carolina Order 91-1002

5. Public Service Commission of South Carolina Order 93-845

6. Public Service Commission of South Carolina Order 98-502

7. Duke Energy Carolinas Annual Plan, Sept. 1, 2006, updated Oct. 31, 2006

8. Duke Energy Carolinas Annual Plan, November 2007

9. South Carolina Code of Regulations, Section 58-33, Utility Facility Siting and Environmental Protection, http://www.scstatehouse.net/regs/58.doc

10. Annual Report of the NCUC, November 2006

11. South Carolina Code of Regulations, Chapter 103, Public Service Commission, http://www.scstatehouse.net/regs/103.doc

12. NCUC Order dated August 31, 2006, in Docket No. E-100, Sub 103

13. NCUC Order dated July 9, 2007, in Docket No. E-100, Sub 109

8.1 DESCRIPTION OF POWER SYSTEM: THE RELEVANT SERVICE AREA

8.1.1 INTRODUCTION

In the determination of the need for this new baseload energy source an initial requirement is to identify the customers and geographic areas, or "relevant service area," the proposed Lee Nuclear Station will serve. This "relevant service area," as defined by NUREG-1555, is "any region to be served by the proposed facility…[and this] relevant service area is a situational based concept, and it must be determined on a case-by-case basis." Identifying this relevant service area is the specific objective of this section.

In attempting to identify the relevant service area, there are three primary considerations – the geographic scope of Duke Energy's relevant service area, the customers to be served in that service area, and any other reliability or other considerations, such as long term contracts, that will impact the level of electric resources and electric demand required of Duke Energy. Subsection 8.1.2 identifies, from a geographic perspective, Duke Energy's relevant service area. However, this geographic definition has to be expanded to include the customers Duke Energy serves within this region, which are discussed in Subsection 8.1.3. Issues related to Duke Energy's regional reliability obligations and any other considerations, such as long term contractual obligations are addressed in Subsection 8.1.4. Subsection 8.1.5 provides a summary and a precise definition of Duke Energy's relevant service area based on the foregoing analysis.

8.1.2 RELEVANT SERVICE AREA: A GEOGRAPHIC PERSPECTIVE

The purpose of this section is to identify, from a geographic perspective, Duke Energy's relevant service area. An initial, overriding, and primary consideration in the identification of the appropriate geographic region to be served by the proposed facility is the recognition that Duke Energy is an investor-owned, regulated electric utility providing integrated electric service in both North Carolina and South Carolina within a specific franchised service territory. This means that for the vast majority of retail electric customers, neither the customers nor the regulated electric utilities in North Carolina or South Carolina (and for that matter, the Southeast as a whole), have any choice in the provider of electric service. Simply put, Duke Energy has an "obligation to serve" electric customers within its service territory, and neither those customers nor Duke Energy have the ability to choose an alternate supplier.

Therefore, Duke Energy's primary consideration in the construction of any new regulated electric generating facility in either North Carolina or South Carolina is its obligation to provide service to its current and future customers in these franchised service areas. As such, this is the primary geographic-related marketplace responsibility that Duke Energy must consider in the construction of the Lee Nuclear Station.

Duke Energy's service area is a franchise right governed by its service obligations as a franchised public utility in North Carolina and South Carolina. As a general rule, public utilities are defined as having several primary responsibilities, the first being that "within a market (service) area… a public utility must be prepared to serve any customer who is willing and able to pay for the service." (References 1 and 2) This has been defined as a public utility's obligation to serve.

In North Carolina, the obligation to serve and a public utility's specified franchise service territory are governed by the laws of the State and related orders issued by the NCUC. North Carolina General Statutes specify that the service or franchise area for Duke Energy, as an electric supplier in North Carolina[a], is assigned under the following general guidelines:

> § 62-110.2 (c)(1) In order to avoid unnecessary duplication of electric facilities, *the Commission is authorized and directed to assign*, as soon as practicable after January 1, 1966, *to electric suppliers all areas, by adequately defined boundaries*, that are outside the corporate limits of municipalities and that are more than 300 feet from the lines of all electric suppliers as such lines exist on the dates of the assignments.....(emphasis added)

Similarly, in South Carolina, a franchised service area is governed by both State law and PSCSC orders. South Carolina Code of Laws (Reference 3) defines the assignment of Duke Energy's franchise service[b] by the PSCSC under the following general guidelines:

> Section 58-27-640. Assignment of service areas.
>
> The *Public Service Commission shall assign*, beginning as soon as practicable after January 1, 1970, *to electric suppliers*, all areas, by adequately defined boundaries …..[and] … *The Commission shall make assignments of areas in accordance with public convenience and necessity considering, among other things, the location of existing lines and facilities of electric suppliers and the adequacy and dependability of the service of electric suppliers, but not considering rate differentials among electric suppliers.* (emphasis added)

For Duke Energy, in North Carolina and South Carolina, its franchise or designated service area is illustrated in Figure 8.1-1. This figure also shows the major cities Duke Energy serves.

Within its North Carolina and South Carolina service areas, Duke Energy's obligation to provide electric service is governed by both the laws of each State and the rules and regulations of the respective utility commissions. For example, North Carolina General Statutes (Reference 4) declare that it is the policy of the State that regulated electric utilities within North Carolina must provide adequate and reliable electric service within its franchise service area under the following guidelines:

> § 62- 2(a) ... it has been determined that the rates, services and operations of public utilities as defined herein, are affected with the public interest and that the availability *of an adequate and reliable supply of electric power …. to the people, economy and government of North Carolina is a matter of public policy.* It is hereby declared to be the policy of the State of North Carolina …. To promote adequate, reliable and economical utility service to all of the citizens and residents of the State. (emphasis added)

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a. In North Carolina, Duke Energy is defined as both an electric supplier and a public utility. It is identified as an electric supplier under NC G.S. § 62-110.2.

b. In South Carolina, Duke Energy is defined as both an electric supplier and a public utility. It is defined as an electric supplier under SC Code of Laws Section 58-27-610

The NCUC Rule R8-5 (Reference 5) reiterates this service requirement. Similarly, South Carolina Code of Laws requires that Duke Energy has an obligation to provide adequate and reliable electric service to all customers in its service area who request service under the following state laws:

> Section 58-27-1510. Service shall be adequate, efficient and reasonable. *Every electrical utility shall furnish adequate, efficient and reasonable service.* (emphasis added)

Furthermore, the requirement for Duke Energy to provide its South Carolina customers adequate and reliable service is also stipulated under PSCSC Rules Sections 103-301, 103-380, and 103-360 (Reference 6).

In summary, based on Duke Energy's statutory and regulatory responsibilities, Duke Energy's ***relevant service area, from a geographic perspective****, is the provision of adequate and reliable service in its franchise service area. As such, this is the primary geographic related marketplace responsibility that Duke Energy must consider in the construction of the Lee Nuclear Station.*

8.1.3 RELEVANT SERVICE AREA: DUKE ENERGY'S CUSTOMERS AND LOAD CENTERS

Primary Customers in its Relevant Service Area

Subsection 8.1.2 identified Duke Energy's relevant service area from a geographic perspective. This section identifies the specific customers that Duke Energy is obligated to serve in this geographic region. The combination of this geographic service territory, coupled with an identification of the customers served in this region, for the most part, identify Duke Energy's ***relevant service area***.

In North Carolina, Duke Energy's customer base is specified in franchise service obligations that flow from both North Carolina state law and rules promulgated by the NCUC. As noted previously, under North Carolina statutes, Duke Energy is defined as a public utility and as such, North Carolina policy states that a utility must provide adequate and reliable service to all customers in its service area. Based on these North Carolina statutory and regulatory obligations as a public utility, Duke Energy has an obligation to provide adequate and reliable electric service to all present and future customers, except for wholesale and municipal customers, in its franchise service area in North Carolina.

Similarly, in South Carolina, Duke Energy is defined as both an electric supplier and an electric utility. As an electric supplier and public utility, Duke Energy's customer service obligations in South Carolina are defined in that State's Code of Laws (Reference 3) and further defined by PSCSC rules which state:

> PSCSC Rule 103-348. System Extensions.
>
> *Each electric supplier shall be obligated to comply with all requests for service* in accordance with its schedules of rates and service rules and regulations on file with the Commission within areas assigned to it by the Commission and within 300 feet of its lines as they existed on the date of assignment…(emphasis added)

The combination of these South Carolina laws and PSCSC rules establish that, similar to North Carolina, Duke Energy has an obligation to provide service to all customers that request service, except municipal or electric cooperative customers, in its franchise service territory.

Duke Energy's Relevant Service Area Customer Demographics

Duke Energy provides retail electric services to approximately 2.32 million customers in North Carolina and South Carolina (Reference 7). Duke Energy also sells wholesale electricity to incorporated municipalities and to public and private utilities.

As shown in Figure 8.1-1, Duke Energy's major load centers include the largest municipal areas in North Carolina, Charlotte and the Greensboro-Winston-Salem area. In South Carolina the service territory includes the fast growing municipalities of Anderson, Greenville, and Spartanburg, as well as the fast growing industrial corridor stretching along I-85 from the Georgia/South Carolina border almost to the North Carolina/Virginia border[c]. Duke Energy's North and South Carolina service area is comprised of some 22,000 square miles with approximately 70% of the customers being in North Carolina.

Duke Energy's service area has a diversified customer base. Table 8.1-1 and Table 8.1-2 show the number of customers and sales of electricity by customer groupings (Reference 7). In terms of annual sales in 2006, the percentage of total gigawatt-hours (GWH) sold to residential customers was 32%, the percentage to commercial was 32%, industrial was 31%, and wholesale and other was 5%. Over the past five years, while Duke Energy has experienced a decline in the textile business customers, this loss in industrial load has been offset by growth in the residential and general service classes over the same period. This trend is expected to continue (Reference 9).

The residential class continues to show positive growth, driven by steady gains in population within the Duke Energy service area. The resulting annual growth in residential billed sales is expected to average 1.9% over the 15-year forecast horizon. The commercial class is projected to be the fastest growing retail class, with billed sales growing at 2.5% per year over the next ten years. Three sectors that contributed greatly to total commercial sales growth from 2005 to 2006 were offices, medical, and education (Reference 9).

The industrial class continues to decline due to losses in textiles business. Over the forecast horizon, the closing of textile plants is expected to continue. In the non-textile class; however, several sectors are expected to show strong growth. These include auto, rubber and plastics, and chemical (excluding man-made fibers). As a result, total industrial sales are expected to be almost flat over the forecast horizon (Reference 9).

For a more thorough discussion of Duke Energy's customer base and a forecast of future projected electric demand, refer to Section 8.2. In addition to the retail electric service Duke Energy provides in its franchise service area, Duke Energy also provides some wholesale service, discussed in detail in Subsection 8.2.1.

c. "The greatest future growth in the United States is likely to take place in the West, the Sunbelt and along the I-85 corridor between Raleigh, N.C., and Atlanta, Ga." (Reference 8)

Conclusions: Duke Energy's Service Area from a Customer Perspective

Under North Carolina and South Carolina statutory and regulatory obligations, Duke Energy is defined as a public utility and has an obligation to provide adequate and reliable electric service to all present and future customers, except for wholesale and municipal customers, in its franchise service areas in North and South Carolina. *Based on these statutory and regulatory responsibilities, Duke Energy's* ***relevant service area from a customer perspective****, is the provision of adequate and reliable service in its franchise service area to all retail electric customers. As such, retail customers are the primary customer related marketplace responsibility that Duke Energy must consider in the construction of the Lee Nuclear Station.*

8.1.4 RELIABILITY COUNCILS AND OTHER REGIONAL CONSIDERATIONS

Introduction

Beyond Duke Energy's identified geographic relevant market and the customers it is obligated to serve in this area, there are other considerations that must be addressed in properly identifying Duke Energy's relevant service area. Specifically, there are three additional considerations that could potentially expand Duke Energy's relevant service area beyond its North and South Carolina service areas, albeit, these considerations are secondary in nature to its primary responsibility to its service territory. The first revolves around Duke Energy's obligations with respect to reliability, the second is the consideration of any other service or purchase obligations that Duke Energy is committed to, and the third issue relates to any other regional market-based considerations that might impact Duke Energy's relevant market. All three are addressed in this subsection.

Reliability Considerations

Given Duke Energy's statutory and regulatory obligations to provide adequate and reliable service, there are many factors that must be considered in planning the appropriate resources to meet this standard. For example, because of customer demand uncertainty, unit outages, transmission constraints and weather extremes, electric generating reserve margins are necessary to help ensure the availability of adequate resources to meet load obligations. Many factors have an impact on the appropriate level of reserves, including existing generation performance, lead times needed to acquire or develop new resources, product availability in the purchased power market, and reliability related obligations.

With respect to reliability related obligations, Duke Energy, as part of the SERC Reliability Corporation (SERC) (formerly the Southeastern Electric Reliability Council), has obligations related to reliability and service standards beyond its franchised service territory. To explain, following the largest blackout in U. S. history on November 9, 1965[d], the electric industry created the National Electric Reliability Council (NERC) to help improve system reliability and coordinate planning. After another major blackout in the Midwest, Northeast, and Canada on August 14, 2003, the Federal Energy Regulatory Commission (FERC) certified NERC as the electric

d. The largest blackout to this date in history occurred, as 30 million people lost power in the northeastern United States and southeastern Ontario, Canada. New York City and Toronto were among the affected cities. Some customers were without power for 13 hours.

reliability organization (ERO) for the United States with a mission to improve reliability and adequacy of the bulk power system in North America. To achieve this goal, NERC develops and enforces reliability standards; monitors the bulk power system/ assesses future adequacy; audits owners, operators and users for preparedness; and educates and trains industry personnel. NERC is a self-regulated organization that relies on the expertise of industry participants. As the ERO, NERC is subject to audit by the FERC and governmental authorities in Canada (Reference 15).

As mentioned previously, Duke Energy is a member of SERC, one of the 8 regional councils within NERC. SERC serves as a regional entity with delegated authority from NERC for the purpose of proposing and enforcing reliability standards within the SERC Region. SERC is divided geographically into five sub-regions that are identified as Entergy, Gateway, Southern, TVA, and VACAR. Duke Energy is part of the VACAR subregion of SERC. The region is illustrated in Figure 8.1-2.

Duke Energy has an obligation to comply with any applicable NERC and SERC reliability standards. Neither NERC nor the SERC region have implemented a regional reserve margin requirement, thus members adhere to their respective state commissions' regulations regarding maintaining adequate resources (Reference 10). However, as a member of VACAR, Duke Energy has several reliability agreements with the other VACAR members including an agreement to share capacity reserves. Specifically, as a member of VACAR, Duke Energy participates in the VACAR Reserve Sharing Agreement, which requires that Duke Energy maintain a pro-rata share equal to one-and-one-half of the largest unit in the group, Belews Creek 1 or 2, which at this time would be a minimum capacity reserve margin of approximately 1700 MWs, or 8.5 % of Duke's peak summer capacity (Reference 11). Duke Energy uses adjusted system capacity[e], along with interruptible capability to satisfy the Duke Energy's NERC Reliability Standards requirements for operating and contingency reserves. Contingencies include events such as higher than expected unavailability of generating units and increased customer load due to extreme weather conditions (Reference 7).

In addition, VACAR conducts several transmission studies annually, albeit, VACAR's focus is coordination and regional reliability, not planning generating units for member utilities. All members of VACAR participate in these studies which provide the basis for ensuring generation and transmission reliability within the sub-region. All members of VACAR rely heavily on the findings and commitments made by the VACAR members as a result of these studies. The failure of any one member of VACAR to follow through on any of the assumptions, conclusions or commitments determined within the VACAR structure, negatively impacts all other members of the organization. This heightens the importance of strict compliance by each VACAR member with the member's plans as presented to VACAR.

With respect to other reserve margin considerations, Duke Energy's 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 Duke Energy's process for determining its target planning reserve margins, Duke Energy

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

reviews whether the current target planning reserve margin was adequate in the prior period. From July 2004 through August 2007, generating reserves, defined as available Duke Energy generation plus the net of firm purchases less sales, never dropped below 450 MW. Since 1997, Duke Energy has had sufficient reserves to meet customer load reliably with limited need for activation of interruptible programs. The use of these curtailable programs is discussed in Duke Energy's 2007 IRP (Reference 7).

While Duke Energy uses a 17% target planning reserve margin for long-term planning, it also assesses its reserve margins on a short-term basis to determine whether to pursue additional capacity in the short-term power market. As each peak demand season approaches, Duke Energy 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 (Reference 7).

Since 1999, the NCUC has required utilities to include a justification of the reserve margin the utilities use in planning. The NCUC has approved Duke Energy's IRPs including the reserve margin each year since the requirement was put into place.

Other Service or Purchase Obligations

Another set of issues that could impact the definition of Duke Energy's relevant service area is related to whether Duke Energy is committed to any long term contracts for purchase or sale of power that might impact its need for the proposed generating facility. Duke Energy's wholesale power sales obligations are listed in detail in Subsection 8.2.1. In addition, Duke Energy has several wholesale purchase power agreements, listed in Section 8.3. While these wholesale and purchase power obligations must be considered in Duke Energy's planning, they should be considered a second priority in defining Duke Energy's relevant service area. As a first principle, Duke Energy's regulatory and statutory responsibilities are to provide adequate and reliable service to its franchise service area customers in North and South Carolina. In its IRP process, Duke Energy considers wholesale load obligations. These obligations make up less than 10% of Duke Energy's obligations to provide energy. While Duke Energy does not have a statutory "obligation to serve" wholesale customers, it has contractual obligations to serve a certain amount of wholesale load.

Regional Market Based Considerations

Another issue to consider in defining Duke Energy's relevant service area is whether there are any regional market-based considerations that might impact Duke Energy's relevant service area. For example, within the southeast region and nationwide, wholesale power supply continues to be deregulated, and as such, subject to power sales across companies, states, and regions. Moreover, as discussed in Subsection 8.2.1 and the wholesale sales section in Subsection 8.2.1 and Subsection 8.3.3, Duke has both regional wholesale power sales and purchase commitments. Duke Energy's transmission system is directly connected to all the utilities that surround the Duke Energy service area. There are 33 circuits connecting with eight different utilities – Progress Energy Carolinas, American Electric Power, Tennessee Valley Authority, Southern Company, Yadkin, Southeastern Power Administration (SEPA), South Carolina Electric and Gas and Santee Cooper (also known as South Carolina Public Service Authority). These interconnections allow utilities to work together to provide an additional level of reliability (Reference 7). Figure 8.1-3 illustrates these regional transmission ties.

While Duke Energy models known wholesale purchase or sales obligations in its overall long term planning simulations, as discussed in Subsections 8.1.2 and 8.1.3, Duke Energy's relevant service area is primarily dictated by its regulatory and statutory obligations to retail electric customers in its service area. In addition, the proposed generating facility is a baseload facility targeted to serve its retail, regulated electric customers within its geographic franchised service territory, and Duke Energy does not contract for outside baseload to meet its retail needs nor has Duke Energy solicited purchased power bids for baseload capacity[f].

