Lawrence B. Somers
Deputy General Counsel

Mailing Address:
NCRH 20 / P.O. Box 1551
Raleigh, NC 27602

o: 919.546.6722
f: 919.546.2694

bo.somers@duke-energy.com

September 1, 2016

VIA ELECTRONIC FILING

Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Progress, LLC 2016 Integrated Resource Plan and 2016 REPS Compliance Plan
Docket No. E-100, Sub 147

Dear Chief Clerk:

Pursuant to N.C. Gen. Stat. § 62-133.8, Commission Rules R8-60, R8-62(p) and R8-67, I enclose Duke Energy Progress, LLC's ("DEP or the "Company") 2016 Integrated Resource Plan ("IRP") and 2016 Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") Compliance Plan (collectively, the "2016 IRP"), for filing in connection with the referenced matter.

Portions of the DEP 2016 IRP contain confidential information that should be protected from public disclosure. Pages 141 through 144 of Appendix F contain busbar screening curves which represent the confidential and proprietary levelized all-in costs of new supply-side resources, which include capital, operations, and maintenance costs and fuel costs. Tables H-1 and H-2 of Appendix H (on pages 155 and 156) contain information concerning DEP's wholesale contracts. Public disclosure of this information would harm DEP's and/or its counterparties' ability to negotiate in the wholesale market. Table 2 on page 242 of the 2016 REPS Compliance Plan contains the Company's combustion turbine costs. If this commercially sensitive business and technical information were to be publicly disclosed, it would allow competitors, vendors and other market participants to gain an undue advantage, which may ultimately result in harm to customers. Exhibit A of the 2016 REPS Compliance Plan, pages 244 through 251, contains names of counterparties with whom DEP has contracted for Renewable Energy Certificates ("RECs"), contract duration and estimated RECs. Public disclosure of this

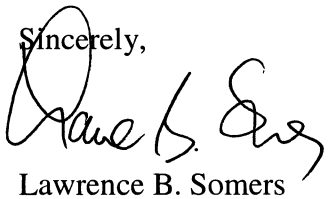
information would harm DEP's ability to negotiate and procure cost-effective purchases and discourage potential bidders from participating in requests for proposals. In addition, the filing contains DEP's most recent FERC Form 715, which contains critical energy infrastructure information that should be kept confidential and non-public.

Accordingly I am filing portions of the 2016 IRP under seal; they should be treated confidentially pursuant to N.C. Gen. Stat. § 132-1.2 and protected from public disclosure. The Company will provide a copy of the confidential information to parties to this proceeding upon execution of an appropriate confidentiality agreement with DEP.

DEP will schedule the Rule R8-60(m) stakeholder meeting by November 30 and will contact parties of record to attempt to accommodate as many as possible with a selected date and location.

Thank you for your attention to this matter. If you have any questions, please let me know.

Sincerely,



Lawrence B. Somers

Enclosure

cc: Parties of record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Progress, LLC's 2016 Integrated Resource Plan and 2016 REPS Compliance Plan, in Docket No. E-100, Sub 147, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to the parties of record:

Antoinette R. Wike
Chief Counsel - Public Staff
North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, NC 27699-4326
antoinette.wike@psncuc.nc.gov

Charlotte A. Mitchell
Law Office of Charlotte Mitchell
PO Box 26212
Raleigh, NC 27611
cmitchell@lawofficecm.com

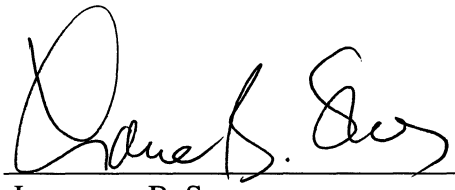
Horace Payne
Dominion North Carolina Power
PO Box 26532
Richmond, VA 23261
horace.p.payne@dom.com

Bruce Burcat
MAREC
P.O. Box 385
Camden, DE 19934
marec.org@gmail.com

Brett Breitschwerdt
McGuire Woods, LLP
434 Fayetteville Street, Suite 2600
Raleigh, NC 27601
bbreitschwerdt@mcguirewoods.com

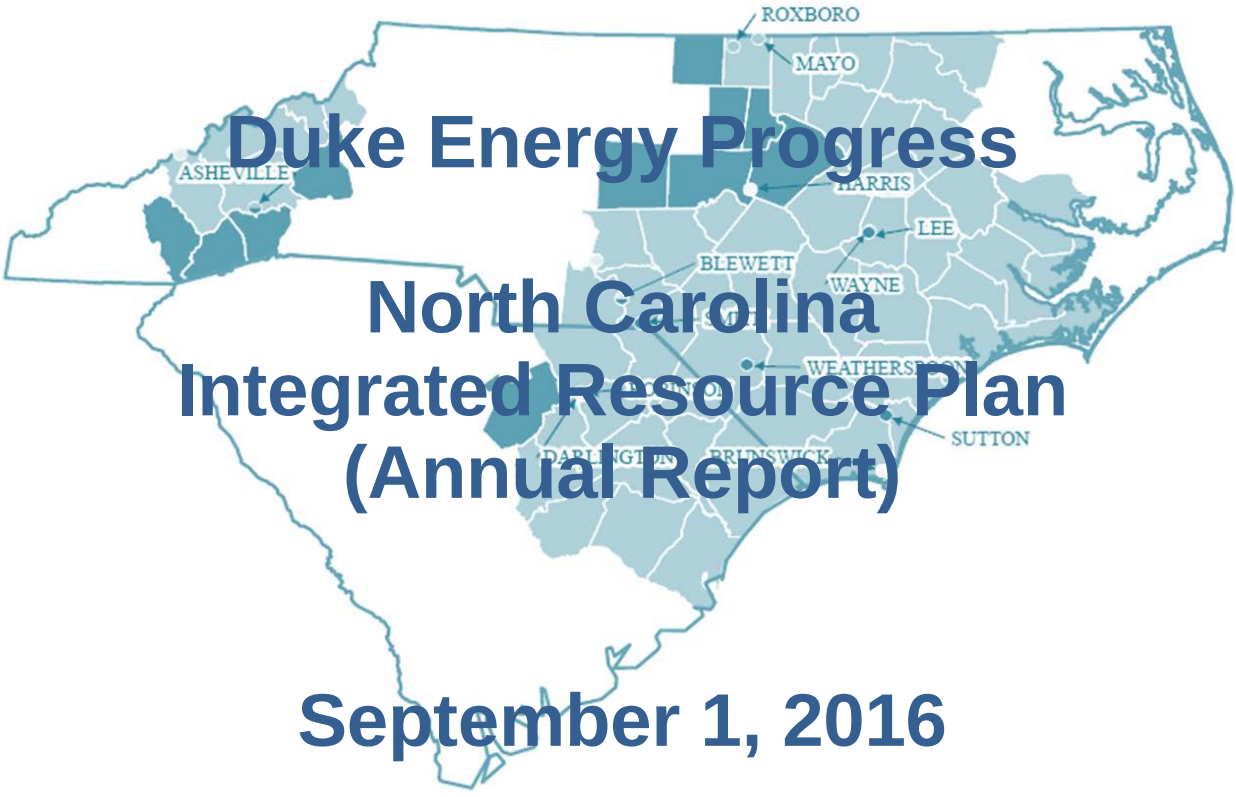
Peter H. Ledford
NC Sustainable Energy Association
4800 Six Forks Road, Suite 300
Raleigh, NC 27609
peter@energync.org

This is the 1st day of September, 2016.

By: 

Lawrence B. Somers
Deputy General Counsel
Duke Energy Corporation
P.O. Box 1551/NCRH 20
Raleigh, North Carolina 27602
Telephone: 919.546.6722
bo.somers@duke-energy.com

DUKE ENERGY®
PROGRESS



Duke Energy Progress

North Carolina Integrated Resource Plan (Annual Report)

September 1, 2016

PUBLIC

DEP 2016 IRP TABLE OF CONTENTS

ABBREVIATIONS	
BCFD	Billion Cubic Feet Per Day
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAPP	Central Appalachian Coal
CC	Combined Cycle
CCR	Coal Combustion Residuals
CECPCN	Certificate of Environmental Compatibility and Public Convenience and Necessity
CFL	Compact Fluorescent Light bulbs
CO_2	Carbon Dioxide
COD	Commercial Operation Date
COL	Combined Construction and Operating License
COWICS	Carolinas Offshore Wind Integration Case Study
CPCN	Certificate of Public Convenience and Necessity
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
DC	Direct Current
DEC	Duke Energy Carolinas
DEP	Duke Energy Progress
DOE	Department of Energy
DSM	Demand Side Management
EE	Energy Efficiency Programs
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FLG	Federal Loan Guarantee
FPS	Feet Per Second
GHG	Greenhouse Gas
HVAC	Heating, Ventilation and Air Conditioning
IGCC	Integrated Gasification Combined Cycle
IRP	Integrated Resource Plan
IS	Interruptible Service
JDA	Joint Dispatch Agreement
LCR Table	Load, Capacity, and Reserve Margin Table
LEED	Leadership in Energy and Environmental Design
MACT	Maximum Achievable Control Technology
MATS	Mercury Air Toxics Standard
MGD	Million Gallons Per Day
NAAQS	National Ambient Air Quality Standards
NAP	Northern Appalachian Coal
NC	North Carolina
NCCSA	North Carolina Clean Smokestacks Act
NCDAQ	North Carolina Division of Air Quality
NCEMC	North Carolina Electric Membership Corporation
NCMPA1	North Carolina Municipal Power Agency #1
NCTPC	NC Transmission Planning Collaborative
NCUC	North Carolina Utilities Commission

ABBREVIATIONS CONT.	
NERC	North American Electric Reliability Corp
NO_X	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standard
OATT	Open Access Transmission Tariff
PD	Power Delivery
PEV	Plug-In Electric Vehicles
PMPA	Piedmont Municipal Power Agency
PPA	Purchase Power Agreement
PPB	Parts Per Billion
PSCSC	Public Service Commission of South Carolina
PSD	Prevention of Significant Deterioration
PV	Photovoltaic
PVDG	Solar Photovoltaic Distributed Generation Program
PVRR	Present Value Revenue Requirements
QF	Qualifying Facility
RCRA	Resource Conservation Recovery Act
REC	Renewable Energy Certificates
REPS	Renewable Energy and Energy Efficiency Portfolio Standard
RFP	Request for Proposal
RIM	Rate Impact Measure
RPS	Renewable Portfolio Standard
SC	South Carolina
SCR	Selective Catalytic Reduction
SEPA	Southeastern Power Administration
SERC	SERC Reliability Corporation
SG	Standby Generation
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TAG	Technology Assessment Guide
TRC	Total Resource Cost
The Company	Duke Energy Carolinas
The Plan	Duke Energy Carolinas Annual Plan
UG/M^3	Micrograms Per Cubic Meter
UCT	Utility Cost Test
VACAR	Virginia/Carolinas
VAR	Volt Ampere Reactive

1. EXECUTIVE SUMMARY

Overview

For more than a century, Duke Energy Progress (DEP) has provided affordable and reliable electricity to customers in North Carolina (NC) and South Carolina (SC) now totaling more than 1.5 million in number. Each year, as required by the North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC), DEP submits a long-range planning document called the Integrated Resource Plan (IRP) detailing potential infrastructure needed to meet the forecasted electricity requirements for our customers over the next 15 years.

The 2016 IRP is the best projection of how the Company's energy portfolio will look over the next 15 years, based on current data assumptions. This projection may change over time as variables such as the projected load forecasts, fuel price forecasts, environmental regulations, technology performance characteristics, and other outside factors change.

The proposed plan will meet the following objectives:

- Provide reliable electricity especially during peak demand periods by maintaining adequate reserve margins. Peak demand refers to the highest amount of electricity being consumed for any given hour across DEP's entire system.
- Add new resources at the lowest reasonable cost to customers. These resources include a balance of energy efficiency programs (EE), demand-side management programs (DSM), renewable resources, nuclear generation and natural gas generation.
- Improve the environmental footprint of the portfolio by meeting or exceeding all federal, state and local environmental regulations.

A New Era – Plans to Specifically Include Consideration of Winter Demand for Power

Historically, DEP's resource plans have projected the need for new resources based primarily on the need to meet summer afternoon peak demand projections. For the first time in the 2016 IRP, DEP is now developing resource plans that also include new resource additions driven by winter peak demand projections inclusive of winter reserve requirements. The completion of a comprehensive reliability study demonstrated the need to include winter peak planning into the IRP process. The study recognized the growing volatility associated with winter morning peak demand conditions such as those observed during recent polar vortex events. The study also incorporated the expected growth in "summer-oriented resources" such as solar facilities and air conditioning load control programs that provide valuable assistance in meeting summer afternoon peak demands on the

system but do little to assist in meeting demand for power on cold winter mornings. As a result of the reliability study, DEP has now added a winter planning reserve target of 17% to its 2016 IRP.

The Road Ahead − Determining Customer Electricity Needs 2017 – 2031

The 2016 IRP identifies the incremental amount of electricity our customers will require over the next 15 years using the following basic formula:

Growth in Peak Demand and Energy Consumption	**+**	**Resource Retirements**	**=**	**New Resource Needs**

The annual energy consumption growth rate for all retail and wholesale customers is forecasted to be 1.1%. The growth rate is offset by projections for utility-sponsored EE impacts, reducing the projected growth rate by 0.2% for a net growth rate of 0.9% after accounting for energy efficiency. Peak demand growth net of EE is expected to grow slightly faster than overall energy consumption with an average projected growth rate of 1.3% (winter). Peak demand refers to the highest hourly level of energy consumption, given expected weather, throughout the year. The Company also carries reserve capacity to provide reliable supply during extreme weather conditions.

Projected electricity consumption growth rates by customer class are as follows:

- Commercial class, mainly driven by offices, education and retail, is the fastest growing class with a projected growth rate of 1.3%.
- Industrial class has a projected growth rate of 0.8%.
- Residential class has a projected growth rate of 1.1%.

In addition to customer growth, plant retirements and expiring purchase power contracts create the need to add incremental resources to allow the Company to reliably meet future customer demand. Over the last several years, aging, less efficient coal power plants have been replaced with a combination of renewable energy, EE, DSM and state-of-the-art natural gas generation facilities.

In November of 2013, Sutton Steam Station Units 1 – 3, the last of DEP's coal units that lacked advanced emission controls, were shuttered. Since 2011, DEP has retired approximately 1,700 MW/1,600 megawatts (MW) (winter/summer) at 12 older coal units in favor of cleaner burning natural gas plants that comply with stringent air, water and waste rules. Additionally, Darlington

combustion turbine (CT) Unit 11 (67 MW/52 MW (winter/summer)) was retired in November of 2015, further reducing older combustion turbine generation. Since 2012, DEP has retired 250 MW/200 MW (winter/summer) of older CT units. Over the 15-year planning horizon, the Company will continue to modernize its fleet with the planned retirements of older coal units and CT units including:

- Sutton CT Units 1, 2A and 2B, located in Wilmington, NC, totaling 76 MW/61MW (winter/summer), by 2017.
- Asheville Coal Units 1-2, located in Asheville, NC, totaling 384 MW/378 MW (winter/summer) by November 2019.
- Darlington CT Units 1 - 10, located in Darlington County, SC, totaling 645 MW/501 MW (winter/summer) by 2020.
- Blewett CT Units 1 – 4, located in Lilesville, NC, totaling 68 MW/52 MW (winter/summer), by 2027.
- Weatherspoon CT Units 1 – 4, located in Lumberton, NC, totaling 164 MW/128 MW (summer), by 2027.

The ultimate timing of unit retirements can be influenced by factors that impact the economics of continued unit operations. Such factors include changes in relative fuel prices, operations and maintenance costs and the costs associated with compliance of evolving environmental regulations. As such, unit retirement schedules are expected to change over time as market conditions change.

Western Carolinas Modernization Project – Energy Innovation Asheville

The Western Carolinas Modernization Project is an energy innovation project for the Asheville area in the western region of DEP. The goal of this project is to partner with the local community and elected leaders to help transition western NC to a cleaner, smarter and more reliable energy future.

Duke Energy Progress is committed to this partnership to promote the efficient use of energy in the region. The project allows for the retirement of the existing Asheville coal units and would replace the capacity with efficient natural gas units and solar. Additionally, the project calls for increased promotion and access to new and existing EE/DSM programs, deliberate investment in distributed energy resources and more customer involvement to determine what products and services are considered valuable.

Strategy to Meet New Resource Needs

Natural Gas

Currently, natural gas resources such as combined cycles (CC) and combustion turbines only make up 35% of the winter generating capacity in DEP. The 2016 IRP identifies the need for new natural gas resources that are economic, highly efficient and reliable. The planning document outlines the following relative to new natural gas resources. Locations for most of these facilities have not been finalized:

- Complete 100 MW/84 MW (winter/summer) Sutton fast start/black start CT in 2017.
- Complete 560 MW/495 MW (winter/summer) natural gas CC at Asheville, NC in late 2019.
- Plan for a 1,221 MW/1,123 MW (winter/summer) natural gas CC in 2022.
- Plan for a potential 186 MW/161 MW (winter/summer) CT in late 2023.
- Plan for 468 MW/435 MW (winter/summer) of CT capacity in 2023.
- Plan for 468 MW/435 MW (winter/summer) of CT capacity in 2026.
- Plan for 468 MW/435 MW (winter/summer) of CT capacity in each year from 2028 to 2030.
- Plan for 936 MW/870 MW (winter/summer) of CT capacity in 2031.

Nuclear Power

The 2016 IRP continues to support new nuclear generation as a carbon-free, cost-effective, reliable option within the Company's resource portfolio. Historically low natural gas prices, ambiguity regarding the timing and impact of environmental regulations and uncertainty regarding the potential to extend the licenses of existing nuclear units affects the timing of the need for new nuclear generation. The Company views all of its nuclear plants as excellent candidates for license extensions, however to date no nuclear plant licenses have been extended to operate from 60 years to 80 years. DEP will continue to study the possibility of license extension from the current 60 years to 80 years at its nuclear stations. Given the uncertainty of license extension, the IRP Base Case does not assume license extension at this time, but rather considers relicensing as a sensitivity to the Base Case.

While the 2016 Base Case does not call for DEP to construct additional self-owned nuclear generation before 2030, it is considered in the IRP's alternative Joint Planning Case. The Joint Planning Case projects shared DEP-DEC ownership of the W.S. Lee Nuclear Facility in 2026.

Nuclear generation currently serves approximately half of the total demand for energy on the system and continues to be the primary source of carbon-free generation in the Company's portfolio.

Renewable Energy and Solar Resources

Renewable mandates, extended federal tax subsidies and declining technology costs make solar energy the Company's primary renewable energy resource in the 2016 IRP. DEP continues to add solar to its resource mix through Purchased Power Agreements (PPAs), Renewable Energy Credit (REC) purchases and Qualifying Facilities (QFs) under the Public Utility Regulatory Policy Act (PURPA). The 2016 IRP projects:

- Increasing all solar energy resources from 1,710 MW in 2017 to 3,270 MW in 2031.
- Complying with NC Renewable Energy and Energy Efficiency Portfolio Standards (NC REPS or REPS) through a combination of solar, other renewables, EE and REC purchases.
- Meeting increasing goals of the South Carolina Distributed Energy Resource Program (SC DER) through 2020.
- Meeting growing customer demand for renewable resources outside of mandated compliance programs.
- Planning for incremental solar resources that are put onto the system as QFs under PURPA.

While the Company has aggressively pursued solar as a renewable resource, the 2016 IRP recognizes and plans for its operational limitations. Solar energy is an intermittent renewable energy source that cannot be dispatched to meet changing customer demand during all hours of the day and night or through all types of weather. Solar has limited ability to meet peak demand conditions that occur during early morning winter hours or summer evening hours. As such, solar energy must be combined with resources such as EE, DSM, natural gas and nuclear generation to make up the Company's diverse resource portfolio to ensure system reliability.

Energy Efficiency and Demand-Side Management

Existing programs, along with new EE and DSM programs approved since the last biennial IRP in 2014, are supporting efforts to reduce the annual forecasted demand growth over the next 15 years. Aggressive marketing campaigns have been launched to make customers aware of DEP's extensive EE and DSM program offerings, successfully increasing customer adoption. The Company is forecasting continued energy and capacity savings from both EE and DSM programs through the planning period as depicted in the table below.

Table Exec-1: DEP Projected EE and DSM Energy and Capacity Savings (Winter)

Projected EE and DSM Energy and Capacity Savings		
Year	**Energy (MWh)**	**Capacity (MW)**
2017	344,700	476
2031	2,284,700	829

Cost-effective EE and DSM programs can help delay the Company's need to construct and operate new generation. The Base Case includes the current projections for cost-effective achievable savings. Even greater savings may be possible depending on variables such as customer participation and future technology innovations. Alternative resource portfolios with these higher levels are presented in Appendix A.

Alternative Generation

DEP continues to explore alternative generation types for feasibility and economic viability to potentially meet future customer demand. As these generation types become viable and economically feasible, the Company will consider them in the planning process. In the 2016 IRP, capacity from Combined Heat and Power (CHP) projects have been increased in the resource plan. CHP projects efficiently provide both power to the grid while simultaneously meeting the steam requirements of large institutions and industries in the Carolinas. The current CHP projection for DEP is 66 MW/60 MW (winter/summer) of CHP in the 2019 – 2021 timeframe.

Strong Trend Toward Cleaner, More Environmentally Friendly Generation

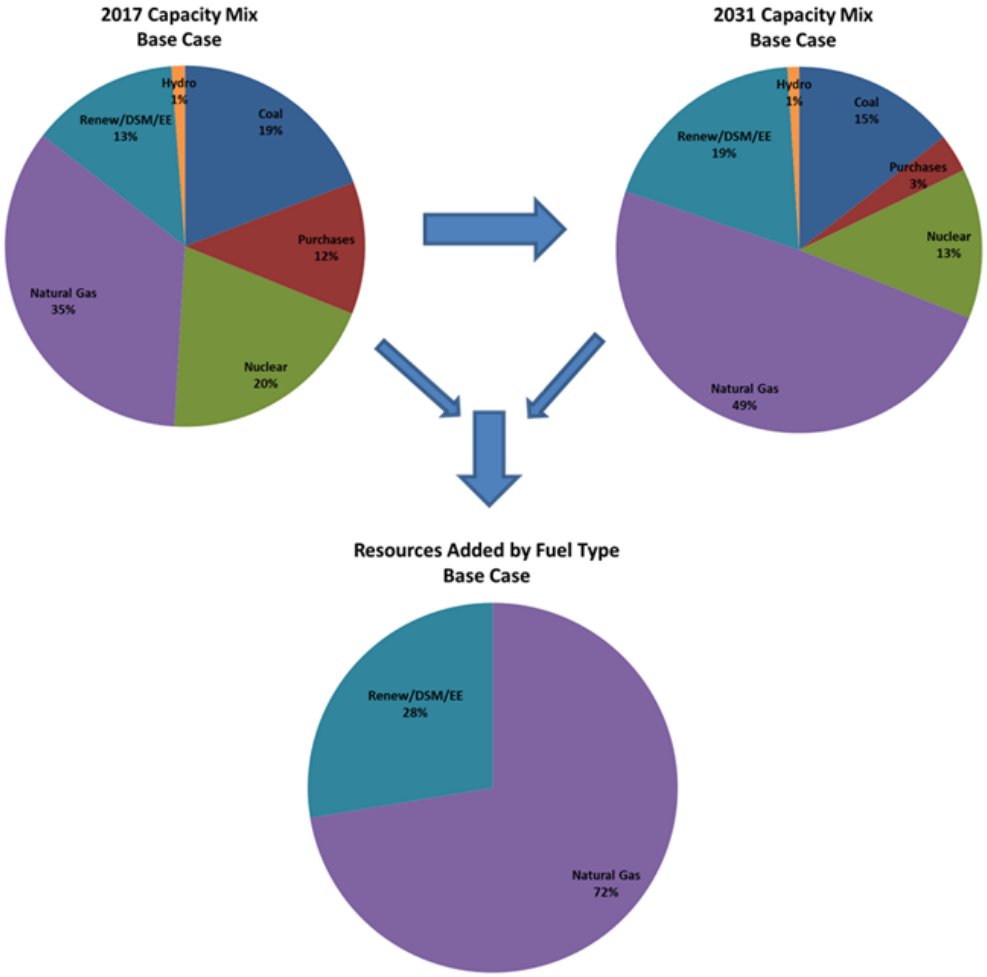
When viewed in total, approximately 54% of DEP and DEC's collective energy needs in 2017 are met by emission-free resources. This includes nuclear energy, hydro-electric power, DSM, EE and renewable energy. The remaining 44% of the energy portfolio includes clean, efficient natural gas units and coal plants that are equipped with state-of-the-art emission technology. Based upon the Environmental Protection Agency (EPA) carbon standards for new generation, the 2016 IRP does not call for the construction of any new coal plants.

The EPA's Clean Power Plan continues to influence the development of the Company's resource plans. While the CPP was stayed by the U.S. Supreme Court in 2016, the Company continues to plan for a range of carbon dioxide (CO_2) legislative outcomes. As such, DEP's base resource plan

assumes some level of carbon emission restrictions consistent with the CPP, while alternate views of CO_2 legislative outcomes were considered as sensitivities.

The figure below illustrates how the Company's capacity mix is expected to change over the planning horizon. As shown in the bottom pie chart, DSM, EE and renewables will combine to represent 28% of the Company's new installed capacity over the study period. The remaining 72% of future new capacity will come from new natural gas generation. In aggregate, the incremental resource additions identified in the 2016 IRP contribute to an economic, reliable and increasingly clean energy portfolio for the citizens of North Carolina and South Carolina.

Figure Exec-1: 2017 & 2031 Capacity Mix and Sources of Incremental Capacity Additions



Note: Capacity based on winter ratings (renewables based on nameplate)

This report is intended to provide stakeholders insight into the Company's planning process for meeting forecasted customer peak demand and cumulative energy needs over the 15-year planning horizon. Such stakeholders include: legislative policymakers, public utility commissioners and their staffs, residential, commercial and industrial retail customers, wholesale customers, environmental advocates, renewable resource industry groups and the general public. A more detailed presentation of the Base Case, as described in the above Executive Summary, is included in this document in Chapter 8 and Appendix A.

The following chapters of this document provide an overview of the inputs, analysis and results included in the 2016 IRP. In addition to the Base Case plan, five different resource portfolios were analyzed under multiple sensitivities. Finally, the appendices to the document give even greater detail and specific information regarding the input development and the analytic process utilized in the 2016 IRP.

2. SYSTEM OVERVIEW

DEP's service area covers approximately 32,485 square miles, including a substantial portion of the coastal plain of North Carolina extending from the Piedmont to the Atlantic coast between the Pamlico River and the South Carolina border, the lower Piedmont section of North Carolina, an area in western North Carolina in and around the city of Asheville and an area in the northeastern portion of South Carolina. In addition to retail sales to approximately 1.52 million residential, commercial and industrial customers, the Company also sells wholesale electricity to incorporated municipalities and to public and private utilities.

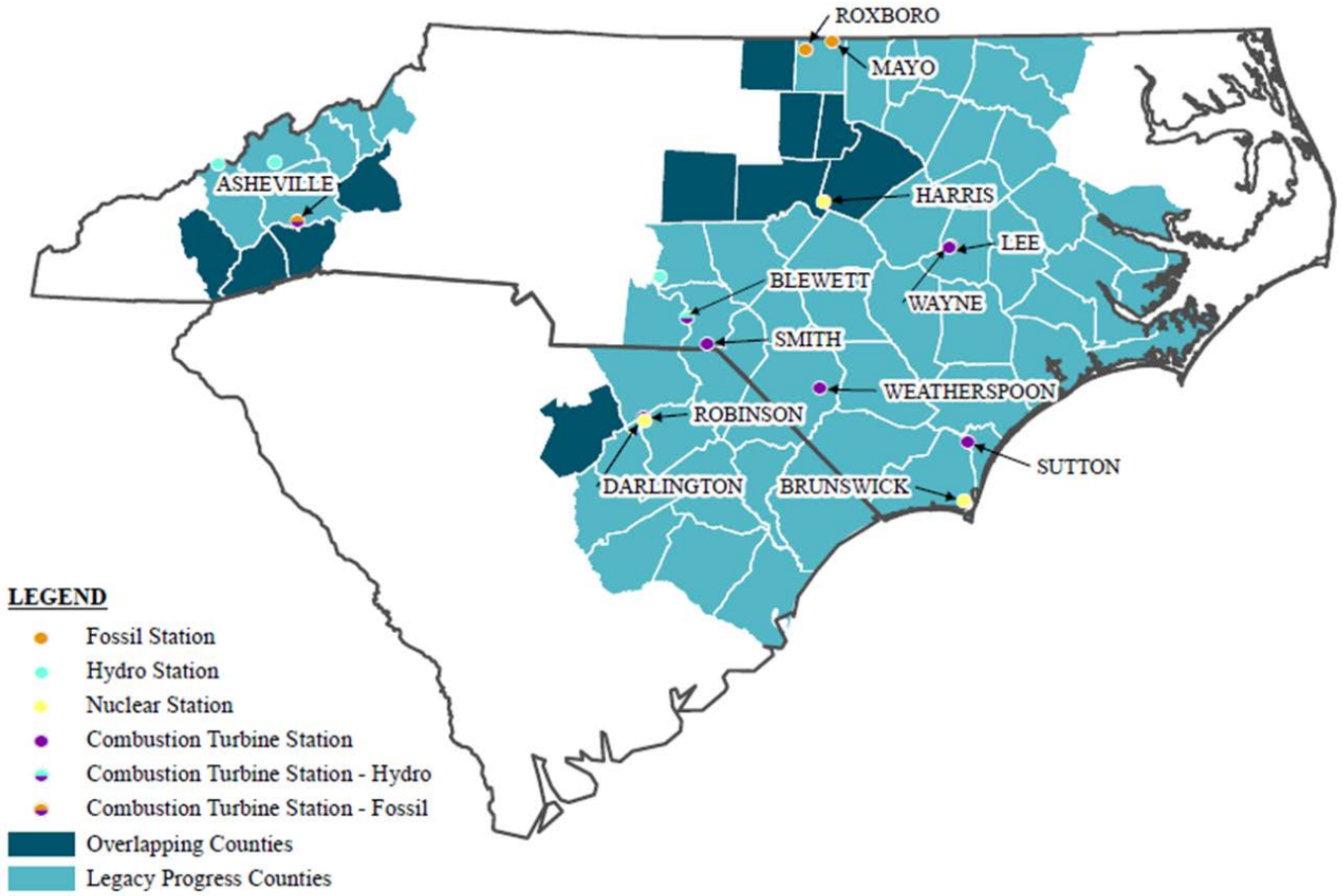
DEP currently meets energy demand, in part, by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets:

- Three nuclear generating stations with a combined net capacity of 3,698 MW/3,539 MW (winter/summer)
- Three coal-fired stations with a combined capacity of 3,592 MW/3,544 MW (winter/summer)
- Four hydroelectric stations with a combined capacity of 227 MW (winter/summer)
- Ten combustion turbine stations including four combined cycle units with a combined capacity of 6,455 MW/5,563 MW (winter/summer)
- Three utility-owned solar facilities with a combined firm capacity of 44.4 MW

DEP's power delivery system consists of approximately 67,800 miles of distribution lines and 6,300 miles of transmission lines. The transmission system is directly connected to all of the Transmission Operators that surround the DEP service area. There are 42 tie-line circuits connecting with six different Transmission Operators: DEC, PJM, Tennessee Valley Authority (TVA), Yadkin, South Carolina Electric & Gas (SCE&G), and Santee Cooper. These interconnections allow utilities to work together to provide an additional level of reliability. The strength of the system is also reinforced through coordination with other electric service providers in the Virginia-Carolinas (VACAR) sub-region, SERC Reliability Corporation (SERC), and North American Electric Reliability Corporation (NERC).

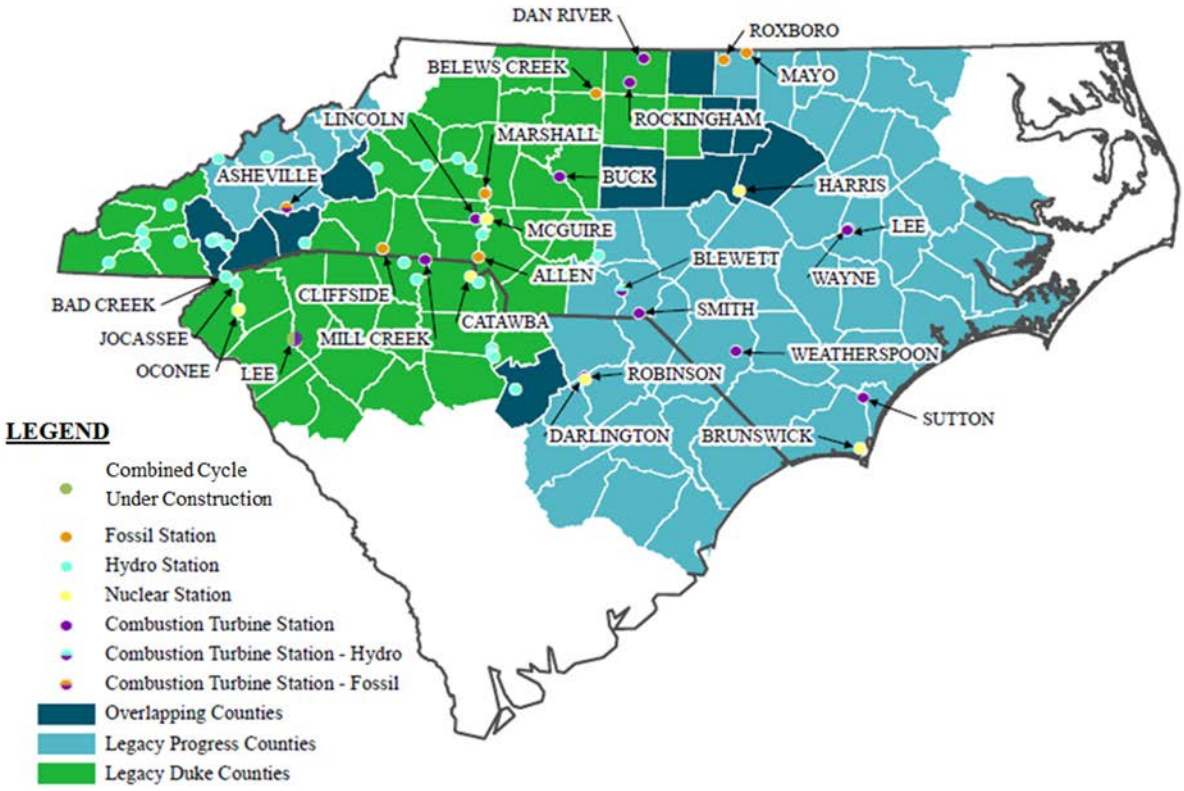
The map on the following page provides a high-level view of the DEP service area.

Chart 2-A Duke Energy Progress Service Area



With the closing of the Duke Energy Corporation and Progress Energy Corporation merger, the service territories for both DEP and DEC lend to future opportunities for collaboration and potential sharing of capacity to create additional savings for North Carolina and South Carolina customers of both utilities. An illustration of the service territories of the Companies are shown in the map below.

Chart 2-B DEP and DEC Service Area



3. ELECTRIC LOAD FORECAST

The Duke Energy Progress Spring 2016 Forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2017 – 2031 and represents the needs of the Retail and Wholesale Customers.

Energy projections are developed with econometric models using key economic factors such as income, electricity prices, industrial production indices, along with weather, appliance efficiency trends, rooftop solar trends, and electric vehicle trends. Population is also used in the Residential customer model. Regression analysis is utilized and has yielded consistently reasonable results over the years.

The economic projections used in the Spring 2016 Forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the states of North Carolina and South Carolina.

The Retail forecast consists of the three major classes: Residential, Commercial and Industrial.

The Residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electric price and appliance efficiencies.

The usage per customer forecast was derived using a Statistical Adjusted End-Use Model (SAE). This is a regression-based framework that uses projected appliance saturation and efficiency trends developed by Itron using Energy Information Administration (EIA) data. It incorporates naturally occurring efficiency trends and government mandates more explicitly than other models. The outlook for usage per customer is essentially flat through much of the forecast horizon, so most of the growth is primarily due to customer increases. The projected energy growth rate of Residential in the Spring 2016 Forecast after all adjustments for Utility EE programs, Solar and Electric Vehicles from 2017-2031 is 1.1%.

The Commercial forecast also uses an SAE model in an effort to reflect naturally occurring as well as government mandated efficiency changes. The three largest sectors in the Commercial class are Offices, Education and Retail. Commercial is expected to be the fastest growing class, with a projected energy growth rate of 1.3% after adjustments.

The Industrial class is forecasted by a standard econometric model with drivers such as total manufacturing output, textile output, and the price of electricity. Overall, Industrial energy sales are expected to grow 0.8% over the forecast horizon, after all adjustments.

Peak Demand and Energy Forecast

If the impacts of new Duke Energy Progress UEE[1] programs are included, the projected compound annual growth rate for the summer peak demand is 1.1%, while winter peaks are forecasted to grow at a rate of 1.3%. The forecasted compound annual growth rate for annual energy consumption is 0.9% after the impacts of UEE programs are subtracted.

The Spring 2016 Forecast is lower than the Spring 2015 Forecast, with a growth in the summer peak of 1.3% in the 2015 forecast versus 1.1% in the new forecast. The Spring 2016 Forecast is lower due to large Industrial plant closings in recent years, strong UEE accomplishments in recent years, stronger projected Commercial heating and cooling efficiencies, and a reduction in the projected Wholesale outlook.

[1] The term UEE is utilized in the load forecasting sections which represents utility-sponsored EE impacts net of free riders. The term "Gross EE" represents UEE plus naturally occurring energy efficiency in the marketplace.

The load forecast projection for energy and capacity including the impacts of EE that was utilized in the 2016 IRP is shown in Table 3-A.

Table 3-A Load Forecast with Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2017	13,127	13,158	65,000
2018	13,234	13,277	65,414
2019	13,385	13,442	65,952
2020	13,444	13,542	65,869
2021	13,599	13,728	66,442
2022	13,753	13,918	67,137
2023	13,919	14,107	67,873
2024	14,083	14,300	68,751
2025	14,249	14,488	69,413
2026	14,435	14,689	70,184
2027	14,601	14,874	70,938
2028	14,792	15,082	71,855
2029	14,973	15,283	72,558
2030	15,164	15,497	73,388
2031	15,365	15,719	74,166

A detailed discussion of the electric load forecast is provided in Appendix C.

4. ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT

DEP is committed to making sure electricity remains available, reliable and affordable and that it is produced in an environmentally sound manner and, therefore, DEP advocates a balanced solution to meeting future energy needs in the Carolinas. That balance includes a strong commitment to energy efficiency and demand side management.

Since 2008, DEP has been actively developing and implementing new EE and DSM programs throughout its North Carolina and South Carolina service areas to help customers reduce their electricity demands. DEP's EE and DSM plan is designed to be flexible, with programs being evaluated on an ongoing basis so that program refinements and budget adjustments can be made in a timely fashion to maximize benefits and cost-effectiveness. Initiatives are aimed at helping all customer classes and market segments use energy more wisely. The potential for new technologies and new delivery options is also reviewed on an ongoing basis in order to provide customers with access to a comprehensive and current portfolio of programs.

DEP's EE programs encourage customers to save electricity by installing high efficiency measures and/or changing the way they use their existing electrical equipment. DEP evaluates the cost-effectiveness of EE/DSM programs from the perspective of program participants, non-participants, all customers as a whole and total utility spending using the four California Standard Practice tests (i.e., Participant Test, Rate Impact Measure (RIM) Test, Total Resource Cost (TRC) Test and Utility Cost Test (UCT), respectively) to ensure the programs can be provided at a lower cost than building supply-side alternatives. The use of multiple tests can ensure the development of a reasonable set of programs and indicate the likelihood that customers will participate. DEP will continue to seek approval from state utility commissions to implement EE and DSM programs that are cost-effective and consistent with DEP's forecasted resource needs over the planning horizon. DEP currently has approval from the NCUC and PSCSC to offer a large variety of EE and DSM programs and measures to help reduce electricity consumption across all types of customers and end-uses.

For IRP purposes, these EE-based demand and energy savings are treated as a reduction to the load forecast, which also serves to reduce the associated need to build new supply-side generation, transmission and distribution facilities. DEP also offers a variety of DSM (or demand response) programs that signal customers to reduce electricity use during select peak hours as specified by the Company. The IRP treats these "dispatchable" types of programs as resource options that can be dispatched to meet system capacity needs during periods of peak demand.

To better understand the long-term EE savings potential, DEP commissioned a market potential study by Forefront Economics, Inc. in 2012 that estimated the technical, economic and achievable potential for EE within the DEP service area. The results of that market potential study are suitable for integrated resource planning purposes and use in long-range system planning models, however, the study did not attempt to closely forecast short-term EE achievements from year to year. Therefore, the Base Case EE/DSM savings contained in this IRP were projected by blending near-term program planning forecasts into the long-term achievable potential projections from the market potential study. An updated Market Potential Study is currently underway and the results of that study should be available in time for the next DEP IRP process.

DEP prepared a Base Portfolio savings projection that was based on DEP's five year program plan for 2016-2020. For periods beyond 2020, the Base Portfolio assumed that the annual savings projected for 2020 would continue to be achieved in each year thereafter until such time as the total cumulative EE projections reached approximately 60% of the Economic Potential as estimated by the Market Potential Study described above. Beyond reaching 60% of the Economic Potential, sufficient EE savings would be added to keep up with growth in the customer load.

DEP also prepared a High Portfolio EE savings projection that assumed that the same types of programs offered in the Base Portfolio, including potential new technologies, can be offered at higher levels of participation provided that additional money is spent on program costs to encourage additional customers to participate.

Additionally, for both the Base and High Portfolios described above, DEP included an assumption that, when the EE measures included in the forecast reach the end of their useful lives, the impacts associated with these measures are removed from the future projected EE impacts. This concept of "rolling off" the impacts from EE programs is explained further in Appendix C.

See Appendix D for further detail on DEP's EE, DSM and consumer education programs, which also includes a discussion of the methodology for determining the cost effectiveness of EE and DSM programs. Grid Modernization demand response impacts are also discussed in Appendix D.

5. RENEWABLE ENERGY STRATEGY / FORECAST

Since the last IRP was filed, the growth of renewable generation in the US continues to outpace that of non-renewable generation. In 2015, over 13,000 MW of wind and solar capacity were installed nationwide compared to 6,500 MW for natural gas, coal, nuclear, and other technologies. Most of the renewable growth is occurring in states with higher than average retail rates, renewable state mandates like NC REPS and/or tax incentives. Additionally, the requirements of the Public Utilities Regulatory Policy Act (PURPA) have driven renewable generation growth, especially in states with higher avoided cost rates and/or contract terms that are favorable to Qualifying Facilities (QFs). North Carolina has experienced this growth firsthand. The state ranked in the top three in the country in universal solar installations (>1MW in size) during the last two years, with the majority of that generating capacity owned by non-utility third parties.

Renewable mandates, substantial federal and state tax subsidies, and declining installed costs make solar capacity the Company's primary renewable energy resource in the 2016 IRP. The 2016 IRP makes the following key assumptions regarding renewable energy:

- Solar capacity increases from 1,710 MW in 2017 to 3,270 MW in 2031[2] (Base Case);
- Compliance with the NC REPS continues to be met through a combination of solar, other renewables, EE, and REC purchases;
- Achievement of the SC DER Program goal of 39 MW of solar capacity located in DEP-South Carolina (DEP-SC);
- With no change in policy, and even with the expiration of the NC state tax incentive in 2015, additional renewable capacity, particularly in the form of solar, will continue unabated, above and beyond the NC REPS requirements, driven by continued expected technology cost declines, local, state, and/or Federal incentives for these technologies, and PURPA implementation unique to North Carolina.

NC REPS Compliance

DEP is committed to meeting the requirements of NC REPS, including the poultry waste, swine waste, and solar set-asides, and the general requirement, which will be met with additional solar, hydro, biomass, landfill gas and EE resources. NC REPS allows for compliance utilizing not only renewable energy resources supplying bundled energy, RECs, and EE, but also by procuring unbundled RECs (both in-state and out-of-state) and thermal RECs. Therefore, the actual

[2] Solar capacities are adjusted to account for an annual 0.50% degradation of nameplate capacity.

renewable energy delivered to the DEP system is impacted by the amount of EE, unbundled RECs and thermal RECs utilized for compliance.

Based on currently signed projects and projections of what will materialize from the interconnection queue, DEP will be well positioned to meet the general NC REPS compliance requirement in the future. For details of DEP's NC REPS compliance plan, please reference the NC REPS Compliance Plan attachment.

Solar: PURPA and the Interconnection Queue

The rapid growth of new solar facilities continues to dominate the renewable energy market landscape. As discussed above, DEP purchases solar energy from non-utility generators in North Carolina to comply with NC REPS requirements. In addition to the NC REPS compliance requirements, however, DEP is also subject to PURPA, which requires that it purchase power from QFs at its avoided cost, regardless of the utility's need for such energy. Thus, another driver of the significant growth in solar purchases relates to the avoided cost rates a utility must pay for this power under PURPA. The utility's avoided costs rates, as approved by the NCUC, are a critical input for forecasting renewable penetration from QFs. Expected avoided costs, which are a key input to the rates paid to solar generators, are subject to factors such as commodity price volatility, regulatory changes, system operating conditions, and weather. Therefore, determining the future value of avoided costs is not easy and cannot be done with a high degree of accuracy.

Given the currently approved avoided cost rates and standard offer terms in NC, the NC REPS mandate, continuing impacts from the 35% North Carolina Renewable Energy Investment Tax Credit Safe Harbor Provision (which expired at the end of 2015), and the 30% Federal Solar Investment Tax Credit (ITC) (which was extended in December 2015), the QF market remains very active in the DEP service territory. Illustrating this trend are these facts:

- DEP had over 800 MW-AC (includes compliance and non-compliance MW) of third-party solar facilities on its system through the end of 2015, with close to half of the facilities interconnecting in 2015.
- When renewable resources were evaluated for the 2016 IRP, DEP reported another ~450 MW of third-party solar under construction and over 3,000 MW in the interconnection queue, including over 600 MW requested during the first quarter of 2016.

Projecting future solar connections from the interconnection queue, and its impact on future resource needs, presents a significant challenge as a large number of projects and interconnection requests have historically been cancelled or their ownership has changed hands numerous times. Given the size of the DEP and DEC queues, the time to complete the process from interconnection request to project completion where a facility is connected and supplying energy to the grid, often takes 2 years or more (please refer to Docket E-100 Sub 101A). The interconnection queue as of June 30, 2016 is provided in Appendix H.

While forecasting what will materialize from the current queue is difficult, projecting long-term solar growth is even more challenging. There are a number of factors that are difficult to predict, but necessary to estimate future renewable generation. These variables include, but are not limited to, interest rates, technology costs, construction and maintenance costs, energy and tax policy and operational constraints such as interconnection feasibility or land availability. In total, DEP expects 1,155 MW-AC of nameplate non-compliance mandated PURPA solar capacity by 2031.

Utility-Owned Solar and Integration

DEP continues to evaluate utility-owned solar additions to support operational flexibility. For example, DEP recently constructed, and is owning and operating four new utility-scale solar projects as part of its efforts to encourage emission free generation resources and help meet its compliance targets, totaling 141 MW-AC:

- Camp Lejeune Solar Facility – 13MW, located in Onslow County, placed in service in November 2015;
- Warsaw Solar Facility – 65MW, located in Duplin County, placed in service in December 2015;
- Fayetteville Solar Facility – 23MW, located in Bladen County, placed in service in December 2015; and
- Elm City Solar Facility – 40MW, located in Wilson County, placed in service in March 2016.

While there is uncertainty in the rate of decline in the cost of solar over time, in most scenarios evaluated in the IRP planning process, additional utility-owned solar was not selected above and beyond the total capacity expected for NC REPS compliance, PURPA puts, and customer product offerings like SC DER. As described in more detail in Appendix A, scenarios where solar was selected required assumptions in which lower installed solar cost and/or higher emissions constraints were utilized relative to the Base Case assumptions. Such price declines may be realized,

and the Company will continue to position itself for delivering quality, cost-effective projects that leverage the utility's scale and knowledge. DEP continues to build its relationships with suppliers, Engineering, Procurement, and Construction Contractors (EPCs), and other entities to create greater efficiencies in the supply chain, reduce construction costs, reduce operating and maintenance costs (O&M), and enhance system design. DEP will continue to evaluate how to increase its ownership of renewable generation to expand its portfolio of clean energy resources, meet future customer demand, and comply with evolving government regulations that promote the use of such resources.

Positioning itself to properly integrate renewable resources to the grid, especially solar, is critical. The Company is already observing that significant volumes of solar capacity result in excess energy challenges during the middle of the day during mild conditions when overall system demand is low. As a result, the Company sees an increasing need for operational control of the solar facilities connected to the grid. Additionally, the intermittency of solar output will require the Company to evaluate and invest in technologies to provide solutions for voltage, Volt Ampere Reactive (VaR), and/or higher ancillary reserve requirements. DEP expects that it can safely and reliably integrate renewable resources like solar through a combination of utility-owned assets and cooperation with third parties. DEP will evaluate the potential for acquiring facilities, where appropriate, to help ensure the Company has needed operational control, while minimizing the costs associated with system integration.

SC DER Solar and Customer Program Solar

In addition to PURPA and NC REPS compliance solar, solar growth has also been embraced with customer-oriented strategies such as SC DER.

In 2015, the Company's DER plan was approved by the PSCSC, thus allowing the Company to pursue a portfolio of initiatives designed to increase the solar capacity located in the Company's South Carolina service area. The program contains three tiers; each is equivalent to 1% of the Company's estimated average South Carolina retail peak demand (or 13 MW of nameplate solar capacity). The plan calls for a total of ~39MW of solar capacity[3] distributed across three tiers:

- Tier I: 13 MW of solar capacity from facilities each >1 MW and less than 10 MW in size.
- Tier II: 13 MW met via behind-the-meter rooftop solar facilities ≤1 MW for residential, commercial, and industrial customers with at least a quarter of that capacity from facilities each ≤ 20 kilowatts (kW). Since Tier II is behind the meter, the expected solar generation is embedded in the load forecast as a reduction to expected load.

[3] One percent of the Company's South Carolina retail peak is equal to approximately 13 MW.

- Tier III: Investment by the utility in 13 MW of solar capacity from facilities each >1 MW and less than 10 MW in size. Upon completion of Tiers I and II (to occur no later than 2021), the Company can directly invest in additional solar generation to complete Tier III.

In DEP-South Carolina, as part of the SC DER plan, the Company launched its first Shared Solar program. Often called "community solar," shared solar refers to both a solar facility and a billing structure in which multiple customers subscribe to and share in the economic benefits of the output of a single solar facility. The Company designed its initial SC DER shared solar program such that it would have strong appeal to residential and commercial customers who rent or lease their premise, to residential customers who reside in multifamily housing units or shaded housing, and to residential customers for whom the relatively high up-front costs of solar photovoltaic (PV) make net metering unattainable. The Company is evaluating the potential for a shared solar offer to North Carolina customers. Furthermore, the Company continues to study the potential for programs that support more load-centered rooftop solar PV installation in North Carolina.

DEP is also evaluating additional programs similar to the Green Source Rider in DEC as companies nationwide have demonstrated a desire for solar to support growing sustainability goals. For example, technology companies that often have data centers have signed around 1 GW of renewable energy PPAs nationally from 2015-June 2016.

Battery Storage and Wind

In addition to solar, the Company is assessing renewable technologies such as battery storage and wind. Battery storage costs are expected to decline significantly which may make it a viable option in the long run to support operational challenges caused by uncontrolled solar penetration. In the short run, battery storage is expected to be used primarily to support localized distribution based issues. For example, DEP is committed to the Western Carolinas Modernization Project (WCMP) where DEP will site at least 15 MW of solar and 5 MW of storage capacity in the DEP-Western Region to support the retirement of the two coal units at Asheville. The WCMP will be a great learning experience for the Company on how to effectively deploy more battery storage in the future to facilitate safe, reliable, and cost effective integration of renewable resources with the rest of the generation, transmission, and distribution systems.

Similar to solar, at the end of 2015, wind received a boost from the announcement of a multi-year extension of the wind energy Production Tax Credit (PTC). Investing in wind inside of DEP's footprint is unlikely in the short term in spite of the PTC. This is primarily due to a lack of suitable sites and permitting challenges, as well as less significant expected drops in capital costs compared

to other renewable technologies like solar. As discussed in the NC REPS compliance plan however, additional opportunities may be pursued to transmit wind energy from out of state regions where wind is more prevalent and into the Carolinas.

Summary of Expected Renewable Resource Capacity Additions

The 2016 IRP incorporated three different renewable capacity forecasts: Low Case, Base Case, and High Case. Each of these cases includes renewable capacity required for compliance with NC REPS, non-compliance PURPA renewable purchases, as well as SC DER and other solar capacity associated with customer programs. The Company anticipates a diverse portfolio including solar, biomass, hydro, and other resources. Actual results could vary substantially depending on the uncertainties listed above as well as other potential changes to future legislative requirements, supportive tax policies, technology, and other market forces. The details of the forecasted capacity additions, including both nameplate and contribution to winter and summer peaks are summarized in Table 5-A below.

While solar doesn't normally reach its maximum output at the time of DEP's expected peak load in the summer, solar's contribution to summer peak load is large enough (44% of nameplate solar capacity) that it may push the time of summer peak (net of solar) from hour beginning 4:00 PM to 5:00 PM or later if solar penetration levels continue to increase. Note, however, that solar is unlikely to have a similar impact on the morning winter peak (net of solar) due to lower expected solar output in the morning hours (5% of nameplate solar capacity contribution).

Table 5-A DEP Base Case Total Renewables

DEP Base Renewables - Compliance + Non-Compliance										
	MW Nameplate			MW Contribution to Summer Peak				MW Contribution to Winter Peak		
	Solar	Biomass/ Hydro	Total	Solar	Biomass/ Hydro	Total		Solar	Biomass/ Hydro	Total
2017	1710	290	2000	752	290	1042	2016/2017	85	290	376
2018	1989	240	2229	875	240	1115	2017/2018	99	240	340
2019	2302	240	2543	1013	240	1253	2018/2019	115	240	355
2020	2560	236	2795	1126	236	1362	2019/2020	128	236	364
2021	2810	236	3046	1236	236	1472	2020/2021	140	236	376
2022	2969	172	3141	1306	172	1478	2021/2022	148	172	320
2023	3015	90	3105	1327	90	1416	2022/2023	151	90	240
2024	3050	90	3139	1342	90	1431	2023/2024	152	90	242
2025	3081	90	3171	1356	90	1445	2024/2025	154	90	244
2026	3112	90	3202	1369	90	1459	2025/2026	156	90	245
2027	3145	88	3233	1384	88	1472	2026/2027	157	88	245
2028	3178	85	3263	1398	85	1483	2027/2028	159	85	244
2029	3212	76	3288	1413	76	1489	2028/2029	161	76	237
2030	3244	76	3320	1428	76	1503	2029/2030	162	76	238
2031	3270	76	3346	1439	76	1515	2030/2031	163	76	239

* Solar includes 0.5% per year degradation

Given the significant volume and uncertainty around solar penetration, high and low solar portfolios were evaluated compared to the Base Case described above. The portfolios don't envision a specific market condition, but rather the potential combined effect of a number of factors. For example, the high sensitivity could occur given events such as high carbon prices, lower solar capital costs, economical solar plus storage, continuation of renewal subsidies, and/or stronger renewable energy mandates. On the other hand, the low sensitivity may occur given events such as lower fuel prices for more traditional generation technologies, higher solar installation and interconnection costs, lower avoided costs, and/or less favorable PURPA terms. Tables 5-B and 5-C below provide the high and low solar nameplate capacity summaries as well as their corresponding expected contributions to summer and winter peaks.

Table 5-B DEP High Case Total Renewables

DEP High Renewables - Compliance + Non-Compliance										
	MW Nameplate			MW Contribution to Summer Peak				MW Contribution to Winter Peak		
	Solar	Biomass/ Hydro	Total	Solar	Biomass/ Hydro	Total		Solar	Biomass/ Hydro	Total
2017	1769	290	2059	779	290	1069	2016/2017	88	290	379
2018	2089	240	2329	919	240	1159	2017/2018	104	240	345
2019	2472	240	2712	1088	240	1328	2018/2019	124	240	364
2020	2797	236	3033	1231	236	1467	2019/2020	140	236	376
2021	3048	236	3284	1341	236	1577	2020/2021	152	236	388
2022	3384	172	3556	1489	172	1661	2021/2022	169	172	341
2023	3626	90	3715	1595	90	1685	2022/2023	181	90	271
2024	3817	90	3906	1679	90	1769	2023/2024	191	90	280
2025	3995	90	4084	1758	90	1847	2024/2025	200	90	289
2026	4175	90	4264	1837	90	1927	2025/2026	209	90	298
2027	4357	88	4445	1917	88	2005	2026/2027	218	88	306
2028	4542	85	4627	1998	85	2083	2027/2028	227	85	312
2029	4728	76	4804	2080	76	2156	2028/2029	236	76	312
2030	4911	76	4987	2161	76	2237	2029/2030	246	76	321
2031	5062	76	5138	2227	76	2303	2030/2031	253	76	329

* Solar includes 0.5% per year degradation

Table 5-C DEP Low Case Total Renewables

DEP Low Renewables - Compliance + Non-Compliance										
	MW Nameplate			MW Contribution to Summer Peak				MW Contribution to Winter Peak		
	Solar	Biomass/ Hydro	Total	Solar	Biomass/ Hydro	Total		Solar	Biomass/ Hydro	Total
2017	1710	290	2000	752	290	1042	2016/2017	85	290	376
2018	1782	240	2022	784	240	1024	2017/2018	89	240	329
2019	1873	240	2113	824	240	1064	2018/2019	94	240	334
2020	1947	236	2182	857	236	1092	2019/2020	97	236	333
2021	2018	236	2254	888	236	1124	2020/2021	101	236	337
2022	2086	172	2258	918	172	1090	2021/2022	104	172	276
2023	2151	90	2241	947	90	1036	2022/2023	108	90	197
2024	2213	90	2303	974	90	1063	2023/2024	111	90	200
2025	2271	90	2361	999	90	1089	2024/2025	114	90	203
2026	2330	90	2419	1025	90	1115	2025/2026	116	90	206
2027	2389	88	2477	1051	88	1139	2026/2027	119	88	207
2028	2449	85	2534	1077	85	1163	2027/2028	122	85	207
2029	2510	76	2586	1104	76	1180	2028/2029	125	76	201
2030	2569	76	2645	1130	76	1206	2029/2030	128	76	204
2031	2618	76	2694	1152	76	1228	2030/2031	131	76	207

* Solar includes 0.5% per year degradation

6. SCREENING OF GENERATION ALTERNATIVES

As previously discussed, the Company develops the load forecast and adjusts for the impacts of EE programs that have been pre-screened for cost-effectiveness. The growth in this adjusted load forecast and associated reserve requirements, along with existing unit retirements or purchased power contract expirations, creates a need for future generation. This need is partially met with DSM resources and the renewable resources required for compliance with NC REPS. The remainder of the future generation needs can be met with a variety of potential supply side technologies.

For purposes of the 2016 IRP, the Company considered a diverse range of technology choices utilizing a variety of different fuels, including ultra-supercritical pulverized coal (USCPC) units with carbon capture and sequestration (CCS), integrated gasification combined cycle (IGCC) with CCS, CTs, CCs with inlet chillers and duct firing, Combined Heat and Power, reciprocating engines, and nuclear units. In addition, Duke Energy Progress considered renewable technologies such as wind, solar, battery storage and landfill gas in the screening analysis.

For the 2016 IRP screening analysis, the Company screened technology types within their own respective general categories of baseload, peaking/intermediate and renewable, with the ultimate goal of screening to pass the best alternatives from each of these three categories to the integration process. As in past years, the reason for the initial screening analysis is to determine the most viable and cost-effective resources for further evaluation. This initial screening evaluation is necessary to narrow down options to be further evaluated in the quantitative analysis process as discussed in Appendix A.

The results of these screening processes determine a smaller, more manageable subset of technologies for detailed analysis in the expansion planning model. The following list details the technologies that were evaluated in the screening analysis phase of the IRP process. The technical and economic screening is discussed in detail in Appendix F.

Dispatchable (Summer Ratings)

- Base load – 782 MW Ultra-Supercritical Pulverized Coal with CCS
- Base load – 557 MW 2x1 IGCC with CCS
- Base load – 2 x 1,117 MW Nuclear Units (AP1000)
- Base load – 576 MW – 1x1x1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Base load – 1,160 MW – 2x2x1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Base load – 20 MW – Combined Heat & Power
- Peaking/Intermediate – 166 MW 4 x LM6000 Combustion Turbines

- Peaking/Intermediate – 201 MW 12 x Reciprocating Engine Plant
- Peaking/Intermediate – 870 MW 4 x 7FA.05 Combustion Turbines (CTs)
- Renewable – 2 MW / 8 MWh Li-ion Battery

Non-Dispatchable

- Renewable – 150 MW Wind - On-Shore
- Renewable – 5 MW Solar PV

7. RESOURCE ADEQUACY

Background

Resource adequacy refers to the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Utilities require a margin of reserve generating capacity in order to provide reliable service. Periodic scheduled outages are required to perform maintenance, inspections of generating plant equipment, and to refuel nuclear plants. Unanticipated mechanical failures may occur at any given time, which 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. The Company utilizes a reserve margin target in its IRP process to ensure resource adequacy. Reserve margin is defined as total resources minus peak demand, divided by peak demand. The reserve margin target is established based on probabilistic assessments as described below.

