CHAPTER 8
NEED FOR POWER

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ACRONYMS AND ABBREVIATIONS

CAP	climate action plan
CAPAG	Climate Action Plan Advisory Group
CC	combined cycle
CPCN	Certificate of Public Convenience and Necessity
CSA	Clean Smokestacks Act
CT	combustion turbine
DNCP	Dominion North Carolina Power
DSM	demand-side management
Duke	Duke Energy Corporation
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
ER	Environmental Report
ERAG	Eastern Interconnection Reliability Assessment Group
ESRP	Environmental Standard Review Plan
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GHG	greenhouse gases
G.S.	General Statute
ha	hectare
HAR	proposed Shearon Harris Nuclear Power Plant Units 2 and 3
HAR 2	proposed Shearon Harris Nuclear Power Plant Unit 2
HAR 3	proposed Shearon Harris Nuclear Power Plant Unit 3
HNP	existing Shearon Harris Nuclear Power Plant Unit 1

ACRONYMS AND ABBREVIATIONS (CONTINUED)

IOU	investor-owned utility
IRP	Integrated Resource Plan
km^2	square kilometer
kV	kilovolt
kWh	kilowatt hour
LCGCC	Legislative Commission on Global Climate Change
LOLE	Loss-of-Load Expectations
LT-PFSG	Long-term Power Flow Study Group
MW	megawatt
MWe	megawatt electric
MWh	megawatt hour
MSW	municipal solid waste
NCDENR	North Carolina Department of Environment and Natural Resources
NCEMC	North Carolina Electric Membership Corporation
NCEMPA	North Carolina Eastern Municipal Power Agency
NCUC	North Carolina Utilities Commission
NCSEA	North Carolina Sustainable Energy Association
NERC	North American Electric Reliability Corporation
NO_x	nitrogen oxides
NRC	U.S. Nuclear Regulatory Commission
NT-PFSG	Near-term Power Flow Study Group
NUG	non-utility generation
O&M	operation and maintenance

ACRONYMS AND ABBREVIATIONS (CONTINUED)

OASIS	Open-Access Same-Time Information System
PEC	Progress Energy Carolinas, Inc.
PURPA	Public Utility Regulatory Policies Act
QF	qualifying facility
RCI	residential, commercial, and industrial
ROI	Region of Interest
REPS	Renewable Energy Portfolio Standard
RRC	regional reliability councils
RTO	regional transmission organization
SCPSC	South Carolina Public Service Commission
SEPA	Southeastern Power Administration
SERC	Southeastern Electric Reliability Council
SO_2	sulphur dioxide
TAG	Technical Power Guide
USDOE	U.S. Department of Energy
VACAR	Virginia-Carolinas

8.0 NEED FOR POWER

This chapter of the Environmental Report (ER) supports the need for the power that may be generated by the proposed Shearon Harris Nuclear Power Plant Units 2 and 3 (HAR), based on Progress Energy Carolinas, Inc.'s (PEC's) service territory. PEC territory consists of an area approximately 34,000 square miles (mi.^{2}), and includes northeastern South Carolina, and portions of the coastal plain, lower piedmont section, and a portion of western North Carolina (Reference 8.0-001). PEC prepares Integrated Resource Plans (IRPs) for both North Carolina and South Carolina. The Region of Interest (ROI) for the HAR ER has been defined as PEC's service territory in both North Carolina and South Carolina. Figure 8.0-1 shows the PEC service territory. PEC's service territory and the ROI are also the relevant service area that will be served by the HAR.

PEC's IRP is submitted to the North Carolina Utilities Commission (NCUC), which incorporates it into the NCUC annual report to the North Carolina State Legislature (Reference 8.0-002). PEC submits its annual plan to the NCUC in the fourth quarter of each year. In South Carolina, PEC's IRP is submitted to the South Carolina Public Service Commission (SCPSC) (Reference 8.0-001). PEC submits the IRP for South Carolina to the SCPSC in June of each year.

NCUC Rule R8-60 defines an overall framework within which this planning occurs (Reference 8.0-003). Rule R8-60 requires each regulated utility in North Carolina (such as PEC) to submit an annual report of its resource plan to the NCUC that contains details of the following:

- A 10-year forecast of loads and generating capacity.
- Conservation, load management, and other demand-side options accounted for in the process.
- New utility-owned generating plants.
- Non-utility generation and other supply-side options.

The content is designed to identify the resource plan that will be most cost effective for the ratepayers while supplying adequate, reliable service. The legislature receives an annual update from the NCUC (Reference 8.0-004).

In 1998, the SCPSC issued Order No. 98-502 requiring IRP submittals to contain the following information:

- The demand and energy forecast for at least a 15-year period.
- The supplier's or producer's program for meeting the requirements shown in its forecast in an economic and reliable manner, including demand-side and supply-side options.

- Brief description and summary of cost-benefit analysis, if available, of each option that was considered, including those not selected.

- The supplier's or producer's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy services, and a description of the external environmental and economic consequences of the plan to the extent practicable. (Reference 8.0-005)

PEC integrates its resource planning for both North Carolina and South Carolina, but submits individual IRPs to both states.

As noted in NUREG-1555, Environmental Standard Review Plan (ESRP) 8.1:

> Affected States and/or regions are expected to prepare a need-for-power evaluation. [U.S. Nuclear Regulatory Commission] NRC will review the evaluation and determine if it is (1) systematic, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty. If the need-for-power evaluation is found acceptable, no additional independent review by NRC is needed, and the analysis can be the basis for ESRPs 8.2 through 8.4.

Since the HAR is proposed for construction in the state of North Carolina, the focus of this chapter will be on North Carolina. The following sections show that the North Carolina IRP process meets these four criteria and is adequate for supporting the need for power evaluation in this ER.

8.1 STATE NEED FOR POWER PLANNING

This section reviews the criteria described in NUREG-1555:

> Affected States and/or regions are expected to prepare a need-for-power evaluation. NRC will review the evaluation and determine if it is (1) systematic, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty. If the need for power evaluation is found acceptable, no additional independent review by NRC is needed, and the analysis can be the basis for ESRPs 8.2 through 8.4.
>
> As part of their analyses of the need for power, States and/or regional authorities are expected to describe and assess the regional power system. The reviewer should evaluate the description, and determine if it is comprehensive and subject to confirmation. If it is found acceptable, no additional data collection by NRC should usually be needed. These data may be supplemented by information sources such as the Energy Information Administration [EIA], FERC [Federal Energy Regulatory Commission], the North American Electric Reliability Council, and others.

The statutes of North Carolina require the NCUC to analyze probable growth in electricity use and long-range need for future generating capacity in the state.

North Carolina General Statute (G.S.) § 62-110.1(c) provides, in part, the following:

> The [NCUC] shall develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity, the probable needed generating reserves, the extent, size, mix and general location of generating plants and arrangements for pooling power to the extent not regulated by the Federal Power Commission and other arrangements with other utilities and energy suppliers to achieve maximum efficiencies for the benefit of the people of North Carolina, and shall consider such analysis in acting upon any petition by any utility for construction.…Each year, the [NCUC] shall submit to the Governor, and to the appropriate committees of the General Assembly, a report of its analysis and plan, the progress to date in carrying out such plan, and the program of the Commission for the ensuing year in connection with such plan. (Reference 8.1-001)

North Carolina G.S. § 62-2 provides, in part, that the state will take measures:

> (3a) To assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills. (Reference 8.1-002)

The NCUC and its Public Staff put these provisions into action by requiring each regulated utility, including PEC, to present an annual IRP showing the utility's growth calculations and plans to meet projected loads (Reference 8.0-002).

Additionally, no public utility or any other person may begin the construction of any facility for the generation of electricity in the State of North Carolina without first obtaining a certificate from the NCUC that the "public convenience and necessity" requires (or will require) such construction. The North Carolina G.S. and NCUC regulations specify the steps to obtain a certificate. Under North Carolina G.S. § 62-110.1(a), prior to construction, PEC (and all other utilities) are required to obtain a Certificate of Public Convenience and Necessity (CPCN) from the NCUC (Reference 8.1-001). The purpose of this certificate is to determine whether there is a need for a new electric generating plant to meet the electricity needs of PEC's customers.

PEC is required to file the following information with the NCUC at least 120 days before applying for the CPCN for a generating plant with a capacity of 300 megawatts (MW) or more:

- Information concerning geological, aesthetic, ecological, meteorological, seismic, water supply, population, and general load center data.
- A statement of need for the facility.
- A description of investigations completed, in progress or proposed, concerning the site.
- A statement of any known plans by governmental or private entities for other development near the proposed site.
- A statement of any environmental evaluation program to meet the applicable air and water quality standards.
- A description of practicable transmission line routes from the site.
- A list of all agencies from which any approvals will be sought (including the type and nature of such approvals).
- Estimated capital cost information for the facility (including the initial core for nuclear plants) and all operating expenses (including fuel costs and total generating costs per net kilowatt-hours (kWh) at the plant, and information concerning capacity factor, heat rate, and plant service life.
- Comparative cost information of other final alternatives considered.
- A schedule showing the anticipated beginning dates for construction, testing, and commercial operation of the facility.

The actual application for the CPCN must include the following:

- The most recent annual report of IRP updates.
- Testimony indicating the extent that the proposed facility complies with the annual report.
- Testimony supporting any proposal to update the most recent annual report.

PEC must publish a notice of the proposed facility in a local daily newspaper with circulation in Wake County. This notice is required at least once per week for four successive weeks. If anyone submits a complaint within 10 days after the last

date of the publication of the notice, the NCUC is required to schedule a public hearing to determine if a CPCN is to be awarded. If a hearing is held, all parties are given a chance to be heard, and are given an opportunity to submit briefs and oral arguments. Upon a finding that the public convenience and necessity requires the new facility, the NCUC will issue the CPCN.