The Duke Energy position with regard to this issue is based on the premise that baseload capacity is fundamentally different from peaking and intermediate capacity. This is based on two key considerations with respect to using the wholesale market for baseload capacity. First, generation outside Duke Energy's franchise service or control area could be subject to interruption due to transmission issues that are beyond the control or oversight of Duke Energy, the NCUC, or the PSCSC. Second, supplier default could jeopardize the ability to provide reliable service. Consequently, a Duke Energy owned baseload option is considered the most reliable means for Duke Energy to meet its service obligations in a cost-effective and reliable manner.

In a proceeding, which examined whether to require utilities to solicit purchased power bids for capacity need, the PSCSC concluded "it is in the best interest of the electric ratepayers of South Carolina and the regulated community of electric utilities to only require mandatory [requests for proposals] for new peaking generation." (Reference 12) Also, in its recent North Carolina Certificate of Public Convenience and Necessity hearing for its new Cliffside generating facility, Duke Energy did not issue an RFP and asserted that baseload additions were different from intermediate and peaking resources. The NCUC noted in its Order that, "On the present record, without setting a precedent for other cases, the Commission cannot conclude that Duke should have issued an RFP for the capacity at issue herein." (Reference 13)

The NCUC has also recently (August 31, 2006) supported Duke Energy's policy of not using generation sources from outside its service area for baseload generation. Specifically, in the approval of Duke Energy's IRP in a discussion about future nuclear and fossil fuel generating plants (Reference 14), the NCUC held:

> *"Using power generated in other states in place of power generated in North Carolina would not result in any major reduction in electric usage or in any meaningful environmental benefits and would have at least one serious adverse affect.* During periods of peak consumption, the state's utilities might have to pay extremely high rates to purchase power from other utilities; in some case they may be unable to import sufficient power at all because of the limitations of the transmission system or for other reasons. Consequently, a policy prohibiting the construction of all nuclear and fossil-fired plants may create risks of both excessive electric rates and unreliable service. Such a policy would contravene G.S. 62-2(a)(3), which provides that a primary purpose of utility regulation is "[t]o promote adequate, reliable, and economical utility service to all of the citizens and residents of the State." (emphasis added)

f. Duke Energy has used the competitive wholesale market to supply peaking needs and currently has a Request for Proposal (RFP) for peaking and intermediate capacity from any qualified suppler who wishes to bid on this proposal.

8.1.5 CONCLUSION: DUKE ENERGY'S RELEVANT SERVICE AREA

Duke Energy's relevant service area has three primary considerations – the geographic scope of Duke Energy's relevant service area, the customers to be served in that service area, and any other reliability or regional considerations. As a regulated electric utility providing retail electric service to customers in North Carolina and South Carolina, Duke Energy's statutory and regulatory responsibilities in these states identify Duke Energy's relevant service area, from a geographic perspective, as its franchise service area in both states. Duke Energy maintains interconnections to other utilities for reliability purposes but not as a regional power marketer. With respect to specific customers in this franchise service area, again based on statutory and regulatory obligations, Duke Energy's relevant service area is composed primarily of present and future retail electric service customers in its franchise service area in both states.

In addition, Duke Energy has some reliability, wholesale, and purchase power obligations that must be considered in Duke Energy's planning. However, other than reliability considerations, these should be considered a second priority in defining Duke Energy's relevant service area. Also, based on the fact that Duke Energy's proposed generating facility is a baseload facility, and these facilities are not subject to RFPs or purchase power options in South Carolina and RFPs are not required in North Carolina, Duke Energy's interconnections with neighboring utilities does not impact the definition of relevant service area.

Based on these considerations, Duke Energy's relevant service area and the primary service consideration in the consideration of the Lee Nuclear Station, is its regulatory and statutory obligation to provide service to its customers in North and South Carolina. More specifically, ***Duke Energy defines its relevant service area as follows:***

- ***A geographic region encompassing Duke Energy's franchise service areas in North Carolina and South Carolina,***
- ***Primarily retail electric customers within this geographic region along with any longer term wholesale power obligations and reliability related reserve margin standards, and***
- ***The relevant service area does not include the option for long-term purchases of baseload power.***

Given this fact, the best, and potentially only regulatory acceptable source for this type generation, is Duke Energy-owned baseload capacity.

8.1.6 REFERENCES

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3. South Carolina, Code of Laws, Title 58, Public Utilities, Services and Carriers, http://www.scstatehouse.net/code/titl58.htm

4. North Carolina General Statutes, Chapter 62, Public Utilities, http://www.ncga.state.nc.us/gascripts/Statutes/StatutesTOC.pl?Chapter=0062

5. North Carolina Utilities Commission, Rules and Regulations, Chapter 8, Electric Light and Power, http://www.ncuc.commerce.state.nc.us/ncrules/Chapter08.pdf

6. South Carolina Code of Regulations, Chapter 103, Public Service Commission, http://www.scstatehouse.net/regs/103.doc

7. Duke Energy Carolinas Annual Plan, November 2007

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10. North American Reliability Council, “2006 Long-Term Reliability Assessment,” October 2006

11. SERC Reliability Corporation, Contingency Reserve Policy, October 19, 2006

12. PSCSC Order dated September 13, 2007, Docket No. 2005-191-E, issued August 15, 2007

13. NCUC Order dated March 21, 2007, in Docket No. E-7, Sub 790

14. NCUC Order Approving Integrated Resource Plans and Requiring Additional Information in Future Reports dated August 31, 2006, in Docket No. E-100, Sub 103

15. FERC Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing ,issued July 20, 2006, ftp://www.nerc.com/pub/sys/all_updl/docs/ferc/20060720_ERO_certification.pdf

TABLE 8.1-1
RETAIL CUSTOMERS (1000s, BY NUMBER BILLED)

	2006	2005	2004	2003
Residential	1,909	1,874	1,841	1,814
General Service	318	312	306	300
Industrial	7	8	8	8
Nantahala Power & Light	70	68	67	66
Other[a]	13	13	12	11
Total	2,317	2,275	2,234	2,199

a) Other = Municipal street lighting and traffic signals

(Number of customers is average of monthly figures)

Source: Reference 7

TABLE 8.1-2
ELECTRICITY SALES (GWH SOLD - YEARS ENDED DECEMBER 31)

Electric Operations	2006	2005	2004	2003
Residential	25,147	25,460	24,542	23,356
General Service	25,585	25,236	24,775	23,933
Industrial	24,396	25,361	25,085	24,645
Nantahala Power & Light	1,256	1,227	1,163	1,134
Other[a]	269	266	267	268
Total Retail Sales	76,653	77,550	75,832	73,336
Wholesale Sales[b]	2,318	2,251	1,969	2,359
Total GWH Sold	78,971	79,801	77,801	75,695

a) Other = Municipal street lighting and traffic signals

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

Source: Reference 7

8.2 POWER DEMAND, FACTORS AFFECTING DEMAND

The review of the need for power and energy required by NUREG-1555 must consider both historic and future electric loads, in the relevant market area. In addition, it requires an examination of factors affecting these needs. Both issues are reviewed in this section, with Subsection 8.2.1 reviewing the historic and projected electricity demands, and Subsection 8.2.2 reviewing the factors that affect these demands. NUREG-1555 directs that this analysis and forecast focus on the "relevant service area or market" and goes on to say that "if the need for power is based solely on needs within a utility service area (no surplus will be produced for export) and there are no alternative plants proposed by competitors, then [the] analysis can be confined to the utility service area." This is the situation with respect to the power to be produced by the proposed Lee Nuclear Station and therefore, the forecast in this section will be dedicated to Duke Energy's service territory and primarily retail electric customers in that service area, which is the relevant service area as defined in Subsection 8.1.5.

It should be noted that NUREG-1555 allows for the forecast analysis to be based on an acceptable state or regional need-for power evaluation if the evaluation meets these four criteria; that the methodology be (1) developed in a systematic fashion, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty. Accordingly, the bulk of the data and information provided in this section was prepared for and contained in Duke Energy's 2007 IRP (Reference 1) and Duke Energy Carolinas' 2007 Spring Forecast (Reference 2), which were filed in both North Carolina and South Carolina as required under those State's IRP rules and regulations and those States' annual resource planning requirements. As discussed and demonstrated in Section 8.0, this IRP meets or exceeds these four criteria. In addition, as will be discussed and demonstrated in Subsection 8.2.1 and Subsection 8.2.2, the results and methodologies contained in this IRP meet additional criteria discussed in NUREG-1555.

8.2.1 POWER AND ENERGY REQUIREMENTS

Introduction

This subsection, as directed by NUREG-1555, provides the forecast methodology and electric energy and demand forecast, the latter provided in terms of forecasted power (peakload) and forecasted energy (hourly consumption) requirements in the relevant service area. The bulk of the data provided in this section is prepared for and contained in Duke Energy's 2007 IRP (Reference 1). Where possible, the data and information were confirmed by other independent sources.

Forecasting Methodology

Introduction

Duke Energy undertakes an extensive, bottom-up approach in developing its forecast. This bottom-up approach essentially begins at the customer level and develops a forecast for each customer class, and these forecasts are accumulated along with any other requirements to provide the overall forecast of future power needs.

There are three major types of forecasts produced in this process, including;

- Monthly and annual megawatt hour (MWH) sales forecasts

- Monthly and annual peak demand forecasts
- Hourly demand forecasts for every hour of a year (typically 8,760 hourly forecasts per year)

Each forecast methodology is weather normalized and the process is described below.

Monthly and Annual MWH Forecast

The methodology used to develop monthly and annual MWH sales forecasts is as follows. For each of the major classes of customers (Residential, Commercial, Industrial, Resale, etc.), econometric linear regression models are developed that relate historical MWH sales to historical "key variables" such as:

- Cooling degree days (hours) for the Duke Energy service area
- Heating degree days (hours) for the Duke Energy service area
- Total personal income earned in North Carolina and South Carolina
- Total population for counties in the Duke Energy power service area
- Total Gross State Product (GSP) in North Carolina and South Carolina
- Non-Manufacturing GSP in North Carolina and South Carolina
- Non-Manufacturing employment in North Carolina and South Carolina
- Manufacturing GSP in North Carolina and South Carolina per industry group (Textiles, etc.)
- Employment in North Carolina and South Carolina per industry group (Textiles, etc.)
- Indicators that account for seasonal differences over a year
- Price of electricity
- Appliance stock that incorporates saturations and efficiencies

Model coefficients are determined by a statistical software package called EVIEWS. These models, in combination with forecasts of the "key variables" are used to produce forecasts of monthly and annual MWH sales. The sources of forecasts of the "key variables," used to produce forecasts of monthly and annual MWH sales, are weather variables and economy variables. The weather variables include variables such as cooling degree days and hours (CDD/CDH) for the Duke Energy service area and heating degree days and hours (HDD/HDH) for the Duke Energy service area[a].

The economy variables include variables such as total personal income earned in North Carolina and South Carolina and total population for counties in North Carolina and South Carolina. The main source of history and forecasts of this economic data is Economy.Com, a large economic consulting firm, located near Philadelphia, PA. Economy.Com provides total gross domestic product (GDP), GDP for each 2-digit manufacturing Standard Industry Code (SIC), and GDP for each one digit non-manufacturing SIC. Employment by each of these groups is also provided. This output and employment data is given for the US, North Carolina, and South Carolina. Also, data such as income, the prime rate and unemployment rate are provided. In addition to Economy.Com, Duke Energy also solicits feedback on the textile industry from the National Council of Textile Organizations. The final monthly and annual MWH sales forecast are determined by summing the MWH sales forecasts from the econometric linear regression models for each class of customers are added together to determine the final forecast. Additional adjustments are made to these final forecasts for the sales impacts of marketing programs that are not implicitly captured within the historical MWH sales data.

Monthly and Annual Peak Demand Forecasts

The methodology used to develop monthly and annual peak demand forecasts is described below. Using data from the last twenty years, econometric linear regression models are developed for each month that relate daily peak demands at the expected hour of summer/winter peak to historical "key variables" such as:

- Daily degree hours from 1 to 5 PM for the Duke Energy service area (summer month models)
- Daily degree hours for minimum morning temperature for the Duke Energy service area (summer month models)

a. CDD/CDH and HDD/HDH are based on a simple average of temperatures recorded at the three principal weather stations located within its service area, Charlotte, Greensboro, and Greenville-Spartanburg. For each day, the degree hours are calculated by subtracting each hour's temperature from a base of 65 degrees and then summing the resulting degree hours over the 24 hour period. Note that by summing over each day, heating and cooling degree hours within the day can cancel each other out, resulting in a day being designated as either a heating or cooling day but not both. Forecasts of CDD/CDH are calculated by using a rolling 10 year simple average of actual annual CDD/CDH to determine the CDD/CDH normals. Once the annual CDD/CDH values are calculated, the individual monthly CDD/CDH are determined. For HDD/HDH, the process is similar to CDD/CDH.

- Daily degree hours for maximum temperature from the prior day for the Duke Energy service area (summer month models)
- Daily degree hours from 7 to 8 AM for the Duke Energy service area (winter month models)
- Daily degree hours for the temperature at 4 PM from the prior day for the Duke Energy service area (winter month models)
- Monthly MWH from the class level forecasts (all monthly models)

For each month only those days that experienced temperatures that were reasonably close to normal temperatures at the time of monthly peak were used. Model coefficients are determined using historical data in a statistical software package called EVIEWS. These models are used in combination with forecasts of the "key variables" to produce forecasts of the monthly peaks. All weather variables are derived from a simple average of temperatures recorded at the three principal weather stations located within the Duke Energy service area, Charlotte, Greensboro, and Greenville-Spartanburg. Forecasts of these weather variables are based on a median of the last twenty years of historical data. The overall annual peak forecast for Duke Energy is the July peak forecast. The annual winter peak forecast is the January peak forecast.

Hourly Demand Forecasts

The methodology used to develop the hourly demand forecasts for every hour of a year (typically 8,760 hourly forecasts per year) is as follows. Typical hourly load shapes were developed several years ago for every day of every month in the years covering the forecast horizon. These hourly load shapes are then placed under two constraints. One constraint is the sum of the hourly loads over every month in the years covering the forecast horizon must match the monthly MWH sales forecast. The second constraint is the peak MW load for every month in the years covering the forecast horizon must match the monthly peak demand forecasts.

The two sources of forecasts used in this process are the results of the monthly and annual MWH sales forecast and the results of the monthly and annual peak demand forecasts. The final forecasts of every hour of a year (typically 8,760 hourly forecasts per year) are determined as follows. The Electric Power Research Institute (EPRI) software program called HELM is used to produce the final forecasts of every hour of a year based on the stated methodology. Two additional checks are made after the final forecasts are completed. The first check is that HELM produces a monthly summary of the forecast which is compared to the same monthly summary from a prior forecast. The second check is a Statistical Analysis System (SAS) software program, which is used to sum the final forecasts of every hour of a year over every month and then compare this result to the results of the Monthly MWH sales forecast.

Forecasting Uncertainty and Sensitivity

In order to test the validity of the overall modeling assumptions and capture the potential for uncertainty or variance in Duke Energy's forecast, three load forecasts were produced for the 2007 IRP filing. These load forecasts comprise high, normal, and low load forecasts with the extremes at the 95% and 5% confidence limits. These limits are more stringent than the 75% and 25% confidence limits referenced in the NUREG-1555, ESRP 8.2 guidelines. In the IRP process, various resource portfolios are tested not only against these load forecast variations,

but also against numerous other variable sensitivities including: fuel costs; construction costs; load forecasts; potential carbon taxes; and other environmental laws and regulations. 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 the 2007 IRP (Reference 1), the scenarios considered were:

- Reference Case Without CO2 restrictions/tax
- Carbon Case With CO2 restrictions/tax plus a Renewable Portfolio Standard (RPS)

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

- Load forecast variations
  - Increase relative to base forecast (growth rates of 1.9% and 1.7% for peak demand and energy, respectively, versus 1.6% and 1.4%, respectively, in the base case forecast)
  - Decrease relative to base forecast (growth rates of 1.3% and 1.1% for peak demand and energy, respectively, versus 1.6% and 1.4%, respectively, in the base case forecast)

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

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

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

Forecasting Methodology Analysis

NUREG-1555 provides some very specific criteria for evaluating the efficacy of the forecast methodology. These criteria are listed below:

Does Forecasting Model Incorporate These Features?	Does Duke Forecast Methodology Meet This Criteria?
Electricity price and elasticity	Yes*
Energy efficiency, renewables	Yes
Price of alternative fuels	Yes**
Income	Yes
Economic activity	Yes
Weather normalized	Yes
Number of customers	Yes
Weather	Yes
Electric device saturation levels	Yes
Uncertainty	Yes

* Refer to the “Price and Rate Structure” segment in Subsection 8.2.2 for an explanation of how price elasticity is incorporated into the modeling process.

** Refer to Subsection 8.4.2 which discusses the IRP modeling process and how differing alternative fuel prices are incorporated into the model.

Conclusion: As the information listed above indicates, the Duke Energy forecast methodology incorporates all the features suggested by NUREG-1555.

In addition to the evaluation presented above, NUREG-1555 requires that if the forecast is contained in a need-for-power report prepared for a state, which is the circumstance in this case, then a second means for evaluating the forecasting methodology is appropriate. This alternative means for evaluating the forecast and forecast methodology is an indirect, more subjective approach than the evaluation presented above. This evaluation is presented in Subsection 8.2.3.

Historical and Forecast Electric Demand

To determine total resources needed, Duke Energy considers its forecast load obligations in its relevant market area plus a 17 percent target planning reserve margin, discussed in Subsection 8.1.4.

The 2007 Spring Forecast (Reference 2), which was used in the 2007 IRP (Reference 1), includes projections for meeting the energy needs of new and existing customers in Duke Energy service territory. The forecasts for 2007 through 2027 include the energy needs of the Duke Energy retail customers. Certain wholesale customers have the option of obtaining all or a portion of their future energy needs from other suppliers. In addition, Duke Energy assumes for planning purposes that its existing wholesale customer load (excluding some Catawba Nuclear Station owner loads as discussed below) will remain part of the load obligation. The basis for the assumptions on wholesale loads is discussed in Subsection 8.1.4.

The forecast includes the following considerations:

- Load equating to the portion of Catawba Nuclear Station ownership related to the Saluda River Electric Cooperative Inc. (SR) until January 1, 2009[b].

- Duke Energy provides full requirements wholesale power sales to Western Carolina University (WCU), the city of Highlands and to customers served under Rate Schedule 10A. These customers' load requirements are included in the Duke Energy load obligation.

- Duke Energy has a contract to serve Blue Ridge, Piedmont and Rutherford Electric Membership Cooperatives' supplemental load requirements from 2006 forward.

- Hourly electricity sale to North Carolina Electric Membership Corporation (NCEMC) beginning in January 2009.

- Under Interconnection Agreements, Duke Energy also is obligated to provide backstand service for NCEMC throughout the 20-year planning horizon.