In 2012, the Company retained Astrape Consulting to conduct a resource adequacy study to determine the level of reserves needed to maintain adequate generation system reliability. Based on results of the 2012 Astrape analysis, the Company adopted a 14.5% minimum summer planning reserve margin for scheduling new resource additions.

In 2016, the Company again retained Astrape Consulting to conduct an update to the resource adequacy study performed in 2012. The updated study was warranted due to two primary factors. First, the extreme weather experienced in the service territory in recent winter periods was so impactful to the system that additional review with the inclusion of recent years' weather history was warranted. Second, since the last resource adequacy study the system has added, and projects to add, a large amount of resources that provide meaningful capacity benefits in the summer. From a peak reduction perspective, summer-oriented resources include summer load control programs, chiller additions to natural gas combined cycle units, and solar generation. Solar resources contribute approximately 44% of nameplate capacity at the time of the expected summer peak demand and only about 5% of nameplate capacity at the time of expected winter peak demand. The interconnection queue for solar facilities shows the potential to add significantly to the solar resources already incorporated on the system.

2016 Resource Adequacy Study Results

Astrape conducted an updated resource adequacy assessment in 2016 that incorporated the uncertainty of weather, economic load growth, unit availability, and the availability of transmission and generation capacity for emergency assistance. Astrape analyzed the optimal planning reserve margin based on providing an acceptable level of physical reliability and minimizing economic costs to customers. The most common physical reliability metric used in the industry is to target a system reserve margin that satisfies the one day in 10 years Loss of Load Expectation (LOLE) standard. This standard is interpreted as one firm load shed event every 10 years due to a shortage of generating capacity. From an economic perspective, as planning reserve margin increases, the total cost of reserves increases while the costs related to reliability events decline. Similarly, as planning reserve margin decreases, the cost of reserves decreases while the costs related to reliability events increase, including the costs to customers for loss of power. Thus, there is an economic optimum point where the cost of additional reserves plus the cost of reliability events to customers is minimized.

In the past, loss of load risk has typically been concentrated during the summer months and a summer reserve margin target provided adequate reserves in the summer and winter and was thus sufficient for ensuring resource adequacy. However, the incorporation of recent winter load data and the significant amount of solar penetration in the updated study, shows that the majority of loss of load risk is now heavily concentrated during the winter period. Since solar capacity contribution to peak is much greater in the summer compared to the winter, use of a summer reserve margin target will no longer ensure that adequate reserve levels are maintained in the winter. As a result, a winter planning reserve margin target is now needed to ensure that adequate resources are available throughout the year to meet customer demand.

Based on results of the 2016 resource adequacy assessment, the Company has adopted a 17% minimum winter reserve margin target for scheduling new resource additions. Astrape also recommends maintaining a 15% minimum summer reserve margin to ensure adequate reliability is maintained during the summer period. However, given the portfolio of existing and projected new resources, a 15% summer reserve margin will always be satisfied if a 17% winter reserve margin is maintained. The Company will continue to monitor its generation portfolio and other planning assumptions that can impact resource adequacy and initiate new studies as appropriate.

Adequacy of Projected Reserves

DEP's resource plan reflects winter reserve margins ranging from approximately 18% to 27% through the planning period. Reserves projected in DEP's IRP meet the minimum planning reserve

margin target and thus satisfy the one day in 10 years LOLE criterion. The projected reserve margin exceeds the minimum 17% winter target by 3% or more through the winter of 2018/19 primarily due to lower load growth resulting from a slightly slower economic forecast as shown in recent IRPs, as well as a reduction in the wholesale load forecast.

The IRP provides general guidance in the type and timing of resource additions. Since capacity is generally added in large blocks to take advantage of economies of scale, it should be noted that projected planning reserve margins in years immediately following new generation additions will often be somewhat higher than the minimum target. Large resource additions are deemed economic only if they have a lower Present Value Revenue Requirement (PVRR) over the life of the asset as compared to smaller resources that better fit the short-term reserve margin need. Reserves projected in DEP's IRP are appropriate for providing an economic and reliable power supply.

8. EVALUATION AND DEVELOPMENT OF THE RESOURCE PLAN

As described in the previous chapter, DEP has added a winter planning reserve margin criteria to the IRP process. To meet the future needs of DEP's customers, it is necessary for the Company to adequately understand the load and resource balance. For each year of the planning horizon, DEP develops a load forecast of cumulative energy sales and hourly peak demand. To determine total resources needed, the Company considers the peak demand load obligation plus a 17% minimum planning winter reserve margin. The projected capability of existing resources, including generating units, EE and DSM, renewable resources and purchased power contracts is measured against the total resource need. Any deficit in future years will be met by a mix of additional resources that reliably and cost-effectively meet the load obligation and planning reserve margin while complying with all environmental and regulatory requirements. It should be noted that DEP considers the non-firm energy purchases and sales associated with the Joint Dispatch Agreement (JDA) with DEC in the development of its independent Base Case and five alternative portfolios as discussed later in this chapter and in Appendix A.

IRP Process

The following section summarizes the Data Input, Generation Alternative Screening, Portfolio Development and Detailed Analysis steps in the IRP process. A more detailed discussion of the IRP Process and development of the Base Case and additional portfolios is provided in Appendix A.

Data Inputs

The initial step in the IRP development process is one of input data refreshment and revision. For the 2016 IRP, data inputs such as load forecast, EE and DSM projections, fuel prices, projected CO_2 prices, individual plant operating and cost information, and future resource information were updated with the most current data. These data inputs were developed and provided by Company subject matter experts and/or based upon vendor studies, where available. Furthermore, DEP and DEC continue to benefit from the combined experience of both utilities' subject matter experts utilizing best practices from each utility in the development of their respective IRP inputs. Where appropriate, common data inputs were utilized.

As expected, certain data elements and issues have a larger impact on the IRP than others. Any changes in these elements may result in a noticeable impact to the plan, and as such, these elements are closely monitored. Some of the most consequential data elements are listed below. A detailed discussion of each of these data elements has been presented throughout this document and are examined in more detail in the appendices.

- Load Forecast for Customer Demand
- EE/DSM
- Renewable Resources and Cost Projections
- Fuel Costs Forecasts
- Technology Costs and Operating Characteristics
- Environmental Legislation and Regulation

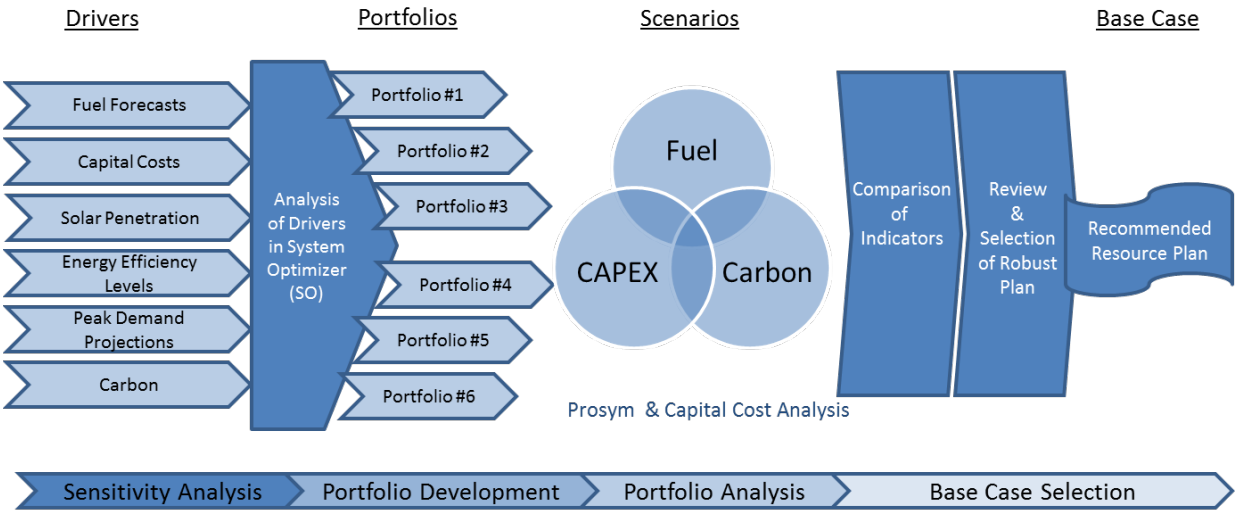
Generation Alternative Screening

DEP reviews generation resource alternatives on a technical and economic basis. Resources must also be demonstrated to be commercially available for utility scale operations. The resources that are found to be both technically and economically viable are then passed to the detailed analysis process for further analysis.

Portfolio Development and Detailed Analysis

The following figure provides an overview of the process for the portfolio development and detailed analysis phase of the IRP.

Figure 8-A Overview of Portfolio Development and Detailed Analysis Phase



The Sensitivity Analysis and Portfolio Development phases rely upon the updated data inputs and results of the generation alternative screening process to derive resource portfolios or resource plans. The Sensitivity Analysis and Portfolio Development phases utilize an expansion planning model to determine the best mix of capacity additions for the Company's short- and long-term resource needs with an objective of selecting a robust plan that minimizes the PVRR and is environmentally sound complying with all State and Federal regulations.

Sensitivity analysis of input variables such as load forecast, fuel costs, renewable energy, EE, and capital costs are considered as part of the quantitative analysis within the resource planning process. Utilizing the results of these sensitivities, possible expansion plan options for the DEP system are developed. These expansion plans are reviewed to determine if any overarching trends are present across the plans, and based on this analysis, specific portfolios are developed to represent these trends. Finally, the portfolios are analyzed using a capital cost model and an hourly production cost model (PROSYM) under various fuel price, capital cost and carbon scenarios to evaluate the robustness and economic value of each portfolio, and at this point, the Base Case portfolio is selected.

In addition to evaluating these portfolios solely within the DEP system, the potential benefits of sharing capacity within DEP and DEC are examined in a common Joint Planning Case. A detailed discussion of these portfolios is provided in Appendix A.

Selected Portfolios

For the 2016 IRP, six representative portfolios were identified through the Sensitivity Analysis and Portfolio Development steps. Four of the portfolios were developed under a Carbon Tax paradigm where varying levels of an intrastate CO_2 tax were applied to existing coal and gas units as envisioned in EPA's Clean Power Plan. These portfolios included a portfolio that was mainly centered around CT technology, a portfolio that was centered around CC technology, a portfolio with high renewable penetration, and a portfolio with high EE penetration.

The remaining two portfolios were developed under a System CO_2 Mass Cap that represented an alternative outcome of the CPP. In these portfolios total system CO_2 emissions were constrained starting in 2022 and declined until 2030, and total system emission were held flat from 2030 throughout the remaining planning horizon. One of these portfolios included base EE and base renewable assumptions, while the other portfolio included higher levels of EE and renewables. In general, both of these portfolios required relicensing or replacement of existing nuclear generation in both DEP and DEC, along with construction of the Lee Nuclear Plant in the late 2020s in DEC.

Portfolio Analysis & Base Case Selection

The six portfolios identified in the screening analysis were evaluated in more detail with an hourly production cost model under several scenarios. The four scenarios are summarized in Table 8-A and included sensitivities on fuel, carbon, and capital cost.

Table 8-A Scenarios for Portfolio Analysis

	Carbon Tax/No Carbon Tax Scenarios[1]	**Fuel**	**CO_2**	**CAPEX**
1	Current Trends	Base	CO_2 Tax	Base
2	Economic Recession	Low Fuel	No CO_2 Tax	Low
3	Economic Expansion	High Fuel	CO_2 Tax	High

[1]Run Portfolios 1 - 4 through each of these 3 scenarios

	System Mass Cap Scenarios[2]	**Fuel**	**CO_2**	**CAPEX**
4	Current Trends - CO_2 Mass Cap	Base	Mass Cap	Base

[2]Run Portfolios 5 - 6 through this single MC2 scenario

Portfolios 1 through 4 were analyzed under a current economic trend scenario (Scenario #1), an economic recession scenario (Scenario #2), and an economic expansion scenario (Scenario #3). Portfolios 5 & 6 were only evaluated under the Current Trends – System Mass Cap scenario (Scenario #4).

Under a cap on system carbon emissions, fuel price and capital cost will have little impact on the optimization of the system as the carbon output of the various generators will control dispatch to a greater extent than the fuel price.

Table 8-B lists the Portfolios that were developed under a Carbon Tax paradigm, along with their PVRR rankings under the three scenarios.

Table 8-B: Portfolios 1 – 4 PVRR Rankings

Portfolio	Scenario #1 (Current Trends)	Scenario #2 (Economic Recession)	Scenario #3 (Economic Expansion)
Portfolio #1 – **Base Case**	1	1	1
Portfolio #2 (High Renew)	4	4	4
Portfolio #3 (High EE)	2	2	2
Portfolio #4 (High CC)	3	3	3

In the three scenarios, Portfolio #1 (Base Case) was the lowest cost portfolio. The costs of Portfolios 2 & 3 were negatively impacted by expanding the amount of renewable resources beyond the NC REPS requirements and energy efficiency above the achievable potential. However, Portfolio #3 (High EE) had a PVRR that was nearly as low as Portfolio #1 when capital costs and fuel prices were increased in the Economic Expansion scenario. Portfolio #2 (High Renewables) had the lowest carbon footprint in each of the three scenarios evaluated; however, this Portfolio had the highest PVRR cost. The higher capital cost and fixed gas pipeline costs associated with combined cycles caused Portfolio #4 (High CC) to have a higher cost than Portfolio #1.

Future CO_2 legislation is still uncertain, and a system mass cap on carbon emissions is still a possibility. The short term build plan from Portfolio #1 (Base Case) would keep the Company on track if a System CO_2 Mass Cap were implemented. Additionally, Portfolio #1 was the least cost portfolio from a revenue requirements perspective.

Based on the PVRR Rankings, the robustness of the portfolio, and the belief that there will be some type of carbon legislation in the future, Portfolio #1 was selected as the Base Case under a Carbon Tax paradigm in the 2016 IRP.

Finally, Portfolios 5 and 6 were evaluated under the Current Trends scenario with a System CO_2 Mass Cap carbon constraint. Under the Mass Cap carbon paradigm, the high EE and high renewable combination led to a significantly higher PVRR versus the Base Case. The $1.7B savings in system production costs was not enough to overcome the $2.5B capital cost of the high EE/high renewable portfolio. Given the PVRR delta between the two cases, and the uncertainty of achieving the high

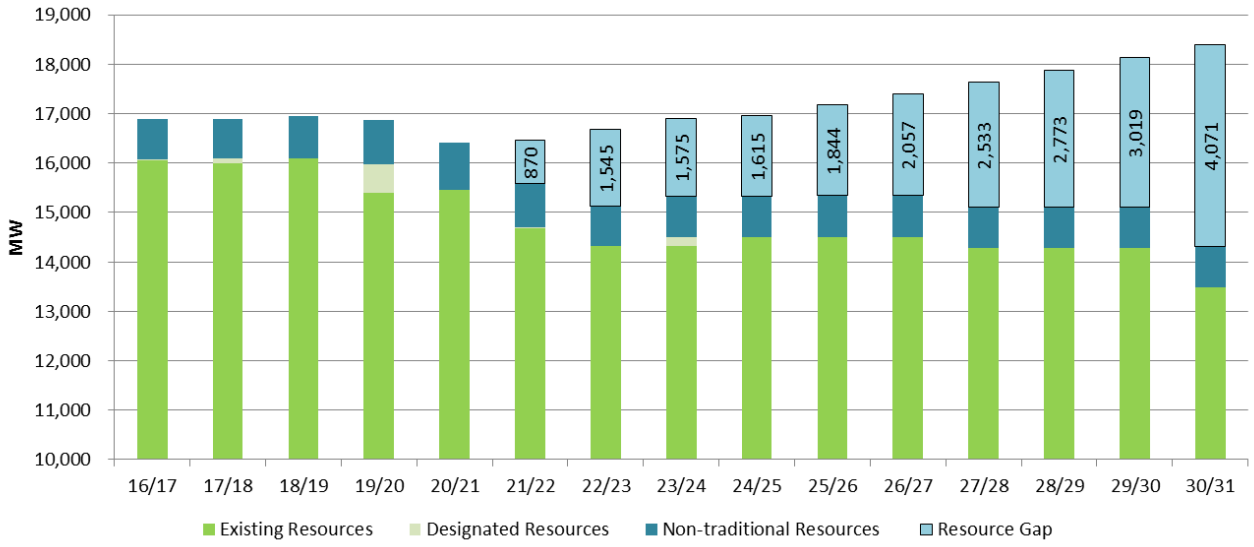
EE targets, Portfolio #5 was selected to represent the base case under a System Mass Cap carbon plan.

Base Case

The Base Case was selected based upon the evaluation of the portfolios in the Carbon Tax paradigm. The Base Case was developed utilizing consistent assumptions and analytic methods between DEP and DEC, where appropriate. This case does not take into account the sharing of capacity between DEP and DEC. However, the Base Case incorporates the JDA between DEP and DEC, which represents a non-firm energy only commitment between the Companies. A Joint Planning Case that begins to explore the potential for DEP and DEC to share firm capacity was also developed and is discussed later in this chapter and in Appendix A.

The Load and Resource Balance Chart shown in Chart 8-A illustrates the resource needs that are required for DEP to meet its load obligation inclusive of a required reserve margin. The existing generating resources, designated resource additions and EE resources do not meet the required load and reserve margin beginning in 2022. As a result, the resource plan analyses described above have determined the most robust plan to meet this resource gap.

Chart 8-A DEP Base Case Load Resource Balance (Winter)



Cumulative Resource Additions to Meet Winter Load Obligation and Reserve Margin (MW)

Year	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24
Resource Need	0	0	0	0	0	870	1,545	1,575
Year	24/25	25/26	26/27	27/28	28/29	29/30	30/31	
Resource Need	1,615	1,844	2,057	2,533	2,773	3,019	4,071	

Tables 8-C and 8-D present the Load, Capacity and Reserves (LCR) tables for the Base Case analysis that was completed for DEP's 2016 IRP.

Table 8-C Load, Capacity and Reserves Table - Winter

Winter Projections of Load, Capacity, and Reserves for Duke Energy Progress 2016 Annual Plan

	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
Load Forecast															
1 Duke System Peak	13,190	13,336	13,527	13,653	13,872	14,085	14,296	14,511	14,721	14,942	15,146	15,365	15,573	15,787	16,010
2 Firm Sale	150	150	150	150	150	150	150	150	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(31)	(59)	(85)	(110)	(144)	(166)	(189)	(210)	(232)	(253)	(272)	(284)	(289)	(289)	(291)
4 Adjusted Duke System Peak	**13,308**	**13,427**	**13,592**	**13,692**	**13,878**	**14,068**	**14,257**	**14,450**	**14,488**	**14,689**	**14,874**	**15,082**	**15,283**	**15,497**	**15,719**
Existing and Designated Resources															
5 Generating Capacity	13,972	13,852	13,876	13,890	13,561	13,561	13,567	13,567	13,757	13,757	13,757	13,757	13,525	13,525	13,525
6 Designated Additions / Uprates	8	100	14	572	0	6	0	190	0	0	0	0	0	0	0
7 Retirements / Derates	(128)	(76)	0	(901)	0	0	0	0	0	0	0	(232)	0	0	(797)
8 Cumulative Generating Capacity	**13,852**	**13,876**	**13,890**	**13,561**	**13,561**	**13,567**	**13,567**	**13,757**	**13,757**	**13,757**	**13,757**	**13,525**	**13,525**	**13,525**	**12,728**
Purchase Contracts															
9 Cumulative Purchase Contracts	**2,323**	**2,329**	**2,337**	**2,029**	**2,033**	**1,211**	**834**	**834**	**834**	**833**	**833**	**830**	**830**	**830**	**829**
Non-Compliance Renewable Purchases	109	115	123	128	134	82	82	82	82	81	81	81	81	80	80
Non-Renewables Purchases	2,214	2,214	2,214	1,901	1,899	1,129	752	752	752	752	752	749	749	749	749
Undesignated Future Resources															
10 Nuclear															
11 Combined Cycle						1,221									
12 Combustion Turbine							468			468		468	468		1,404
Renewables															
13 Cumulative Renewables Capacity	267	224	233	236	242	238	158	160	162	164	164	163	156	158	159
14 Combined Heat & Power	0	0	22	22	22	0	0	0	0	0	0	0	0	0	0
15 Cumulative Production Capacity	**16,442**	**16,430**	**16,481**	**15,869**	**15,902**	**16,302**	**16,314**	**16,505**	**16,507**	**16,976**	**16,977**	**17,208**	**17,669**	**17,670**	**18,279**
Demand Side Management (DSM)															
16 Cumulative DSM Capacity	**445**	**462**	**477**	**490**	**503**	**508**	**512**	**515**	**519**	**522**	**526**	**530**	**533**	**535**	**538**
17 Cumulative Capacity w/ DSM	**16,886**	**16,892**	**16,958**	**16,359**	**16,404**	**16,811**	**16,825**	**17,021**	**17,026**	**17,499**	**17,502**	**17,738**	**18,201**	**18,206**	**18,817**
Reserves w/ DSM															
18 Generating Reserves	3,578	3,464	3,366	2,667	2,526	2,742	2,568	2,570	2,537	2,810	2,629	2,656	2,918	2,708	3,098
19 % Reserve Margin	**27%**	**26%**	**25%**	**19%**	**18%**	**19%**	**18%**	**18%**	**18%**	**19%**	**18%**	**18%**	**19%**	**17%**	**20%**

Table 8-D Load, Capacity and Reserves Table - Summer

Summer Projections of Load, Capacity, and Reserves for Duke Energy Progress 2016 Annual Plan

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Load Forecast															
1 Duke System Peak	13,185	13,327	13,512	13,602	13,786	13,969	14,164	14,355	14,550	14,764	14,954	15,160	15,347	15,538	15,741
2 Firm Sale	150	150	150	150	150	150	150	150	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(58)	(93)	(128)	(158)	(187)	(216)	(245)	(272)	(301)	(329)	(353)	(368)	(374)	(374)	(376)
4 Adjusted Duke System Peak	**13,277**	**13,384**	**13,535**	**13,594**	**13,749**	**13,903**	**14,069**	**14,233**	**14,249**	**14,435**	**14,601**	**14,792**	**14,973**	**15,164**	**15,365**
Existing and Designated Resources															
5 Generating Capacity	12,873	12,805	12,812	12,820	12,531	12,535	12,535	12,537	12,698	12,698	12,698	12,518	12,518	12,518	11,777
6 Designated Additions / Uprates	88	7	8	495	4	0	2	161	0	0	0	0	0	0	0
7 Retirements / Derates	(156)	0	0	(784)	0	0	0	0	0	0	(180)	0	0	(741)	0
8 Cumulative Generating Capacity	**12,805**	**12,812**	**12,820**	**12,531**	**12,535**	**12,535**	**12,537**	**12,698**	**12,698**	**12,698**	**12,518**	**12,518**	**12,518**	**11,777**	**11,777**
Purchase Contracts															
9 Cumulative Purchase Contracts	**2,416**	**2,471**	**2,367**	**2,271**	**1,613**	**1,262**	**1,260**	**1,258**	**1,256**	**1,254**	**1,252**	**1,247**	**1,245**	**1,243**	**1,241**
Non-Compliance Renewable Purchases	341	396	460	509	558	535	533	531	528	526	524	522	520	518	517
Non-Renewables Purchases	2,075	2,075	1,907	1,762	1,054	727	727	727	727	727	727	724	724	724	724
Undesignated Future Resources															
10 Nuclear															
11 Combined Cycle						1,123									
12 Combustion Turbine							435			435		435	435		1,305
Renewables															
13 Cumulative Renewables Capacity	701	720	794	852	914	943	884	901	917	933	947	961	969	985	998
14 Combined Heat & Power	0	0	20	20	20	0	0	0	0	0	0	0	0	0	0
15 Cumulative Production Capacity	**15,922**	**16,002**	**16,000**	**15,695**	**15,121**	**15,923**	**16,298**	**16,475**	**16,488**	**16,937**	**16,770**	**17,214**	**17,654**	**16,928**	**18,244**
Demand Side Management (DSM)															
16 Cumulative DSM Capacity	**869**	**913**	**951**	**983**	**1,006**	**1,016**	**1,019**	**1,023**	**1,026**	**1,030**	**1,033**	**1,037**	**1,040**	**1,043**	**1,047**
17 Cumulative Capacity w/ DSM	**16,792**	**16,915**	**16,951**	**16,678**	**16,128**	**16,939**	**17,318**	**17,497**	**17,515**	**17,967**	**17,803**	**18,250**	**18,694**	**17,971**	**19,291**
Reserves w/ DSM															
18 Generating Reserves	3,514	3,531	3,416	3,084	2,379	3,036	3,248	3,264	3,266	3,532	3,202	3,458	3,721	2,807	3,926
19 % Reserve Margin	**26%**	**26%**	**25%**	**23%**	**17%**	**22%**	**23%**	**23%**	**23%**	**24%**	**22%**	**23%**	**25%**	**19%**	**26%**

DEP - Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Winter Projections of Load, Capacity, and Reserves table. All values are MW (winter ratings) except where shown as a Percent.

1. Planning is done for the peak demand for the Duke Energy Progress System.

2. Firm sale of 150 MW through 2024.

3. Cumulative energy efficiency and conservation programs (does not include demand response programs).

4. Peak load adjusted for firm sales and cumulative energy efficiency.

5. Existing generating capacity reflecting designated additions, planned uprates, retirements and derates as of January 1, 2016.

   Includes total unit capacity of jointly owned units.

6. Capacity Additions include:

   Planned nuclear uprates totaling 44 MW in the 2017-2024 timeframe.

   100 MW Sutton Blackstart combustion turbine addition in 2017.

   560 MW Asheville combined cycle addition in November 2019.

   Potential 186 MW Asheville combustion turbine addition in 2024.

7. Planned Retirements include:

   384 MW Asheville Coal Units 1-2 in November 2019.

   76 MW Sutton CT Units 1, 2A and 2B in 2017.

   645 MW Darlington CT Units 1-10 by 2020.

   232 MW Blewett CT Units 1-4 and Weatherspoon CT units 1-4 in 2027.

   Planning assumptions for nuclear stations assume retirement at the end of their current license extension.

   797 MW Robinson 2 in 2030.

DEP - Assumptions of Load, Capacity, and Reserves Table (cont.)

All retirement dates are subject to review on an ongoing basis. Dates used in the 2016 IRP are for planning purposes only, unless already planned for retirement.

8. Sum of lines 5 through 7.

9. Cumulative Purchase Contracts have several components:

   Purchased capacity from PURPA Qualifying Facilities, Anson and Hamlet CT tolling, Butler Warner purchase, Southern CC purchase, and Broad River CT purchase.

   Additional line items are shown under the total line item to show the amounts of renewable and traditional QF purchases.

   Renewables in these line items are not used for NC REPS compliance.

10. New nuclear resources selected to meet load and minimum planning reserve margin

    Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of the next year.

    No new nuclear resources were selected in the Base Case in the 15 year study period.

11. New combined cycle resources economically selected to meet load and minimum planning reserve margin.

    Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of the next year.

    Addition of 1,221 MW of combined cycle capacity online December 2021.

12. New combustion turbine resources economically selected to meet load and minimum planning reserve margin.

    Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of the next year.

    Addition of 468 MW of combustion turbine capacity in online in December of 2022, 2025, 2027, and 2028.

DEP - Assumptions of Load, Capacity, and Reserves Table (cont.)

Addition of 1,404 MW of combustion turbine capacity online December 2030.

13. Resources to comply with NC REPS along with solar customer product offerings such as Green Source and SC DER. Solar resources reflect 5% of nameplate capacity contribution at the time of winter peak demand and 44% of nameplate capacity contribution at the time of summer peak demand.

14. New 21.7 MW (winter) combined heat and power units included in 2019, 2020 and 2021. The 2016 IRP represents increased CHP resources as compared to the 2015 IRP.

15. Sum of lines 8 through 14.

16. Cumulative Demand Side Management programs including load control and DSDR.

17. Sum of lines 15 and 16.

18. The difference between lines 17 and 4.

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

    Line 18 divided by Line 4.

    Minimum target planning reserve margin is 17%.

A tabular presentation of the Base Case resource plan represented in the above LCR table is shown below:

Table 8-E DEP Base Case

Duke Energy Progress Resource Plan (1) Base Case - Winter		
Year	**Resource**	**MW**
2017	Nuclear Uprates	8
2018	Sutton Blackstart CT	100
2019	Nuclear Uprates	14
	CHP	22
2020	Nuclear Uprates	12
	Asheville CC	560
	CHP	22
2021	CHP	22
2022	Nuclear Uprates	6
	New CC	1221
2023	New CT	468
2024	Nuclear Uprates	4
	Potential Asheville CT	186
2025		
2026	New CT	468
2027		
2028	New CT	468
2029	New CT	468
2030		
2031	New CT	1404

Notes: (1) Table includes both designated and undesignated capacity additions
Future additions of renewables, EE and DSM not included

Additionally, a summary of the above table by fuel type is represented below in Table 8-F.

Table 8-F DEP Base Case Winter Resources by Fuel Type

DEP Base Case Resources
Cumulative Winter Totals - 2017 - 2031

Nuclear	44
CC	1781
CT	3562
CHP	66
Total	5453

The following charts illustrate both the current and forecasted capacity by fuel type for the DEP system, as projected by the Base Case. As demonstrated in Chart 8-B, the capacity mix for the DEP system changes with the passage of time. In 2031, the Base Case projects that DEP will have a smaller reliance on coal, nuclear and external purchases and a higher reliance on gas-fired resources, renewable resources and EE as compared to the current state. It should be noted that the Company's Base Case resources depicted in Chart 8-B below reflect a significant amount of solar capacity with nameplate solar growing from 1,710 MW in 2017 to 3,270 MW by 2031. However, given that solar resources only contribute 5% of nameplate capacity at the time of the Company's winter peak, solar capacity contribution to winter peak only grows from 85 MW in 2017 to 163 MW by 2031.

Chart 8-B Duke Energy Progress Capacity by Fuel Type – Base Case[4]

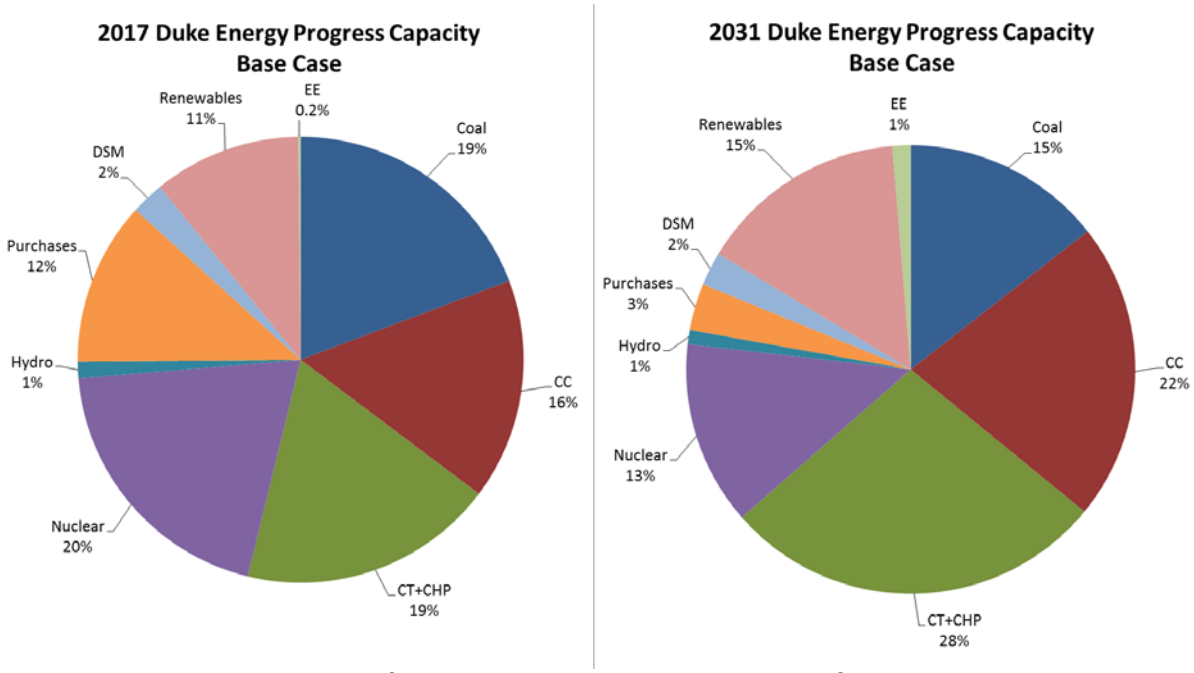
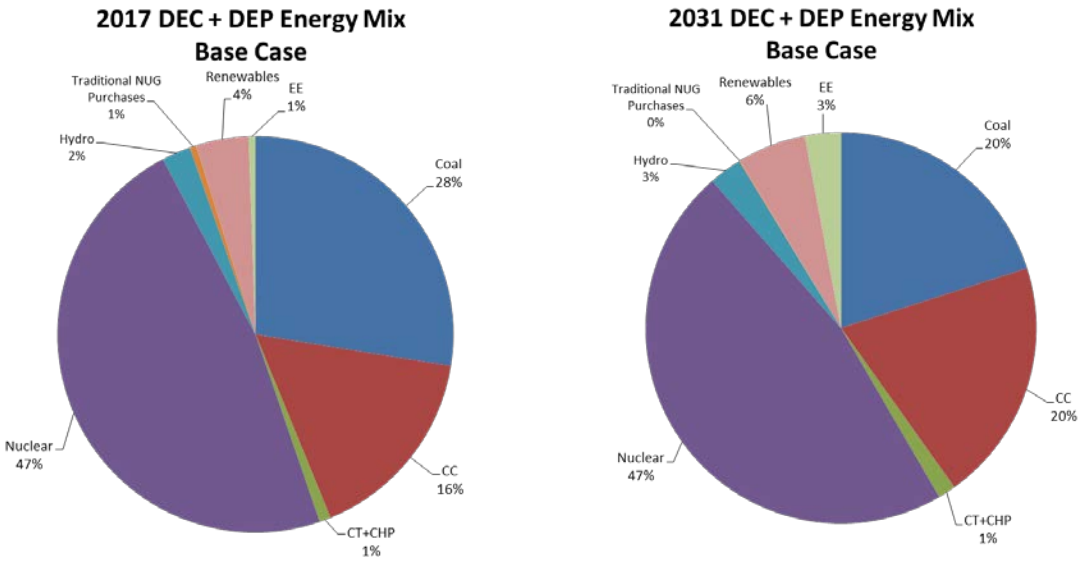


Chart 8-C represents the energy of the DEP and DEC Base Cases by fuel type. These energy charts represent both the DEP and DEC base cases. Due to the joint dispatch agreement (JDA), it is prudent to combine the energy of both utilities to develop a meaningful base case energy chart. From 2017 to 2031, the chart shows that nuclear resources will continue to serve almost half of DEC and DEP energy needs, a reduction in the energy served by coal, and an increase in energy served by natural gas, renewables and EE.

[4] Capacity based on winter ratings (renewables based on nameplate)

Chart 8-C DEP and DEC Energy by Fuel Type – Base Case



A detailed discussion of the assumptions, inputs and analytics used in the development of the Base Case is contained in Appendix A. As previously noted, the further out in time planned additions or retirements are within the 2016 IRP the greater the opportunity for input assumptions to change. Thus, resource allocation decisions at the end of the planning horizon have a greater possibility for change as compared to those earlier in the planning horizon.

System Carbon Mass Cap Case

The System Carbon Mass Cap Case assumes that total system CO_2 emissions are constrained starting in 2022 and decline until 2030, and total system emission are held flat from 2030 throughout the remaining planning horizon. In order to hold system emissions flat, new nuclear generation, along with re-licensing or replacement of existing nuclear generation, is required in the early 2030s. To this point, additional new nuclear generation is required between the retirement of Robinson Nuclear Plant in 2030 and Brunswick 2 Nuclear Plant in 2035. Additionally, incremental solar generation begins to be economically selected (without inclusion of integration costs) just beyond the planning horizon shown in Table 8-G. It should be noted that the expansion planning model does not incorporate incremental solar integration costs when selecting resources, however these costs are added later when calculating the total PVRR of the resource plan.[5]

[5] Solar integration costs represented in the Duke Energy Photovoltaic Integration Study published by Pacific Northwest National Lab in March 2014.

Table 8-G DEP System Carbon Mass Cap Case

Duke Energy Progress Resource Plan [1] System Mass Cap - Winter						
Year	**Resource**			**MW**		
2017	Nuclear Uprates			8		
2018	Sutton Blackstart CT			100		
2019	Nuclear Uprates	CHP		14	22	
2020	Nuclear Uprates	Asheville CC	CHP	12	560	22
2021	CHP			22		
2022	Nuclear Uprates	New CC		6	1221	
2023	New CT			468		
2024	Nuclear Uprates	Potential Asheville CT		4	186	
2025						
2026	New CT			468		
2027						
2028	New CT			468		
2029	New CT			468		
2030						
2031	New CC			1221		

Notes: (1) Table includes both designated and undesignated capacity additions
Future additions of renewables, EE and DSM not included

Additionally, a summary of the above table by fuel type is represented below in Table 8-H.

Table 8-H DEP System Carbon Mass Cap Case Winter Resources by Fuel Type

DEP System Mass Cap Resources Cumulative Winter Totals - 2017 - 2031	
Nuclear	44
CC	3002
CT	2158
CHP	66
Total	5270

A detailed discussion of the assumptions, inputs and analytics used in the development of the System Mass Cap Case is contained in Appendix A. As previously noted, the further out in time planned additions or retirements are within the 2016 IRP the greater the opportunity for input assumptions to change. Thus, resource allocation decisions at the end of the planning horizon have a greater possibility for change as compared to those earlier in the planning horizon.

Joint Planning Case

A Joint Planning Case that begins to explore the potential for DEP and DEC to share firm capacity between the Companies was also developed. The focus of this case is to illustrate the potential for the Utilities to collectively defer generation investment by utilizing each other's capacity when available and by jointly owning or purchasing new capacity additions. This case does not address the specific implementation methods or issues required to implement shared capacity. Rather, this case illustrates the benefits of joint planning between DEP and DEC with the understanding that the actual execution of capacity sharing would require separate regulatory proceedings and approvals.

Table 8-I below represents the annual non-renewable incremental additions reflected in the combined DEP and DEC winter Base Cases as compared to the Joint Planning Case. The plan contains the undesignated additions for DEP and DEC over the planning horizon. As presented in Table 8-I, the Joint Planning Case allows for the delay of several blocks of CT resources through the 15-year study period.

Table 8-I Joint Planning Case

DEC and DEP Combined Resource Plan (1) Base Case - Winter				
Year	Resource		MW	
2017				
2018				
2019				
2020				
2021				
2022	New CC		1221	
2023	New CC	New CT	1221	468
2024				
2025	New CT		468	
2026				
2027	New Nuclear	New CT	1117	468
2028	New CT		468	
2029	New Nuclear	New CT	1117	468
2030				
2031	New CT		1404	

Delay & Combine

Delay

Beyond Study Period

DEC and DEP Joint Planning Resource Plan (1) Base Case - Winter		
Year	Resource	MW
2017		
2018		
2019		
2020		
2021		
2022	New CC	1221
2023	New CC	1221
2024		
2025		
2026	New CT	936
2027	New Nuclear	1117
2028	New CT	468
2029	New Nuclear	1117
2030		
2031	New CT	1872

Notes: (1) Table only includes undesignated capacity additions.

A comparison of both the DEP and DEC Combined Base Case and Joint Planning Base Case by fuel type is represented below in Table 8-J.

Table 8-J DEC and DEP Base Case and Joint Planning Case Comparison by Fuel Type

DEP and DEC Combined Base Case Resources

Cumulative Winter Totals - 2017 - 2031

Nuclear	2234
CC	2442
CT	3744
Total	8420

DEP and DEC Joint Base Case Resources

Cumulative Winter Totals - 2017 - 2031

Nuclear	2234
CC	2442
CT	3276
Total	7952

9. SHORT-TERM ACTION PLAN

The Company's Short-Term Action Plan, which identifies accomplishments in the past year and actions to be taken over the next five years, is summarized below:

Continued Planning to Include Consideration of Winter Peaks

As the Company looks forward, the planning focus will include consideration of winter peak demand based upon resource adequacy study results. As additional summer-oriented resources such as solar are added to both the DEP and DEC systems, it will be important to maintain a focus on the impacts of these resources to the winter peak and the operational requirements of the system.

Continued Reliance on EE and DSM Resources:

The Company is committed to continuing to grow the amount of EE and DSM resources utilized to meet customer growth. The following are the ways in which DEP will increase these resources:

- Continue to execute the Company's EE and DSM plan, which includes a diverse portfolio of EE and DSM programs spanning the residential, commercial, and industrial classes.

- Continue on-going collaborative work to develop and implement additional cost-effective EE and DSM products and services.

- Continue to seek enhancements to the Company's EE/DSM portfolio by: (1) adding new or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new measurement and verification (M&V) results and (3) other EE research & development pilots.

- Continue to seek additional DSM programs that will specifically benefit during winter peak situations.

Continued Focus on Renewable Energy Resources:

DEP is committed to full compliance with NC REPS in North Carolina and to explore least cost options to add renewable resources in South Carolina pursuant to supportive distributed energy resource legislation in that state. Due to Federal and State subsidies for solar developers, the Company is experiencing a substantial increase in solar QFs in the interconnection queue. With this level of interest in solar development, DEP will likely obtain additional solar generation on its

system regardless of the need for such energy. This level of solar being put to the DEP grid presents certain integration challenges to the generation portfolio and T&D grid as referenced in Chapter 5.

In 2015, DEP received approval for SC DER which includes a portfolio of initiatives designed to increase the capacity of renewable generation located in South Carolina's service area. The program contains three tiers; each is equivalent to 1% of the Company's estimated average South Carolina retail peak demand (or 13 MW of nameplate solar capacity). The first tier of SC DER is comprised of a combination of utility scale PPA's and ~1 MW shared solar facilities. The second tier of SC DER is met via behind the meter net rooftop solar for residential, commercial, and industrial customers. Since tier 2 is behind the meter, the expected solar generation is embedded in the load forecast as a reduction to expected load. Upon completion of tiers 1 and 2 (to occur no later than 2021), the legislation calls for the utility to directly invest in additional solar generation to complete tier 3 which DEP contemplates doing in 2019.

DEP continues to evaluate market options for renewable generation and procure capacity, as appropriate. PPAs have been signed with developers of solar PV and landfill gas. Also, REC purchase agreements have been executed for purchases of unbundled RECs from wind, solar PV, solar thermal and hydroelectric facilities. Additionally, shared solar programs and utility-owned solar continue to be considered.

Addition of Clean Natural Gas Resources:

- Continue to evaluate older CTs on the DEP system. The Company is evaluating the condition and economic viability of the older CTs on the system. In doing so, DEP is preparing for the potential retirement of these units. This includes determining the type of resources needed to reliably replace these units to maintain a minimum planning reserve margin.

  - Sutton Units 1, 2A and 2B (76 MW/61 MW (winter/summer)) are planned for retirement in 2017. A Certificate of Public Convenience and Necessity (CPCN) has been received for the units to be replaced with two LM6000 CT units expected online June 30, 2017.

- Take actions to ensure capacity needs beginning in 2022 are met. In addition to seeking to meet the Company's EE and DSM goals, meeting the Company's NC REPS requirements and SC DER projections actions to secure additional capacity may include purchased power or Company-owned generation. he 2016 IRP projects that the best resource to meet this demand is a combined cycle unit.

Western Carolinas Modernization Plan (WCMP)

The Western Carolinas Modernization Project allows for the early retirement of the Asheville Plant coal-fired units. The generation will be replaced with:

- Two new 280-megawatt combined cycle natural gas-fueled units.
- One contingent natural gas-fueled 186-megawatt simple cycle combustion turbine unit in 2023 timeframe subject to potential deferral or elimination as subsequently discussed.
- New solar generation at the Asheville plant site.

Additionally, Duke Energy Progress is committed to partnering with the community and elected leaders to reduce energy use by:

- Providing increased promotion of and access to new and existing EE/DSM programs.
- Making deliberate investment in distributed energy resources, including at least 15 megawatts of solar energy and at least 5 megawatts of energy storage.
- Delivering products and services customers value and help them connect with the role they play in this important work, through active community engagement.

The goal of this work is twofold:

1. To transition western North Carolina to a cleaner, smarter and more reliable energy future.
2. To delay or avoid the construction of the contingent combustion turbine.

This is significant work and success requires dedicated leadership and commitment. A partnership between Duke Energy Progress, Buncombe County, and the City of Asheville has been formed to develop innovative energy solutions to meet the area's growing energy needs and avoid the construction of the contingent combustion turbine. If successful, this collaboration could present an opportunity to create a replicable model for other communities and utilities to work together to build a smarter and cleaner energy future.

The cornerstone of this partnership was created by joint resolution between the City of Asheville and Buncombe County, fully endorsed by Duke Energy, to co-convene the Energy Innovation Task Force (EITF). Members of the EITF represent a wide array of community interests with one key attribute in common – a desire for a smarter, cleaner and more reliable energy future.

To jumpstart the EITF, task force leaders, including Duke Energy, participated in Rocky Mountain

Institute's (RMI) third annual eLab Accelerator in April 2016. Together, they created an initial work plan, milestones and immediate next steps.

Since eLab Accelerator, the EITF has convened and is rapidly moving forward to create a longer-term work plan in early 2017. The plan is expected to leverage utility expertise, programs, and investments; city and county resources; actions by EITF member constituencies; the outreach and engagement capacity of community groups; and capabilities and knowledge of national experts.

This work has become a foundation for community collaboration and successful implementation of the Western Carolinas Modernization Project.

Continued Focus on Environmental Compliance and Wholesale:

- Retire older coal generation. As of December 2013, all of DEP's older, un-scrubbed coal units have been retired. DEP has retired 1,700 MW/1,600 MW (winter/summer) of older coal units in total since 2011.[6]

- Retire older CT generation. As of December 2013, DEP has retired approximately 250 MW/200 MW (winter/summer) of older CT generation. The Company is evaluating the condition and economic viability of the older CTs. In doing so, DEP is preparing for the retirement of additional older CT unit in the near future. Darlington Unit 11 was retired in November 2015. Sutton Units 1, 2A and 2B are expected to retire by 2017 while Darlington Units 1-10 are expected to retire by 2020.

- Continue to investigate the future environmental control requirements and resulting operational impacts associated with existing and potential environmental regulations such as EPA's Clean Power Plan (Section 111d of Clean Air Act regulating CO_2 from existing power plants), Mercury Air Toxics Standard (MATS), the Coal Combustion Residuals (CCR) rule, the Cross State Air Pollution Rule (CSAPR) and the new Ozone National Ambient Air Quality Standard (NAAQS).

- Continue to pursue existing and potential opportunities for wholesale power sales agreements within the Duke Energy balancing authority area.

[6] The ultimate timing of unit retirements can be influenced by factors changing the economics of continued unit operations. Such factors include changes in relative fuel prices, operations and maintenance costs and the costs associated with compliance of evolving environmental regulations. As such, unit retirement schedules are expected change over time as market conditions change.

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

- Continue to examine the benefits of joint capacity planning and pursue appropriate regulatory actions.

A summarization of the capacity resource changes for the reference plan in the 2016 IRP is shown in Table 9-A below. Capacity retirements and additions are presented as incremental values in the year in which the change impacts the winter peak. The values shown for renewable resources, EE and DSM represent cumulative totals.

Table 9-A DEP Short-Term Action Plan

Duke Energy Progress Short-Term Action Plan[1]						
			Compliance Renewable Resources (Cumulative Nameplate MW)			
Year	Retirements[2]	Additions	Solar [3]	Biomass/Hydro	EE	DSM [4]
2017		8 MW Nuc Uprate	1114	211	31	445
2018	76 MW Sutton 1, 2A, 2B	100 MW Sutton CT Repl	1270	161	59	462
2019		14 MW Nuc Uprate	1438	161	85	477
2020	384 MW Asheville 1-2 645 MW Darlington CT	560 MW Asheville CC 12 MW Nuc Uprate	1582	156	110	490
2021			1721	156	144	503

Notes:

(1) Capacities shown in winter ratings unless otherwise noted.

(2) Darlington Units 1-10 assume to retire March 2020. Darlington 4 & 6 are currently offline and are represented as a derate through 2020 until retirement.

(3) Capacity is shown in nameplate ratings. For planning purposes, solar has a 5% contribution to winter peak.

(4) Includes impacts of grid modernization.

DEP Request for Proposal (RFP) Activity

Supply-Side

No supply-side RFPs have been issued since the filing of DEP's 2015 IRP.

Renewable Energy

Duke Energy Distributed Energy Resource Solar RFP – South Carolina

Shared Solar Program RFP

A Shared Solar Program RFP was released on August 20, 2015, to solicit for up to 5 MW_{AC} (4 MW_{AC} in DEC/1 MW_{AC} in DEP) of solar PV facilities that would provide power and associated energy certificates within the DEP and DEC service territories in the state of South Carolina. Executed contracts in response to this RFP will be utilized to comply with the Duke Energy's "Shared Solar Program" under the South Carolina Distributed Energy Resource Program Act.

The RFP's interest was in solar PPAs and turnkey asset purchase proposals with a nameplate capacity sized > 250 kilowatts (kW_{AC}) but no greater than 1 MW_{AC}. Proposals must be directly connected to the DEP or DEC transmission or distribution system in South Carolina. Projects must be in-service and capable of delivering fully rated output by December 31, 2016. PPA contract durations shall be a 10 year term.

Respondents were notified, February 22, 2016 of their proposal status and if they had been selected as a proposal of interest.

Proposals of interest were allowed to refresh bid pricing following the completion of DEP/DEC estimated interconnection costs. Proposals of interest are currently in varying stages of negotiations and contract execution.

Utility Scale Solar Program RFP

A Utility Scale Program RFP was released on August 20, 2015, to solicit 40 MW_{AC} in DEC and 13 MW_{AC} in DEP of solar PV facilities that would provide power and associated renewable energy certificates within the DEP and DEC service territories in South Carolina. Executed contracts in response to this RFP will be utilized to comply with the Duke Energy's "Utility Solar Program" under the South Carolina Distributed Energy Resource Program Act.

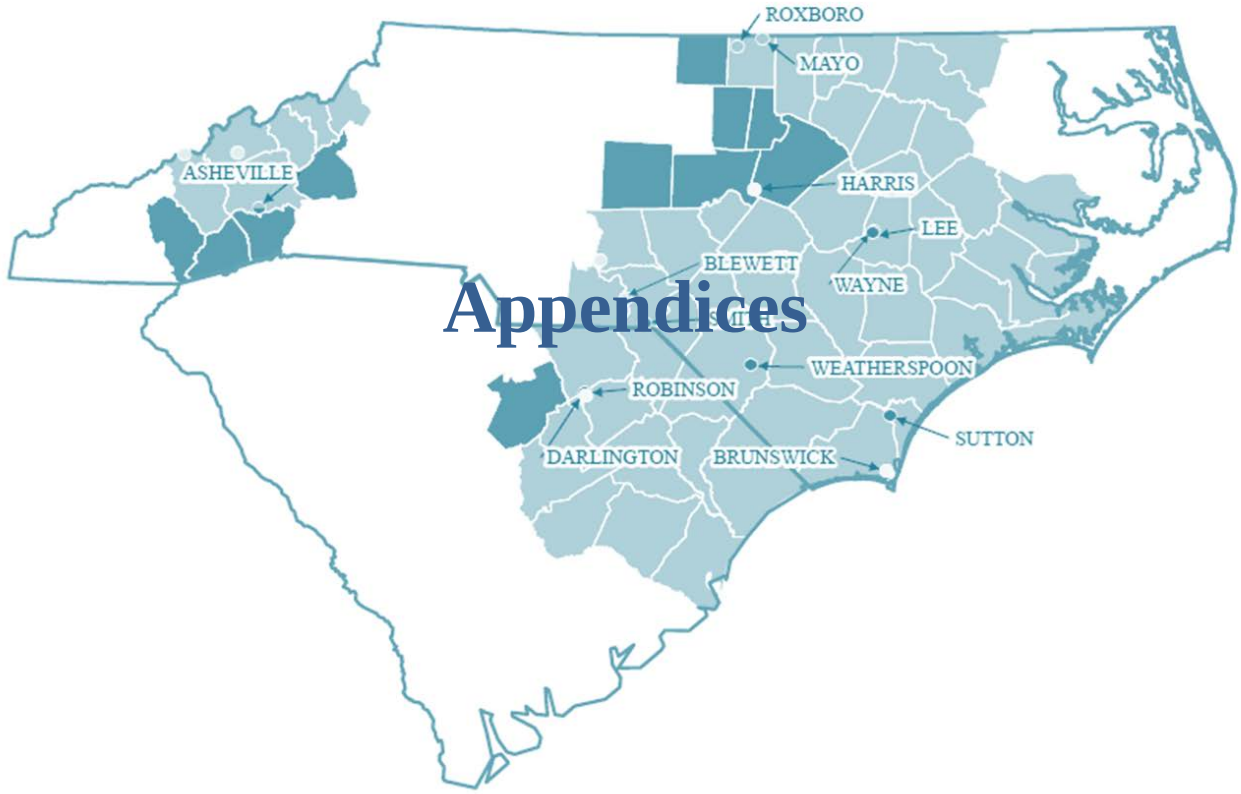
The RFP's interest was in solar PPAs and Turnkey asset purchase proposals with a nameplate capacity sized > 1 MW_{AC} and up to 10 MW_{AC}. Proposals must be directly connected to the DEP or DEC transmission or distribution system in South Carolina. Projects must be in-service and capable of delivering fully rated output by December 31, 2016. PPA contract durations shall be a 15 year term.

Respondents were notified, February 22, 2016 of their proposal status and if they had been selected as a proposal of interest.

Proposals of interest were allowed to refresh bid pricing following the completion of DEP/DEC estimated interconnection costs.

Proposals of interest are currently in varying stages of negotiations and contract execution.

DUKE ENERGY®
PROGRESS



Appendices

APPENDICES TABLE OF CONTENTS:

SECTION: **PAGE:**

APPENDIX A: QUANTITATIVE ANALYSIS

This appendix provides an overview of the Company's quantitative analysis of the resource options available to meet customers' future energy needs. Sensitivities on major inputs resulted in multiple portfolios that were then evaluated under several scenarios that varied fuel prices, capital costs, and CO_2 constraints. These portfolios were analyzed using a least cost analysis to determine the Base Case for the 2016 IRP. The selection of this plan takes into account the cost to customers, resource diversity and reliability and the long-term carbon intensity of the system.

The future resource needs were optimized for DEP and DEC independently. However, an additional case representative of jointly planning future capacity on a DEP/DEC combined system basis using the Base Case assumptions was also analyzed to demonstrate potential customer savings, if this option was available in the future. Resource capacities discussed in this appendix reflect winter ratings and new resource additions are assumed online in January of the year indicated unless otherwise noted.

A. Overview of Analytical Process

The analytical process consists of four steps:

1. Assess resource needs
2. Identify and screen resource options for further consideration
3. Develop portfolio configurations
4. Perform portfolio analysis over various scenarios

1. Assess Resource Needs

The required load and generation resource balance needed to meet future customer demands was assessed as outlined below:

- Customer peak demand and energy load forecast – identified future customer aggregate demands to determine system peak demands and developed the corresponding energy load shape. Post-2020 consideration was also given to increased energy prices associated with a carbon constrained future.
- Existing supply-side resources – summarized each existing generation resource's operating characteristics including unit capability, potential operational constraints and life expectancy.

- Operating parameters – determined operational requirements including target planning reserve margins and other regulatory considerations.

Customer load growth, the expiration of purchased power contracts and additional asset retirements result in significant resource needs to meet energy and peak demands in the future. The following assumptions impacted the 2016 resource plan:

- Peak Demand and Energy Growth - The growth in winter customer peak demand including the impacts of energy efficiency averaged 1.3% from 2017 through 2031. The forecasted compound annual growth rate for energy consumption is 0.9% after the impacts of energy efficiency programs are included.
- Generation
    - Nuclear units uprates totaling 44 MW by 2024 at Brunswick and Harris plants.
    - Completion of the 100 MW Sutton LM 6000 CT (two units) in June 2017.
    - Completion of the 560 MW Asheville CC (two units) in November 2019.
    - Completion of the potential 186 MW Asheville CT in 2024, dependent upon success of EE initiatives.
- Retirements
    - Asheville Coal Units 1 & 2 located in Arden, NC, totaling 384 MW by 2020
    - Sutton CT Units 1, 2A and 2B, located in Wilmington, NC, totaling 76 MW in June 2017
    - Darlington CT Units 1 - 10, located in Darlington County, SC, totaling 645 MW by 2020
    - Blewett CT Units 1 – 4, located in Lilesville, NC, totaling 68 MW by 2027
    - Weatherspoon CT Units 1 – 4, located in Lumberton, NC, totaling 164 MW by 2027
    - Robinson 2 Nuclear Plant located in Hartsville, SC totaling 797 MW by June 2030

- Reserve Margin - A 17% minimum winter planning reserve margin for the planning horizon

2. Identify and Screen Resource Options for Further Consideration

The IRP process evaluated EE, DSM and traditional and non-traditional supply-side options to meet customer energy and capacity needs. The Company developed EE and DSM projections based on existing EE/DSM program experience, the most recent market potential study, input from its EE/DSM collaborative and cost-effectiveness screening for use in the IRP. Supply-side options reflect a diverse mix of technologies and fuel sources (gas, nuclear and renewable). Supply-side options are initially screened based on the following attributes:

- Technical feasibility and commercial availability in the marketplace
- Compliance with all Federal and State requirements
- Long-run reliability
- Reasonableness of cost parameters

The Company compared the capacity size options and operational capabilities of each technology, with the most cost-effective options of each being selected for inclusion in the portfolio analysis phase. An overview of resources screened on technical basis and a levelized economic basis is discussed in Appendix F.

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 (winter ratings):

- Baseload – 2 x 1,117 MW Nuclear units (AP1000)
- Baseload – 1,221 MW – 2 x 1 Advanced Combined Cycle (Duct Fired)
- Baseload – 22 MW – Combined heat and power
- Peaking/Intermediate – 468 MW – 2 x 7FA.05 CTs
    - (Based upon the cost to construct 4 units, available for brownfield sites only)
- Peaking/Intermediate – 936 MW – 4 x 7FA.05 CTs
- Renewable – 5 MW – Solar PV

Energy Efficiency and Demand-Side Management

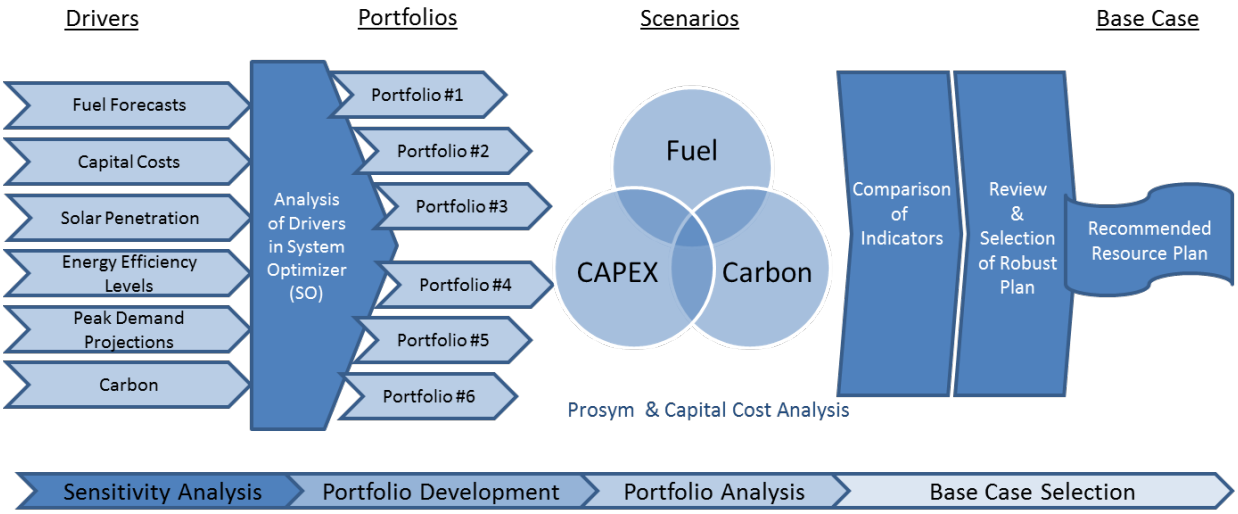
EE and DSM programs continue to be an important part of Duke Energy Progress' system mix. The Company considered both EE and DSM programs in the IRP analysis. As described in Appendix D, EE and DSM measures are compared to generation alternatives to identify cost-effective EE and DSM programs.

The Base Case EE/DSM savings contained in this IRP were projected by blending near-term program planning forecasts into the long-term achievable potential projections from the market potential study

3. Develop Portfolio Configurations

Once the load and generation balance was assessed, and resource options were screened, the portfolios and scenarios were developed, and the preferred base cases were selected, based on the following simplified diagram.

Figure A-1: Simplified Process Flow Diagram for Development and Selection of Base Case



The Company conducted a sensitivity analysis of various drivers using the simulation modeling software, *System Optimizer* (SO). The expansion plans produced by SO were compared and six portfolios that encompass the impact of the range of input sensitivities evaluated were identified[7]. An overview of the base planning assumptions and sensitivities considered is outlined below:

- Impact of potential carbon constraints
  - Portfolios were evaluated under scenarios that included the impacts of potential future carbon emission regulations. The final rule of the Clean Power Plan was published in the Federal Register October 23rd, 2015 which aims to reduce CO_2 emissions from existing electric utility stationary sources. The Supreme Court granted a stay of this rule February 9th 2016 pending challenges from state and industry groups to the U.S. Court of Appeals for the D.C. Circuit. There is much

[7] An additional portfolio (No CO_2 constraints) was also developed, but was not evaluated as a potential base case portfolio through the Portfolio Analysis process.

uncertainty regarding the final outcome and timing of this rule but for the purposes of this IRP the CPP was used as a basis for evaluating potential impacts of carbon constraints. Two potential outcomes of the CPP were evaluated to provide guidance on the impact to existing, and potentially future units, over the planning horizon:

- Carbon Constraint #1: Carbon Tax – Incorporated an intrastate CO_2 tax starting in 2022 that was applied to existing coal and gas units.