The CPCN is subject to the following requirements:

- The CPCN is subject to revocation if the applicant fails to obtain any of the other federal or state licenses, permits, or exemptions required for construction and operation of the generating facility.

- Annual progress reports and any revision in the cost estimate for the construction approved under the CPCN as approved by the NCUC are required by G.S. § 62-110.1(f) until construction is completed.

- The CPCN holder must advise the NCUC of any plans to sell, transfer, or assign the certificate or the generating facility, or any significant changes in the facility information.

South Carolina has a process similar to North Carolina for siting a power plant that involves attaining a Certificate of Environmental Compatibility and Public Convenience and Necessity from the SCPSC (Reference 8.1-003). This licensing process considers emissions, water use, and water quality in reaching siting decisions. As noted above in Section 8.0, the certification process for South Carolina will not be discussed in detail in this chapter since the plant will be constructed in North Carolina.

The following subsections show how North Carolina's IRP meets the NRC's four criteria and present explanations about why the state's power planning strategies should be used in the place of NRC's independent analysis of the need for power. PEC employs the same planning process for North Carolina and South Carolina. As stated above, PEC integrates its resource planning process for both states and submits an IRP for each state independently.

8.1.1 THE IRP PROCESS IS SYSTEMATIC

In order to meet statutory requirements, the NCUC defined an overall framework for planning power needs within the IRP process. The key rule, Rule R8-60, requires a regulated utility such as PEC to analyze and account for conservation, load management, and other demand-side options, along with new utility-owned generating plants, non-utility generation, and other supply-side options. This is required in order to identify the resource plan that will be most cost effective for the ratepayers while supplying adequate, reliable service (Reference 8.0-004). The NCUC Public Staff assists the NCUC by reviewing and commenting on the utility's report and by presenting written reviews to the NCUC. Rule R8-60 requires public hearings and permits evidentiary hearings at the discretion of the NCUC. If an evidentiary hearing is conducted, the NCUC hears testimony from

experts, the utilities, and interested parties. Ultimately, the NCUC issues an order approving or disapproving the IRP report. Figure 8.1-1 shows the general planning process.

The utilities' IRPs are also relied upon by the NCUC in making an annual report to the North Carolina General Assembly and the Governor regarding the state's long-term need for additional electric generation facilities to serve the state's electricity needs (Reference 8.1-001).

Pursuant to Rule R8-60, PEC submitted its 2006 IRP to the NCUC (Reference 8.1-004). Throughout early 2007, the Public Staff and the public at-large submitted comments on the utility's plan (Reference 8.1-005). These comments showed a continued high public interest in energy efficiency and conservation (Reference 8.0-004). The NCUC directed the Public Staff to conduct public hearings (Reference 8.1-006). On July 9, 2007, the NCUC issued its order approving the IRP. This process occurs annually, as required by law (Reference 8.1-007).

8.1.2 THE IRP PROCESS IS COMPREHENSIVE

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 most cost-effective way of providing electric service. The primary purpose of the IRP process is to integrate demand-side and supply-side resource planning into one comprehensive procedure that weighs the costs and benefits of all reasonably available options in order to identify those options that are most cost effective for the ratepayers while providing adequate, reliable service. (Reference 8.0-004)

The IRP process in North Carolina requires each regulated utility to present a report that describes its resource plan and contains a 15-year forecast of loads and generating capacity. The South Carolina IRP process also requires a 15-year forecast of loads and generating capacity. Table 8.1-1 shows the historical system peak and load for 1997 through 2006.

Revised rules promulgated in 1998 provide a streamlined process that changed the 3-year report period to an annual review (Reference 8.0-004). Additionally, Rule R8-60 sets forth the following aspects of the power supply system that must be included in a regulated utility's annual report:

- Tabulation of summer and winter peak loads, annual energy forecast, generating capability, and reserve margins for each year, as well as a description of the methods and assumptions used by the utility to prepare its forecast.

- List of existing plants in service, along with capacity, plant type, and location.

- 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, along with location, capacity, plant type, and proposed date of operation.

- List of proposed generating units at locations not known, with capacity, plant type, and date of operation included to the extent known.

- List of units to be retired from service, along with location, capacity, and expected date of retirement from the system.

- 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.

- List of transmission lines and other associated facilities (161 kilovolt [kV] or over) that are under construction or for which there are specific plans, along with the capacity and voltage levels, location, and schedules for completion and operation.

- List of any generation and associated transmission facilities under construction that have delays of over 6 months in the previously reported in-service dates and the major causes of such delays. Upon request from the NCUC Staff, the reporting utility shall supply a statement of the economic impact of such delays.

- List of demand-side options reflected in the resource plan.

- List of wholesale purchase power commitments reflected in the resource plan.

- List of wholesale power sales commitments reflected in the resource plan. (Reference 8.0-003)

The NCUC rule also allows the staff or any other intervener to file a report, evaluation, or comments to a utility's report and identify issues that interested parties believe should be the subject of an evidentiary hearing. Rule R8-60(d) further provides for detailed review of the IRP reports filed by the utilities and Public Staff. The NCUC has the authority to hold an evidentiary hearing at its discretion (Reference 8.0-003).

8.1.3 THE IRP PROCESS IS SUBJECT TO CONFIRMATION

The IRP rules allow an extensive public comment and response period. During the course of public and, if scheduled, evidentiary hearings, the NCUC takes

testimony as necessary from interveners that have requested a hearing, hears the testimony of experts on various issues, and issues an order approving the IRP or orders further information required for future reports. The NCUC reviews and approves the reports annually. (Reference 8.0-003)

The plans are fully reviewed on an annual basis. For example, in hearings reviewing the utilities' 2006 IRP report, the NCUC reviewed the following issues:

- The validity of the utilities' load forecasting methods.
- Whether the companies are employing and developing adequate demand-side management (DSM) and displacing the need for additional generation assets.
- The potential opportunities for cost-effective energy efficiency and conservation measures, as described in North Carolina G.S. § 62-2.
- The degree to which utility programs can effectively reduce consumption, including information on the amount of customer education necessary and financial incentives employed by the companies to encourage customer energy efficiency measures.
- Funding mechanisms that could be employed to implement specific energy efficiency measures.

After a series of hearings, the NCUC approved the utilities' 2006 IRPs (Reference 8.1-007).

8.1.4 THE IRP PROCESS CONSIDERS UNCERTAINTY

Pursuant to Rule R8-60, PEC submitted an IRP to NCUC in the fourth quarter of 2007 report (Reference 8.0-002). PEC notes that it has used econometric and statistical methods to predict future capacity needs. Further, in determining the level of reserve margins, the following is involved:

> PEC employs both deterministic and probabilistic reliability criteria in the resource planning process. PEC establishes a reserve criterion for planning purposes based on probabilistic assessments of generation reliability, industry practice, historical operating experience, and judgment (Reference 8.0-002).

Additionally, PEC develops its resource plans based on maintaining summer and winter capacity margin range to account for the forecasting uncertainty in the long-term or potential delays in bringing capacity online. The summer capacity margin forecast for the years 2008 through 2022 ranges from 11 percent to 21 percent. The winter capacity margin forecast for the same time period ranges from 25 percent to 33 percent.

At the end of 2006, PEC had a winter peak generating capacity of 13,237 MW and a summer peak generating capacity of 12,409 MW. The generation mix included nuclear steam plants, coal-fired plants, internal combustion turbines, combined cycle, and hydroelectric plants. In 2008, nuclear and coal generation is projected to provide approximately 63 percent of PEC's total capacity resources, yet account for about 91 percent of the total energy requirements. Gas and oil generation accounts for about 25 percent of total supply capacity, yet less than 3 percent of the total energy. (Reference 8.0-002)

PEC's gas and oil resources are projected to increase to about 29 percent of total supply capacity for 2022, while only serving about 4 percent of the total energy requirements. Nuclear and coal are projected to account for approximately 64 percent of total capacity resources and serve about 94 percent of total system energy requirements for 2022. (Reference 8.0-002) This indicates that nuclear and coal resources will continue to account for the largest share of the PEC system capacity (MW) and satisfy most of the system energy (megawatt hour [MWh]) requirements. Currently, PEC holds approximately 83.83 percent ownership interest in the existing Shearon Harris Nuclear Power Plant Unit 1 (HNP) (Reference 8.1-008).

Additionally, in 2006, residential users accounted for approximately 36 percent of the major users of energy produced, commercial 25 percent, industrial 17 percent, wholesale 18 percent, and governmental and miscellaneous both accounted for 2 percent each (Reference 8.1-009). According to PEC's 2007 IRP, wholesale sales have become more uncertain due to the 1992 Energy Policy Act, subsequent FERC initiatives related to the wholesale market, the continuing evolution of the wholesale market, and overall market conditions. PEC is currently pursuing purchase power opportunities for 2010 and beyond. Table 8.1-2 shows the co-ops and municipally owned power companies that PEC has wholesale purchase power commitments and Table 8.1-3 lists PEC's wholesale power sales agreements. PEC currently has no existing agreements to regularly sell power outside the service territory. At times, PEC does make available off-system sales to adjacent regional reliability councils (RRC); to date these have been short-term sales (e.g., several hours or days), but PEC may explore selling long term as more capacity is added.

The NCUC Public Staff also recognizes and accounts for uncertainty in its review:

> Forecasting electric load growth into the future is, at best, an imprecise undertaking. Virtually all forecasting tools commonly used today assume that certain historical trends or relationships will continue into the future, and that historical correlations give meaningful clues to future usage patterns. As a result, any shift in such correlations or relationships can introduce significant error into the forecast. PEC, Duke Energy Corporation (Duke), and Dominion North Carolina Power (DNCP) each utilize generally accepted forecasting procedures. Although their respective forecasting models are different, the econometric techniques

employed by each utility are widely used for projecting future trends. Each of the models requires the analysis of large amounts of data, the selection of a broad range of demographic and economic variables, and the use of advanced statistical techniques (Reference 8.0-004).