- As part of the joint ownership arrangement for the Catawba Nuclear Station, the North Carolina Municipal Power Agency 1 (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 Nuclear Station. Beginning January 1, 2005, NCMPA1 entered into a backstand

b. Beginning in 2009, the Saluda River ownership portion of Catawba Nuclear Station is not reflected in the forecast due to a future sale of this interest expected to take place in fall of 2008, which will cause SR to become a full-requirements customer of another utility. Saluda River exercised its three-year notice to terminate the Interconnection Agreement (which includes provisions for reserves) in September 2005, which will result in termination of power requirement sales to Saluda River at the end of September 2008.

agreement of up to 432 MW of NCMPA1's nuclear capacity (depending on operation of the Catawba and McGuire facilities) that expires December 31, 2007. The backstand agreement was extended through 2010. These changes reduce the Duke Energy's load forecast by the forecasted NCMPA1 load in the control area (953 MW at 2006 summer peak) and the available capacity to meet the load obligation by its Catawba ownership (832 MW). The 2007 IRP assumes that the reductions remain over the 20-year planning horizon.

- The Piedmont Municipal Power Agency (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 Nuclear Station be included in the load forecast beginning in 2006, because PMPA also terminated its existing Interconnection Agreement with Duke Energy effective January 1, 2006. Therefore, Duke Energy is not responsible for providing reserves for the PMPA ownership interest in Catawba Nuclear Station. These changes reduce the Duke Energy load forecast by the forecasted PMPA load in the control area (445 MW at 2006 summer peak) and the available capacity to meet the load obligation by its Catawba Nuclear Station ownership (277 MW). The 2007 IRP (Reference 1) assumes that the reductions remain over the 20-year planning horizon.

A table of wholesale load commitments can be found in the Duke Energy 2007 IRP (Reference 1).

The current 20-year forecast reflects a 1.6 percent average annual growth in summer peak demand, while winter peaks are forecasted to grow at an average annual rate of 1.4 percent. The forecast for average annual growth in territorial energy need is 1.4 percent. The peak demand growth rates use 2007 as the base year with a 17,870 MW summer peak, a 15,725 MW winter peak and a 93,593,599 GWH average annual territorial energy need. Table 8.2-1 reflects this forecast. In addition, the Duke Energy Spring 2007 Forecast (Reference 2) contains a variety of tables and charts showing both historical and projected electric use, both demand and energy, for each of Duke Energy's customer classes and in total.

From a historical perspective, referring to Table 8.2-2, Duke Energy retail sales have grown at an average annual rate of 1.5 percent from 1991 to 2006. This 15-year period of history reflects 10 years of strong load growth from 1991 to 2001 followed by five years of very little growth from 2001 to 2006 (Reference 1).

A decline in the industrial textile class was the key contributor to the low load growth from 2001 to 2006, offset by growth in the residential and general service classes over the same period. Duke Energy’s total retail load growth over the planning horizon is driven by the expected growth in residential and general service classes. Sales to the industrial textile class are expected to decline over the forecast period, but not as much as in the last five years. The industrial non-textile class is expected to show positive growth, particularly in the automobile, rubber and plastics, and chemical (excluding man-made fibers) industries (Reference 1).

Evaluation of the Forecast

For comparison purposes, the Duke Energy forecasted energy growth rate, was compared to the most recent Energy Information Administration (EIA) forecast in Table 8.2-3. The EIA prepares

an annual independent regional forecast of electric use by sector. As this table indicates, the Duke Energy forecast, both by sector and overall, are quite comparable to the EIA's. For example, Duke Energy's residential energy load growth is projected to be 1.9% per year as compared to the EIA's 1.73%. Duke Energy's overall energy load growth is projected to be 1.5% per year, slightly below the EIA's projection of 1.68%. This also compares favorably to the SERC regional forecast projecting energy load growth of 1.7% annually through 2016 (Reference 3).

Conclusion: Duke Energy's electric demand and energy forecast is comparable to another independent forecast from the EIA, which is identified as an industry "best practices" forecasting entity in NUREG-1555.

Duke Energy's historical forecast accuracy was reviewed as another check on the overall veracity of the Duke Energy's forecast and forecasting methodology. As shown in Table 8.2-4, in the years 1991 thru 2006 the Duke Energy's average absolute error was ± 3.2%, and on a weather normalized basis it was ± 2.4%. The forecast error, while quite reasonable, had actually been even lower prior to the last four years where totally unexpected and significant losses in the textile industry contributed to a larger forecast error than in prior years.

Conclusion: Duke Energy's historical forecasts have been reasonably accurate over the last 15 years.

In addition to the two evaluations of the Duke Energy's forecasting capabilities discussed above, NUREG-1555 provides some additional specific criteria for evaluating the efficacy of the forecast. These criteria and how Duke Energy's plan complies with these criteria is shown below.

Does Forecast Incorporate These Features?	Does Duke Forecast Meet This Criteria?
Historic and forecast electric use by major categories for both energy and demand in relevant area	Yes[a]
Data covers historical years through 3 years after plant in service	Yes[a]
Load factor information	Yes[b]
Annual rate of growth	Yes[a]
Agreement with other forecast	Yes[c]
Proper forecasting methodology employed	Yes[d]

[a] Tables 8.2-2 & 8.2-3 and References 1 and 2

[b] References 1 and 2

[c] Table 8.2-3

[d] Refer to forecast methodology Subsection 8.2.1

Conclusion: As the information above indicates, the Duke Energy forecast provides all of the information and data suggested by NUREG-1555.

8.2.2 FACTORS AFFECTING GROWTH OF DEMAND

Introduction

The review of the need for power and energy must consider the various factors affecting both historic and future electric loads. This subsection, as directed by NUREG-1555, examines three categories of factors that affect the demand for electricity, (1) economic and demographic trends, (2) energy efficiency and substitution, and (3) price and rate structure. The bulk of the data provided in this section is prepared for and contained in Duke Energy's 2007 IRP (Reference 1), its related material, and the Duke Energy's Spring 2007 Forecast (Reference 2) or contained in the backup material to these documents. As directed by NUREG-1555, the information and data provided in this subsection focuses on factors in or relevant to Duke Energy's relevant service area.

Economic and Demographic Trends

NUREG-1555 identifies several economic and/or demographic factors that influence the demand for electricity, such as growth in (1) employment, (2) population, or (3) income. Duke Energy's forecast uses each of these variables. The general framework of Duke Energy's forecast methodology begins with forecasts of regional economic activity, demographic trends and expected long-term weather. The economic forecasts used are obtained from Moody's Economy.com, a nationally recognized economic forecasting firm, and include economic forecasts for the two states of North Carolina and South Carolina. These economic forecasts represent long-term projections of numerous economic concepts including the following:

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

Total population forecasts are obtained from the two states' demographic offices for each county in each state, which are then used to derive the total population forecast for the 46 counties that Duke Energy serves in the Carolinas (Reference 2).

A comparison of Duke Energy's electric energy growth forecast to the EIA growth forecast is shown in Table 8.2-3. Based on the fact that these two independent forecasted annual growth rates are quite similar, it is reasonable to assume that the economic and demographic variables employed in Duke Energy's forecasting model are reasonable. In addition, NUREG-1555 indicates that "growth in demand typically follows patterns of growth in population…" Duke Energy's forecast annual growth in demand is 1.5%. The US Census Bureau (March 2004)

projects that North Carolina and South Carolina will experience annual population growth of 1.41% and 0.83%, respectively. Given that 70% of Duke Energy's load is in North Carolina, these population growth rates compare favorably to Duke Energy's forecasted energy growth rates.

Conclusion: The Duke Energy forecast, provided in its IRP, properly incorporates both economic and demographic variables identified in NUREG-1555.

Demand-Side Initiatives, Energy Efficiency, and Fuel Substitution

NUREG-1555 identifies several energy efficiency and energy substitution factors that influence the demand for electricity, and as such, should be included in the development of any electric demand forecast. The Duke Energy forecast methodology employed in its 2007 IRP (Reference 1) and Spring 2007 forecast (Reference 2) identifies energy efficiency, demand-side initiatives, and substitutes in its forecasting. The impact of these factors and how they are incorporated into Duke Energy's forecast is summarized below.

Current Energy Efficiency and Demand-Side Management Programs

Duke Energy uses energy efficiency (EE) and demand-side (DSM) programs to help manage customer demand in an efficient, cost-effective manner. In general, programs include two primary categories: programs that reduce energy consumption (conservation programs) and programs that reduce energy demand (demand response programs and certain rate structures).

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

Demand Response - Load Control Curtailment Programs

Residential Air Conditioning Direct Load Control

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

Residential Water Heating Direct Load Control

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

Demand Response - Interruptible Programs

Interruptible Power Service

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

Standby Generator Control

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

Demand Response - Time of Use Programs

Residential Time-of-Use

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

General Service and Industrial Time-of-Use

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

Hourly Pricing for Incremental Load

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

Energy Efficiency Programs

Residential Energy Star Rates

This rate promotes the development of homes that are significantly more energy-efficient than a standard home. Homes are certified when they meet the standards set by the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Energy. To earn the symbol, a home must be at least 30 percent more efficient than the national Model Energy Code for homes, or 15 percent more efficient than the state energy code, whichever is more rigorous. Independent third-party inspectors test the homes to ensure they meet the standards to receive the Energy Star symbol. The independent home inspection is the responsibility of the homeowner or builder. Electric space heating and/or electric domestic water heating are not required.

Existing Residential Housing Program

This residential program encourages increased energy efficiency in existing residential structures. The program consists of loans for heat pumps, central air conditioning systems, and energy-efficiency measures such as insulation, HVAC tune-ups, duct sealant, etc.

Special Needs Energy Products Loan Program

This residential program encourages increased energy efficiency in existing residential structures for low-income customers. The program consists of loans for heat pumps, central air conditioning systems and energy-efficiency measures such as insulation, HVAC tune-ups, duct sealant, etc.

The NCUC's May 22, 2006 Order Approving the Joint Recommendation of Duke Energy Carolinas, the Public Staff and the Attorney General for Conservation and Energy Efficiency Programs, approved the programs and required Duke Energy to file a status report as to the funding and implementation of the programs on or before July 2, 2007. Duke Energy has completed the contribution requirements to Energy Efficiency and Conservation through the programs listed above. The following provides descriptions of the initiatives undertaken and the impacts to customers.

Energy Efficiency Kits for Residential Customers

Duke Energy distributed energy efficiency starter kits with energy saving measures including a low flow shower head, window sealant material, high efficiency fluorescent bulbs, weather stripping, wall outlet and switch plate insulation material, and faucet aerators. Approximately 60,000 kits were distributed to residential customers in North Carolina through various channels including North Carolinas Assistance Agencies and in conjunction with Duke Energy's Personalized Energy Report program. Duke Energy surveyed a number of participants and currently estimates an average energy savings of 403 kWh per kit, yielding a total estimated savings of 24,200 MWh for all kits distributed. These savings estimates are for the measures only and do not include any customer behavioral changes or additional measures purchased by the customer after exposure to the kit and other DSM materials.

Energy Efficiency Video for Residential Customers

Duke Energy distributed a home education, video-based energy efficiency series for residential customers. Individual videos covered energy saving tips for summer, winter, around the house, humidity, and HVAC.

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

Large Business Customer Energy Efficiency Assessments

Duke Energy provided phone based and on-site energy efficiency assessments to North Carolina commercial, industrial, and institutional customers. Where applicable, companies partnering with Duke Energy to provide assessments used energy simulation software to develop models for customer facilities. Approximately 100 customer facilities participated in a phone-based and/or on-site assessment.

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

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

Large Business Customer Energy Efficiency Tools

Duke Energy provided an online assessment tool for commercial, manufacturing, and institutional customers through Duke Energy's Business Services Newsline. This assessment tool was developed through cooperation between Duke Energy and the provider of the Newsline service. Approximately 40 customers have used the online tool to generate a report of potential energy saving opportunities. The online audits provide energy saving ideas for customers in a general manner based on customer responses to a few questions. The report provides numerous links to articles in the Newsline for areas of particular interest.

As stated above, Duke Energy worked with several partners to perform Energy Efficiency Assessments. Where applicable, additional energy efficiency modeling tools such as eQuest (a U.S. Department of Energy modeling tool found at www.doe2.com) and Energy Star Portfolio Manager were used to further evaluate customer facilities and enhance the value of the assessments (Reference 1).

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

With this new approach, Duke Energy would be compensated similarly for meeting customer demand, whether through saving a watt or producing a watt. The approach encourages the expansion of cost effective EE/DSM programs by driving program costs down and innovation up. The company would be compensated for the results it produces.

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

Yet pursuing EE/DSM initiatives will not meet all Duke Energy's growing demands for electricity. Duke Energy still envisions the need to build or buy clean coal, nuclear, and gas generation as well as cost-effective renewable generation, but the save-a-watt approach can address a portion of the 3190 MW needed by 2012 by obtaining approximately 600 MW of new EE/DSM over the next four years.

Duke Energy's save-a-watt proposal is designed to expand the reach of EE/DSM programs in its retail service territory by providing the company with appropriate regulatory incentives to aggressively pursue such expansion. The proposed regulatory treatment enables the company to meet a portion of its substantial near-term capacity resource needs on a cost-effective basis, while at the same time reducing overall air emissions. Further, customers will be provided more options to control their energy bills. Over the long term, the regulatory treatment proposed by the company should encourage the company to pursue additional EE/DSM initiatives, further offsetting capacity needs.

In 2006, Duke Energy established EE/DSM-related collaborative groups, consisting of stakeholders from across its service area, and charged them with recommending a new set of DSM-related programs for the Company's customers. Collaborative participants include: Environmental Defense, the Sierra Club, North Carolina Sustainable Energy Association (visitor), Environmental Edge Consulting, Air Products, The Timken Company, Lowe's Home Improvement Corporation, Food Lion, Greenville County Schools, Charlotte-Mecklenburg Schools, University of North Carolina Chapel Hill, University of South Carolina Upstate, South Carolina State Energy Office, North Carolina State Energy Office, North Carolina Attorney General's Office, South Carolina Office of Regulatory Staff, North Carolina Utilities Commission Public Staff, Duke Energy, and Advanced Energy (as meeting facilitator).

Duke Energy filed its EE/DSM plan in North Carolina on May 7, 2007 (Reference 4) and in South Carolina on September 28, 2007 (Reference 5), and proposed implementation of approximately 1,865 MW and 743 GWh of new and replacement DSM across North and South Carolina by 2011. Future measurement and verification (M&V) analyses along with ongoing product management decisions will be utilized to incorporate updated information into the 2007 IRP.

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

Demand Response - Power Manager

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

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

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

***Demand Response* - PowerShare®**

PowerShare® is a non-residential curtailable program consisting of two options, an Emergency Option and a Voluntary Option. The Emergency Option customers will receive capacity credits monthly based on the amount of load they agree to curtail during utility-initiated emergency events. Customers enrolled in the Emergency Option may also be enrolled in the Voluntary Option and eligible to earn additional credits. Voluntary Option customers will be notified of pending emergency or economic events and log on to a Web site to view a posted energy price for that particular event. Customers will then have the option to nominate load for the event and will be paid the posted energy credit for load curtailed.

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

Conservation Programs - Residential Energy Assessments

This program will assist residential customers in assessing their energy usage and provide recommendations for more efficient use of energy in their homes. The program will also help identify those customers who could benefit most by investing in new demand-side management measures, undertaking more energy efficient practices and participating in Duke Energy 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 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 will provide an Online Home Energy Audit including specific energy saving recommendations.

- On-site Audit and Analysis. Duke Energy will perform one on-site assessment of an owner-occupied home and its energy efficiency-related features during the life of this program.

- Low-Income Multi-Family Assessment Pilot. Duke Energy will select property managers to coordinate communication and scheduling of property audits with tenants. Assessments will focus primarily on building envelope and HVAC.

Conservation Programs - Smart $aver® for Residential Customers

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

This residential compact fluorescent light bulbs (CFLs) incentive program will provide market incentives to customers and market support to retailers to promote use of CFLs. Special incentives to buyers and in-store support will increase demand for the products, spur store

participation, and increase availability of CFLs to customers. Part of this program is to educate customers on the advantages (functionality and savings) of CFLs so that they will continue to purchase these bulbs in the future when no direct incentive is available.

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

Conservation Programs - Low Income Services

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

Conservation Programs - 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.

Conservation Programs - Non-Residential Energy Assessments

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

The types of available energy assessments are as follows:

- Online Analysis. The customer provides information about their facility. Duke Energy will provide a report including energy saving recommendations.

- Telephone Interview Analysis. The customer provides information to Duke Energy through a telephone interview after which billing data, and if available, load profile data, will be analyzed. Duke Energy 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 will cover 50% of the costs of an on-site assessment. Duke Energy 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 system. Duke Energy may provide additional engineering and analysis, if requested and the customer agrees to pay the full cost of the additional assessment.

Conservation Programs - Smart $aver® for Non-Residential Customers

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

Fuel Substitution

NUREG-1555 requires the consideration of the effect of substitution on load growth in order to determine if potential fuel substitution could tend to increase or decrease the demand for electricity.

Residential Fuel Substitution

Residential customers in the Duke Energy service area can choose alternative fuels for space heating and water heating. Among the fuel choices are electricity, natural gas, fuel oil, or solar. Although the price of alternate fuels was not used directly in the Spring, 2007 Forecast, the residential forecast used appliance stock information from the EIA. EIA's projection of the residential appliance stock incorporates prices of alternate fuels. Market penetration and trends in the penetration of electric end-use are incorporated into the forecast through use of historical data and through use of external forecasting sources. Thus the impact of fuel switching is incorporated into the forecast.

Non-residential Fuel Substitution

Industrial customers can often choose natural gas or electricity for processes. Sometimes customers have equipment such as boilers that can switch between fuels. The trends for fuel substitution are incorporated in the forecast through the use of historical data. Duke Energy further modifies the industrial and commercial forecasts to reflect the effects of fuel switching from customer's switching to electric or dual fueled boilers. The rate of switching is based on the expected price of natural gas versus electricity. The amount of the boiler projections that differ from historical trends are added back to the forecast.

Conclusion: The Duke Energy forecast provided in its IRP, properly incorporates demand-side options, energy efficiency, and fuel substitution, which was identified in NUREG-1555 as factors to consider in developing an electric energy forecast.

Price and Rate Structure

NUREG-1555 identifies factors related to energy price as affecting the forecast of future electric demand. It goes on to suggest three price-related factors that could affect future electric demand, including (1) the price of electricity, (2) alternative rate structures, and (3) economic, employment and demographic trends. With respect to the impact of price, NUREG-1555 suggests that price elasticity be employed to generate more accurate forecasts.

Price elasticity is a measure of the responsiveness of Kwh usage to price changes. It is an estimate of the effect that a given percentage change in price would have on Kwh sales and is

defined to be the ratio of the percent change in Kwh usage divided by the percent change in price. An elasticity less than one indicates that electricity is relatively inelastic to price. In the Duke Energy 2007 Spring Forecast (Reference 2) the price elasticities employed were for residential (-0.205), commercial (-0.270) and industrial (-0.388). Duke's estimates of elasticity are comparable to results of surveys from other electric utilities. In addition, the IRP analyses that included a carbon tax included the impact of the tax on price of electricity and thus demand.