- Carbon Constraint #2: System Mass Cap – An alternate means of compliance for CPP in which total system CO_2 emissions were constrained starting in 2022 and declined until 2030. Total system emission were held flat from 2030 throughout the planning horizon.

- An additional sensitivity without any carbon restrictions (no Carbon Tax, no System Mass Cap) was also performed.

- Retirements

  - Coal assets – For the purpose of this IRP, the depreciation book life was used as a placeholder for future retirement dates for coal assets, unless otherwise noted. Based on this assumption, Asheville Coal Units 1 & 2 were retired in November 2019 consistent with the Company's CPCN to replace the generation with new combined cycle units.

  - Nuclear assets – Currently, nuclear sites are licensed for 40 years with a 20 year license extension beyond that. To date, no nuclear units in the United States have received a license extension beyond 60 years. Robinson Nuclear Station's current operating license has been extended to 60 years and expires in 2030. For the purpose of this IRP, the Robinson Station is assumed to retire in 2030.

    - A sensitivity was performed assuming an additional 20 year license renewal of existing nuclear units at the end of the current license life of 60 years.

  - Combustion Turbines – Based on a prior condition assessment for the older CTs in the DEP system it was determined that the Sutton CTs need to be retired by 2017 and Darlington Units 1 through 11 by 2020. Due to reliability concerns,

Darlington Units 4 and 6 are not counted on to contribute capacity to the DEP system throughout the planning horizon. Additionally, Darlington 11 was retired in November 2015. The Blewett and Weatherspoon CTs are expected to be retired in 2027.

- Coal and natural gas fuel prices
  - Short-term pricing: Natural gas prices were based on market observations from 2017 through 2026 transitioning to fundamental prices by 2032. Coal prices were based on market observations from 2017 through 2021 transitioning to fundamental prices by 2027.
  - Long-term pricing: Based on the Company's fundamental fuel price projections.
    - Sensitivities - A high fuel sensitivity was performed where the average Compound Annual Growth Rate (CAGR) for coal and gas was increased by 0.5% through 2035 and a low fuel sensitivity where the average CAGR for coal and gas was decreased by 1% CAGR through 2035.
- Capital Cost Sensitivities
  - All Assets (Nuclear, CC/CT, Renewables)
    - High Capital – Increased the inflation rate from 2.5% to 4%.
    - Low Capital – Decreased the inflation rate from 2.5% to 1%.
  - Renewables Only: Solar facility costs continue to decrease through 2020 with a 30% Federal ITC through 2019, 26% ITC in 2020, 22% ITC in 2021 and 10% ITC thereafter.
    - Low Cost - To determine if a lower cost would impact the economic selection of additional solar resources, a capital cost sensitivity was performed where solar prices continue to decrease through 2025 with the same ITC assumptions as in the Base Case.

- Renewable Penetration

  - Base Penetration - Resources to comply with NC REPS along with solar customer product offerings such as Green Source and SC DER were input as existing resources. As described in Chapter 5, qualified facilities that the Company is required to purchase under PURPA and who do not sell renewable energy certificates to the Company are captured as non-compliance renewable purchases in the IRP as well. Below is an overview of the solar base planning assumptions and the sensitivities performed:

    - Higher Solar Penetration – To assess the impact if additional, non-compliance solar resources were installed on the system beyond the Base Case. The amount of base solar was increased by 789 MW by 2031.

    - Low Solar Penetration – To assess the potential impact of lower solar penetration levels due to lower fuel prices for more traditional generation technologies, higher solar installation and interconnection costs, lower avoided costs, and/or less favorable PURPA terms. The amount of base solar was decreased by 235 MW by 2031.

    - Under the System CO_2 Mass Cap paradigm, additional economic solar was allowed to be selected up to 10% of the total system energy. Incremental solar integration costs were added as a capital cost based on total solar added to the system *after* economic selection in SO.[8]

- Energy Efficiency

  - Base EE corresponds to the Company's current projections for achievable cost-effective EE program acceptance.

    - High EE – The high case EE/DSM savings included in the IRP modeling assumed a 50% increase in participation for the majority of the Base Case programs as further explained in Appendix D. By 2031, this accounts for an additional 173 MW reduction in total winter load.

- Nuclear Selection – New generic nuclear was included as a resource option in both the Carbon Tax and the System Mass Cap portfolios.

[8] Solar integration costs represented in the Duke Energy Photovoltaic Integration Study published by Pacific Northwest National Lab in March 2014.

  - A sensitivity was performed assuming a combination of higher penetration of solar (High Solar Penetration as described above) and a higher penetration of EE (High EE as described above) under a System Mass Cap restriction. The purpose of the sensitivity was to determine the impact on additional economically selected nuclear generation.

- High and Low Load – Sensitivities were performed assuming changes in load of +6.5% starting in 2021 for High Load and – 6.5% for Low Load on average through 2031.

- A sensitivity was performed assuming joint planning with DEP and DEC to demonstrate the benefits of shared resources and how new generation could be delayed. .

Results

A review of the results from the sensitivity analysis yielded some common themes.

Initial Resource Needs

- 2017 - The 2016 IRP reflects the replacement of the existing Sutton CTs with two LM6000 dual-fueled, fast start, black start CTs totaling 100 MW. The new CTs are scheduled to be in-service in June 2017.

- 2019 – Asheville Units 1 and 2 are being retired in November 2019 and replaced with two CCs with combined generation of 580 MW.

- 2021 - The first resource need in DEP other than the fast start CTs and the Asheville CCs listed above is 2022. Combined cycle generation was selected optimally for the in all sensitivities except for the low load sensitivity. In the low load sensitivity the CC was delayed from 2022 to 2023.

- One Balancing Authority - The first resource needs are CCs, one in DEP in 2022 and one in DEC in 2023. When planning as One Balancing Authority the DEP and DEC CCs are not delayed but the 2023 CT need in DEP and the 2025 CT need in DEC are delayed until 2026.

New Nuclear Selection – The Carbon Tax only applies to existing coal and gas generation and new nuclear does not have a carbon advantage over new CC generation. Without a carbon advantage new nuclear is not economically selected, however system carbon emission continue increase into the future. In the System Mass Cap constrained cases, additional generic nuclear is needed 2034 timeframe to maintain flat CO_2 emissions after 2030. In the

sensitivity with the inclusion of higher EE and higher renewables the additional generic nuclear is still needed in 2034.

Gas Firing Technology Options – In general, the first need was shown to be best met with CC generation, followed by CT generation through 2030. Only in the High Load sensitivity was additional CC selected during this timeframe.

Renewable Generation – In the cases developed under a Carbon Tax paradigm, no additional solar generation in excess of the base assumptions was selected. This was due in part due to the significant level of solar already in the Base Case resource plan which reduces the value of incremental solar on the system. In the low cost solar sensitivity where prices continued to decrease until 2026, additional economic solar was selected in several years beyond the study period. In the System Mass Cap paradigm, additional economic solar was selected in the early 2030s timeframe until 10% of the total energy was met with solar generation.

- *High Renewables* – A sensitivity was performed using the High Renewable case in the Carbon Tax paradigm. The inclusion of increased implementation cost associated with high renewables resulted in a higher revenue requirement than the base expansion plan.

High EE – A sensitivity was performed using the High EE case in the Carbon Tax paradigm. Within the 15 year planning horizon the only change to the expansion plan was a delay in the 2029 CT need to 2030, and a 2031 CT need to 2032. The inclusion of increased implementation cost associated with high EE resulted in a higher revenue requirement than the base expansion plan.

High EE and Renewables – In the System Mass Cap paradigm, a sensitivity was performed with a combination of High EE and Renewables to test the impact on new nuclear generation. The generic nuclear remained in 2035, however a CC need in the early 2030s was delayed several years.

Portfolio Development

Using insights gleaned from the sensitivity analysis, six portfolios were developed. These portfolios were developed in order to assess the relative value of various generating technologies including CCs, CTs, Renewables, and Nuclear, as well as, EE under multiple scenarios. Portfolios 1 – 4 were developed under a Carbon Tax paradigm where varying levels of an intrastate CO_2 tax were applied to existing coal and gas units as envisioned in EPA's CPP. Portfolios 5 and 6 were developed under a System CO_2 Mass Cap that represented an alternative outcome of the CPP. It should be noted that while Portfolios 5 and

6 could meet the requirements of the Carbon Tax constraints, Portfolios 1 – 4 would not meet the CO_2 system mass cap. A description of the six portfolios follows:

Portfolio 1 (Base Case)
This portfolio represents the majority of expansions plans identified through the SO analysis. While CCs are the preferred initial generating option in both DEP and DEC, CTs make up the majority of additional resources added over the 15 year planning horizon. This portfolio includes base EE and renewable assumptions.

Portfolio 2 (High Renewables, Base EE)
This portfolio includes high renewables capacity through the planning period. In DEP, the high renewables assumption has the effect of delaying a 2031 CT need by one year in the 15 year planning horizon. Beyond the 15 year horizon, a CC and additional CTs are delayed by one to two years with increased renewable capacity. This portfolio also includes base EE assumptions.

Portfolio 3 (High EE, Base Renewables)
This portfolio includes high EE targets through the planning period. The high EE assumption has the effect of delaying the 2029 CT need and a 2031 CT need by one year in the 15 year planning horizon. This portfolio also includes base renewable assumptions.

Portfolio 4 (CC centric, Base EE/Renewables)
This portfolio replaces a grouping of CTs in the mid 2020's with a single CC in 2026 along with replacing a grouping of CTs in 2031 with a single CC in the same year. This portfolio includes base renewable and base EE assumptions.

Portfolio 5 (System Mass Cap – Additional nuclear generation, Base EE/Renewables)
This portfolio was developed under a System Mass Cap carbon constraint. This expansion plan is similar to Portfolio #1 through 2029, however a group of CTs in the early 2030s are replaced by a single CC in 2031. Additionally, one new nuclear unit is shown in 2035 in DEP and one new nuclear unit, in addition to Lee Nuclear, is also required in DEC to meet the carbon constraint. This portfolio includes base renewable and base EE assumptions plus additional economically selected solar in the 2030s.

Portfolio 6 (System Mass Cap –Additional nuclear generation, High EE/Renewables)
Similar to Portfolio #5, this portfolio was developed under a System Mass Cap carbon constraint. This portfolio includes both high EE targets and high renewables assumptions. Through 2031, this expansion plan converts a 2031 CC need from Portfolio #5 to a CT need,

and continues to show a new nuclear plant in 2035 in DEP and one new nuclear plant, in addition to Lee Nuclear, in DEC. Additional economic solar is not selected before 2035.

An overview of the resource needs of each portfolio are shown in Table A-1 below. The amount of solar in each portfolio is summarized in Table A-2.

Table A-1 Duke Energy Progress Portfolio Summary Plans

Year	Portfolio #1 (CT Centric)	Portfolio #2 (High Renewable)	Portfolio #3 (High EE)	Portfolio #4 (High CC)	Portfolio #5 (System Mass Cap)	Portfolio #6 (System Mass Cap - High EE / High Renewables)
2017						
2018						
2019						
2020						
2021	1123 MW CC	1123 MW CC	1123 MW CC	1123 MW CC	1123 MW CC	1123 MW CC
2022	435 MW CT	435 MW CT	435 MW CT	435 MW CT	435 MW CT	435 MW CT
2023						
2024						
2025	435 MW CT	435 MW CT	435 MW CT	1123 MW CC	435 MW CT	435 MW CT
2026						
2027	435 MW CT	435 MW CT	435 MW CT		435 MW CT	435 MW CT
2028	435 MW CT	435 MW CT			435 MW CT	
2029			435 MW CT	435 MW CT		435 MW CT
2030	1305 MW CT	870 MW CT	870 MW CT	1123 MW CC	1123 MW CC	870 MW CT
2031		435 MW CT	435 MW CT		90 Incremental Solar	
2017 - 2031 Total	1123 MW CC 3045 MW CT 0 Generic Nuclear 0 Incremental Solar	1123 MW CC 3045 MW CT 0 Generic Nuclear 0 Incremental Solar	1123 MW CC 3045 MW CT 0 Generic Nuclear 0 Incremental Solar	3369 MW CC 870 MW CT 0 Generic Nuclear 0 Incremental Solar	2246 MW CC 1740 MW CT 0 Generic Nuclear 90 Incremental Solar	1123 MW CC 2610 MW CT 0 Generic Nuclear 0 Incremental Solar

*Note: Timing for all resources in the above table are December 1st of the year indicated. Throughout the remainder of the document timing is based on units in service in January 1st of the year indicated. Incremental solar is "economically" selected solar beyond the base and high renewable assumptions.

Table A-2 DEP Cumulative Solar Summary

Year	Portfolio #1	Portfolio #2	Portfolio #3	Portfolio #4	Portfolio #5	Portfolio #6
2017	1,710	1,769	1,710	1,710	1,710	1,769
2018	1,990	2,089	1,990	1,990	1,990	2,089
2019	2,303	2,472	2,303	2,303	2,303	2,472
2020	2,559	2,797	2,559	2,559	2,559	2,797
2021	2,810	3,048	2,810	2,810	2,810	3,048
2022	2,969	3,384	2,969	2,969	2,969	3,384
2023	3,015	3,626	3,015	3,015	3,015	3,626
2024	3,049	3,817	3,049	3,049	3,049	3,817
2025	3,081	3,995	3,081	3,081	3,081	3,995
2026	3,113	4,175	3,113	3,113	3,113	4,175
2027	3,145	4,357	3,145	3,145	3,145	4,357
2028	3,178	4,542	3,178	3,178	3,178	4,542
2029	3,212	4,728	3,212	3,212	3,212	4,728
2030	3,244	4,911	3,244	3,244	3,244	4,911
2031	3,270	5,062	3,270	3,270	3,360	5,062

4. Perform Portfolio Analysis

The six portfolios identified in the screening analysis were evaluated in more detail with an hourly production cost model called PROSYM under several scenarios. The four scenarios are summarized in Table A-3 and included sensitivities on fuel, carbon, and capital cost.

Table A-3 Scenarios for Portfolio Analysis

	Carbon Tax/No Carbon Tax Scenarios[1]	Fuel	CO_2	CAPEX
1	Current Trends	Base	CO_2 Tax	Base
2	Economic Recession	Low Fuel	No CO_2 Tax	Low
3	Economic Expansion	High Fuel	CO_2 Tax	High

[1]Run Portfolios 1 - 4 through each of these 3 scenarios

	System Mass Cap Scenarios[2]	Fuel	CO_2	CAPEX
4	Current Trends - CO_2 Mass Cap	Base	Mass Cap	Base

[2]Run Portfolios 5 - 6 through this single MC2 scenario

Portfolios 1 through 4 were analyzed under a current economic trend scenario (Scenario #1), an economic recession scenario (Scenario #2), and an economic expansion scenario (Scenario #3). Portfolios 5 & 6 were only run under the Current Trends – CO_2 Mass Cap scenario (Scenario #4).

Under a System Mass Cap for carbon, fuel price and capital cost will have little impact on the optimization of the system as the carbon output of the various generators will control dispatch to a greater extent than the fuel price.

Portfolio 1 – 4 Analysis

Table A-4 below summarizes the present value revenue requirements (PVRR) of each portfolio compared to Portfolio #4 over the range of scenarios and sensitivities[9].

Table A-4 Delta PVRR for Portfolios #1 - #4 under Scenarios #1-#3

Delta PVRR 2016 - 2061, $Billions compared to Portfolio #1

Portfolio	Scenario #1 (Current Trends)	Scenario #2 (Economic Recession)	Scenario #3 (Economic Expansion)
Portfolio #1 (Base Case)	$0	$0	$0
Portfolio #2 (High Renew)	$1,184	$1,598	$1,522
Portfolio #3 (High EE)	$76	$316	$13
Portfolio #4 (High CC)	$636	$814	$652

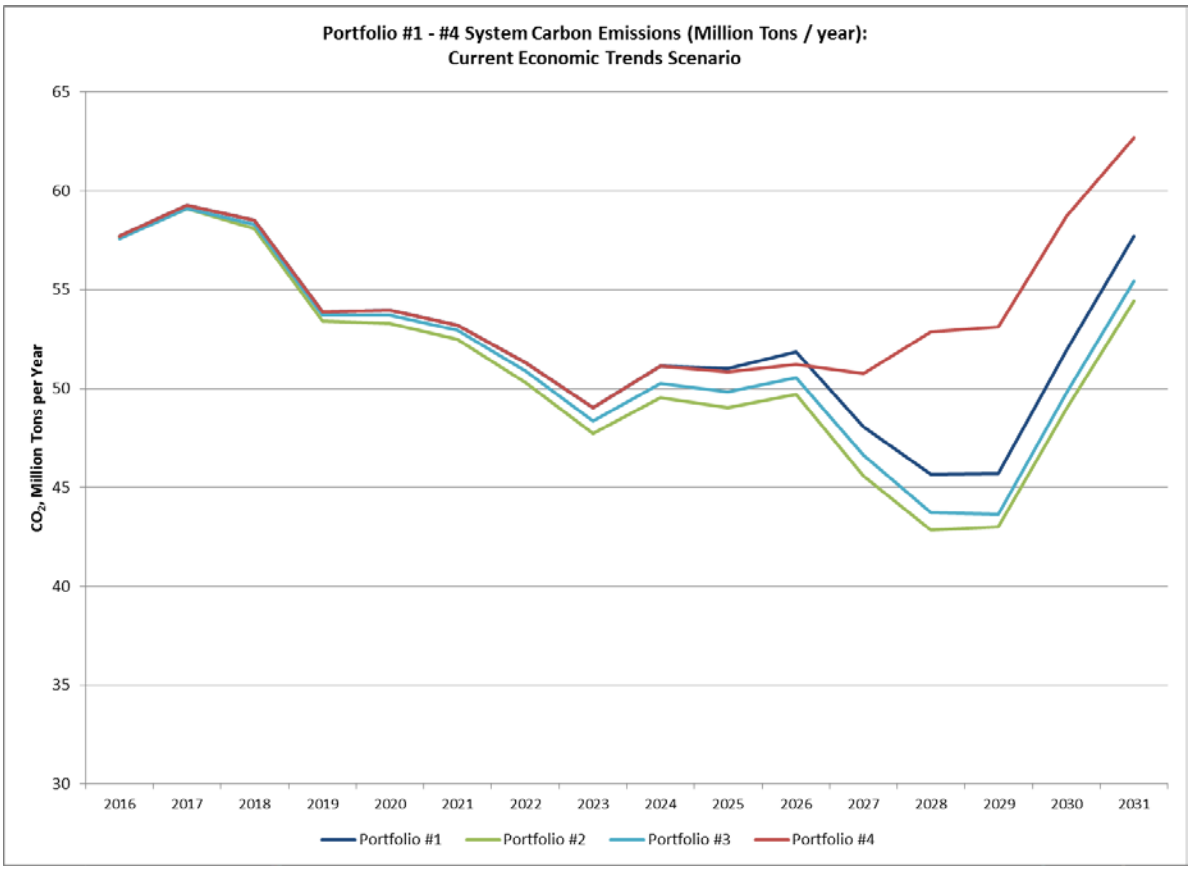
*Note: Positive values indicate Portfolio #1 is a lower cost, Negative values indicate Portfolio #1 is a higher cost

[9] PVRR includes the cost of integrating solar as represented in the Duke Energy Photovoltaic Integration Study published by Pacific Northwest National Lab in March 2014.

In the three scenarios, Portfolio #1 (Base Case) was the lowest cost portfolio. The costs of Portfolios 2 and 3 were negatively impacted by expanding the amount of renewable resources beyond the NC REPS requirements and energy efficiency above the Base Case assumptions. However, Portfolio #3 (High EE) had a PVRR that was nearly as low as Portfolio #1 when capital costs and fuel prices were increased in the Economic Expansion scenario. Portfolio #2 (High Renewables) had the lowest carbon footprint in each of the three scenarios evaluated. The higher capital cost and fixed gas pipeline costs associated with combined cycles caused Portfolio #4 (High CC) to have a higher cost than Portfolio #1.

Without the addition of new nuclear to replace retiring nuclear units, the CO_2 emissions increase significantly in the 2030 to 2035 timeframe. Figure A–2 illustrates this point by comparing the cumulative DEP and DEC total system CO_2 emissions of the Portfolios 1 - 4 through 2031 in the Current Trends scenario. To this point, when Robinson 2 is retired in 2030 all Portfolios experience increased carbon emissions.

Figure A-2 Cumulative DEP & DEC System Carbon Emissions Summary for Portfolios 1-4– Current Trends Scenario



Portfolio 5 & 6 Analysis

Table A-5 below summarizes the revenue requirements of Portfolios #5 and #6 under Scenario #4.

Table A-5 Delta PVRR for Portfolios #5 & #6 under Scenario #4

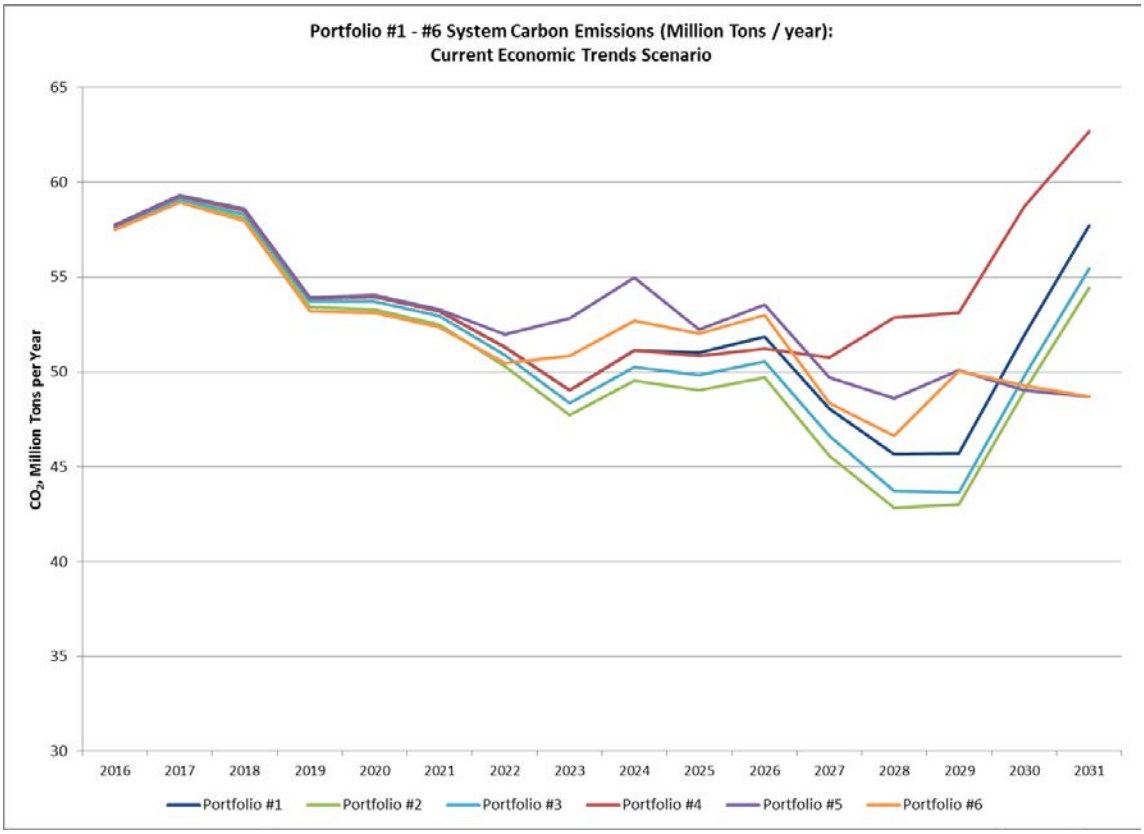
Delta PVRR 2016 - 2061, $Billions compared to Portfolio #5

Portfolio	Scenario #1 (Current Trends)
Portfolio #5 (System Mass Cap Base)	$0
Portfolio #6 (High EE / Renew)	$829

The high EE and high renewable combination led to a higher PVRR versus the Base Case under a System Mass Cap carbon plan. The $1.7B savings in system production costs was not enough to overcome the $2.5B capital cost of the high EE/high renewable portfolio.

Cumulative DEP and DEC system carbon emissions for both Portfolio #5 and Portfolio #6 average under 50 Million tons/year by the late-2020s and are projected to remain flat to declining beyond the study period as shown in Figure A-3.

Figure A-3 Cumulative DEP & DEC System Carbon Emissions Summary for Portfolios 1-6– Current Trends Scenario



Conclusions

For planning purposes, Duke Energy considers the potential impact of a future where carbon emissions are constrained as the base plan. Portfolio #1 is the least cost portfolio from a revenue requirement basis in the Carbon Tax paradigm, however its carbon footprint would not be sustainable in the long-term in a System CO_2 Mass Cap scenario if new nuclear generation was not available in the early 2030s. By 2034, approximately 3,300 MW of existing nuclear generation will be retired in DEP and DEC unless their licenses can be extended. To date, no nuclear units in the United States have received a license extension beyond sixty years.

Duke Energy's current modeling practice uses a proxy CO_2 price forecast from a third party to simulate compliance where carbon emissions are constrained under the now stayed EPA Clean Power Plan. With the stay, the future of CO_2 legislation is still uncertain, and a system mass cap on carbon emissions is still a possibility. Portfolio #1 was chosen as the Base Case portfolio because the short term build plan would keep the Company on track if a System CO_2 Mass Cap were implemented, and it was the least cost portfolio from a revenue requirements perspective.

Value of Joint Planning

To demonstrate the value of sharing capacity with DEP, a Joint Planning Case was developed to examine the impact of joint capacity planning on the resource plans. The impacts were determined by comparing how the combined Base Cases of DEP and DEC would change if a 17% minimum winter planning reserve margin was applied at the combined system level, rather than the individual company level.

An evaluation was performed comparing the optimally selected Portfolio 1 for DEP and DEC to a combined Joint Planning Case in which existing and future capacity resources could be shared between DEP and DEC to meet the 17% minimum winter planning reserve margin. In this Joint Planning Case, sharing the Lee Nuclear Station on a load ratio basis with DEP was the most economic selection. Table A-4 shows the base expansion plans (Portfolio #1 for both DEP and DEC) through 2031, if separately planned, compared to the Joint Planning Case. The sum total of the two combined resource requirements is then compared to the amount of resources needed if DEP and DEC were able to jointly plan for capacity.

Table A-4 Comparison of Base Case Portfolio to Joint Planning Case

	DEC	DEP	Joint Planning (1BA)
2021		1123 MW CC	1123 MW CC
2022	1123 MW CC	435 MW CT	1123 MW CC
2023			
2024	435 MW CT		
2025		435 MW CT	870 MW CT
2026	1117 MW Lee Nuc 1		1117 MW Lee Nuc 1
2027		435 MW CT	435 MW CT
2028	1117 MW Lee Nuc 2	435 MW CT	1117 MW Lee Nuc 2
2029			
2030		1305 MW CT	1740 MW CT
2031	435 MW CT		1305 MW CT
2016 - 2031 Total	1123 MW CC 870 MW CT 1117 MW Lee Nuc 1 1117 MW Lee Nuc 2 0 Generic Nuclear 0 Incremental Solar	1123 MW CC 3045 MW CT 0 MW Lee Nuc 1 0 MW Lee Nuc 2 0 Generic Nuclear 0 Incremental Solar	2246 MW CC 4350 MW CT 1117 MW Lee Nuc 1 1117 MW Lee Nuc 2 0 Generic Nuclear 0 Incremental Solar
Average Winter Reserve Margin (2021 thru 2031)	19.4%	18.6%	18.4%
DEC / DEP Average Reserve Margin with Separate & Joint Planning (2021 thru 2031)	19.0%		
SO Calculated PVRR thru 2061, $B	$124.2		$123.6

*Note: Timing for all resources in the above table are December 1st of the year indicated other than Lee Nuclear 1, which is assumed as November 2026, and Lee Nuclear 2, which is assumed as May 2028. Throughout the remainder of the document timing is based on units in service in January 1st of the year indicated.

A comparison of the DEP and DEC Combined Base Case resource requirements to the Joint Planning Scenario requirements illustrates the ability to defer CT resources over the 2016 to 2031 planning horizon. Consequently, the Joint Planning Case also results in a lower overall reserve margin. This is confirmed by a review of the reserve margins for the Combined Base Case as compared to the Joint Planning Case, which averaged 19.0% and 18.4%, respectively, from the first resource need in 2021 through 2031. The lower reserve margin in the Joint Planning Case indicates that DEP and DEC more efficiently and economically meet capacity needs when planning for capacity jointly. This is reflected in a total PVRR savings of $0.6 billion for the Joint Planning Case as compared to the Base Case.

B. Quantitative Analysis Summary

The quantitative analysis resulted in several key takeaways that are important for near-term decision-making, as well as in planning for the longer term.

1. The first undesignated resource need is in December of 2021 to meet the minimum reserve margin requirement in the winter of 2022. The results of this analysis show that this need is best met with CC generation.

2. The ability to jointly plan capacity with DEP provides customer savings by allowing for the deferral of new generation resources over the 2017 through 2031 planning horizon.

3. New nuclear generation is selected as an economic resource in a System CO_2 Mass Cap future as identified in Portfolios 5 & 6. In the 15-year planning horizon, the addition of two additional generic nuclear units, one in DEC and the other in DEP, were selected prior to 2040.

Portfolio 1 supports 100% ownership of Lee Nuclear Station by DEC. However, the Company continues to consider the benefits of regional nuclear generation. Sharing new baseload generation resources between multiple parties allows for resource additions to be better matched with load growth and for new construction risk to be shared among the parties. This results in positive benefits for the Company's customers. The benefits of co-ownership of the Lee Nuclear Station with DEP were also illustrated with the ability to jointly plan as represented in the Joint Planning Case.

APPENDIX B: DUKE ENERGY PROGRESS OWNED GENERATION

Duke Energy Progress' generation portfolio includes a balanced mix of resources with different operating and fuel characteristics. This mix is designed to provide energy at the lowest reasonable cost to meet the Company's obligation to serve its customers. Duke Energy Progress-owned generation, as well as purchased power, is evaluated on a real-time basis in order to select and dispatch the lowest-cost resources to meet system load requirements. In 2015, Duke Energy Progress' nuclear, gas-fired and coal-fired generating units met the vast majority of customer needs by providing 44%, 34% and 21%, respectively, of Duke Energy Progress' energy from generation. Hydro-electric generation, Combustion Turbine generation, Combined Cycle generation, solar generation, long-term PPAs, and economical purchases from the wholesale market supplied the remainder.

The tables below list the Duke Energy Progress' plants in service in North Carolina and South Carolina with plant statistics, and the system's total generating capability.

Existing Generating Units and Ratings [1, 3]
All Generating Unit Ratings are as of January 1, 2016.

Coal						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Asheville	1	192	189	Arden, NC	Coal	Intermediate
Asheville	2	192	189	Arden, NC	Coal	Intermediate
Mayo [2]	1	746	727	Roxboro, NC	Coal	Intermediate
Roxboro	1	380	379	Semora, NC	Coal	Intermediate
Roxboro	2	673	671	Semora, NC	Coal	Intermediate
Roxboro	3	698	691	Semora, NC	Coal	Intermediate
Roxboro [2]	4	711	698	Semora, NC	Coal	Intermediate
Total Coal		3,592	3,544			

Combustion Turbines						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Asheville	3	185	164	Arden, NC	Natural Gas/Oil	Peaking
Asheville	4	185	160	Arden, NC	Natural Gas/Oil	Peaking
Blewett	1	17	13	Lilesville, NC	Oil	Peaking
Blewett	2	17	13	Lilesville, NC	Oil	Peaking
Blewett	3	17	13	Lilesville, NC	Oil	Peaking
Blewett	4	17	13	Lilesville, NC	Oil	Peaking
Darlington	1	63	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	2	64	48	Hartsville, SC	Oil	Peaking
Darlington	3	63	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	4	66	50	Hartsville, SC	Oil	Peaking
Darlington	5	66	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	6	62	45	Hartsville, SC	Oil	Peaking
Darlington	7	65	51	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	8	66	48	Hartsville, SC	Oil	Peaking
Darlington	9	65	52	Hartsville, SC	Oil	Peaking
Darlington	10	65	51	Hartsville, SC	Oil	Peaking
Darlington	12	133	118	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	13	133	116	Hartsville, SC	Natural Gas/Oil	Peaking
Smith [4]	1	183	157	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	2	183	156	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	3	185	155	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	4	186	159	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	6	179	153	Hamlet, NC	Natural Gas/Oil	Peaking
Sutton	1	12	11	Wilmington, NC	Oil/Natural Gas	Peaking
Sutton	2A	31	24	Wilmington, NC	Oil/Natural Gas	Peaking
Sutton	2B	33	26	Wilmington, NC	Oil/Natural Gas	Peaking
Wayne	1/10	192	177	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	2/11	192	174	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	3/12	193	173	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	4/13	185	170	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	5/14	197	169	Goldsboro, NC	Oil/Natural Gas	Peaking
Weatherspoon	1	41	32	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	2	41	32	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	3	41	33	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	4	41	31	Lumberton, NC	Natural Gas/Oil	Peaking
Total NC		2,553	2,208			
Total SC		911	735			
Total CT		3,464	2,943			

Combined Cycle						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Lee	CT1A	223	177	Goldsboro, NC	Natural Gas/Oil	Base
Lee	CT1B	222	176	Goldsboro, NC	Natural Gas/Oil	Base
Lee	CT1C	223	179	Goldsboro, NC	Natural Gas/Oil	Base
Lee	ST1	379	378	Goldsboro, NC	Natural Gas/Oil	Base
Smith [4]	CT7	189	160	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT8	189	157	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	ST4	175	165	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT9	214	178	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT10	214	178	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	ST5	246	250	Hamlet, NC	Natural Gas/Oil	Base
Sutton	CT1A	225	179	Wilmington, NC	Natural Gas/Oil	Base
Sutton	CT1B	225	179	Wilmington, NC	Natural Gas/Oil	Base
Sutton	ST1	267	264	Wilmington, NC	Natural Gas/Oil	Base
Total CC		2,991	2,620			

Hydro						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Blewett	1	4	4	Lilesville, NC	Water	Intermediate
Blewett	2	4	4	Lilesville, NC	Water	Intermediate
Blewett	3	4	4	Lilesville, NC	Water	Intermediate
Blewett	4	5	5	Lilesville, NC	Water	Intermediate
Blewett	5	5	5	Lilesville, NC	Water	Intermediate
Blewett	6	5	5	Lilesville, NC	Water	Intermediate
Marshall	1	2	2	Marshall, NC	Water	Intermediate
Marshall	2	2	2	Marshall, NC	Water	Intermediate
Tillery	1	21	21	Mt. Gilead, NC	Water	Intermediate
Tillery	2	18	18	Mt. Gilead, NC	Water	Intermediate
Tillery	3	21	21	Mt. Gilead, NC	Water	Intermediate
Tillery	4	24	24	Mt. Gilead, NC	Water	Intermediate
Walters	1	36	36	Waterville, NC	Water	Intermediate
Walters	2	40	40	Waterville, NC	Water	Intermediate
Walters	3	36	36	Waterville, NC	Water	Intermediate
Total Hydro		227	227			

Nuclear						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Brunswick [2]	1	975	938	Southport, NC	Uranium	Base
Brunswick[2]	2	953	932	Southport, NC	Uranium	Base
Harris [2]	1	973	928	New Hill, NC	Uranium	Base
Robinson	2	797	741	Hartsville, SC	Uranium	Base
Total NC		2,901	2,798			
Total SC		797	741			
Total Nuclear		3,698	3,539			

Solar						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
NC Solar		44.4	44.4	NC	Solar	Intermittent

Total Generation Capability		
	Winter Capacity (MW)	Summer Capacity (MW)
TOTAL DEP SYSTEM - N.C.	12,308	11,441
TOTAL DEP SYSTEM - S.C.	1,708	1,476
TOTAL DEP SYSTEM	14,016	12,917

Note 1: Ratings reflect compliance with NERC reliability standards and are gross of co-ownership interest as of 12/31/15.

Note 2: Duke Energy Progress completed the purchase from NCEMC of jointly owned Roxboro 4, Mayo 1, Brunswick 1 & 2 and Harris 1units effective 7/31/2015.

Note 3: Resource type based on NERC capacity factor classifications which may alternate over the forecast period.

Planned Uprates			
Unit	Date	Winter MW	Summer MW
Brunswick 1 [1]	May 2018	4	2
Brunswick 2 [1]	May 2019	6	4
Brunswick 2 [1]	May 2021	6	4
Brunswick 2 [1]	May 2023	4	2
Brunswick 2 [1]	May 2019	6	4
Harris 1 [1]	Oct 2016	8	4
Harris 1[1]	May 2018	10	5

Note 1: Capacity not reflected in Existing Generating Units and Ratings section.

Retirements				
Unit & Plant Name	Location	Capacity (MW) Winter / Summer	Fuel Type	Retirement Date
Cape Fear 5	Moncure, NC	148 / 144	Coal	10/1/12
Cape Fear 6	Moncure, NC	175 / 172	Coal	10/1/12
Cape Fear 1A	Moncure, NC	14 / 11	Combustion Turbine	3/31/13
Cape Fear 1B	Moncure, NC	14 / 12	Combustion Turbine	3/31/13
Cape Fear 2A	Moncure, NC	15 / 12	Combustion Turbine	3/31/13
Cape Fear 2B	Moncure, NC	14 / 11	Combustion Turbine	10/1/12
Cape Fear 1	Moncure, NC	12 / 11	Steam Turbine	3/31/11
Cape Fear 2	Moncure, NC	12 / 7	Steam Turbine	3/31/11
Darlington 11	Hartsville, SC	67 / 52	Combustion Turbine	11/8/15
Lee 1	Goldsboro, NC	80 / 74	Coal	9/15/12
Lee 2	Goldsboro, NC	80 / 68	Coal	9/15/12
Lee 3	Goldsboro, NC	252 / 240	Coal	9/15/12
Lee 1	Goldsboro, NC	15 / 12	Combustion Turbine	10/1/12
Lee 2	Goldsboro, NC	27 / 21	Combustion Turbine	10/1/12
Lee 3	Goldsboro, NC	27 / 21	Combustion Turbine	10/1/12
Lee 4	Goldsboro, NC	27 / 21	Combustion Turbine	10/1/12
Morehead 1	Morehead City, NC	15 / 12	Combustion Turbine	10/1/12
Robinson 1	Hartsville, SC	179 / 177	Coal	10/1/12
Robinson 1	Hartsville, SC	15 / 11	Combustion Turbine	3/31/13
Weatherspoon 1	Lumberton, NC	49 / 48	Coal	9/30/11
Weatherspoon 2	Lumberton, NC	49 / 48	Coal	9/30/11
Weatherspoon 3	Lumberton, NC	79 / 74	Coal	9/30/11
Sutton 1	Wilmington, NC	98 / 97	Coal	11/27/13
Sutton 2	Wilmington, NC	95 / 90	Coal	11/27/13
Sutton 3	Wilmington, NC	389 / 366	Coal	11/4/13
Total		1,947 MW / 1,812 MW		

Planning Assumptions – Unit Retirements[a]					
Unit & Plant Name	Location	Summer Capacity (MW)	Winter Capacity (MW)	Fuel Type	Expected Retirement
Asheville 1	Arden, N.C.	189	192	Coal	11/2019
Asheville 2	Arden, N.C.	189	192	Coal	11/2019
Mayo 1	Roxboro, N.C.	727	746	Coal	6/2035
Roxboro 1	Semora, N.C.	379	380	Coal	6/2032
Roxboro 2	Semora, N.C.	665	673	Coal	6/2032
Roxboro 3	Semora, N.C.	691	698	Coal	6/2035
Roxboro 4	Semora, N.C.	698	711	Coal	6/2035
Robinson 2 [b]	Hartsville, S.C.	741	797	Nuclear	6/2030
Darlington 1	Hartsville, S.C.	52	63	Natural Gas/Oil	1/2020
Darlington 2	Hartsville, S.C.	48	64	Oil	1/2020
Darlington 3	Hartsville, S.C.	52	63	Natural Gas/Oil	1/2020
Darlington 4	Hartsville, S.C.	50	66	Oil	1/2020[c]
Darlington 5	Hartsville, S.C.	52	66	Natural Gas/Oil	1/2020
Darlington 6	Hartsville, S.C.	45	62	Oil	1/2020[c]
Darlington 7	Hartsville, S.C.	51	65	Natural Gas/Oil	1/2020
Darlington 8	Hartsville, S.C.	48	66	Oil	1/2020
Darlington 9	Hartsville, S.C.	52	65	Oil	1/2020
Darlington 10	Hartsville, S.C.	51	65	Oil	1/2020
Sutton 1	Wilmington, N.C.	11	12	Natural Gas/Oil	6/2017
Sutton 2A	Wilmington, N.C.	24	31	Natural Gas/Oil	6/2017
Sutton 2B	Wilmington, N.C.	26	33	Natural Gas/Oil	6/2017
Blewett 1	Lilesville, N.C.	13	17	Oil	6/2027
Blewett 2	Lilesville, N.C.	13	17	Oil	6/2027
Blewett 3	Lilesville, N.C.	13	17	Oil	6/2027
Blewett 4	Lilesville, N.C.	13	17	Oil	6/2027
Weatherspoon 1	Lumberton, N.C.	32	41	Natural Gas/Oil	1/2027
Weatherspoon 2	Lumberton, N.C.	32	41	Natural Gas/Oil	1/2027
Weatherspoon 3	Lumberton, N.C.	33	41	Natural Gas/Oil	1/2027
Weatherspoon 4	Lumberton, N.C.	31	41	Natural Gas/Oil	1/2027
Total		5021	5409		

Note a: Retirement assumptions are for planning purposes only; dates are based on useful life expectations of the unit.
Note b: Nuclear retirements for planning purposes are based on the end of current operating license.
Note c: Darlington Units 4 and 6 are currently not contributing capacity to the DEP system for the 2016 IRP. They are counted as a derate until 2020, when Darlington Units 1-10 are expected to retire.

Planning Assumptions – Unit Additions					
Unit & Plant Name	**Location**	**Summer Capacity (MW)**	**Winter Capacity (MW)**	**Fuel Type**	**Expected Commercial Date**
Asheville CC	Arden, N.C.	495	560	Natural Gas	11/2019
Asheville CT (Potential)	Arden, N.C.	161	186	Natural Gas	12/2023
Sutton CT	Wilmington, N.C.	84	100	Natural Gas	6/2017

Operating License Renewal

Planned Operating License Renewal				
Unit & Plant Name	Location	Original Operating License Expiration	Date of Approval	Extended Operating License Expiration
Blewett #1-6 [1]	Lilesville, NC	04/30/08	*Pending*	2058[2]
Tillery #1-4 [1]	Mr. Gilead, NC	04/30/08	*Pending*	2058[2]
Robinson #2	Hartsville, SC	07/31/10	04/19/2004	07/31/2030
Brunswick #2	Southport , NC	12/27/14	06/26/2006	12/27/2034
Brunswick #1	Southport, NC	09/08/16	06/26/2006	09/08/2036
Harris #1	New Hill, NC	10/24/26	12/12/2008	10/24/2046

Note 1: The license renewal application for the Blewett and Tillery Plants was filed with the FERC on 04/26/06; the Company is awaiting issuance of the new license from FERC. Pending receipt of a new license, these plants are currently operating under a renewable one-year license extension which has been in effect since May 2008. Although Progress Energy has requested a 50-year license, FERC may not grant this term.

Note 2: Estimated - New license expiration date will be determined by FERC license issuance date and term of granted license.

APPENDIX C: ELECTRIC LOAD FORECAST

Methodology

The Duke Energy Progress Spring 2016 Forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2017 – 2031 and represents the needs of the following customer classes:

- Residential
- Commercial
- Industrial
- Other Retail
- Wholesale

Energy projections are developed with econometric models using key economic factors such as income, electricity prices, industrial production indices, along with weather, appliance efficiency trends, rooftop solar trends, and electric vehicle trends. Population is also used in the Residential customer model. Regression analysis has yielded consistently reasonable results over the years.

The economic projections used in the Spring 2016 Forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the states of North Carolina and South Carolina.

The Retail forecast consists of the three major classes: Residential, Commercial and Industrial.

The Residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electric price and appliance efficiencies.

The usage per customer forecast was derived using a Statistical Adjusted End-Use Model. This is a regression based framework that uses projected appliance saturation and efficiency trends developed by Itron using EIA data. It incorporates naturally occurring efficiency trends and government mandates more explicitly than other models. The outlook for usage per customer is essentially flat through much of the forecast horizon, so most of the growth is primarily due to customer increases. The projected growth rate of Residential in the Spring 2016 Forecast after all adjustments for Utility Energy Efficiency programs, Solar and Electric Vehicles from 2017-2031 is 1.1%.

The Commercial forecast also uses an SAE model in an effort to reflect naturally occurring as well as government mandated efficiency changes. The three largest sectors in the Commercial class are

Offices, Education and Retail. Commercial is expected to be the fastest growing class, with a projected growth rate of 1.3%, after adjustments.

The Industrial class is forecasted by a standard econometric model, with drivers such as total manufacturing output, textile output, and the price of electricity. Overall, Industrial sales are expected to grow 0.8% over the forecast horizon, after all adjustments.

County population projections are obtained from the North Carolina Office of State Budget and Management as well as the South Carolina Budget and Control Board. These are then used to derive the total population forecast for the counties that comprise the DEP service area.

Weather impacts are incorporated into the models by using Heating Degree Days and Cooling Degree Days with a base temperature of 65. The forecast of degree days is based on a 30-year average, which is updated every year.

The appliance saturation and efficiency trends are developed by Itron using data from the EIA. Itron is a recognized firm providing forecasting services to the electric utility industry. These appliance trends are used in the residential and commercial sales models.

Peak demands were projected using the SAE approach in the Spring 2016 Forecast. The peak forecast was developed using a monthly SAE model, similar to the sales SAE models, which includes monthly appliance saturations and efficiencies, interacted with weather and the fraction of each appliance type that is in use at the time of monthly peak.

Assumptions

Below are the projected average annual growth rates of several key drivers from DEP's Spring 2015 Forecast.

	2017-2031
Real Income	2.9%
Mfg. IPI	1.8%
Population	1.0%

In addition to economic, demographic, and efficiency trends, the forecast also incorporates the expected impacts of UEE, as well as projected effects of electric vehicles and behind the meter solar technology.

Wholesale

For a description of the Wholesale forecast, please see Appendix H.

Historical Values

It should be noted that long-term structurally decline of the Textile industry and the recession of 2008-2009 have had an adverse impact on DEP sales. The worst of the Textile decline appears to be over, and Moody's Analytics expects the Carolina's economy to show solid growth going forward.

In tables C-1 and C-2 below the history of DEP customers and sales are given. As a note, the values in Table C-3 are not weather adjusted.

Table C-1 Retail Customers (Thousands, Annual Average)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential	1,877	1,916	2,012	2,024	2,034	2,041	2,053	2,068	2,089	2,117
Commercial	317	322	334	331	333	335	337	339	342	345
Industrial	7	7	7	7	7	7	7	7	7	6
Other	13	13	14	14	14	14	14	14	15	15
Total	2,214	2,259	2,367	2,377	2,389	2,397	2,411	2,428	2,452	2,484

Table C-2 Electricity Sales (GWh Sold - Years Ended December 31)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential	16,664	16,259	17,200	17,000	17,117	19,108	17,764	16,663	18,201	17,954
Commercial	13,314	13,358	14,033	13,940	13,639	14,184	13,709	13,581	13,887	14,039
Industrial	12,741	12,416	11,883	11,216	10,375	10,677	10,573	10,508	10,321	10,288
Military &Other	1,410	1,419	1,438	1,467	1,497	1,574	1,591	1,602	1,614	1,597
Total Retail	44,129	43,451	44,553	43,622	42,628	45,544	43,637	42,355	44,023	43,876
Wholesale	12,210	12,231	12,656	12,868	12,772	12,772	12,267	12,676	13,578	15,782
Total System	56,340	55,682	57,209	56,489	55,400	58,316	55,903	55,031	57,601	59,658

Note: The wholesale values in Table 3-B exclude NCEMPA sales for all years except 2015, and is only included for part of 2015. In Tables 3-F and 3-G, however, the values include NCEMPA for the full year, for all years in the forecast.

Utility Energy Efficiency

A new process for reflecting the impacts of UEE on the forecast was introduced in Spring 2015. In the latest forecast the concept of 'Measure Life' for a program was included in the calculations. For example, if the accelerated benefit of a residential UEE program is expected to have occurred 8 years before the energy reduction program would have been otherwise adopted, then the UEE effects after year 8 are subtracted ("rolled off") from the total cumulative UEE. With the SAE models framework, the naturally occurring appliance efficiency trends replace the rolled off UEE benefits serving to continue to reduce the forecasted load resulting from energy efficiency adoption.

The table below illustrates this process.

- Column A: Total energy before reduction of future UEE
- Column B: Total cumulative UEE
- Column C: Column B minus Historical UEE
- Column D: Roll-off amount of the incremental future UEE programs
- Column E: UEE amount to subtract from Column A
- Column F: Total energy after incorporating UEE (column A less column E)

Table C-3 UEE Program Life Process (MWh)

	A	B	C	D	E	F
	Forecast Before UEE	Total Cumulative UEE	Column B Less Historical UEE	Roll-Off Forecasted UEE	UEE to Subtract From Forecast	Forecast After UEE
2017	65,342	1,624	342	0	342	65,000
2018	65,969	1,838	556	0	556	65,414
2019	66,716	2,042	764	0	764	65,952
2020	66,824	2,222	955	0	955	65,869
2021	67,576	2,401	1,134	0	1,134	66,442
2022	68,450	2,580	1,313	0	1,313	67,137
2023	69,359	2,759	1,491	5	1,486	67,873
2024	70,406	2,939	1,670	15	1,655	68,751
2025	71,237	3,118	1,849	24	1,825	69,413
2026	72,177	3,297	2,027	34	1,994	70,184
2027	73,080	3,476	2,206	63	2,143	70,938
2028	74,095	3,656	2,385	145	2,240	71,855
2029	74,829	3,835	2,564	293	2,270	72,558
2030	75,653	4,015	2,742	477	2,266	73,388
2031	76,440	4,194	2,921	647	2,274	74,166

Results

A tabulation of the utility's forecasts for 2017-2031, including peak loads for summer and winter seasons of each year and annual energy forecasts, both with and without the impact of UEE programs, are shown below in Tables C-4 and C-5.

Load duration curves, with and without UEE programs, follow Tables C-6 and C-7, and are shown as Charts C-1 and C-2.

The values in these tables reflect the loads that Duke Energy Progress is contractually obligated to provide and cover the period from 2017 to 2031.

For the period 2017-2031, the Spring 2016 Forecast projects an average annual compound growth rate of 1.3% for summer peaks and 1.4% for winter peaks. These rates do not reflect the impacts of Duke Energy Progress UEE programs. The forecasted compound annual growth rate for energy is 1.1% before UEE program impacts are subtracted.

If the impacts of new Duke Energy Progress UEE programs are included, the projected compound annual growth rate for the summer peak demand is 1.1%, while winter peaks are forecasted to grow

at a rate of 1.3%. The forecasted compound annual growth rate for energy is 0.9% after the impacts of UEE programs are subtracted.

As a note, all of the loads and energy in the tables and charts below are at generation, except for the class sales forecast, which is at the meter.

Table C-4 Retail Customers (Thousands, Annual Average)

	Residential	Commercial	Industrial	Other	Retail
	Customers	Customers	Customers	Customers	Customers
2017	1,309	231	4	2	1,546
2018	1,325	234	4	2	1,564
2019	1,340	236	4	2	1,582
2020	1,356	239	4	2	1,601
2021	1,371	241	4	2	1,618
2022	1,386	243	4	2	1,635
2023	1,401	246	4	2	1,653
2024	1,416	249	4	2	1,671
2025	1,431	252	4	2	1,689
2026	1,446	255	4	2	1,707
2027	1,461	257	4	2	1,725
2028	1,476	260	4	2	1,742
2029	1,491	263	4	2	1,760
2030	1,506	266	4	2	1,778
2031	1,520	269	4	2	1,796

Table C-5 Electricity Sales (GWh Sold - Years Ended December 31)

	Residential	Commercial	Industrial	Other	Retail
	Gwh	Gwh	Gwh	Gwh	Gwh
2017	17,903	14,147	10,366	1,593	44,010
2018	18,023	14,272	10,452	1,590	44,337
2019	18,161	14,400	10,547	1,588	44,696
2020	18,354	14,568	10,644	1,594	45,160
2021	18,512	14,706	10,721	1,600	45,538
2022	18,711	14,880	10,814	1,597	46,003
2023	18,937	15,063	10,894	1,595	46,488
2024	19,175	15,301	11,000	1,592	47,068
2025	19,369	15,479	11,083	1,590	47,522
2026	19,588	15,700	11,177	1,588	48,053
2027	19,796	15,928	11,266	1,586	48,576
2028	20,079	16,169	11,372	1,584	49,204
2029	20,290	16,388	11,453	1,582	49,712
2030	20,568	16,630	11,544	1,580	50,321
2031	20,831	16,876	11,640	1,578	50,925

Table C-6
Load Forecast without Energy Efficiency Programs and Before Demand Reduction Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2017	13,185	13,190	65,342
2018	13,327	13,336	65,969
2019	13,512	13,527	66,716
2020	13,602	13,653	66,824
2021	13,786	13,872	67,576
2022	13,969	14,085	68,450
2023	14,164	14,296	69,359
2024	14,355	14,511	70,406
2025	14,550	14,721	71,237
2026	14,764	14,942	72,177
2027	14,954	15,146	73,080
2028	15,160	15,365	74,095
2029	15,347	15,573	74,829
2030	15,538	15,787	75,653
2031	15,741	16,010	76,440

Chart C-1

Load Duration Curve without Energy Efficiency Programs and Before Demand Response Programs

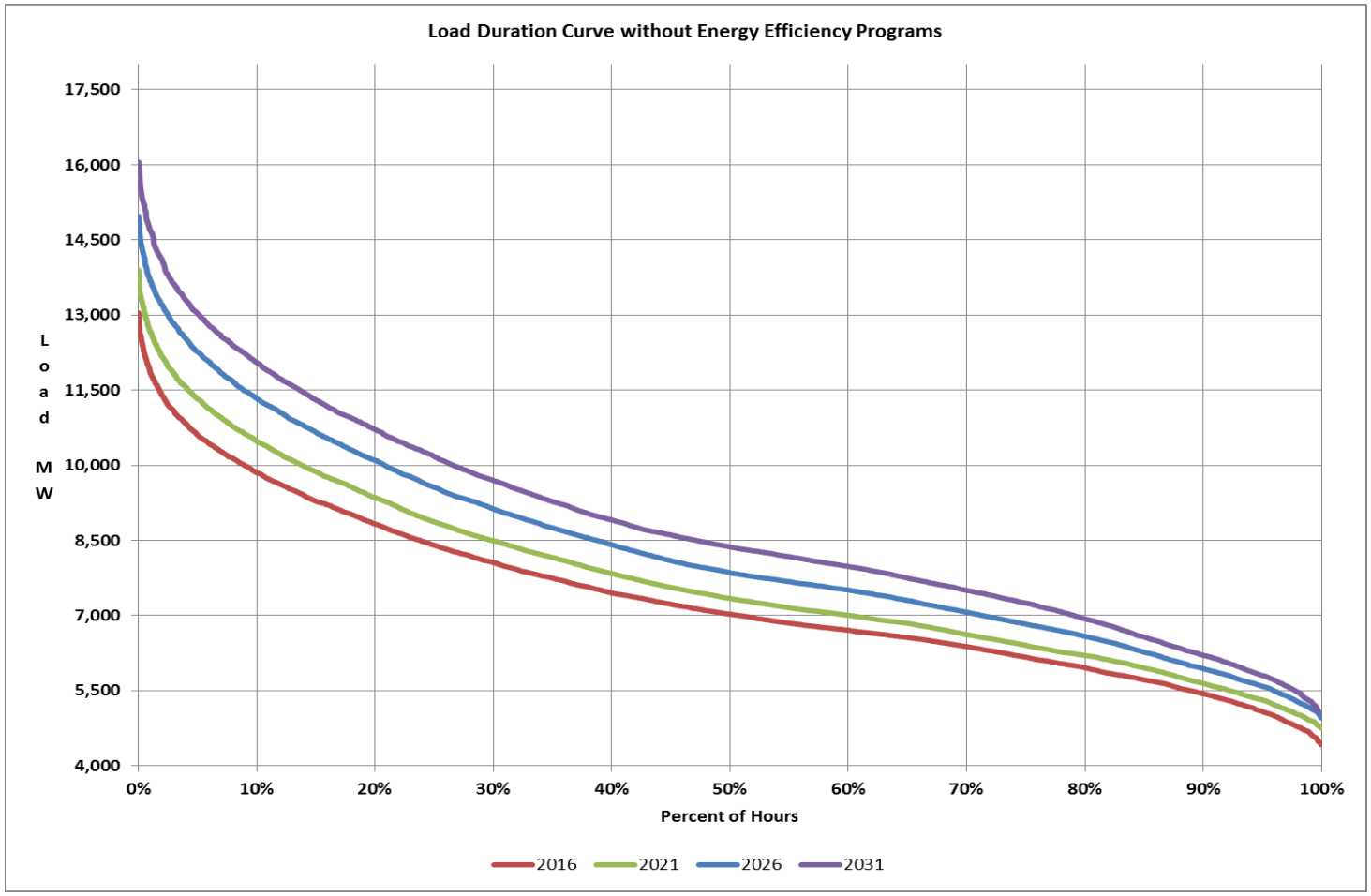
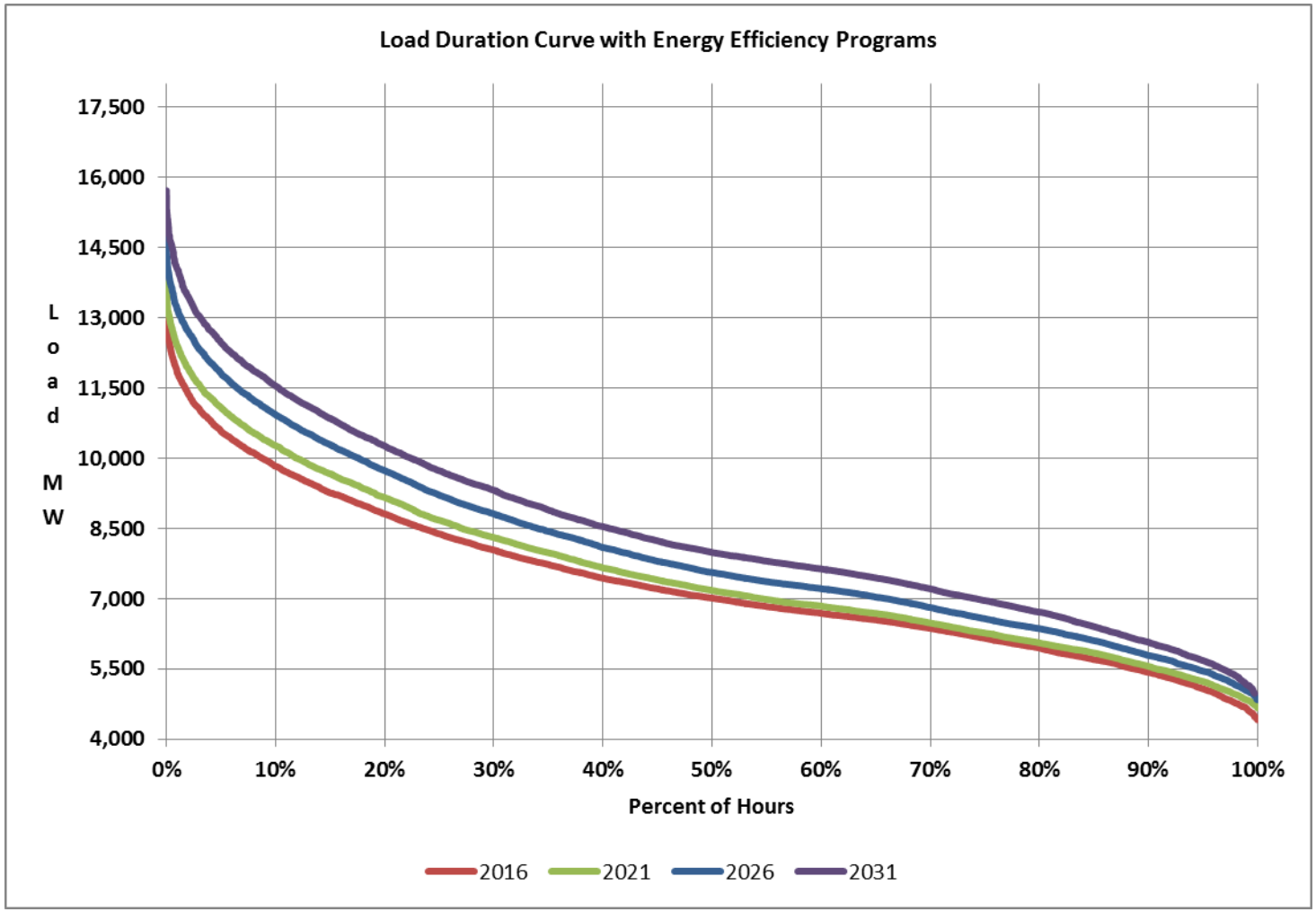


Table C-7
Load Forecast with Energy Efficiency Programs and Before Demand Reduction Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2017	13,127	13,158	65,000
2018	13,234	13,277	65,414
2019	13,385	13,442	65,952
2020	13,444	13,542	65,869
2021	13,599	13,728	66,442
2022	13,753	13,918	67,137
2023	13,919	14,107	67,873
2024	14,083	14,300	68,751
2025	14,249	14,488	69,413
2026	14,435	14,689	70,184
2027	14,601	14,874	70,938
2028	14,792	15,082	71,855
2029	14,973	15,283	72,558
2030	15,164	15,497	73,388
2031	15,365	15,719	74,166

Chart C-2

Load Duration Curve with Energy Efficiency Programs & Before Demand Response Programs



APPENDIX D: ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT

Demand Side Management and Energy Efficiency Programs

DEP continues to pursue a long-term, balanced capacity and energy strategy to meet the future electricity needs of its customers. This balanced strategy includes a strong commitment to demand side management and EE programs, investments in renewable and emerging energy technologies, and state-of-the art power plants and delivery systems.