In addition, the US Congress passed an energy bill in 1978 titled the Public Utility Regulatory Policies Act (PURPA). PURPA dealt with several energy industry issues and required investor-owned electric utilities to interconnect and purchase power from non-utility owned generating facilities as long as those facilities meet a set of guidelines. A facility that meets those standards and guidelines is deemed to be a Qualifying Facility (QF) under PURPA. PURPA broadly defined two types of QFs, cogenerators and small power producers. Cogenerators produce electricity and another useful form of thermal energy (such as heat or steam) that can be used for industrial, commercial, residential, or institutional purposes. This two-fold use of a fuel source is more efficient than just producing heat or steam for a process or just generating electricity alone. Small power producers produce energy from renewable resources such as wind, solar, hydroelectric, geothermal, biomass, or some waste product.

Through the IRP process, PEC periodically assesses various generating technologies to ensure that projections for new resource additions capture new and emerging technologies over the planning horizon. This analysis involves a preliminary screening of the generation resource alternatives based on commercial availability, technical feasibility, and cost. The alternative screening process is generic in nature, not site-specific. The IRP process looks at the commercial availability, the technological feasibility for commercially available technologies, and the levelized cost of energy production. To accomplish this, the PEC IRP process incorporates sophisticated resource optimization computer models to evaluate future generation alternatives.

As of December 2007, PEC's IRP includes purchased power from two municipal solid waste (MSW) facilities and contracts with landfill gas facilities. PEC is also actively engaged in a variety of projects to develop new alternative sources of energy, including solar, hydrogen, biomass, and landfill gas technologies. In addition, wind and solar, as well as other renewables, such as hog waste and other plant and animal wastes, are being evaluated for their ability to meet renewable energy requirements on a case-by-case basis and included as a resource option if appropriate. PEC is committed to meeting renewable energy requirements associated with the North Carolina Renewable Energy Portfolio Standards (RPS). PURPA QF (NUG QF Cogen, NUG QF Renewable, and NUG QF Other) entities and capacity in North Carolina from 2008-2022 are listed under Purchases and Other Resources in Tables 8.1-4 and 8.1-5.

These margin calculations are an important hedge against future power needs. The current reliability margins are predicted to remain stable. With increasing demand (Tables 8.1-4 and 8.1-5), additional capacity necessarily protects that margin (Reference 8.0-004).

Table 8.1-1
Progress Energy Carolinas
System Peak and Load by Year

Year	Annual Peak (MW)	Annual Load (MWH)
1997	10,030	53,299,020
1998	10,529	55,446,256
1999	10,948	55,826,866
2000	11,157	59,022,369
2001	11,376	57,474,749
2002	11,977	60,127,653
2003	11,771	60,291,652
2004	11,495	61,929,724
2005	12,577	64,040,249
2006	12,496	62,941,246

Notes:

MW = megawatts
MWH = megawatts per hour

Table 8.1-2
Progress Energy Carolinas
Wholesale Purchase Power Commitments

Purchase	In-Service Date	Contract End Date	Summer Rating (MW)	Winter Rating (MW)
SEPA	Various	Perpetual	109	109
NUG-Cogen	2003	Various	179	179
NUG-Renewables	2006	Various	4	4
NUG-Other	1989	2009	16	16
AEP/Rockport #2	January 1, 1990	December 31, 2009	250	250
Broad River CTs #1-5	2001-2002	2021-22	816	841
Southern Purchase	01/01/10	12/31/19	150	150

Notes:

MW = megawatts

SEPA = Southeastern Power Administration

NUG = Non-utility generation

Cogen = Cogeneration

CTs = Combustion turbine

Source: Reference 8.0-002

Table 8.1-3
Progress Energy Carolinas
List of Wholesale Power Sales Commitments

City of Camden, South Carolina
City of Fayetteville, North Carolina
City of Seneca, South Carolina
French Broad EMC
NCEMC
NCEMPA
Mitigation Sales
Piedmont EMC
Town of Black Creek, North Carolina
Town of Lucama, North Carolina
Town of Stantonsburg, North Carolina
Town of Sharpsburg, North Carolina
Town of Waynesville, North Carolina
Town of Winterville, North Carolina
Anticipate renewal and load growth

Notes:

EMC = Electric Membership Corporation

NCEMC = North Carolina Electric Membership Corporation

NCEMPA = North Carolina Eastern Municipal Power Agency

Source: Reference 8.0-002

Table 8.1-4 (Sheet 1 of 2)
Progress Energy–Carolinas December 2007 North Carolina Resource Plan Filing (Summer)

	2008	2009	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
GENERATION ADDITIONS															
Wayne County CT		157													
Richmond County CC				600											
Planned Projects	19	21	20		5										
Pollution Control Derates	(39)	(38)	(1)		(1)	(2)									
Undesignated [(a)]			168		129			168	168		1,085	1,085			
Roxboro CT retirement	(12)														
INSTALLED GENERATION															
Nuclear	3,485	3,495	3,515	3,515	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520
Fossil	5,196	5,169	5,168	5,168	5,168	5,166	5,166	5,166	5,166	5,166	5,166	5,166	5,166	5,166	5,166
Hydro	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225
Combined Cycle	528	528	528	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128
Combustion Turbine	2,939	3,096	3,096	3,096	3,096	3,096	3,096	3,096	3,096	3,096	3,096	3,096	3,096	3,096	3,096
Undesignated [(a)]			168	168	297	297	297	465	633	633	1,718	2,803	2,803	2,803	2,803
PURCHASES & OTHER RESOURCES															
SEPA	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
AEP/Rockport 2	250	250													
Broad River CT	816	816	816	816	816	816	816	816	816	816	816	816	816	816	816
NUG QF - Cogen	179	179	20	20	20	20	20	20	20	20	20	20	20	20	20
NUG QF - Renewable	4	8	8	8	8	8	4	4	4	4	4	4	4	4	4
NUG QF - Other	16	9													
Southern CC Purchase			150	150	150	150	150	150	150	150	150	150			
Undesignated Short-term Purchase*			150	150											
TOTAL SUPPLY RESOURCES	**13,733**	**13,869**	**13,938**	**14,538**	**14,522**	**14,520**	**14,516**	**14,684**	**14,852**	**14,852**	**15,937**	**17,022**	**16,872**	**16,872**	**16,872**

Table 8.1-4 (Sheet 2 of 2)
Progress Energy–Carolinas December 2007 North Carolina Resource Plan Filing (Summer)

	2008	2009	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
PEAK DEMAND															
Retail	8,946	9,031	9,108	9,183	9,255	9,331	9,412	9,498	9,592	9,682	9,801	9,957	10,129	10,302	10,499
Wholesale	3,063	2,981	2,977	3,015	3,139	3,221	3,303	3,337	3,371	3,400	3,416	3,448	3,482	3,562	3,592
SYSTEM PEAK LOAD	12,009	12,012	12,085	12,198	12,394	12,552	12,715	12,835	12,963	13,082	13,217	13,405	13,611	13,864	14,091
Firm Sales	200	200	200	200	100	100	100	100	100	100	100	100	100	100	100
FIRM OBLIGATION	12,209	12,212	12,285	12,398	12,494	12,652	12,815	12,935	13,063	13,182	13,317	13,505	13,711	13,964	14,191
Energy Efficiency/Demand Reduction	431	526	644	771	888	1,000	1,110	1,216	1,321	1,414	1,484	1,523	1,547	1,568	1,584
TOTAL LOAD	**12,640**	**12,738**	**12,929**	**13,169**	**13,382**	**13,652**	**13,925**	**14,151**	**14,384**	**14,596**	**14,801**	**15,028**	**15,258**	**15,532**	**15,775**
RESERVES [b]	1,524	1,657	1,653	2,140	2,028	1,868	1,701	1,749	1,789	1,670	2,620	3,517	3,161	2,908	2,681
Capacity Margin [c]	11%	12%	12%	15%	14%	13%	12%	12%	12%	11%	16%	21%	19%	17%	16%
Reserve Margin [d]	12%	14%	13%	17%	16%	15%	13%	14%	14%	13%	20%	26%	23%	21%	19%
ANNUAL SYSTEM ENERGY (GWh)	**65,589**	**66,137**	**66,762**	**67,937**	**69,224**	**70,397**	**71,581**	**72,703**	**73,850**	**74,916**	**75,951**	**77,108**	**78,293**	**79,586**	**80,855**

Notes:

* Purchases are being pursued beginning 2010 and beyond

a) For planning purposes only; does not indicate a commitment to type, amount or ownership.

b) Reserves = Total Supply Resources - Firm Obligations.

c) Capacity Margin = Reserves / Total Supply Resources * 100.

d) Reserve Margin = Reserves / Firm Obligations * 100.