Consider now the second price related factor identified by NUREG-1555 - alternative rate structures. In North Carolina it has been the policy of the State (Reference 6):

> "to conserve energy through efficient utilization of all resources... [and] ...make plans for the public utilities to bill customers by a system of nondiscriminatory peak pricing, with incentive rates for off peak use of electricity charging more for peak periods than for off peak periods to reflect the higher cost of providing electric service during periods of peak demand on the utility system…" "Subject to the approval of the Commission, however, electrical utilities, distribution electric cooperatives and consolidated political subdivisions may establish classifications of rates and services and such classifications may take into account the conditions and circumstances surrounding the service, such as the time when used, the purpose for which used, the demand upon plant facilities, the value of the service rendered and any other reasonable consideration"

South Carolina Code of Laws Section 58-27-840 similarly promotes time based rates.

Furthermore, Duke Energy has been actively promoting time-based rates for at least the last three decades[c]. Today, in North Carolina and South Carolina, Duke Energy offers voluntary time-based rates for virtually every customer, including residential, commercial, and industrial and Duke Energy has approximately 2000 residential customers, 18,000 commercial customers, and 1,800 industrial accounts on time-of-use. Energy sales on time-of-use rates accounts for almost 50% of retail energy sales (Reference 7).

Based on the fact that the Duke Energy has offered and customers accepted time-based rate structures for at least two plus decades, the impact of these type rates is already reflected in the historical energy usage data. Consequently, Duke Energy's forecasting methodology, which incorporates this historical information, properly accommodates the impact of time differentiated rate structures.

Conclusion: The Duke Energy forecast, provided in its IRP, properly incorporates both price and rate structure variables identified in NUREG-1555.

8.2.3 THE NEED FOR POWER: OVERALL EVALUATION OF FINDINGS

Subsections 8.2.1 and 8.2.2 discussed the need for power both from a forecast perspective and from the perspective of factors that could impact the demand for electric service. As discussed in

c. In NCUC Docket No. E-100, Sub 32, in the Order Adopting 1978 Report, issued Dec. 29, 1978, this Commission ordered the Companies to offer voluntary time-of-day pricing rates to certain customers.

these subsections, Duke Energy's forecast and the methodology used to produce this forecast leads to the following specific conclusions:

- Duke Energy's forecast methodology incorporates all the features suggested by NUREG-1555.
- Duke Energy's historical forecasts have been reasonably accurate over the last 15 years.
- Duke Energy's electric demand and energy forecast is comparable to an independent forecast from the EIA.
- Duke Energy's electric demand and energy forecast provides all the information and data suggested by NUREG-1555.
- The Duke Energy forecast properly incorporates both economic and demographic variables identified as factors to consider in NUREG-1555.
- The Duke Energy forecast properly incorporates demand-side programs, energy efficiency, and fuel substitution identified as factors to consider in NUREG-1555.
- The Duke Energy forecast, provided in its IRP, properly incorporates both price and rate structure variables identified as factors to consider in NUREG-1555.

8.2.4 REFERENCES

1. Duke Energy Carolinas Annual Plan, November 2007
2. Duke Energy Carolinas Spring 2007 Forecast
3. SERC 2007 Information Summary, July 2007
4. Duke Energy Carolinas, Energy Efficiency Plan, NCUC Docket E-1, Sub 831, Filed May 7, 2007.
5. Duke Energy Carolinas, Energy Efficiency Plan, PSCSC, Filed September 28, 2007
6. NCGS 62-155, "Electric Power Rates to Promote Conservation", http://www.ncga.state.nc.us/gascripts/Statutes/StatutesTOC.pl?Chapter=0062
7. Duke Energy Carolinas, FERC Form 1, for 2006, page 304

TABLE 8.2-1
PEAK DEMAND LOAD FORECAST

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

a) The MW (demand) forecasts above are the same as those shown on page 32 of the Spring 2007 Forecast Book, but the peak forecasts vary from those shown on pages 27-30 of the Forecast Book, primarily because Spring 2007 Forecast Book's peak forecasts include the total resource needs for all Catawba Joint Owners and do not include the total resource needs of Nantahala Power & Light.

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

c) The load forecast includes Duke Energy's contract to serve Blue Ridge, Piedmont and Rutherford Electric Membership Cooperatives' supplemental load requirements from 2006 through 2027. A new contract between Duke Energy and NCEMC will provide additional hourly electricity sales to NCEMC beginning in January 2009.

d) As part of the joint ownership arrangement for the Catawba Nuclear Station, the NCMPA1 took sole responsibility for its supplemental load requirements beginning January 1, 2001. As a result, NCMPA1 supplemental load requirements above its ownership interest in Catawba Nuclear Station are not reflected in the forecast. In 2002, NCMPA1 entered into a firm-capacity sale beginning January 1, 2003, when it sold 400 MW of its ownership interest in Catawba. In 2003, NCMPA1 entered into another agreement beginning January 2004, when it chose not to buy reserves for its remaining ownership interest (432 MW) from Duke Energy. These changes reduce the Duke Energy load forecast by the forecasted NCMPA1 load in the control area (953 MW at 2006 summer peak) and the available capacity to meet the load obligation by its Catawba ownership (832 MW). The Plan assumes that the reductions remain over the 20-year planning horizon.

e) The PMPA assumed sole responsibility for its supplemental load requirements beginning January 1, 2006. Therefore, PMPA supplemental load requirements above its ownership interest in Catawba Nuclear Station are not reflected in the load forecast beginning in 2006. Neither will the PMPA ownership interest in Catawba be included in the load forecast beginning in 2006, because PMPA also terminated its existing Interconnection Agreement with Duke Energy effective January 1, 2006.

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

Source: Reference 1

TABLE 8.2-2
ELECTRIC ENERGY RETAIL LOAD GROWTH

Time Period	Total Retail	Residential	General Service	Industrial Textile	Industrial Non-Textile
1991 to 2006	1.5%	2.3%	3.4%	-4.4%	1.5%
1991 to 2001	2.0%	2.4%	4.1%	-2.5%	1.8%
2001 to 2006	0.6%	2.1%	1.9%	-8.1%	0.7%
2006 to 2027	1.5%	1.8%	2.4%	-4.4%	1.0%

Source: Reference 2

TABLE 8.2-3
DUKE ENERGY FORECAST OF ENERGY RATE OF GROWTH COMPARED TO EIA FORECASTS

GROWTH RATE FORECAST (2006-2017)

Customer Class	Duke Energy[a]	EIA[b] SERC Region
Residential	1.9%	1.73%
Commercial	2.5%	2.62%
Industrial	-0.1%[c]	0.67%
Total	1.5%	1.68%

a) Reference 2

b) EIA, Annual Energy Outlook, Supplemental Tables, 2007, http://www.eia.doe.gov/oiaf/aeo/index.html

c) Non-Textile Industrial growth is projected to be 1.1% while Textile growth is projected to be 5.5%

TABLE 8.2-4
DUKE ENERGY HISTORICAL FORECAST ACCURACY

Year	Actual Absolute Forecast Error	Weather Normalized Absolute Forecast Error
1991	1.1%	0.2%
1992	0.4%	1.4%
1993	2.9%	0.4%
1994	4.9%	1.8%
1995	3.5%	1.4%
1996	2.0%	3.2%
1997	1.1%	2.1%
1998	1.5%	2.0%
1999	2.2%	2.0%
2000	1.7%	2.0%
2001	1.8%	1.5%
2002	1.6%	1.7%
2003	5.9%	3.2%
2004	8.6%	2.8%
2005	2.0%	3.6%
2006	2.9%	3.3%
AVERAGE	**3.2%**	**2.4%**

8.3 POWER SUPPLY

8.3.1 INTRODUCTION

The purpose of this subsection, as specified in NUREG-1555 is to identify the present and planned generating capability and the present and planned purchases and sales of power and energy. As directed by NUREG-1555, the scope of this review "will include consideration of the type (e.g., coal-fired) and function (e.g., baseload) of the relevant region's plants, the nature of purchases and sales (firm and nonfirm) of power and energy, and any proposed additions, retirements, redesignations, deratings, or upratings of the relevant region's plants."

Based on the fact that this is baseload generation, and as such not subject to a long term power purchase agreement (see Subsection 8.1.4), and because the relevant service area has been shown to be Duke's retail customers in its franchise service territory (Subsection 8.1.5), this analysis needs to primarily focus on resources in Duke Energy's franchise service territory. In addition, very little competitive generation has become available in the service area. There is no baseload merchant generation in the service area. There are two merchant generating facilities with approximately 1800 MWs of peaking/intermediate capacity. The Broad River Energy Facility, owned by Calpine is a simple-cycle combustion turbine, 847 MW. The Rowan Facility, owned by Southern Company, is three simple-cycle combustion turbines and one combined cycle unit, 925 MW.

There is no regional generation planning group or ISO, so Duke Energy's IRP (Reference 1) and State public service commission reports, as well as SERC (reliability only) and EIA reports, comprise the principal generation studies available for review. These documents are relied upon extensively in this subsection. It should be noted that NUREG-1555 allows for the power supply review and evaluation to be based on acceptable state or regional reports if the evaluation meets these four criteria; that the methodology be (1) developed in a systematic fashion, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty. As discussed and demonstrated in Section 8.0, the Duke Energy IRP process meets or exceeds these four criteria. In addition, as will be discussed and demonstrated in this subsection, the power supply information contained in the Duke Energy IRP meets additional criteria discussed in NUREG-1555.

Baseload plants are generally defined as those plants operating nearly full cycle, or 24 hours a day, seven days a week, and typically operate more than 5000 hours annually. Baseload facilities are usually either nuclear or coal-fired. Intermediate facilities cycle when load increases or decreases, and typically these are smaller or older coal-fired facilities and oil/gas plants that typically operate between 1000 and 5000 hours per year. Peaking facilities operate infrequently to meet system peak demand. These are usually combustion turbines and pumped storage, hydro, or other smaller units that typically operate less than 1000 hours per year (Reference 2).

As directed by NUREG-1555 the power supply data is presented in four basic categories:

- existing and planned generation in Subsection 8.3.2,
- purchases and sales in Subsection 8.3.3,
- distributed and self-generation in Subsection 8.3.4, and

- other resources in Subsection 8.3.5.

This section ends with an overall forecast of Duke Energy's load/demand resource balance presented in Subsection 8.3.6.

8.3.2 EXISTING AND PLANNED GENERATING CAPABILITY

Existing Generation in Relevant Service Area

The relevant service area existing and planned generating capability are shown in Tables 8.3-1, 8.3-2, and 8.3-3. Duke Energy currently has 21,180 MW of Summer Capacity and 21,902 MW of Winter Capacity. At the present time baseload generation comprises approximately 55% of the summer capacity. Table 8.3-4 shows the capacity factors for the past 3 years. Duke Energy's baseload facilities (operating greater than 5000 hours per year) are Belews Creek Steam Station, Marshall Steam Station, Allen Steam Station, Cliffside Steam Station Unit 5, Oconee Nuclear Station, McGuire Nuclear Station, and Catawba Nuclear Station[a].

Planned Additions, Life Extensions, or Upratings to Generation in Relevant Service Area

Duke Energy 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 expiration, and adjustments in DSM capability affect the amount of resources Duke Energy will have to meet its load obligation. Below are the known or anticipated changes and their impacts on the resource mix.

New Cliffside Pulverized Coal Unit

On March 21, 2007, the NCUC granted a Certificate of Public Convenience and Necessity (CPCN) for the construction of one 800-MW supercritical pulverized coal unit at the existing Cliffside Station (Reference 3). A number of conditions were also part of the order, including: 1) retiring the existing Cliffside Units 1-4 (approximately 200 MW) no later than the commercial operation date of the new unit, 2) honoring Duke Energy's commitment to invest 1% of its annual retail revenues in demand-side management programs (subject to the results of the ongoing collaborative workshops and appropriate regulatory treatment), and 3) that Duke Energy shall retire older coal-fired generating units (in addition to Cliffside Units 1-4) (Table 8.3-6) 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 DSM programs up to the MW level added by the new Cliffside unit.

The draft air permit was issued for public comment and there was a public hearing on September 18, 2007. A final permit is expected to be issued in November 2007. Other permit approvals such as erosion control permits, wastewater discharge permits, and landfill permits are expected over the next year. Construction is expected to start in the first quarter of 2008 with a commercial operation date of 2012.

a. Duke Energy owns 12.5% of the Catawba Nuclear Station.

Catawba Nuclear Station

In December 2006, Duke Energy announced an agreement to purchase a portion of Saluda River Electric Cooperative, Inc.'s ownership interest in the Catawba Nuclear Station. Under the terms of the agreement, Duke Energy will pay approximately $158 million for an additional ownership interest in the station. Following the close of the transaction, Duke Energy will own approximately 19 percent of the Catawba Nuclear Station, compared to the current ownership of 12.5 percent. The transaction, which is expected to close in the third quarter of 2008, is subject to approval by various state and federal agencies, including the PSCSC (for a revision to the CPCN), the NRC, and FERC. The filings for these approvals are expected to begin during the fourth quarter of 2007.

Bridgewater Hydro Powerhouse Upgrade

Seismic remediation requirements for the Linville Dam resulted in a compacted fill design that would require removal of the existing Bridgewater powerhouse and generation. There were two options to accomplish water release: 1) installation of flow valves, or 2) a new powerhouse and generation equipment. The latter option was selected with the two existing 11.5 megawatt units being replaced by two 15 megawatt units and a small 1.5 megawatt unit to be used to meet continuous release requirements. The NCUC granted a CPCN to install the new powerhouse and generation equipment (Reference 4). The current schedule projects powerhouse construction to begin in March 2008 with a release to dispatch date of June 2010.

Pending CPCN Proceedings

Buck Combined Cycle Unit

On June 29, 2007, Duke Energy filed preliminary information for a CPCN for approximately 600 MW of combined cycle generation at the Buck Steam Station in Salisbury, N.C. A final CPCN application is expected to be filed with the NCUC by the end of 2007. The CPCN approval is expected to be received by the beginning of the third quarter of 2008. The air permit application is expected to be submitted during the fourth quarter of 2007, with the final permit expected to be received by the third quarter of 2008. The unit would be phased, in that the simple cycle capacity would be available for operation by the summer of 2010, with the combined cycle operation available by the summer of 2011 for a total capacity of 1200 MW.

Dan River Combined Cycle Unit

On June 29, 2007, Duke Energy also filed a preliminary CPCN for approximately 600 MW of combined cycle generation at the Dan River Steam Station in Eden, N.C. A final CPCN application is expected to be filed with the NCUC by the end of 2007. The unit would be phased, in that the simple cycle capacity would be available for operation by the summer of 2011, with the combined cycle operation available by the summer of 2012.

Hydroelectric Relicensing

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

During 2003, Duke Energy filed applications to renew licenses for 4 MW of hydroelectric capacity for:

- Bryson
- Dillsboro
- Franklin
- Mission

In 2004, Duke Energy filed applications to renew licenses approximately 58 MW of capacity at:

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

Inability to renew these licenses would result in a loss of over 60 MW capacity for Duke Energy.

In May 2004, Duke Energy filed an application to surrender the license for its Dillsboro Project (230 kW), a result of binding settlement agreements with stakeholders related to the relicensing of the East Fork, West Fork, and Nantahala Projects. Those settlement agreements were filed with FERC in January 2004 and call for the removal of the Dillsboro Dam.

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

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

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

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

18 CFR 16.18(c), an annual license under section 15(a)(1) of the FPA is renewed automatically without further order or notice by the Commission."

On March 23, 2007, FERC issued a notice of authorization for continued project operation for the West Fork project, authorizing continued operation under the terms of the previous license until January 31, 2007. The FERC notice states, "[I]f issuance of a new license (or other disposition) does not take place on or before January 31, 2007, notice is hereby given that, pursuant to 18 CFR 16.18(c), an annual license under section 15(a)(1) of the FPA is renewed automatically without further order or notice by the Commission."

Duke Energy filed a Notice of Intent to File an Application for a New License for the Catawba/ Wateree Project No. 2232 in 2003, five years prior to expiration of the license. The Catawba-Wateree Project (852 MW) includes the following developments:

- Bridgewater,
- Rhodhiss,
- Oxford,
- Lookout Shoals,
- Cowans Ford,
- Mountain Island,
- Wylie,
- Fishing Creek,
- Great Falls,
- Dearborn,
- Rocky Creek,
- Cedar Creek, and
- Wateree.

Duke Energy's Catawba-Wateree Hydro Project relicensing process gave early and ongoing involvement to local governments, state and federal resource agencies, special interest groups and the general public. More than 160 stakeholders from more than 80 organizations were involved in a collaborative process that involves two state licensing teams and four regional advisory groups. The goal of these groups was to reach a mutually acceptable agreement on all interests related to the project and include those agreements in Duke Energy's Federal Energy Regulatory Commission license application. Final agreement was reached with 82% (70) of the stakeholders.

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

Table 8.3-5 provides a summary of the hydro relicensing efforts.

Planned Generation Unit Retirements in Relevant Service Area

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 8.3-6 reflects current assessments of generating units with identified decision dates for retirement or major refurbishment, including the commitments associated with the conditions in Reference 3, granting a CPCN to build Cliffside Unit 6. This table shows the assumptions used for planning purposes rather than firm commitments concerning the specific units to be retired and/or their exact retirement dates. The conditions of the units are evaluated annually and decision dates are revised as appropriate. Duke Energy will develop orderly retirement plans that consider the implementation, evaluation, and achievement of demand-side management goals, system reliability considerations, long-term generation maintenance and capital spending plans, manpower allocations, long-term contracts including fuel supply and contractors, long-term transmission planning, and major site retirement activities.

Regional Generation Forecast

Duke Energy does not rely upon purchase power for baseload needs as discussed in Subsection 8.1.4. Nevertheless, it is instructive to consider whether the possibility even exists for such an option. To examine this potential, NERC annually issues a "Long-Term Reliability Assessment" that is a ten year forecast of generation, load, and transmission for the entire US, presented on a regional basis (Reference 5). Referring to this latest reliability assessment the SERC region is expected to have capacity margins between 14% and 15% through 2015, and these margins assume the use of load management and interruptible contracts. A capacity margin of 14% to 15% equates to a reserve margin of 16.3% to 17.4% which is essentially equal to or slightly below Duke Energy's planning reserve margins, and Duke Energy's planning reserve margin has been deemed appropriate by its North Carolina and South Carolina regulators[b] (see Subsection 8.1.4). The capacity margin projections include the planned addition of 37,000 MWs of capacity in the SERC Region, indicating a need for additional generation to maintain acceptable capacity reserve margins across the region (Reference 5). In and of itself, assuming other states in the SERC region required similar reserve margin, this level of reserves in the SERC region would indicate that Duke Energy would not likely be able to purchase, on a long-term basis, any baseload capacity from other potential suppliers in the SERC region. Power purchased outside the SERC region would likely suffer too much transmission loss to be worthwhile. Moreover, the NERC Reliability Assessment goes on to say that in SERC, "the majority of planned capacity additions are gas/oil fueled, combustion turbine or combined-cycle units," (Reference 5) and these type generating units are not suitable generating units to provide baseload capacity.

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

Therefore, it is unreasonable to assume that there would be sufficient, baseload type, long-term purchase power available within SERC to offset the need for the Lee Nuclear Station.