DEP uses EE and DSM programs in its IRP to efficiently and cost-effectively alter customer demands and reduce the long-run supply costs for energy and peak demand. These programs can vary greatly in their dispatch characteristics, size and duration of load response, certainty of load response, and level and frequency of customer participation. In general, programs are offered in two primary categories: EE programs that reduce energy consumption and DSM programs that reduce peak demand (demand-side management or demand response programs and certain rate structure programs).

Following are the EE and DSM programs currently available through DEP.

Residential Customer Programs

- Residential Home Energy Improvement
- Residential New Construction
- Residential Neighborhood Energy Saver (Low-Income)
- Residential Appliance Recycling Program
- Residential My Home Energy Report
- Residential Multi-Family Energy Efficiency
- Energy Efficiency Education
- Residential Energy Assessments
- Residential Save Energy and Water Kit
- Residential EnergyWise^{SM} Home

Non-Residential Customer Programs

- Energy Efficiency for Business
- Small Business Energy Saver
- Business Energy Report Pilot
- CIG Demand Response Automation Program
- EnergyWise^{SM} for Business

Combined Residential/Non-Residential Customer Programs

- Energy Efficient Lighting
- Distribution System Demand Response (DSDR)

Energy Efficiency Programs

Energy Efficiency programs are typically non-dispatchable education or incentive-based programs. Energy and capacity savings are achieved by changing customer behavior or through the installation of more energy-efficient equipment or structures. All cumulative effects (gross of Free Riders, at the Plant[10]) since the inception of these existing programs through the end of 2015 are summarized below. Please note that the cumulative impacts listed below include the impact of any Measurement and Verification performed since program inception and also note that a "Participant" in the information included below is based on the unit of measure for specific energy efficiency measure (e.g. number of bulbs, kWh of savings, tons of refrigeration, etc.), and may not be the same as the number of customers that actually participate in these programs. The following provides more detail on DEP's existing EE programs:

Residential EE Programs

Residential Home Energy Improvement Program

The Residential Home Energy Improvement Program offers DEP customers a variety of energy conservation measures designed to increase energy efficiency for existing residential dwellings that can no longer be considered new construction. The prescriptive menu of energy efficiency measures provided by the program allows customers the opportunity to participate based on the needs and characteristics of their individual homes. In 2015, an enhanced version of the program was approved and implemented which expanded the number of HVAC measure options and introducing several new measures. Financial incentives are provided to participants for each of the conservation measures promoted within this program. The program utilizes a network of pre-qualified contractors to install each of the following energy efficiency measures:

- High-Efficiency Heat Pumps and Central A/C
- Duct Repair
- HVAC Audit
- Insulation Upgrades/Attic Sealing
- High Efficiency Room Air Conditioners

[10] "Gross of Free Riders" means that the impacts associated with the EE programs have not been reduced for the impact of Free Riders. "At the Plant" means that the impacts associated with the EE programs have been increased to include line losses.

- Heat Pump Water Heater
- HVAC Quality Installation
- Smart Thermostat
- Variable Speed Pool Pumps

Due to the timing of approval for these program enhancements discussed above, the expected impacts from this program were not included in the EE forecasts used in this IRP.

Residential Home Energy Improvement Program			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	114,832	49,373	34,343

Residential New Construction Program

The Residential New Construction Program incents the installation of high-efficiency heating ventilating and air conditioning and heat pump water heating equipment in new residential construction. Additionally, the Program incents new construction built to or above the 2012 North Carolina Energy Conservation Code's High Efficiency Residential Option (HERO). If elected by a builder or developer constructing to the HERO standard, the Program also offers the homebuyer a Heating and Cooling Energy Usage Limited Guarantee that guarantees the heating and cooling consumption of the dwelling's total annual energy costs.

The primary objectives of this program are to reduce system peak demands and energy consumption within new homes. New construction represents a unique opportunity for capturing cost effective EE savings by encouraging the investment in energy efficiency features that would otherwise be impractical or more costly to install at a later time. These are often referred to as lost opportunities.

Residential New Construction Program			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	14,128	21,679	8,083

Note: The participants and impacts are from both the Residential New Construction program and the previous Home Advantage program.

Residential Neighborhood Energy Saver (Low-Income) Program

DEP's Neighborhood Energy Saver Program reduces energy usage through the direct installation of energy efficiency measures within the households of income qualifying residential customers. The Program utilizes a Company-selected vendor to: (1) provide an on-site energy assessment of the residence to identify appropriate energy conservation measures, (2) install a comprehensive package of energy conservation measures at no cost to the customer, and (3) provide one-on-one energy education. Program measures address end-uses in lighting, refrigeration, air infiltration and HVAC applications.

Program participants receive a free energy assessment of their home followed by a recommendation of energy efficiency measures to be installed at no cost to the resident. A team of energy technicians will install applicable measures and provide one-on-one energy education about each measure emphasizing the benefit of each and recommending behavior changes to reduce and control energy usage.

Residential Neighborhood Energy Saver Program			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	27,993	15,829	2,229

Residential Appliance Recycling Program

The Appliance Recycling Program promotes the removal and responsible disposal of operating refrigerators and freezers from DEP residential customers. An eligible refrigerator or freezer must have a capacity of at least 10 cubic feet but not more than 30 cubic feet. The Program recycles approximately 95% of the material from the harvested appliances.

The implementation vendor for this program abruptly discontinued operations in November 2015. As a result, the program is not currently being offered to customers and future potential impacts associated with this program beyond 2015 were not included in this IRP analysis.

Residential Appliance Recycling Program			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	47,680	50,738	6,048

Residential My Home Energy Report Program

The My Home Energy Report (MyHER) Program was designed to help customers better understand their energy usage. The program provides customers with a periodic comparative usage report that compares a their energy use to similar residences in the same geographical area based upon the age, size and heating source of the home. Energy saving recommendations are included in the report to encourage energy saving behavior. The reports are distributed up to 12 times per year (delivery may be interrupted during the off-peak energy usage months in the fall and spring). Each customer's usage is compared to the average home (top 50 percent) in their area as well as the efficient home (top 25 percent). Suggested energy efficiency improvements, given the usage profile for that home, are also provided. In addition, measure-specific offers, rebates or audit follow-ups from other Company offered programs are offered to customers, based on the customer's energy profile.

MyHER received regulatory approval during the last quarter of 2014 and eligible customers received their first report during the first quarter of 2015.

Residential My Home Energy Report Program			
Capability as of:	**Number of Participants**	**Gross Savings (at plant)**	
		MWh Energy	**Peak kW**
December 31, 2015	682,389	132,316	35,955

Energy Efficiency Education Program

The Energy Efficiency Education Program is an energy efficiency program available to students in grades K-12 enrolled in public and private schools who reside in households served by Duke Energy Progress. The Program provides principals and teachers with an innovative curriculum that educates students about energy, resources, how energy and resources are related, ways energy is wasted and how to be more energy efficient. The centerpiece of the current curriculum, which is administered by The National Theatre for Children, is a live theatrical production focused on concepts such as energy, renewable fuels and energy efficiency performed by two professional actors. Teachers receive supportive educational material for classroom and student take home assignments. The workbooks, assignments and activities meet state curriculum requirements.

Following the performance, students are encouraged to complete a home energy survey with their family (included in their classroom and family activity book) to receive an Energy Efficiency Starter Kit. The kit contains specific energy efficiency measures to reduce home energy consumption. The kit is available at no cost to all student households at participating schools, including customers and non-customers.

Energy Efficiency Education Program			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2015	10,060	2,284	226

Multi-Family Energy Efficiency Program

The Multi-family Energy Efficiency Program allows DEP to utilize an alternative delivery channel which targets multi-family apartment complexes for energy efficiency upgrades. The Program is designed to help property managers upgrade lighting with energy efficient compact fluorescent light bulbs (CFLs) and also save energy by offering water measures such as bath and kitchen faucet aerators, water saving showerheads and pipe wrap to eligible customers with electric water heating. The Program also offers properties the option of direct install service by a third-party vendor or to use their own property maintenance crews to complete the installations. Post-installation Quality Assurance inspections by an independent third-party are conducted on 20 percent of properties that completed installations in a given month.

The program launched in January 2015 after receiving regulatory approval late in 2014.

Residential Multi-Family Energy Efficiency Program			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2015	347,412	19,822	1,998

Energy Efficient Lighting Program

The Lighting Program launched in January of 2010 and expanded to offer additional measures in January 2013 (now called Energy Efficient Lighting Program). This program works through lighting manufacturers and retailers to offer discounts to DEP customers at the register on CFLs, light emitting diodes (LEDs), and energy-efficient fixtures. Participation levels for all years of the program have been higher than originally forecasted. This success can be attributed to high customer interest in energy efficiency, low socket penetration of energy efficient lighting in the DEP territory and effective promotion of the program in the marketplace.

As the program enters the sixth year, the DEP Energy Efficient Lighting Program will continue to encourage customers to adopt energy efficient lighting through incentives on a wide range of lighting products. Customer education is imperative to ensure customers are purchasing the right

bulb for the application in order to obtain high satisfaction with lighting products and subsequent purchases.

Energy Efficient Lighting Program			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2015	23,688,204	1,323,144	204,694

Residential Energy Assessments Program

The Residential Energy Assessments Program provides eligible customers with a free in-home energy assessment performed by a Building Performance Institute (BPI) certified energy specialist designed to help customers reduce energy usage and save money. The BPI certified energy specialist completes a 60 to 90 minute walk through assessment of a customer's home and analyzes energy usage to identify energy savings opportunities. The energy specialist discusses behavioral and equipment modifications that can save energy and money with the customer. The customer also receives a customized report that identifies actions the customer can take to increase their home's efficiency.

In addition to a customized report, customers receive an energy efficiency starter kit with a variety of measures that can be directly installed by the energy specialist. The kit includes measures such as energy efficiency lighting, low flow shower head, low flow faucet aerators, outlet/switch gaskets, weather stripping and an energy saving tips booklet.

The program was approved by the NCUC in February 2016 and a forecast of expected future impacts was included in this IRP.

Save Water and Energy Kit Program

The Save Energy and Water Kit is designed to increase the energy efficiency within single family homes by offering low flow water fixtures and insulated pipe tape to residential customers with electric water heaters. Participants receive a free kit that includes installation instructions and varying numbers (based on the number of full bathrooms in their home) of bath aerators, kitchen aerators, shower heads and pipe insulation tape. The program has a website in place that customers can access to learn more about the program or watch video's produced to aid in the installation of the kit measures.

The program launched in November 2015 and a forecast of expected future impacts was included in this IRP.

Non-Residential EE Programs

Energy Efficiency for Business Program

The Energy Efficiency for Business Program provides incentives to DEP commercial and industrial customers to install high efficiency equipment in applications involving new construction and retrofits and to replace failed equipment.

Commercial and industrial customers can have significant energy consumption but may lack knowledge and understanding of the benefits of high efficiency alternatives. The Program provides financial incentives to help reduce the cost differential between standard and high efficiency equipment, offer a quicker return on investment, save money on customers' utility bills that can be reinvested in their business, and foster a cleaner environment. In addition, the Program encourages dealers and distributors (or market providers) to stock and provide these high efficiency alternatives to meet increased demand for the products.

The program provides incentives through prescriptive measures, custom measures and technical assistance.

- *Prescriptive Measures*: Customers receive incentive payments after the installation of certain high efficiency equipment found on the list of pre-defined prescriptive measures, including lighting; heating, ventilating and air conditioning equipment; and refrigeration measures and equipment.
- *Custom Measures*: Custom measures are designed for customers with electrical energy saving projects involving more complicated or alternative technologies, whole-building projects, or those measures not included in the Non-Residential Energy Efficiency for Business measure list. The intent of the Program is to encourage the implementation of energy efficiency projects that would not otherwise be completed without the Company's technical or financial assistance. Unlike Prescriptive portion of the program, all Custom measure incentives requires pre-approval prior to the project implementation.
- *Technical Assistance*: Technical Assistance incentives are offered for new construction and retrofit application to provide assistance to qualified customers with development or implementation of system and building enhancements. Assistance may include, but is not limited to, feasibility studies, detailed energy audits, and retro-commissioning of existing systems, or for efficiency design or energy modeling for new structures and systems. All measures involving technical assistance incentives must receive pre-approval before implementation.

Energy Efficiency for Business Program			
Cumulative as of:	Number of Participants*	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2015	358,551,358	358,551	68,745

* Note: One participant equals one kWh.

Small Business Energy Saver Program

The Small Business Energy Saver Program reduces energy usage through the direct installation of energy efficiency measures within qualifying small non-residential customer facilities. Program measures address major end-uses in lighting, refrigeration, and HVAC applications. The program is available to existing non-residential customers that are not opted-out of the Company's EE/DSM rider and have an average annual demand of 100 kW or less per active account.

Program participants receive a free, no-obligation energy assessment of their facility followed by a recommendation of energy efficiency measures to be installed in their facility along with the projected energy savings, costs of all materials and installation, and up-front incentive amount from Duke Energy Progress. Upon receiving the results of the energy assessment, if the customer decides to move forward with the proposed energy efficiency project, the customer makes the final determination of which measures will be installed. The energy efficiency measure installation is then scheduled at a convenient time for the customer and the measures are installed by electrical subcontractors of the Company-authorized vendor.

All aspects of the program are administered by a single Company-authorized vendor. The program is designed as a pay-for-performance offering, meaning that the Company-authorized vendor administering the Program is only compensated for energy savings produced through the installation of energy efficiency measures.

Small Business Energy Saver Program			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2015	95,893,808	95,894	19,445

* Note: One participant equals one kWh.

Business Energy Report Pilot

The Business Energy Report Pilot is a periodic comparative usage report that compares a customer's energy use to their peer groups. Comparative groups are identified based on the customer's energy use, type of business, operating hours, square footage, geographic location,

weather data and heating/cooling sources. Pilot participants will receive targeted energy efficiency tips in their report informing them of actionable ideas to reduce their energy consumption. The recommendations may include information about other Company offered energy efficiency programs. Participants will receive at least six reports over the course of a year.

Distribution System Demand Response Program (DSDR)

The DSDR program is an application of Smart Grid technology that provides the capability to reduce peak demand for four to six hours at a time, which is the duration consistent with typical peak load periods, while also maintaining customer delivery voltage above the minimum requirement when the program is in use. The increased peak load reduction capability and flexibility associated with DSDR will result in the displacement of the need for additional peaking generation capacity. This capability is accomplished by investing in a robust system of advanced technology, telecommunications, equipment, and operating controls. The DSDR Program helps DEP implement a least cost mix of demand reduction and generation measures that meet the electricity needs of its customers. With the full implementation of DSDR in June 2014, all of DEP's voltage control capability now falls under the DSDR program.

Distribution System Demand Response Program			
		Gross Savings (at plant)	
Cumulative as of:	Number of Participants	MWh Energy	Summer MW Capability
December 31, 2015	NA	41,988	308

Since DEP's last biennial resource plan was filed on September 2, 2014, there have been 60 voltage control activations through June 30, 2016. The following table shows the date, starting and ending time, and duration for all voltage control activations from July 2014 through June 2016.

Voltage Control			
Date	Start Time	End Time	Duration (H:MM)
7/2/2014	15:00	18:00	3:00
7/9/2014	15:00	16:03	1:03
7/14/2014	15:00	18:00	3:00
7/16/2014	10:00	11:00	1:00
7/23/2014	15:00	18:00	3:00
7/28/2014	15:00	17:30	2:30

Voltage Control			
Date	Start Time	End Time	Duration (H:MM)
8/6/2014	15:00	18:00	3:00
8/12/2014	16:08	16:25	0:17
8/20/2014	15:00	18:00	3:00
8/21/2014	15:00	18:00	3:00
8/22/2014	15:00	17:00	2:00
9/17/2014	13:00	14:00	1:00
11/17/2014	10:00	11:00	1:00
11/19/2014	6:30	9:00	2:30
11/22/2014	17:13	17:29	0:16
12/8/2014	8:06	8:40	0:34
12/12/2014	7:58	8:30	0:32
12/16/2014	8:00	8:30	0:30
1/7/2015	7:00	8:05	1:05
1/8/2015	6:00	9:10	3:10
1/9/2015	7:00	8:05	1:05
1/23/2015	8:21	8:37	0:16
1/28/2015	6:30	8:43	2:13
1/29/2015	6:30	8:38	2:08
2/3/2015	6:30	8:35	2:05
2/6/2015	6:30	8:35	2:05
2/13/2015	6:30	8:41	2:11
2/15/2015	19:00	22:11	3:11
2/16/2015	6:30	9:40	3:10
2/19/2015	6:30	9:40	3:10
2/19/2015	19:00	22:30	3:30
2/20/2015	6:30	7:00	0:30
2/20/2015	7:00	8:30	1:30
2/20/2015	8:30	9:26	0:56
2/20/2015	19:00	22:30	3:30
4/9/2015	17:35	18:11	0:36
4/29/2015	12:30	13:00	0:30
5/19/2015	12:00	13:00	1:00
5/26/2015	11:00	12:00	1:00
6/15/2015	16:00	19:35	3:35
6/16/2015	16:00	19:31	3:31

Voltage Control			
Date	Start Time	End Time	Duration (H:MM)
6/18/2015	15:00	16:56	1:56
6/22/2015	15:00	18:46	3:46
6/23/2015	16:03	16:17	0:14
6/24/2015	12:00	13:35	1:35
6/24/2015	15:00	19:08	4:08
7/7/2015	14:00	15:01	1:01
7/9/2015	16:45	17:28	0:43
7/20/2015	15:30	19:05	3:35
7/21/2015	15:30	19:05	3:35
7/27/2015	16:28	16:34	0:06
8/4/2015	15:30	19:09	3:39
8/5/2015	15:30	19:04	3:34
8/18/2015	14:01	14:18	0:16
8/25/2015	14:00	15:35	1:35
9/2/2015	12:00	13:35	1:35
1/19/2016	6:00	8:37	2:37
1/20/2016	6:00	8:43	2:43
2/7/2016	13:15	13:31	0:16
2/8/2016	6:00	8:51	2:51
2/11/2016	6:00	8:58	2:58
3/7/2016	6:32	7:25	0:53
5/16/2016	9:00	9:25	0:25
5/17/2016	9:00	10:02	1:02
6/5/2016	14:51	15:15	0:24
6/7/2016	15:02	15:12	0:10
6/8/2016	12:30	13:30	1:00
6/16/2016	15:30	17:00	1:30
6/21/2016	12:30	14:09	1:39
6/24/2016	15:30	15:45	0:14
6/29/2016	12:00	13:00	1:00

Demand Side Management Programs

Residential EnergyWise℠ Home Program

The Residential EnergyWise℠ Home Program allows DEP to install load control switches at the customer's premise to remotely control the following residential appliances:

- Central air conditioning or electric heat pumps
- Auxiliary strip heat on central electric heat pumps (Western Region only)
- Electric water heaters (Western Region only).

For each of the appliance options above, an initial one-time bill credit of $25 following the successful installation and testing of load control device(s) and an annual bill credit of $25 is provided to program participants in exchange for allowing the Company to control the listed appliances.

Residential EnergyWise℠ Home Program			
		MW Capability	
Cumulative as of:	Number of Participants*	Summer	Winter
December 31, 2015	143,186	281	10.3

* Number of participants represents the number of measures under control.

The following table shows Residential EnergyWise℠ Home Program activations that were not for testing purposes from July 1, 2014 through December 31, 2015.

Residential EnergyWise℠ Home			
Start Time	End Time	Duration (Minutes)	MW Load Reduction*
7/8/2014 15:30	7/8/2014 18:00	150	110.3
9/2/2014 15:00	9/2/2014 18:00	180	108.2
1/8/2015 6:30	1/8/2015 9:00	150	9.4
1/9/2015 6:30	1/9/2015 9:30	180	9.2
2/19/2015 6:30	2/19/2015 9:30	180	14.9
2/20/2015 6:30	2/20/2015 9:30	180	16
6/15/2015 15:00	6/15/2015 18:00	180	144
6/16/2015 15:00	6/16/2015 18:00	180	149.5
6/23/2015 15:00	6/23/2015 18:00	180	115.4

7/10/2015 16:30	7/10/2015 17:00	30	227.9
7/21/2015 15:00	7/21/2015 17:30	150	107.1
8/21/2015 16:00	8/5/2015 17:30	90	112.9

EnergyWise℠ for Business Program

EnergyWise℠ for Business is both an energy efficiency and demand response program for non-residential customers that allows DEP to reduce the operation of participants air conditioning units to mitigate system capacity constraints and improve reliability of the power grid.

Program participants can choose between a Wi-Fi thermostat or load control switch that will be professionally installed for free on each air conditioning or heat pump unit. In addition to equipment choice, participants can also select the cycling level they prefer (i.e., a 30%, 50% or 75% reduction of the normal on/off cycle of the unit). During a conservation period, DEP will send a signal to the thermostat or switch to reduce the on time of the unit by the cycling percentage selected by the participant. Participating customers will receive a $50 annual bill credit for each unit at the 30% cycling level, $85 for 50% cycling, or $135 for 75% cycling. Participants that have a heat pump unit with electric resistance emergency/back up heat and choose the thermostat can also participate in a winter option that allows control of the emergency/back up heat at 100% cycling for an additional $25 annual bill credit. Participants will also be allowed to override two conservation periods per year.

Participants choosing the thermostat will be given access to a portal that will allow them to set schedules, adjust the temperature set points, and receive energy conservation tips and communications from DEP anywhere they have internet access. In addition to the portal access, participants will also receive conservation period notifications, so they can make adjustments to their schedules or notify their employees of upcoming conservation periods.

The DEP EnergyWise℠ for Business program was implemented in January 2016.

Commercial, Industrial, and Governmental (CIG) Demand Response Automation Program

The CIG Demand Response Automation Program allows DEP to install load control and data acquisition devices to remotely control and monitor a wide variety of electrical equipment capable of serving as a demand response resource. The goal of this program is to utilize customer education, enabling two-way communication technologies, and an event-based incentive structure to maximize load reduction capabilities and resource reliability. The primary objective of this program is to reduce DEP's need for additional peaking generation. This is accomplished by

reducing DEP's seasonal peak load demands, primarily during the summer months, through deployment of load control and data acquisition technologies.

In response to EPA regulations finalized January 2013, a new Emergency Generator Option was implemented effective January 1, 2014, to allow customers with emergency generators to continue participation in demand response programs. To comply with the new rule, dispatch of the Emergency Generator Option was limited to NERC Level II (EEA2) except for an annual readiness test. More recently, on May 1, 2016, the DC Circuit Court of Appeals mandated vacatur of the provision that included demand response participation in the rule's 100 hour allowance. The vacatur resulted in the inability of existing Emergency Generator Option participants to continue participation as of May 1, 2016, and the need for DEP to begin plans to close the program option and file for approval to revise the rider to only include the Curtailable Option.

CIG Demand Response Automation Statistics			
Cumulative as of:	**Number of Participants**	**MW Capability**	
		Summer	**Winter**
December 31, 2015	59	24.3	14.0

The table below shows information for each CIG Demand Response Automation Program non-test control event from July 1, 2014 through December 31, 2015.

CIG Demand Response Automation – Curtailable Option			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction***
7/8/14 13:00	7/8/14 19:00	360	18.8
7/28/14 13:00	7/8/14 19:00	360	15.9
8/21/14 13:00	8/21/14 19:00	360	16.8
1/8/15 6:00	1/8/15 10:00	240	8.0
2/20/15 6:00	2/20/15 10:00	240	8.6
6/16/15 14:00	6/16/15 19:00	300	20.3
6/23/15 14:00	6/23/15 19:00	300	20.5

CIG Demand Response Automation – Emergency Generator Option			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction***
7/8/14 13:00	7/8/14 19:00	360	0.6
2/20/15 6:00	2/20/15 9:00	180	1.1
6/16/15 14:00	6/16/15 19:00	300	5.1

Previously Existing Demand Side Management and Energy Efficiency Programs

Prior to the passage of North Carolina Senate Bill 3 in 2007, DEP had a number of DSM/EE programs in place. These programs are available in both North and South Carolina and include the following:

Energy Efficient Home Program
Program Type: Energy Efficiency

In the early 1980s, DEP introduced an Energy Efficient Home program that provides residential customers with a 5% discount of the energy and demand portions of their electricity bills when their homes met certain thermal efficiency standards that were significantly above the existing building codes and standards. Homes that pass an ENERGY STAR® test receive a certificate as well as a 5% discount on the energy and demand portions of their electricity bills.

Curtailable Rates
Program Type: Demand Response

DEP began offering its curtailable rate options in the late 1970s, whereby industrial and commercial customers receive credits for DEP's ability to curtail system load during times of high energy costs and/or capacity constrained periods. The table below shows curtailable rate activation not for testing during the period from July 1, 2014 through December 31, 2015.

Curtailable Rate Activations			
Date	**Start/End Time**	**Duration (Minutes)**	**MW Load Reduction***
1/8/2015	06:00-10:00	240	240
2/20/2015	06:00-10:00	240	240

Time-of-Use Rates
Program Type: Demand Response

DEP has offered voluntary Time-of-Use (TOU) rates to all customers since 1981. These rates provide incentives to customers to shift consumption of electricity to lower-cost off-peak periods and lower their electric bill.

Thermal Energy Storage Rates
Program Type: Demand Response

DEP began offering thermal energy storage rates in 1979. The present General Service (Thermal Energy Storage) rate schedule uses two-period pricing with seasonal demand and energy rates applicable to thermal storage space conditioning equipment. Summer on-peak hours are noon to 8 p.m. and non-summer hours of 6 a.m. to 1 p.m. weekdays.

Real-Time Pricing
Program Type: Demand Response

DEP's Large General Service (Experimental) Real Time Pricing tariff was implemented in 1998. This tariff uses a two-part real time pricing rate design with baseline load representative of historic usage. Hourly rates are provided on the prior business day. A minimum of 1 MW load is required. This rate schedule is presently fully subscribed.

Summary of Available Existing Demand-Side and Energy Efficiency Programs

The following table provides current information available at the time of this report on DEP's pre-Senate Bill 3 DSM/EE programs (i.e., those programs that were in effect prior to January 1, 2008). This information, where applicable, includes program type, capacity, energy, and number of customers enrolled in the program as of the end of 2015, as well as load control activations since those enumerated in DEP's last biennial resource plan. The energy savings impacts of these existing programs are embedded within DEP's load and energy forecasts.

Program Description	Type	Capacity (MW)	Annual Energy (MWH)	Participants	Activations Since Last Biennial Report
Energy Efficiency Programs[11]	EE	473	NA	NA	NA
Real Time Pricing (RTP)	DSM	45	NA	105	NA
Commercial & Industrial TOU	DSM	10.9	NA	30,749	NA
Residential TOU	DSM	6.2	NA	28,011	NA
Curtailable Rates	DSM	269	NA	70	2

Future EE and DSM Programs

DEP is continually seeking to enhance its DSM/EE portfolio by: (1) adding new or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new measurement and verification (M&V) results, and (3) other EE pilots.

Potential new programs and/or measures will be reviewed with the DSM Collaborative then submitted to the Public Utility Commissions as required for approval.

EE and DSM Program Screening

The Company evaluates the costs and benefits of DSM and EE programs and measures by using the same data for both generation planning and DSM/EE program planning to ensure that demand-side resources are compared to supply side resources on a level playing field.

The analysis of energy efficiency and demand side management cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the California Standard tests: Utility Cost Test, Rate Impact Measure Test, Total Resource Cost Test, and Participant Test (PCT).

- The UCT compares utility benefits (avoided costs) to the costs incurred by the utility to implement the program, and does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided

[11] Impacts from these existing programs are embedded within the load and energy forecast.

costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, including the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs, and load (line) losses.

- The RIM Test, or non-participants test, indicates if rates increase or decrease over the long-run as a result of implementing the program.
- The TRC Test compares the total benefits to the utility and to participants relative to the costs to the utility to implement the program along with the costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the Participant Test, however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC.
- The Participant Test evaluates programs from the perspective of the program's participants. The benefits include reductions in utility bills, incentives paid by the utility and any State, Federal or local tax benefits received.

The use of multiple tests can ensure the development of a reasonable set of cost-effective DSM and EE programs and indicate the likelihood that customers will participate.

Energy Efficiency and Demand-Side Management Program Forecasts

The NCUC, in their Order Approving Integrated Resource Plans and REPS Compliance Plans regarding the 2014 Biennial IRP's, dated June 26, 2015 in Docket E-100, Sub141, issued the following Orders relative to EE/DSM analysis and forecasts:

7. *That the IOUs should continue to monitor and report any changes of more than 10% in the energy and capacity savings derived from DSM and EE between successive IRPs, and evaluate and discuss any changes on a program-specific basis. Any issues impacting program deployment should be thoroughly explained and quantified in future IRPs.*

8. *That each IOU shall continue to include a discussion of the status of EE market potential studies or updates in their future IRPs.*

These two Orders that are specific to EE and DSM are addressed in the following sections.

Forecast Methodology

In early 2012, DEP commissioned a new energy efficiency market potential study to obtain new estimates of the technical, economic and achievable potential for EE savings within the DEP service area. The final report, "Progress Energy Carolinas: Electric Energy Efficiency Potential

Assessment," was prepared by Forefront Economics Inc. and H. Gil Peach and Associates, LLC and was completed on June 5, 2012.

The Forefront study results are suitable for IRP purposes and for use in long-range system planning models. This study also helps to inform utility program planners regarding the extent of EE opportunities and to provide broadly defined approaches for acquiring savings. This study did not, however, attempt to closely forecast EE achievements in the short-term or from year to year. Such an annual accounting is highly sensitive to the nature of programs adopted as well as the timing of the introduction of those programs. As a result, it was not designed to provide detailed specifications and work plans required for program implementation. The study provides part of the picture for planning EE programs. Fully implementable EE program plans are best developed considering this study along with the experience gained from currently running programs, input from DEP program managers and EE planners, feedback from the DSM Collaborative and with the possible assistance of implementation contractors. An updated Market Potential Study is currently underway and the results of that study should be available in time for the next DEP IRP process.

DEP prepared a Base Portfolio savings projection that was based on DEP's five year program plan for 2016-2020. For periods beyond 2020, the Base Portfolio assumed that the annual savings projected for 2020 would continue to be achieved in each year thereafter until such time as the total cumulative EE projections reached approximately 60% of the Economic Potential as estimated by the Market Potential Study described above. This level of cumulative EE savings was projected to be reached in 2033. For periods beyond 2033, DEP assumed that additional EE savings impacts would continue to be achieved, however, the annual amount of those savings would be reduced to a level required to maintain the same cumulative EE achievement as a percentage of the Economic Potential. In other words, sufficient EE savings would be added to keep up with growth in the customer load.

Additionally, for the Base Portfolio described above DEP included an assumption for the purpose of the IRP analysis that, when the EE measures included in the forecast reach the end of their useful lives, the impacts associated with these measures are removed from the future projected EE impacts. This concept of "rolling off" the impacts from EE programs is explained further in Appendix C of this document.

The table below provides the Base Portfolio projected MWh load impacts of all DEP EE programs implemented since 2007 on a Gross and Net of Free Riders basis. Forecasted DSDR program impacts are adjusted each year based on actual results from the prior year and updated retail peak and system load forecasts. The Company assumes total EE savings will continue to grow on an annual basis throughout the planning period until reaching approximately 60% of the Economic Potential in about 2034, however, the components of future programs are uncertain at this time and

will be informed by the experience gained under the current plan. Please note that this table includes a column that shows historical EE program savings since the inception of the EE programs in 2009 through the end of 2015, which accounts for approximately an additional 2,070 gigawatt-hour (GWh) of Gross energy savings.

The following forecast is for the Base Portfolio without the effects of "rolloff":

Base Portfolio MWh Load Impacts of EE Programs

	Annual MWh Load Reduction - Gross				Annual MWh Load Reduction - Net			
	Including measures added in 2016 and beyond			Including measures added since 2007	Including measures added in 2016 and beyond			Including measures added since 2007
Year	Post SB-3 EE	DSDR	Total		Post SB-3 EE	DSDR	Total	
2007-15				2,069,991				1,528,724
2016	290,105	48,723	338,828	2,408,819	235,374	48,723	284,097	1,812,821
2017	556,862	49,325	606,187	2,676,178	448,751	49,325	498,076	2,026,800
2018	820,610	49,971	870,581	2,940,572	662,640	49,971	712,611	2,241,335
2019	1,071,028	50,602	1,121,629	3,191,621	865,695	50,602	916,296	2,445,020
2020	1,295,170	51,178	1,346,348	3,416,339	1,044,683	51,178	1,095,861	2,624,585
2021	1,519,312	51,670	1,570,983	3,640,974	1,223,369	51,670	1,275,040	2,803,764
2022	1,743,455	52,195	1,795,650	3,865,641	1,402,055	52,195	1,454,250	2,982,974
2023	1,967,597	52,701	2,020,299	4,090,290	1,580,740	52,701	1,633,442	3,162,166
2024	2,191,740	53,349	2,245,089	4,315,080	1,759,426	53,349	1,812,775	3,341,499
2025	2,415,882	53,912	2,469,794	4,539,785	1,938,112	53,912	1,992,024	3,520,748
2026	2,640,024	54,615	2,694,639	4,764,630	2,116,797	54,615	2,171,412	3,700,136
2027	2,864,167	55,277	2,919,444	4,989,435	2,295,483	55,277	2,350,760	3,879,484
2028	3,088,309	56,042	3,144,351	5,214,343	2,474,169	56,042	2,530,211	4,058,935
2029	3,312,451	56,700	3,369,152	5,439,143	2,652,854	56,700	2,709,555	4,238,279
2030	3,536,594	57,432	3,594,026	5,664,017	2,831,540	57,432	2,888,972	4,417,696
2031	3,760,736	58,236	3,818,972	5,888,963	3,010,226	58,236	3,068,462	4,597,186

**Please note that the MWh totals included in the tables above represent the annual year-end impacts associated with EE programs, however, the MWh totals included in the load forecast portion of this document represent the sum of the expected hourly impacts.*

The MW impacts from the EE programs are included in the Load Forecasting section of this IRP. The table below provides the Base Portfolio projected MW load impacts of all current and projected DEP DSM.

Base Portfolio Load Impacts of DSM Programs

	Annual Peak MW Reduction - Gross				Annual Peak MW Reduction - Net			
Year	DSM	DSDR	Pre SB-3 Programs	Total Annual Peak	DSM	DSDR	Pre SB-3 Programs	Total Annual Peak
2016	334	222	270	825	334	222	270	825
2017	372	224	273	869	372	224	273	869
2018	409	228	276	913	409	228	276	913
2019	440	232	278	951	440	232	278	951
2020	467	235	281	983	467	235	281	983
2021	484	238	284	1,006	484	238	284	1,006
2022	490	241	285	1,016	490	241	285	1,016
2023	490	244	285	1,019	490	244	285	1,019
2024	490	247	285	1,023	490	247	285	1,023
2025	491	250	285	1,026	491	250	285	1,026
2026	491	254	285	1,030	491	254	285	1,030
2027	491	257	285	1,033	491	257	285	1,033
2028	491	260	285	1,037	491	260	285	1,037
2029	491	264	285	1,040	491	264	285	1,040
2030	491	267	285	1,043	491	267	285	1,043
2031	491	271	285	1,047	491	271	285	1,047

Pursuing EE and DSM initiatives is not expected to meet the growing demand for electricity. DEP still envisions the need to secure additional generation, as well as cost-effective renewable generation, but the EE and DSM programs offered by DEP will address a significant portion of this need if such programs perform as expected.

EE Savings Variance since last IRP

In response to Order number 7 in the NCUC Order Approving Integrated Resource Plans and REPS Compliance Plans regarding the 2014 Biennial IRP's, the Base Portfolio EE savings forecast of MW and MWh was compared to the 2014 IRP and the cumulative achievements projected in the 2016 IRP at year 2033 of the forecast are approximately 30.1% higher than the cumulative achievements in the 2014 IRP for the same time period as shown in the table below. Part of this variance is due to an exceptionally strong performance over the last two years, during which time DEP's actual EE accomplishments were 28.5% higher than projected. This near-term variance, as well as the longer-term forecast variance, is due to an aggressive expansion of new and existing programs in the DEP EE portfolio over the past several years, including expansion of the My Home Energy Report into the DEP territory, the Multi Family EE Program, the Energy Efficiency Education Program, the Residential Energy Assessments Program and the Residential Save Energy and Water Kit Program. As mentioned earlier, another factor is the adoption of a revised forecast methodology that better aligns with the method used in the DEC IRP.

Base Portfolio Comparison to 2014 IRP - Gross

Year	2014 IRP Annual MWh Load Reduction		2016 IRP Annual MWh Load Reduction		% Change from 2014 to 2016 IRP
	Including measures added in 2014 and beyond	Including measures added since 2007	Including measures added in 2016 and beyond	Including measures added since 2007	
2014	225,214	1,368,084			
2015	467,656	1,610,527		2,069,991	28.5%
2016	724,195	1,867,066	290,105	2,360,096	26.4%
2017	915,163	2,058,034	556,862	2,626,853	27.6%
2018	1,135,353	2,278,223	820,610	2,890,601	26.9%
2019	1,381,341	2,524,212	1,071,028	3,141,019	24.4%
2020	1,644,724	2,787,595	1,295,170	3,365,161	20.7%
2021	1,918,355	3,061,226	1,519,312	3,589,304	17.3%
2022	2,185,183	3,328,054	1,743,455	3,813,446	14.6%
2023	2,444,434	3,587,305	1,967,597	4,037,588	12.6%
2024	2,695,143	3,838,014	2,191,740	4,261,731	11.0%
2025	2,894,882	4,037,753	2,415,882	4,485,873	11.1%
2026	3,074,232	4,217,103	2,640,024	4,710,015	11.7%
2027	3,230,876	4,373,747	2,864,167	4,934,158	12.8%
2028	3,362,169	4,505,040	3,088,309	5,158,300	14.5%
2029	3,467,037	4,609,908	3,312,451	5,382,442	16.8%
2030	3,531,384	4,674,255	3,536,594	5,606,585	19.9%
2031	3,572,999	4,715,870	3,760,736	5,830,727	23.6%

High EE Savings Projection

The Base Portfolio level EE forecast described above encompasses what the Company expects is achievable given the information about the economic potential and the achievable potential. In addition to this Base Portfolio level EE forecast, DEP also prepared a High Portfolio EE savings projection that assumed that the same types of programs offered in the Base Portfolio, including potential new technologies, can be offered at higher levels of participation provided that additional money is spent on program costs to encourage additional customers to participate. The High Portfolio included in the IRP modeling assumed a 50% increase in participation for all of the Base Portfolio programs, with the exception of programs already designed to reach all eligible participants in the Base Portfolio, including the various behavioral programs (MyHER and Business Energy Reports). In addition, due to changes in the costs and availability of LED lighting technologies, programs in the Base Portfolio related to CFL lighting were assumed to be fully addressed in the Base Portfolio, however, the High Portfolio assumes that additional KWh savings will be captured through LED programs. Finally, the High Portfolio assumed the same "rolling-off" assumption that was included in the Base portfolio. Specifically, that when the EE measures

included in the forecast reach the end of their useful lives, the impacts associated with those measures are removed from the future projected EE impacts.

The High Portfolio EE savings projections are higher than the expected achievable savings based on the Market Potential Study. The effort to achieve this High Portfolio would require a substantial expansion of DEP's current Commission-approved EE portfolio. More importantly, significantly higher levels of customer participation would need to be generated.

The table below show the projected High Portfolio savings on both Gross and Net of Free Riders basis without the effects of "rolloff":

High Portfolio MWh Load Impacts of EE Programs

	Annual MWh Load Reduction - Gross				Annual MWh Load Reduction - Net			
	Including measures added in 2016 and beyond			Including measures added since 2007	Including measures added in 2016 and beyond			Including measures added since 2007
Year	Post SB-3 EE	DSDR	Total		Post SB-3 EE	DSDR	Total	
2007-15				2,069,991				1,528,724
2016	428,638	48,723	477,361	2,547,352	346,541	48,723	395,265	1,923,989
2017	833,929	49,325	883,253	2,953,245	671,105	49,325	720,429	2,249,153
2018	1,236,209	49,971	1,286,180	3,356,172	997,332	49,971	1,047,303	2,576,027
2019	1,625,160	50,602	1,675,762	3,745,753	1,312,063	50,602	1,362,665	2,891,389
2020	1,987,836	51,178	2,039,014	4,109,005	1,602,844	51,178	1,654,022	3,182,746
2021	2,350,511	51,670	2,402,182	4,472,173	1,893,161	51,670	1,944,832	3,473,556
2022	2,713,187	52,195	2,765,382	4,835,373	2,183,479	52,195	2,235,674	3,764,399
2023	3,075,862	52,701	3,128,564	5,198,555	2,473,797	52,701	2,526,498	4,055,222
2024	3,438,538	53,349	3,491,887	5,561,878	2,764,115	53,349	2,817,464	4,346,188
2025	3,801,213	53,912	3,855,125	5,925,116	3,054,432	53,912	3,108,344	4,637,068
2026	4,163,889	54,615	4,218,503	6,288,495	3,344,750	54,615	3,399,365	4,928,089
2027	4,526,564	55,277	4,581,841	6,651,832	3,635,068	55,277	3,690,345	5,219,069
2028	4,889,239	56,042	4,945,282	7,015,273	3,925,385	56,042	3,981,428	5,510,152
2029	5,251,915	56,700	5,308,615	7,378,607	4,215,703	56,700	4,272,403	5,801,128
2030	5,614,590	57,432	5,672,023	7,742,014	4,506,021	57,432	4,563,453	6,092,177
2031	5,977,266	58,236	6,035,502	8,105,493	4,796,338	58,236	4,854,575	6,383,299

At this time, there is significant uncertainty in the development of new technologies that will impact the level of EE achievement from future programs and/or enhancements to existing programs, as well as in the ability to secure high levels of customer participation, to risk including the high EE savings projection in the base assumptions for developing the 2016 IRP. DEP expects that over time, as EE programs are implemented, the Company will continue to

gain experience and evidence on the viability of the level of EE achieved given actual customer participation. As information becomes available on actual participation, technology changes, and EE achievement, then the EE savings forecast used for integrated resource planning purposes will be revised in future IRP's to reflect the most realistic projection of EE savings.

Programs Evaluated but Rejected

Duke Energy Progress has not rejected any cost-effective programs as a result of its EE and DSM program screening.

Looking to the Future - Grid Modernization (Smart Grid Impacts)

Duke Energy Progress' Distribution System Demand Response (DSDR) program is an Integrated Volt-Var Control (IVVC) program that better manages the application and operation of voltage regulators (the Volt) and capacitors (the VAR) on the Duke Energy Progress distribution system. In general, the project tends to optimize the operation of these devices, resulting in a "flattening" of the voltage profile across an entire circuit, starting at the substation and continuing out to the farthest endpoint on that circuit. This flattening of the voltage profile is accomplished by automating the substation level voltage regulation and capacitors, line capacitors and line voltage regulators while integrating them into a single control system. This control system continuously monitors and operates the voltage regulators and capacitors to maintain the desired "flat" voltage profile. Once the system is operating with a relatively flat voltage profile across an entire circuit, the resulting circuit voltage at the substation can then be operated at a lower overall level. Lowering the circuit voltage at the substation, results in an immediate reduction of system loading during peak conditions.

Discontinued Demand Side Management and Energy Efficiency Programs

Since the last biennial Resource Plan filing, DEP discontinued the following DSM/EE programs or measures.

- Residential Energy Efficient Benchmarking Program – The NCUC approved terminating this program in December 2014, at which time it also approved the My Home Energy Report (MyHER) as a new program.

Current and Anticipated Consumer Education Programs

In addition to the DSM/EE programs previously listed, DEP also has the following informational and educational programs.

- On Line Account Access
- "Lower My Bill" Toolkit
- Online Energy Saving Tips
- Energy Resource Center
- Large Account Management
- eSMART Kids Website
- Community Events

On Line Account Access

On Line Account Access provides energy analysis tools to assist customers in gaining a better understanding of their energy usage patterns and identifying opportunities to reduce energy consumption. The service allows customers to view their past 24 months of electric usage including the date the bill was mailed; number of days in the billing cycle; and daily temperature information. This program was initiated in 1999.

"Lower My Bill" Toolkit

This tool, implemented in 2004, provides on-line tips and specific steps to help customers reduce energy consumption and lower their utility bills. These range from relatively simple no-cost steps to more extensive actions involving insulation and heating and cooling equipment.

Online Energy Saving Tips

DEP has been providing tips on how to reduce home energy costs since approximately 1981. DEP's web site includes information on household energy wasters and how a few simple actions can increase efficiency. Topics include: Energy Efficient Heat Pumps, Mold, Insulation R-Values, Air Conditioning, Appliances and Pools, Attics and Roofing, Building/Additions, Ceiling Fans, Ducts, Fireplaces, Heating, Hot Water, Humidistats, Landscaping, Seasonal Tips, Solar Film, and Thermostats.

Energy Resource Center

In 2000, DEP began offering its large commercial, industrial, and governmental customers a wide array of tools and resources to use in managing their energy usage and reducing their electrical demand and overall energy costs. Through its Energy Resource Center, located on the DEP web site, DEP provides newsletters, online tools and information, which cover a variety of energy efficiency topics such as electric chiller operation, lighting system efficiency, compressed air systems, motor management, variable speed drives and conduct an energy audit.

Large Account Management

All DEP commercial, industrial, and governmental customers with an annual electric bill greater than $250,000 are assigned to a DEP Account Executive (AE). The AEs are available to personally assist customers in evaluating energy improvement opportunities and can bring in other internal resources to provide detailed analyses of energy system upgrades. The AEs provide their customers with a monthly electronic newsletter, which includes energy efficiency topics and tips. They also offer numerous educational opportunities in group settings to provide information about DEP's new DSM and EE program offerings and to help ensure the customers are aware of the latest energy improvement and system operational techniques.

e-SMART Kids Website

DEP is offering an educational online resource for teachers and students in our service area called e-SMART Kids. The web site educates students on energy efficiency, conservation, and renewable energy and offers interactive activities in the classroom. It is available on the web at http://www.e-smartonline.net/safeelectricity/.

Community Events

DEP representatives participated in community events across the service territory to educate customers about DEP's energy efficiency programs and rebates and to share practical energy saving tips. DEP energy experts attended events and forums to host informational tables and displays, and distributed handout materials directly encouraging customers to learn more about and sign up for approved DSM/EE energy saving programs.

Discontinued Consumer Education Programs

DEP has not discontinued any consumer education programs since the last biennial Resource Plan filing.

APPENDIX E: FUEL SUPPLY

Duke Energy Progress' current fuel usage consists primarily of coal and uranium. Oil and gas have traditionally been used for peaking generation, but natural gas has begun to play a more important role in the fuel mix due to lower pricing and the addition of a significant amount of combined cycle generation. These additions will further increase the importance of gas to the Company's generation portfolio. A brief overview and issues pertaining to each fuel type are discussed below.

Natural Gas

During 2015, spot Henry Hub natural gas prices averaged approximately $2.60 per million BTU (MMBtu) and U.S. lower-48 net dry production averaged approximately 72 billion cubic feet per day (BCF/day). For 2016, natural gas spot prices at the Henry Hub averaged approximately $2.27 in January 2016. Henry Hub spot pricing decreased throughout the remaining winter months and reached a low of approximately $1.485 per MMBtu on March 5, 2016. The decline in short-term spot prices during the first quarter of 2016 were driven by both fundamental supply and demand factors.

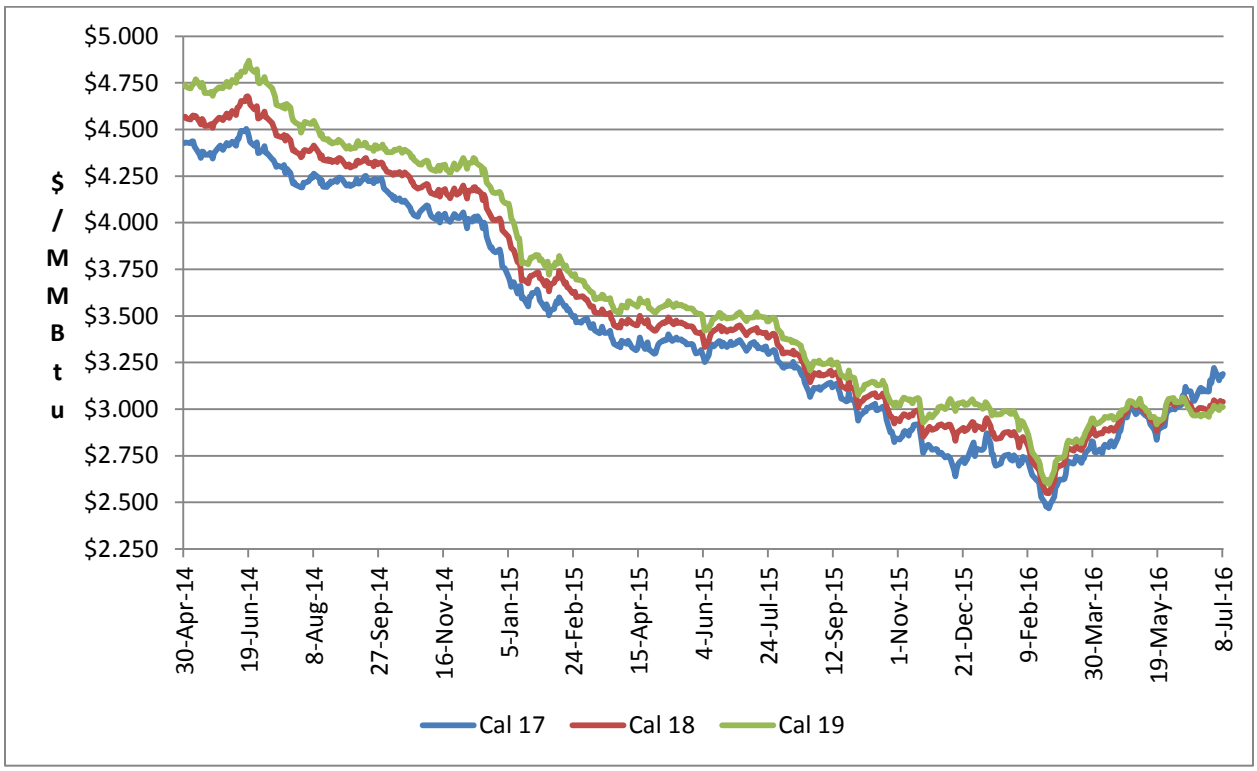
Average daily U.S. net dry production levels of approximately 72.7 BCF/day in the first quarter of 2016 were relatively comparable with 2015 net dry production. Storage ended the winter withdrawal season at a record high of 2.47 per trillion cubic feet (TCF) on March 31, 2016. Lower-48 U.S. demand in the first quarter of 2016 was lower than normal due to the mild winter weather which lowered residential heating needs.

Summer 2016 spot natural gas prices have increased from the March 2016 lows outlined previously. The Henry Hub spot price settled in a range between approximately $2.65 to $2.85 per MMBtu in mid-July 2016. Working gas in storage remains above the 5 year average and storage balances from a year ago, although the surplus has declined over the last few months with higher gas generation burns and declining overall net dry gas production which as of August 15, 2016 is approximately 71.4 BCF/day. Observed average NYMEX Henry Hub prices for the winter period November 2016 through March 2017 have increased along with the overall market to approximately $3.09 per MMBtu from the lows observed in late February 2016. Although predicting actual storage balances at the end of the typical injection season is not possible, current projections are roughly 3.8 to 3.9 TCF of working gas in storage at the end of the injection season.

Natural gas consumption is expected to remain strong through the remainder of 2016 and 2017, due primarily to increases in electric power usage. Per the EIA's short-term energy outlook released on July 12, 2016, this year is forecasted to be a record-setting year for gas consumption by power

generators. Gas generation is forecasted to exceed coal for the first time annually and account for approximately 34% of U.S. electricity. The EIA estimates that total natural gas production has decreased approximately 1 BCF/day from February 2016 to June 2016 as the market is responding to lower market prices. Producers are right sizing their well production and cutting capex in response to lower spot and forward natural gas prices. With advanced drilling techniques, producers appear able to adjust drilling programs in response to changing market prices to shorten or extend the term of the producing well. According to Baker Hughes, as of July 15, 2016 the U.S. Natural Gas rig count was at 89. This is down from 218 natural gas last year at the same time. This represents a 19 year low in the gas rig count.

In addition to the trends in shorter term natural gas spot price levels for 2016, in late February 2016, the observed forward market prices for the periods of 2017 through 2020 declined to approximately $2.58 per MMBtu. Prices have increased over the last few months from these historical low forward price levels to approximately $3.03 per MMBtu as of late July 2016. This is illustrated in the graph below.



Looking forward, the forward 5 and 10 year observable market curve are at $3.06 and $3.37 per MMBtu, respectively as of the July 21, 2016 close. In addition, as of the close of business on July 8, 2016, the one(1), three(3) and five(5) years strips were all approximately $3.07 per MMBtu. As

illustrated with these price levels and relationships, the forward NYMEX Henry Hub price curve is extremely flat with the periods of 2018 and 2019 currently trading at discounts to 2017 prices. The gas market is expected to remain relatively stable due to an improving economic picture which may provide supply and demand to further come into balance. . As noted above, demand from the power sector for 2016 is expected to be higher than coal generation due to coal retirements, which are tied to the implementation of the EPA's MATS rule covering mercury and acid gasses. This increase is expected to be followed by new demand in the industrial and LNG export sectors, which both ramp up in the 2016 through 2020 timeframe. Lastly, although the outcome and timing is uncertain given the current legal status of the Clean Power Plan, there could be additional gas demand as a result of the implementation of the previously announced EPA requirement to reduce carbon emissions.

The long-term fundamental gas price outlook continues to be little changed from previous forecast even though it includes higher overall demand. The North American gas resource picture is a story of unconventional gas production dominating the gas industry. Shale gas now accounts for approximately 60% of net natural gas production today, which has increased from approximately 38% in 2014. Per the Short-Term EIA outlook dated July 12, 2016, the EIA expects production to rise in the second half of 2016 and 2017 in response to forecasted increases in prices and liquefied natural gas (LNG) exports. Additionally, the EIA forecasts the United States transitioning from a net importer of 1.3 TCF of natural gas in 2013 to a net exporter in 2017. Overall, the EIA expects marketed natural gas to rise by approximately 1.7% for the balance of 2016 and by 4.3% by the end of 2017.

The US power sector still represents the largest area of potential new gas demand, but increased usage is expected to be somewhat volatile as generation dispatch is sensitive to price. Looking forward, economic dispatch competition is expected to continue between gas and coal, although there has been some permanent loss in overall coal generation due to the number of coal unit retirements. Overall declines in energy consumption tend to result from the adoption of more energy-efficient technologies and policies that promote energy efficiency.

In order to ensure adequate natural gas supplies, transportation and storage, the company has gas procurement strategies that include periodic RFPs, market solicitations, and short-term market engagement activities to procure a reliable, flexible, diverse, and competitively priced natural gas supply that supports DEP's CT and CC facilities. With respect to storage and transportation needs, the company has continued to add incremental firm pipeline capacity and gas storage as its gas generation fleet has grown. The company will continue to evaluate competitive options to meet its growing need for gas pipeline infrastructure as the gas generation fleet grows.

Coal

On average, the 2016 Duke fundamental outlook for coal prices is lower than the 2015 outlook. The power sector accounted for 90.5 % of total demand for coal in 2015, equivalent to 772 million tons of burn. The main determinants of power sector coal demand are natural gas prices, electricity demand growth, and non-fossil electric generation, namely nuclear, hydro, and renewables.

Low natural gas prices continue to exert extreme pressure on the coal fleet resulting in the reduction of coal's competitiveness across virtually all basins and caused generator coal stocks to reach near-term highs. Coal shipments to generators will be even lower than actual burn as these high inventory levels are worked down, a process that could take about two years.

Annual electric load growth, inclusive of energy efficiency impacts, is roughly 1%. The U.S. Supreme Court granted a stay, halting implementation of the EPA's Clean Power Plan pending the resolution of legal challenges to the program in court. Though stayed, the CPP makes retention of coal capacity less desirable. The fundamental outlook anticipates the eventual implementation of CPP beginning in 2022, resulting in a long-term decline in power generation from coal. The coal fired power plants projected to retire during the forecast period burned almost 60 million tons of coal during 2015 which represents approximately 8% of the total 2015 burn. Growth in renewable generation also contributes to the decline in coal demand.

Exports of both thermal and metallurgical coals have been hurt by the strength of the US dollar coupled with the slowing growth of the Chinese economy. In addition, China has implemented import tariffs to protect their domestic coal production.

Finally, the coal industry is in the midst of unprecedented restructuring. It is uncertain how responsive either producers or transporters of coal will be if faced with unexpected periods of increased demand.

Nuclear Fuel

To provide fuel for Duke Energy's nuclear fleet, the Company maintains a diversified portfolio of natural uranium and downstream services supply contracts from around the world.

Requirements for uranium concentrates, conversion services and enrichment services are primarily met through a portfolio of long-term supply contracts. The contracts are diversified by supplier, country of origin and pricing. In addition, DEP staggers its contracting so that its

portfolio of long-term contracts covers the majority of fleet fuel requirements in the near-term and decreasing portions of the fuel requirements over time thereafter. By staggering long-term contracts over time, the Company's purchase price for deliveries within a given year consists of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. Diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply. Near-term requirements not met by long-term supply contracts have been and are expected to be fulfilled with spot market purchases.

Due to the technical complexities of changing suppliers of fuel fabrication services, DEP generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

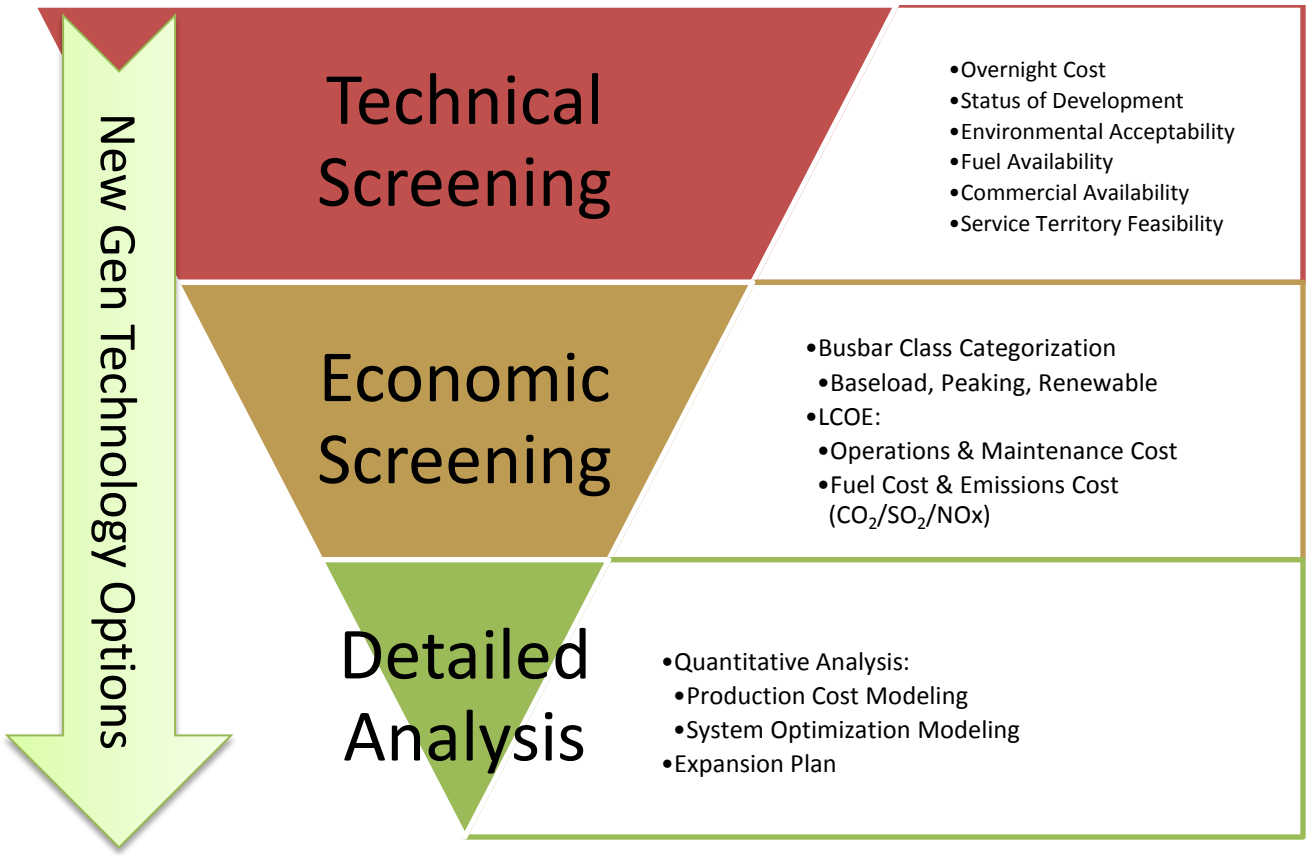
As fuel with a low cost basis is used and lower-priced legacy contracts are replaced with contracts at higher market prices, nuclear fuel expense is expected to increase in the future. Although the costs of certain components of nuclear fuel are expected to increase in future years, nuclear fuel costs are expected to be competitive with alternate generation and customers will continue to benefit from the Company's diverse generation mix.