CC = combined cycle

NUG = non-utility generation

CT = combustions turbine

QF = qualifying facility

Source: Reference 8.0-002

Table 8.1-5 (Sheet 1 of 2)
Progress Energy–Carolinas December 2007 South Carolina Resource Plan Filing (Summer)

	2008	2009	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
GENERATION ADDITIONS															
Wayne County CT		157													
Richmond County CC				600											
Planned Projects	19	21	20		5										
Pollution Control Derates	(39)	(38)	(1)		(1)	(2)									
Undesignated [(a)]			168		129			168	168		1,085	1,085			
Roxboro CT retirement	(12)														
INSTALLED GENERATION															
Nuclear	3,485	3,495	3,515	3,515	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520
Fossil	5,196	5,169	5,168	5,168	5,168	5,166	5,166	5,166	5,166	5,166	5,166	5,166	5,166	5,166	5,166
Hydro	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225
Combined Cycle	528	528	528	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128
Combustion Turbine	2,939	3,096	3,096	3,096	3,096	3,096	3,096	3,096	3,096	3,096	3,096	3,096	3,096	3,096	3,096
Undesignated [(a)]			168	168	297	297	297	465	633	633	1,718	2,803	2,803	2,803	2,803
PURCHASES & OTHER RESOURCES															
SEPA	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
AEP/Rockport 2	250	250													
Broad River CT	816	816	816	816	816	816	816	816	816	816	816	816	816	816	816
NUG QF - Cogen	179	179	20	20	20	20	20	20	20	20	20	20	20	20	20
NUG QF - Renewable	4	8	8	8	8	8	4	4	4	4	4	4	4	4	4
NUG QF - Other	16	9													
Southern CC Purchase			150	150	150	150	150	150	150	150	150	150			
Undesignated Short-term Purchase*			150	150											
TOTAL SUPPLY RESOURCES	**13,733**	**13,869**	**13,938**	**14,538**	**14,522**	**14,520**	**14,516**	**14,684**	**14,852**	**14,852**	**15,937**	**17,022**	**16,872**	**16,872**	**16,872**

Table 8.1-5 (Sheet 2 of 2)
Progress Energy–Carolinas December 2007 South Carolina Resource Plan Filing (Summer)

	2008	2009	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
PEAK DEMAND															
Retail	8,946	9,031	9,108	9,183	9,255	9,331	9,412	9,498	9,592	9,682	9,801	9,957	10,129	10,302	10,499
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SYSTEM PEAK LOAD	12,009	12,012	12,085	12,198	12,394	12,552	12,715	12,835	12,963	13,082	13,217	13,405	13,611	13,864	14,091
Firm Sales	200	200	200	200	100	100	100	100	100	100	100	100	100	100	100
FIRM OBLIGATION	12,209	12,212	12,285	12,398	12,494	12,652	12,815	12,935	13,063	13,182	13,317	13,505	13,711	13,964	14,191
Energy Efficiency/Demand Reduction	431	526	644	771	888	1,000	1,110	1,216	1,321	1,414	1,484	1,523	1,547	1,568	1,584
TOTAL LOAD	**12,640**	**12,738**	**12,929**	**13,169**	**13,382**	**13,652**	**13,925**	**14,151**	**14,384**	**14,596**	**14,801**	**15,028**	**15,258**	**15,532**	**15,775**
RESERVES [(b)]	1,524	1,657	1,653	2,140	2,028	1,868	1,701	1,749	1,789	1,670	2,620	3,517	3,161	2,908	2,681
Capacity Margin [(c)]	11%	12%	12%	15%	14%	13%	12%	12%	12%	11%	16%	21%	19%	17%	16%
Reserve Margin [(d)]	12%	14%	13%	17%	16%	15%	13%	14%	14%	13%	20%	26%	23%	21%	19%
ANNUAL SYSTEM ENERGY (GWh)	**65,589**	**66,137**	**66,762**	**67,937**	**69,224**	**70,397**	**71,581**	**72,703**	**73,850**	**74,916**	**75,951**	**77,108**	**78,293**	**79,586**	**80,855**

Notes:

* Purchases are being pursued beginning 2010 and beyond.

a) For planning purposes only; does not indicate a commitment to type, amount or ownership.

b) Reserves = Total Supply Resources - Firm Obligations.

c) Capacity Margin = Reserves / Total Supply Resources * 100.

d) Reserve Margin = Reserves / Firm Obligations * 100.

CC = combined cycle

NUG = non-utility generation

CT = combustions turbine

QF = qualifying facility

Source: Reference 8.0-001

8.2 POWER DEMAND

The guidance in NUREG-1555, ESRP 8.2, requires that a state program, describing current power demand and forecasts, may support the need for power. This section describes the power planning by PEC and the NCUC.

8.2.1 POWER AND ENERGY REQUIREMENTS

NUREG-1555 provides the following guidance in ESRP 8.2.1:

> Affected States and/or regions continue to prepare need-for-power evaluations for proposed energy facilities. The NRC will review the evaluation and determine if it is (1) systematic, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty. Forecasts should include demand scenarios for midrange, high, low, 75th percentile, and 25th percentile conditions. If the need for power evaluation is found acceptable, no additional independent review by the NRC is needed, and the analysis can be the basis for ESRPs 8.2 through 8.4.

PEC is required to provide the following information in tabular form:

> 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 (Reference 8.0-003).

PEC submitted its demand forecast tables (Tables 8.1-4, 8.1-5, 8.2-1, and 8.2-2) with the 2007 IRP reports for both North Carolina and South Carolina. It should be noted that Tables 8.1-4 and 8.2-1 for North Carolina reflect PEC's 2007 IRP process, while Tables 8.1-5 and 8.2-2 for South Carolina reflect PEC's 2007 IRP process. The forecast numbers used to support the evaluation for North Carolina are from the 2007 IRP. The methodology used by PEC in the 2007 IRP process for North Carolina is discussed below (Reference 8.0-002):

> Peak Load and Energy Forecast
>
> *Methodology*
>
> PEC forecasting processes have utilized econometric and statistical methods since the mid-70s. During this time, enhancements have been made to the methodology as data and software have become more available and accessible. Enhancements have also been undertaken over time to meet the changing data needs of internal and external customers.
>
> The System Peak Load Forecast is developed from the System Energy Forecast using a load factor approach. This load forecast method couples the two forecasts directly, assuring consistency of assumptions and data.

Class peak loads are developed from the class energy using individual class load factors. Peak loads for the residential, commercial, and industrial classes are then adjusted for projected load management impacts. The individual loads for the retail classes, wholesale customers, NCEMPA (North Carolina Eastern Municipal Power Agency), and Company Use are then totaled and adjusted for losses between generation and the customer meter to determine System Peak Load.

Wholesale sales and demands include a portion that will be provided by the Southeastern Power Administration (SEPA). NCEMPA sales and demands include power which will be provided under the joint ownership agreement with them.

Assumptions

The filed forecast represents a retail growth rate of approximately 1.8 percent across the forecast period before subtracting for DSM. The retail demand growth rate drops to 1.1 percent after adjusting for DSM. Wholesale sales have become more uncertain due to the 1992 Energy Policy Act, subsequent FERC initiatives related to the wholesale market, the continuing evolution of the wholesale market, and market conditions. As expectations for the various wholesale contracts change, those expectations are appropriately reflected in the wholesale forecast.

Generally, growth in the standard of living as reflected in personal income and Gross Domestic Product (GDP) per capita is expected to slow modestly over the long-term relative to historic levels. Real dollar prices are used to enhance model reliability during periods of varying inflation.

The forecast of system energy usage and peak load does not explicitly incorporate periodic expansions and contractions of business cycles, which are likely to occur from time to time during any long-range forecast period. While long-run economic trends exhibit considerable stability, short-run economic activity is subject to substantial variation. The exact nature, timing and magnitude of such short-term variations are unknown years in advance of their occurrence. The forecast, while it is a trended projection, nonetheless reflects the general long-run outcome of business cycles because actual historical data, which contain expansions and contractions, are used to develop the general relationships between economic activity and energy use. Weather normalized temperatures are assumed for the energy and system peak forecasts.

Resource Planning Process

The resource planning process used by PEC incorporates sophisticated resource optimization computer models to evaluate future generation alternatives. The integrated planning process combines existing and new generation resources, demand-side management programs, and

purchased power contracts in a portfolio that will provide reliable electric service at a reasonable overall cost to PEC's customers over the planning horizon.

Screening of Generation Alternatives

Methodology

PEC periodically assesses various generating technologies to ensure that projections for new resource additions capture new and emerging technologies over the planning horizon. This analysis involves a preliminary screening of the generation resource alternatives based on commercial availability, technical feasibility, and cost.

First, the commercial availability of each technology is examined for use in utility-scale applications. For a particular technology to be considered commercially available, the technology must be able to be built and operated on an appropriate commercial scale in continuous service by or for an electric utility. Reasonable levels of detail for emerging technologies were developed to allow PEC to screen the technology options and to stay abreast of potential economic benefits as they mature.

Second, technical feasibility for commercially available technologies was considered to determine if the technology met PEC's particular generation requirements and if it would integrate well into the PEC system. The evaluation of technical feasibility included the size, fuel type, and construction requirements of the particular technology and the ability to match the technology to the service it would be required to perform on the Carolinas system (e.g., baseload, intermediate, or peaking).

Finally, for each alternative, an estimate of the levelized cost of energy production, or "busbar" cost, was developed. Busbar analysis allows for the long-term economic comparison of capital, fuel, and operations and maintenance (O&M) costs over the typical life expectancy of a future unit at varying capacity factor levels. For the screening of alternatives, the data are generic in nature and thus not site specific. The costs and operating parameters are adjusted to reflect installation in the southeastern United and, for most technologies, the performance and costs are based on a specific unit size. Cost and performance projections were made with the assistance of EPRI's Technical Assessment Guide (TAG) software and internal PEC resources.

For the screening of alternatives, the data are generic in nature and thus not site-specific. Cost and performance projections are based on EIA's 2007 Annual Energy Outlook report and on internal PEC resources.

Capital and operating costs reflect the effect of known and emerging environmental requirements to the extent that such requirements can be

quantified at this time. As these requirements and their impacts are more clearly defined in the future, capital and operating costs are subject to change. Such changes could alter the relative cost of one technology versus another and therefore result in the selection of different generating technologies for the future.

The IRP reflects the following “dispatchable” DSM programs, which can be used to directly reduce summer or winter peak loads when needed:
Large Load Curtailment

This program provides a source of load that may be curtailed at the Company’s request in order to meet system load requirements. Customers who participate in this program receive a credit on their bill.

Voltage Control

This procedure involves reducing distribution voltage by up to 5 percent during periods of capacity constraints. This level of reduction does not adversely effect customer equipment or operations.