In addition, there are only two large merchant generators in the Duke Energy relevant service area. These facilities are gas-fired simple cycle combustion turbines and one combined cycle unit with a nameplate capacity of about 1800 MWs. At the present time, the Duke Energy has no contract for purchases from these facilities. However, due to the fact that these resources are gas-fired facilities and operate at a much higher cost than nuclear power, they would not be an appropriate substitute for the baseload Lee Nuclear Station.

8.3.3 PURCHASES AND SALES

Wholesale Power Sales

Duke Energy provides full requirements wholesale power sales to Western Carolina University (WCU), the city of Highlands and to customers served under Rate Schedule 10A. These customers' load requirements are included in the Duke Energy load obligation. Under Interconnection Agreements, Duke Energy is obligated to provide backstand service for NCEMC throughout the 20-year planning horizon and Saluda River until January 1, 2009, up to the amount of their ownership entitlement in Catawba Nuclear Station. In 2009, the Saluda River ownership portion of Catawba will not be reflected in the forecast due to Saluda River's sale of this interest. NCEMC and Duke Energy are purchasing Saluda River's share of Catawba. The share purchased by NCEMC will be added to the NCEMC total beginning in 2009. Saluda River will become a full-requirements customer of another utility as of January 1, 2009.

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

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

Beginning September 1, 2006, firm wholesale agreements became effective between Duke Energy and three entities, Blue Ridge Electric Membership Cooperative, Piedmont Electric Membership Cooperative, and Rutherford Electric Membership Cooperative. Duke Energy will supply their supplemental resource needs through 2021. This need grows to approximately 600 MW by 2011 and approximately 800 MW by 2021. The analyses in this Annual Plan assumed that these contracts would be renewed or extended through the end of the planning horizon.

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

Table 8.3-7 contains information on Duke Energy's wholesale sale contracts.

Wholesale Power Purchases

Duke Energy is an active participant in the wholesale market for capacity and energy. Duke Energy has issued RFPs for purchased intermediate and peaking power capacity over the past several years, and has entered into purchased power arrangements for over 2,000 MW over the past 10 years. All of these arrangements expire by the end of 2010. In addition, Duke Energy has contracts with a number of Qualifying Facilities. Table 8.3-8 shows both the purchased power capacity obtained through RFPs as well as the larger Qualifying Facility agreements. The 2007 IRP provides additional information on all purchases from Qualifying Facilities (Reference 1).

Requests for Proposals

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

An RFP for conventional energy supply proposals was released on May 14, 2007. The RFP requested bids for intermediate and peaking resources of up to 800 megawatts for the 2009-2010 period and up to 2000 megawatts for 2013 and beyond. Ten bidders submitted a total of forty-five bids spanning time periods of two to twenty years. A third party facilitator is being utilized through short list selection to assure selection integrity. Bid evaluation and short list selection is underway. Negotiations and execution of contracts are expected to be completed by the end of the first quarter of 2008 (Reference 1).

8.3.4 DISTRIBUTED AND SELF GENERATION

There are a number of small power producers that provide additional limited electric generating resources to Duke Energy. Typically, these are renewable or combined heat and power projects which are promoted by both federal and state policies, such as guaranteed purchase obligations on the part of utilities and tax incentives. These are listed in Table 8.3-9 and they are included in Duke Energy's resource mix. There are also a number of small, customer-owned generating units used for standby generation that are included in Duke Energy's supply resources, listed in Table 8.3-10. In addition, there are a number of smaller, customer-owned generating units that are mostly diesel fired, that are not in the Duke Energy's supply resources but whose impact is reflected in the load forecast, and these are listed in Table 8.3-11.

8.3.5 OTHER RESOURCES

There are additional demand-side resources that must be considered in the final determination of resource needs. These have already been discussed in Subsection 8.2.2, but they will be summarized here. There are essentially three categories of EE/DSM program: load control or curtailable service whereby the utility can activate the curtailment, voluntary interruptible or rate related programs, and energy efficiency programs. Table 8.3-12 provides a forecast of the EE/DSM activities.

8.3.6 OVERALL FORECAST LOAD BALANCE

Duke Energy's planned capacity not only has to meet the forecasted energy and demand load, but also meet Duke Energy's planning reserve margin of 17 % (see Subsection 8.1.4). Based on current planning and forecasts, in order to meet the forecasted load growth, plus 17 percent target planning reserve margin, Duke Energy needs additional energy capacity as illustrated in Figure 8.3-1. Table 8.3-13 provides a year-to-year forecast of the cumulative resource additions required to meet projected needs. As this table and figure indicate, the need for additional capacity grows over time due to load growth, unit capacity adjustments, unit retirements, EE/DSM program reductions and expirations of purchased-power contracts. The need for additional capacity grows to approximately 6620 MW by 2017 and 10,680 MW by 2027.

8.3.7 REFERENCES

1. Duke Energy Carolinas Annual Plan, November, 2007

2. NCUC Annual Report Regarding Long Range Needs for Expansion of Electric Generation Facilities for Service in North Carolina, November 2006, page 15

3. NCUC Order dated March 21, 2007, in Docket No. E-7, Sub 790

4. NCUC Order dated June 7, 2007, in Docket No. E-7, Sub 827.

5. NERC 2006 Long-Term Reliability Assessment, November 2006, p. 91

TABLE 8.3-1 (Sheet 1 of 8)
NORTH CAROLINA EXISTING GENERATION [(a)(b)(c)]

Name	Unit	Summer Capacity MW	WInter Capacity MW	Location	Plant Type
Allen	1	165.0	170.0	Belmont, N.C.	Conventional Coal
Allen	2	165.0	170.0	Belmont, N.C.	Conventional Coal
Allen	3	265.0	274.0	Belmont, N.C.	Conventional Coal
Allen	4	280.0	286.0	Belmont, N.C.	Conventional Coal
Allen	5	270.0	279.0	Belmont, N.C.	Conventional Coal
Allen Steam Station		1145.0	1179.0		
Belews Creek	1	1135.0	1160.0	Belews Creek, N.C.	Conventional Coal
Belews Creek	2	1135.0	1160.0	Belews Creek, N.C.	Conventional Coal
Belews Creek Steam Station		2270.0	2320.0		
Buck	3	75.0	76.0	Salisbury, N.C.	Conventional Coal
Buck	4	38.0	39.0	Salisbury, N.C.	Conventional Coal
Buck	5	128.0	131.0	Salisbury, N.C.	Conventional Coal
Buck	6	128.0	131.0	Salisbury, N.C.	Conventional Coal
Buck Steam Station		369.0	377.0		
Cliffside	1	38.0	39.0	Cliffside, N.C.	Conventional Coal
Cliffside	2	38.0	39.0	Cliffside, N.C.	Conventional Coal
Cliffside	3	61.0	62.0	Cliffside, N.C.	Conventional Coal
Cliffside	4	61.0	62.0	Cliffside, N.C.	Conventional Coal
Cliffside	5	562.0	568.0	Cliffside, N.C.	Conventional Coal
Cliffside Steam Station		760.0	770.0		
Dan River	1	67.0	69.0	Eden, N.C.	Conventional Coal
Dan River	2	67.0	69.0	Eden, N.C.	Conventional Coal
Dan River	3	142.0	145.0	Eden, N.C.	Conventional Coal

TABLE 8.3-1 (Sheet 2 of 8)
NORTH CAROLINA EXISTING GENERATION [a][b][c]

Name	Unit	Summer Capacity MW	WInter Capacity MW	Location	Plant Type
Dan River Steam Station		276.0	283.0		
Marshall	1	385.0	385.0	Terrell, N.C.	Conventional Coal
Marshall	2	385.0	385.0	Terrell, N.C.	Conventional Coal
Marshall	3	670.0	670.0	Terrell, N.C.	Conventional Coal
Marshall	4	670.0	670.0	Terrell, N.C.	Conventional Coal
Marshall Steam Station		2110.0	2110.0		
Riverbend	4	94.0	96.0	Mt. Holly, N.C.	Conventional Coal
Riverbend	5	94.0	96.0	Mt. Holly, N.C.	Conventional Coal
Riverbend	6	133.0	136.0	Mt. Holly, N.C.	Conventional Coal
Riverbend	7	133.0	136.0	Mt. Holly, N.C.	Conventional Coal
Riverbend Steam Station		454.0	464.0		
TOTAL N.C. CONVENTIONAL COAL		7384.0 MW	7503.0 MW		
Buck	7C	31.0	31.0	Salisbury, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Buck	8C	31.0	31.0	Salisbury, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Buck	9C	31.0	31.0	Salisbury, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Buck Station CTs		93.0	93.0		
Dan River	4C	30.0	30.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine

TABLE 8.3-1 (Sheet 3 of 8)
NORTH CAROLINA EXISTING GENERATION [a][b][c]

Name	Unit	Summer Capacity MW	WInter Capacity MW	Location	Plant Type
Dan River	5C	30.0	30.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Dan River	6C	25.0	25.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Dan River Station CTs		85.0	85.0		
Lincoln	1	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	2	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	3	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	4	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	5	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	6	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	7	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	8	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	9	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine

TABLE 8.3-1 (Sheet 4 of 8)
NORTH CAROLINA EXISTING GENERATION [a][b][c]

Name	Unit	Summer Capacity MW	WInter Capacity MW	Location	Plant Type
Lincoln	10	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	11	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	12	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	13	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	14	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	15	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	16	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln Station CTs		1267.2	1488.0		
Riverbend	8C	30.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	9C	30.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	10C	30.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	11C	30.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine

TABLE 8.3-1 (Sheet 5 of 8)
NORTH CAROLINA EXISTING GENERATION [a][b][c]

Name	Unit	Summer Capacity MW	WInter Capacity MW	Location	Plant Type
Riverbend Station CTs		120.0	120.0		
Rockingham	1	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	2	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	3	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	4	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	5	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham CTs		825.0	825.0		
TOTAL N.C. COMB. TURBINE		2390.2 MW	2611.0 MW		
McGuire	1	1100.0	1156.0	Huntersville, N.C.	Nuclear
McGuire	2	1100.0	1156.0	Huntersville, N.C.	Nuclear
McGuire Nuclear Station		2200.0	2312.0		
TOTAL N.C. NUCLEAR		2200.0 MW	2312.0 MW		
Bridgewater	1	11.5	11.5	Morganton, N.C.	Hydro
Bridgewater	2	11.5	11.5	Morganton, N.C.	Hydro

TABLE 8.3-1 (Sheet 6 of 8)
NORTH CAROLINA EXISTING GENERATION [(a)(b)(c)]

Name	Unit	Summer Capacity MW	WInter Capacity MW	Location	Plant Type
Bridgewater Hydro Station		23.0	23.0		
Bryson City	1	0.48	0.48	Whittier, N.C.	Hydro
Bryson City	2	0.5	0.5	Whittier, N.C.	Hydro
Bryson City Hydro Station		0.98	0.98		
Cowans Ford	1	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	2	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	3	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	4	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford Hydro Station		325.0	325.0		
Dillsboro	1	0.175	0.175	Dillsboro, N.C.	Hydro
Dillsboro	2	0.05	0.05	Dillsboro, N.C.	Hydro
Dillsboro Hydro Station		0.225	0.225		
Lookout Shoals	1	9.3	9.3	Statesville, N.C.	Hydro
Lookout Shoals	2	9.3	9.3	Statesville, N.C.	Hydro
Lookout Shoals	3	9.3	9.3	Statesville, N.C.	Hydro
Lookout Shoals Hydro Station		28.0	28.0		
Mountain Island	1	14	14	Mount Holly, N.C.	Hydro
Mountain Island	2	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.	Hydro

TABLE 8.3-1 (Sheet 7 of 8)
NORTH CAROLINA EXISTING GENERATION [a][b][c]

Name	Unit	Summer Capacity MW	WInter Capacity MW	Location	Plant Type
Mountain Island Hydro Station		62.0	62.0		
Oxford	1	20.0	20.0	Conover, N.C.	Hydro
Oxford	2	20.0	20.0	Conover, N.C.	Hydro
Oxford Hydro Station		40.0	40.0		
Rhodhiss	1	9.5	9.5	Rhodhiss, N.C.	Hydro
Rhodhiss	2	11.5	11.5	Rhodhiss, N.C.	Hydro
Rhodhiss	3	9.0	9.0	Rhodhiss, N.C.	Hydro
Rhodhiss Hydro Station		30.0	30.0		
Tuxedo	1	3.2	3.2	Flat Rock, N.C.	Hydro
Tuxedo	2	3.2	3.2	Flat Rock, N.C.	Hydro
Tuxedo Hydro Station		6.4	6.4		
Bear Creek	1	9.45	9.45	Tuckasegee, N.C.	Hydro
Bear Creek Hydro Station		9.45	9.45		
Cedar Cliff	1	6.4	6.4	Tuckasegee, N.C.	Hydro
Cedar Cliff Hydro Station		6.4	6.4		
Franklin	1	0.5	0.5	Franklin, N.C.	Hydro
Franklin	2	0.5	0.5	Franklin, N.C.	Hydro
Franklin Hydro Station		1.0	1.0		
Mission	1	0.6	0.6	Murphy, N.C.	Hydro
Mission	2	0.6	0.6	Murphy, N.C.	Hydro
Mission	3	0.6	0.6	Murphy, N.C.	Hydro

TABLE 8.3-1 (Sheet 8 of 8)
NORTH CAROLINA EXISTING GENERATION [a][b][c]

Name	Unit	Summer Capacity MW	WInter Capacity MW	Location	Plant Type
Mission Hydro Station		1.8	1.8		
Nantahala	1	50.0	50.0	Topton, N.C.	Hydro
Nantahala Hydro Station		50.0	50.0		
Tennessee Creek	1	9.8	9.8	Tuckasegee, N.C.	Hydro
Tennessee Creek Hydro Station		9.8	9.8		
Thorpe	1	19.7	19.7	Tuckasegee, N.C.	Hydro
Thorpe Hydro Station		19.7	19.7		
Tuckasegee	1	2.5	2.5	Tuckasegee, N.C.	Hydro
Tuckasegee Hydro Station		2.5	2.5		
Queens Creek	1	1.44	1.44	Topton, N.C.	Hydro
Queens Creek Hydro Station		1.44	1.44		
TOTAL N.C. HYDRO		617.7 MW	617.7 MW		
TOTAL N.C. CAPABILITY		12,591.9 MW	13,043.7 MW		

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

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

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

Source: Reference 1

TABLE 8.3-2 (Sheet 1 of 7)
SOUTH CAROLINA EXISTING GENERATION [a][b][c][d][e]

Name	Unit	Summer Capacity MW	WInter Capacity MW	Location	Plant Type
Lee	1	100.0	100.0	Pelzer, S.C.	Conventional Coal
Lee	2	100.0	102.0	Pelzer, S.C.	Conventional Coal
Lee	3	170.0	170.0	Pelzer, S.C.	Conventional Coal
Lee Steam Station		**370.0**	**372.0**		
TOTAL S.C. CONVENTIONAL COAL		**370.0 MW**	**372.0 MW**		
Buzzard Roost	6C	22.0	22.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	7C	22.0	22.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	8C	22.0	22.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	9C	22.0	22.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	10C	18.0	18.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	11C	18.0	18.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	12C	18.0	18.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	13C	18.0	18.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	14C	18.0	18.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine

TABLE 8.3-2 (Sheet 2 of 7)
SOUTH CAROLINA EXISTING GENERATION [a][b][c][d][e]

Name	Unit	Summer Capacity MW	WInter Capacity MW	Location	Plant Type
Buzzard Roost	15C	18.0	18.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost Station CTs		**196.0**	**196.0**		
Lee	7C	40.0	40.0	Pelzer, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Lee	8C	40.0	40.0	Pelzer, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Lee Station CTs		**80.0**	**80.0**		
Mill Creek	1	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	2	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	3	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	4	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	5	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	6	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	7	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	8	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine

TABLE 8.3-2 (Sheet 3 of 7)
SOUTH CAROLINA EXISTING GENERATION [a][b][c][d][e]

Name	Unit	Summer Capacity MW	WInter Capacity MW	Location	Plant Type
Mill Creek Station CTs		**595.4**	**739.2**		
TOTAL S.C. COMB TURBINE		**871.4 MW**	**1015.2 MW**		
Catawba	1	1129.0	1163.0	York, S.C.	Nuclear
Catawba	2	1129.0	1163.0	York, S.C.	Nuclear
Catawba Nuclear Station		**2258.0**	**2326.0**		
Oconee	1	846.0	865.0	Seneca, S.C.	Nuclear
Oconee	2	846.0	865.0	Seneca, S.C.	Nuclear
Oconee	3	846.0	865.0	Seneca, S.C.	Nuclear
Oconee Nuclear Station		**2538.0**	**2595.0**		
TOTAL S.C. NUCLEAR		**4796.0 MW**	**4921.0 MW**		
Jocassee	1	170.0	170.0	Salem, S.C.	Pumped Storage
Jocassee	2	170.0	170.0	Salem, S.C.	Pumped Storage
Jocassee	3	170.0	170.0	Salem, S.C.	Pumped Storage
Jocassee	4	170.0	170.0	Salem, S.C.	Pumped Storage
Jocassee Pumped Hydro Station		**680.0**	**680.0**		
Bad Creek	1	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	2	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	3	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	4	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek Pumped Hydro Station		**1360.0**	**1360.0**		
TOTAL PUMPED STORAGE		**2040.0 MW**	**2040.0 MW**		
Cedar Creek	1	15.0	15.0	Great Falls, S.C.	Hydro

TABLE 8.3-2 (Sheet 4 of 7)
SOUTH CAROLINA EXISTING GENERATION [a][b][c][d][e]

Name	Unit	Summer Capacity MW	WInter Capacity MW	Location	Plant Type
Cedar Creek	2	15.0	15.0	Great Falls, S.C.	Hydro
Cedar Creek	3	15.0	15.0	Great Falls, S.C.	Hydro
Cedar Creek Hydro Station		**45.0**	**45.0**		
Dearborn	1	14.0	14.0	Great Falls, S.C.	Hydro
Dearborn	2	14.0	14.0	Great Falls, S.C.	Hydro
Dearborn	3	14.0	14.0	Great Falls, S.C.	Hydro
Dearborn Hydro Station		**42.0**	**42.0**		
Fishing Creek	1	11.0	11.0	Great Falls, S.C.	Hydro
Fishing Creek	2	9.5	9.5	Great Falls, S.C.	Hydro
Fishing Creek	3	9.5	9.5	Great Falls, S.C.	Hydro
Fishing Creek	4	11.0	11.0	Great Falls, S.C.	Hydro
Fishing Creek	5	8.0	8.0	Great Falls, S.C.	Hydro
Fishing Creek Hydro Station		**49.0**	**49.0**		
Gaston Shoals	3	1.0	1.0	Blacksburg, S.C.	Hydro
Gaston Shoals	4	1.0	1.0	Blacksburg, S.C.	Hydro
Gaston Shoals	5	1.0	1.0	Blacksburg, S.C.	Hydro
Gaston Shoals	6	1.7	1.7	Blacksburg, S.C.	Hydro

TABLE 8.3-2 (Sheet 5 of 7)
SOUTH CAROLINA EXISTING GENERATION [a][b][c][d][e]

Name	Unit	Summer Capacity MW	WInter Capacity MW	Location	Plant Type
Gaston Shoals Hydro Station		**4.7**	**4.7**		
Great Falls	1	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	2	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	3	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	4	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	5	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	6	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	7	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	8	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls Hydro Station		**24.0**	**24.0**		
Rocky Creek	1	2.9	2.9	Great Falls, S.C.	Hydro
Rocky Creek	2	2.9	2.9	Great Falls, S.C.	Hydro
Rocky Creek	3	2.9	2.9	Great Falls, S.C.	Hydro
Rocky Creek	4	2.9	2.9	Great Falls, S.C.	Hydro
Rocky Creek	5	4.8	4.8	Great Falls, S.C.	Hydro
Rocky Creek	6	4.8	4.8	Great Falls, S.C.	Hydro
Rocky Creek	7	2.9	2.9	Great Falls, S.C.	Hydro

TABLE 8.3-2 (Sheet 6 of 7)
SOUTH CAROLINA EXISTING GENERATION [a][b][c][d][e]

Name	Unit	Summer Capacity MW	WInter Capacity MW	Location	Plant Type
Rocky Creek	8	2.9	2.9	Great Falls, S.C.	Hydro
Rocky Creek Hydro Station		**27.0**	**27.0**		
Wateree	1	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	2	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	3	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	4	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	5	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree Hydro Station		**85.0**	**85.0**		
Wylie	1	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie	2	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie	3	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie	4	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie Hydro Station		**72.0**	**72.0**		
99 Islands	1	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	2	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	3	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	4	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	5	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	6	1.6	1.6	Blacksburg, S.C.	Hydro

TABLE 8.3-2 (Sheet 7 of 7)
SOUTH CAROLINA EXISTING GENERATION [a][b][c][d][e]

Name	Unit	Summer Capacity MW	WInter Capacity MW	Location	Plant Type
99 Islands Hydro Station		**9.6**	**9.6**		
Keowee	1	76.0	76.0	Seneca, S.C.	Hydro
Keowee	2	76.0	76.0	Seneca, S.C.	Hydro
Keowee Hydro Station		**152.0**	**152.0**		
TOTAL S.C. HYDRO		**510.3 MW**	**510.3 MW**		
TOTAL S.C. CAPABILITY		**8587.7 MW**	**8858.5 MW**		

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

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

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

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.