APPENDIX F: SCREENING OF GENERATION ALTERNATIVES

The Company screens generation technologies prior to performing detailed analysis in order to develop a manageable set of possible generation alternatives. Generating technologies are screened from both a technical perspective, as well as an economic perspective. In the technical screening, technology options are reviewed to determine technical limitations, commercial availability issues and feasibility in the Duke Energy Progress service territory.

Economic screening is performed using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves. The technologies must be technically and economically viable in order to be passed on to the detailed analysis phase of the IRP process.

Figure 6-A: New Generation Technologies Screening Process



Technical Screening

The first step in the Company's supply-side screening process for the IRP is a technical screening of the technologies to eliminate those that have technical limitations, commercial availability issues, or are not feasible in the Duke Energy Progress service territory. A brief explanation of the technologies excluded at this point and the basis for their exclusion follows:

- **Geothermal** was eliminated because there are no suitable geothermal resources in the region to develop into a power generation project.

- **Pumped Storage Hydropower (PSH)** is the only conventional, mature, commercial, utility-scale electricity storage option available currently. This technology consumes off-peak electricity by pumping water from a lower reservoir to an upper reservoir. When the electric grid needs more electricity and when electricity prices are higher, water is released from the upper reservoir. As the water flows from the upper reservoir to the lower reservoir, it goes through a hydroelectric turbine to generate electricity. Many operational pumped storage hydropower plants are providing electric reliability and reserves for the electric grid in high demand situations. PSH can provide a high amount of power because its only limitation is the capacity of the upper reservoir. Typically, these plants can be as large as 4,000 MW, and have an efficiency of 76% - 85% Electric Power Research Institute (EPRI, 2012). Therefore, this technology is effective at meeting electric demand and transmission overload by shifting, storing, and producing electricity. This is important because an increasing supply of intermittent renewable energy generation such as solar will cause challenges to the electric grid. PSH installations are greatly dependent on regional geography and face several challenges including: environmental impact concerns, a long permitting process, and a relatively high initial capital cost. Duke Energy currently has two PSH assets on the DEC system, Bad Creek Reservoir and Jocassee Hydro with an approximate combined generating capacity of 2,140MW.

- **Compressed Air Energy Storage (CAES)**, although demonstrated on a utility scale and generally commercially available, is not a widely applied technology and remains relatively expensive. Traditional systems require a suitable storage site, commonly underground where the compressed air is stored and later used to boost the output of a gas turbine. The high capital requirements for these resources arise from the fact that suitable sites that possess the proper geological formations and conditions necessary for the compressed air storage reservoir are relatively scarce, especially in the

Carolinas. However, above-ground compressed air energy storage (AGCAES) technologies are under development but at a much smaller scale, approximately 0.5 - 20MW. Several companies have attempted to develop cost effective CAES systems using above ground storage tanks. Most attempts to date have not been commercially successful, but their development is being monitored.

- **Small Modular Nuclear Reactors (SMR)** are generally defined as having capabilities of less than 300 MW. In 2012, the U.S. Department of Energy (DOE) solicited bids for companies to participate in a small modular reactor grant program with the intent to "promote the accelerated commercialization of SMR technologies to help meet the nation's economic energy security and climate change objectives." SMRs are still conceptual in design and are developmental in nature. Licensing for SMR's has not been approved by the NRC at present. Currently, there is no industry experience with developing this technology outside of the conceptual phase. Duke Energy will be monitoring the progress of the SMR projects for potential consideration and evaluation for future resource plans as they provide an emission free source of fuel diverse, flexible generation.

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

- **Supercritical CO_2 Brayton Cycle** is of increasing interest; however, the technology is not mature or ready for commercialization. Several pilots are underway and Duke Energy will continue to monitor their development as a potential source of future generation needs.

- **Poultry waste and swine waste digesters** remain relatively expensive and are often faced with operational and/or permitting challenges. Research, development, and demonstration continue, but these technologies remain generally too expensive or face obstacles that make them impractical energy choices outside of specific mandates calling for use of these technologies.

- **Off-shore Wind**, although demonstrated on a utility scale and commercially available, is not a widely applied technology and not easily permitted in the United States. This technology remains expensive even with the five year tax credit extension granted in December 2015 and has yet to actually be constructed anywhere in the United States. Pioneer wind farm is the first to "break water" off the coast of Rhode Island. Federal waters have not yet been released for wind turbine farm siting; however, state waters are within the rights of the State to exercise jurisdiction. Rhode Island's Block Island is within the 3-mile State waters jurisdiction but strategically located in a manner to gain enough available wind resource to support its economic feasibility. Pioneer is a 30MW demonstration that will utilize five, 6 MW Alstom wind turbines and is expected to be operational by year end 2016. The U.S. Department of the Interior's Bureau of Ocean Energy Management (BOEM) has held several auctions for offshore lease. These sites will be utilized to collect marine and wind data for potential future development of an offshore wind farm.

- **Solar Steam Augmentation** systems utilize solar thermal energy to supplement a Rankine steam cycle such as that in a fossil generating plant. The supplemental steam could be integrated into the steam cycle and support additional MW generation similar in concept to the purpose of duct firing a heat recovery steam generator. This technology, although attractive has several hurdles yet to clear, including a clean operating history and initial capital cost reductions. This technology is very site specific and Duke Energy will continue to monitor developments in the area of steam augmentation.

A brief explanation of the technology additions for 2016 and the basis for their inclusion follows:

- **Addition of Combined Heat & Power (CHP) to the IRP**

  Combined Heat and Power systems, also known as cogeneration, generate electricity and useful thermal energy in a single, integrated system. CHP is not a new technology, but an approach to applying existing technologies. Heat that is normally wasted in conventional power generation is recovered as useful energy, which avoids the losses that would otherwise be incurred from separate generation of heat and power. CHP incorporating a CT and heat recovery steam generator (HRSG) is more efficient than the conventional method of producing usable heat and power separately via a gas package boiler.

Duke Energy is exploring and working with potential customers with good base thermal loads on a regulated Combined Heat and Power offer. The CHP asset will be included as part of Duke Energy's IRP as a placeholder for future projects as described below. The steam sales are credited back to the revenue requirement of the projects to reduce the total cost of this generation grid resource. Along with the potential to be a competitive cost generation resource, CHP can result in CO_2 emission reductions, deferral of T&D expenses, and present economic development opportunities for the state.

Duke Energy has publically announced its first CHP project, a 20 MW (summer) investment at Duke University. We are currently working with other industrial, military and Universities for future project expansions.

- **Addition of Battery Storage to the IRP**

Energy storage solutions are becoming an ever growing necessity in support of grid stability at peak demand times and in support of energy shifting and smoothing from renewable sources. Energy Storage in the form or battery storage is becoming more feasible with the advances in battery technology (Tesla low-cost Lithium-ion battery technology) and the reduction in battery cost; however, their uses (even within Duke Energy) have been concentrated on frequency regulation, solar smoothing, and/or energy shifting from localized renewable energy sources with a high incidence of intermittency (i.e. solar and wind applications).

Duke Energy has several projects in operation since 2011, mainly in support of regulating output voltages/frequencies from renewable energy sources to the grid. This includes projects as large as the Notrees Battery Storage project (36 MW) which supports a wind farm down to the smaller 250 kW Marshall Battery Storage Project which supports a 1.2 MW solar array. Additional examples include the Rankin Battery Storage Project (402 kW), the McAlpine Community Energy Storage Project (24 kW), McAlpine Substation Energy Storage Project (200 kW), and a 2 MW facility on Ohio's former Beckjord Station grounds. Each of these applications supports frequency regulation, solar smoothing, or energy shifting from a local solar array. These examples are only a few in support of a growing trend of coupling Battery Storage with an intermittent renewable energy source such as solar or wind in an effort to stabilize output and increase a facility's (renewable plus storage) net capacity factor.

Beginning in 2016, Distributed Energy Resources, formed an Energy Storage (ES) team to develop a fifteen year battery storage prediction model and begin the development of battery storage deployment plans for the next five year budget cycle. The ES team will focus their five year plan across multiple jurisdictions, however, the first two areas that will most likely provide deployment sites are Duke Energy Indiana (DEI) (substation utility scale application) and western NC, Asheville Regional area (130kV distribution circuit assessment) in DEP. Regional battery storage modeling is proceeding in 2016 to establish battery system sites, use case designs and cost/benefit analysis. Regulatory approvals and cost recovery development will play a key role in the timing of full operational battery system deployment.

Economic Screening

The Company screens all technologies using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves. The screening within each general class (Baseload, Peaking/Intermediate, and Renewables), as well as the final screening across the general classes uses a spreadsheet-based screening curve model developed by Duke Energy. This model is considered proprietary, confidential and competitive information by Duke Energy.

This screening curve analysis model includes the total costs associated with owning and maintaining a technology type over its lifetime and computes a levelized $/kW-year value over a range of capacity factors. The Company repeats this process for each supply technology to be screened resulting in a family of lines (curves). The lower envelope along the curves represents the least costly supply options for various capacity factors or unit utilizations. Some technologies have screening curves limited to their expected operating range on the individual graphs. Lines that never become part of the lower envelope, or those that become part of the lower envelope only at capacity factors outside of their relevant operating ranges, have a very low probability of being part of the least cost solution, and generally can be eliminated from further analysis.

The Company selected the technologies listed below for the screening curve analysis. While Clean Power Plan (CPP) regulation may effectively preclude new coal-fired generation, Duke Energy Progress has included ultra-supercritical pulverized coal (USCPC) with carbon capture sequestration (CCS) and integrated gasification combined cycle (IGCC) technologies with CCS of 1400 pounds/net MWh capture rate as options for base load analysis consistent with the pending version of the EPA Clean Power Plan for new coal plants. Additional detail on the expected impacts from EPA regulations to new coal-fired options is included in Appendix G. 2016 additions include Combined Heat and Power as a base load technology and Lithium ion Battery Storage as a renewable technology.

Dispatchable (Summer Ratings)

- Base load – 782 MW Ultra-Supercritical Pulverized Coal with CCS
- Base load – 557 MW 2x1 IGCC with CCS
- Base load – 2 x 1,117 MW Nuclear Units (AP1000)
- Base load – 576 MW – 1x1x1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Base load – 1,160 MW – 2x2x1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Base load – 20 MW – Combined Heat & Power (CHP)
- Peaking/Intermediate – 166 MW 4 x LM6000 Combustion Turbines
- Peaking/Intermediate – 201 MW 12 x Reciprocating Engine Plant
- Peaking/Intermediate – 870 MW 4 x 7FA.05 Combustion Turbines
- Renewable – 2 MW / 8 MWh Li-ion Battery

Non-Dispatchable

- Renewable – 150 MW Wind - On-Shore
- Renewable – 5 MW Solar PV

Information Sources

The cost and performance data for each technology being screened is based on research and information from several sources. These sources include, but may not be limited to the following internal Departments: Duke Energy's Project Management & Construction, Emerging Technologies, and Generation & Regulatory Strategy. The following external sources may also be utilized: proprietary third-party engineering studies, the Electric Power Research Institute Technical Assessment Guide (TAG®), and Energy Information Administration (EIA). In addition, fuel and operating cost estimates are developed internally by Duke Energy, or from other sources such as those mentioned above, or a combination of the two. EPRI information or other information or estimates from external studies are not site-specific, but generally reflect the costs and operating parameters for installation in the Carolinas. Finally, every effort is made to ensure that capital, O&M costs fuel costs and other parameters are current and include similar scope across the technologies being screened. The supply-side screening analysis uses the same fuel prices for coal and natural gas, and nitrogen oxides (NO_X), sulfur dioxide (SO_2), and CO_2 allowance prices as those utilized downstream in the detailed analysis (discussed in Appendix A). Screening curves were developed for each technology to show the economics with and without carbon costs (i.e. No Carbon Tax, Carbon Tax, System Carbon Mass Cap).

Screening Results

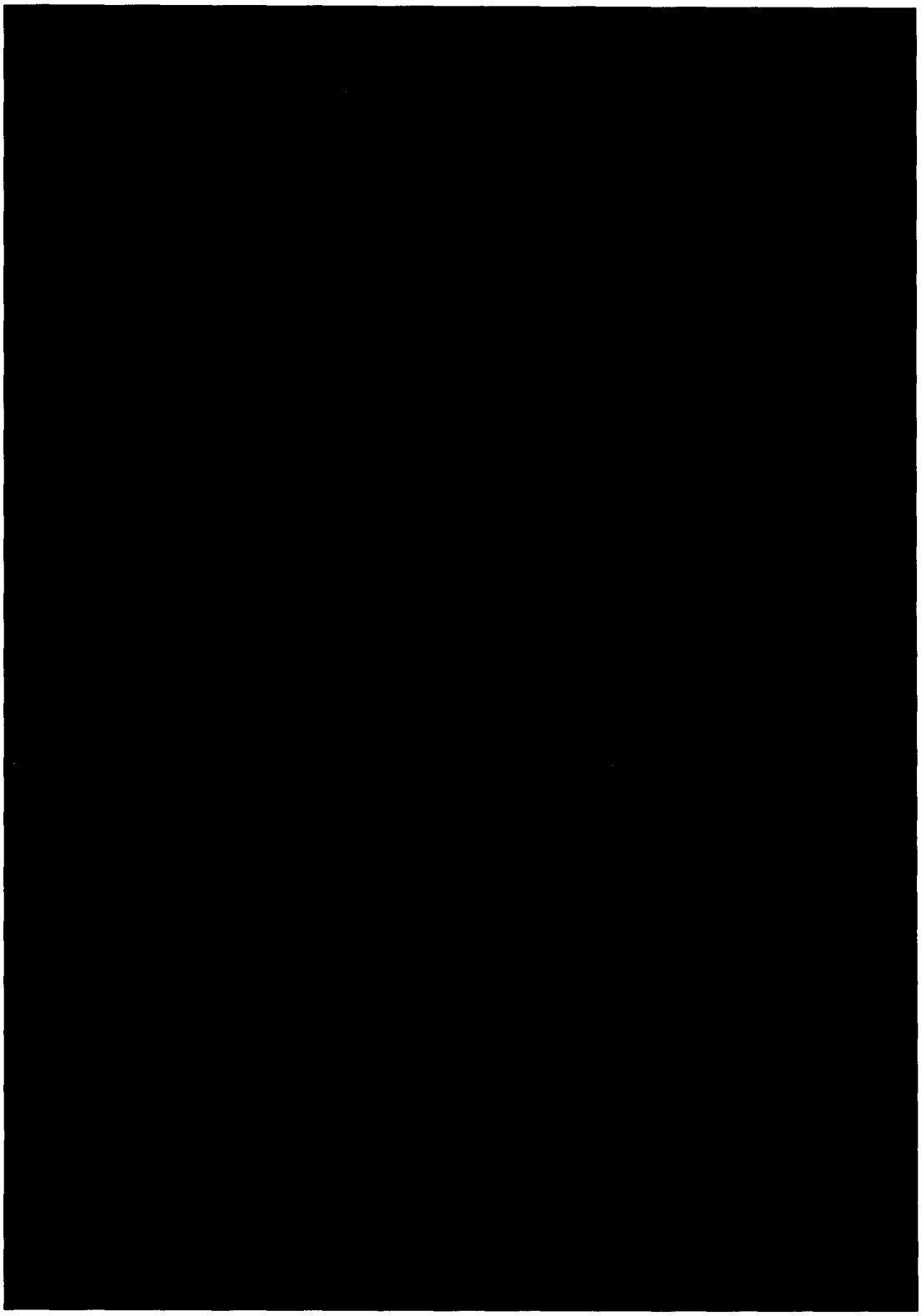
The results of the screening within each category are shown in the figures below. Results of the baseload screening show that natural gas combined cycle generation is the least-cost base load resource. With lower gas prices, larger capacities and increased efficiency, natural gas combined cycle units have become more cost-effective at higher capacity factors in all carbon scenario screening cases (i.e. No Carbon Tax, Carbon Tax, System Carbon Mass Cap). Although CHP is competitive with CC at the upper end of the capacity range, it is site specific, requiring a local steam and electrical load. The baseload curves also show that nuclear generation may be a cost effective option at high capacity factors with CO_2 costs included. Carbon capture systems have been demonstrated to reduce coal-fired CO_2 emissions to levels similar to natural gas and will continue to be monitored as they mature; however, their current cost and uncertainty of safe, reliable storage options has limited the technical viability of this technology.

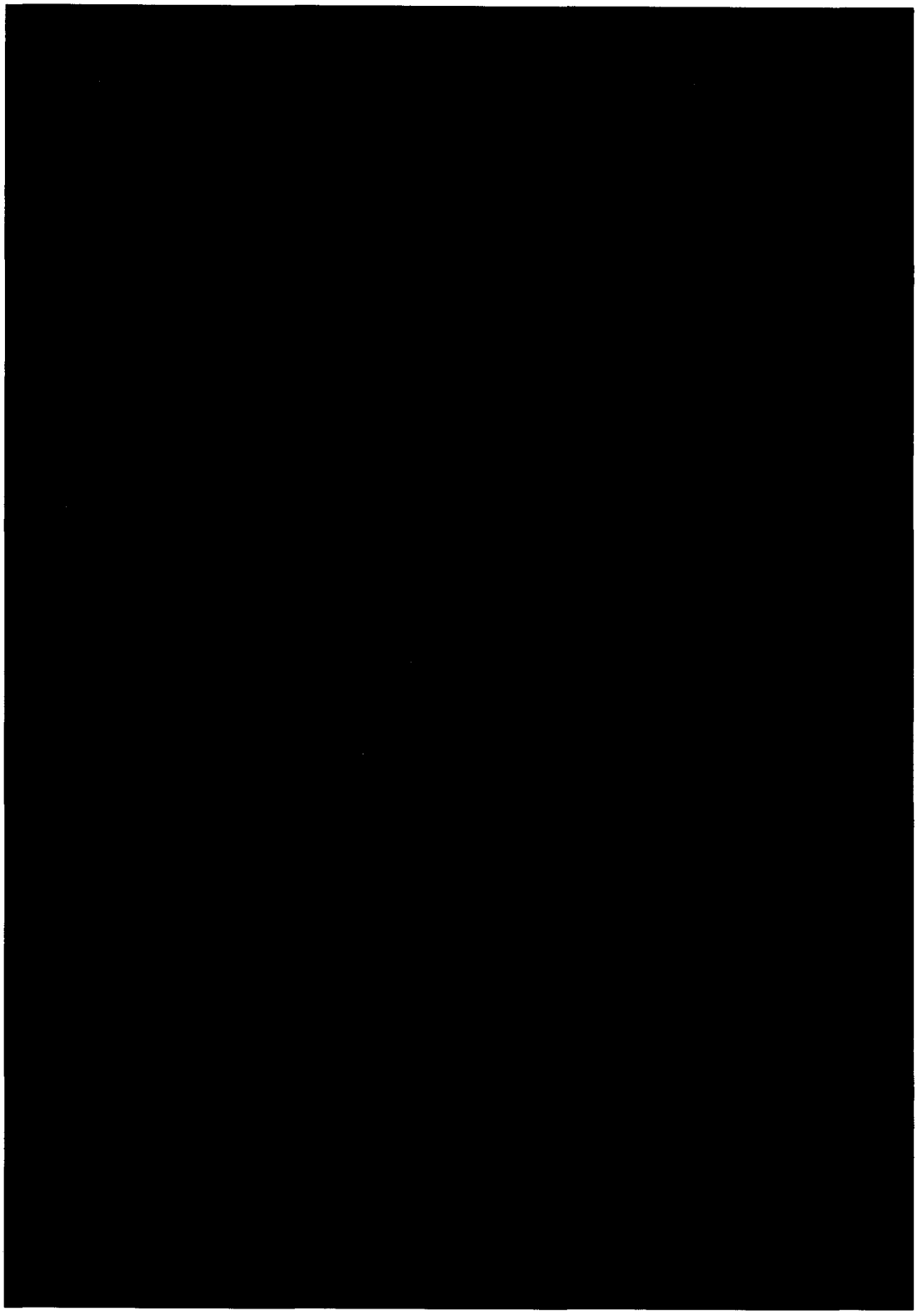
The peaking/intermediate technology screening included F-frame combustion turbines, fast start aero-derivative combustion turbines, and fast start reciprocating engines. The screening curves show the F-frame CTs to be the most economic peaking resource unless there is a special application that requires the fast start capability of the aero-derivative CTs or reciprocating engines. Reciprocating engine plants offer the lowest heat rates and fastest start times among simple cycle options. In addition, the recent strength of the U.S. dollar compared to the Euro has led to reduced costs for reciprocating engines imported from Europe. However, the volatility of the exchange rates should be considered for the generic selection of this technology, especially with the potential British withdrawal from the European Union (EU).

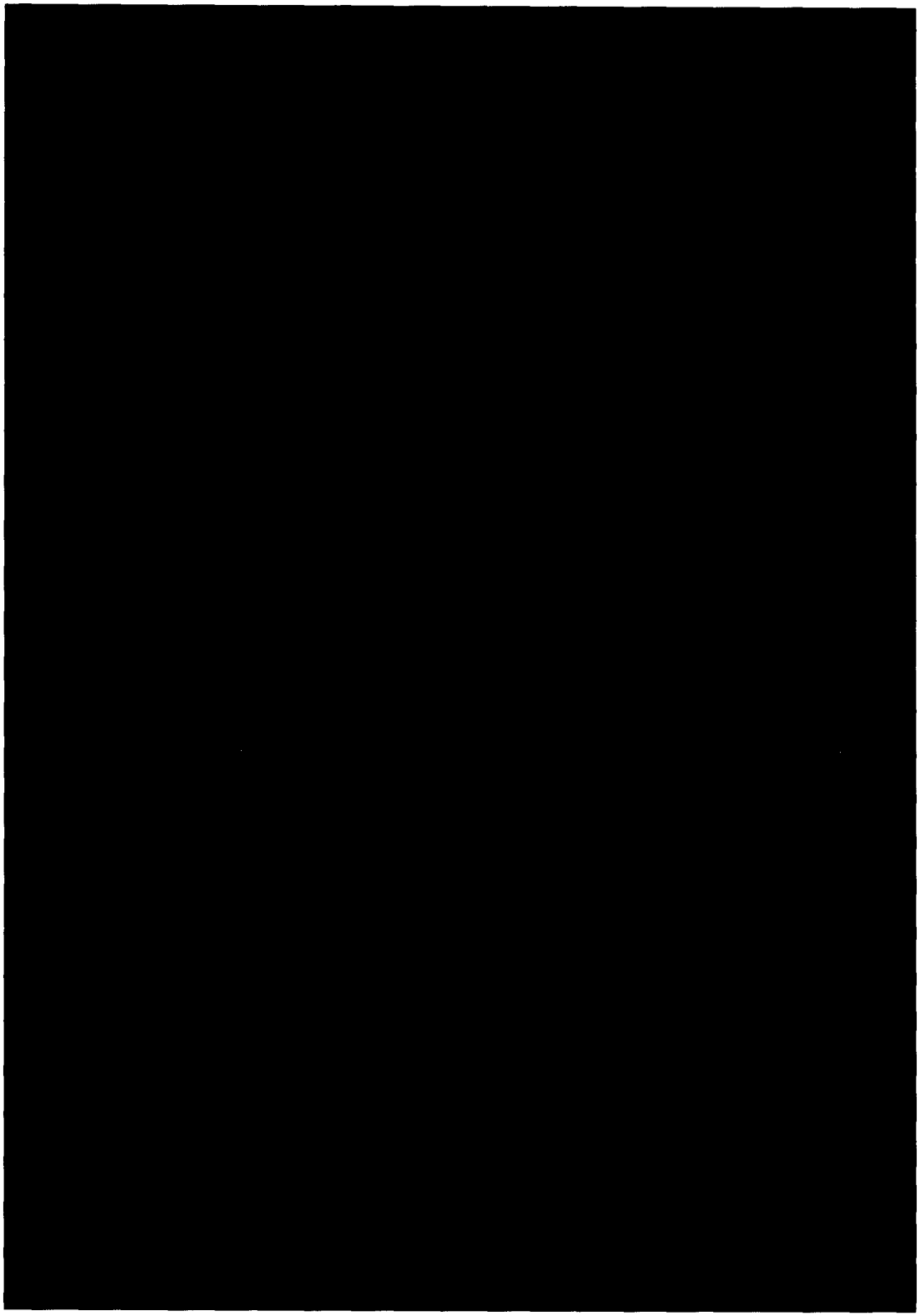
The renewable screening curves show solar is a more economical alternative than wind and landfill gas generation. Solar and wind projects are technically constrained from achieving high capacity factors making them unsuitable for intermediate or baseload duty cycles. Landfill gas projects are limited based on site availability but are dispatchable. Solar projects, like wind, are not dispatchable and therefore less suited to provide consistent peaking capacity. Aside from their technical limitations, solar and wind technologies are not currently economically competitive generation technologies without State and Federal subsidies. These renewable resources do play an important role in meeting the Company's NC REPS requirements.

Centralized generation, as depicted above, will remain the backbone of the grid for Duke Energy in the long-term; however, in addition it is likely that distributed generation will begin to share more and more grid responsibilities over time as technologies such as energy storage increase our grid's flexibility.

The screening curves are useful for comparing costs of resource types at various capacity factors but cannot be solely utilized for determining a long-term resource plan because future units must be optimized with an existing system containing various resource types. Results from the screening curve analysis provide guidance for the technologies to be further considered in the more detailed quantitative analysis phase of the planning process.







CONFIDENTIAL

APPENDIX G: ENVIRONMENTAL COMPLIANCE

Legislative and Regulatory Issues

Duke Energy Progress, which is subject to the jurisdiction of Federal agencies including the Federal Energy Regulatory Commission EPA, and the NRC, as well as State commissions and agencies, is potentially impacted by State and Federal legislative and regulatory actions. This section provides a high-level description of several issues Duke Energy Progress is actively monitoring or engaged in that could potentially influence the Company's existing generation portfolio and choices for new generation resources.

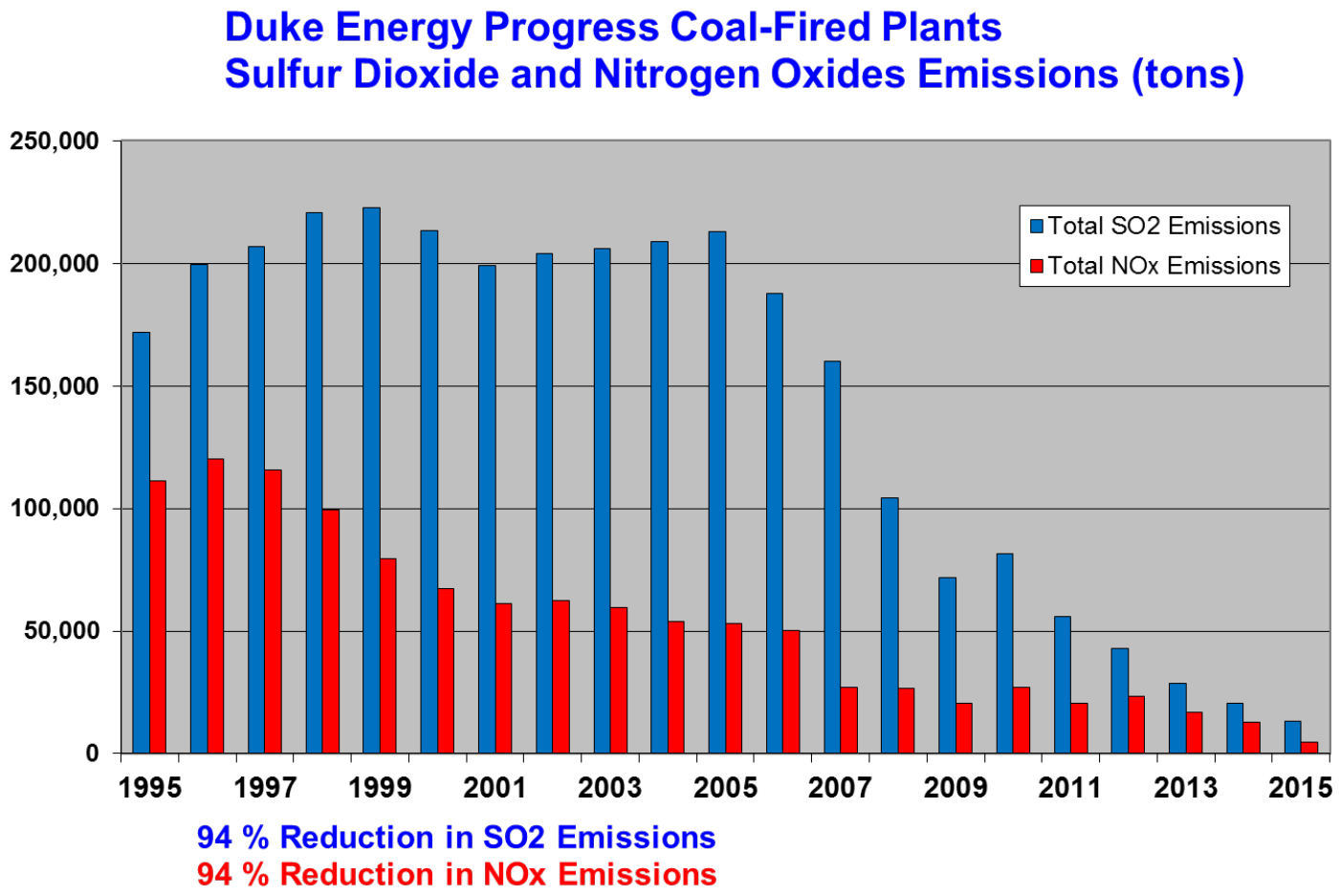
Air Quality

Duke Energy Progress is required to comply with numerous State and Federal air emission regulations, including the current Cross State Air Pollution Rule (CSAPR) NO_x and SO_2 cap-and-trade program, the Mercury and Air Toxics Standards (MATS) rule, and the 2002 North Carolina Clean Smokestacks Act (NC CSA).

As a result of complying with the NC CSA, Duke Energy Progress reduced its SO_2 emissions by approximately 95% from 2000 to 2015. This landmark legislation, which was passed by the North Carolina General Assembly in June of 2002, calls for some of the lowest state-mandated emission levels in the nation, and was passed with Duke Energy Progress' input and support.

The chart below shows the significant downward trend in both NO_x and SO_2 emissions through 2015 as a result of actions taken at Duke Energy Progress facilities.

Chart G-1 DEP NO_X and SO_2 Emissions



The following is brief summary of the major air related federal regulatory programs that are currently impacting or that could impact Duke Energy Progress operations in North Carolina.

Cross-State Air Pollution Rule (CSAPR)

In August, 2011 the EPA finalized the Cross-State Air Pollution Rule. The CSAPR established state-level caps on annual SO_2 and NO_X emissions and ozone season NO_X emissions from electric generating units (EGUs) across the Eastern U.S., including North Carolina. The CSAPR was set up as a two-phase program with Phase I taking effect in 2012 and Phase II taking effect in 2014. Legal challenges to the rule resulted in Phase I implementation being delayed until 2015 and Phase II implementation being delayed until 2017. Duke Energy Progress has been complying with Phase I of the CSAPR and is well positioned to comply with the Phase II annual programs beginning in 2017.

The CSAPR ozone season NO_X program was designed to address interstate transport for the 80 parts per billion (ppb) ozone standard that was established in 1997. In 2008 the EPA lowered the ozone standard to 75 ppb. In late 2015 the EPA proposed a rule, referred to as the CSAPR Update Rule, to revise Phase II of the CSAPR ozone season NO_X program to address interstate transport for the 75 ppb standard. EPA proposed to lower the Phase II ozone season NO_X emission caps for most affected states, including North Carolina, with the lower caps taking effect on May 1, 2017. The EPA has indicated that it plans to finalize the rule in the summer of 2016. Duke Energy Progress cannot predict the outcome of this rulemaking so it does not know at this time what, if any impact it may have on operations in North Carolina.

Mercury and Air Toxics Standards (MATS) Rule

In March 2011 the EPA proposed the Mercury and Air Toxics Standards rule to regulate emissions of mercury and other hazardous air pollutants from coal-fired EGUs. The rule establishing unit-level emission limits for mercury, acid gases, and non-mercury metals, was finalized in February, 2012. Compliance with the emission limits was required by April 16, 2015, or April 16, 2016 if the state permitting authority granted up to a 1-year compliance extension. Duke Energy Progress is complying with all rule requirements.

National Ambient Air Quality Standards (NAAQS)

8-Hour Ozone NAAQS

In October, 2015, EPA finalized a revision to the 8-Hour Ozone NAAQS, lowering it from 75 to 70 ppb. State recommendations to EPA regarding area designations under the 70 ppb standard are due

to EPA by October 1, 2016. The EPA expects to finalize area designations by October 1, 2017 based on 2014-2016 air quality. Attainment dates for any areas designated nonattainment will depend on the area's nonattainment classification, but will not be earlier than October, 2020.

The 70 ppb ozone standard is being challenged in court by numerous parties. Some are challenging the standard as being too low, while others are challenging the standard as not being low enough. Duke Energy Progress cannot predict the outcome of the litigation or assess the potential impact of the lower standard on future operations in North Carolina at this time given the uncertainty surrounding area designations.

SO_2 NAAQS

On June 22, 2010, EPA finalized a rule establishing a 75 ppb 1-hour SO_2 NAAQS. Since then, EPA has completed two rounds of area designations, neither of which resulted in any areas in North Carolina being designated nonattainment.

In August, 2015, the EPA finalized its Data Requirements Rule which established requirements for state air agencies to characterize SO_2 air quality levels around certain EGUs using ambient air quality monitoring or air quality modeling. The Data Requirements Rule also laid out the timeline for state air agencies to complete air quality characterizations and submit the information to EPA, and for EPA to finalize area designations.

The North Carolina Department of Environmental Quality is characterizing SO_2 air quality around the Duke Energy Progress Mayo and Asheville stations using air quality modeling, and around the Duke Energy Progress Roxboro station using air quality monitoring. The modeling analyses must be submitted to EPA by January 13, 2017, and EPA must complete designations of the areas surrounding the Mayo and Asheville stations by December 31, 2017. The complete monitoring data must be submitted to EPA in 2020, and EPA must complete the designation of the area around the Roxboro station by December 31, 2020. For any area designated nonattainment, the North Carolina Department of Environmental Quality would be required to submit a state implementation plan to EPA within 18 months of the area's designation that establishes the requirements for bringing the area into attainment within 5 years of its nonattainment designation.

Fine Particulate Matter ($PM_{2.5}$) NAAQS

On December 14, 2012, the EPA finalized a rule establishing a 12 microgram per cubic meter annual $PM_{2.5}$ NAAQS. The EPA finalized area designations for this standard in December 2014.

That designation process did not result in any areas in North Carolina being designated as a nonattainment area.

Greenhouse Gas Regulation

On August 3, 2015, the EPA finalized a rule establishing CO_2 new source performance standards for pulverized coal (PC) and natural gas combined cycle EGUs that initiated or that initiates construction after January 8, 2014. The EPA finalized emission standards of 1,400 lb CO_2 per gross MWh of electricity generation for PC units and 1,000 lb CO_2 per gross MWh for NGCC units. The standard for PC units can only be achieved with carbon capture and sequestration technology. Duke Energy Progress views the EPA rule as barring the development of new coal-fired generation because CCS is not a demonstrated and available technology for applying to PC units. Duke Energy Progress considers the standard for NGCC units to be achievable. Numerous parties have filed petitions with the U.S. Court of Appeals for the District of Columbia (D.C. Circuit) challenging the EPA's final emission standard for new PC units.

On August 3, 2015, the EPA finalized the Clean Power Plan, a rule to limit CO_2 emissions from existing fossil fuel-fired EGUs (existing EGUs are units that commenced construction prior to January 8, 2014). The CPP requires states to develop and submit to EPA for approval a state implementation plan designed to achieve the required CO_2 emission limitations. The CPP required states to submit an initial plan by September 6, 2016, and a final plan by September 6, 2018. The CPP established two rate-based compliance pathways and two mass-based compliance pathways for states to choose from when developing their state implementation plans. At this time it is unknown which approach the state of North Carolina might select for its implementation plan. The EPA would review and approve or disapprove state plans within 12 months of receipt. The CPP required emission limitations to take effect beginning in 2022 and get gradually more stringent through 2030.

The CPP does not directly impose regulatory requirements on Duke Energy Progress. An approved North Carolina state implementation plan would establish the regulatory requirements that would apply to Duke Energy Progress. If North Carolina were not to submit an approvable plan, EPA would impose a federal implementation plan on affected Duke Energy Progress EGUs to achieve the required CO_2 emission limitations.

Numerous legal challenges to the CPP were filed with the DC Circuit. Many petitioners also asked the DC Circuit to stay the rule until questions about its legal status get resolved. The DC Circuit denied motions to stay the CPP, but shortly thereafter the Supreme Court granted a stay of the rule, halting implementation of the CPP through any final decision in the case by the Supreme Court.

This means the CPP has no legal effect, and EPA cannot enforce any of the deadlines or rule requirements while the stay is in place.

Briefing of the case before the D.C. Circuit was completed in April, 2016. Oral arguments before the full D.C. Circuit are scheduled for September 27, 2016. A decision by the D.C. Circuit will most likely be issued in early 2017. It is expected that the losing parties in that decision will seek Supreme Court review, and it is likely that the Supreme Court will grant review. In this event, final resolution of the case might not occur until sometime in 2018.

Generally, the CPP is designed to cause the replacement of coal-fired generation with generation from natural gas and renewable energy sources. If the CPP is ultimately upheld by the courts and implementation goes forward, Duke Energy Progress could incur increased fuel, purchased power, operation and maintenance and other costs for replacement generation. However, Duke Energy Progress is unable to assess the specific impact of the CPP on its operations at this time due to the many uncertainties currently surrounding the rule's potential implementation.

One of the uncertainties surrounding the CPP is the implementation schedule that would apply if the CPP is found to be lawful. In prior instances where a final rule has been stayed but eventually found to be lawful, all implementation dates have been delayed by at least the number of days the stay was in place. While an exact implementation schedule for the CPP under such an outcome is uncertain, what does seem certain is that if the CPP is found to be lawful, the schedule for implementation will be delayed from what is in the final rule.

Water Quality and By-product Issues

CWA 316(b) Cooling Water Intake Structures

Federal regulations implementing §316(b) of the Clean Water Act (CWA) for existing facilities were published in the Federal Register on August 15, 2014 with an effective date of October 14, 2014. The rule regulates cooling water intake structures at existing facilities to address environmental impacts from fish being impinged (pinned against cooling water intake structures) and entrainment (being drawn into cooling water systems and affected by heat, chemicals or physical stress). The final rule establishes aquatic protection requirements at existing facilities and new on-site generation that withdraw 2 million gallons per day (MGD) or greater from rivers, streams, lakes, reservoirs, estuaries, oceans, or other waters of the United States. All Duke Energy nuclear fueled, coal-fired and combined cycle stations, in North and South Carolina are affected

sources, with the exception of Smith Energy[12].

The rule establishes two standards, one for impingement and one for entrainment. To demonstrate compliance with the impingement standard, facilities must choose and implement one of the following options:

- Closed cycle re-circulating cooling system; or
- Demonstrate the maximum design through screen velocity is less than 0.5 feet per second (fps) under all conditions; or
- Demonstrate the actual through screen velocity, based on measurement, is less than 0.5 fps; or
- Install modified traveling water screens and optimize performance through a two-year study; or
- Demonstrate a system of technologies, practices, and operational measures are optimized to reduce impingement mortality; or
- Demonstrate the impingement latent mortality is reduced to no more than 24% annually based on monthly monitoring.

In addition to these options, the final rule allows the state permitting agency to establish less stringent standards if the capacity utilization rate is less than 8% averaged over a 24-month contiguous period. The rule, also, allows the state permitting agency to determine no further action warranted if impingement is considered *de minimis*. Compliance with the impingement standard is not required until requirements for entrainment are established.

The entrainment standard does not mandate the installation of a technology but rather establishes a process for the state permitting agency to determine necessary controls, if any, are required to reduce entrainment mortality on a site-specific basis. Facilities that withdraw greater than 125 MGD are required to submit information to characterize the entrainment and assess the engineering feasibility, costs, and benefits of closed-cycle cooling, fine mesh screens and other technological and operational controls. The state permitting agency can determine no further action is required, or require the installation of fine mesh screens, or conversion to closed-cycle cooling.

The rule requires facilities with a NPDES permit that expire after July 14, 2018 to submit all necessary 316(b) reports with the renewal application. For facilities with a NPDES permit that expire prior to July 14, 2018 or are in the renewal process, the state permitting agency is allowed to establish an alternate submittal schedule. We expect submittals to be due in the 2018 to 2021

[12] Richmond County supplies cooling water to Smith Energy; therefore the rule is not applicable.

timeframe and intake modifications, if necessary to be required in the 2019 to 2022 timeframe, depending on the NPDES permit renewal date and compliance schedule developed by the state permitting agency.

Steam Electric Effluent Guidelines

Federal regulations revising the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (ELG Rule) were published in the Federal Register on November 3, 2015 with an effective date of January 4, 2016. While the ELG Rule is applicable to all steam electric generating units, waste streams affected by these revisions are generated at DEP's coal-fired facilities. The revisions prohibit the discharge of bottom and fly ash transport water, and flue gas mercury control wastewater, and establish technology based limits on the discharge of wastewater generated by Flue Gas Desulfurization (FGD) systems, and leachate from coal combustion residual landfills and impoundments. The rule, also, establishes technology based limits on gasification wastewater, but this waste stream is not generated at any of the DEP facilities. The new limits must be incorporated into the applicable stations' National Pollutant Discharge Elimination System permit based on a date determined by the permitting authority that is as soon as possible beginning November 1, 2018, but no later than December 31, 2023, with the exception of limits for CCR leachate, which are effective upon issuance of the permit after the effective date of the rule. For discharges to publically owned treatment works (POTW), the limits must be met by November 1, 2018.

The extent to which the rule will affect a particular steam electric generating unit will depend on the treatment technology currently installed at the station. A summary of the impacts are as follows:

- Fly Ash Transport Water: All DEP coal-fired units either handling fly ash dry during normal operation or are scheduled to be retired prior to the compliance date. However, to ensure fly ash is handled dry without disruptions to generation, dry fly ash reliability projects are being completed.
- Bottom Ash Transport Water: All DEP coal-fired units, except for Asheville and Mayo Steam Station, will be required to install a closed-loop or a dry bottom ash handling system.
- FGD Wastewater: All DEP coal-fired units, except for Mayo Steam Station will be required to upgrade or completely replace the existing FGD wastewater treatment system.
- CCR Leachate: The revised limits for CCR leachate from impoundments and landfills are the same as the previous existing limits for low volume waste. Potential impacts are being evaluated on a facility-specific basis.

Coal Combustion Residuals

In January 2009, following Tennessee Valley Authority's Kingston ash pond dike failure December 2008, Congress issued a mandate to EPA to develop Federal regulations for the disposal of coal combustion residuals. CCR includes fly ash, bottom ash, and flue gas desulfurization solids. In the interim, EPA conducted structural integrity inspections of all the surface impoundments nationwide that were used for disposal of CCR. In June 2010, EPA published its proposed rule for the disposal of CCR. The proposed rule offers two regulatory program options: 1) a hazardous waste classification under Resource Conservation Recovery Act (RCRA) Subtitle C; and 2) a non-hazardous waste classification under RCRA Subtitle D, both programs included requirements for dam safety and integrity standards. Both options would require strict new requirements regarding the handling, disposal and potential re-use ability of CCR. The final rule will force dry handling of fly ash and bottom ash and the need for additional landfill capacity resulting from the closure of existing surface impoundments used manage CCR. This will also result in a need for alternative wastewater treatment capacity with smaller lined ponds to manage the other process wastewaters that were treated in the surface impoundments used to manage CCR. Final regulations are expected to be issued by EPA in December of 2014 or later. EPA's regulatory classification of CCR as hazardous or non-hazardous will be critical in developing plans for managing the disposal of CCR. However, under either option of the proposed rule, the impact to Duke Energy Progress is likely to be significant. Based on a 2014 final rule date, compliance with new regulations will begin immediately and with full compliance with all aspects of the rule 5 years later in 2019.

APPENDIX H: NON-UTILITY GENERATION AND WHOLESALE

This appendix contains wholesale sales contracts, firm wholesale purchased power contracts and non-utility generation contracts.

Table H-1 Wholesale Sales Contracts

CONFIDENTIAL

Table H-2 Firm Wholesale Purchased Power Contracts

CONFIDENTIAL

[redacted]

Table H-3 Non-Utility Generation – North Carolina

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
North Carolina Generators:						
Facility 1	Asheville	NC	Solar	Intermediate	Yes	6.893
Facility 2	Garner	NC	Solar	Intermediate	Yes	50
Facility 3	Raleigh	NC	Solar	Intermediate	Yes	400
Facility 4	Weaverville	NC	Solar	Intermediate	Yes	4.48
Facility 5	Weaverville	NC	Solar	Intermediate	Yes	4.5
Facility 6	Asheboro	NC	Solar	Intermediate	Yes	5.16
Facility 7	Wake Forest	NC	Solar	Intermediate	Yes	1.76
Facility 8	Holly Springs	NC	Solar	Intermediate	Yes	400
Facility 9	Raleigh	NC	Solar	Intermediate	Yes	7.711
Facility 10	Cary	NC	Solar	Intermediate	Yes	4.456
Facility 11	Weaverville	NC	Solar	Intermediate	Yes	6.61
Facility 12	Cary	NC	Solar	Intermediate	Yes	2.84
Facility 13	Siler City	NC	Solar	Intermediate	Yes	4.7
Facility 14	Clinton	NC	Solar	Intermediate	Yes	5.783
Facility 15	Jacksonville	NC	Solar	Intermediate	Yes	8.887
Facility 16	Southport	NC	Other	Intermediate	Yes	4950
Facility 17	Raleigh	NC	Solar	Intermediate	Yes	3.1
Facility 18	Morrisville	NC	Solar	Intermediate	Yes	150
Facility 19	Fairview	NC	Solar	Intermediate	Yes	4.24
Facility 20	Sanford	NC	Solar	Intermediate	Yes	4.24
Facility 21	Apex	NC	Solar	Intermediate	Yes	9.99
Facility 22	Cary	NC	Solar	Intermediate	Yes	9.123
Facility 23	Raleigh	NC	Solar	Intermediate	Yes	3.7
Facility 24	Knightdale	NC	Solar	Intermediate	Yes	1
Facility 25	Raleigh	NC	Solar	Intermediate	Yes	4.5
Facility 26	Raleigh	NC	Solar	Intermediate	Yes	1.63
Facility 27	Sanford	NC	Solar	Intermediate	Yes	25
Facility 28	Albertson	NC	Solar	Intermediate	Yes	5000
Facility 29	Fairview	NC	Solar	Intermediate	Yes	2.8
Facility 30	Pinehurst	NC	Solar	Intermediate	Yes	2.86
Facility 31	Fuquay-Varina	NC	Solar	Intermediate	Yes	11.818
Facility 32	Candler	NC	Solar	Intermediate	Yes	2.37
Facility 33	Southern Pines	NC	Solar	Intermediate	Yes	4.32
Facility 34	Wake Forest	NC	Solar	Intermediate	Yes	8.661
Facility 35	Wilmington	NC	Solar	Intermediate	Yes	6.46
Facility 36	Asheville	NC	Solar	Intermediate	Yes	6
Facility 37	Raleigh	NC	Solar	Intermediate	Yes	3.1
Facility 38	Raleigh	NC	Solar	Intermediate	Yes	2.43
Facility 39	Raleigh	NC	Solar	Intermediate	Yes	4.77
Facility 40	Dunn	NC	Solar	Intermediate	Yes	10.663
Facility 41	Pittsboro	NC	Solar	Intermediate	Yes	77
Facility 42	Raleigh	NC	Solar	Intermediate	Yes	3
Facility 43	Wilmington	NC	Solar	Intermediate	Yes	9
Facility 44	Goldsboro	NC	Solar	Intermediate	Yes	5000
Facility 45	Asheville	NC	Solar	Intermediate	Yes	0.78
Facility 46	Wilmington	NC	Solar	Intermediate	Yes	7.22
Facility 47	Asheville	NC	Solar	Intermediate	Yes	3.85
Facility 48	Morrisville	NC	Solar	Intermediate	Yes	5.128
Facility 49	Raleigh	NC	Solar	Intermediate	Yes	7.47
Facility 50	Pittsboro	NC	Solar	Intermediate	Yes	2.24

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 51	Asheville	NC	Solar	Intermediate	Yes	11
Facility 52	Pittsboro	NC	Solar	Intermediate	Yes	1.632
Facility 53	Asheville	NC	Solar	Intermediate	Yes	3.86
Facility 54	Wilmington	NC	Solar	Intermediate	Yes	2.39
Facility 55	Roseboro	NC	Solar	Intermediate	Yes	1980
Facility 56	Asheville	NC	Solar	Intermediate	Yes	4.29
Facility 57	Chapel Hill	NC	Solar	Intermediate	Yes	4.16
Facility 58	Pikeville	NC	Solar	Intermediate	Yes	16.614
Facility 59	Benson	NC	Solar	Intermediate	Yes	3
Facility 60	Rougemont	NC	Solar	Intermediate	Yes	4.12
Facility 61	Pittsboro	NC	Solar	Intermediate	Yes	3.7
Facility 62	Raleigh	NC	Solar	Intermediate	Yes	5
Facility 63	New Bern	NC	Solar	Intermediate	Yes	5000
Facility 64	Wrightsville Beach	NC	Solar	Intermediate	Yes	7.92
Facility 65	Star	NC	Solar	Intermediate	Yes	2.3
Facility 66	Leicester	NC	Solar	Intermediate	Yes	2.4
Facility 67	Angier	NC	Solar	Intermediate	Yes	4400
Facility 68	Asheboro	NC	Solar	Intermediate	Yes	12.2
Facility 69	Raleigh	NC	Solar	Intermediate	Yes	5
Facility 70	Raleigh	NC	Solar	Intermediate	Yes	2.125
Facility 71	Raleigh	NC	Solar	Intermediate	Yes	2.85
Facility 72	Coats	NC	Solar	Intermediate	Yes	3.84
Facility 73	Pinehurst	NC	Solar	Intermediate	Yes	7.639
Facility 74	Wilmington	NC	Solar	Intermediate	Yes	3.9
Facility 75	Asheville	NC	Solar	Intermediate	Yes	6
Facility 76	Asheville	NC	Solar	Intermediate	Yes	3
Facility 77	Asheville	NC	Solar	Intermediate	Yes	4
Facility 78	Hampstead	NC	Solar	Intermediate	Yes	4.3
Facility 79	Castalia	NC	Solar	Intermediate	Yes	3
Facility 80	Fletcher	NC	Solar	Intermediate	Yes	3.809
Facility 81	Angier	NC	Solar	Intermediate	Yes	2.58
Facility 82	Goldsboro	NC	Solar	Intermediate	Yes	4.983
Facility 83	Pittsboro	NC	Solar	Intermediate	Yes	8
Facility 84	Wake Forest	NC	Solar	Intermediate	Yes	1.76
Facility 85	Clyde	NC	Solar	Intermediate	Yes	9
Facility 86	Snow Hill	NC	Solar	Intermediate	Yes	1999
Facility 87	Arden	NC	Solar	Intermediate	Yes	23
Facility 88	Asheboro	NC	Solar	Intermediate	Yes	398
Facility 89	Cary	NC	Solar	Intermediate	Yes	190
Facility 90	Warrenton	NC	Solar	Intermediate	Yes	383
Facility 91	Laurinburg	NC	Solar	Intermediate	Yes	193
Facility 92	Raleigh	NC	Solar	Intermediate	Yes	9.29
Facility 93	Cary	NC	Solar	Intermediate	Yes	8
Facility 94	Cary	NC	Solar	Intermediate	Yes	2.45
Facility 95	Fairview	NC	Solar	Intermediate	Yes	5.85
Facility 96	Cary	NC	Solar	Intermediate	Yes	2.6
Facility 97	Raleigh	NC	Solar	Intermediate	Yes	3.75
Facility 98	Fairview	NC	Solar	Intermediate	Yes	34
Facility 99	Fletcher	NC	Solar	Intermediate	Yes	40

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 100	Asheville	NC	Solar	Intermediate	Yes	6
Facility 101	Asheville	NC	Solar	Intermediate	Yes	5
Facility 102	Asheville	NC	Solar	Intermediate	Yes	6.8
Facility 103	Rose Hill	NC	Solar	Intermediate	Yes	5000
Facility 104	Raleigh	NC	Solar	Intermediate	Yes	4.01
Facility 105	Morrisville	NC	Solar	Intermediate	Yes	2.77
Facility 106	Raleigh	NC	Solar	Intermediate	Yes	4.7
Facility 107	Raleigh	NC	Solar	Intermediate	Yes	4.92
Facility 108	Beulaville	NC	Solar	Intermediate	Yes	4998
Facility 109	Hampstead	NC	Solar	Intermediate	Yes	10
Facility 110	Raleigh	NC	Solar	Intermediate	Yes	3.89
Facility 111	Clayton	NC	Solar	Intermediate	Yes	2.4
Facility 112	Raleigh	NC	Solar	Intermediate	Yes	2.751
Facility 113	Henderson	NC	Solar	Intermediate	Yes	5.28
Facility 114	Cameron	NC	Solar	Intermediate	Yes	9
Facility 115	Asheville	NC	Solar	Intermediate	Yes	9.6
Facility 116	Aberdeen	NC	Solar	Intermediate	Yes	4.14
Facility 117	Cary	NC	Solar	Intermediate	Yes	7.8
Facility 118	Bailey	NC	Solar	Intermediate	Yes	4950
Facility 119	Raleigh	NC	Solar	Intermediate	Yes	5
Facility 120	Raleigh	NC	Solar	Intermediate	Yes	5
Facility 121	Raleigh	NC	Solar	Intermediate	Yes	32
Facility 122	Raleigh	NC	Solar	Intermediate	Yes	4
Facility 123	Clayton	NC	Solar	Intermediate	Yes	3.74
Facility 124	Clayton	NC	Solar	Intermediate	Yes	3.33
Facility 125	Spring Lake	NC	Solar	Intermediate	Yes	4.555
Facility 126	Raleigh	NC	Solar	Intermediate	Yes	4.19
Facility 127	Sanford	NC	Solar	Intermediate	Yes	5000
Facility 128	Fuquay-Varina	NC	Solar	Intermediate	Yes	7.019
Facility 129	Holly Springs	NC	Solar	Intermediate	Yes	3.27
Facility 130	Asheville	NC	Solar	Intermediate	Yes	10.703
Facility 131	Cary	NC	Solar	Intermediate	Yes	5.61
Facility 132	Cary	NC	Solar	Intermediate	Yes	5.94
Facility 133	Leicester	NC	Solar	Intermediate	Yes	6
Facility 134	Louisburg	NC	Solar	Intermediate	Yes	2.49
Facility 135	Durham	NC	Solar	Intermediate	Yes	5
Facility 136	Asheville	NC	Solar	Intermediate	Yes	3
Facility 137	Apex	NC	Solar	Intermediate	Yes	6.55
Facility 138	Asheville	NC	Solar	Intermediate	Yes	60
Facility 139	Asheville	NC	Solar	Intermediate	Yes	3.26
Facility 140	Wilmington	NC	Solar	Intermediate	Yes	6.98
Facility 141	Fairview	NC	Solar	Intermediate	Yes	7.251
Facility 142	Cary	NC	Solar	Intermediate	Yes	6
Facility 143	Cary	NC	Solar	Intermediate	Yes	5.75
Facility 144	Raleigh	NC	Solar	Intermediate	Yes	3.89
Facility 145	Asheville	NC	Solar	Intermediate	Yes	5.07
Facility 146	Weaverville	NC	Solar	Intermediate	Yes	6.908
Facility 147	Apex	NC	Solar	Intermediate	Yes	20
Facility 148	Weaverville	NC	Solar	Intermediate	Yes	4.38
Facility 149	Clayton	NC	Solar	Intermediate	Yes	17.48
Facility 150	Fayetteville	NC	Solar	Intermediate	Yes	6.222

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 151	Jacksonville	NC	Solar	Intermediate	Yes	5.69
Facility 152	Zebulon	NC	Solar	Intermediate	Yes	13.312
Facility 153	Raleigh	NC	Solar	Intermediate	Yes	5.305
Facility 154	Chocowinity	NC	Solar	Intermediate	Yes	15000
Facility 155	Four Oaks	NC	Solar	Intermediate	Yes	798
Facility 156	Asheville	NC	Solar	Intermediate	Yes	6.88
Facility 157	Raleigh	NC	Solar	Intermediate	Yes	3.82
Facility 158	Raleigh	NC	Solar	Intermediate	Yes	3.2
Facility 159	Cary	NC	Solar	Intermediate	Yes	4.148
Facility 160	Southern Pines	NC	Solar	Intermediate	Yes	3
Facility 161	Wilmington	NC	Solar	Intermediate	Yes	3.21
Facility 162	Weaverville	NC	Solar	Intermediate	Yes	3.01
Facility 163	Louisburg	NC	Solar	Intermediate	Yes	4.71
Facility 164	Asheville	NC	Solar	Intermediate	Yes	3.072
Facility 165	Spruce Pine	NC	Solar	Intermediate	Yes	1
Facility 166	Apex	NC	Solar	Intermediate	Yes	3.9
Facility 167	Clayton	NC	Solar	Intermediate	Yes	2.5
Facility 168	Rocky Mount	NC	Solar	Intermediate	Yes	2.907
Facility 169	Alexander	NC	Solar	Intermediate	Yes	9.04
Facility 170	Boiling Spring Lakes	NC	Solar	Intermediate	Yes	2.4
Facility 171	Asheville	NC	Solar	Intermediate	Yes	2
Facility 172	Pittsboro	NC	Solar	Intermediate	Yes	8
Facility 173	Pittsboro	NC	Solar	Intermediate	Yes	6.86
Facility 174	Fuquay Varina	NC	Solar	Intermediate	Yes	6.22
Facility 175	Raleigh	NC	Solar	Intermediate	Yes	9.05
Facility 176	Apex	NC	Solar	Intermediate	Yes	5.32
Facility 177	Carolina Beach	NC	Solar	Intermediate	Yes	4.28
Facility 178	Asheville	NC	Solar	Intermediate	Yes	3.4
Facility 179	Raleigh	NC	Solar	Intermediate	Yes	1.1
Facility 180	Lillington	NC	Solar	Intermediate	Yes	3.23
Facility 181	Southern Pines	NC	Solar	Intermediate	Yes	2.15
Facility 182	Beulaville	NC	Solar	Intermediate	Yes	1999
Facility 183	Raleigh	NC	Solar	Intermediate	Yes	2.448
Facility 184	Goldsboro	NC	Solar	Intermediate	Yes	4.6
Facility 185	Fuquay Varina	NC	Solar	Intermediate	Yes	2.1
Facility 186	Clayton	NC	Solar	Intermediate	Yes	407
Facility 187	Cary	NC	Solar	Intermediate	Yes	3.209
Facility 188	Cary	NC	Solar	Intermediate	Yes	1.4
Facility 189	Cary	NC	Solar	Intermediate	Yes	7
Facility 190	Cary	NC	Solar	Intermediate	Yes	5
Facility 191	Weaverville	NC	Solar	Intermediate	Yes	6
Facility 192	Apex	NC	Solar	Intermediate	Yes	20
Facility 193	Asheville	NC	Solar	Intermediate	Yes	1500
Facility 194	Asheville	NC	Solar	Intermediate	Yes	2.5
Facility 195	Oxford	NC	Solar	Intermediate	Yes	7.4
Facility 196	Asheville	NC	Solar	Intermediate	Yes	3.9
Facility 197	Asheville	NC	Solar	Intermediate	Yes	2.4
Facility 198	Asheville	NC	Solar	Intermediate	Yes	3.9
Facility 199	Asheville	NC	Solar	Intermediate	Yes	1.4