In addition, the effects of significant other energy efficiency programs that have reduced PEC’s peak summer demand are implicitly captured in the energy and load forecasts, and therefore, are reflected in the resource plan.

In addition to the existing efficiency measures above, PEC continues to develop and test new programs to encourage energy efficiency and reduce peak demand. Starting with an initial database of over 1200 individual DSM programs currently in use in the United States and Canada, PEC is evaluating a wide array of potential options across all customer classes.

Reserve Criteria

Utilities require a margin of generating capacity reserve available to the system in order to provide reliable service. Periodic scheduled outages are required to perform maintenance and inspections of generating plant equipment and to refuel nuclear plants. Unanticipated mechanical failures may occur at any given time that may require shutdown of equipment to repair failed components. Adequate reserve capacity must be available to accommodate these unplanned outages and to compensate for higher than projected peak demand due to forecast uncertainty and weather extremes. In addition, some capacity must also be available as operating reserve to maintain the balance between supply and demand on a real-time basis.

The amount of generating reserve needed to maintain a reliable power supply is a function of the unique characteristics of a utility system

> including load shape, unit sizes, capacity mix, fuel supply, maintenance scheduling, unit availabilities, and the strength of the transmission interconnections with other utilities. There is no one standard measure of reliability that is appropriate for all systems since these characteristics are particular to each individual utility.
>
> *Methodology*
>
> PEC employs both deterministic and probabilistic reliability criteria in the resource planning process. PEC establishes a reserve criterion for planning purposes based on probabilistic assessments of generation reliability, industry practice, historical operating experience, and judgment.
>
> PEC conducts multi-area probabilistic analyses to assess generation system reliability in order to capture the random nature of system behavior and to incorporate the capacity assistance available through interconnections with other utilities. Decision analysis techniques are also incorporated in the analysis to capture the uncertainty in system demand. Generation reliability depends on the strength of the interconnections, the generating reserves available from neighboring systems, and also the diversity in loads throughout the interconnected area. Thus, the interconnected system analysis shows the overall level of generation reliability and reflects the expected risk of capacity deficient conditions for supplying load.
>
> A Loss-of-Load Expectation (LOLE) of one day in 10 years continues to be a widely accepted criterion for establishing system reliability. PEC uses a target reliability of one day in ten years LOLE for generation reliability assessments. LOLE can be viewed as the expected number of days that load will exceed available capacity. Thus, LOLE indicates the expected number of days that a capacity deficient condition would occur resulting in the inability to supply some portion of customer demand. Results of the probabilistic assessments are correlated to appropriate deterministic measures of reliability, such as capacity margin or reserve margin, for use as targets in developing the resource plan. However, the real measure of reliability is the loss of load expectation.

The NCUC recapped its 2006 approval process in its November 2006 report to the legislature. In its 2006 IRP report, the NCUC compares the forecasts in its report with the growth forecasts of the nation as a whole. The NCUC notes that growth demand nationally was roughly in line with forecasts from the utilities:

> North Carolina utility forecasts of future electrical peak demand growth rates are about the same as forecasts for the nation as a whole. The 2005-2014 Reliability Assessment by the NERC indicates that the national forecast of average annual growth in summer peak demand for the period is 2.0 percent. This number is the same as shown in NERC's

prior year report, but down from the 2.4 percent growth rate experienced over the last ten years (Reference 8.0-004).

8.2.2 FACTORS AFFECTING POWER GROWTH AND DEMAND

This subsection reviews the factors that affect growth in power demand in the service area. PEC plans to add approximately 2803 MW of generating capacity within the ROI. The forecasts show retail sales growth in North Carolina of nearly 2 percent annually for the next 15 years before subtracting for DSM. The retail demand growth rate drops to 1.1 percent after adjusting for DSM. Wholesale sales have become more uncertain due to the 1992 Energy Policy Act, subsequent FERC initiatives related to the wholesale market, the continuing evolution of the wholesale market, and market conditions. As expectations for the various wholesale contracts change, PEC wholesale forecasts will appropriately reflect those expectations. Generally, growth in the standard of living as reflected in personal income and GDP per capita is expected to slow modestly over the long term relative to historical levels. PEC uses real dollar prices to enhance model reliability during periods of varying inflation. While long-run economic trends exhibit considerable stability, short-run economic activity is subject to substantial variation. The exact nature, timing and magnitude of such short-term variations are unknown years in advance of their occurrence (Reference 8.0-002).

PEC currently serves 1.4 million customers in the North Carolina and South Carolina and expects to be serving at least 1.9 million customers by 2026. This growth is expected because PEC is adding between 25,000 to 30,000 new homes and businesses annually. In addition, larger homes and more appliances and electronics mean that there is a greater reliance on electricity for homes and businesses. Similar growth projections are also shown in the forecasts for South Carolina. PEC's Report to Shareholders for 2006 shows that PEC plans to meet this annual growth by maintaining all of its existing plants and by adding new capacity to meet resource plan requirements (Reference 8.2-001).

PEC faces a need for power over the next decade to meet the growing demand for electricity. There is tremendous economic and population growth in the Carolinas. The expected increase in demand for electricity in PEC's service territory and price volatility and unreliability of purchased power, coupled with the planned decommissioning of the 12 – 18 MW internal Combustion Turbine (CT) #1 operation in Roxboro, has resulted in prompting PEC to take steps to build or acquire new generation. This includes the planned peaking capacity additions of approximately 633 MW as well as the additional undesignated base value of 2170 MW expected to come into service in 2018-19 with the construction of the proposed Shearon Harris Nuclear Power Plant Unit 2 (HAR 2) and the proposed Shearon Harris Nuclear Power Plant Unit 3 (HAR 3). The addition of HAR 2 in 2018 and HAR 3 in 2019 will improve the diversity of resources serving PEC customers and their cost of power. It will also reduce the reliance of the PEC area on fossil fuels, particularly coal. PEC currently has no firm plans for retiring any of its generating units. PEC is adding environmental controls and maintaining

existing generating units as necessary to keep them operational and in compliance with environmental requirements.

PEC has an active DSM system. The DSM system is designed to improve energy efficiency and identify new ways to ease demand load without adding new baseload capacity. This program has been effectively used to decrease the demand for power (Reference 8.1-002). In responses to comments and testimony in the 2006 proceedings, the NCUC suggested that PEC and other utilities increase the discussion and focus on DSM efforts in future IRP proceedings (Reference 8.1-007).

Population growth in the service area, specifically in North Carolina, that increases the demand for electricity and higher prices for some fuel alternatives contribute to the evaluation of the need for power from the proposed project.

8.2.2.1 Economic and Demographic Trends

As noted in ER Section 2.5, the HAR facility is located in a region of rapid economic and population growth. Table 2.5-14 shows that between the years 1999 and 2003, the Research Triangle region experienced robust industrial investment. In 2003, new and expanded industry investment in the region reached $856 million and resulted in an estimated 5038 jobs (Reference 8.2-002).

The North Carolina Sustainable Energy Association (NCSEA) projects that the demand for energy in North Carolina will grow 35 percent by 2020, compared with an increase in national energy demand of 19 percent across the country. North Carolina is the third-fastest growing state east of the Mississippi River. In 1990, the state had a population of just over 6 million people, and currently the population is nearly 9 million. This rapid population growth is driving the increased energy demand in the state, and the growth in the population is expected to reach an additional 4 million people by the year 2030 (Reference 8.2-003).

8.2.2.2 Energy Efficiency and Substitution

PEC described an active DSM program in its North Carolina 2007 IRP report. Additionally, the IRP reflects “dispatchable” DSM programs that can be used for directly reducing summer and winter peak loads. Tables 8.1-4 and 8.2-1 show the effects of “large-load curtailment” and “voltage reduction” programs on the overall load. The energy efficiency/demand reduction shown on Table 8.1-4 is not considered to be an addition. Firm obligation is the minimal total load after meeting efficiencies. Other energy efficiency programs have reduced PEC’s summer peak load demand, and these programs are implicitly captured in the company’s 2007 report. These so-called “forecast embedded” programs include aggressive customer education programs, “home energy checks,” financial incentives, rate incentives, and commercial reduction strategies. PEC also has

an active program to review future DSM programs to encourage energy efficiency and reduce peak demand (Reference 8.1-004).

PEC also describes its DSM Program in its 2007 South Carolina IRP. Consistent with the results described above for North Carolina, the South Carolina IRP concludes that DSM programs can be used to reduce peak demand loads (Reference 8.0-001).

PEC is committed to a long-term balanced solution to meet the energy needs of the region. In June 2007, PEC announced a goal of displacing 2000 MW of power generation through DSM and energy efficiency programs. To meet this goal, PEC must double the approximate 1000 MW currently saved with existing programs. The additional 1000-MW reduction would be equal to the capacity of more than six combustion-turbine power plants. The displacement of an additional 1000 MW through DSM measures does not eliminate the need for additional future baseload generation.

PEC plans to implement aggressive residential, commercial, and industrial energy-efficiency programs and, over the next 2 years, evaluate their effectiveness and participation rates to determine their viability in further reducing electricity demand. The additional reductions in future electricity demand growth through energy efficiency could push the need for new power plants further into the future. As part of the energy needs balanced solution, PEC plans to invest in renewable energy sources and other emerging technologies, as well as upgrade existing power plants and consider investing in new plants when needed.
PEC is committed to a long-term, balanced strategic solution to meeting growing energy needs — a solution that includes four main components: (1) increased energy efficiency/DSM programs and incentives, (2) investments in renewable energy sources and other emerging energy technologies, (3) upgrading of existing power plants with modern state-of-the-art equipment, and (4) an investment in new, cleaner and more efficient electric power generation. Because it takes many years to site and build new power plants, PEC is working to keep future power plant options open (Reference 8.2-004).