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

Catawba Owner	Percent of Ownership
Duke Energy	12.5%
North Carolina Electric Membership Corporation (NCEMC)	28.125%
NCMPA#1	37.5%
Piedmont Municipal Power Agency (PMPA)	12.5%
Saluda River (SR)	9.375%

Source: Reference 1

TABLE 8.3-3
TOTAL GENERATION CAPACITY [a][b][c][d][e]

Name	Summer Capacity MW	WInter Capacity MW
TOTAL DUKE ENERGY GENERATING CAPABILITY	21,180	21,902

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

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

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

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.

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

Catawba Owner	Percent of Ownership
Duke Energy	12.5%
North Carolina Electric Membership Corporation (NCEMC)	28.125%
NCMPA#1	37.5%
Piedmont Municipal Power Agency (PMPA)	12.5%
Saluda River (SR)	9.375%

Source: Reference 1

TABLE 8.3-4
HISTORICAL CAPACITY FACTOR INFORMATION

Historical Capacity Factors

Stations	2006	2005	2004
Nuclear			
Catawba	80%	91%	88%
McGuire	86%	82%	85%
Oconee	85%	88%	80%
Coal-Fired			
Allen	64%	63%	62%
Belews Creek	82%	81%	79%
Buck	48%	51%	48%
Cliffside	60%	55%	51%
Dan River	41%	26%	28%
Lee	40%	46%	36%
Marshall	74%	89%	86%
Riverbend	46%	45%	39%
Combustion Turbine Station			
Buck	0%	0%	0%
Buzzard Roost	0%	0%	0%
Dan River	0%	0%	0%
Lee	0%	0%	0%
Lincoln	1%	0%	0%
Mill Creek	2%	1%	1%

Source: Duke Energy Carolinas FERC Form 1s, pages 402-403, for periods ending December 31, 2004, 2005, and 2006 (NCUC Docket No. E-7, Sub 614)

TABLE 8.3-5
HYDRO GENERATING UNITS WITH PLANS FOR LIFE EXTENSION

Station	Notice of Intent to Relicense Filed	Present License Expiration Date
Bryson Project No. 2601	1/27/2000	Good until license renewed
Dillsboro Project No. 2602	1/19/2000	Good until FERC acts on application for renewal or surrender
Franklin Project No. 2603	1/27/2000	Good until license renewed
Mission Project No. 2619	2/15/2000	Good until license renewed
East Fork Project No. 2698	7/25/2000	Good until license renewed
West Fork Project No. 2686	7/28/2000	Good until license renewed
Nantahala Project No. 2692	8/7/2000	Good until license renewed
Catawba/Wateree Project No. 2232	7/21/2003	9/1/2008

Source: Reference 1

TABLE 8.3-6 (Sheet 1 of 2)
PROJECTED UNIT RETIREMENTS

Station	Capacity in MW	Location	Decision Date	Plant Type
Buck 4[a]	38	Salisbury, N.C.	6/30/2010	Conventional Coal
Buck 3[a]	75	Salisbury, N.C.	6/30/2011	Conventional Coal
Cliffside 1[a]	38	Cliffside, N.C.	6/30/2012	Conventional Coal
Cliffside 2[a]	38	Cliffside, N.C.	6/30/2012	Conventional Coal
Cliffside 3[a]	61	Cliffside, N.C.	6/30/2012	Conventional Coal
Cliffside 4[a]	61	Cliffside, N.C.	6/30/2012	Conventional Coal
Dan River 1[a]	67	Eden, N.C.	6/30/2013	Conventional Coal
Dan River 2[a]	67	Eden, N.C.	6/30/2013	Conventional Coal
Dan River 3[a]	142	Eden, N.C.	6/30/2013	Conventional Coal
Buzzard Roost 6C	22	Chappels, S.C.	6/30/2014	Combustion Turbine
Buzzard Roost 7C	22	Chappels, S.C.	6/30/2014	Combustion Turbine
Buzzard Roost 8C	22	Chappels, S.C.	6/30/2014	Combustion Turbine
Buzzard Roost 9C	22	Chappels, S.C.	6/30/2014	Combustion Turbine
Buzzard Roost 10C	18	Chappels, S.C.	6/30/2014	Combustion Turbine
Buzzard Roost 11C	18	Chappels, S.C.	6/30/2014	Combustion Turbine
Buzzard Roost 12C	18	Chappels, S.C.	6/30/2014	Combustion Turbine
Buzzard Roost 13C	18	Chappels, S.C.	6/30/2014	Combustion Turbine
Buzzard Roost 14C	18	Chappels, S.C.	6/30/2014	Combustion Turbine
Buzzard Roost 15C	18	Chappels, S.C.	6/30/2014	Combustion Turbine
Riverbend 8C	30	Mt. Holly, N.C.	6/30/2015	Combustion Turbine

TABLE 8.3-6 (Sheet 2 of 2)
PROJECTED UNIT RETIREMENTS

Station	Capacity in MW	Location	Decision Date	Plant Type
Riverbend 9C	30	Mt. Holly, N.C.	6/30/2015	Combustion Turbine
Riverbend 10C	30	Mt. Holly, N.C.	6/30/2015	Combustion Turbine
Riverbend 11C	30	Mt. Holly, N.C.	6/30/2015	Combustion Turbine
Buck 7C	31	Spencer, N.C.	6/30/2015	Combustion Turbine
Buck 8C	31	Spencer, N.C.	6/30/2015	Combustion Turbine
Buck 9C	31	Spencer, N.C.	6/30/2015	Combustion Turbine
Dan River 4C	30	Eden, N.C.	6/30/2015	Combustion Turbine
Dan River 5C	30	Eden, N.C.	6/30/2015	Combustion Turbine
Dan River 6C	25	Eden, N.C.	6/30/2015	Combustion Turbine
Riverbend 4[a]	94	Mt. Holly, N.C.	6/30/2015	Conventional Coal
Riverbend 5[a]	94	Mt. Holly, N.C.	6/30/2015	Conventional Coal
Riverbend 6[a]	133	Mt. Holly, N.C.	6/30/2016	Conventional Coal
Riverbend 7[a]	133	Mt. Holly, N.C.	6/30/2017	Conventional Coal

a) Retirement assumptions associated with the conditions in the North Carolina Utilities Commission Order in Docket No. E-7, Sub 790, granting a CPCN to build Cliffside Unit 6.

Source: Reference 1

TABLE 8.3-7 (Sheet 1 of 2)
DUKE ENERGY WHOLESALE SALE CONTRACTS

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

TABLE 8.3-7 (Sheet 2 of 2)
DUKE ENERGY WHOLESALE SALE CONTRACTS

Wholesale Customer	Contract Designation	Type	Contract Term	Commitment (MW)																			
				2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
NCEMC **See Note 2**	Catawba Contract Backstand	Native Load Priority/System Firm	Through Operating Life of Catawba Nuclear Station and McGuire Nuclear Station	627	687	687	687	687	687	687	687	687	687	687	687	687	687	687	687	687	687	687	687
Saluda River EC **See Note 2**	Catawba Contract Backstand	Native Load Priority	September 30, 2008	209																			
NCMPA1	Generation Backstand	Native Load Priority	January 1, 2008 through December 31, 2010	73	73	73																	
NCEMC	Shaped Capacity Sale	Native Load Priority	January 1, 2009 through December 31, 2038		72	72	97	97	97	97	97	122	122	122	122	147	147	147	147	147	147	147	147

Note 1: The analyses in this Annual Plan assumed that the contracts would be renewed or extended through the end of the planning horizon.

Note 2: The annual commitment shown is the ownership share of Catawba Nuclear Station and is included in the load forecast. Equivalent capacity is included as a portion of the Catawba Nuclear Station resource.

Source: Reference 1

TABLE 8.3-8
WHOLESALE PURCHASED POWER COMMITMENTS

Supplier	City	State	Summer Firm Capacity (MW)	Winter Firm Capacity (MW)	Contract Start	Contract Expiration
Catawba County	Newton	NC	3	3	8/23/99	8/22/14
Cherokee County Cogeneration Partners, L.P.	Gaffney	SC	88	95	7/1/96	6/30/13
Northbrook Carolina Hydro, LLC	Various	Both	6	6	12/4/06	Ongoing
Salem Energy Systems, LLC	Winston-Salem	NC	4	4	7/10/96	7/10/11
Southern Power	Salisbury	NC	153	185	6/1/07	12/31/10
Southern Power	Salisbury	NC	153	185	1/1/06	12/31/10
Southern Power	Salisbury	NC	153	185	6/1/04	5/31/08
Southern Power	Salisbury	NC	153	185	6/1/08	12/31/10
Town of Lake Lure	Lake Lure	NC	2	2	2/21/06	2/20/11
Misc. Small Hydro/Other	Various	Both	5	5	Various	Assumed Evergreen

Source: Reference 1

TABLE 8.3-9 (Sheet 1 of 4)
PURPA QUALIFYING FACILITIES

Purpa Qualifying Facilities (Selling Power to Duke)					
Name	**City**	**State**	**Nameplate KW**	**Primary Fuel Type**	**Part of Total Supply Resources[a]**
Advantage Investment Group, LLC[b]	Spencer Mtn	NC	640	Hydroelectric	Yes[a]
Barbara Ann Evans - Caroleen Mills	Caroleen	NC	324	Hydroelectric	Yes[a]
Byron P. Matthews	Chapel Hill	NC	3	Photovoltaic	Yes[a]
Catawba County - Blackburn Landfill	Newton	NC	4,000	Landfill Gas	Yes[a]
Cliffside Mills, LLC	Cliffside	NC	1,600	Hydroelectric	Yes[a]
David K. Birkhead	Hillsborough	NC	2	Photovoltaic	Yes[a]
David Ringenburg	Chapel Hill	NC	7	Photovoltaic	Yes[a]
David Wiener dba JZ Solar Electric	Chapel Hill	NC	3	Photovoltaic	Yes[a]
Delta Products Corporation	RTP	NC	30	Photovoltaic	Yes[a]
Frances L. Thompson (formery Habitat)	Hickory	NC	4	Photovoltaic	Yes[a]
Hardins Resources Company	Hardins	NC	820	Hydroelectric	Yes[a]
Haneline Power, LLC	Millersville	NC	365	Hydroelectric	Yes[a]
Haw River Hydro	Saxapahaw	NC	1,500	Hydroelectric	Yes[a]

TABLE 8.3-9 (Sheet 2 of 4)
PURPA QUALIFYING FACILITIES

Purpa Qualifying Facilities (Selling Power to Duke)					
Name	**City**	**State**	**Nameplate KW**	**Primary Fuel Type**	**Part of Total Supply Resources[a]**
Hayden-Harman Foundation	Burlington	NC	2	Photovoltaic	Yes[a]
Holzworth Holdings, Inc.	Durham	NC	3	Photovoltaic	Yes[a]
Jafasa Farms - Residence	Mills River	NC	6	Photovoltaic	Yes[a]
Jafasa Farms - Greenhouse	Mills River	NC	6	Photovoltaic	Yes[a]
James B. Sherman	Chapel Hill	NC	5	Photovoltaic	Yes[a]
Jim Alexander	Chapel Hill	NC	4	Photovoltaic	Yes[a]
Mark A. Powers	Chapel Hill	NC	2	Photovoltaic	Yes[a]
Mayo Hydropower, LLC - Avalon Dam	Mayodan	NC	1,275	Hydroelectric	Yes[a]
Mayo Hydropower, LLC - Mayo Dam	Mayodan	NC	950	Hydroelectric	Yes[a]
MegaWatt Solar	Hillsborough	NC	5	Photovoltaic	Yes[a]
Mill Shoals Hydro Co - High Shoals Hydro	High Shoals	NC	1,800	Hydroelectric	Yes[a]
Northbrook Carolina Hydro, LLC - Turner Shoals Hydro	Mill Springs	NC	5,500	Hydroelectric	Yes[a]
Personal Touch Interiors	Iron Station	NC	2	Photovoltaic	Yes[a]

TABLE 8.3-9 (Sheet 3 of 4)
PURPA QUALIFYING FACILITIES

Purpa Qualifying Facilities (Selling Power to Duke)					
Name	**City**	**State**	**Nameplate KW**	**Primary Fuel Type**	**Part of Total Supply Resources[a]**
Pickens Mill Hydro, LLC - Stice Shoals Hydro[c]	Shelby	NC	600	Hydroelectric	Yes[a]
Pippin Home Designs	Sherrills Ford	NC	2	Photovoltaic	Yes[a]
Salem Energy Systems	Winston-Salem	NC	4,270	Landfill Gas	Yes[a]
Shawn L. Slome	Chapel Hill	NC	2	Photovoltaic	Yes[a]
South Yadkin Power, Inc	Cooleemee	NC	1,400	Hydroelectric	Yes[a]
Spray Cotton Mills	Eden	NC	500	Hydroelectric	Yes[a]
Steve Mason Enterprises-Long Shoals Hydro	Long Shoals	NC	900	Hydroelectric	Yes[a]
Town of Chapel Hill	Chapel Hill	NC	4	Photovoltaic	Yes[a]
Town of Lake Lure	Lake Lure	NC	3,600	Hydroelectric	Yes[a]
Aquenergy Systems Inc	Piedmont	SC	1,050	Hydroelectric	Yes[a]
Aquenergy Systems Inc	Ware Shoals	SC	6,300	Hydroelectric	Yes[a]
Cherokee County Cogeneration Partners	Gaffney	SC	100,000	Natural gas	Yes[a]
Converse Energy Inc	Converse	SC	1,250	Hydroelectric	Yes[a]

TABLE 8.3-9 (Sheet 4 of 4)
PURPA QUALIFYING FACILITIES

Purpa Qualifying Facilities (Selling Power to Duke)					
Name	**City**	**State**	**Nameplate KW**	**Primary Fuel Type**	**Part of Total Supply Resources[a]**
Northbrook Carolina Hydro, LLC - Boyds Mill Hydro	Ware Shoals	SC	1,500	Hydroelectric	Yes[a]
Northbrook Carolina Hydro, LLC - Hollidays Bridge Hydro	Belton	SC	3,500	Hydroelectric	Yes[a]
Northbrook Carolina Hydro, LLC - Saluda Hydro	Greenville	SC	2,400	Hydroelectric	Yes[a]
Pacolet River Power Co	Clifton	SC	800	Hydroelectric	Yes[a]
Pelzer Hydro Co - Upper Hydro	Pelzer	SC	2,020	Hydroelectric	Yes[a]
Pelzer Hydro Co - Lower Hydro	Williamston	SC	3,300	Hydroelectric	Yes[a]

a) Nameplate rating generally exceeds the contract capacity negotiated for Duke Power

b) Formerly Northbrook Carolina, LLC - Spencer Mountain Hydro

c) Formerly Northbrook Carolina, LLC - Stice Shoals Hydro

MERCHANT GENERATORS					
NAME	CITY	STATE	NAMEPLATE KW	PRIMARY FUEL TYPE	PART OF TOTAL SUPPLY RESOURCES[a]
Southern Power	Salisbury	NC	458,000	Natural gas	Yes[a]
Broad River Energy Center, LLC	Gaffney	SC	875,000	Natural gas	No

a) Nameplate rating generally exceeds the contract capacity negotiated for Duke Energy Carolinas

Source: Reference 1

TABLE 8.3-10 (Sheet 1 of 7)
CUSTOMER OWNED STANDBY GENERATION IN RESOURCE MIX

City	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources[a]
Belmont	NC	350	Unknown	Yes[a]
Belmont	NC	350	Unknown	Yes[a]
Belmont	NC	500	Unknown	Yes[a]
Bessemer City	NC	440	Unknown	Yes[a]
Burlington	NC	550	Unknown	Yes[a]
Burlington	NC	600	Unknown	Yes[a]
Burlington	NC	650	Unknown	Yes[a]
Burlington	NC	225	Unknown	Yes[a]
Burlington	NC	200	Unknown	Yes[a]
Burlington	NC	1150	Unknown	Yes[a]
Butner	NC	750	Unknown	Yes[a]
Butner	NC	1250	Unknown	Yes[a]
Carrboro	NC	1135	Unknown	Yes[a]
Carrboro	NC	2000	Unknown	Yes[a]
Carrboro	NC	500	Unknown	Yes[a]
Chapel Hill	NC	500	Unknown	Yes[a]
Charlotte	NC	1750	Unknown	Yes[a]
Charlotte	NC	1000	Unknown	Yes[a]
Charlotte	NC	1200	Unknown	Yes[a]
Charlotte	NC	1250	Unknown	Yes[a]
Charlotte	NC	1135	Unknown	Yes[a]
Charlotte	NC	1135	Unknown	Yes[a]
Charlotte	NC	1500	Unknown	Yes[a]
Charlotte	NC	10000	Unknown	Yes[a]
Charlotte	NC	200	Unknown	Yes[a]