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 200	Asheville	NC	Solar	Intermediate	Yes	3.57
Facility 201	Biscoe	NC	Solar	Intermediate	Yes	5000
Facility 202	Cary	NC	Solar	Intermediate	Yes	6.8
Facility 203	Selma	NC	Solar	Intermediate	Yes	4998
Facility 204	Roseboro	NC	Landfill Gas	Intermediate	Yes	9000
Facility 205	Black Mountain	NC	Solar	Intermediate	Yes	3.2
Facility 206	Black Mountain	NC	Solar	Intermediate	Yes	3.2
Facility 207	Bladenboro	NC	Solar	Intermediate	Yes	4975
Facility 208	Greensboro	NC	Solar	Intermediate	Yes	5000
Facility 209	Fairview	NC	Solar	Intermediate	Yes	7.12
Facility 210	Rose Hill	NC	Solar	Intermediate	Yes	6.49
Facility 211	Willow Spring	NC	Solar	Intermediate	Yes	5.47
Facility 212	Raleigh	NC	Solar	Intermediate	Yes	3.15
Facility 213	Newport	NC	Solar	Intermediate	Yes	10.6
Facility 214	Cary	NC	Solar	Intermediate	Yes	4
Facility 215	Asheville	NC	Solar	Intermediate	Yes	4.3
Facility 216	Fuquay Varina	NC	Solar	Intermediate	Yes	3.9
Facility 217	Grantham	NC	Solar	Intermediate	Yes	5000
Facility 218	Raleigh	NC	Solar	Intermediate	Yes	6.98
Facility 219	Fuquay Varina	NC	Solar	Intermediate	Yes	385
Facility 220	Apex	NC	Solar	Intermediate	Yes	3.9
Facility 221	Cary	NC	Solar	Intermediate	Yes	4.16
Facility 222	Pittsboro	NC	Solar	Intermediate	Yes	3.23
Facility 223	Wilmington	NC	Solar	Intermediate	Yes	4.25
Facility 224	Pittsboro	NC	Solar	Intermediate	Yes	4.96
Facility 225	Warrenton	NC	Solar	Intermediate	Yes	4975
Facility 226	Cary	NC	Solar	Intermediate	Yes	2.19
Facility 227	Pinehurst	NC	Solar	Intermediate	Yes	2.88
Facility 228	Raleigh	NC	Solar	Intermediate	Yes	3.5
Facility 229	Pinehurst	NC	Solar	Intermediate	Yes	3.21
Facility 230	Asheville	NC	Solar	Intermediate	Yes	3.44
Facility 231	Asheville	NC	Solar	Intermediate	Yes	3.024
Facility 232	Alexander	NC	Solar	Intermediate	Yes	2.91
Facility 233	Asheville	NC	Solar	Intermediate	Yes	4.514
Facility 234	Raleigh	NC	Solar	Intermediate	Yes	3.26
Facility 235	Asheville	NC	Solar	Intermediate	Yes	2.92
Facility 236	Asheville	NC	Solar	Intermediate	Yes	7.579
Facility 237	Randleman	NC	Solar	Intermediate	Yes	3.976
Facility 238	Nashville	NC	Solar	Intermediate	Yes	4.131
Facility 239	Asheville	NC	Solar	Intermediate	Yes	5.89
Facility 240	Raleigh	NC	Solar	Intermediate	Yes	6.93
Facility 241	Raleigh	NC	Solar	Intermediate	Yes	3.72
Facility 242	Wilmington	NC	Solar	Intermediate	Yes	2.46
Facility 243	Black Mountain	NC	Solar	Intermediate	Yes	3.93
Facility 244	Clayton	NC	Solar	Intermediate	Yes	3.95
Facility 245	Zebulon	NC	Solar	Intermediate	Yes	5.36
Facility 246	Raleigh	NC	Solar	Intermediate	Yes	4.68
Facility 247	Oxford	NC	Solar	Intermediate	Yes	5000
Facility 248	Benson	NC	Solar	Intermediate	Yes	3.49
Facility 249	Angier	NC	Solar	Intermediate	Yes	2.58
Facility 250	Oxford	NC	Solar	Intermediate	Yes	2.83

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 251	Sanford	NC	Solar	Intermediate	Yes	5.75
Facility 252	Raleigh	NC	Solar	Intermediate	Yes	9.84
Facility 253	Pinehurst	NC	Solar	Intermediate	Yes	4.86
Facility 254	Wilmington	NC	Solar	Intermediate	Yes	5
Facility 255	Raleigh	NC	Solar	Intermediate	Yes	3.14
Facility 256	Raleigh	NC	Solar	Intermediate	Yes	7.7
Facility 257	Asheville	NC	Solar	Intermediate	Yes	4.62
Facility 258	Cary	NC	Solar	Intermediate	Yes	3.6
Facility 259	Baltimore Lake	NC	Solar	Intermediate	Yes	6
Facility 260	Leland	NC	Solar	Intermediate	Yes	3.4
Facility 261	Fairview	NC	Solar	Intermediate	Yes	2.16
Facility 262	Hampstead	NC	Solar	Intermediate	Yes	2.3
Facility 263	Sanford	NC	Solar	Intermediate	Yes	5.02
Facility 264	Semora	NC	Solar	Intermediate	Yes	4.585
Facility 265	Apex	NC	Solar	Intermediate	Yes	4
Facility 266	Chadbourn	NC	Solar	Intermediate	Yes	5000
Facility 267	Raleigh	NC	Solar	Intermediate	Yes	2.2
Facility 268	Moncure	NC	Hydroelectric	Baseload	Yes	1500
Facility 269	New Hill	NC	Solar	Intermediate	Yes	9.643
Facility 270	Cary	NC	Solar	Intermediate	Yes	5.28
Facility 271	Biltmore Lake	NC	Solar	Intermediate	Yes	3.564
Facility 272	Cary	NC	Solar	Intermediate	Yes	3.82
Facility 273	Fayetteville	NC	Solar	Intermediate	Yes	4.1
Facility 274	Chapel Hill	NC	Solar	Intermediate	Yes	3.182
Facility 275	Cary	NC	Solar	Intermediate	Yes	3.615
Facility 276	Goldsboro	NC	Solar	Intermediate	Yes	4.77
Facility 277	Apex	NC	Solar	Intermediate	Yes	3.687
Facility 278	Asheville	NC	Solar	Intermediate	Yes	2.38
Facility 279	Angier	NC	Solar	Intermediate	Yes	6.913
Facility 280	Roxboro	NC	Solar	Intermediate	Yes	3.8
Facility 281	Wilmington	NC	Solar	Intermediate	Yes	2.5
Facility 282	Asheville	NC	Solar	Intermediate	Yes	3
Facility 283	Pittsboro	NC	Solar	Intermediate	Yes	3
Facility 284	Balsam	NC	Solar	Intermediate	Yes	3.8
Facility 285	Asheville	NC	Solar	Intermediate	Yes	4.3
Facility 286	Raleigh	NC	Solar	Intermediate	Yes	5.7
Facility 287	Black Mountain	NC	Solar	Intermediate	Yes	10
Facility 288	Clayton	NC	Solar	Intermediate	Yes	11.24
Facility 289	Biltmore Lake	NC	Solar	Intermediate	Yes	7.127
Facility 290	Pittsboro	NC	Solar	Intermediate	Yes	2.19
Facility 291	Pinehurst	NC	Solar	Intermediate	Yes	6.69
Facility 292	Raleigh	NC	Solar	Intermediate	Yes	5.622
Facility 293	Raleigh	NC	Solar	Intermediate	Yes	3
Facility 294	Alexander	NC	Landfill Gas	Intermediate	Yes	1415
Facility 295	Selma	NC	Solar	Intermediate	Yes	4.31
Facility 296	Vass	NC	Solar	Intermediate	Yes	4.03
Facility 297	Spring Hope	NC	Solar	Intermediate	Yes	9.439
Facility 298	Garner	NC	Solar	Intermediate	Yes	4.917
Facility 299	Black Mountain	NC	Solar	Intermediate	Yes	5.31

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 300	Black Mountain	NC	Solar	Intermediate	Yes	1.566
Facility 301	Raleigh	NC	Solar	Intermediate	Yes	4.23
Facility 302	Pittsboro	NC	Solar	Intermediate	Yes	4.48
Facility 303	Asheville	NC	Solar	Intermediate	Yes	3.299
Facility 304	Fairview	NC	Solar	Intermediate	Yes	9.094
Facility 305	Cary	NC	Solar	Intermediate	Yes	4.01
Facility 306	Asheville	NC	Solar	Intermediate	Yes	4.56
Facility 307	Wilmington	NC	Solar	Intermediate	Yes	3.3
Facility 308	Chapel Hill	NC	Solar	Intermediate	Yes	5.218
Facility 309	Barnardsville	NC	Solar	Intermediate	Yes	0.86
Facility 310	Apex	NC	Solar	Intermediate	Yes	5.4
Facility 311	Ramseur	NC	Solar	Intermediate	Yes	4.5
Facility 312	Wilmington	NC	Solar	Intermediate	Yes	1.63
Facility 313	Chapel Hill	NC	Solar	Intermediate	Yes	5.07
Facility 314	Holly Springs	NC	Solar	Intermediate	Yes	3.32
Facility 315	Cary	NC	Solar	Intermediate	Yes	5.67
Facility 316	Asheville	NC	Solar	Intermediate	Yes	3.8
Facility 317	Vass	NC	Solar	Intermediate	Yes	4.7
Facility 318	Vass	NC	Solar	Intermediate	Yes	8
Facility 319	Raleigh	NC	Solar	Intermediate	Yes	7.54
Facility 320	Henderson	NC	Solar	Intermediate	Yes	16
Facility 321	Black Mountain	NC	Solar	Intermediate	Yes	6.1
Facility 322	Black Mountain	NC	Solar	Intermediate	Yes	2.3
Facility 323	Raleigh	NC	Solar	Intermediate	Yes	9.02
Facility 324	Black Mountain	NC	Solar	Intermediate	Yes	7.96
Facility 325	Asheville	NC	Solar	Intermediate	Yes	8.337
Facility 326	Wilmington	NC	Solar	Intermediate	Yes	1.4
Facility 327	Wilmington	NC	Solar	Intermediate	Yes	4
Facility 328	Asheville	NC	Solar	Intermediate	Yes	5.29
Facility 329	Raleigh	NC	Solar	Intermediate	Yes	2.43
Facility 330	Pittsboro	NC	Solar	Intermediate	Yes	3.61
Facility 331	New Hill	NC	Solar	Intermediate	Yes	7.96
Facility 332	Raleigh	NC	Solar	Intermediate	Yes	8.131
Facility 333	New Hanover	NC	Solar	Intermediate	Yes	4.275
Facility 334	Pittsboro	NC	Solar	Intermediate	Yes	2.96
Facility 335	Asheville	NC	Solar	Intermediate	Yes	1.8
Facility 336	Chapel Hill	NC	Solar	Intermediate	Yes	2.67
Facility 337	Cary	NC	Solar	Intermediate	Yes	3.79
Facility 338	Fletcher	NC	Solar	Intermediate	Yes	1.72
Facility 339	West End	NC	Solar	Intermediate	Yes	2.5
Facility 340	Timberlake	NC	Solar	Intermediate	Yes	520
Facility 341	Raleigh	NC	Solar	Intermediate	Yes	40
Facility 342	Raleigh	NC	Solar	Intermediate	Yes	200
Facility 343	Asheville	NC	Solar	Intermediate	Yes	193
Facility 344	Asheboro	NC	Solar	Intermediate	Yes	2.412
Facility 345	Asheville	NC	Solar	Intermediate	Yes	7.66
Facility 346	Cary	NC	Solar	Intermediate	Yes	4.52
Facility 347	Asheville	NC	Solar	Intermediate	Yes	3.85
Facility 348	Morehead City	NC	Solar	Intermediate	Yes	1.2
Facility 349	Sanford	NC	Solar	Intermediate	Yes	3
Facility 350	Bayboro	NC	Solar	Intermediate	Yes	9.99

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 351	Cary	NC	Solar	Intermediate	Yes	3.4
Facility 352	Asheville	NC	Solar	Intermediate	Yes	3.9
Facility 353	Raleigh	NC	Solar	Intermediate	Yes	4.16
Facility 354	Wilmington	NC	Solar	Intermediate	Yes	3.04
Facility 355	Asheville	NC	Solar	Intermediate	Yes	7.083
Facility 356	Castalia	NC	Solar	Intermediate	Yes	1999
Facility 357	Raleigh	NC	Solar	Intermediate	Yes	4.4
Facility 358	Goldston	NC	Solar	Intermediate	Yes	7.032
Facility 359	Raleigh	NC	Solar	Intermediate	Yes	5.93
Facility 360	Cary	NC	Solar	Intermediate	Yes	2.6
Facility 361	Barnardsville	NC	Solar	Intermediate	Yes	4.36
Facility 362	Raleigh	NC	Solar	Intermediate	Yes	6
Facility 363	Laurinburg	NC	Solar	Intermediate	Yes	2.2
Facility 364	Raleigh	NC	Solar	Intermediate	Yes	2.58
Facility 365	Elizabethtown	NC	Solar	Intermediate	Yes	4800
Facility 366	Garner	NC	Solar	Intermediate	Yes	2500
Facility 367	Garner	NC	Solar	Intermediate	Yes	1050
Facility 368	Raleigh	NC	Solar	Intermediate	Yes	43
Facility 369	Fayetteville	NC	Solar	Intermediate	Yes	5
Facility 370	Candler	NC	Solar	Intermediate	Yes	2.4
Facility 371	Beulaville	NC	Solar	Intermediate	Yes	5000
Facility 372	Raleigh	NC	Solar	Intermediate	Yes	134
Facility 373	Asheville	NC	Solar	Intermediate	Yes	12.301
Facility 374	Pittsboro	NC	Solar	Intermediate	Yes	0.7
Facility 375	Asheville	NC	Solar	Intermediate	Yes	14.62
Facility 376	Cary	NC	Solar	Intermediate	Yes	8.294
Facility 377	Chapel Hill	NC	Solar	Intermediate	Yes	3.1
Facility 378	Whiteville	NC	Solar	Intermediate	Yes	5000
Facility 379	Pinehurst	NC	Solar	Intermediate	Yes	4.79
Facility 380	Cary	NC	Solar	Intermediate	Yes	1.5
Facility 381	Chapel Hill	NC	Solar	Intermediate	Yes	4.1
Facility 382	Pittsboro	NC	Solar	Intermediate	Yes	4.671
Facility 383	Cary	NC	Solar	Intermediate	Yes	5.41
Facility 384	Fuquay Varina	NC	Solar	Intermediate	Yes	4
Facility 385	Pinehurst	NC	Solar	Intermediate	Yes	3.44
Facility 386	Black Mountain	NC	Solar	Intermediate	Yes	4.68
Facility 387	Fletcher	NC	Solar	Intermediate	Yes	3.23
Facility 388	Wilmington	NC	Solar	Intermediate	Yes	2.2
Facility 389	Cameron	NC	Solar	Intermediate	Yes	8.45
Facility 390	Weaverville	NC	Solar	Intermediate	Yes	5.01
Facility 391	Cameron	NC	Solar	Intermediate	Yes	9.46
Facility 392	Rocky Point	NC	Solar	Intermediate	Yes	3
Facility 393	Pittsboro	NC	Solar	Intermediate	Yes	6.12
Facility 394	Wilmington	NC	Solar	Intermediate	Yes	1.4
Facility 395	Pittsboro	NC	Solar	Intermediate	Yes	2.64
Facility 396	Pittsboro	NC	Solar	Intermediate	Yes	1.72
Facility 397	Angier	NC	Solar	Intermediate	Yes	5.82
Facility 398	Asheboro	NC	Solar	Intermediate	Yes	2.58
Facility 399	Asheville	NC	Solar	Intermediate	Yes	5.16

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 400	Raleigh	NC	Solar	Intermediate	Yes	4.34
Facility 401	Lake Waccamaw	NC	Solar	Intermediate	Yes	4975
Facility 402	Cary	NC	Solar	Intermediate	Yes	3.868
Facility 403	Middlesex	NC	Solar	Intermediate	Yes	5000
Facility 404	Kinston	NC	Solar	Intermediate	Yes	3
Facility 405	Raleigh	NC	Solar	Intermediate	Yes	6.398
Facility 406	Jacksonville	NC	Solar	Intermediate	Yes	2.48
Facility 407	Raleigh	NC	Solar	Intermediate	Yes	5.331
Facility 408	Angier	NC	Solar	Intermediate	Yes	6.277
Facility 409	Cary	NC	Solar	Intermediate	Yes	4.57
Facility 410	Albertson	NC	Solar	Intermediate	Yes	5000
Facility 411	Chocowinity	NC	Solar	Intermediate	Yes	5000
Facility 412	Raleigh	NC	Solar	Intermediate	Yes	4
Facility 413	Asheville	NC	Solar	Intermediate	Yes	4.7
Facility 414	Asheville	NC	Solar	Intermediate	Yes	10
Facility 415	Wilmington	NC	Solar	Intermediate	Yes	9.9
Facility 416	Apex	NC	Solar	Intermediate	Yes	2
Facility 417	Unknown	NC	Hydroelectric	Baseload	Yes	80
Facility 418	Angier	NC	Solar	Intermediate	Yes	5
Facility 419	Wilmington	NC	Solar	Intermediate	Yes	4.08
Facility 420	Fuquay Varina	NC	Solar	Intermediate	Yes	0.82
Facility 421	Waynesville	NC	Solar	Intermediate	Yes	3.62
Facility 422	Leicester	NC	Solar	Intermediate	Yes	9
Facility 423	Cary	NC	Solar	Intermediate	Yes	2.72
Facility 424	Cary	NC	Solar	Intermediate	Yes	5.07
Facility 425	Biltmore Lake	NC	Solar	Intermediate	Yes	3.42
Facility 426	Smithfield	NC	Landfill Gas	Intermediate	Yes	1760
Facility 427	Asheville	NC	Solar	Intermediate	Yes	2.9
Facility 428	Pinehurst	NC	Solar	Intermediate	Yes	2
Facility 429	Bunn	NC	Solar	Intermediate	Yes	5000
Facility 430	Raleigh	NC	Solar	Intermediate	Yes	12.1
Facility 431	Raleigh	NC	Solar	Intermediate	Yes	11
Facility 432	Raleigh	NC	Solar	Intermediate	Yes	39
Facility 433	Raleigh	NC	Solar	Intermediate	Yes	19
Facility 434	Raleigh	NC	Solar	Intermediate	Yes	23
Facility 435	Raleigh	NC	Solar	Intermediate	Yes	2.3
Facility 436	Wilmington	NC	Solar	Intermediate	Yes	9.6
Facility 437	Wilmington	NC	Solar	Intermediate	Yes	60
Facility 438	Wilmington	NC	Solar	Intermediate	Yes	24
Facility 439	Wilmington	NC	Solar	Intermediate	Yes	5.4
Facility 440	Franklinton	NC	Solar	Intermediate	Yes	3.9
Facility 441	Canton	NC	Solar	Intermediate	Yes	2.58
Facility 442	Leland	NC	Solar	Intermediate	Yes	3.96
Facility 443	Raleigh	NC	Solar	Intermediate	Yes	2.02
Facility 444	Pittsboro	NC	Solar	Intermediate	Yes	2.72
Facility 445	Atlantic Beach	NC	Solar	Intermediate	Yes	3
Facility 446	Hampstead	NC	Solar	Intermediate	Yes	3
Facility 447	Holly Springs	NC	Solar	Intermediate	Yes	4.94
Facility 448	Raleigh	NC	Solar	Intermediate	Yes	2.44
Facility 449	Asheville	NC	Solar	Intermediate	Yes	7.7
Facility 450	Raleigh	NC	Solar	Intermediate	Yes	5.22

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 451	Cary	NC	Solar	Intermediate	Yes	5
Facility 452	Barnardsville	NC	Solar	Intermediate	Yes	7.6
Facility 453	Raleigh	NC	Solar	Intermediate	Yes	5.54
Facility 454	Pollocksville	NC	Solar	Intermediate	Yes	300
Facility 455	Cary	NC	Solar	Intermediate	Yes	9.9
Facility 456	Coats	NC	Solar	Intermediate	Yes	4998
Facility 457	Clayton	NC	Solar	Intermediate	Yes	6.023
Facility 458	Cary	NC	Solar	Intermediate	Yes	3.877
Facility 459	Cary	NC	Solar	Intermediate	Yes	3.08
Facility 460	Pittsboro	NC	Solar	Intermediate	Yes	3.6
Facility 461	Hampstead	NC	Solar	Intermediate	Yes	4.2
Facility 462	Morehead City	NC	Solar	Intermediate	Yes	2.22
Facility 463	Raleigh	NC	Solar	Intermediate	Yes	3.3
Facility 464	Carolina Beach	NC	Solar	Intermediate	Yes	2.19
Facility 465	Raleigh	NC	Solar	Intermediate	Yes	6.6
Facility 466	Sanford	NC	Solar	Intermediate	Yes	5.829
Facility 467	Raleigh	NC	Solar	Intermediate	Yes	9
Facility 468	Hampstead	NC	Solar	Intermediate	Yes	4.77
Facility 469	Southern Pines	NC	Solar	Intermediate	Yes	5.5
Facility 470	Raleigh	NC	Solar	Intermediate	Yes	8
Facility 471	Mount Olive	NC	Solar	Intermediate	Yes	2.26
Facility 472	Raleigh	NC	Solar	Intermediate	Yes	2.5
Facility 473	Maxton	NC	Solar	Intermediate	Yes	3
Facility 474	Cary	NC	Solar	Intermediate	Yes	5.23
Facility 475	Asheville	NC	Solar	Intermediate	Yes	4
Facility 476	Black Mountain	NC	Solar	Intermediate	Yes	0.441
Facility 477	Sanford	NC	Solar	Intermediate	Yes	9.42
Facility 478	Pittsboro	NC	Solar	Intermediate	Yes	3.71
Facility 479	Chapel Hill	NC	Solar	Intermediate	Yes	4.32
Facility 480	Zebulon	NC	Solar	Intermediate	Yes	257
Facility 481	Pittsboro	NC	Solar	Intermediate	Yes	7.237
Facility 482	Raleigh	NC	Solar	Intermediate	Yes	2.49
Facility 483	Pinehurst	NC	Solar	Intermediate	Yes	2.02
Facility 484	Apex	NC	Solar	Intermediate	Yes	3.77
Facility 485	Asheville	NC	Solar	Intermediate	Yes	5.181
Facility 486	Cedar Falls	NC	Hydroelectric	Baseload	Yes	400
Facility 487	Asheville	NC	Solar	Intermediate	Yes	4.16
Facility 488	Fairview	NC	Solar	Intermediate	Yes	2.88
Facility 489	Asheville	NC	Solar	Intermediate	Yes	3.95
Facility 490	Pittsboro	NC	Solar	Intermediate	Yes	3.38
Facility 491	Oxford	NC	Solar	Intermediate	Yes	4999
Facility 492	Raleigh	NC	Solar	Intermediate	Yes	4.341
Facility 493	Clayton	NC	Solar	Intermediate	Yes	3.47
Facility 494	Kinston	NC	Solar	Intermediate	Yes	4998
Facility 495	Biltmore Forest	NC	Solar	Intermediate	Yes	6.852
Facility 496	Asheville	NC	Solar	Intermediate	Yes	3.38
Facility 497	Raleigh	NC	Solar	Intermediate	Yes	4.9
Facility 498	Fuquay Varina	NC	Solar	Intermediate	Yes	3.371
Facility 499	Raleigh	NC	Solar	Intermediate	Yes	5.65

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 500	Oxford	NC	Solar	Intermediate	Yes	5000
Facility 501	Raleigh	NC	Solar	Intermediate	Yes	7.471
Facility 502	Raleigh	NC	Solar	Intermediate	Yes	4.3
Facility 503	Laurinburg	NC	Solar	Intermediate	Yes	2.1
Facility 504	Arden	NC	Solar	Intermediate	Yes	160
Facility 505	Waynesville	NC	Solar	Intermediate	Yes	3.8
Facility 506	Pittsboro	NC	Solar	Intermediate	Yes	2.88
Facility 507	Asheville	NC	Solar	Intermediate	Yes	2.24
Facility 508	Barnardsville	NC	Solar	Intermediate	Yes	7.6
Facility 509	Asheville	NC	Solar	Intermediate	Yes	3
Facility 510	New Hill	NC	Solar	Intermediate	Yes	2.89
Facility 511	Chapel Hill	NC	Solar	Intermediate	Yes	1.6
Facility 512	Sanford	NC	Solar	Intermediate	Yes	6
Facility 513	Morrisville	NC	Solar	Intermediate	Yes	2.76
Facility 514	Arden	NC	Solar	Intermediate	Yes	3.9
Facility 515	Asheville	NC	Solar	Intermediate	Yes	4.123
Facility 516	Ashville	NC	Solar	Intermediate	Yes	3.8
Facility 517	Southern Pines	NC	Solar	Intermediate	Yes	1.63
Facility 518	Wilmington	NC	Solar	Intermediate	Yes	6.336
Facility 519	Cary	NC	Solar	Intermediate	Yes	4
Facility 520	Pittsboro	NC	Solar	Intermediate	Yes	1.8
Facility 521	Raleigh	NC	Solar	Intermediate	Yes	1.5
Facility 522	Siler City	NC	Solar	Intermediate	Yes	8
Facility 523	Wilmington	NC	Solar	Intermediate	Yes	2.87
Facility 524	Pittsboro	NC	Solar	Intermediate	Yes	4.08
Facility 525	Garner	NC	Solar	Intermediate	Yes	8.42
Facility 526	Cary	NC	Solar	Intermediate	Yes	3.85
Facility 527	Raleigh	NC	Solar	Intermediate	Yes	3.79
Facility 528	Apex	NC	Solar	Intermediate	Yes	4.62
Facility 529	Wilmington	NC	Solar	Intermediate	Yes	7.115
Facility 530	Raleigh	NC	Solar	Intermediate	Yes	6.05
Facility 531	Angier	NC	Solar	Intermediate	Yes	1.72
Facility 532	Asheville	NC	Solar	Intermediate	Yes	5
Facility 533	Cary	NC	Solar	Intermediate	Yes	4.5
Facility 534	Raleigh	NC	Solar	Intermediate	Yes	24
Facility 535	Raleigh	NC	Solar	Intermediate	Yes	57
Facility 536	Raleigh	NC	Solar	Intermediate	Yes	73
Facility 537	Asheville	NC	Solar	Intermediate	Yes	0.86
Facility 538	Cameron	NC	Solar	Intermediate	Yes	2.58
Facility 539	Nashville	NC	Solar	Intermediate	Yes	4.5
Facility 540	Asheville	NC	Solar	Intermediate	Yes	4.128
Facility 541	Raleigh	NC	Solar	Intermediate	Yes	1.92
Facility 542	Asheville	NC	Solar	Intermediate	Yes	4.6
Facility 543	Chapel Hill	NC	Solar	Intermediate	Yes	3.6
Facility 544	Raleigh	NC	Solar	Intermediate	Yes	2.94
Facility 545	Apex	NC	Solar	Intermediate	Yes	6.15
Facility 546	Raleigh	NC	Solar	Intermediate	Yes	3.1
Facility 547	Asheville	NC	Solar	Intermediate	Yes	2.6
Facility 548	Asheville	NC	Solar	Intermediate	Yes	4.4
Facility 549	Asheville	NC	Solar	Intermediate	Yes	3
Facility 550	Asheville	NC	Solar	Intermediate	Yes	3.8

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 551	Asheville	NC	Solar	Intermediate	Yes	8.75
Facility 552	Asheville	NC	Solar	Intermediate	Yes	3.75
Facility 553	Castle Hayne	NC	Solar	Intermediate	Yes	58
Facility 554	Bear Creek	NC	Solar	Intermediate	Yes	6.96
Facility 555	Candler	NC	Solar	Intermediate	Yes	0.7
Facility 556	Asheville	NC	Solar	Intermediate	Yes	5.88
Facility 557	Fairview	NC	Solar	Intermediate	Yes	4.02
Facility 558	Wilmington	NC	Solar	Intermediate	Yes	8.8
Facility 559	Raleigh	NC	Solar	Intermediate	Yes	1.76
Facility 560	Fairview	NC	Solar	Intermediate	Yes	8
Facility 561	Raleigh	NC	Solar	Intermediate	Yes	2.4
Facility 562	Pittsboro	NC	Solar	Intermediate	Yes	5.2
Facility 563	Raleigh	NC	Solar	Intermediate	Yes	2
Facility 564	Pittsboro	NC	Solar	Intermediate	Yes	4.83
Facility 565	Wilmington	NC	Solar	Intermediate	Yes	2.45
Facility 566	Pinehurst	NC	Solar	Intermediate	Yes	4.43
Facility 567	Asheville	NC	Solar	Intermediate	Yes	5.558
Facility 568	Raeford	NC	Solar	Intermediate	Yes	7.24
Facility 569	Raleigh	NC	Solar	Intermediate	Yes	4.85
Facility 570	Asheboro	NC	Solar	Intermediate	Yes	2.38
Facility 571	Raleigh	NC	Solar	Intermediate	Yes	5.7
Facility 572	Raleigh	NC	Solar	Intermediate	Yes	4
Facility 573	Raleigh	NC	Solar	Intermediate	Yes	2.848
Facility 574	Southern Pines	NC	Solar	Intermediate	Yes	9.15
Facility 575	Holly Springs	NC	Solar	Intermediate	Yes	3.2
Facility 576	Raleigh	NC	Solar	Intermediate	Yes	4.76
Facility 577	Ramseur	NC	Hydroelectric	Baseload	Yes	675
Facility 578	Cary	NC	Solar	Intermediate	Yes	2.48
Facility 579	Fayetteville	NC	Solar	Intermediate	Yes	16.083
Facility 580	Raleigh	NC	Solar	Intermediate	Yes	3.735
Facility 581	Garner	NC	Solar	Intermediate	Yes	4.25
Facility 582	Delco	NC	Solar	Intermediate	Yes	5000
Facility 583	Asheville	NC	Solar	Intermediate	Yes	44
Facility 584	Henderson	NC	Solar	Intermediate	Yes	4975
Facility 585	Morrisville	NC	Solar	Intermediate	Yes	3
Facility 586	Cary	NC	Solar	Intermediate	Yes	5.39
Facility 587	Raleigh	NC	Solar	Intermediate	Yes	5.66
Facility 588	Raleigh	NC	Solar	Intermediate	Yes	3.78
Facility 589	Chadbourn	NC	Solar	Intermediate	Yes	5000
Facility 590	Raleigh	NC	Solar	Intermediate	Yes	3.16
Facility 591	Raleigh	NC	Solar	Intermediate	Yes	3.74
Facility 592	Barnardsville	NC	Solar	Intermediate	Yes	3.6
Facility 593	Wake Forest	NC	Solar	Intermediate	Yes	5.94
Facility 594	Asheville	NC	Solar	Intermediate	Yes	5
Facility 595	Fayetteville	NC	Solar	Intermediate	Yes	7.6
Facility 596	Louisburg	NC	Solar	Intermediate	Yes	5.16
Facility 597	Asheville	NC	Solar	Intermediate	Yes	4.74
Facility 598	Asheville	NC	Solar	Intermediate	Yes	6.044
Facility 599	Pittsboro	NC	Solar	Intermediate	Yes	3.18

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 600	Carolina Beach	NC	Solar	Intermediate	Yes	2.5
Facility 601	Weaverville	NC	Solar	Intermediate	Yes	3.391
Facility 602	Cary	NC	Solar	Intermediate	Yes	7.28
Facility 603	Asheville	NC	Solar	Intermediate	Yes	8
Facility 604	Fairview	NC	Solar	Intermediate	Yes	5.33
Facility 605	Southern Pines	NC	Solar	Intermediate	Yes	3.1
Facility 606	Raleigh	NC	Solar	Intermediate	Yes	4.66
Facility 607	Weaverville	NC	Solar	Intermediate	Yes	2.1
Facility 608	Fletcher	NC	Solar	Intermediate	Yes	2.75
Facility 609	Zebulon	NC	Solar	Intermediate	Yes	5
Facility 610	Raleigh	NC	Solar	Intermediate	Yes	4.8
Facility 611	Weaverville	NC	Solar	Intermediate	Yes	4.52
Facility 612	Biltmore	NC	Solar	Intermediate	Yes	1.72
Facility 613	Weaverville	NC	Solar	Intermediate	Yes	3
Facility 614	Wilmington	NC	Solar	Intermediate	Yes	3
Facility 615	Wilmington	NC	Solar	Intermediate	Yes	3.69
Facility 616	Morehead City	NC	Solar	Intermediate	Yes	3.9
Facility 617	Nashville	NC	Solar	Intermediate	Yes	3.4
Facility 618	Asheville	NC	Solar	Intermediate	Yes	4.55
Facility 619	Chapel Hill	NC	Solar	Intermediate	Yes	2.32
Facility 620	Waynesville	NC	Solar	Intermediate	Yes	2.88
Facility 621	Smithfield	NC	Solar	Intermediate	Yes	5.48
Facility 622	Hampstead	NC	Solar	Intermediate	Yes	3
Facility 623	Raleigh	NC	Solar	Intermediate	Yes	0.25
Facility 624	Asheville	NC	Solar	Intermediate	Yes	1.5
Facility 625	Arden	NC	Solar	Intermediate	Yes	5.32
Facility 626	Pittsboro	NC	Solar	Intermediate	Yes	5.86
Facility 627	Pittsboro	NC	Solar	Intermediate	Yes	3.01
Facility 628	Chapel Hill	NC	Solar	Intermediate	Yes	6.84
Facility 629	Chapel Hill	NC	Solar	Intermediate	Yes	6.3
Facility 630	Raleigh	NC	Solar	Intermediate	Yes	2.94
Facility 631	Morehead City	NC	Solar	Intermediate	Yes	9
Facility 632	Apex	NC	Solar	Intermediate	Yes	3.7
Facility 633	Cary	NC	Solar	Intermediate	Yes	5.08
Facility 634	Asheville	NC	Solar	Intermediate	Yes	6.78
Facility 635	Raleigh	NC	Solar	Intermediate	Yes	16
Facility 636	Sanford	NC	Solar	Intermediate	Yes	5.6
Facility 637	Pittsboro	NC	Solar	Intermediate	Yes	3.23
Facility 638	Morehead City	NC	Solar	Intermediate	Yes	2.54
Facility 639	Alexander	NC	Solar	Intermediate	Yes	2.01
Facility 640	Candler	NC	Solar	Intermediate	Yes	4.817
Facility 641	Asheville	NC	Solar	Intermediate	Yes	5.278
Facility 642	Cary	NC	Solar	Intermediate	Yes	4.11
Facility 643	Southport	NC	Solar	Intermediate	Yes	5.208
Facility 644	Leland	NC	Solar	Intermediate	Yes	5.62
Facility 645	Dunn	NC	Solar	Intermediate	Yes	1999
Facility 646	Holly Springs	NC	Solar	Intermediate	Yes	5.92
Facility 647	Kenansville	NC	Solar	Intermediate	Yes	5000
Facility 648	Warsaw	NC	Solar	Intermediate	Yes	5000
Facility 649	Bald Head Island	NC	Solar	Intermediate	Yes	4.63
Facility 650	Asheville	NC	Solar	Intermediate	Yes	2.4

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 651	Raleigh	NC	Solar	Intermediate	Yes	5.16
Facility 652	Southern Pines	NC	Solar	Intermediate	Yes	4.34
Facility 653	Southern Pines	NC	Solar	Intermediate	Yes	6.547
Facility 654	Raleigh	NC	Solar	Intermediate	Yes	10
Facility 655	Raleigh	NC	Solar	Intermediate	Yes	2.7
Facility 656	Goldsboro	NC	Solar	Intermediate	Yes	1999
Facility 657	Cary	NC	Solar	Intermediate	Yes	8.8
Facility 658	Laurinburg	NC	Solar	Intermediate	Yes	5000
Facility 659	Weaverville	NC	Solar	Intermediate	Yes	42
Facility 660	Raleigh	NC	Solar	Intermediate	Yes	3.13
Facility 661	Asheville	NC	Solar	Intermediate	Yes	3.6
Facility 662	Fuquay Varina	NC	Solar	Intermediate	Yes	3.8
Facility 663	New Hill	NC	Solar	Intermediate	Yes	6.2
Facility 664	Raleigh	NC	Solar	Intermediate	Yes	5.3
Facility 665	Vass	NC	Solar	Intermediate	Yes	7.4
Facility 666	Arden	NC	Solar	Intermediate	Yes	7.22
Facility 667	Raleigh	NC	Solar	Intermediate	Yes	3.63
Facility 668	Asheville	NC	Solar	Intermediate	Yes	7.35
Facility 669	Asheville	NC	Solar	Intermediate	Yes	7.35
Facility 670	Asheville	NC	Solar	Intermediate	Yes	3
Facility 671	Pittsboro	NC	Solar	Intermediate	Yes	2
Facility 672	Asheville	NC	Solar	Intermediate	Yes	3.5
Facility 673	Asheville	NC	Solar	Intermediate	Yes	3.597
Facility 674	Spring Hope	NC	Solar	Intermediate	Yes	176
Facility 675	Pinehurst	NC	Solar	Intermediate	Yes	4.82
Facility 676	Garner	NC	Solar	Intermediate	Yes	4
Facility 677	Cary	NC	Solar	Intermediate	Yes	2.64
Facility 678	Candler	NC	Solar	Intermediate	Yes	5.34
Facility 679	Raleigh	NC	Solar	Intermediate	Yes	3
Facility 680	Asheville	NC	Solar	Intermediate	Yes	5
Facility 681	Troy	NC	Landfill Gas	Intermediate	Yes	6400
Facility 682	Pittsboro	NC	Solar	Intermediate	Yes	6.4
Facility 683	Asheville	NC	Solar	Intermediate	Yes	4.109
Facility 684	Pittsboro	NC	Solar	Intermediate	Yes	3.74
Facility 685	Asheville	NC	Solar	Intermediate	Yes	4.31
Facility 686	Asheville	NC	Solar	Intermediate	Yes	7.6
Facility 687	Fuquay Varina	NC	Solar	Intermediate	Yes	2.1
Facility 688	Asheville	NC	Solar	Intermediate	Yes	2.9
Facility 689	Wilmington	NC	Solar	Intermediate	Yes	12.787
Facility 690	Weaverville	NC	Solar	Intermediate	Yes	4
Facility 691	Sanford	NC	Solar	Intermediate	Yes	5000
Facility 692	Fairview	NC	Solar	Intermediate	Yes	7.76
Facility 693	Raleigh	NC	Solar	Intermediate	Yes	4.58
Facility 694	Alexander	NC	Landfill Gas	Intermediate	Yes	983
Facility 695	Burnsville	NC	Solar	Intermediate	Yes	5
Facility 696	Burnsville	NC	Solar	Intermediate	Yes	2
Facility 697	Cary	NC	Solar	Intermediate	Yes	7.915
Facility 698	Wendell	NC	Solar	Intermediate	Yes	4.1
Facility 699	Raleigh	NC	Solar	Intermediate	Yes	4.13

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 700	Fuquay Varina	NC	Solar	Intermediate	Yes	8.5
Facility 701	Canton	NC	Solar	Intermediate	Yes	2
Facility 702	Asheville	NC	Solar	Intermediate	Yes	6.88
Facility 703	Asheville	NC	Solar	Intermediate	Yes	4
Facility 704	Asheville	NC	Solar	Intermediate	Yes	8.143
Facility 705	Dunn	NC	Solar	Intermediate	Yes	4950
Facility 706	Four Oaks	NC	Solar	Intermediate	Yes	5000
Facility 707	Fletcher	NC	Solar	Intermediate	Yes	424
Facility 708	Newton Grove	NC	Solar	Intermediate	Yes	1980
Facility 709	Princeton	NC	Solar	Intermediate	Yes	5000
Facility 710	New Bern	NC	Solar	Intermediate	Yes	977.9
Facility 711	Wilmington	NC	Solar	Intermediate	Yes	2.34
Facility 712	Chapel Hill	NC	Solar	Intermediate	Yes	2.5
Facility 713	Asheville	NC	Solar	Intermediate	Yes	3.7
Facility 714	Chapel Hill	NC	Solar	Intermediate	Yes	4.27
Facility 715	Pittsboro	NC	Solar	Intermediate	Yes	5.76
Facility 716	Wilmington	NC	Solar	Intermediate	Yes	6.98
Facility 717	Asheville	NC	Solar	Intermediate	Yes	2.65
Facility 718	Weaverville	NC	Solar	Intermediate	Yes	3.84
Facility 719	Weaverville	NC	Solar	Intermediate	Yes	3.84
Facility 720	Troy	NC	Hydroelectric	Baseload	Yes	792
Facility 721	Raleigh	NC	Solar	Intermediate	Yes	452.76
Facility 722	Asheville	NC	Solar	Intermediate	Yes	3
Facility 723	Garner	NC	Solar	Intermediate	Yes	24
Facility 724	Raleigh	NC	Solar	Intermediate	Yes	4.5
Facility 725	Apex	NC	Solar	Intermediate	Yes	4.13
Facility 726	Pittsboro	NC	Solar	Intermediate	Yes	5
Facility 727	Fairview	NC	Solar	Intermediate	Yes	7.7
Facility 728	Faison	NC	Solar	Intermediate	Yes	1900
Facility 729	Cary	NC	Solar	Intermediate	Yes	2
Facility 730	Raleigh	NC	Solar	Intermediate	Yes	3.29
Facility 731	Raleigh	NC	Solar	Intermediate	Yes	5.03
Facility 732	Raleigh	NC	Solar	Intermediate	Yes	3.3
Facility 733	Asheville	NC	Solar	Intermediate	Yes	1.678
Facility 734	Weaverville	NC	Solar	Intermediate	Yes	4.844
Facility 735	Angier	NC	Solar	Intermediate	Yes	5.96
Facility 736	Sanford	NC	Solar	Intermediate	Yes	4.38
Facility 737	Chapel Hill	NC	Solar	Intermediate	Yes	1000
Facility 738	Eagle Springs	NC	Solar	Intermediate	Yes	4.12
Facility 739	Pinehurst	NC	Solar	Intermediate	Yes	5.04
Facility 740	Candler	NC	Solar	Intermediate	Yes	134.4
Facility 741	Candler	NC	Solar	Intermediate	Yes	9.5
Facility 742	Chapel Hill	NC	Solar	Intermediate	Yes	2.01
Facility 743	Pinehurst	NC	Solar	Intermediate	Yes	2.29
Facility 744	Leland	NC	Solar	Intermediate	Yes	2.946
Facility 745	Asheville	NC	Solar	Intermediate	Yes	4.875
Facility 746	Wilmington	NC	Solar	Intermediate	Yes	2.75
Facility 747	Black Mountain	NC	Solar	Intermediate	Yes	11.4
Facility 748	Raleigh	NC	Solar	Intermediate	Yes	565
Facility 749	Raleigh	NC	Solar	Intermediate	Yes	1000
Facility 750	Asheville	NC	Solar	Intermediate	Yes	8

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 751	Raleigh	NC	Solar	Intermediate	Yes	6.05
Facility 752	Apex	NC	Solar	Intermediate	Yes	6.9
Facility 753	Roxboro	NC	Solar	Intermediate	Yes	4.478
Facility 754	Raleigh	NC	Solar	Intermediate	Yes	3.85
Facility 755	Weaverville	NC	Solar	Intermediate	Yes	19
Facility 756	Asheville	NC	Solar	Intermediate	Yes	4.2
Facility 757	Pittsboro	NC	Solar	Intermediate	Yes	3.69
Facility 758	Chapel Hill	NC	Solar	Intermediate	Yes	4.72
Facility 759	Canton	NC	Solar	Intermediate	Yes	440
Facility 760	Apex	NC	Solar	Intermediate	Yes	1500
Facility 761	Clyde	NC	Solar	Intermediate	Yes	77
Facility 762	Canton	NC	Solar	Intermediate	Yes	66
Facility 763	Fairmont	NC	Solar	Intermediate	Yes	4320
Facility 764	Ellerbe	NC	Solar	Intermediate	Yes	1999
Facility 765	Lumberton	NC	Solar	Intermediate	Yes	1999
Facility 766	Raleigh	NC	Solar	Intermediate	Yes	204
Facility 767	Raleigh	NC	Solar	Intermediate	Yes	81
Facility 768	Raleigh	NC	Solar	Intermediate	Yes	8.528
Facility 769	Lumberton	NC	Solar	Intermediate	Yes	4320
Facility 770	Albertson	NC	Solar	Intermediate	Yes	4800
Facility 771	Orrum	NC	Solar	Intermediate	Yes	4999
Facility 772	Asheville	NC	Solar	Intermediate	Yes	3.5
Facility 773	Hope Mills	NC	Diesel	Peak	Yes	350
Facility 774	Cary	NC	Diesel	Peak	Yes	350
Facility 775	Raleigh	NC	Diesel	Peak	Yes	350
Facility 776	Clayton	NC	Diesel	Peak	Yes	438
Facility 777	Morrisville	NC	Diesel	Peak	Yes	438
Facility 778	Whispering Pines	NC	Diesel	Peak	Yes	438
Facility 779	Southport	NC	Solar	Intermediate	Yes	2.33
Facility 780	Black Mountain	NC	Solar	Intermediate	Yes	4.27
Facility 781	Biltmore Lake	NC	Solar	Intermediate	Yes	6.652
Facility 782	Garner	NC	Solar	Intermediate	Yes	15
Facility 783	Clayton	NC	Solar	Intermediate	Yes	6.398
Facility 784	Sanford	NC	Solar	Intermediate	Yes	9.647
Facility 785	Raleigh	NC	Solar	Intermediate	Yes	2.644
Facility 786	Raleigh	NC	Solar	Intermediate	Yes	3.98
Facility 787	West End	NC	Solar	Intermediate	Yes	5000
Facility 788	Raleigh	NC	Solar	Intermediate	Yes	4.5
Facility 789	Asheville	NC	Solar	Intermediate	Yes	3.8
Facility 790	Asheboro	NC	Solar	Intermediate	Yes	4.1
Facility 791	Asheville	NC	Solar	Intermediate	Yes	3.14
Facility 792	Louisburg	NC	Solar	Intermediate	Yes	1999
Facility 793	Louisburg	NC	Solar	Intermediate	Yes	2000
Facility 794	Arden	NC	Solar	Intermediate	Yes	4.04
Facility 795	Pittsboro	NC	Solar	Intermediate	Yes	2.65
Facility 796	Wilmington	NC	Solar	Intermediate	Yes	2.4
Facility 797	Holly Springs	NC	Solar	Intermediate	Yes	9.21
Facility 798	Raleigh	NC	Solar	Intermediate	Yes	3
Facility 799	Cary	NC	Solar	Intermediate	Yes	4.17

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 800	Fuquay Varina	NC	Solar	Intermediate	Yes	6.53
Facility 801	Siler City	NC	Solar	Intermediate	Yes	8.81
Facility 802	Black Mountain	NC	Solar	Intermediate	Yes	3.72
Facility 803	Raleigh	NC	Solar	Intermediate	Yes	4.7
Facility 804	Elm City	NC	Solar	Intermediate	Yes	5000
Facility 805	Cordova	NC	Solar	Intermediate	Yes	5000
Facility 806	Fayetteville	NC	Solar	Intermediate	Yes	5000
Facility 807	Snow Hill	NC	Solar	Intermediate	Yes	5000
Facility 808	Asheboro	NC	Solar	Intermediate	Yes	5000
Facility 809	Zebulon	NC	Solar	Intermediate	Yes	3.44
Facility 810	Cary	NC	Solar	Intermediate	Yes	3.43
Facility 811	Asheville	NC	Solar	Intermediate	Yes	1.56
Facility 812	Willow Springs	NC	Solar	Intermediate	Yes	5000
Facility 813	Fuquay Varina	NC	Solar	Intermediate	Yes	4.58
Facility 814	Oxford	NC	Solar	Intermediate	Yes	4.91
Facility 815	Chapel Hill	NC	Solar	Intermediate	Yes	1.2
Facility 816	Chapel Hill	NC	Solar	Intermediate	Yes	3.25
Facility 817	Staley	NC	Solar	Intermediate	Yes	5.502
Facility 818	Hampstead	NC	Solar	Intermediate	Yes	9.89
Facility 819	Siler City	NC	Solar	Intermediate	Yes	3.87
Facility 820	Asheville	NC	Solar	Intermediate	Yes	8.4
Facility 821	Cary	NC	Solar	Intermediate	Yes	7.566
Facility 822	Raleigh	NC	Solar	Intermediate	Yes	3.54
Facility 823	Hampstead	NC	Solar	Intermediate	Yes	7.89
Facility 824	Wilmington	NC	Solar	Intermediate	Yes	6.04
Facility 825	Asheville	NC	Solar	Intermediate	Yes	2.93
Facility 826	Angier	NC	Solar	Intermediate	Yes	3.35
Facility 827	Swansboro	NC	Solar	Intermediate	Yes	2.1
Facility 828	Wilmington	NC	Solar	Intermediate	Yes	5.24
Facility 829	Chadbourn	NC	Solar	Intermediate	Yes	3800
Facility 830	Cary	NC	Solar	Intermediate	Yes	4.7
Facility 831	Morrisville	NC	Solar	Intermediate	Yes	5.16
Facility 832	Asheville	NC	Solar	Intermediate	Yes	4
Facility 833	Raleigh	NC	Solar	Intermediate	Yes	4.46
Facility 834	Zebulon	NC	Solar	Intermediate	Yes	5.68
Facility 835	Leicester	NC	Solar	Intermediate	Yes	4.608
Facility 836	Willow Springs	NC	Solar	Intermediate	Yes	2.05
Facility 837	Roxboro	NC	Solar	Intermediate	Yes	2.36
Facility 838	La Grange	NC	Solar	Intermediate	Yes	11.4
Facility 839	Leland	NC	Solar	Intermediate	Yes	3.6
Facility 840	Asheville	NC	Solar	Intermediate	Yes	4.286
Facility 841	Asheville	NC	Solar	Intermediate	Yes	2.33
Facility 842	Wilmington	NC	Solar	Intermediate	Yes	3.74
Facility 843	Louisburg	NC	Solar	Intermediate	Yes	5
Facility 844	Asheville	NC	Solar	Intermediate	Yes	2.7
Facility 845	Roxboro	NC	Solar	Intermediate	Yes	3.31
Facility 846	Spring Hope	NC	Solar	Intermediate	Yes	10
Facility 847	Garner	NC	Solar	Intermediate	Yes	6.02
Facility 848	Pittsboro	NC	Solar	Intermediate	Yes	1.8
Facility 849	Asheville	NC	Solar	Intermediate	Yes	3.8
Facility 850	Fairview	NC	Solar	Intermediate	Yes	2.8

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 851	Raleigh	NC	Solar	Intermediate	Yes	2.58
Facility 852	Cary	NC	Solar	Intermediate	Yes	3.4
Facility 853	Chapel Hill	NC	Solar	Intermediate	Yes	6
Facility 854	Chapel Hill	NC	Solar	Intermediate	Yes	3.08
Facility 855	Weaverville	NC	Solar	Intermediate	Yes	3.68
Facility 856	Wilmington	NC	Solar	Intermediate	Yes	5.9
Facility 857	Chapel Hill	NC	Solar	Intermediate	Yes	4.69
Facility 858	Candler	NC	Solar	Intermediate	Yes	7.25
Facility 859	Apex	NC	Solar	Intermediate	Yes	4.21
Facility 860	Pinehurst	NC	Solar	Intermediate	Yes	2.45
Facility 861	Willard	NC	Solar	Intermediate	Yes	4.07
Facility 862	Raleigh	NC	Solar	Intermediate	Yes	2.03
Facility 863	Raleigh	NC	Solar	Intermediate	Yes	5.618
Facility 864	Hampstead	NC	Solar	Intermediate	Yes	8.337
Facility 865	Cary	NC	Solar	Intermediate	Yes	3.93
Facility 866	Knightdale	NC	Solar	Intermediate	Yes	2
Facility 867	Wilmington	NC	Solar	Intermediate	Yes	4.82
Facility 868	Chapel Hill	NC	Solar	Intermediate	Yes	2.08
Facility 869	Apex	NC	Solar	Intermediate	Yes	3.1
Facility 870	Apex	NC	Solar	Intermediate	Yes	5.64
Facility 871	Norlina	NC	Solar	Intermediate	Yes	384
Facility 872	Fletcher	NC	Solar	Intermediate	Yes	6.45
Facility 873	Raleigh	NC	Solar	Intermediate	Yes	3
Facility 874	Wendell	NC	Solar	Intermediate	Yes	2.83
Facility 875	Raleigh	NC	Solar	Intermediate	Yes	4.25
Facility 876	Cary	NC	Solar	Intermediate	Yes	3.9
Facility 877	Wilmington	NC	Solar	Intermediate	Yes	4.42
Facility 878	Chapel Hill	NC	Solar	Intermediate	Yes	4.52
Facility 879	Rocky Point	NC	Solar	Intermediate	Yes	2.67
Facility 880	Pittsboro	NC	Solar	Intermediate	Yes	3.43
Facility 881	Pittsboro	NC	Solar	Intermediate	Yes	6.93
Facility 882	Chapel Hill	NC	Solar	Intermediate	Yes	5.39
Facility 883	Cary	NC	Solar	Intermediate	Yes	5.547
Facility 884	Fuquay Varina	NC	Solar	Intermediate	Yes	4.13
Facility 885	Cary	NC	Solar	Intermediate	Yes	1.841
Facility 886	Newport	NC	Solar	Intermediate	Yes	7.6
Facility 887	Chapel Hill	NC	Solar	Intermediate	Yes	2.861
Facility 888	Asheville	NC	Solar	Intermediate	Yes	7.933
Facility 889	Raleigh	NC	Solar	Intermediate	Yes	3.3
Facility 890	Raleigh	NC	Solar	Intermediate	Yes	2.6
Facility 891	Oriental	NC	Solar	Intermediate	Yes	3.6
Facility 892	Zebulon	NC	Solar	Intermediate	Yes	5.5
Facility 893	Raleigh	NC	Solar	Intermediate	Yes	2.72
Facility 894	Pittsboro	NC	Solar	Intermediate	Yes	2.2
Facility 895	Pittsboro	NC	Solar	Intermediate	Yes	3.02
Facility 896	Barnardsville	NC	Solar	Intermediate	Yes	2.7
Facility 897	Oxford	NC	Solar	Intermediate	Yes	2750
Facility 898	Holly Springs	NC	Solar	Intermediate	Yes	4.1
Facility 899	Fairview	NC	Solar	Intermediate	Yes	9

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 900	West End	NC	Solar	Intermediate	Yes	4.93
Facility 901	Raleigh	NC	Solar	Intermediate	Yes	4.21
Facility 902	Chapel Hill	NC	Solar	Intermediate	Yes	14
Facility 903	Bahama	NC	Solar	Intermediate	Yes	3.66
Facility 904	Cary	NC	Solar	Intermediate	Yes	4.545
Facility 905	Cary	NC	Solar	Intermediate	Yes	6.38
Facility 906	Kinston	NC	Solar	Intermediate	Yes	192.5
Facility 907	Fletcher	NC	Solar	Intermediate	Yes	2.52
Facility 908	Raleigh	NC	Solar	Intermediate	Yes	4
Facility 909	Garner	NC	Solar	Intermediate	Yes	160
Facility 910	Asheville	NC	Solar	Intermediate	Yes	4.73
Facility 911	Pittsboro	NC	Solar	Intermediate	Yes	6.372
Facility 912	Morrisville	NC	Solar	Intermediate	Yes	3.49
Facility 913	Robbins	NC	Solar	Intermediate	Yes	3.08
Facility 914	Hampstead	NC	Solar	Intermediate	Yes	3.09
Facility 915	Asheville	NC	Solar	Intermediate	Yes	4.25
Facility 916	Raleigh	NC	Solar	Intermediate	Yes	4.59
Facility 917	Raleigh	NC	Solar	Intermediate	Yes	7.7
Facility 918	Raleigh	NC	Solar	Intermediate	Yes	4.5
Facility 919	Cary	NC	Solar	Intermediate	Yes	4.42
Facility 920	Wilmington	NC	Solar	Intermediate	Yes	5.18
Facility 921	Raleigh	NC	Solar	Intermediate	Yes	3.49
Facility 922	Raleigh	NC	Solar	Intermediate	Yes	5.45
Facility 923	Asheville	NC	Solar	Intermediate	Yes	2.06
Facility 924	Morrisville	NC	Solar	Intermediate	Yes	5.64
Facility 925	Raleigh	NC	Solar	Intermediate	Yes	5.61
Facility 926	Hampstead	NC	Solar	Intermediate	Yes	4.75
Facility 927	Raleigh	NC	Solar	Intermediate	Yes	2.53
Facility 928	Asheville	NC	Solar	Intermediate	Yes	2.5
Facility 929	Calypso	NC	Solar	Intermediate	Yes	5.59
Facility 930	Weaverville	NC	Solar	Intermediate	Yes	3.797
Facility 931	Nashville	NC	Solar	Intermediate	Yes	4.15
Facility 932	Waynesville	NC	Solar	Intermediate	Yes	4.063
Facility 933	Hope Mills	NC	Solar	Intermediate	Yes	4.609
Facility 934	Asheville	NC	Solar	Intermediate	Yes	7.083
Facility 935	Pinehurst	NC	Solar	Intermediate	Yes	3.86
Facility 936	Cary	NC	Solar	Intermediate	Yes	5.262
Facility 937	Weaverville	NC	Solar	Intermediate	Yes	7.34
Facility 938	Garner	NC	Solar	Intermediate	Yes	7.127
Facility 939	Raleigh	NC	Solar	Intermediate	Yes	3.67
Facility 940	Asheboro	NC	Solar	Intermediate	Yes	3.724
Facility 941	Benson	NC	Solar	Intermediate	Yes	4000
Facility 942	Hamlet	NC	Solar	Intermediate	Yes	4.214
Facility 943	Fairview	NC	Solar	Intermediate	Yes	2.373
Facility 944	Asheville	NC	Solar	Intermediate	Yes	4.8
Facility 945	Holly Springs	NC	Solar	Intermediate	Yes	4.83
Facility 946	Raleigh	NC	Solar	Intermediate	Yes	4.36
Facility 947	Mt Olive	NC	Solar	Intermediate	Yes	4999
Facility 948	Morehead City	NC	Diesel	Peak	Yes	875
Facility 949	Wilmington	NC	Diesel	Peak	Yes	750
Facility 950	Wilmington	NC	Solar	Intermediate	Yes	4.093

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 951	Wendell	NC	Solar	Intermediate	Yes	4.33
Facility 952	Wake Forest	NC	Solar	Intermediate	Yes	2.65
Facility 953	Ashville	NC	Solar	Intermediate	Yes	5.877
Facility 954	Raleigh	NC	Solar	Intermediate	Yes	7.235
Facility 955	Pinebluff	NC	Solar	Intermediate	Yes	2.795
Facility 956	Chapel Hill	NC	Solar	Intermediate	Yes	10.32
Facility 957	Asheville	NC	Solar	Intermediate	Yes	2.88
Facility 958	Clayton	NC	Solar	Intermediate	Yes	2.25
Facility 959	Raleigh	NC	Solar	Intermediate	Yes	3.001
Facility 960	Cary	NC	Solar	Intermediate	Yes	7.307
Facility 961	Bailey	NC	Solar	Intermediate	Yes	3.87
Facility 962	Knightdale	NC	Solar	Intermediate	Yes	2.95
Facility 963	Asheville	NC	Solar	Intermediate	Yes	4.82
Facility 964	Angier	NC	Solar	Intermediate	Yes	12.042
Facility 965	Fayetteville	NC	Solar	Intermediate	Yes	3.51
Facility 966	Asheville	NC	Solar	Intermediate	Yes	4.571
Facility 967	Asheville	NC	Solar	Intermediate	Yes	4.32
Facility 968	Waynesville	NC	Solar	Intermediate	Yes	5.251
Facility 969	Willow Spring	NC	Solar	Intermediate	Yes	1999
Facility 970	Raleigh	NC	Solar	Intermediate	Yes	2
Facility 971	Raleigh	NC	Solar	Intermediate	Yes	3.53
Facility 972	Asheville	NC	Solar	Intermediate	Yes	5
Facility 973	Pittsboro	NC	Solar	Intermediate	Yes	4.26
Facility 974	Raleigh	NC	Solar	Intermediate	Yes	2.18
Facility 975	Fuquay Varina	NC	Solar	Intermediate	Yes	5.6
Facility 976	Kure Beach	NC	Solar	Intermediate	Yes	2.44
Facility 977	Asheville	NC	Solar	Intermediate	Yes	6
Facility 978	Asheville	NC	Solar	Intermediate	Yes	6
Facility 979	Black Mountain	NC	Solar	Intermediate	Yes	5
Facility 980	Pittsboro	NC	Solar	Intermediate	Yes	3.32
Facility 981	Arden	NC	Solar	Intermediate	Yes	1.44
Facility 982	Pittsboro	NC	Solar	Intermediate	Yes	2.77
Facility 983	Holly Springs	NC	Solar	Intermediate	Yes	4.53
Facility 984	Angier	NC	Solar	Intermediate	Yes	5.63
Facility 985	Wilmington	NC	Solar	Intermediate	Yes	5.06
Facility 986	Raleigh	NC	Solar	Intermediate	Yes	3.78
Facility 987	Raleigh	NC	Solar	Intermediate	Yes	4.165
Facility 988	Henderson	NC	Solar	Intermediate	Yes	100
Facility 989	Henderson	NC	Solar	Intermediate	Yes	125
Facility 990	Raleigh	NC	Solar	Intermediate	Yes	3.46
Facility 991	Laurinburg	NC	Solar	Intermediate	Yes	5000
Facility 992	Wilmington	NC	Solar	Intermediate	Yes	2.81
Facility 993	Biltmore Lake	NC	Solar	Intermediate	Yes	3.49
Facility 994	Hubert	NC	Solar	Intermediate	Yes	6.98
Facility 995	Asheville	NC	Solar	Intermediate	Yes	2.25
Facility 996	Spruce Pine	NC	Solar	Intermediate	Yes	17
Facility 997	Spruce Pine	NC	Solar	Intermediate	Yes	3.8
Facility 998	Grifton	NC	Solar	Intermediate	Yes	4999
Facility 999	Stoney Creek	NC	Solar	Intermediate	Yes	5000