This strategy provides long-term stability for PEC's growing customer base and delivers (1) a reliable supply of electricity, (2) more stable cost structure, (3) less dependence on imported energy, and (4) a cleaner environment.

8.2.2.3 Price and Rate Structure

8.2.2.3.1 Price Response in Forecast

A real price term is included in the forecast regression equations. PEC's forecast methodology uses the following factors to develop the price models: the number of customers, weather, energy prices, employment, personal income, population, and housing stock.

PEC compares the forecast retail residential, commercial, and industrial (RCI) real prices with the rates provided in the most recent U.S. Department of Energy (DOE) EIA Annual Energy Outlook for the southeastern United States. PEC uses the DOE's forecast when it is higher than PEC's forecast.

8.2.2.3.2 Effect of Growth on Load-Shape

The PEC load and energy process starts at the retail class and individual wholesale customer level. The demand forecast for an individual class or customer is a direct product of the energy forecast and the individual coincidence peak load factor of the entity. This process allows for a dynamic system load factor for modeling future system load-shape.

8.2.2.3.3 Competition

The largest portion of PEC's wholesale sales is under contracts for only a portion of the customers load. As noted in ER Subsection 8.1.4, PEC is committed to meeting renewable energy requirements associated with PEC's North Carolina RPS. By the year 2020, PEC will be required to meet 12.5 percent of retail sales by a mixture of renewables, DSM, or renewable credit energy purchases. PEC has 18 percent of their power commitments in firm contracts and that is through power authority co-ops and municipal power companies. For those smaller customers on full requirements contracts, other factors are more critical than price in forecasting future load. The prospect of adding or losing a major manufacturing facility, or opportunity to grow commercial load along new highways, are larger drivers than price. PEC collects this information and the account representatives for the wholesale accounts reflect this in the forecast. The forecast assumes that full requirements customers continue after contract expiration. However, a forecast version is prepared that recognizes the contract termination dates of these customers.

8.2.2.3.4 Appliance Efficiency

The historic forecast data contains the effects of past appliance efficiency gains and company conservation programs. As such, the forecast reflects these historic trends continuing into the future. Additional DSM and conservation programs are directly reduced from the forecast.

Table 8.2-1 (Sheet 1 of 2)
Progress Energy–Carolinas December 2007 North Carolina Resource Plan Filing (Winter)

	07/08	08/09	09/10	10/11*	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22
GENERATION ADDITIONS															
Wayne County CT			185												
Richmond County CC					650										
Planned Projects	9	21	10	20	5										
Pollution Control Derates	(14)	(41)	(23)		(1)	(2)									
Undesignated [(a)]				195	147				195	195		1,125	1,125		
Roxboro CT retirement	(18)														
INSTALLED GENERATION															
Nuclear	3,505	3,505	3,515	3,535	3,540	3,540	3,540	3,540	3,540	3,540	3,540	3,540	3,540	3,540	3,540
Fossil	5,320	5,290	5,268	5,268	5,268	5,266	5,266	5,266	5,266	5,266	5,266	5,266	5,266	5,266	5,266
Hydro	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
Combined Cycle	621	621	621	621	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271
Combustion Turbine	3,511	3,522	3,707	3,707	3,707	3,707	3,707	3,707	3,707	3,707	3,707	3,707	3,707	3,707	3,707
Undesignated [(a)]				195	342	342	342	342	537	732	732	1,857	2,982	2,982	2,982
PURCHASES & OTHER RESOURCES															
SEPA	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
NUG QF - Cogen	179	179	20	20	20	20	20	20	20	20	20	20	20	20	20
NUG QF - Renewable	4	4	8	8	8	8	4	4	4	4	4	4	4	4	4
NUG QF - Other	16	9													
AEP/Rockport 2	250	250													
Broad River CT	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841
Southern CC Purchase			150	150	150	150	150	150	150	150	150	150			
Undesignated Short-term Purchase*			150	150											
TOTAL SUPPLY RESOURCES	**14,570**	**14,543**	**14,603**	**14,818**	**15,470**	**15,468**	**15,464**	**15,464**	**15,659**	**15,854**	**15,854**	**16,979**	**17,954**	**17,954**	**17,954**

Table 8.2-1 (Sheet 2 of 2)
Progress Energy–Carolinas December 2007 North Carolina Resource Plan Filing (Winter)

	07/08	08/09	09/10	10/11*	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22
PEAK DEMAND															
Retail	7,896	7,866	8,022	8,073	8,112	8,158	8,227	8,302	8,385	8,456	8,551	8,681	8,836	8,987	9,164
Wholesale	2,777	2,796	2,694	2,726	2,847	2,924	3,000	3,027	3,057	3,083	3,092	3,121	3,149	3,224	3,249
SYSTEM PEAK LOAD	10,673	10,662	10,716	10,799	10,959	11,082	11,227	11,329	11,442	11,539	11,643	11,802	11,985	12,211	12,413
Firm Sales	200	200	200	200	100	100	100	100	100	100	100	100	100	100	100
FIRM OBLIGATION	10,873	10,862	10,916	10,999	11,059	11,182	11,327	11,429	11,542	11,639	11,743	11,902	12,085	12,311	12,513
Energy Efficiency/Demand Reduction	523	622	740	874	996	1,115	1,216	1,317	1,413	1,507	1,587	1,633	1,657	1,677	1,694
TOTAL LOAD	11,396	11,484	11,656	11,873	12,055	12,297	12,543	12,746	12,955	13,146	13,330	13,535	13,742	13,988	14,207
RESERVES [(b)]	3,697	3,681	3,687	3,819	4,411	4,286	4,137	4,035	4,117	4,215	4,111	5,077	5,869	5,643	5,441
Capacity Margin [(c)]	25%	25%	25%	26%	29%	28%	27%	26%	26%	27%	26%	30%	33%	31%	30%
Reserve Margin [(d)]	34%	34%	34%	35%	40%	38%	37%	35%	36%	36%	35%	43%	49%	46%	43%

Notes:

* Purchases are being pursued beginning 2010 and beyond.

a) For planning purposes only; does not indicate a commitment to type, amount or ownership.

b) Reserves = Total Supply Resources - Firm Obligations.

c) Capacity Margin = Reserves / Total Supply Resources * 100.

d) Reserve Margin = Reserves / Firm Obligations * 100.

CC = combined cycle

NUG = non-utility generation

CT = combustions turbine

QF = qualifying facility

Source: Reference 8.0-002

Table 8.2-2 (Sheet 1 of 2)
Progress Energy–Carolinas December 2007 South Carolina Resource Plan Filing (Winter)

	07/08	08/09	09/10	10/11*	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22
GENERATION ADDITIONS															
Wayne County CT			185												
Richmond County CC					650										
Planned Projects	9	21	10	20	5										
Pollution Control Derates	(14)	(41)	(23)		(1)	(2)									
Undesignated [(a)]				195	147				195	195		1,125	1,125		
Roxboro CT retirement	(18)														
INSTALLED GENERATION															
Nuclear	3,505	3,505	3,515	3,535	3,540	3,540	3,540	3,540	3,540	3,540	3,540	3,540	3,540	3,540	3,540
Fossil	5,320	5,290	5,268	5,268	5,268	5,266	5,266	5,266	5,266	5,266	5,266	5,266	5,266	5,266	5,266
Hydro	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
Combined Cycle	621	621	621	621	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271
Combustion Turbine	3,511	3,522	3,707	3,707	3,707	3,707	3,707	3,707	3,707	3,707	3,707	3,707	3,707	3,707	3,707
Undesignated [(a)]				195	342	342	342	342	537	732	732	1,857	2,982	2,982	2,982
PURCHASES & OTHER RESOURCES															
SEPA	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
NUG QF - Cogen	179	179	20	20	20	20	20	20	20	20	20	20	20	20	20
NUG QF - Renewable	4	4	8	8	8	8	4	4	4	4	4	4	4	4	4
NUG QF - Other	16	9													
AEP/Rockport 2	250	250													
Broad River CT	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841
Southern CC Purchase			150	150	150	150	150	150	150	150	150	150			
Undesignated Short-term Purchase*			150	150											
TOTAL SUPPLY RESOURCES	**14,570**	**14,543**	**14,603**	**14,818**	**15,470**	**15,468**	**15,464**	**15,464**	**15,659**	**15,854**	**15,854**	**16,979**	**17,954**	**17,954**	**17,954**

Table 8.2-2 (Sheet 2 of 2)
Progress Energy–Carolinas December 2007 South Carolina Resource Plan Filing (Winter)

	07/08	08/09	09/10	10/11*	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22
PEAK DEMAND															
Retail	7,896	7,866	8,022	8,073	8,112	8,158	8,227	8,302	8,385	8,456	8,551	8,681	8,836	8,987	9,164
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Firm Sales	200	200	200	200	100	100	100	100	100	100	100	100	100	100	100
FIRM OBLIGATION	10,873	10,862	10,916	10,999	11,059	11,182	11,327	11,429	11,542	11,639	11,743	11,902	12,085	12,311	12,513
Energy Efficiency/Demand Reduction	523	622	740	874	996	1,115	1,216	1,317	1,413	1,507	1,587	1,633	1,657	1,677	1,694
TOTAL LOAD	**11,396**	**11,484**	**11,656**	**11,873**	**12,055**	**12,297**	**12,543**	**12,746**	**12,955**	**13,146**	**13,330**	**13,535**	**13,742**	**13,988**	**14,207**
RESERVES [(b)]	3,697	3,681	3,687	3,819	4,411	4,286	4,137	4,035	4,117	4,215	4,111	5,077	5,869	5,643	5,441
Capacity Margin [(c)]	25%	25%	25%	26%	29%	28%	27%	26%	26%	27%	26%	30%	33%	31%	30%
Reserve Margin [(d)]	34%	34%	34%	35%	40%	38%	37%	35%	36%	36%	35%	43%	49%	46%	43%

Notes:

* Purchases are being pursued beginning 2010 and beyond.

a) For planning purposes only; does not indicate a commitment to type, amount or ownership.

b) Reserves = Total Supply Resources - Firm Obligations.

c) Capacity Margin = Reserves / Total Supply Resources * 100.

d) Reserve Margin = Reserves / Firm Obligations * 100.