TABLE 8.3-10 (Sheet 2 of 7)
CUSTOMER OWNED STANDBY GENERATION IN RESOURCE MIX

City	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources[a]
Charlotte	NC	2200	Unknown	Yes[a]
Charlotte	NC	700	Unknown	Yes[a]
Charlotte	NC	5600	Unknown	Yes[a]
Charlotte	NC	4000	Unknown	Yes[a]
Concord	NC	680	Unknown	Yes[a]
Danbury	NC	400	Unknown	Yes[a]
Durham	NC	1300	Unknown	Yes[a]
Durham	NC	2500	Unknown	Yes[a]
Durham	NC	1100	Unknown	Yes[a]
Durham	NC	3200	Unknown	Yes[a]
Durham	NC	1600	Unknown	Yes[a]
Durham	NC	1400	Unknown	Yes[a]
Durham	NC	1500	Unknown	Yes[a]
Durham	NC	2250	Unknown	Yes[a]
Durham	NC	4525	Unknown	Yes[a]
Durham	NC	1750	Unknown	Yes[a]
Durham	NC	1900	Unknown	Yes[a]
Durham	NC	7000	Unknown	Yes[a]
Durham	NC	4500	Unknown	Yes[a]
Durham	NC	6400	Unknown	Yes[a]
Durham	NC	625	Unknown	Yes[a]
Durham	NC	2000	Unknown	Yes[a]
Eden	NC	1700	Unknown	Yes[a]
Elkin	NC	400	Unknown	Yes[a]
Elkin	NC	500	Unknown	Yes[a]

TABLE 8.3-10 (Sheet 3 of 7)
CUSTOMER OWNED STANDBY GENERATION IN RESOURCE MIX

City	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources[a]
Gastonia	NC	910	Unknown	Yes[a]
Gastonia	NC	680	Unknown	Yes[a]
Gastonia	NC	12500	Unknown	Yes[a]
Graham	NC	800	Unknown	Yes[a]
Greensboro	NC	1350	Unknown	Yes[a]
Greensboro	NC	125	Unknown	Yes[a]
Greensboro	NC	1000	Unknown	Yes[a]
Greensboro	NC	1500	Unknown	Yes[a]
Greensboro	NC	2000	Unknown	Yes[a]
Greensboro	NC	250	Unknown	Yes[a]
Greensboro	NC	750	Unknown	Yes[a]
Greensboro	NC	1280	Unknown	Yes[a]
Greensboro	NC	700	Unknown	Yes[a]
Hendersonville	NC	500	Unknown	Yes[a]
Hendersonville	NC	1000	Unknown	Yes[a]
Hendersonville	NC	1000	Unknown	Yes[a]
Hickory	NC	1500	Unknown	Yes[a]
Hickory	NC	750	Unknown	Yes[a]
Hickory	NC	1000	Unknown	Yes[a]
Hickory	NC	1500	Unknown	Yes[a]
Hickory	NC	1040	Unknown	Yes[a]
Hickory	NC	500	Unknown	Yes[a]
Huntersville	NC	2950	Unknown	Yes[a]
Huntersville	NC	775	Unknown	Yes[a]
Huntersville	NC	3200	Unknown	Yes[a]

TABLE 8.3-10 (Sheet 4 of 7)
CUSTOMER OWNED STANDBY GENERATION IN RESOURCE MIX

City	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources[a]
Indian Trail	NC	900	Unknown	Yes[a]
King	NC	800	Unknown	Yes[a]
Lexington	NC	750	Unknown	Yes[a]
Lexington	NC	2950	Unknown	Yes[a]
Lincolnton	NC	300	Unknown	Yes[a]
Marion	NC	650	Unknown	Yes[a]
Matthews	NC	1450	Unknown	Yes[a]
Mebane	NC	400	Unknown	Yes[a]
Midland	NC	4000	Unknown	Yes[a]
Midland	NC	6000	Unknown	Yes[a]
Monroe	NC	400	Unknown	Yes[a]
Mooresville	NC	750	Unknown	Yes[a]
Morganton	NC	200	Unknown	Yes[a]
Mt. Airy	NC	600	Unknown	Yes[a]
Mt. Airy	NC	750	Unknown	Yes[a]
Mt. Holly	NC	210	Unknown	Yes[a]
N. Wilkesboro	NC	600	Unknown	Yes[a]
N. Wilkesboro	NC	155	Unknown	Yes[a]
North Wilkesboro	NC	1250	Unknown	Yes[a]
Pfafftown	NC	4000	Unknown	Yes[a]
Reidsville	NC	750	Unknown	Yes[a]
Research Triangle	NC	750	Unknown	Yes[a]
Research Triangle	NC	1000	Unknown	Yes[a]
Research Triangle	NC	350	Unknown	Yes[a]
Research Triangle	NC	750	Unknown	Yes[a]

TABLE 8.3-10 (Sheet 5 of 7)
CUSTOMER OWNED STANDBY GENERATION IN RESOURCE MIX

City	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources[a]
Rural Hall	NC	1050	Unknown	Yes[a]
Rutherfordton	NC	800	Unknown	Yes[a]
Salisbury	NC	1500	Unknown	Yes[a]
Salisbury	NC	1500	Unknown	Yes[a]
Shelby	NC	4480	Unknown	Yes[a]
Valdese	NC	600	Unknown	Yes[a]
Valdese	NC	800	Unknown	Yes[a]
Welcome	NC	300	Unknown	Yes[a]
Winston	NC	750	Unknown	Yes[a]
Winston Salem	NC	1800	Unknown	Yes[a]
Winston Salem	NC	3360	Unknown	Yes[a]
Winston Salem	NC	1250	Unknown	Yes[a]
Winston Salem	NC	3000	Unknown	Yes[a]
Winston Salem	NC	2000	Unknown	Yes[a]
Winston Salem	NC	3000	Unknown	Yes[a]
Winston-Salem	NC	500	Unknown	Yes[a]
Winston-Salem	NC	3200	Unknown	Yes[a]
Winston-Salem	NC	400	Unknown	Yes[a]
Winston-Salem	NC	3750	Unknown	Yes[a]
Yadkinville	NC	500	Unknown	Yes[a]
Yadkinville	NC	1200	Unknown	Yes[a]
Anderson	SC	2250	Unknown	Yes[a]
Anderson	SC	1500	Unknown	Yes[a]
Bullock Creek	SC	275	Unknown	Yes[a]
Clinton	SC	447	Unknown	Yes[a]

TABLE 8.3-10 (Sheet 6 of 7)
CUSTOMER OWNED STANDBY GENERATION IN RESOURCE MIX

City	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources[a]
Clover	SC	625	Unknown	Yes[a]
Clover	SC	75	Unknown	Yes[a]
Duncan	SC	600	Unknown	Yes[a]
Fort Mill	SC	1600	Unknown	Yes[a]
Gaffney	SC	1200	Unknown	Yes[a]
Greenville	SC	3650	Unknown	Yes[a]
Greenville	SC	2500	Unknown	Yes[a]
Greenville	SC	300	Unknown	Yes[a]
Greenville	SC	500	Unknown	Yes[a]
Greenville	SC	1500	Unknown	Yes[a]
Greenwood	SC	2400	Unknown	Yes[a]
Greenwood	SC	600	Unknown	Yes[a]
Greer	SC	125	Unknown	Yes[a]
Greer	SC	1250	Unknown	Yes[a]
Inman	SC	165	Unknown	Yes[a]
Kershaw	SC	165	Unknown	Yes[a]
Kershaw	SC	1500	Unknown	Yes[a]
Lancaster	SC	1500	Unknown	Yes[a]
Lancaster	SC	300	Unknown	Yes[a]
Lyman	SC	1000	Unknown	Yes[a]
Mt. Holly	SC	265	Unknown	Yes[a]
Simpsonville	SC	900	Unknown	Yes[a]
Simpsonville	SC	458	Unknown	Yes[a]
Spartanburg	SC	600	Unknown	Yes[a]
Spartanburg	SC	450	Unknown	Yes[a]

TABLE 8.3-10 (Sheet 7 of 7)
CUSTOMER OWNED STANDBY GENERATION IN RESOURCE MIX

City	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources[a]
Spartanburg	SC	2900	Unknown	Yes[a]
Spartanburg	SC	650	Unknown	Yes[a]
Spartanburg	SC	2700	Unknown	Yes[a]
Spartanburg	SC	1600	Unknown	Yes[a]
Taylor	SC	350	Unknown	Yes[1]
Van Wyck	SC	450	Unknown	Yes[a]
Van Wyck	SC	365	Unknown	Yes[a]
Walhalla	SC	350	Unknown	Yes[a]

a) 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.

Source: Reference 1

TABLE 8.3-11 (Sheet 1 of 4)
CUSTOMER OWNED STANDBY GENERATION NOT LISTED IN THE SUPPLY RESOURCE MIX – IMPACT IS REFLECTED IN LOAD FORECAST

County	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources
Burke	NC	800	Diesel	No[a]
Cabarrus	NC	32,000	Diesel	No[a]
Catawba	NC	250	Coal, Wood Cogen	No[a]
Catawba	NC	8,050	Diesel	No[a]
Cleveland	NC	5,025	Diesel	No[a]
Cleveland	NC	4,500	Diesel	No[a]
Cleveland	NC	2,000	Diesel	No[a]
Durham	NC	2	Photovoltaic	No[a]
Durham	NC	1	Photovoltaic	No[a]
Durham	NC	3	Photovoltaic	No[a]
Durham	NC	2	Photovoltaic	No[a]
Durham	NC	3	Photovoltaic	No[a]
Forsyth	NC	8,400	Coal, Wood Cogen	No[a]
Forsyth	NC	4	Photovoltaic	No[a]
Gaston	NC	1,056	Hydroelectric	No[a]
Guilford	NC	3	Photovoltaic	No[a]
Guilford	NC	2,000	Diesel	No[a]
Guilford	NC	900	Diesel	No[a]
Guilford	NC	2,000	Diesel	No[a]
Guilford	NC	2	Photovoltaic	No[a]
Guilford	NC	2	Photovoltaic	No[a]
Guilford	NC	3	Photovoltaic	No[a]
Iredell	NC	1,050	Diesel	No[a]
Iredell	NC	8	Photovoltaic	No[a]

TABLE 8.3-11 (Sheet 2 of 4)
CUSTOMER OWNED STANDBY GENERATION NOT LISTED IN THE SUPPLY RESOURCE MIX – IMPACT IS REFLECTED IN LOAD FORECAST

County	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources
Mecklenburg	NC	4	Photovoltaic	No[a]
Mecklenburg	NC	4	Photovoltaic	No[a]
Mecklenburg	NC	3	Photovoltaic	No[a]
Orange	NC	4	Photovoltaic	No[a]
Orange	NC	2	Photovoltaic	No[a]
Orange	NC	2	Photovoltaic	No[a]
Orange	NC	28,000	Coal Cogen	No[a]
Orange	NC	2	Photovoltaic	No[a]
Randolph	NC	2	Photovoltaic	No[a]
Randolph	NC	2	Photovoltaic	No[a]
Rockingham	NC	5,480	Coal Cogen	No[a]
Rockingham	NC	2	Photovoltaic	No[a]
Rowan	NC	8	Photovoltaic/Wind	No[a]
Rowan	NC	2	Photovoltaic	No[a]
Rutherford	NC	1,625	Hydroelectric	No[a]
Rutherford	NC	6,400	Diesel	No[a]
Rutherford	NC	4,800	Diesel	No[a]
Rutherford	NC	750	Diesel	No[a]
Rutherford	NC	1,000	Diesel	No[a]
Rutherford	NC	350	Diesel	No[a]
Surry	NC	2,500	Unknown	No[a]
Transylvania	NC	2	Photovoltaic	No[a]
Union	NC	12,500	Diesel	No[a]
Union	NC	7,400	Diesel	No[a]

TABLE 8.3-11 (Sheet 3 of 4)
CUSTOMER OWNED STANDBY GENERATION NOT LISTED IN THE SUPPLY RESOURCE MIX – IMPACT IS REFLECTED IN LOAD FORECAST

County	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources
Union	NC	4,950	Diesel	No[a]
Union	NC	4,200	Diesel	No[a]
Union	NC	1,600	Diesel	No[a]
Union	NC	1,600	Diesel	No[a]
Union	NC	1,600	Diesel	No[a]
Yadkin	NC	7	Photovoltaic	No[a]
Abbeville	SC	3,250	Hydroelectric	No[a]
Abbeville	SC	2,865	Diesel	No[a]
Cherokee	SC	8,000	Diesel	No[a]
Cherokee	SC	4,140	Hydroelectric	No[a]
Greenville	SC	4,550	Diesel Cogen	No[a]
Greenville	SC	5,000	Natural Gas, Landfill Gas	No[a]
Greenville	SC	100	Photovoltaic	No[a]
Greenville	SC	370	Digester Gas	No[a]
Greenville	SC	250	Unknown	No[a]
Laurens	SC	2,150	Diesel	No[a]
Laurens	SC	4,000	Diesel	No[a]
Oconee	SC	700	Hydroelectric	No[a]
Oconee	SC	9,175	Diesel	No[a]
Oconee	SC	2,865	Diesel	No[a]
Pickens	SC	2,865	Diesel	No[a]
Pickens	SC	6,400	Diesel	No[a]
Spartanburg	SC	1,000	Hydroelectric	No[a]
Greenville	SC	2,550	Diesel	No[a]

TABLE 8.3-11 (Sheet 4 of 4)
CUSTOMER OWNED STANDBY GENERATION NOT LISTED IN THE SUPPLY RESOURCE MIX – IMPACT IS REFLECTED IN LOAD FORECAST

County	State	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources
Union	SC	15,900	Hydroelectric	No[a]
Union	SC	6,000	Diesel	No[a]
Union	SC	5,730	Diesel	No[a]
York	SC	42,500	Coal, Wood Cogen	No[a]
York	SC	3,000	Diesel	No[a]
York	SC	2,865	Diesel	No[a]
York	SC	2,865	Diesel	No[a]
Utility-Owned Standby Generation				
Alamance	NC	275	Diesel	No
Burke	NC	2,000	Diesel	No
Durham	NC	1,750	Diesel	No
Granville	NC	1,750	Diesel	No
Guilford	NC	1,750	Diesel	No
Mecklenburg	NC	1,750	Diesel	No
Mecklenburg	NC	1,500	Diesel	No
Mecklenburg	NC	150	Diesel	No
Mecklenburg	NC	200	Diesel	No
Mecklenburg	NC	400	Diesel	No
Mecklenburg	NC	1,000	Diesel	No
Mecklenburg	NC	500	Diesel	No
Surry	NC	125	Diesel	No
Wilkes	NC	2,000	Diesel	No
Greenville	SC	1,000	Diesel	No

a) The Load Forecast in the Annual Plan reflects the impact of these generating resources

Source: Reference 1

TABLE 8.3-12 (Sheet 1 of 2)
FORECAST OF DSM PROGRAMS

PROJECTED DEMAND-SIDE MANAGEMENT LOAD IMPACTS
Conservation and Demand Response Programs

	Conservation Program Load Impact				Demand Response Impacts							
	MWH				Summer Peak MW				Summer Peak MW			Summer Peak
Year	Residential	Non-Residential	$2 Million Program	Total	Residential	Non-Residential	$2 Million Program	Total EE	Power Share	Power Manager	Total DR	Total MW Impacts
2008	70,884	27,048	4,394	102,326	31	7	1	40	517	244	761	801
2009	209,399	79,277	4,394	293,070	88	21	1	110	653	244	898	1,008
2010	339,275	134,200	4,394	477,869	139	35	1	175	771	244	1,016	1,190
2011	462,983	192,473	4,394	659,850	185	51	1	237	771	244	1,016	1,253
2012	594,609	247,610	4,394	846,612	237	65	1	302	771	244	1,016	1,318
2013	731,649	299,272	4,394	1,035,315	293	78	1	373	771	244	1,016	1,388
2014	861,534	354,193	4,394	1,220,121	344	93	1	437	771	244	1,016	1,453
2015	985,243	412,483	4,394	1,402,120	390	108	1	499	771	244	1,016	1,515
2016	1,118,318	468,202	4,394	1,590,914	442	122	1	565	771	244	1,016	1,581
2017	1,253,913	519,295	4,394	1,777,601	499	136	1	635	771	244	1,016	1,651
2018	1,383,790	574,188	4,394	1,962,372	549	150	1	700	771	244	1,016	1,716
2019	1,507,494	632,478	4,394	2,144,365	595	166	1	762	771	244	1,016	1,778
2020	1,571,146	661,730	4,394	2,237,270	615	172	1	789	771	244	1,016	1,805

TABLE 8.3-12 (Sheet 2 of 2)
FORECAST OF DSM PROGRAMS

PROJECTED DEMAND-SIDE MANAGEMENT LOAD IMPACTS
Conservation and Demand Response Programs

	Conservation Program Load Impact				Demand Response Impacts							
	MWH				Summer Peak MW				Summer Peak MW			Summer Peak
Year	Residential	Non-Residential	$2 Million Program	Total	Residential	Non-Residential	$2 Million Program	Total EE	Power Share	Power Manager	Total DR	Total MW Impacts
2021	1,566,746	660,015	4,394	2,231,155	615	172	1	789	771	244	1,016	1,805
2022	1,566,755	660,015	4,394	2,231,164	615	172	1	789	771	244	1,016	1,805
2023	1,566,774	660,027	4,394	2,231,195	615	172	1	789	771	244	1,016	1,805
2024	1,571,129	661,730	4,394	2,237,253	615	172	1	789	771	244	1,016	1,805
2025	1,566,755	660,013	4,394	2,231,162	615	172	1	789	771	244	1,016	1,805
2026	1,566,756	660,031	4,394	2,231,181	615	172	1	789	771	244	1,016	1,805
2027	1,566,746	660,015	4,394	2,231,155	615	172	1	789	771	244	1,016	1,805
2028	1,571,128	661,726	4,394	2,237,248	615	172	1	789	771	244	1,016	1,805
2029	1,568,201	660,579	4,394	2,233,173	615	172	1	789	771	244	1,016	1,805
2030	1,568,209	660,625	4,394	2,233,228	615	172	1	789	771	244	1,016	1,805
2031	1,568,205	660,608	4,394	2,233,207	615	172	1	789	771	244	1,016	1,805
2032	1,571,125	661,739	4,394	2,237,258	615	172	1	789	771	244	1,016	1,805

Source: Reference 1

TABLE 8.3-13
CUMULATIVE RESOURCE ADDITIONS TO MEET A 17 PERCENT PLANNING RESERVE MARGIN

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Resource Need	0	60	430	990	2340	3190	4030	4630	5540	6090	6620

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Resource Need	7020	7430	7880	8270	8670	9070	9470	9880	10280	10680

Source: Reference 1

8.4 ASSESSMENT OF NEED FOR POWER

8.4.1 INTRODUCTION

The purpose of this subsection, as specified in NUREG-1555 is to provide a "review and assessment of the need for the new baseload generating capacity." As directed by NUREG-1555, the scope of this review "should include a comparison of baseload capacity with baseload demand, a reserve margin assessment, projected cost of power, a comparison of total capacity in relation to peakload demand, a schedule evaluation, and an ultimate conclusion regarding the need for the electrical-production capability of the proposed facility. As such, it will draw on Section 8.2 and Section 8.3."