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1000	Asheville	NC	Solar	Intermediate	Yes	5.001
Facility 1001	Wilmington	NC	Solar	Intermediate	Yes	6.28
Facility 1002	Carthage	NC	Solar	Intermediate	Yes	6.335
Facility 1003	Clayton	NC	Solar	Intermediate	Yes	4.719
Facility 1004	Pittsboro	NC	Solar	Intermediate	Yes	3.73
Facility 1005	Asheville	NC	Solar	Intermediate	Yes	5.32
Facility 1006	Princeton	NC	Solar	Intermediate	Yes	6.91
Facility 1007	Willow Spring	NC	Solar	Intermediate	Yes	3.76
Facility 1008	Raleigh	NC	Solar	Intermediate	Yes	7.09
Facility 1009	Arden	NC	Solar	Intermediate	Yes	3
Facility 1010	Pittsboro	NC	Solar	Intermediate	Yes	3.52
Facility 1011	Raleigh	NC	Solar	Intermediate	Yes	2
Facility 1012	Siler City	NC	Solar	Intermediate	Yes	4.1
Facility 1013	Peachland	NC	Solar	Intermediate	Yes	2.56
Facility 1014	Raleigh	NC	Solar	Intermediate	Yes	3.27
Facility 1015	Linden	NC	Solar	Intermediate	Yes	4.2
Facility 1016	Raleigh	NC	Solar	Intermediate	Yes	3.67
Facility 1017	Maxton	NC	Solar	Intermediate	Yes	19800
Facility 1018	Pittsboro	NC	Solar	Intermediate	Yes	3.06
Facility 1019	Raleigh	NC	Solar	Intermediate	Yes	18.421
Facility 1020	Asheville	NC	Solar	Intermediate	Yes	4.26
Facility 1021	Smyrna	NC	Solar	Intermediate	Yes	2.19
Facility 1022	Raleigh	NC	Solar	Intermediate	Yes	3.84
Facility 1023	Benson	NC	Solar	Intermediate	Yes	6
Facility 1024	Cary	NC	Solar	Intermediate	Yes	5.8
Facility 1025	Carolina Beach	NC	Solar	Intermediate	Yes	3.41
Facility 1026	Clayton	NC	Solar	Intermediate	Yes	3.5
Facility 1027	Marshall	NC	Wind	(blank)	Yes	1.84
Facility 1028	Alexander	NC	Solar	Intermediate	Yes	3.4
Facility 1029	Raleigh	NC	Solar	Intermediate	Yes	4.9
Facility 1030	Spruce Pine	NC	Solar	Intermediate	Yes	4.6
Facility 1031	Apex	NC	Solar	Intermediate	Yes	6.44
Facility 1032	Elm City	NC	Solar	Intermediate	Yes	2.03
Facility 1033	Henderson	NC	Solar	Intermediate	Yes	9
Facility 1034	New Bern	NC	Solar	Intermediate	Yes	4.67
Facility 1035	Pittsboro	NC	Solar	Intermediate	Yes	6.97
Facility 1036	Chapel Hill	NC	Solar	Intermediate	Yes	3.53
Facility 1037	Holly Springs	NC	Solar	Intermediate	Yes	5.1
Facility 1038	Fuquay Varina	NC	Solar	Intermediate	Yes	4.97
Facility 1039	Raleigh	NC	Solar	Intermediate	Yes	3.05
Facility 1040	Asheville	NC	Solar	Intermediate	Yes	15.2
Facility 1041	Wilmington	NC	Solar	Intermediate	Yes	4.63
Facility 1042	Candler	NC	Solar	Intermediate	Yes	2.19
Facility 1043	Clayton	NC	Solar	Intermediate	Yes	2.907
Facility 1044	Carolina Beach	NC	Solar	Intermediate	Yes	6.91
Facility 1045	Raleigh	NC	Solar	Intermediate	Yes	5.37
Facility 1046	Weaverville	NC	Solar	Intermediate	Yes	4.537
Facility 1047	Asheville	NC	Solar	Intermediate	Yes	6.479
Facility 1048	Cary	NC	Solar	Intermediate	Yes	2.89
Facility 1049	High Falls	NC	Hydroelectric	Baseload	Yes	600
Facility 1050	Greensboro	NC	Hydroelectric	Baseload	Yes	990

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1051	Oxford	NC	Solar	Intermediate	Yes	200
Facility 1052	Oxford	NC	Solar	Intermediate	Yes	158
Facility 1053	Williston	NC	Solar	Intermediate	Yes	7.9
Facility 1054	New Bern	NC	Landfill Gas	Intermediate	Yes	4000
Facility 1055	Apex	NC	Landfill Gas	Intermediate	Yes	7300
Facility 1056	Raleigh	NC	Solar	Intermediate	Yes	5
Facility 1057	Canton	NC	Solar	Intermediate	Yes	1300
Facility 1058	Shannon	NC	Solar	Intermediate	Yes	4999
Facility 1059	Maxton	NC	Solar	Intermediate	Yes	4999
Facility 1060	Leicester	NC	Solar	Intermediate	Yes	1990
Facility 1061	Leicester	NC	Solar	Intermediate	Yes	800
Facility 1062	Leicester	NC	Solar	Intermediate	Yes	800
Facility 1063	Snow Hill	NC	Solar	Intermediate	Yes	4995
Facility 1064	Clinton	NC	Solar	Intermediate	Yes	4995
Facility 1065	Carolina Beach	NC	Solar	Intermediate	Yes	1
Facility 1066	Wilmington	NC	Solar	Intermediate	Yes	4.869
Facility 1067	Goldsboro	NC	Solar	Intermediate	Yes	9.683
Facility 1068	Asheboro	NC	Solar	Intermediate	Yes	5.34
Facility 1069	Cary	NC	Solar	Intermediate	Yes	3.76
Facility 1070	Cary	NC	Solar	Intermediate	Yes	3.4
Facility 1071	Pittsboro	NC	Solar	Intermediate	Yes	1.632
Facility 1072	Waynesville	NC	Solar	Intermediate	Yes	5.679
Facility 1073	Roxboro	NC	Solar	Intermediate	Yes	1.85
Facility 1074	Asheville	NC	Solar	Intermediate	Yes	6.8
Facility 1075	Siler City	NC	Solar	Intermediate	Yes	4.8
Facility 1076	Dudley	NC	Solar	Intermediate	Yes	22.31
Facility 1077	Morrisville	NC	Solar	Intermediate	Yes	4.07
Facility 1078	Godwin	NC	Solar	Intermediate	Yes	5.123
Facility 1079	Cary	NC	Solar	Intermediate	Yes	2.94
Facility 1080	Wilmington	NC	Solar	Intermediate	Yes	2.5
Facility 1081	Cary	NC	Solar	Intermediate	Yes	6.482
Facility 1082	Broadway	NC	Solar	Intermediate	Yes	8.55
Facility 1083	Broadway	NC	Solar	Intermediate	Yes	8.5
Facility 1084	Fuquay Varnia	NC	Solar	Intermediate	Yes	2.49
Facility 1085	Asheville	NC	Solar	Intermediate	Yes	7.68
Facility 1086	Wilmington	NC	Solar	Intermediate	Yes	4
Facility 1087	Candler	NC	Solar	Intermediate	Yes	3.36
Facility 1088	Clayton	NC	Solar	Intermediate	Yes	2.7
Facility 1089	Pittsboro	NC	Solar	Intermediate	Yes	1.8
Facility 1090	Holly Springs	NC	Solar	Intermediate	Yes	3.8
Facility 1091	Black Mountain	NC	Solar	Intermediate	Yes	2.752
Facility 1092	Pittsboro	NC	Solar	Intermediate	Yes	6
Facility 1093	Cary	NC	Solar	Intermediate	Yes	4.5
Facility 1094	Fuquay Varina	NC	Solar	Intermediate	Yes	6.57
Facility 1095	Pinehurst	NC	Solar	Intermediate	Yes	6.75
Facility 1096	Fremont	NC	Solar	Intermediate	Yes	1.54
Facility 1097	Fletcher	NC	Solar	Intermediate	Yes	3.672
Facility 1098	Fletcher	NC	Solar	Intermediate	Yes	9.48
Facility 1099	Raleigh	NC	Solar	Intermediate	Yes	5.88

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1100	Cary	NC	Solar	Intermediate	Yes	3
Facility 1101	Fairview	NC	Solar	Intermediate	Yes	3
Facility 1102	Goldsboro	NC	Solar	Intermediate	Yes	4.47
Facility 1103	Wilmington	NC	Solar	Intermediate	Yes	4.5
Facility 1104	Boiling Spring Lakes	NC	Solar	Intermediate	Yes	2.48
Facility 1105	Weaverville	NC	Solar	Intermediate	Yes	5.2
Facility 1106	Fairview	NC	Solar	Intermediate	Yes	3.84
Facility 1107	Weaverville	NC	Solar	Intermediate	Yes	4.3
Facility 1108	Montreat	NC	Solar	Intermediate	Yes	2.45
Facility 1109	Clayton	NC	Solar	Intermediate	Yes	3.6
Facility 1110	Wearverville	NC	Solar	Intermediate	Yes	6
Facility 1111	Asheville	NC	Solar	Intermediate	Yes	4.42
Facility 1112	Asheville	NC	Solar	Intermediate	Yes	5
Facility 1113	New Bern	NC	Solar	Intermediate	Yes	3
Facility 1114	Asheville	NC	Solar	Intermediate	Yes	7.5
Facility 1115	Raleigh	NC	Solar	Intermediate	Yes	4.5
Facility 1116	Pittsboro	NC	Solar	Intermediate	Yes	3.02
Facility 1117	Asheville	NC	Solar	Intermediate	Yes	3.78
Facility 1118	Wilmington	NC	Solar	Intermediate	Yes	8.78
Facility 1119	Raleigh	NC	Solar	Intermediate	Yes	3.26
Facility 1120	Cary	NC	Solar	Intermediate	Yes	4
Facility 1121	Asheville	NC	Solar	Intermediate	Yes	3.8
Facility 1122	Wilmington	NC	Solar	Intermediate	Yes	3.1
Facility 1123	Raleigh	NC	Solar	Intermediate	Yes	2.9
Facility 1124	Cary	NC	Solar	Intermediate	Yes	1.5
Facility 1125	Cary	NC	Solar	Intermediate	Yes	5.988
Facility 1126	Maggie Valley	NC	Solar	Intermediate	Yes	7.68
Facility 1127	Raleigh	NC	Solar	Intermediate	Yes	2.88
Facility 1128	Raleigh	NC	Solar	Intermediate	Yes	1.54
Facility 1129	Garner	NC	Solar	Intermediate	Yes	5.16
Facility 1130	Asheville	NC	Solar	Intermediate	Yes	5
Facility 1131	Swannanoa	NC	Solar	Intermediate	Yes	3.8
Facility 1132	Wilmington	NC	Solar	Intermediate	Yes	1.8
Facility 1133	Raleigh	NC	Solar	Intermediate	Yes	1.8
Facility 1134	Manson	NC	Solar	Intermediate	Yes	3.88
Facility 1135	Cary	NC	Solar	Intermediate	Yes	5.92
Facility 1136	Raleigh	NC	Solar	Intermediate	Yes	5.531
Facility 1137	Cary	NC	Solar	Intermediate	Yes	4.68
Facility 1138	Dunn	NC	Solar	Intermediate	Yes	6.777
Facility 1139	Raleigh	NC	Solar	Intermediate	Yes	3.08
Facility 1140	Fletcher	NC	Solar	Intermediate	Yes	6.12
Facility 1141	Vass	NC	Solar	Intermediate	Yes	6.24
Facility 1142	Fuquay Varina	NC	Solar	Intermediate	Yes	4.4
Facility 1143	Pittsboro	NC	Solar	Intermediate	Yes	1.57
Facility 1144	Pittsboro	NC	Solar	Intermediate	Yes	3.62
Facility 1145	Alexander	NC	Solar	Intermediate	Yes	5
Facility 1146	Holly Springs	NC	Solar	Intermediate	Yes	6
Facility 1147	Cary	NC	Solar	Intermediate	Yes	4.5
Facility 1148	Cary	NC	Solar	Intermediate	Yes	1.5
Facility 1149	Henderson	NC	Solar	Intermediate	Yes	3
Facility 1150	Fuquay Varina	NC	Solar	Intermediate	Yes	2.58

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1151	Laurinburg	NC	Solar	Intermediate	Yes	1.72
Facility 1152	Wilmington	NC	Solar	Intermediate	Yes	1
Facility 1153	Asheville	NC	Solar	Intermediate	Yes	4
Facility 1154	Asheville	NC	Solar	Intermediate	Yes	3
Facility 1155	Asheville	NC	Solar	Intermediate	Yes	3
Facility 1156	Weaverville	NC	Solar	Intermediate	Yes	5.16
Facility 1157	Weaverville	NC	Solar	Intermediate	Yes	1.51
Facility 1158	Chapel Hill	NC	Solar	Intermediate	Yes	5.16
Facility 1159	Pittsboro	NC	Solar	Intermediate	Yes	1.63
Facility 1160	Asheville	NC	Solar	Intermediate	Yes	4
Facility 1161	Wake Forest	NC	Solar	Intermediate	Yes	2.35
Facility 1162	Southern Pines	NC	Solar	Intermediate	Yes	7.3
Facility 1163	Raleigh	NC	Solar	Intermediate	Yes	4
Facility 1164	Raleigh	NC	Solar	Intermediate	Yes	2.7
Facility 1165	Pittsboro	NC	Solar	Intermediate	Yes	4
Facility 1166	Alexander	NC	Solar	Intermediate	Yes	2.8
Facility 1167	Barnardsville	NC	Solar	Intermediate	Yes	3.64
Facility 1168	Barnardsville	NC	Solar	Intermediate	Yes	3.64
Facility 1169	Black Mountain	NC	Solar	Intermediate	Yes	5.08
Facility 1170	Hampstead	NC	Solar	Intermediate	Yes	3
Facility 1171	Humpstead	NC	Solar	Intermediate	Yes	4
Facility 1172	Raleigh	NC	Solar	Intermediate	Yes	4.5
Facility 1173	Pittsboro	NC	Solar	Intermediate	Yes	5
Facility 1174	Raleigh	NC	Solar	Intermediate	Yes	6.88
Facility 1175	Raleigh	NC	Solar	Intermediate	Yes	9
Facility 1176	Asheville	NC	Solar	Intermediate	Yes	4.3
Facility 1177	Zebulon	NC	Solar	Intermediate	Yes	9.9
Facility 1178	Asheville	NC	Solar	Intermediate	Yes	5.16
Facility 1179	Pinehurst	NC	Solar	Intermediate	Yes	4
Facility 1180	Bakersville	NC	Solar	Intermediate	Yes	3.2
Facility 1181	Asheville	NC	Solar	Intermediate	Yes	1.75
Facility 1182	Asheville	NC	Solar	Intermediate	Yes	1.6
Facility 1183	Louisburg	NC	Solar	Intermediate	Yes	3.672
Facility 1184	Cary	NC	Solar	Intermediate	Yes	2.304
Facility 1185	Cary	NC	Solar	Intermediate	Yes	3
Facility 1186	Raleigh	NC	Solar	Intermediate	Yes	5.31
Facility 1187	Siler City	NC	Solar	Intermediate	Yes	4.2
Facility 1188	Siler City	NC	Solar	Intermediate	Yes	2.5
Facility 1189	Willow Springs	NC	Solar	Intermediate	Yes	3
Facility 1190	Lilesville	NC	Solar	Intermediate	Yes	1.72
Facility 1191	Weaverville	NC	Solar	Intermediate	Yes	3.96
Facility 1192	Raleigh	NC	Solar	Intermediate	Yes	3.72
Facility 1193	Asheville	NC	Solar	Intermediate	Yes	7.6
Facility 1194	Wilmington	NC	Solar	Intermediate	Yes	1
Facility 1195	Rose Hill	NC	Other	Intermediate	Yes	100
Facility 1196	Woodfin	NC	Solar	Intermediate	Yes	5.278
Facility 1197	Asheville	NC	Solar	Intermediate	Yes	7.83
Facility 1198	Wilmington	NC	Solar	Intermediate	Yes	5.928
Facility 1199	Raleigh	NC	Solar	Intermediate	Yes	4.52

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1200	Asheville	NC	Solar	Intermediate	Yes	4.25
Facility 1201	Benson	NC	Solar	Intermediate	Yes	4.933
Facility 1202	Asheville	NC	Solar	Intermediate	Yes	4.33
Facility 1203	Fairview	NC	Solar	Intermediate	Yes	2.7
Facility 1204	Hampstead	NC	Solar	Intermediate	Yes	4
Facility 1205	Asheboro	NC	Solar	Intermediate	Yes	5
Facility 1206	Canton	NC	Solar	Intermediate	Yes	9.18
Facility 1207	Asheville	NC	Solar	Intermediate	Yes	2
Facility 1208	Chapel Hill	NC	Solar	Intermediate	Yes	4.158
Facility 1209	Garner	NC	Solar	Intermediate	Yes	4.019
Facility 1210	Pittsboro	NC	Solar	Intermediate	Yes	3.466
Facility 1211	New Hill	NC	Hydroelectric	Baseload	Yes	4400
Facility 1212	Siler City	NC	Solar	Intermediate	Yes	1.5
Facility 1213	Chapel Hill	NC	Solar	Intermediate	Yes	6
Facility 1214	Henderson	NC	Solar	Intermediate	Yes	4.7
Facility 1215	Raleigh	NC	Solar	Intermediate	Yes	2.76
Facility 1216	Goldsboro	NC	Solar	Intermediate	Yes	4.06
Facility 1217	Asheville	NC	Solar	Intermediate	Yes	4.3
Facility 1218	Cary	NC	Solar	Intermediate	Yes	3.98
Facility 1219	Wendell	NC	Solar	Intermediate	Yes	5.76
Facility 1220	Pittsboro	NC	Solar	Intermediate	Yes	2.48
Facility 1221	Raleigh	NC	Solar	Intermediate	Yes	1000
Facility 1222	Fayetteville	NC	Solar	Intermediate	Yes	7.5
Facility 1223	Leland	NC	Solar	Intermediate	Yes	5.886
Facility 1224	Raleigh	NC	Solar	Intermediate	Yes	1.72
Facility 1225	Asheville	NC	Solar	Intermediate	Yes	5.16
Facility 1226	Aberdeen	NC	Solar	Intermediate	Yes	11.59
Facility 1227	Aberdeen	NC	Solar	Intermediate	Yes	10
Facility 1228	Asheville	NC	Solar	Intermediate	Yes	1.74
Facility 1229	Bahama	NC	Solar	Intermediate	Yes	6
Facility 1230	Barnardsville	NC	Solar	Intermediate	Yes	1.92
Facility 1231	Cameron	NC	Solar	Intermediate	Yes	8.6
Facility 1232	Southern Pines	NC	Solar	Intermediate	Yes	7.8
Facility 1233	Asheville	NC	Solar	Intermediate	Yes	1.73
Facility 1234	Willow Springs	NC	Solar	Intermediate	Yes	8.508
Facility 1235	Asheville	NC	Solar	Intermediate	Yes	22.5
Facility 1236	Asheville	NC	Solar	Intermediate	Yes	22.5
Facility 1237	Raleigh	NC	Solar	Intermediate	Yes	2.4
Facility 1238	Raleigh	NC	Solar	Intermediate	Yes	3.15
Facility 1239	Raleigh	NC	Solar	Intermediate	Yes	5.5
Facility 1240	Raleigh	NC	Solar	Intermediate	Yes	5.66
Facility 1241	Cary	NC	Solar	Intermediate	Yes	4.398
Facility 1242	Raleigh	NC	Solar	Intermediate	Yes	9.99
Facility 1243	Morrisville	NC	Solar	Intermediate	Yes	3.636
Facility 1244	Pinehurst	NC	Solar	Intermediate	Yes	8.2
Facility 1245	Weaverville	NC	Solar	Intermediate	Yes	3.29
Facility 1246	Weaverville	NC	Solar	Intermediate	Yes	2.66
Facility 1247	Alexander	NC	Solar	Intermediate	Yes	3.1
Facility 1248	Swannanoa	NC	Solar	Intermediate	Yes	1.46
Facility 1249	Asheville	NC	Solar	Intermediate	Yes	6
Facility 1250	Leicester	NC	Solar	Intermediate	Yes	6

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1251	Pinehurst	NC	Solar	Intermediate	Yes	4.3
Facility 1252	Cary	NC	Solar	Intermediate	Yes	2.442
Facility 1253	Weaverville	NC	Solar	Intermediate	Yes	3.45
Facility 1254	Candler	NC	Solar	Intermediate	Yes	2.26
Facility 1255	Morehead City	NC	Solar	Intermediate	Yes	2.04
Facility 1256	Raleigh	NC	Solar	Intermediate	Yes	2.58
Facility 1257	Pittsboro	NC	Solar	Intermediate	Yes	2.5
Facility 1258	Pittsboro	NC	Solar	Intermediate	Yes	1.7
Facility 1259	Cary	NC	Solar	Intermediate	Yes	2.3
Facility 1260	Weaverville	NC	Solar	Intermediate	Yes	3.7
Facility 1261	Canton	NC	Solar	Intermediate	Yes	6.88
Facility 1262	Cary	NC	Solar	Intermediate	Yes	7.38
Facility 1263	Four Oaks	NC	Solar	Intermediate	Yes	5000
Facility 1264	Pittsboro	NC	Solar	Intermediate	Yes	7.977
Facility 1265	Sanford	NC	Solar	Intermediate	Yes	10.312
Facility 1266	Carolina Beach	NC	Solar	Intermediate	Yes	3.5
Facility 1267	Carolina Beach	NC	Solar	Intermediate	Yes	4.3
Facility 1268	Siler City	NC	Solar	Intermediate	Yes	7.1
Facility 1269	Biscoe	NC	Solar	Intermediate	Yes	3.44
Facility 1270	Wade	NC	Solar	Intermediate	Yes	7.16
Facility 1271	Candler	NC	Solar	Intermediate	Yes	1
Facility 1272	Candler	NC	Solar	Intermediate	Yes	0.86
Facility 1273	Asheville	NC	Solar	Intermediate	Yes	7.6
Facility 1274	Raleigh	NC	Solar	Intermediate	Yes	3.01
Facility 1275	Asheville	NC	Solar	Intermediate	Yes	5
Facility 1276	Wilmington	NC	Solar	Intermediate	Yes	3.118
Facility 1277	Raleigh	NC	Solar	Intermediate	Yes	4.84
Facility 1278	Swannanoa	NC	Solar	Intermediate	Yes	1.829
Facility 1279	Swannanoa	NC	Solar	Intermediate	Yes	1.829
Facility 1280	Kenansville	NC	Solar	Intermediate	Yes	1999
Facility 1281	Kenansville	NC	Solar	Intermediate	Yes	4500
Facility 1282	Warsaw	NC	Solar	Intermediate	Yes	1999
Facility 1283	Clyde	NC	Solar	Intermediate	Yes	2.88
Facility 1284	Asheville	NC	Solar	Intermediate	Yes	3.7
Facility 1285	Maggie Valley	NC	Solar	Intermediate	Yes	7.6
Facility 1286	Raleigh	NC	Solar	Intermediate	Yes	1.8
Facility 1287	Pinehurst	NC	Solar	Intermediate	Yes	10.14
Facility 1288	Warrenton	NC	Solar	Intermediate	Yes	3000
Facility 1289	Pittsboro	NC	Solar	Intermediate	Yes	4.84
Facility 1290	Fremont	NC	Solar	Intermediate	Yes	6
Facility 1291	Wilmington	NC	Solar	Intermediate	Yes	5
Facility 1292	Asheville	NC	Solar	Intermediate	Yes	3.2
Facility 1293	Cary	NC	Solar	Intermediate	Yes	4.341
Facility 1294	Wilmington	NC	Solar	Intermediate	Yes	1.44
Facility 1295	Canton	NC	Solar	Intermediate	Yes	11.52
Facility 1296	Apex	NC	Solar	Intermediate	Yes	6.27
Facility 1297	Wilmington	NC	Solar	Intermediate	Yes	4
Facility 1298	Raleigh	NC	Solar	Intermediate	Yes	4.43
Facility 1299	Chapel Hill	NC	Solar	Intermediate	Yes	4.9

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1300	Cary	NC	Solar	Intermediate	Yes	4.33
Facility 1301	Raleigh	NC	Solar	Intermediate	Yes	2.39
Facility 1302	Raleigh	NC	Solar	Intermediate	Yes	4.628
Facility 1303	Cary	NC	Solar	Intermediate	Yes	2.92
Facility 1304	Zebulon	NC	Solar	Intermediate	Yes	11.338
Facility 1305	Holly Springs	NC	Solar	Intermediate	Yes	5.652
Facility 1306	Pittsboro	NC	Solar	Intermediate	Yes	2.097
Facility 1307	Broadway	NC	Solar	Intermediate	Yes	5.83
Facility 1308	Pittsboro	NC	Solar	Intermediate	Yes	2.24
Facility 1309	Asheville	NC	Solar	Intermediate	Yes	4.4
Facility 1310	Fuquay Varina	NC	Solar	Intermediate	Yes	5.36
Facility 1311	Cary	NC	Solar	Intermediate	Yes	4.29
Facility 1312	Kinston	NC	Solar	Intermediate	Yes	4998
Facility 1313	Hookerton	NC	Solar	Intermediate	Yes	1999
Facility 1314	Fuquay Varina	NC	Solar	Intermediate	Yes	14.56
Facility 1315	Pittsboro	NC	Solar	Intermediate	Yes	4.627
Facility 1316	Carthage	NC	Solar	Intermediate	Yes	5.71
Facility 1317	Warsaw	NC	Solar	Intermediate	Yes	5000
Facility 1318	Cary	NC	Solar	Intermediate	Yes	4.418
Facility 1319	Fletcher	NC	Solar	Intermediate	Yes	7.36
Facility 1320	Henderson	NC	Solar	Intermediate	Yes	3.68
Facility 1321	Kure Beach	NC	Solar	Intermediate	Yes	2.56
Facility 1322	Raleigh	NC	Solar	Intermediate	Yes	5.25
Facility 1323	Cary	NC	Solar	Intermediate	Yes	4.83
Facility 1324	Raleigh	NC	Solar	Intermediate	Yes	5.7
Facility 1325	Pittsboro	NC	Solar	Intermediate	Yes	6.6
Facility 1326	Apex	NC	Solar	Intermediate	Yes	5.05
Facility 1327	Raleigh	NC	Solar	Intermediate	Yes	3.92
Facility 1328	Raleigh	NC	Solar	Intermediate	Yes	3.62
Facility 1329	Biltmore Lake	NC	Solar	Intermediate	Yes	5.848
Facility 1330	Hampstead	NC	Solar	Intermediate	Yes	5.73
Facility 1331	Cary	NC	Solar	Intermediate	Yes	2.14
Facility 1332	Bailey	NC	Solar	Intermediate	Yes	5000
Facility 1333	Cary	NC	Solar	Intermediate	Yes	4.39
Facility 1334	Cary	NC	Solar	Intermediate	Yes	2.442
Facility 1335	Raleigh	NC	Solar	Intermediate	Yes	2.143
Facility 1336	Raleigh	NC	Solar	Intermediate	Yes	2.64
Facility 1337	Pinehurst	NC	Solar	Intermediate	Yes	4.58
Facility 1338	Cary	NC	Solar	Intermediate	Yes	5.67
Facility 1339	Raleigh	NC	Solar	Intermediate	Yes	3.62
Facility 1340	Vass	NC	Solar	Intermediate	Yes	8.58
Facility 1341	Raleigh	NC	Solar	Intermediate	Yes	3.02
Facility 1342	Pittsboro	NC	Solar	Intermediate	Yes	3.52
Facility 1343	Garner	NC	Solar	Intermediate	Yes	2.711
Facility 1344	Raleigh	NC	Solar	Intermediate	Yes	5
Facility 1345	Wilmington	NC	Solar	Intermediate	Yes	4.54
Facility 1346	Asheville	NC	Solar	Intermediate	Yes	3.8
Facility 1347	Pittsboro	NC	Solar	Intermediate	Yes	4.86
Facility 1348	Asheville	NC	Solar	Intermediate	Yes	4.65
Facility 1349	Wilmington	NC	Solar	Intermediate	Yes	3.66
Facility 1350	Pittsboro	NC	Solar	Intermediate	Yes	5.12

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1351	Wilmington	NC	Solar	Intermediate	Yes	5.26
Facility 1352	Franklinville	NC	Hydroelectric	Baseload	Yes	550
Facility 1353	Raleigh	NC	Solar	Intermediate	Yes	4
Facility 1354	Raleigh	NC	Solar	Intermediate	Yes	2.4
Facility 1355	Parkton	NC	Hydroelectric	Baseload	Yes	800
Facility 1356	Raleigh	NC	Solar	Intermediate	Yes	3.858
Facility 1357	Pittsboro	NC	Solar	Intermediate	Yes	2.52
Facility 1358	Asheville	NC	Solar	Intermediate	Yes	2.1
Facility 1359	Angier	NC	Solar	Intermediate	Yes	2.98
Facility 1360	Jackson Spring	NC	Solar	Intermediate	Yes	47000
Facility 1361	Chapel Hill	NC	Solar	Intermediate	Yes	2.46
Facility 1362	LaGrange	NC	Solar	Intermediate	Yes	4998
Facility 1363	Arden	NC	Solar	Intermediate	Yes	4.36
Facility 1364	Four Oaks	NC	Solar	Intermediate	Yes	5000
Facility 1365	Apex	NC	Solar	Intermediate	Yes	4.6
Facility 1366	Fairview	NC	Solar	Intermediate	Yes	4.71
Facility 1367	Raleigh	NC	Solar	Intermediate	Yes	5.62
Facility 1368	Black Mountain	NC	Solar	Intermediate	Yes	6
Facility 1369	Zebulon	NC	Solar	Intermediate	Yes	1.6
Facility 1370	Raleigh	NC	Solar	Intermediate	Yes	3.444
Facility 1371	Chapel Hill	NC	Solar	Intermediate	Yes	1
Facility 1372	Asheville	NC	Solar	Intermediate	Yes	4.8
Facility 1373	Raleigh	NC	Solar	Intermediate	Yes	2.67
Facility 1374	Raleigh	NC	Solar	Intermediate	Yes	8.12
Facility 1375	Castalia	NC	Solar	Intermediate	Yes	4.944
Facility 1376	Ashville	NC	Solar	Intermediate	Yes	5.335
Facility 1377	Wilmington	NC	Solar	Intermediate	Yes	2.34
Facility 1378	Pittsboro	NC	Solar	Intermediate	Yes	3.04
Facility 1379	Asheville	NC	Solar	Intermediate	Yes	3.8
Facility 1380	Lillington	NC	Solar	Intermediate	Yes	2.25
Facility 1381	Asheville	NC	Solar	Intermediate	Yes	3.84
Facility 1382	Cary	NC	Solar	Intermediate	Yes	2.52
Facility 1383	Laurinburg	NC	Solar	Intermediate	Yes	1999
Facility 1384	Cary	NC	Solar	Intermediate	Yes	7.6
Facility 1385	Cary	NC	Solar	Intermediate	Yes	6.58
Facility 1386	Black Mountain	NC	Solar	Intermediate	Yes	2.9
Facility 1387	Asheville	NC	Solar	Intermediate	Yes	2.9
Facility 1388	Waynesville	NC	Solar	Intermediate	Yes	2.848
Facility 1389	Raleigh	NC	Solar	Intermediate	Yes	5.32
Facility 1390	Chapel Hill	NC	Solar	Intermediate	Yes	4.62
Facility 1391	Raleigh	NC	Solar	Intermediate	Yes	6.21
Facility 1392	Rougemont	NC	Solar	Intermediate	Yes	3
Facility 1393	Raleigh	NC	Solar	Intermediate	Yes	3.394
Facility 1394	Raleigh	NC	Solar	Intermediate	Yes	3.42
Facility 1395	Asheville	NC	Solar	Intermediate	Yes	3.3
Facility 1396	Grifton	NC	Solar	Intermediate	Yes	5000
Facility 1397	Kinston	NC	Solar	Intermediate	Yes	4975
Facility 1398	Raleigh	NC	Solar	Intermediate	Yes	2.3
Facility 1399	Pinehurst	NC	Solar	Intermediate	Yes	2.83

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1400	Alexander	NC	Solar	Intermediate	Yes	6.64
Facility 1401	Asheville	NC	Solar	Intermediate	Yes	6
Facility 1402	Raleigh	NC	Solar	Intermediate	Yes	5.379
Facility 1403	Swannanoa	NC	Solar	Intermediate	Yes	4.24
Facility 1404	Cary	NC	Solar	Intermediate	Yes	5.68
Facility 1405	Raleigh	NC	Solar	Intermediate	Yes	6.33
Facility 1406	Black Mountain	NC	Solar	Intermediate	Yes	1.92
Facility 1407	Asheville	NC	Solar	Intermediate	Yes	4.428
Facility 1408	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 1409	Asheville	NC	Solar	Intermediate	Yes	2.3
Facility 1410	Wilmington	NC	Solar	Intermediate	Yes	4.61
Facility 1411	Chapel Hill	NC	Solar	Intermediate	Yes	4.31
Facility 1412	Fuquay Varina	NC	Solar	Intermediate	Yes	4.38
Facility 1413	Raleigh	NC	Solar	Intermediate	Yes	5.39
Facility 1414	Apex	NC	Solar	Intermediate	Yes	6
Facility 1415	Raleigh	NC	Solar	Intermediate	Yes	2.3
Facility 1416	Apex	NC	Solar	Intermediate	Yes	3.4
Facility 1417	Raleigh	NC	Solar	Intermediate	Yes	2.83
Facility 1418	Pittsboro	NC	Solar	Intermediate	Yes	4
Facility 1419	Southport	NC	Solar	Intermediate	Yes	2.88
Facility 1420	Cary	NC	Solar	Intermediate	Yes	2.4
Facility 1421	Asheville	NC	Solar	Intermediate	Yes	3.84
Facility 1422	Wrightsville Beach	NC	Solar	Intermediate	Yes	6.571
Facility 1423	Sanford	NC	Solar	Intermediate	Yes	3.83
Facility 1424	Raleigh	NC	Solar	Intermediate	Yes	4.028
Facility 1425	Raleigh	NC	Solar	Intermediate	Yes	12.279
Facility 1426	West End	NC	Solar	Intermediate	Yes	3.57
Facility 1427	Asheville	NC	Solar	Intermediate	Yes	3.333
Facility 1428	Cary	NC	Solar	Intermediate	Yes	2.52
Facility 1429	Raleigh	NC	Solar	Intermediate	Yes	4
Facility 1430	Apex	NC	Solar	Intermediate	Yes	2.442
Facility 1431	Apex	NC	Solar	Intermediate	Yes	9.8
Facility 1432	Wilmington	NC	Solar	Intermediate	Yes	4.02
Facility 1433	Raleigh	NC	Solar	Intermediate	Yes	6.63
Facility 1434	Vass	NC	Solar	Intermediate	Yes	5.456
Facility 1435	Wilmington	NC	Solar	Intermediate	Yes	20.827
Facility 1436	Wilmington	NC	Solar	Intermediate	Yes	7.044
Facility 1437	Biscoe	NC	Solar	Intermediate	Yes	4.158
Facility 1438	Asheville	NC	Solar	Intermediate	Yes	13.069
Facility 1439	Southern Pines	NC	Solar	Intermediate	Yes	9.821
Facility 1440	Weaverville	NC	Solar	Intermediate	Yes	3.517
Facility 1441	Chocowinity	NC	Solar	Intermediate	Yes	6.1
Facility 1442	Asheville	NC	Solar	Intermediate	Yes	5.1
Facility 1443	Wilmington	NC	Solar	Intermediate	Yes	4.57
Facility 1444	Raleigh	NC	Solar	Intermediate	Yes	6.413
Facility 1445	Asheville	NC	Solar	Intermediate	Yes	0.8
Facility 1446	Asheville	NC	Solar	Intermediate	Yes	5
Facility 1447	Weaverville	NC	Solar	Intermediate	Yes	3.24
Facility 1448	Asheville	NC	Solar	Intermediate	Yes	5.087
Facility 1449	Raleigh	NC	Solar	Intermediate	Yes	4.05
Facility 1450	Roxboro	NC	Solar	Intermediate	Yes	11.49

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1451	Wilmington	NC	Solar	Intermediate	Yes	4.09
Facility 1452	Zebulon	NC	Solar	Intermediate	Yes	3
Facility 1453	Garner	NC	Solar	Intermediate	Yes	3.261
Facility 1454	Weaverville	NC	Solar	Intermediate	Yes	7.5
Facility 1455	Leicester	NC	Solar	Intermediate	Yes	4.571
Facility 1456	Pittsboro	NC	Solar	Intermediate	Yes	2.8
Facility 1457	Sanford	NC	Solar	Intermediate	Yes	5
Facility 1458	Gerton	NC	Solar	Intermediate	Yes	2.5
Facility 1459	Raleigh	NC	Solar	Intermediate	Yes	3.74
Facility 1460	Asheville	NC	Solar	Intermediate	Yes	10
Facility 1461	Asheville	NC	Solar	Intermediate	Yes	21
Facility 1462	Cary	NC	Solar	Intermediate	Yes	43
Facility 1463	Pittsboro	NC	Solar	Intermediate	Yes	4.86
Facility 1464	West End	NC	Solar	Intermediate	Yes	8.989
Facility 1465	Asheville	NC	Solar	Intermediate	Yes	6
Facility 1466	Marshall	NC	Hydroelectric	Baseload	Yes	1000
Facility 1467	Cary	NC	Solar	Intermediate	Yes	9
Facility 1468	Kenly	NC	Solar	Intermediate	Yes	123
Facility 1469	Fayetteville	NC	Solar	Intermediate	Yes	3.87
Facility 1470	Carthage	NC	Solar	Intermediate	Yes	4.501
Facility 1471	Raleigh	NC	Solar	Intermediate	Yes	4.22
Facility 1472	Apex	NC	Solar	Intermediate	Yes	7.19
Facility 1473	Raleigh	NC	Solar	Intermediate	Yes	4.35
Facility 1474	Hampstead	NC	Solar	Intermediate	Yes	6.27
Facility 1475	Garland	NC	Solar	Intermediate	Yes	4998
Facility 1476	Holly Springs	NC	Solar	Intermediate	Yes	4.1
Facility 1477	Cary	NC	Solar	Intermediate	Yes	3.8
Facility 1478	Cameron	NC	Solar	Intermediate	Yes	4.7
Facility 1479	Asheville	NC	Solar	Intermediate	Yes	4
Facility 1480	Pittsboro	NC	Solar	Intermediate	Yes	1.632
Facility 1481	Pinehurst	NC	Solar	Intermediate	Yes	3.457
Facility 1482	Raleigh	NC	Solar	Intermediate	Yes	1.72
Facility 1483	Knightdale	NC	Solar	Intermediate	Yes	2.82
Facility 1484	Cary	NC	Solar	Intermediate	Yes	1.5
Facility 1485	Weaverville	NC	Solar	Intermediate	Yes	1
Facility 1486	Carolina Beach	NC	Solar	Intermediate	Yes	5.7
Facility 1487	Apex	NC	Solar	Intermediate	Yes	2.89
Facility 1488	Robbins	NC	Solar	Intermediate	Yes	2.82
Facility 1489	Fletcher	NC	Solar	Intermediate	Yes	7.6
Facility 1490	Raleigh	NC	Solar	Intermediate	Yes	1.8
Facility 1491	Asheville	NC	Solar	Intermediate	Yes	4.128
Facility 1492	Raleigh	NC	Solar	Intermediate	Yes	3
Facility 1493	Asheville	NC	Solar	Intermediate	Yes	4.92
Facility 1494	Angier	NC	Solar	Intermediate	Yes	7.5
Facility 1495	Pittsboro	NC	Solar	Intermediate	Yes	7.62
Facility 1496	Raleigh	NC	Solar	Intermediate	Yes	2.9
Facility 1497	Raleigh	NC	Solar	Intermediate	Yes	1.643
Facility 1498	Raleigh	NC	Solar	Intermediate	Yes	2.1
Facility 1499	Fletcher	NC	Solar	Intermediate	Yes	20

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1500	Asheville	NC	Solar	Intermediate	Yes	4
Facility 1501	Pittsboro	NC	Solar	Intermediate	Yes	2.3
Facility 1502	Cary	NC	Solar	Intermediate	Yes	9.94
Facility 1503	Raleigh	NC	Solar	Intermediate	Yes	5.29
Facility 1504	Wake Forest	NC	Solar	Intermediate	Yes	2.4
Facility 1505	Asheville	NC	Solar	Intermediate	Yes	3.37
Facility 1506	Wilmington	NC	Solar	Intermediate	Yes	4.493
Facility 1507	Apex	NC	Solar	Intermediate	Yes	3.41
Facility 1508	Clayton	NC	Solar	Intermediate	Yes	4.62
Facility 1509	Asheville	NC	Solar	Intermediate	Yes	8.35
Facility 1510	Raleigh	NC	Solar	Intermediate	Yes	9.58
Facility 1511	Raleigh	NC	Solar	Intermediate	Yes	12
Facility 1512	Apex	NC	Solar	Intermediate	Yes	4
Facility 1513	Henderson	NC	Solar	Intermediate	Yes	3000
Facility 1514	Wilmington	NC	Solar	Intermediate	Yes	4.89
Facility 1515	Wilmington	NC	Solar	Intermediate	Yes	6.98
Facility 1516	Asheville	NC	Solar	Intermediate	Yes	5.01
Facility 1517	Siler City	NC	Solar	Intermediate	Yes	3.261
Facility 1518	Jacksonville	NC	Solar	Intermediate	Yes	4
Facility 1519	Asheville	NC	Solar	Intermediate	Yes	7.1
Facility 1520	Asheville	NC	Solar	Intermediate	Yes	3.8
Facility 1521	Asheville	NC	Solar	Intermediate	Yes	4.68
Facility 1522	Asheville	NC	Solar	Intermediate	Yes	2.24
Facility 1523	Raleigh	NC	Solar	Intermediate	Yes	4
Facility 1524	Raleigh	NC	Solar	Intermediate	Yes	3.08
Facility 1525	Hot Springs	NC	Solar	Intermediate	Yes	4
Facility 1526	Weaverville	NC	Solar	Intermediate	Yes	6
Facility 1527	Asheville	NC	Solar	Intermediate	Yes	6
Facility 1528	Raleigh	NC	Solar	Intermediate	Yes	3.44
Facility 1529	Southern Pines	NC	Solar	Intermediate	Yes	3.8
Facility 1530	Raleigh	NC	Solar	Intermediate	Yes	3.67
Facility 1531	Candler	NC	Solar	Intermediate	Yes	6.1
Facility 1532	Apex	NC	Solar	Intermediate	Yes	4.28
Facility 1533	Raleigh	NC	Solar	Intermediate	Yes	4.5
Facility 1534	Wilmington	NC	Solar	Intermediate	Yes	1.38
Facility 1535	Asheville	NC	Solar	Intermediate	Yes	3.8
Facility 1536	Asheville	NC	Solar	Intermediate	Yes	3.714
Facility 1537	Whiteville	NC	Solar	Intermediate	Yes	5.305
Facility 1538	Raleigh	NC	Solar	Intermediate	Yes	3.06
Facility 1539	Semora	NC	Solar	Intermediate	Yes	20
Facility 1540	Asheville	NC	Solar	Intermediate	Yes	3
Facility 1541	Wilmington	NC	Solar	Intermediate	Yes	3.4
Facility 1542	Cary	NC	Solar	Intermediate	Yes	4.78
Facility 1543	Sanford	NC	Solar	Intermediate	Yes	4.64
Facility 1544	Hollister	NC	Solar	Intermediate	Yes	2.58
Facility 1545	Pinehurst	NC	Solar	Intermediate	Yes	9.33
Facility 1546	New Bern	NC	Solar	Intermediate	Yes	4.43
Facility 1547	Wilmington	NC	Solar	Intermediate	Yes	4.16
Facility 1548	Asheville	NC	Solar	Intermediate	Yes	18.9
Facility 1549	Asheville	NC	Solar	Intermediate	Yes	16.2
Facility 1550	Rowland	NC	Solar	Intermediate	Yes	5000

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1551	Wilmington	NC	Solar	Intermediate	Yes	2.6
Facility 1552	Weaverville	NC	Solar	Intermediate	Yes	4.94
Facility 1553	Asheville	NC	Solar	Intermediate	Yes	6.063
Facility 1554	Asheville	NC	Solar	Intermediate	Yes	3.01
Facility 1555	Asheville	NC	Solar	Intermediate	Yes	0.993
Facility 1556	Asheville	NC	Solar	Intermediate	Yes	2.82
Facility 1557	Asheville	NC	Solar	Intermediate	Yes	2.02
Facility 1558	Kure Beach	NC	Solar	Intermediate	Yes	5.42
Facility 1559	Lumber Bridge	NC	Solar	Intermediate	Yes	4950
Facility 1560	Leland	NC	Solar	Intermediate	Yes	7.586
Facility 1561	Cary	NC	Solar	Intermediate	Yes	552
Facility 1562	Raleigh	NC	Solar	Intermediate	Yes	2.64
Facility 1563	Siler City	NC	Solar	Intermediate	Yes	6.97
Facility 1564	Siler City	NC	Solar	Intermediate	Yes	2.65
Facility 1565	Whiteville	NC	Solar	Intermediate	Yes	4950
Facility 1566	Angier	NC	Solar	Intermediate	Yes	4.47
Facility 1567	Willow Spring	NC	Solar	Intermediate	Yes	5.51
Facility 1568	Raleigh	NC	Solar	Intermediate	Yes	5.7
Facility 1569	Raleigh	NC	Solar	Intermediate	Yes	2.59
Facility 1570	Wilmington	NC	Solar	Intermediate	Yes	5.38
Facility 1571	Leland	NC	Solar	Intermediate	Yes	3.42
Facility 1572	Bahama	NC	Solar	Intermediate	Yes	3.795
Facility 1573	Kenly	NC	Solar	Intermediate	Yes	75
Facility 1574	Hampstead	NC	Solar	Intermediate	Yes	4.33
Facility 1575	Apex	NC	Solar	Intermediate	Yes	5.96
Facility 1576	Garner	NC	Solar	Intermediate	Yes	2.37
Facility 1577	Henderson	NC	Solar	Intermediate	Yes	5000
Facility 1578	Alexander	NC	Solar	Intermediate	Yes	1.53
Facility 1579	Pittsboro	NC	Solar	Intermediate	Yes	3.26
Facility 1580	Raleigh	NC	Solar	Intermediate	Yes	1.898
Facility 1581	Cary	NC	Solar	Intermediate	Yes	1.84
Facility 1582	Morrisville	NC	Solar	Intermediate	Yes	1.288
Facility 1583	Holly Springs	NC	Solar	Intermediate	Yes	1.6
Facility 1584	Holly Springs	NC	Solar	Intermediate	Yes	1.8
Facility 1585	Morehead City	NC	Solar	Intermediate	Yes	3.44
Facility 1586	Pittsboro	NC	Solar	Intermediate	Yes	3.6
Facility 1587	Asheville	NC	Hydroelectric	Baseload	Yes	2500
Facility 1588	Asheville	NC	Solar	Intermediate	Yes	4.47
Facility 1589	Wilmington	NC	Solar	Intermediate	Yes	5.34
Facility 1590	Hamptead	NC	Solar	Intermediate	Yes	2.58
Facility 1591	Carthage	NC	Solar	Intermediate	Yes	8
Facility 1592	Apex	NC	Solar	Intermediate	Yes	1.1
Facility 1593	Weaverville	NC	Solar	Intermediate	Yes	3.75
Facility 1594	Clayton	NC	Solar	Intermediate	Yes	5.886
Facility 1595	Cary	NC	Solar	Intermediate	Yes	3.78
Facility 1596	Pinehurst	NC	Solar	Intermediate	Yes	4.896
Facility 1597	Asheville	NC	Solar	Intermediate	Yes	5
Facility 1598	Zebulon	NC	Solar	Intermediate	Yes	7.5
Facility 1599	Raeford	NC	Solar	Intermediate	Yes	3

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1600	Pittsboro	NC	Solar	Intermediate	Yes	2.6
Facility 1601	Pittsboro	NC	Solar	Intermediate	Yes	1.84
Facility 1602	Cary	NC	Solar	Intermediate	Yes	3.75
Facility 1603	Chapel Hill	NC	Solar	Intermediate	Yes	2.057
Facility 1604	Fletcher	NC	Solar	Intermediate	Yes	3.8
Facility 1605	Fletcher	NC	Solar	Intermediate	Yes	3.8
Facility 1606	Weaverville	NC	Solar	Intermediate	Yes	5.087
Facility 1607	Chapel Hill	NC	Solar	Intermediate	Yes	3.37
Facility 1608	Middlesex	NC	Solar	Intermediate	Yes	2.17
Facility 1609	Apex	NC	Solar	Intermediate	Yes	1.6
Facility 1610	Asheville	NC	Solar	Intermediate	Yes	3.2
Facility 1611	Wrightsville Beach	NC	Solar	Intermediate	Yes	4.05
Facility 1612	Pittsboro	NC	Solar	Intermediate	Yes	1.92
Facility 1613	Rougemont	NC	Solar	Intermediate	Yes	5000
Facility 1614	Asheville	NC	Solar	Intermediate	Yes	4
Facility 1615	Raleigh	NC	Solar	Intermediate	Yes	2
Facility 1616	Raleigh	NC	Solar	Intermediate	Yes	3.68
Facility 1617	Asheville	NC	Solar	Intermediate	Yes	4.04
Facility 1618	Asheville	NC	Solar	Intermediate	Yes	2.76
Facility 1619	Apex	NC	Solar	Intermediate	Yes	4.81
Facility 1620	Pittsboro	NC	Solar	Intermediate	Yes	5.01
Facility 1621	Lilesville	NC	Solar	Intermediate	Yes	5000
Facility 1622	Cary	NC	Solar	Intermediate	Yes	4.276
Facility 1623	Asheville	NC	Solar	Intermediate	Yes	4.75
Facility 1624	Raleigh	NC	Solar	Intermediate	Yes	273
Facility 1625	Asheville	NC	Solar	Intermediate	Yes	2.92
Facility 1626	Pittsboro	NC	Solar	Intermediate	Yes	2.6
Facility 1627	Holly Springs	NC	Solar	Intermediate	Yes	4.124
Facility 1628	Pinehurst	NC	Solar	Intermediate	Yes	2.64
Facility 1629	Raleigh	NC	Solar	Intermediate	Yes	3.35
Facility 1630	Raleigh	NC	Solar	Intermediate	Yes	3.35
Facility 1631	Raleigh	NC	Solar	Intermediate	Yes	8.236
Facility 1632	Raleigh	NC	Solar	Intermediate	Yes	2.922
Facility 1633	Moncure	NC	Solar	Intermediate	Yes	4975
Facility 1634	Fairview	NC	Solar	Intermediate	Yes	3.436
Facility 1635	Coats	NC	Solar	Intermediate	Yes	2.46
Facility 1636	Wilmington	NC	Solar	Intermediate	Yes	3
Facility 1637	Lillington	NC	Solar	Intermediate	Yes	2.88
Facility 1638	Asheville	NC	Solar	Intermediate	Yes	3.92
Facility 1639	Biscoe	NC	Solar	Intermediate	Yes	20000
Facility 1640	Asheville	NC	Solar	Intermediate	Yes	5.605
Facility 1641	Rocky Mount	NC	Solar	Intermediate	Yes	6.394
Facility 1642	Southern Pines	NC	Solar	Intermediate	Yes	8.184
Facility 1643	Pittsboro	NC	Solar	Intermediate	Yes	3.75
Facility 1644	Goldsboro	NC	Solar	Intermediate	Yes	4.61
Facility 1645	La Grange	NC	Solar	Intermediate	Yes	4975
Facility 1646	Raleigh	NC	Solar	Intermediate	Yes	4.82
Facility 1647	Louisburg	NC	Solar	Intermediate	Yes	5000
Facility 1648	Raleigh	NC	Solar	Intermediate	Yes	9.9
Facility 1649	Pittsboro	NC	Solar	Intermediate	Yes	3.87
Facility 1650	Wilmington	NC	Solar	Intermediate	Yes	3.5

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1651	Pittsboro	NC	Solar	Intermediate	Yes	2.9
Facility 1652	Pittsboro	NC	Solar	Intermediate	Yes	4.69
Facility 1653	Weaverville	NC	Solar	Intermediate	Yes	9.028
Facility 1654	Beaufort	NC	Solar	Intermediate	Yes	2.59
Facility 1655	Asheville	NC	Solar	Intermediate	Yes	16.461
Facility 1656	Raleigh	NC	Solar	Intermediate	Yes	5
Facility 1657	Wilmington	NC	Solar	Intermediate	Yes	5.23
Facility 1658	Holly Springs	NC	Solar	Intermediate	Yes	3.33
Facility 1659	Fayetteville	NC	Solar	Intermediate	Yes	3.27
Facility 1660	Mt Olive	NC	Solar	Intermediate	Yes	4998
Facility 1661	Holly Springs	NC	Solar	Intermediate	Yes	3.75
Facility 1662	Dudley	NC	Landfill Gas	Intermediate	Yes	3180
Facility 1663	Asheville	NC	Solar	Intermediate	Yes	6.84
Facility 1664	Mt Olive	NC	Solar	Intermediate	Yes	4999
Facility 1665	Mount Olive	NC	Solar	Intermediate	Yes	4975
Facility 1666	Cary	NC	Solar	Intermediate	Yes	2.442
Facility 1667	Cary	NC	Solar	Intermediate	Yes	4.26
Facility 1668	Liberty	NC	Solar	Intermediate	Yes	3.3
Facility 1669	Clayton	NC	Solar	Intermediate	Yes	4000
Facility 1670	Wilmington	NC	Solar	Intermediate	Yes	4.2
Facility 1671	Candler	NC	Solar	Intermediate	Yes	1.736
Facility 1672	Apex	NC	Solar	Intermediate	Yes	4.12
Facility 1673	Spring Hope	NC	Solar	Intermediate	Yes	7.78
Facility 1674	Clayton	NC	Solar	Intermediate	Yes	5.28
Facility 1675	Asheville	NC	Solar	Intermediate	Yes	5.15
Facility 1676	Cary	NC	Solar	Intermediate	Yes	2.5
Facility 1677	Garner	NC	Solar	Intermediate	Yes	3.95
Facility 1678	Raleigh	NC	Solar	Intermediate	Yes	4
Facility 1679	Cary	NC	Solar	Intermediate	Yes	6.34
Facility 1680	Asheville	NC	Solar	Intermediate	Yes	3.94
Facility 1681	Asheville	NC	Solar	Intermediate	Yes	5
Facility 1682	Cary	NC	Solar	Intermediate	Yes	5.899
Facility 1683	Asheville	NC	Solar	Intermediate	Yes	2.5
Facility 1684	Raleigh	NC	Solar	Intermediate	Yes	2.9
Facility 1685	Raleigh	NC	Solar	Intermediate	Yes	4.743
Facility 1686	Cary	NC	Solar	Intermediate	Yes	3.71
Facility 1687	Raleigh	NC	Solar	Intermediate	Yes	1.8
Facility 1688	Clinton	NC	Wind	(blank)	Yes	1.9
Facility 1689	Raleigh	NC	Solar	Intermediate	Yes	1.8
Facility 1690	Black Mountain	NC	Solar	Intermediate	Yes	1.9
Facility 1691	Garner	NC	Solar	Intermediate	Yes	4.26
Facility 1692	Nashville	NC	Solar	Intermediate	Yes	4950
Facility 1693	Spring Hope	NC	Solar	Intermediate	Yes	4950
Facility 1694	Middlesex	NC	Solar	Intermediate	Yes	4998
Facility 1695	Nashville	NC	Solar	Intermediate	Yes	1980
Facility 1696	Cary	NC	Solar	Intermediate	Yes	2.442
Facility 1697	Siler City	NC	Solar	Intermediate	Yes	2.65
Facility 1698	Boilings Springs Lakes	NC	Solar	Intermediate	Yes	3.84
Facility 1699	Oxford	NC	Solar	Intermediate	Yes	5.4

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1700	Pinehurst	NC	Solar	Intermediate	Yes	2.9
Facility 1701	Smyrna	NC	Solar	Intermediate	Yes	9.6
Facility 1702	Smyrna	NC	Wind	(blank)	Yes	10
Facility 1703	Vass	NC	Solar	Intermediate	Yes	13
Facility 1704	Raleigh	NC	Solar	Intermediate	Yes	4.8
Facility 1705	Raleigh	NC	Solar	Intermediate	Yes	5.4
Facility 1706	Raleigh	NC	Solar	Intermediate	Yes	3.73
Facility 1707	Wilmington	NC	Solar	Intermediate	Yes	4.92
Facility 1708	Wilmington	NC	Solar	Intermediate	Yes	3.58
Facility 1709	Pittsboro	NC	Solar	Intermediate	Yes	4.2
Facility 1710	Apex	NC	Solar	Intermediate	Yes	3.1
Facility 1711	Raleigh	NC	Solar	Intermediate	Yes	3.457
Facility 1712	Holly Springs	NC	Solar	Intermediate	Yes	5.27
Facility 1713	Wilmington	NC	Solar	Intermediate	Yes	3.31
Facility 1714	Raleigh	NC	Solar	Intermediate	Yes	1040
Facility 1715	Ernul	NC	Solar	Intermediate	Yes	4975
Facility 1716	Zebulon	NC	Solar	Intermediate	Yes	7.473
Facility 1717	Zebulon	NC	Solar	Intermediate	Yes	2.03
Facility 1718	Raleigh	NC	Solar	Intermediate	Yes	5.95
Facility 1719	Cary	NC	Solar	Intermediate	Yes	4.1
Facility 1720	Pittsboro	NC	Solar	Intermediate	Yes	5
Facility 1721	Raleigh	NC	Solar	Intermediate	Yes	3.906
Facility 1722	Clayton	NC	Solar	Intermediate	Yes	4.2
Facility 1723	NC	NC	Solar	Intermediate	Yes	1.806
Facility 1724	Asheville	NC	Solar	Intermediate	Yes	1.815
Facility 1725	Raleigh	NC	Solar	Intermediate	Yes	4.74
Facility 1726	Raleigh	NC	Solar	Intermediate	Yes	2.37
Facility 1727	West End	NC	Solar	Intermediate	Yes	4.28
Facility 1728	Smithfield	NC	Solar	Intermediate	Yes	5000
Facility 1729	Asheville	NC	Solar	Intermediate	Yes	3.943
Facility 1730	Asheville	NC	Solar	Intermediate	Yes	5.982
Facility 1731	Apex	NC	Solar	Intermediate	Yes	9.12
Facility 1732	Timberlake,	NC	Solar	Intermediate	Yes	3.028
Facility 1733	Cary	NC	Solar	Intermediate	Yes	4.743
Facility 1734	Asheville	NC	Solar	Intermediate	Yes	5
Facility 1735	Apex	NC	Solar	Intermediate	Yes	2.57
Facility 1736	Semora	NC	Solar	Intermediate	Yes	3.59
Facility 1737	Raleigh	NC	Solar	Intermediate	Yes	3.4
Facility 1738	Laurinburg	NC	Solar	Intermediate	Yes	2000
Facility 1739	Laurinburg	NC	Solar	Intermediate	Yes	2000
Facility 1740	Gibson	NC	Solar	Intermediate	Yes	5000
Facility 1741	Castalia	NC	Solar	Intermediate	Yes	4998
Facility 1742	Raleigh	NC	Solar	Intermediate	Yes	3.259
Facility 1743	Pittsboro	NC	Solar	Intermediate	Yes	2.41
Facility 1744	Henderson	NC	Solar	Intermediate	Yes	5.54
Facility 1745	Wilmington	NC	Solar	Intermediate	Yes	46
Facility 1746	Laurinburg	NC	Solar	Intermediate	Yes	4950
Facility 1747	Asheville	NC	Solar	Intermediate	Yes	15.91
Facility 1748	Wilmington	NC	Solar	Intermediate	Yes	2.28
Facility 1749	Raleigh	NC	Diesel	Peak	Yes	500
Facility 1750	Wilmington	NC	Solar	Intermediate	Yes	3.42

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1751	Spring Hope	NC	Hydroelectric	Baseload	Yes	350
Facility 1752	Raleigh	NC	Solar	Intermediate	Yes	3.918
Facility 1753	Jacksonville	NC	Solar	Intermediate	Yes	4.6
Facility 1754	Jacksonville	NC	Landfill Gas	Intermediate	Yes	1753
Facility 1755	Raleigh	NC	Solar	Intermediate	Yes	2.5
Facility 1756	Pittsboro	NC	Solar	Intermediate	Yes	2.69
Facility 1757	Cary	NC	Solar	Intermediate	Yes	3.61
Facility 1758	Asheville	NC	Solar	Intermediate	Yes	7.28
Facility 1759	Asheville	NC	Solar	Intermediate	Yes	2.26
Facility 1760	Candler	NC	Solar	Intermediate	Yes	9.931
Facility 1761	Asheville	NC	Solar	Intermediate	Yes	4.76
Facility 1762	Wilmington	NC	Solar	Intermediate	Yes	7.29
Facility 1763	Angier	NC	Solar	Intermediate	Yes	4.76
Facility 1764	Angier	NC	Solar	Intermediate	Yes	5.866
Facility 1765	Raleigh	NC	Solar	Intermediate	Yes	4.56
Facility 1766	Pittsboro	NC	Solar	Intermediate	Yes	3.25
Facility 1767	Raleigh	NC	Solar	Intermediate	Yes	2.55
Facility 1768	Swannanoa	NC	Solar	Intermediate	Yes	1.5
Facility 1769	Wilmington	NC	Solar	Intermediate	Yes	2.59
Facility 1770	Asheville	NC	Solar	Intermediate	Yes	4
Facility 1771	Chapel Hill	NC	Solar	Intermediate	Yes	6.79
Facility 1772	Carolina Beach	NC	Solar	Intermediate	Yes	4.39
Facility 1773	Arden	NC	Solar	Intermediate	Yes	6.2
Facility 1774	Cary	NC	Solar	Intermediate	Yes	1.72
Facility 1775	Pinehurst	NC	Solar	Intermediate	Yes	3.14
Facility 1776	Garner	NC	Solar	Intermediate	Yes	6.33
Facility 1777	Cary	NC	Solar	Intermediate	Yes	5.7
Facility 1778	Asheville	NC	Solar	Intermediate	Yes	2.8
Facility 1779	Raleigh	NC	Solar	Intermediate	Yes	3.04
Facility 1780	Asheville	NC	Solar	Intermediate	Yes	4.571
Facility 1781	Raleigh	NC	Solar	Intermediate	Yes	3.44
Facility 1782	Raleigh	NC	Solar	Intermediate	Yes	5.547
Facility 1783	Rocky Point	NC	Solar	Intermediate	Yes	2.5
Facility 1784	Raleigh	NC	Solar	Intermediate	Yes	6.27
Facility 1785	Weaverville	NC	Solar	Intermediate	Yes	2.9
Facility 1786	Barnardsville	NC	Solar	Intermediate	Yes	2.5
Facility 1787	Red Springs	NC	Solar	Intermediate	Yes	4950
Facility 1788	Cary	NC	Solar	Intermediate	Yes	4.97
Facility 1789	Morrisville	NC	Solar	Intermediate	Yes	2.442
Facility 1790	Willow Spring	NC	Solar	Intermediate	Yes	2
Facility 1791	Raleigh	NC	Solar	Intermediate	Yes	2.69
Facility 1792	Candler	NC	Solar	Intermediate	Yes	4
Facility 1793	Pinehurst	NC	Solar	Intermediate	Yes	3.8
Facility 1794	Asheville	NC	Solar	Intermediate	Yes	3.4
Facility 1795	Asheville	NC	Solar	Intermediate	Yes	3.4
Facility 1796	Raleigh	NC	Solar	Intermediate	Yes	2.496
Facility 1797	Barnardsville	NC	Solar	Intermediate	Yes	4.6
Facility 1798	Asheville	NC	Solar	Intermediate	Yes	1.42
Facility 1799	Garner	NC	Solar	Intermediate	Yes	7.33