CC = combined cycle

NUG = non-utility generation

CT = combustions turbine

QF = qualifying facility

Source: Reference 8.0-001

8.3 POWER SUPPLY

Tables 8.1-4 and 8.2-1 show the power analysis performed by PEC to satisfy the NCUC requirement. The need for power analysis in this section is supported by the NCUC's annual report, described earlier in this chapter. The NCUC analyzes need for power and power supply issues by dividing existing capacity into the following three categories:

- **Baseload**. Operates nearly full cycle.
- **Intermediate**. Cycles with load increases and decreases.
- **Peaking**. Operates infrequently to meet system peak demand. (Reference 8.0-004)

The NRC's NUREG-1555 guidance also allows an applicant to rely on a state's regulatory power planning structure:

> Affected States and/or regions are expected to prepare a need-for-power evaluation. NRC will review the evaluation and determine if it is (1) systematic, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty. If the need for power evaluation is found acceptable, no additional independent review by NRC is needed, and the analysis can be the basis for ESRPs 8.2 through 8.4.
>
> As part of their analyses of the need for power, States and/or regional authorities are expected to describe and assess the regional power system. The reviewer should evaluate the description, determine if it is comprehensive, and subject to confirmation. If it is found acceptable, no additional data collection by NRC should usually be needed. These data may be supplemented by information from sources such as the EIA, FERC, NERC, and others.

As noted in other sections of this chapter, PEC relies primarily on the IRP process for their service area in North Carolina and South Carolina to outline the existing power supply and need for power. Additionally, PEC provides its individual IRPs to both North Carolina and South Carolina.

8.3.1 EXISTING AND PLANNED CAPACITY IN THE REGION OF INTEREST

The ROI related to existing and planned capacity is PEC's service territory in both North Carolina and South Carolina. Historically, the regulated utilities in North Carolina have met demand by power purchase and installing their own generating capacity (Reference 8.0-004). The NCUC manages power supply information through an IRP, captured annually in a report provided to the state legislature (Reference 8.1-001). The NCUC's 2006 annual report outlines the

state's traditional mix of power generation and supply. In addition, the state relies heavily on reliability reports from NERC, the Southeastern Electric Reliability Council (SERC), and the Virginia-Carolinas area (VACAR), as described in the following subsections. Currently, SERC has surplus capacity, most of which is in Entergy; however, transmission capabilities are the limiting factor. PEC is in the process of adding approximately 1000 MW of additional transmission import capability into the PEC system, but 800 MW are currently reserved in PEC's Open-Access Same-time Information System (OASIS) according to FERC regulations.

The IRP report for North Carolina outlines total supply resources for the ROI. An increase of 2803 megawatt electric (MWe) is identified under the heading of Generation Additions as "Undesignated" in Table 8.1-4 (Reference 8.0-002). In order to meet the requirements for Generation Additions, new baseload generation will be necessary. Baseload units are the most cost-effective new resources to address a very predictable and stable load. Firm capacity from nuclear and coal plants provide most of the baseload capacity in the ROI. Intermediate capacity is provided by older plants and small oil/gas facilities. PEC does not have any joint ventures for capacity additions and available capacity. Finally, peaking needs are supplied by combustion turbines and other sources.

PEC acknowledged in both the 2007 IRP for North Carolina and 2007 IRP for South Carolina that a public announcement had been issued in January 2006 that the HNP near New Hill, North Carolina, was being evaluated for possible nuclear generation expansion to increase baseload capacity in the ROI. DSM as described above will result in the reduction in peak demand, but will not eliminate the need for additional baseload capacity. PEC's IRP process for North Carolina clearly establishes the need for additional baseload capacity in the ROI in 2018.

8.3.2 RELIABILITY IN THE REGION OF INTEREST

The NCUC notes that measures of reliability generally are divided between probabilistic measures (loss of load probability, frequency, and duration of outages) and non-probabilistic measures (reserve margin and capacity margin). The commonly used "capacity margin" is the ratio of reserve capacity to actual capacity (Reference 8.0-004). PEC bases its reserve criterion on probabilistic assessments of generation reliability, industry practice, historical operating experience, and judgment. As noted in the company's 2007 IRP report, current PEC capacity margins (11 to 21 percent) can provide adequate reliability to the system (Reference 8.0-002).

Reserves projected in PEC's current "Resource Plan" (Table 8.1-4) are appropriate for providing an adequate and reliable power supply with capacity margins ranging from about 11 to 21 percent through the study period (2007 to 2022). These reserve levels correspond to reserve margins of about 13 to 27 percent (Reference 8.0-002). The higher reserves occur later in the planning period with the possible addition of large baseload generating plants.

NERC's "2006 Long-Term Reliability Assessment" indicates that the SERC region 2006 forecast for capacity margins show that the margin is projected to remain at or above 14 percent throughout the 10-year period. Capacity margins from last year's forecast started above 12 percent, fell below 10 percent in the near term, and remained between 6 to 8 percent in the longer term. SERC predicts adequate reserve margins and capacity resources during the period. Between 2006 and 2017, the average annual summer peak demand growth rate for the entire SERC area is forecast to be 2.1 percent.

The forecast for the average annual growth for the Entergy subregion over the next 10 years is 1.9 percent, compared to the historical growth rate over the last 10 years that has averaged 1.8 percent. The 2006 forecast growth rate in energy usage is 1.6 percent. The projected capacity margin was 21.1 percent for the 2006 summer, and declines to 5.8 percent in 2015.

The forecast for the average annual growth rate over the next ten years for the Gateway subregion is 1.2 percent, compared to the historical growth rate of approximately 1.3 percent, on average. The 2006 forecast growth rate in energy usage for the Gateway subregion is 1.1 percent. The projected capacity margin was 31.3 percent for the 2006 summer, and remains above 31 percent over the remainder of the planning period.

The forecast for the average annual growth for the Southern subregion over the next 10 years is 2.5 percent, compared to the historical growth rate over the last 10 years of 2.4 percent. The 2006 forecast growth rate in energy usage is 2.3 percent. The historical growth rate for the last 10 years is 2.8 percent. The projected capacity margin for the Southern subregion was 14.7 percent for the 2006 summer, and ranges from 11.4 percent to 14.6 percent over the remainder of the planning period.

The average annual growth rate over the next 10 years for the TVA subregion is 2.2 percent. This is slightly lower than the 2005 forecast growth rate of 2.3 percent. The historical growth rate has averaged 1.7 percent (excluding new members). The 2006 forecast growth rate in energy usage for the TVA subregion is 1.3 percent. The historical growth rate for the last 10 years is 2.9 percent, which is higher than forecast due to the inclusion of two new members into the subregion in the past year. The projected capacity margin was 11.4 percent for the 2006 summer, and ranges from 10.8 percent to 12.5 percent over the remainder of the planning period.

The VACAR region (excluding PEC) represents approximately 50,000 MW of generating capacity. The average annual demand growth rate for the VACAR subregion during this period is forecast to be 2.0 percent. The VACAR forecast growth rate for overall energy usage during the next 10 years is 2.0 percent, compared with a historical growth rate for the last 10 years of 2.5 percent. These forecasts are based on average weather and economic conditions (Reference 8.3-001).

While the NCUC notes that reserve margins are adequate to provide reliable power supplies, its 2006 report raises some concerns over the reliability of resources. For example, the NCUC notes that most of the new generating facilities throughout the area use natural gas as the primary fuel. The NCUC is particularly concerned about natural gas deliverability. North Carolina is almost entirely dependent on one natural gas pipeline (Reference 8.0-004). Additionally, price concerns, availability concerns, and supply constraints have led to a growing preference for fuel diversity. As a result, the NCUC noted that there is "an increasing interest in the use of coal and nuclear facilities to meet future baseload generation needs" (Reference 8.0-004).

8.3.3 EFFECT OF PURCHASES AND SALES IN THE REGION OF INTEREST

The NCUC annual report notes that significant portions of power supply are generated within the state by the investor-owned utilities (IOUs) for customers in North Carolina. Purchased power, where the regulated utilities purchase power from non-utilities or merchant plants outside the state, is less than 35 percent of the energy resource (Reference 8.0-004). PEC, for example, predicts that approximately 16 percent of its capacity will be derived from purchased power in the timeframe from 2008 to 2022 (Reference 8.0-002). Additionally, no merchant plants are currently located within the PEC service territory.

According to PEC's December 2007 IRP submitted to the NCUC, PEC coordinates its transmission planning and operations with neighboring systems to assure the safety, reliability, and economy of its power system. As part of this effort to ensure that the transmission system will continue to be adequate, PEC regularly conducts coordinated near-term operating studies and longer-range planning studies that involve representatives from the VACAR and adjacent subregions and regions to provide interregional coordination. As of 2008, PEC policy does not stipulate a percentage of power capacity that must be purchased. VACAR does not have much available surplus power to purchase and inter-ties are limited to 400-500 MW power purchases, even with transmission upgrades.

Additionally, PEC actively participates on the Intra-regional Long-term Power Flow Study Group (LT-PFSG), the Intra-regional Near-term Power Flow Study Group (NT-PFSG), the VACAR reliability committees, and the Eastern Interconnection Reliability Assessment Group (ERAG) and has participated in development efforts for a potential regional transmission organization (RTO) in the southeast.

In addition, PEC, Duke, NCEMPA, and the North Carolina Electric Membership Corporation (NCEMC) are engaged in a collaborative transmission planning process (the North Carolina Transmission Planning Collaborative). This effort allows NCEMPA and NCEMC to participate in all stages of the transmission planning process, resulting in Duke and PEC moving towards a single collaborative transmission plan for their control areas that addresses both reliability and market access.