NUREG-1555 allows for this analysis to rely upon reports focused on the need-for-power from a State or NERC if the report meets these four criteria; that the methodology be (1) developed in a systematic fashion, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty. The bulk of the data and information provided in this section is prepared for and contained in Duke Energy's 2007 IRP (Reference 1) or contained in the backup material to this document, which is filed in both North Carolina and South Carolina public service commissions as required under those state's IRP rules and regulations and those states' annual resource planning requirements. As discussed and demonstrated in Subsection 8.0, the IRP (Reference 1) meets or exceeds these four criteria. Where applicable, the state reported data will be supplemented by NERC reports or with data from other competent sources, like the EIA. Because this analysis and evaluation will rely heavily upon Duke Energy's IRP, Subsection 8.4.2 will provide an overview of the process Duke Energy undertakes in the preparation of this document.

In the determination of the need for this new baseload energy source, the demonstrated need must be specific to Duke Energy's relevant service area, which is identified in Subsection 8.1.5 as its franchise service area and primarily the retail electric service customers in this geographic area. Within this relevant service area, Subsection 8.4.3 will evaluate the need for new baseload capacity and Subsection 8.4.4 will provide a summary of this section.

8.4.2 THE IRP MODELING PROCESS

The basic IRP process Duke Energy undertakes can be construed as an eight step process outlined below:

1. Develop an econometric based load forecast;

2. Develop an inventory or database of costs and operating characteristics of existing supply-side and demand-side resources, as well as assumptions regarding inputs such as capital and operating costs and operating characteristics of new supply-side and demand-side resource options, including fuel and emission allowance price projections;

3. Use screening curves to identify the most cost effective, technologically available, supply-side options;

4. Screen demand-side options based on their cost, availability, expected saturation levels, and expected energy savings;

5. Use an advanced computer optimization model (Global Energy Decisions CEM is the model Duke Energy used for the 2007 IRP) that matches cost effective resources to the expected future load;

6. Use the screening results to develop potential resource portfolios to test in the detailed analyses;

7. Perform detailed analyses on the portfolios with a variety of sensitivity analyses around varying inputs such as expected future fuel prices, capital costs, future environmental regulations, load sensitivities, and other variables;

8. Identify the "best portfolios" of supply-side and demand-side options in terms of cost, reliability, safety, regulatory constraints (such as fuel diversity or baseload vs. purchase power see Subsection 8.1.4), risks, and uncertainties (see Subsections 8.2.1 and 8.2.3).

In summary, the Duke Energy resource planning process provides a framework for Duke Energy to assess, analyze and implement a cost-effective plan to meet customers' growing energy needs reliably.

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

- 1.6% average summer peak system demand growth over the next 20 years
- Generation reductions of more than 450 MW due to purchased power contract expirations by 2011
- Generation retirements of approximately 500 MW of old fleet combustion turbines by 2015
- Generation retirements of approximately 1000 MW of older coal units associated with the addition of Cliffside Unit 6
- Approximately 84 MW of net generation reductions due to application of 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

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

- Technically feasible and commercially available in the marketplace

- Compliant with all federal and state requirements
- Long-run reliability
- Cost parameters.

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

Resource Options

Supply-Side

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

- Supercritical Pulverized coal - 800 MW
- Natural gas combined-cycle with duct firing and inlet cooling – 620 MW
- Natural gas simple-cycle combustion turbine – 632 MW (4-unit plant)
- Nuclear AP 1000 – 2,234 MW (2 – 1117 MW units)
- Integrated Coal Gasification Combined Cycle (IGCC) – 630 MW
- On Shore Wind purchased power agreement (PPA) – 50 MW (15% contribution to capacity on peak)
- Solar PPA (70% contribution to capacity on peak)
- Biomass Firing PPA
- Hog Waste Digester PPA
- Poultry Waste PPA

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

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

Demand-Side Management

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

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

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

Develop Theoretical Portfolio Configurations

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

The nominal set of inputs included:

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

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

The model considers various generating resources. Using decision criteria, similar to the criteria used by Duke Energy to dispatch power, the model selects and designates various resources to be installed and used as either baseload, intermediate or peaking units. This assignment is based on the decision criteria, rather than a prima facie definition of the unit as baseload, intermediate or peaking. The decision criteria are sensitive to economic and regulatory environments and may change from year to year as the model re-evaluates the appropriateness of the resource mix.

Although the model results confirm the need for additional nuclear capacity, the screening results demonstrate that the optimal timing of nuclear varies widely from no nuclear to two units with timeframes from 2016 to 2023. For the purposes of the detailed modeling, portfolios were developed with no nuclear units or one unit in 2018 or a two unit plant with staggered operation dates of 2018 and 2020. The use of a 2018 date is for modeling purposes only. Because the model is sensitive to changes in economic or regulatory climate, the actual planned operational date may be accelerated or delayed as additional information becomes available on critical issues such as enactment of carbon legislation.

Develop Various Portfolio Options

Using the insights gleaned from developing theoretical portfolios, Duke Energy 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 the Annual Plan were chosen in order to focus on the near-term (i.e., within the next five years) decisions that must be made while placing less emphasis on differences in portfolios ten to twenty years in the future that Duke Energy will have the opportunity to re-visit in subsequent annual plans. For example, Duke Energy has a substantial need for additional resources by 2010 that can be filled by a combination of combustion turbine (CT), combined cycle (CC), DSM, and Renewable resources, so variations in these resource combinations were studied. While potential new nuclear plant capacity could not go in service until 2016 at the earliest, decisions concerning continuing to pursue this alternative are needed to preserve this option. However, the permitting process remains a source of uncertainty that may delay or even prevent its development. Therefore, in addition to the nominal input of a nuclear availability date, additional test portfolios assumed no availability at all, in order to examine the extremes.

Table 8.4-1 outlines the planning options that were considered in the portfolio analysis phase. Each portfolio contains the maximum amount of DSM (both demand response and conservation) that was available, with the exception of the combustion turbine and combustion turbine-renewable portfolios, which contain only the existing levels of DSM. In addition, each portfolio contains the addition of Cliffside Unit 6 in 2012 and the unit retirements shown in Table 8.3-6.

8.4.3 THE NEED FOR BASELOAD CAPACITY

Duke Energy's planned capacity has to meet the forecast energy and demand load as well as Duke Energy's planning reserve margin of 17 % (see Subsection 8.1.4). Based on current forecasts, in order to meet this projected need Duke Energy will require the additional energy capacity illustrated in Figure 8.3-1 and shown in more detail on Table 8.3-13. As this table and

figure indicates, the need for additional capacity grows over time to approximately 3300 MW by 2011 and 8200 MW by 2021.

Duke Energy's IRP process does not break out the forecast into baseload, intermediate, and peaking needs; it seeks to select the best portfolio to serve the total capacity and energy needs. The models analyze the costs of serving the forecasted energy in each hour of the 20-year planning horizon. This method ensures the optimal resource mix is selected to serve customers reliably and at the lowest reasonable cost with consideration of uncertainties.

In the modeling and sensitivity analysis presented in Subsection 8.4.2, the approach to choosing the best plans to meet the projected need was to test a series of generation "portfolios" against the various combinations of forecast sensitivities. The quantitative and qualitative analyses suggest that a combination of additional baseload, intermediate, and peaking generation, renewable resources, and DSM programs are required over the next 20 years. New natural gas and nuclear capacity additions are attractive supply-side options under a variety of sensitivities and scenarios. Both conservation and demand response programs play important roles in the development of a balanced, cost-effective portfolio. Renewable generation alternatives are also necessary now that a Renewable Portfolio Standard has been enacted by NCUC. In light of these analyses, as well as the public policy debate on energy and environmental issues, Duke Energy 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.

Conclusions based on the quantitative and qualitative analyses are:

- The new level of DSM and the save-a-watt methodology are cost-effective for customers
    - In every scenario and sensitivity, the portfolios with the new DSM were lower cost than the portfolios with the existing DSM
- Significant renewable resources will be needed to meet the new North Carolina Renewable Energy Portfolio Standard (and potentially a federal standard)
- Gas-fired generation is an important part of the portfolio
- The addition of combined-cycle capacity provides additional flexibility and hedging capability
    - The difference in present value of revenue requirement between the CC portfolios and the CT portfolios is very small
    - Duke Energy does not have any CCs in its current resource mix
    - The CT portfolios have higher CT capacity factors than would normally be expected
- Continuing to pursue regulatory approval of new nuclear facilities is prudent
    - Under Carbon Case conditions, the portfolios with nuclear capacity perform well

- In the High Carbon sensitivity, the portfolios with two nuclear units are superior to those with one or no nuclear units

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

As an independent evaluation of the Duke Energy need-for-power analysis supporting the Lee Nuclear Station coming into service as early as 2016, a comparison was made to information produced by the EIA. The EIA produces an independent evaluation of the electrical needs of each region of the country and based on economic efficiency using its NEMS computer model. The results of this model in the 2007 Annual Energy Outlook (Reference 2) for the SERC region are shown in Table 8.4-2. Duke Energy currently has 7.1 GW of nuclear capacity, which is approximately 22% of the total SERC nuclear capacity of 32.57 GW. In order for Duke Energy to maintain this current ratio of 22%, Duke Energy should add 562 MW of nuclear capacity by 2016 and 1980 MWs of nuclear capacity by 2019 according to the EIA's economic based projections. Based on this comparison, as Table 8.4-2 indicates, Duke Energy would be justified, based on current forecasts, to have the first unit of the Lee Nuclear station operational as early as 2017 and the second unit operational as early as 2019.

8.4.4 SUMMARY AND CONCLUSIONS

Duke Energy's IRP process demonstrates the need for the capacity and energy to be provided by the Lee Nuclear Station.

8.4.5 REFERENCES

1. Duke Energy Carolinas Annual Plan, November, 2007

2. EIA 2007 Annual Energy Outlook, Table 70, http://www.eia.doe.gov/oiaf/aeo/index.html

TABLE 8.4-1 (Sheet 1 of 5)
OPTIONAL PORTFOLIOS CONSIDERED IN THE IRP PLAN

No CO_2/RPS Reference Case

	CT CTs Early/ No Nuclear/ No Renewables/ Existing EE	CTEE CTs Early/ No Nuclear/ No Renewables/ New EE	CCEE CCs Early/ No Nuclear/ No Renewables/ New EE	CTNEE CTs Early/ Nuclear/ No Renewables/ New EE	CCNEE CCs Early/ Nuclear/ No Renewables/ New EE
2007					
2008					
2009					
2010	1264 MW New CTs	632 MW New CTs	316 MW New CTs	632 MW New CTs	316 MW New CTs
2011			620 MW New CCs		620 MW New CCs
	1264 MW New CTs	1264 MW New CTs	316 MW New CTs	1264 MW New CTs	316 MW New CTs
2012			620 MW New CCs		620 MW New CCs
2013	632 MW New CTs	632 MW New CTs	632 MW New CTs	632 MW New CTs	632 MW New CTs
2014	620 MW New CCs	620 MW New CCs			
2015	1240 MW New CCs	620 MW New CCs		620 MW New CCs	
			1264 MW New CTs	632 MW New CTs	1264 MW New CTs
2016	632 MW New CTs				
2017		632 MW New CTs	632 MW New CTs	632 MW New CTs	632 MW New CTs
2018	620 MW New CCs	620 MW New CCs	620 MW New CCs		
				1117 MW New Nuclear	1117 MW New Nuclear
2019	632 MW New CTs				
2020		632 MW New CTs	632 MW New CTs		
2021	620 MW New CCs			620 MW New CCs	
					632 MW New CTs
2022	620 MW New CCs	620 MW New CCs	620 MW New CCs		
2023				620 MW New CCs	620 MW New CCs

TABLE 8.4-1 (Sheet 2 of 5)
OPTIONAL PORTFOLIOS CONSIDERED IN THE IRP PLAN

No CO_2/RPS Reference Case

	CT CTs Early/ No Nuclear/ No Renewables/ Existing EE	CTEE CTs Early/ No Nuclear/ No Renewables/ New EE	CCEE CCs Early/ No Nuclear/ No Renewables/ New EE	CTNEE CTs Early/ Nuclear/ No Renewables/ New EE	CCNEE CCs Early/ Nuclear/ No Renewables/ New EE
		632 MW New CTs	632 MW New CTs		
2024				620 MW New CCs	620 MW New CCs
	632 MW New CTs				
2025	620 MW New CCs	620 MW New CCs	620 MW New CCs		
2026		620 MW New CCs	620 MW New CCs	620 MW New CCs	620 MW New CCs
2027	490 MW New CTs	120 MW New CTs	120 MW New CTs	260 MW New CTs	260 MW New CTs
Nuclear	0	0	0	1117	1117
CC	4340	3720	3720	3100	3100
CT	5546	4544	4544	4052	4052
Renew	0	0	0	0	0

Notes:

All years have reserve margins > 1% below target

All Portfolios contain all of the EE programs (both DR and Conservation) (Bundle 1 in 2008, Bundle 2 in 2012, & Bundle 3 in 2016) except for portfolios with Existing EE and 1 Bundle EE

All Portfolios contain the addition of Cliffside 6 and the retirement of Cliffside 1-4 in 2012

All Portfolios contain the retirement of old CTs in 2011/2012

All Portfolios contain the retirement of Buck 3-4 in 2010, Dan River 1-3 in 2013, Riverbend 4-5 in 2015, Riverbend 6 in 2016, and Riverbend 7 in 2017 except the More Retirement Portfolios which have Riverbend 6&7 in 2016, Buck 5&6 in 2017, and Lee 1-3 in 2018

TABLE 8.4-1 (Sheet 3 of 5)
OPTIONAL PORTFOLIOS CONSIDERED IN THE IRP PLAN

No CO_2/RPS Reference Case

	CTR CTs Early/ No Nuclear/ Renewables/ Existing EE	CTREE CTs Early/ No Nuclear/ Renewables/ New EE	CCREE CCs Early/ No Nuclear/ Renewables/ New EE	CTNREE CTs Early/ Nuclear/ Renewables/ New EE	CCNREE CCs Early/ Nuclear/ Renewables/ New EE
2009					
2010	9 MW Renewables	9 MW Renewables	9 MW Renewables	9 MW Renewables	9 MW Renewables
	1264 MW New CTs	632 MW New CTs	316 MW New CTs (Ph)	632 MW New CTs	316 MW New CTs (Ph)
2011			620 MW New CCs (Ph)		620 MW New CCs(Ph)
			316 MW New CTs(Ph)		316 MW New CTs(Ph)
	1264 MW New CTs	1264 MW New CTs		1264 MW New CTs	632 MW New CTs
2012	215 MW Renewables	156 MW Renewables	156 MW Renewables	156 MW Renewables	156 MW Renewables
			620 MW New CCs (Ph)		620 MW New CCs (Ph)
2013	28 MW Renewables	28 MW Renewables	28 MW Renewables	28 MW Renewables	28 MW Renewables
	632 MW New CTs				
2014	60 MW Renewables	11 MW Renewables	11 MW Renewables	11 MW Renewables	11 MW Renewables
		620 MW New CCs			
			632 MW New CTs	632 MW New CTs	632 MW New CTs
2015	294 MW Renewables	239 MW Renewables	239 MW Renewables	239 MW Renewables	239 MW Renewables
	620 MW New CCs			620 MW New CCs	
		632 MW New CTs	632 MW New CTs		632 MW New CTs
2016	55 MW Renewables				
	620 MW New CCs				
2017	150 MW Renewables	138 MW Renewables	138 MW Renewables	138 MW Renewables	138 MW Renewables
		632 MW New CTs	632 MW New CTs	632 MW New CTs	632 MW New CTs
2018	290 MW Renewables	290 MW Renewables	290 MW Renewables	290 MW Renewables	290 MW Renewables

TABLE 8.4-1 (Sheet 4 of 5)
OPTIONAL PORTFOLIOS CONSIDERED IN THE IRP PLAN

No CO_2/RPS Reference Case

	CTR CTs Early/ No Nuclear/ Renewables/ Existing EE	CTREE CTs Early/ No Nuclear/ Renewables/ New EE	CCREE CCs Early/ No Nuclear/ Renewables/ New EE	CTNREE CTs Early/ Nuclear/ Renewables/ New EE	CCNREE CCs Early/ Nuclear/ Renewables/ New EE
	632 MW New CTs				
				1117 MW New Nuclear	1117 MW New Nuclear
2019					
2020	140 MW Renewables	110 MW Renewables	110 MW Renewables	110 MW Renewables	110 MW Renewables
		620 MW New CCs			
	632 MW New CTs		632 MW New CTs		
2021	154 MW Renewables	154 MW Renewables	154 MW Renewables	154 MW Renewables	154 MW Renewables
2022					
2023	632 MW New CTs	632 MW New CTs	632 MW New CTs		
2024					
2025	620 MW New CCs	620 MW New CCs	620 MW New CCs		
				632 MW New CTs	632 MW New CTs
2026					
2027	380 MW New CTs	280 MW New CTs	280 MW New CTs	400 MW New CTs	400 MW New CTs
Nuclear	0	0	0	1117	1117
CC	1860	1860	1860	620	1240
CT	5436	4072	4072	4192	3560
Renew	1395	1135	1135	1135	1135

TABLE 8.4-1 (Sheet 5 of 5)
OPTIONAL PORTFOLIOS CONSIDERED IN THE IRP PLAN

No CO_2/RPS Reference Case

Notes:

All years have reserve margins > 1% below target

All Portfolios contain all of the EE programs (both DR and Conservation) (Bundle 1 in 2008, Bundle 2 in 2012, & Bundle 3 in 2016) except for portfolios with Existing EE

All Portfolios contain the addition of Cliffside 6 and the retirement of Cliffside 1-4 in 2012

All Portfolios contain the retirement of old CTs in 2014/2015

All Portfolios contain the retirement of Buck 3-4 in 2010, Dan River 1-3 in 2013, Riverbend 4-5 in 2015, Riverbend 6 in 2016, and Riverbend 7 in 2017

The key to the portfolio names is as follows:

CT – Portfolio with CTs early then CCs

CC – Portfolio with CCs early then CTs

N or 2N – Portfolio with one or two 1117 MW nuclear units

R – Portfolio with renewables included (assumes the renewables portion of the standard will be met with renewables instead of buying more than 25% RECs or paying a penalty, if allowed)

EE – New DSM levels; if no EE, then existing DSM is assumed to continue

Source: Reference 1

TABLE 8.4-2
COMPARISON OF EIA PROJECTED ECONOMIC NUCLEAR CAPACITY ADDITIONS VERSUS DUKE ENERGY PLANNED NUCLEAR CAPACITY ADDITIONS

YEAR	Cumulative Unplanned Nuclear Capacity Needed SERC Region (MW)[a]	Duke Nuclear Capacity Additions Necessary to Maintain Current Duke/SERC Nuclear Capacity Ratio (MW)
2015	550	121
2016	2555	562
2017	4810	1058
2018	7500	1650
2019	9000	1980

a) EIA 2007 Annual Energy Outlook Table 70