8.4 ASSESSMENT OF THE NEED FOR POWER

In assessing the costs and benefits of the project, NUREG-1555, ESRP 8.4 provides the following review criterion:

> If a need-for-power analysis conducted by or for one or more relevant regions affected by the proposed plant concludes there is a need for new generating capacity, that finding should be given great weight provided that the analysis was systematic, comprehensive, subject to confirmation, and responsive to forecast uncertainty.
>
> Although this criterion does not show a need for baseload capacity, it does demonstrate a need for new capacity that is independent of type. This criterion, coupled with an affirmative indication that there is a need for baseload capacity, justifies a baseload addition within the timespan determined by the … forecast analysis.

As discussed in Section 8.1, the statutory and regulatory framework of both the North Carolina and South Carolina IRP process, which is well established, provides clear requirements for determining increased demand, reserve margins, energy efficiency, and need for new baseload capacity. Additionally, under North Carolina G.S. § 62-110.1(a), prior to construction, PEC is required to obtain a CPCN from the NCUC. The purpose of this certificate is to determine whether there is a need for a new electric generating plant to meet the electricity needs of PEC's customers (Reference 8.4-001).

8.4.1 ASSESSMENT OF THE NEED FOR NEW CAPACITY

The NCUC's August 2007 findings and Order support the growing understanding that new baseload capacity may be necessary to supply consistent, reliable power. For example, the NCUC asserts that increasing fuel costs and waning interest in deregulation contribute to the need for additional baseload "on the horizon." This conclusion was the result of expert testimony, multiple public hearings, and consideration of the IRP reports submitted pursuant to North Carolina G.S. § 62-110.1(c). (Reference 8.0-004)

The 2006 NCUC Annual Report on the Needs for Expansion of Electric Generation Facilities for Service in North Carolina contained the following information, which recognizes the need for additional baseload generation in North Carolina:

> The Commission recognizes the need for a mix of baseload, intermediate, and peaking facilities and believes that conservation, load management, and the development of alternative energy resources and demand-side options must all play a significant role in meeting the capacity needs of each utility.

> A number of factors, including concern over markedly higher natural gas prices, possible natural gas supply constraints, and a growing preference for fuel supply diversity, have led to increased interest in the use of coal and nuclear facilities to meet future baseload generation needs (Reference 8.0-004).

The 2006 NCUC Annual Report also presented the following information as evidence to the support the positions in the report:

> According to Dr. Wright, changing conditions in the electric industry compelled PEC's and Duke's renewed focus on DSM options in the last year. He explained that, when utilities begin to consider adding new baseload facilities and when fuel costs are higher, DSM programs become more important and more cost-effective. This does not mean, however, that they will displace the need for new generation plants or that a utility will necessarily choose to implement more DSM programs than it was already using.

Within PEC's service area, 2803 MW is identified under the heading of Generation Additions as "Undesignated," as presented in Table 8.1-4. The demand calculations show a continuing annual increase in demand throughout the planning period (Reference 8.0-002). The increases show that the need for power grows by approximately 255 MW per year. As noted in Subsection 8.2.2, with PEC's ratepayer base growing between 25,000 to 30,000 customers annually, the utility and the NCUC recognize that demand will soon outstrip existing capacity.

PEC's strategic planning effort in 2007 to meet the NCUC requirements attempted to look farther ahead than ever before, considering not just the next 10 years but also the next 15 years. Through this new resource planning approach, PEC examined everything from fuel price trends to emerging technologies and environmental policies. PEC also analyzed how best to manage the very large capital requirements for new generation and transmission infrastructure as well as for additional emission-control equipment.

This new planning approach was incorporated into the 2007 IRP, which enabled PEC the option to evaluate more long-term approaches for addressing reliability and reserve capacity concerns. PEC reached the following conclusions in the 2007 IRP:

- Continue to focus on the use of gas-fired generators for peaking and intermediate load needs, when possible, and on oil-fired units for peaking load, when necessary. Gas-fired units are considered to be the most environmentally benign, economical, large-scale capacity additions available and advanced designs of these technologies are more efficient as measured by heat rate than previous designs, resulting in a smaller impact on the environment.

- Pursue expansion of its energy efficiency and conservation programs actively as energy efficiency is one of the most effective ways to reduce energy costs, offset the need for new power plants, and protect the environment.

- Continue to invest in existing generating plants and consider plans for building new baseload plant by evaluating the best available options for this new generation, including advanced design nuclear technologies.

- Establish a 2-year moratorium on construction of new coal-fired plants while simultaneously continue to pursue expansion of energy efficiency and conservation programs.

- Plan to seek license renewal options for the existing hydroelectric and nuclear plants. (Reference 8.0-002)

In addition, NUREG-1555 allows PEC to assess the need for the proposed facility on other grounds. The following criteria suggest the continuing benefits of, and the need for, a new baseload generating facility in the state:

- **The relevant region's need to diversify sources of energy (e.g., using a mix of nuclear fuel and coal for baseload generation)**. The NCUC's 2006 IRP report recognizes the role of fuel diversity in the overall reliability of the State's power system. In addressing the issue of natural gas availability, the NCUC noted three reasons for the continued popularity of a diverse mix of baseload fuels over reliance on natural gas: fuel diversity, fuel deliverability, and fuel availability (Reference 8.0-004).

- **The potential to reduce the average cost of electricity to consumers**. In its 2007 Order, the NCUC noted that baseload capacity would be required in addition to any DSM programs to provide reliable, reasonably priced service to consumers (Reference 8.1-007).

- **The nationwide need to reduce reliance on fossil fuels generally, and imported petroleum, in particular**. The current national policy develops ways to reduce dependence on fossil fuels and, in particular, petroleum. The NCUC notes that reliance on natural gas in the State for baseload capacity is waning as rising prices and reliability concerns rise (Reference 8.0-004).

Although NUREG-1555 does not specifically identify reduction of greenhouse gases (GHG) as one of these benefits, more recent state and national policy statements assert the benefits of baseload capacity that reduces GHG. The concern over GHG and the resulting climate change has triggered a number of national policy trends, as follows:

- During the 109th Congress, both houses of the U.S. Congress introduced resolutions calling for a national program of carbon reduction

(Reference 8.4-002). The Senate Committee on Energy and Natural Resources is reviewing "cap and trade" legislation to reduce GHG emissions during the early days of the 110th Congress (Reference 8.4-003).

- Several states have joined regional GHG initiatives (References 8.4-004 and 8.4-005).

- The North Carolina legislature has addressed local concerns through:

  - The Legislative Commission on Global Climate Change (LCGCC), which is conducting an in-depth examination of global warming and the emerging carbon economy and evaluating the need for a GHG reduction goal. The LCGCC is to report to the General Assembly by April 15, 2008 (Reference 8.4-006).

  - The Clean Smokestacks Act (CSA), which limits nitrogen oxide (NO_X) and sulphur dioxide (SO_2) emissions from coal-fired plants and establishes GHG emission standards (Reference 8.4-007).

  - Development of a climate action plan (CAP) for North Carolina through a North Carolina Department of Environment and Natural Resources (NCDENR) Division of Air Quality-sponsored stakeholder consensus process. This is being accomplished through the North Carolina Climate Action Plan Advisory Group (CAPAG). CAPAG complements LCGCC activities, but it focuses its efforts on developing economic opportunities for action to reduce or mitigate the effects of GHG emissions (Reference 8.4-008).

  - PEC has also responded to its shareholder concerns by developing steps to reduce carbon emissions. Additionally, its resource studies show that carbon emissions (produced by coal and natural gas capacity) will continue to rise through 2017. PEC notes, however, that one new nuclear plant will decrease these emissions significantly (Reference 8.2-001).

Costs of climate change have also triggered concerns about the economic effects of continuing carbon emission growth. The following examples highlight the growing concern in the United States:

- A British study reviewed by the U.S. Senate notes that unabated climate change will sharply affect economic systems globally, ultimately costing more than 20 percent annually of Gross Domestic Product (GDP) by the year 2050 (Reference 8.4-009).

- Economic reviews of the British study performed in the United States support it with "high confidence" (Reference 8.4-009).

8.4.2 COST-BENEFIT SUMMARY

In summary, the costs and benefits of the HAR include the following:

- Both North Carolina and South Carolina have a well-defined, systematic, and comprehensive resource-planning program that adequately reviews both states' resources and growing demand for additional baseload, eliminating the need for additional NRC review.

- Within PEC's service area, 2803 MW is identified under the heading of Generation Additions as "Undesignated" as presented in Table 8.1-4. This Generation Addition starting in 2018 will need to be baseload capacity.

- The NCUC Commissioners have concluded that there is a need for new baseload capacity, and the NCUC's conclusion has been given "great weight" in this ER, as allowed by NUREG-1555.

- The state IRP process gives NRC assurance that the HAR would not proceed without state concurrence that the need for power is real and that the benefits of satisfying that need would be realized.

- PEC would secure a CPCN from the State of North Carolina demonstrating the need for the plant is in the public interest.

- The growing demand for new capacity shows benefits to be derived from the HAR.

- Given concerns in North Carolina about climate change and carbon emissions, the HAR serves another important need by reducing carbon emissions in the state. Given pending and future state and federal legislation related to climate change and carbon emissions, the effect of HAR operations potentially serves another important need by reducing carbon emissions in the state. The operation of the HAR will potentially reduce the need for construction of additional fossil-fuel power generation facilities within the PEC service territory. The effect of HAR operations then could result in a reduction of significant amounts of carbon and other emissions.

ER Section 9.2 discusses the viability of various baseload energy alternatives. ER Section 10.4 further reviews the costs and benefits of the HAR.

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