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1800	Asheville	NC	Solar	Intermediate	Yes	3.14
Facility 1801	Raleigh	NC	Solar	Intermediate	Yes	4.41
Facility 1802	Raleigh	NC	Solar	Intermediate	Yes	1.92
Facility 1803	Four Oaks	NC	Solar	Intermediate	Yes	2.58
Facility 1804	Zebulon	NC	Solar	Intermediate	Yes	1.14
Facility 1805	Weaverville	NC	Solar	Intermediate	Yes	4.08
Facility 1806	Louisburg	NC	Solar	Intermediate	Yes	9.06
Facility 1807	Pittsboro	NC	Solar	Intermediate	Yes	1.49
Facility 1808	Pittsboro	NC	Solar	Intermediate	Yes	1.85
Facility 1809	Asheville	NC	Solar	Intermediate	Yes	1
Facility 1810	Fairview	NC	Solar	Intermediate	Yes	5
Facility 1811	Wendell	NC	Solar	Intermediate	Yes	2.98
Facility 1812	Wendell	NC	Solar	Intermediate	Yes	2.98
Facility 1813	Wilmington	NC	Solar	Intermediate	Yes	2.4
Facility 1814	Chapel Hill	NC	Solar	Intermediate	Yes	2.41
Facility 1815	Siler City	NC	Solar	Intermediate	Yes	8.64
Facility 1816	Arden	NC	Solar	Intermediate	Yes	2.52
Facility 1817	Timberlake	NC	Solar	Intermediate	Yes	1000
Facility 1818	Aurora	NC	Other	Intermediate	Yes	10000
Facility 1819	Timberlake	NC	Solar	Intermediate	Yes	2400
Facility 1820	Raleigh	NC	Solar	Intermediate	Yes	5.021
Facility 1821	Bear Creek	NC	Solar	Intermediate	Yes	2.45
Facility 1822	Raleigh	NC	Solar	Intermediate	Yes	4.271
Facility 1823	Wilmington	NC	Solar	Intermediate	Yes	3.97
Facility 1824	Wilmington	NC	Solar	Intermediate	Yes	2.6
Facility 1825	Wilmington	NC	Solar	Intermediate	Yes	2.4
Facility 1826	Raleigh	NC	Solar	Intermediate	Yes	2.45
Facility 1827	Roxboro	NC	Solar	Intermediate	Yes	5.707
Facility 1828	Pinehurst	NC	Solar	Intermediate	Yes	5.09
Facility 1829	Raleigh	NC	Solar	Intermediate	Yes	8.03
Facility 1830	Beaufort	NC	Solar	Intermediate	Yes	2.064
Facility 1831	Leland	NC	Solar	Intermediate	Yes	4.95
Facility 1832	Angier	NC	Solar	Intermediate	Yes	11.336
Facility 1833	Holly Springs	NC	Solar	Intermediate	Yes	6.95
Facility 1834	Pittsboro	NC	Solar	Intermediate	Yes	11
Facility 1835	Asheville	NC	Solar	Intermediate	Yes	3.75
Facility 1836	Asheville	NC	Solar	Intermediate	Yes	3
Facility 1837	Asheville	NC	Solar	Intermediate	Yes	1.68
Facility 1838	Pittsboro	NC	Solar	Intermediate	Yes	6
Facility 1839	Asheville	NC	Solar	Intermediate	Yes	0.995
Facility 1840	Morrisville	NC	Solar	Intermediate	Yes	6.38
Facility 1841	Angier	NC	Solar	Intermediate	Yes	3.44
Facility 1842	Asheville	NC	Solar	Intermediate	Yes	3
Facility 1843	Southern Pines	NC	Solar	Intermediate	Yes	6
Facility 1844	Sanford	NC	Other	Intermediate	Yes	250
Facility 1845	Chapel Hill	NC	Solar	Intermediate	Yes	4.21
Facility 1846	Asheville	NC	Solar	Intermediate	Yes	4.84
Facility 1847	Raleigh	NC	Solar	Intermediate	Yes	4
Facility 1848	Pittsboro	NC	Solar	Intermediate	Yes	2.48
Facility 1849	Pittsboro	NC	Solar	Intermediate	Yes	2.48
Facility 1850	Raleigh	NC	Solar	Intermediate	Yes	8.64

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1851	Asheville	NC	Solar	Intermediate	Yes	0.77
Facility 1852	Black Mountain	NC	Solar	Intermediate	Yes	5.29
Facility 1853	Cary	NC	Solar	Intermediate	Yes	2.4
Facility 1854	Asheboro	NC	Solar	Intermediate	Yes	6.88
Facility 1855	Leland	NC	Solar	Intermediate	Yes	4.89
Facility 1856	Raleigh	NC	Solar	Intermediate	Yes	4.9
Facility 1857	Cary	NC	Solar	Intermediate	Yes	5.27
Facility 1858	Asheville	NC	Solar	Intermediate	Yes	5.43
Facility 1859	Angier	NC	Solar	Intermediate	Yes	4.75
Facility 1860	Raleigh	NC	Solar	Intermediate	Yes	7.48
Facility 1861	Black Mountain	NC	Solar	Intermediate	Yes	4.063
Facility 1862	Cary	NC	Solar	Intermediate	Yes	4.2
Facility 1863	Wake Forest	NC	Solar	Intermediate	Yes	3.41
Facility 1864	Bynum	NC	Hydroelectric	Baseload	Yes	500
Facility 1865	Candler	NC	Solar	Intermediate	Yes	4.039
Facility 1866	Wilmington	NC	Solar	Intermediate	Yes	3.93
Facility 1867	Raleigh	NC	Solar	Intermediate	Yes	3.62
Facility 1868	Raleigh	NC	Solar	Intermediate	Yes	4.08
Facility 1869	Raleigh	NC	Solar	Intermediate	Yes	2.15
Facility 1870	Wagram	NC	Solar	Intermediate	Yes	15.36
Facility 1871	Leicester	NC	Solar	Intermediate	Yes	4.89
Facility 1872	Leicester	NC	Solar	Intermediate	Yes	3.153
Facility 1873	Wilmington	NC	Solar	Intermediate	Yes	3.78
Facility 1874	Wilmington	NC	Solar	Intermediate	Yes	7.303
Facility 1875	Raleigh	NC	Solar	Intermediate	Yes	3.9
Facility 1876	Vass	NC	Solar	Intermediate	Yes	2
Facility 1877	Cary	NC	Solar	Intermediate	Yes	5.24
Facility 1878	West End	NC	Solar	Intermediate	Yes	3.28
Facility 1879	Ernul	NC	Solar	Intermediate	Yes	4999
Facility 1880	Chapel Hill	NC	Solar	Intermediate	Yes	3.82
Facility 1881	Garner	NC	Solar	Intermediate	Yes	3.14
Facility 1882	Raleigh	NC	Solar	Intermediate	Yes	4.32
Facility 1883	Benson	NC	Solar	Intermediate	Yes	6.35
Facility 1884	Cary	NC	Solar	Intermediate	Yes	2.442
Facility 1885	Raleigh	NC	Solar	Intermediate	Yes	13.476
Facility 1886	Clinton	NC	Biomass	Intermediate	Yes	150
Facility 1887	Raleigh	NC	Solar	Intermediate	Yes	7.387
Facility 1888	Asheville	NC	Solar	Intermediate	Yes	4.605
Facility 1889	Sanford	NC	Diesel	Peak	Yes	1562
Facility 1890	Bunn	NC	Solar	Intermediate	Yes	4000
Facility 1891	Fairmont	NC	Solar	Intermediate	Yes	3500
Facility 1892	Maxton	NC	Solar	Intermediate	Yes	3600
Facility 1893	Kure Beach	NC	Solar	Intermediate	Yes	5.3
Facility 1894	Knightdale	NC	Solar	Intermediate	Yes	6.15
Facility 1895	Asheville	NC	Solar	Intermediate	Yes	2.25
Facility 1896	Wilmington	NC	Solar	Intermediate	Yes	383
Facility 1897	Fayetteville	NC	Solar	Intermediate	Yes	4000
Facility 1898	Pinehurst	NC	Solar	Intermediate	Yes	4.28
Facility 1899	Asheville	NC	Solar	Intermediate	Yes	3

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1900	Asheville	NC	Solar	Intermediate	Yes	7.119
Facility 1901	Raleigh	NC	Solar	Intermediate	Yes	8.084
Facility 1902	Siler City	NC	Solar	Intermediate	Yes	2.34
Facility 1903	Raeford	NC	Solar	Intermediate	Yes	4975
Facility 1904	Cary	NC	Solar	Intermediate	Yes	4.132
Facility 1905	St Pauls	NC	Solar	Intermediate	Yes	4998
Facility 1906	Saint Pauls	NC	Solar	Intermediate	Yes	4975
Facility 1907	Wilmington	NC	Wind	(blank)	Yes	4.2
Facility 1908	Chapel Hill	NC	Solar	Intermediate	Yes	3.2
Facility 1909	Wilmington	NC	Solar	Intermediate	Yes	6.34
Facility 1910	Asheville	NC	Solar	Intermediate	Yes	3.32
Facility 1911	Asheville	NC	Solar	Intermediate	Yes	3.12
Facility 1912	Chapel Hill	NC	Solar	Intermediate	Yes	5.03
Facility 1913	Raleigh	NC	Solar	Intermediate	Yes	2.83
Facility 1914	Willow Spring	NC	Solar	Intermediate	Yes	0.96
Facility 1915	Pittsboro	NC	Solar	Intermediate	Yes	2.48
Facility 1916	Asheville	NC	Solar	Intermediate	Yes	3.33
Facility 1917	Raleigh	NC	Solar	Intermediate	Yes	8.02
Facility 1918	Cary	NC	Solar	Intermediate	Yes	4.914
Facility 1919	Wilmington	NC	Solar	Intermediate	Yes	6.899
Facility 1920	Willow Spring	NC	Solar	Intermediate	Yes	4.54
Facility 1921	Raleigh	NC	Solar	Intermediate	Yes	4.34
Facility 1922	Raleigh	NC	Solar	Intermediate	Yes	1.6
Facility 1923	Louisburg	NC	Solar	Intermediate	Yes	7.6
Facility 1924	Raleigh	NC	Solar	Intermediate	Yes	2.44
Facility 1925	Lillington	NC	Solar	Intermediate	Yes	2.58
Facility 1926	Wilmington	NC	Solar	Intermediate	Yes	3.209
Facility 1927	Wake Forest	NC	Solar	Intermediate	Yes	5.598
Facility 1928	Asheville	NC	Solar	Intermediate	Yes	3.64
Facility 1929	Raleigh	NC	Solar	Intermediate	Yes	5
Facility 1930	Apex	NC	Solar	Intermediate	Yes	3.696
Facility 1931	Raleigh	NC	Solar	Intermediate	Yes	3.84
Facility 1932	Warrenton	NC	Solar	Intermediate	Yes	4990
Facility 1933	Clayton	NC	Solar	Intermediate	Yes	1999
Facility 1934	Fuquay Varina	NC	Solar	Intermediate	Yes	410
Facility 1935	Asheville	NC	Solar	Intermediate	Yes	2.793
Facility 1936	Pittsboro	NC	Solar	Intermediate	Yes	7.06
Facility 1937	Fairview	NC	Solar	Intermediate	Yes	8.65
Facility 1938	Asheville	NC	Solar	Intermediate	Yes	4.571
Facility 1939	Cary	NC	Solar	Intermediate	Yes	2.75
Facility 1940	Asheboro	NC	Solar	Intermediate	Yes	2
Facility 1941	Candler	NC	Solar	Intermediate	Yes	5.62
Facility 1942	Chapel Hill	NC	Solar	Intermediate	Yes	9.46
Facility 1943	Weaverville	NC	Solar	Intermediate	Yes	5.339
Facility 1944	Cary	NC	Solar	Intermediate	Yes	3.74
Facility 1945	Cary	NC	Solar	Intermediate	Yes	192.5
Facility 1946	Apex	NC	Solar	Intermediate	Yes	2.42
Facility 1947	Raleigh	NC	Solar	Intermediate	Yes	9.96
Facility 1948	Cary	NC	Solar	Intermediate	Yes	4.21
Facility 1949	Star	NC	Solar	Intermediate	Yes	6.522
Facility 1950	Weaverville	NC	Solar	Intermediate	Yes	3.041

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1951	Asheville	NC	Solar	Intermediate	Yes	3.98
Facility 1952	Candler	NC	Solar	Intermediate	Yes	5.49
Facility 1953	Pinehurst	NC	Solar	Intermediate	Yes	3.76
Facility 1954	Wilmington	NC	Solar	Intermediate	Yes	4.31
Facility 1955	Cary	NC	Solar	Intermediate	Yes	2.37
Facility 1956	Raleigh	NC	Solar	Intermediate	Yes	2.58
Facility 1957	Pittsboro	NC	Solar	Intermediate	Yes	4
Facility 1958	Fayetteville	NC	Solar	Intermediate	Yes	2.58
Facility 1959	Wendell	NC	Solar	Intermediate	Yes	1.9
Facility 1960	Asheville	NC	Solar	Intermediate	Yes	5.805
Facility 1961	Asheville	NC	Solar	Intermediate	Yes	5
Facility 1962	Asheville	NC	Solar	Intermediate	Yes	6
Facility 1963	Cary	NC	Solar	Intermediate	Yes	17.5
Facility 1964	Aberdeen	NC	Solar	Intermediate	Yes	3.87
Facility 1965	Wilmington	NC	Solar	Intermediate	Yes	2.52
Facility 1966	Chapel Hill	NC	Solar	Intermediate	Yes	7
Facility 1967	Wilmington	NC	Solar	Intermediate	Yes	8.773
Facility 1968	Pittsboro	NC	Solar	Intermediate	Yes	5.2
Facility 1969	Hampstead	NC	Solar	Intermediate	Yes	3.38
Facility 1970	Roxboro	NC	Solar	Intermediate	Yes	5.422
Facility 1971	Raleigh	NC	Solar	Intermediate	Yes	5.31
Facility 1972	Weaverville	NC	Solar	Intermediate	Yes	10.08
Facility 1973	Fairview	NC	Solar	Intermediate	Yes	3.44
Facility 1974	Apex	NC	Solar	Intermediate	Yes	6.323
Facility 1975	Whispering Pines	NC	Solar	Intermediate	Yes	3.74
Facility 1976	Pittsboro	NC	Solar	Intermediate	Yes	2.6
Facility 1977	Laurinburg	NC	Solar	Intermediate	Yes	2.946
Facility 1978	Raleigh	NC	Solar	Intermediate	Yes	2.93
Facility 1979	Asheville	NC	Solar	Intermediate	Yes	3.8
Facility 1980	Asheville	NC	Solar	Intermediate	Yes	5
Facility 1981	Carolina Beach	NC	Solar	Intermediate	Yes	3
Facility 1982	Fletcher	NC	Solar	Intermediate	Yes	11
Facility 1983	Fletcher	NC	Solar	Intermediate	Yes	11
Facility 1984	Asheville	NC	Solar	Intermediate	Yes	4.24
Facility 1985	Barnardsville	NC	Solar	Intermediate	Yes	4.92
Facility 1986	Selma	NC	Solar	Intermediate	Yes	4
Facility 1987	Asheville	NC	Solar	Intermediate	Yes	3.64
Facility 1988	Raleigh	NC	Solar	Intermediate	Yes	3
Facility 1989	Swansboro	NC	Solar	Intermediate	Yes	2.45
Facility 1990	Benson	NC	Solar	Intermediate	Yes	4
Facility 1991	Benson	NC	Solar	Intermediate	Yes	4.6
Facility 1992	Raleigh	NC	Solar	Intermediate	Yes	4.14
Facility 1993	Raleigh	NC	Solar	Intermediate	Yes	4.14
Facility 1994	Kure Beach	NC	Solar	Intermediate	Yes	2.1
Facility 1995	Kure Beach	NC	Solar	Intermediate	Yes	2
Facility 1996	Wilmington	NC	Solar	Intermediate	Yes	1.2
Facility 1997	Asheville	NC	Solar	Intermediate	Yes	7
Facility 1998	Candler	NC	Solar	Intermediate	Yes	7.6
Facility 1999	Asheville	NC	Solar	Intermediate	Yes	6

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2000	Candler	NC	Solar	Intermediate	Yes	12
Facility 2001	Semora	NC	Solar	Intermediate	Yes	5.32
Facility 2002	Semora	NC	Solar	Intermediate	Yes	4.2
Facility 2003	Pinehurst	NC	Solar	Intermediate	Yes	2.58
Facility 2004	Weaverville	NC	Solar	Intermediate	Yes	7.2
Facility 2005	Holly Springs	NC	Solar	Intermediate	Yes	1.8
Facility 2006	Raleigh	NC	Solar	Intermediate	Yes	9.8
Facility 2007	Wilmington	NC	Solar	Intermediate	Yes	9.9
Facility 2008	Hookerton	NC	Solar	Intermediate	Yes	5.06
Facility 2009	Pittsboro	NC	Solar	Intermediate	Yes	1.57
Facility 2010	Clayton	NC	Solar	Intermediate	Yes	2.24
Facility 2011	Asheville	NC	Solar	Intermediate	Yes	6
Facility 2012	Siler City	NC	Solar	Intermediate	Yes	3.53
Facility 2013	Morrisville	NC	Solar	Intermediate	Yes	5.24
Facility 2014	Marston	NC	Solar	Intermediate	Yes	4975
Facility 2015	Marston	NC	Solar	Intermediate	Yes	4999
Facility 2016	Rocky Mount	NC	Hydroelectric	Baseload	Yes	600
Facility 2017	Sanford	NC	Hydroelectric	Baseload	Yes	235
Facility 2018	Raleigh	NC	Solar	Intermediate	Yes	2.25
Facility 2019	Fuquay Varina	NC	Solar	Intermediate	Yes	3.79
Facility 2020	Franklinton	NC	Solar	Intermediate	Yes	3.6
Facility 2021	Wilmington	NC	Solar	Intermediate	Yes	2
Facility 2022	Leasburg	NC	Solar	Intermediate	Yes	4
Facility 2023	Kenansville	NC	Solar	Intermediate	Yes	3
Facility 2024	Swannanoa	NC	Solar	Intermediate	Yes	18
Facility 2025	Leicester	NC	Solar	Intermediate	Yes	7.46
Facility 2026	Candler	NC	Solar	Intermediate	Yes	2.36
Facility 2027	Fuquay Varina	NC	Solar	Intermediate	Yes	3.08
Facility 2028	Fletcher	NC	Solar	Intermediate	Yes	2.31
Facility 2029	Wilmington	NC	Solar	Intermediate	Yes	7
Facility 2030	Waynesville	NC	Solar	Intermediate	Yes	5
Facility 2031	Clayton	NC	Solar	Intermediate	Yes	2.58
Facility 2032	Wilmington	NC	Solar	Intermediate	Yes	3.6
Facility 2033	Black Mountain	NC	Solar	Intermediate	Yes	4.7
Facility 2034	Cary	NC	Solar	Intermediate	Yes	2.907
Facility 2035	Wake Forest	NC	Solar	Intermediate	Yes	10
Facility 2036	Rose Hill	NC	Solar	Intermediate	Yes	1900
Facility 2037	Apex	NC	Solar	Intermediate	Yes	2.442
Facility 2038	Chandler	NC	Solar	Intermediate	Yes	3.225
Facility 2039	Biltmore Lake	NC	Solar	Intermediate	Yes	3.801
Facility 2040	Wilmington	NC	Solar	Intermediate	Yes	2.88
Facility 2041	Raleigh	NC	Solar	Intermediate	Yes	3.24
Facility 2042	Apex	NC	Solar	Intermediate	Yes	2.442
Facility 2043	Apex	NC	Solar	Intermediate	Yes	2.1
Facility 2044	New Bern	NC	Solar	Intermediate	Yes	3.45
Facility 2045	Zebulon	NC	Solar	Intermediate	Yes	8.726
Facility 2046	Roxboro	NC	Solar	Intermediate	Yes	4975
Facility 2047	Oxford	NC	Solar	Intermediate	Yes	5000
Facility 2048	Fayetville	NC	Solar	Intermediate	Yes	5.71
Facility 2049	Pittsboro	NC	Solar	Intermediate	Yes	2
Facility 2050	Weaverville	NC	Solar	Intermediate	Yes	3.84

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2051	Godwin	NC	Solar	Intermediate	Yes	5000
Facility 2052	Chapel Hill	NC	Solar	Intermediate	Yes	5.11
Facility 2053	Wilmington	NC	Solar	Intermediate	Yes	2.63
Facility 2054	Cary	NC	Solar	Intermediate	Yes	3.88
Facility 2055	Asheville	NC	Solar	Intermediate	Yes	4.44
Facility 2056	Apex	NC	Solar	Intermediate	Yes	3.58
Facility 2057	Cary	NC	Solar	Intermediate	Yes	2.87
Facility 2058	Raleigh	NC	Solar	Intermediate	Yes	3.22
Facility 2059	Rougemont	NC	Solar	Intermediate	Yes	7.6
Facility 2060	Cary	NC	Solar	Intermediate	Yes	2.6
Facility 2061	Leasburg	NC	Solar	Intermediate	Yes	8.47
Facility 2062	Cary	NC	Solar	Intermediate	Yes	4
Facility 2063	Gerton	NC	Solar	Intermediate	Yes	3.44
Facility 2064	Vass	NC	Solar	Intermediate	Yes	3.6
Facility 2065	Southport	NC	Solar	Intermediate	Yes	1.5
Facility 2066	Bear Creek	NC	Solar	Intermediate	Yes	7.34
Facility 2067	Hampstead	NC	Solar	Intermediate	Yes	3.03
Facility 2068	Raeford	NC	Solar	Intermediate	Yes	4
Facility 2069	Raleigh	NC	Solar	Intermediate	Yes	8.59
Facility 2070	Southport	NC	Solar	Intermediate	Yes	11.52
Facility 2071	Black Mtn	NC	Solar	Intermediate	Yes	20
Facility 2072	Kure Beach	NC	Solar	Intermediate	Yes	6.468
Facility 2073	Raleigh	NC	Solar	Intermediate	Yes	7.5
Facility 2074	Biscoe	NC	Solar	Intermediate	Yes	5000
Facility 2075	Roseboro	NC	Solar	Intermediate	Yes	1980
Facility 2076	Raleigh	NC	Solar	Intermediate	Yes	4.165
Facility 2077	Asheville	NC	Solar	Intermediate	Yes	20
Facility 2078	Asheville	NC	Solar	Intermediate	Yes	3.3
Facility 2079	Chapel Hill	NC	Solar	Intermediate	Yes	8.46
Facility 2080	Asheville	NC	Solar	Intermediate	Yes	9.067
Facility 2081	Chapel Hill	NC	Solar	Intermediate	Yes	2.34
Facility 2082	Wilmington	NC	Solar	Intermediate	Yes	3.81
Facility 2083	Raleigh	NC	Solar	Intermediate	Yes	3.5
Facility 2084	Raleigh	NC	Solar	Intermediate	Yes	1.9
Facility 2085	Elm City	NC	Solar	Intermediate	Yes	1200
Facility 2086	Asheville	NC	Solar	Intermediate	Yes	5.16
Facility 2087	Asheville	NC	Solar	Intermediate	Yes	4.3
Facility 2088	Raleigh	NC	Solar	Intermediate	Yes	2.75
Facility 2089	Pittsboro	NC	Solar	Intermediate	Yes	2
Facility 2090	Louisburg	NC	Solar	Intermediate	Yes	5000
Facility 2091	Cary	NC	Solar	Intermediate	Yes	72
Facility 2092	Cary	NC	Solar	Intermediate	Yes	960
Facility 2093	Cary	NC	Solar	Intermediate	Yes	800
Facility 2094	Cary	NC	Solar	Intermediate	Yes	2.442
Facility 2095	Lillington	NC	Solar	Intermediate	Yes	3.06
Facility 2096	Cary	NC	Solar	Intermediate	Yes	2.94
Facility 2097	Sanford	NC	Solar	Intermediate	Yes	6.14
Facility 2098	Pittsboro	NC	Solar	Intermediate	Yes	9.471
Facility 2099	Cary	NC	Solar	Intermediate	Yes	3.57

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2100	Cary	NC	Solar	Intermediate	Yes	6.05
Facility 2101	Nashville	NC	Solar	Intermediate	Yes	4.5
Facility 2102	Garner	NC	Solar	Intermediate	Yes	6.864
Facility 2103	Castle Hayne	NC	Solar	Intermediate	Yes	3.3
Facility 2104	Black Mountain	NC	Solar	Intermediate	Yes	4.73
Facility 2105	Raleigh	NC	Solar	Intermediate	Yes	3.76
Facility 2106	Selma	NC	Solar	Intermediate	Yes	4.72
Facility 2107	Chapel Hill	NC	Solar	Intermediate	Yes	3.85
Facility 2108	Asheville	NC	Solar	Intermediate	Yes	8.224
Facility 2109	Raleigh	NC	Solar	Intermediate	Yes	3.6
Facility 2110	Wilmington	NC	Solar	Intermediate	Yes	2.6
Facility 2111	Chapel Hill	NC	Solar	Intermediate	Yes	2.04
Facility 2112	Moncure	NC	Solar	Intermediate	Yes	3.56
Facility 2113	Asheville	NC	Solar	Intermediate	Yes	2.876
Facility 2114	Pittsboro	NC	Solar	Intermediate	Yes	3.06
Facility 2115	Wilmington	NC	Solar	Intermediate	Yes	4.385
Facility 2116	Asheville	NC	Solar	Intermediate	Yes	4.28
Facility 2117	Raleigh	NC	Solar	Intermediate	Yes	4
Facility 2118	Wilmington	NC	Solar	Intermediate	Yes	6.531
Facility 2119	Asheville	NC	Solar	Intermediate	Yes	0.07
Facility 2120	Laurinburg	NC	Solar	Intermediate	Yes	4.95
Facility 2121	Raleigh	NC	Solar	Intermediate	Yes	1.72
Facility 2122	Raleigh	NC	Solar	Intermediate	Yes	8
Facility 2123	Hurdle Mills	NC	Solar	Intermediate	Yes	20
Facility 2124	Raleigh	NC	Solar	Intermediate	Yes	3.62
Facility 2125	Asheville	NC	Solar	Intermediate	Yes	6.5
Facility 2126	Louisburg	NC	Solar	Intermediate	Yes	7.68
Facility 2127	Asheville	NC	Solar	Intermediate	Yes	2.06
Facility 2128	Knightdale	NC	Solar	Intermediate	Yes	6.36
Facility 2129	Raleigh	NC	Solar	Intermediate	Yes	3.44
Facility 2130	Vass	NC	Solar	Intermediate	Yes	4.8
Facility 2131	Wilmington	NC	Solar	Intermediate	Yes	4.678
Facility 2132	Raleigh	NC	Solar	Intermediate	Yes	4.8
Facility 2133	Raleigh	NC	Solar	Intermediate	Yes	4.45
Facility 2134	Spring Lake	NC	Solar	Intermediate	Yes	3.9
Facility 2135	Cary	NC	Solar	Intermediate	Yes	4.537
Facility 2136	Selma	NC	Solar	Intermediate	Yes	5000
Facility 2137	Franklinton	NC	Solar	Intermediate	Yes	2.3
Facility 2138	Cary	NC	Solar	Intermediate	Yes	4.2
Facility 2139	Cary	NC	Solar	Intermediate	Yes	4.46
Facility 2140	Cary	NC	Solar	Intermediate	Yes	2
Facility 2141	Pittsboro	NC	Solar	Intermediate	Yes	1.43
Facility 2142	Raleigh	NC	Solar	Intermediate	Yes	2.6
Facility 2143	Raleigh	NC	Solar	Intermediate	Yes	1.63
Facility 2144	Chapel Hill	NC	Solar	Intermediate	Yes	5
Facility 2145	Cary	NC	Solar	Intermediate	Yes	4.58
Facility 2146	Shannon	NC	Solar	Intermediate	Yes	4975
Facility 2147	Asheville	NC	Solar	Intermediate	Yes	2.43
Facility 2148	Asheville	NC	Solar	Intermediate	Yes	8.64
Facility 2149	Fuquay-Varina	NC	Solar	Intermediate	Yes	4.495
Facility 2150	Raleigh	NC	Solar	Intermediate	Yes	2

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2151	Pittsboro	NC	Solar	Intermediate	Yes	3.3
Facility 2152	Wilmington	NC	Solar	Intermediate	Yes	2.946
Facility 2153	Alexander	NC	Solar	Intermediate	Yes	3.87
Facility 2154	Raleigh	NC	Solar	Intermediate	Yes	3.5
Facility 2155	Fairview	NC	Solar	Intermediate	Yes	3.47
Facility 2156	Cameron	NC	Solar	Intermediate	Yes	3.43
Facility 2157	Wilmington	NC	Solar	Intermediate	Yes	4.18
Facility 2158	Asheville	NC	Solar	Intermediate	Yes	4.9
Facility 2159	Aberdeen	NC	Solar	Intermediate	Yes	5.96
Facility 2160	Kenly	NC	Solar	Intermediate	Yes	3.8
Facility 2161	Fairview	NC	Solar	Intermediate	Yes	2.49
Facility 2162	Fuquay Varina	NC	Solar	Intermediate	Yes	5.88
Facility 2163	Arden	NC	Solar	Intermediate	Yes	3.72
Facility 2164	Cary	NC	Solar	Intermediate	Yes	3.51
Facility 2165	Weaverville	NC	Solar	Intermediate	Yes	3.05
Facility 2166	Hope Mills	NC	Solar	Intermediate	Yes	2.3
Facility 2167	Cary	NC	Solar	Intermediate	Yes	4.905
Facility 2168	Cary	NC	Solar	Intermediate	Yes	3.02
Facility 2169	Wilmington	NC	Solar	Intermediate	Yes	4.3
Facility 2170	Candler	NC	Solar	Intermediate	Yes	5
Facility 2171	Wilmington	NC	Solar	Intermediate	Yes	5.938
Facility 2172	Raeford	NC	Solar	Intermediate	Yes	7.594
Facility 2173	Wilmington	NC	Solar	Intermediate	Yes	2.56
Facility 2174	Asheville	NC	Solar	Intermediate	Yes	14.399
Facility 2175	Louisburg	NC	Solar	Intermediate	Yes	4.91
Facility 2176	Fletcher	NC	Solar	Intermediate	Yes	3.85
Facility 2177	Fuquay-Varina	NC	Solar	Intermediate	Yes	5.59
Facility 2178	Raleigh	NC	Solar	Intermediate	Yes	4.23
Facility 2179	Wilmington	NC	Solar	Intermediate	Yes	2.29
Facility 2180	Cary	NC	Solar	Intermediate	Yes	5.18
Facility 2181	Laurinburg	NC	Solar	Intermediate	Yes	11
Facility 2182	Laurinburg	NC	Solar	Intermediate	Yes	10
Facility 2183	Cary	NC	Solar	Intermediate	Yes	3.856
Facility 2184	Wilmington	NC	Solar	Intermediate	Yes	2.8
Facility 2185	Fuquay Varina	NC	Solar	Intermediate	Yes	8.687
Facility 2186	Hampstead	NC	Solar	Intermediate	Yes	4.15
Facility 2187	Wilmington	NC	Solar	Intermediate	Yes	6.37
Facility 2188	Benson	NC	Solar	Intermediate	Yes	3.76
Facility 2189	Cary	NC	Solar	Intermediate	Yes	7.9
Facility 2190	Holly Springs	NC	Solar	Intermediate	Yes	4.671
Facility 2191	Wilmington	NC	Solar	Intermediate	Yes	2.04
Facility 2192	Willow Spring	NC	Solar	Intermediate	Yes	4.63
Facility 2193	Pittsboro	NC	Solar	Intermediate	Yes	4.69
Facility 2194	Raleigh	NC	Solar	Intermediate	Yes	6.49
Facility 2195	Fuquay Varina	NC	Solar	Intermediate	Yes	4.28
Facility 2196	Fuquay Varina	NC	Solar	Intermediate	Yes	3.5
Facility 2197	Snow Hill	NC	Solar	Intermediate	Yes	1990
Facility 2198	Goldsboro	NC	Solar	Intermediate	Yes	4.62
Facility 2199	Raleigh	NC	Solar	Intermediate	Yes	4.28

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2200	Raleigh	NC	Solar	Intermediate	Yes	2.02
Facility 2201	Louisburg	NC	Solar	Intermediate	Yes	48
Facility 2202	Mount Olive	NC	Solar	Intermediate	Yes	1980
Facility 2203	Raleigh	NC	Solar	Intermediate	Yes	385
Facility 2204	Newton Grove	NC	Solar	Intermediate	Yes	4872
Facility 2205	Clarkton	NC	Solar	Intermediate	Yes	4950
Facility 2206	Dunn	NC	Solar	Intermediate	Yes	5000
Facility 2207	Asheville	NC	Solar	Intermediate	Yes	1.92
Facility 2208	Goldsboro	NC	Solar	Intermediate	Yes	5000
Facility 2209	Youngsville	NC	Solar	Intermediate	Yes	5
Facility 2210	Chapel Hill	NC	Solar	Intermediate	Yes	2.442
Facility 2211	Raleigh	NC	Solar	Intermediate	Yes	4.6
Facility 2212	Chapel Hill	NC	Solar	Intermediate	Yes	2.56
Facility 2213	Cary	NC	Solar	Intermediate	Yes	3.94
Facility 2214	Norlina	NC	Solar	Intermediate	Yes	3500
Facility 2215	Wilmington	NC	Solar	Intermediate	Yes	100
Facility 2216	Wilmington	NC	Solar	Intermediate	Yes	1600
Facility 2217	Rowland	NC	Solar	Intermediate	Yes	4975
Facility 2218	Fletcher	NC	Solar	Intermediate	Yes	1000
Facility 2219	Raleigh	NC	Solar	Intermediate	Yes	4.95
Facility 2220	Pittsboro	NC	Solar	Intermediate	Yes	4.495
Facility 2221	Raleigh	NC	Solar	Intermediate	Yes	7.626
Facility 2222	Raleigh	NC	Solar	Intermediate	Yes	5.11
Facility 2223	Pittsboro	NC	Solar	Intermediate	Yes	3.02
Facility 2224	Angier	NC	Solar	Intermediate	Yes	4.404
Facility 2225	Eagle Springs	NC	Solar	Intermediate	Yes	4950
Facility 2226	Cary	NC	Solar	Intermediate	Yes	5.61
Facility 2227	Southern Pines	NC	Solar	Intermediate	Yes	5.96
Facility 2228	Raleigh	NC	Solar	Intermediate	Yes	6.913
Facility 2229	Raleigh	NC	Solar	Intermediate	Yes	6.35
Facility 2230	Cary	NC	Solar	Intermediate	Yes	5.7
Facility 2231	Asheville	NC	Solar	Intermediate	Yes	45
Facility 2232	Raleigh	NC	Solar	Intermediate	Yes	10.583
Facility 2233	Henderson	NC	Solar	Intermediate	Yes	4999
Facility 2234	Asheboro	NC	Solar	Intermediate	Yes	6.24
Facility 2235	Raleigh	NC	Solar	Intermediate	Yes	2.377
Facility 2236	Chocowinity	NC	Solar	Intermediate	Yes	3.9
Facility 2237	Asheville	NC	Solar	Intermediate	Yes	4.16
Facility 2238	Siler City	NC	Solar	Intermediate	Yes	9.79
Facility 2239	Morrisville	NC	Solar	Intermediate	Yes	3.494
Facility 2240	Pinehurst	NC	Solar	Intermediate	Yes	4.36
Facility 2241	Hampstead	NC	Solar	Intermediate	Yes	4.205
Facility 2242	Apex	NC	Solar	Intermediate	Yes	5.78
Facility 2243	Raleigh	NC	Solar	Intermediate	Yes	7.275
Facility 2244	Raleigh	NC	Solar	Intermediate	Yes	5.5
Facility 2245	Apex	NC	Solar	Intermediate	Yes	3.4
Facility 2246	Southern Pines	NC	Solar	Intermediate	Yes	1.92
Facility 2247	Asheville	NC	Solar	Intermediate	Yes	5.25
Facility 2248	Asheville	NC	Solar	Intermediate	Yes	3.84
Facility 2249	Asheville	NC	Solar	Intermediate	Yes	9.84
Facility 2250	Asheville	NC	Solar	Intermediate	Yes	3.08

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2251	Raleigh	NC	Solar	Intermediate	Yes	2.85
Facility 2252	Wilmington	NC	Solar	Intermediate	Yes	5.06
Facility 2253	Raleigh	NC	Solar	Intermediate	Yes	7.76
Facility 2254	Wilmington	NC	Solar	Intermediate	Yes	3.5
Facility 2255	Weaverville	NC	Solar	Intermediate	Yes	3.25
Facility 2256	Climax	NC	Solar	Intermediate	Yes	7.68
Facility 2257	Weaverville	NC	Solar	Intermediate	Yes	3
Facility 2258	Wilmington	NC	Solar	Intermediate	Yes	4.1
Facility 2259	Cary	NC	Solar	Intermediate	Yes	3.79
Facility 2260	Pittsboro	NC	Solar	Intermediate	Yes	2.96
Facility 2261	Clayton	NC	Solar	Intermediate	Yes	7.34
Facility 2262	Apex	NC	Solar	Intermediate	Yes	7.19
Facility 2263	Pittsboro	NC	Solar	Intermediate	Yes	4.89
Facility 2264	Wilmington	NC	Solar	Intermediate	Yes	4.965
Facility 2265	Pittsboro	NC	Solar	Intermediate	Yes	2.08
Facility 2266	Asheville	NC	Solar	Intermediate	Yes	7.6
Facility 2267	Pittsboro	NC	Solar	Intermediate	Yes	4.55
Facility 2268	Rocky Point	NC	Solar	Intermediate	Yes	2.3
Facility 2269	Weaverville	NC	Solar	Intermediate	Yes	6.001
Facility 2270	Holly Springs	NC	Solar	Intermediate	Yes	2.5
Facility 2271	Rocky Mount	NC	Solar	Intermediate	Yes	5.3
Facility 2272	Rocky Mount	NC	Solar	Intermediate	Yes	4.74
Facility 2273	Durham	NC	Solar	Intermediate	Yes	5.626
Facility 2274	Fletcher	NC	Solar	Intermediate	Yes	6.824
Facility 2275	Cary	NC	Solar	Intermediate	Yes	8.7
Facility 2276	Raleigh	NC	Solar	Intermediate	Yes	2.4
Facility 2277	Garner	NC	Solar	Intermediate	Yes	2.359
Facility 2278	Wilmington	NC	Solar	Intermediate	Yes	2.6
Facility 2279	Raleigh	NC	Solar	Intermediate	Yes	7.342
Facility 2280	Arden	NC	Solar	Intermediate	Yes	3.22
Facility 2281	Morrisville	NC	Solar	Intermediate	Yes	3.9
Facility 2282	Littleton	NC	Solar	Intermediate	Yes	5000
Facility 2283	Henderson	NC	Solar	Intermediate	Yes	4990
Facility 2284	Fair Bluff	NC	Solar	Intermediate	Yes	5000
Facility 2285	Wilmington	NC	Solar	Intermediate	Yes	1000
Facility 2286	Shannon	NC	Solar	Intermediate	Yes	5000
Facility 2287	Weaverville	NC	Solar	Intermediate	Yes	193
Facility 2288	Goldsboro	NC	Solar	Intermediate	Yes	2.58
Facility 2289	Willow Springs	NC	Solar	Intermediate	Yes	4950
Facility 2290	Bahama	NC	Solar	Intermediate	Yes	5.81
Facility 2291	Black Mountain	NC	Solar	Intermediate	Yes	40
Facility 2292	Wilmington	NC	Solar	Intermediate	Yes	4.95
Facility 2293	Williston	NC	Solar	Intermediate	Yes	4
Facility 2294	Cary	NC	Solar	Intermediate	Yes	2.91
Facility 2295	Fletcher	NC	Solar	Intermediate	Yes	6.1
Facility 2296	Asheville	NC	Solar	Intermediate	Yes	3.597
Facility 2297	Candler	NC	Solar	Intermediate	Yes	3.01
Facility 2298	Raleigh	NC	Solar	Intermediate	Yes	6.75
Facility 2299	Wendell	NC	Solar	Intermediate	Yes	3.76

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2300	Asheville	NC	Solar	Intermediate	Yes	4.2
Facility 2301	Castle Hayne	NC	Solar	Intermediate	Yes	5.4
Facility 2302	Raleigh	NC	Solar	Intermediate	Yes	3.16
Facility 2303	Holly Springs	NC	Solar	Intermediate	Yes	4.22
Facility 2304	Asheville	NC	Solar	Intermediate	Yes	2.376
Facility 2305	Raleigh	NC	Solar	Intermediate	Yes	3.545
Facility 2306	Sanford	NC	Solar	Intermediate	Yes	5000
Facility 2307	Pittsboro	NC	Solar	Intermediate	Yes	7.58
Facility 2308	Pittsboro	NC	Solar	Intermediate	Yes	6.88
Facility 2309	Cary	NC	Solar	Intermediate	Yes	8.866
Facility 2310	Apex	NC	Solar	Intermediate	Yes	3.46
Facility 2311	Wilmington	NC	Solar	Intermediate	Yes	4.3
Facility 2312	Raleigh	NC	Solar	Intermediate	Yes	3.508
Facility 2313	Southern Pines	NC	Solar	Intermediate	Yes	19.92
Facility 2314	Asheville	NC	Solar	Intermediate	Yes	5.3
Facility 2315	Wake Forest	NC	Solar	Intermediate	Yes	1.76
Facility 2316	Holly Springs	NC	Solar	Intermediate	Yes	6
Facility 2317	Little Switzerland	NC	Solar	Intermediate	Yes	3
Facility 2318	Carolina Bch	NC	Solar	Intermediate	Yes	2.802
Facility 2319	Asheville	NC	Solar	Intermediate	Yes	6
Facility 2320	Cameron	NC	Solar	Intermediate	Yes	4.3
Facility 2321	Cameron	NC	Solar	Intermediate	Yes	4.3
Facility 2322	Asheville	NC	Solar	Intermediate	Yes	5
Facility 2323	Cary	NC	Solar	Intermediate	Yes	3.54
Facility 2324	Godwin	NC	Solar	Intermediate	Yes	4998
Facility 2325	Youngsville	NC	Solar	Intermediate	Yes	2.6
Facility 2326	Morrisville	NC	Solar	Intermediate	Yes	5.33
Facility 2327	Cary	NC	Solar	Intermediate	Yes	5.305
Facility 2328	Morehead City	NC	Solar	Intermediate	Yes	2.4
Facility 2329	Pinehurst	NC	Solar	Intermediate	Yes	5
Facility 2330	Pinehurst	NC	Solar	Intermediate	Yes	3.56
Facility 2331	Fairview	NC	Solar	Intermediate	Yes	5.39
Facility 2332	Rougemont	NC	Solar	Intermediate	Yes	2.77
Facility 2333	Jacksonville	NC	Solar	Intermediate	Yes	2.58
Facility 2334	Goldsboro	NC	Solar	Intermediate	Yes	4.2
Facility 2335	Aberdeen	NC	Solar	Intermediate	Yes	11.99
Facility 2336	Jacksonville	NC	Solar	Intermediate	Yes	7.667
Facility 2337	Asheville	NC	Solar	Intermediate	Yes	3.9
Facility 2338	Pittsboro	NC	Solar	Intermediate	Yes	3.14
Facility 2339	Raleigh	NC	Solar	Intermediate	Yes	5.262
Facility 2340	Raleigh	NC	Solar	Intermediate	Yes	515
Facility 2341	Wilmington	NC	Solar	Intermediate	Yes	4.73
Facility 2342	Pinehurst	NC	Solar	Intermediate	Yes	3.08
Facility 2343	Asheville	NC	Solar	Intermediate	Yes	8
Facility 2344	Wilmington	NC	Solar	Intermediate	Yes	7.68
Facility 2345	Asheville	NC	Solar	Intermediate	Yes	162.701
Facility 2346	Asheboro	NC	Solar	Intermediate	Yes	340
Facility 2347	Wrightsville Beach	NC	Solar	Intermediate	Yes	16
Facility 2348	Asheville	NC	Solar	Intermediate	Yes	3
Facility 2349	Fairview	NC	Solar	Intermediate	Yes	4
Facility 2350	Robbins	NC	Solar	Intermediate	Yes	2.28

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2351	Benson	NC	Solar	Intermediate	Yes	2.58
Facility 2352	Asheville	NC	Solar	Intermediate	Yes	5.04
Facility 2353	Barnardsville	NC	Solar	Intermediate	Yes	4.7
Facility 2354	Asheville	NC	Solar	Intermediate	Yes	3
Facility 2355	Asheville	NC	Solar	Intermediate	Yes	5.04
Facility 2356	Cary	NC	Solar	Intermediate	Yes	1.7
Facility 2357	Leicester	NC	Solar	Intermediate	Yes	2.064
Facility 2358	Leicester	NC	Solar	Intermediate	Yes	3.07
Facility 2359	Leicester	NC	Solar	Intermediate	Yes	6.88
Facility 2360	Weaverville	NC	Solar	Intermediate	Yes	6
Facility 2361	Weaverville	NC	Solar	Intermediate	Yes	5.45
Facility 2362	Swannanoa	NC	Solar	Intermediate	Yes	6
Facility 2363	Godwin	NC	Solar	Intermediate	Yes	5
Facility 2364	Raleigh	NC	Solar	Intermediate	Yes	4.271
Facility 2365	Raleigh	NC	Solar	Intermediate	Yes	2.09
Facility 2366	Cary	NC	Solar	Intermediate	Yes	4.792
Facility 2367	Raleigh	NC	Solar	Intermediate	Yes	4
Facility 2368	Morrisville	NC	Solar	Intermediate	Yes	6.609
Facility 2369	Raleigh	NC	Solar	Intermediate	Yes	3.75
Facility 2370	Raleigh	NC	Solar	Intermediate	Yes	4.07
Facility 2371	Pittsboro	NC	Solar	Intermediate	Yes	4.53
Facility 2372	Pittsboro	NC	Solar	Intermediate	Yes	2.5
Facility 2373	Hampstead	NC	Solar	Intermediate	Yes	2.34
Facility 2374	Wilmington	NC	Solar	Intermediate	Yes	3.5
Facility 2375	Garner	NC	Solar	Intermediate	Yes	3.261
Facility 2376	Asheville	NC	Solar	Intermediate	Yes	1.65
Facility 2377	Prospect Hill	NC	Solar	Intermediate	Yes	5.11
Facility 2378	Waynesville	NC	Solar	Intermediate	Yes	6
Facility 2379	Raleigh	NC	Solar	Intermediate	Yes	5
Facility 2380	Southern Pines	NC	Solar	Intermediate	Yes	1.8
Facility 2381	Wilmington	NC	Solar	Intermediate	Yes	5.88
Facility 2382	Atlantic Beach	NC	Solar	Intermediate	Yes	2.88
Facility 2383	Henderson	NC	Solar	Intermediate	Yes	6.84
Facility 2384	Leicester	NC	Solar	Intermediate	Yes	4.8
Facility 2385	Cary	NC	Solar	Intermediate	Yes	6.029
Facility 2386	Norlina	NC	Solar	Intermediate	Yes	7.687
Facility 2387	Cary	NC	Solar	Intermediate	Yes	20
Facility 2388	Warsaw	NC	Solar	Intermediate	Yes	630
Facility 2389	Wendell	NC	Solar	Intermediate	Yes	4.19
Facility 2390	Asheville	NC	Solar	Intermediate	Yes	1.5
Facility 2391	Bailey	NC	Solar	Intermediate	Yes	10000
Facility 2392	Pittsboro	NC	Solar	Intermediate	Yes	5.402
Facility 2393	Raleigh	NC	Solar	Intermediate	Yes	2.09
Facility 2394	Wilmington	NC	Solar	Intermediate	Yes	1
Facility 2395	Raleigh	NC	Solar	Intermediate	Yes	3.49
Facility 2396	Morrisville	NC	Solar	Intermediate	Yes	4.992
Facility 2397	Black Mountain	NC	Solar	Intermediate	Yes	4.8
Facility 2398	Leicester	NC	Solar	Intermediate	Yes	5.89
Facility 2399	Chapel Hill	NC	Solar	Intermediate	Yes	5.83

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2400	Pinehurst	NC	Solar	Intermediate	Yes	8
Facility 2401	Pittsboro	NC	Solar	Intermediate	Yes	2.31
Facility 2402	West End	NC	Solar	Intermediate	Yes	5.58
Facility 2403	Garner	NC	Solar	Intermediate	Yes	3.04
Facility 2404	Chapel Hill	NC	Solar	Intermediate	Yes	6.13
Facility 2405	Raleigh	NC	Solar	Intermediate	Yes	9.6
Facility 2406	Apex	NC	Solar	Intermediate	Yes	6.396
Facility 2407	Asheville	NC	Solar	Intermediate	Yes	18
Facility 2408	Fairmont	NC	Solar	Intermediate	Yes	5000
Facility 2409	Asheville	NC	Solar	Intermediate	Yes	3.53
Facility 2410	Asheville	NC	Solar	Intermediate	Yes	3.76
Facility 2411	Asheville	NC	Solar	Intermediate	Yes	3.84
Facility 2412	Raleigh	NC	Solar	Intermediate	Yes	3.33
Facility 2413	Raleigh	NC	Solar	Intermediate	Yes	4.52
Facility 2414	Garner	NC	Solar	Intermediate	Yes	3.457
Facility 2415	Chocowinity	NC	Solar	Intermediate	Yes	4500
Facility 2416	Kinston	NC	Solar	Intermediate	Yes	5000
Facility 2417	Laurinburg	NC	Solar	Intermediate	Yes	5000
Facility 2418	Apex	NC	Solar	Intermediate	Yes	3.11
Facility 2419	Black Mountain	NC	Solar	Intermediate	Yes	20
Facility 2420	Black Mountain	NC	Solar	Intermediate	Yes	9.6
Facility 2421	Black Mountain	NC	Solar	Intermediate	Yes	30
Facility 2422	Black Mountain	NC	Solar	Intermediate	Yes	6.24
Facility 2423	Leland	NC	Solar	Intermediate	Yes	3.77
Facility 2424	Cary	NC	Solar	Intermediate	Yes	3.25
Facility 2425	Asheville	NC	Solar	Intermediate	Yes	24
Facility 2426	Cary	NC	Solar	Intermediate	Yes	4
Facility 2427	Pittsboro	NC	Solar	Intermediate	Yes	5.71
Facility 2428	Cary	NC	Solar	Intermediate	Yes	2.721
Facility 2429	Wilmington	NC	Solar	Intermediate	Yes	3.7
Facility 2430	Cary	NC	Solar	Intermediate	Yes	5.6
Facility 2431	Pittsboro	NC	Solar	Intermediate	Yes	3.17
Facility 2432	Cary	NC	Solar	Intermediate	Yes	3.72
Facility 2433	Cary	NC	Solar	Intermediate	Yes	2.4
Facility 2434	Henderson	NC	Solar	Intermediate	Yes	17.5
Facility 2435	Henderson	NC	Solar	Intermediate	Yes	4998
Facility 2436	Newland	NC	Solar	Intermediate	Yes	5.9
Facility 2437	Asheville	NC	Solar	Intermediate	Yes	12.548
Facility 2438	Apex	NC	Solar	Intermediate	Yes	6.219
Facility 2439	Raleigh	NC	Solar	Intermediate	Yes	6.5
Facility 2440	Fuquay Varina	NC	Solar	Intermediate	Yes	6.742
Facility 2441	Raleigh	NC	Solar	Intermediate	Yes	2.23
Facility 2442	Wilmington	NC	Solar	Intermediate	Yes	3.82
Facility 2443	Raleigh	NC	Solar	Intermediate	Yes	5.64
Facility 2444	Pittsboro	NC	Solar	Intermediate	Yes	48
Facility 2445	Chapel Hill	NC	Solar	Intermediate	Yes	2000
Facility 2446	Henderson	NC	Solar	Intermediate	Yes	5000
Facility 2447	Garner	NC	Solar	Intermediate	Yes	10
Facility 2448	New Bern	NC	Solar	Intermediate	Yes	6.66
Facility 2449	Black Mountain	NC	Solar	Intermediate	Yes	1.44
Facility 2450	Cary	NC	Solar	Intermediate	Yes	1.5

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2451	Pinehurst	NC	Solar	Intermediate	Yes	0.612
Facility 2452	Raleigh	NC	Solar	Intermediate	Yes	4.51
Facility 2453	Asheville	NC	Solar	Intermediate	Yes	2.6
Facility 2454	Asheville	NC	Solar	Intermediate	Yes	3.2
Facility 2455	Pittsboro	NC	Solar	Intermediate	Yes	4
Facility 2456	Weaverville	NC	Solar	Intermediate	Yes	6.28
Facility 2457	Rolesville	NC	Solar	Intermediate	Yes	4
Facility 2458	Raleigh	NC	Solar	Intermediate	Yes	5.2
Facility 2459	Cary	NC	Solar	Intermediate	Yes	6.7
Facility 2460	Rose Hill	NC	Biomass	Intermediate	Yes	120
Facility 2461	Raleigh	NC	Solar	Intermediate	Yes	6.91
Facility 2462	Wadesboro	NC	Solar	Intermediate	Yes	4998
Facility 2463	Wadesboro	NC	Solar	Intermediate	Yes	4998
Facility 2464	Wadesboro	NC	Solar	Intermediate	Yes	5000
Facility 2465	Roxboro	NC	Solar	Intermediate	Yes	4975
Facility 2466	Raleigh	NC	Solar	Intermediate	Yes	308
Facility 2467	Raleigh	NC	Solar	Intermediate	Yes	375
Facility 2468	Chapel Hill	NC	Solar	Intermediate	Yes	3.5
Facility 2469	Cary	NC	Solar	Intermediate	Yes	5.344
Facility 2470	Pittsboro	NC	Solar	Intermediate	Yes	4.66
Facility 2471	Chapel Hill	NC	Solar	Intermediate	Yes	8.196
Facility 2472	Cary	NC	Solar	Intermediate	Yes	3.96
Facility 2473	Wallace	NC	Solar	Intermediate	Yes	1990
Facility 2474	Raleigh	NC	Solar	Intermediate	Yes	2.12
Facility 2475	Leland	NC	Solar	Intermediate	Yes	2.98
Facility 2476	Cary	NC	Solar	Intermediate	Yes	3.66
Facility 2477	Lumberton	NC	Solar	Intermediate	Yes	6.988
Facility 2478	Cary	NC	Solar	Intermediate	Yes	5.254
Facility 2479	Youngsville	NC	Solar	Intermediate	Yes	3.6
Facility 2480	Pinehurst	NC	Solar	Intermediate	Yes	1
Facility 2481	Four Oaks	NC	Solar	Intermediate	Yes	4.126
Facility 2482	Wilmington	NC	Solar	Intermediate	Yes	40
Facility 2483	Hampstead	NC	Solar	Intermediate	Yes	2.68
Facility 2484	Canton	NC	Solar	Intermediate	Yes	9.917
Facility 2485	Pittsboro	NC	Solar	Intermediate	Yes	4.146
Facility 2486	Pittsboro	NC	Solar	Intermediate	Yes	2.26
Facility 2487	Swannanoa	NC	Solar	Intermediate	Yes	9.46
Facility 2488	Warrenton	NC	Solar	Intermediate	Yes	4975
Facility 2489	Warsaw	NC	Solar	Intermediate	Yes	1900
Facility 2490	Warsaw	NC	Solar	Intermediate	Yes	1990
Facility 2491	Morrisville	NC	Solar	Intermediate	Yes	3.25
Facility 2492	Wilmington	NC	Solar	Intermediate	Yes	8.21
Facility 2493	Pittsboro	NC	Solar	Intermediate	Yes	4.89
Facility 2494	Maxton	NC	Solar	Intermediate	Yes	4975
Facility 2495	Wilmington	NC	Solar	Intermediate	Yes	4.8
Facility 2496	Cameron	NC	Solar	Intermediate	Yes	4.94
Facility 2497	Cameron	NC	Solar	Intermediate	Yes	4.6
Facility 2498	Goldsboro	NC	Solar	Intermediate	Yes	4.01
Facility 2499	Mt Olive	NC	Solar	Intermediate	Yes	5000

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2500	Goldsboro	NC	Solar	Intermediate	Yes	5000
Facility 2501	Goldsboro	NC	Solar	Intermediate	Yes	5000
Facility 2502	Asheville	NC	Solar	Intermediate	Yes	6.45
Facility 2503	Knightdale	NC	Solar	Intermediate	Yes	0.5
Facility 2504	Clayton	NC	Solar	Intermediate	Yes	3.78
Facility 2505	Raleigh	NC	Solar	Intermediate	Yes	3.29
Facility 2506	La Grange	NC	Solar	Intermediate	Yes	5.07
Facility 2507	Raleigh	NC	Solar	Intermediate	Yes	3.51
Facility 2508	Smithfield	NC	Solar	Intermediate	Yes	5000
Facility 2509	Asheville	NC	Solar	Intermediate	Yes	6.063
Facility 2510	Asheville	NC	Solar	Intermediate	Yes	3.33
Facility 2511	Oxford	NC	Solar	Intermediate	Yes	4.15
Facility 2512	New Hill	NC	Solar	Intermediate	Yes	5.088
Facility 2513	Wilmington	NC	Solar	Intermediate	Yes	3.43
Facility 2514	Pittsboro	NC	Solar	Intermediate	Yes	4.03
Facility 2515	Raleigh	NC	Solar	Intermediate	Yes	6.31
Facility 2516	Raleigh	NC	Solar	Intermediate	Yes	79
Facility 2517	Pittsboro	NC	Solar	Intermediate	Yes	3.57
Facility 2518	Apex	NC	Solar	Intermediate	Yes	15
Facility 2519	Apex	NC	Solar	Intermediate	Yes	96
Facility 2520	Oxford	NC	Solar	Intermediate	Yes	4.56
Facility 2521	Raleigh	NC	Solar	Intermediate	Yes	5.31
Facility 2522	Pittsboro	NC	Solar	Intermediate	Yes	3.69
Facility 2523	Raleigh	NC	Solar	Intermediate	Yes	6.11
Facility 2524	Saint Pauls	NC	Solar	Intermediate	Yes	2.31
Facility 2525	Chapel Hill	NC	Solar	Intermediate	Yes	4.77
Facility 2526	Middlesex	NC	Solar	Intermediate	Yes	9.078
Facility 2527	Willow Spring	NC	Solar	Intermediate	Yes	3.97
Facility 2528	Clayton	NC	Solar	Intermediate	Yes	5.2
Facility 2529	Asheville	NC	Solar	Intermediate	Yes	4.66
Facility 2530	Wilmington	NC	Solar	Intermediate	Yes	2.43
Facility 2531	Willow Spring	NC	Solar	Intermediate	Yes	2.6
Facility 2532	Pinehurst	NC	Solar	Intermediate	Yes	4.365
Facility 2533	Barnardsville	NC	Solar	Intermediate	Yes	2.6
Facility 2534	Raleigh	NC	Solar	Intermediate	Yes	4.24
Facility 2535	Pittsboro	NC	Solar	Intermediate	Yes	6.23
Facility 2536	Wilmingotn	NC	Solar	Intermediate	Yes	3.8
Facility 2537	Raleigh	NC	Solar	Intermediate	Yes	1.75
Facility 2538	Asheville	NC	Solar	Intermediate	Yes	5.5
Facility 2539	New Bern	NC	Solar	Intermediate	Yes	10
Facility 2540	Pittsboro	NC	Solar	Intermediate	Yes	1.632
Facility 2541	Apex	NC	Solar	Intermediate	Yes	3.84
Facility 2542	Candler	NC	Solar	Intermediate	Yes	6
Facility 2543	Garner	NC	Solar	Intermediate	Yes	4
Facility 2544	Asheville	NC	Solar	Intermediate	Yes	2.11
Facility 2545	Goldsboro	NC	Solar	Intermediate	Yes	2.37
Facility 2546	Raleigh	NC	Solar	Intermediate	Yes	2.58
Facility 2547	West End	NC	Solar	Intermediate	Yes	0.86
Facility 2548	Spring Hope	NC	Solar	Intermediate	Yes	13
Facility 2549	Asheville	NC	Solar	Intermediate	Yes	5
Facility 2550	Waynesville	NC	Solar	Intermediate	Yes	5.68

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2551	Waynesville	NC	Solar	Intermediate	Yes	5.22
Facility 2552	Raleigh	NC	Solar	Intermediate	Yes	3.19
Facility 2553	Raleigh	NC	Solar	Intermediate	Yes	3.19
Facility 2554	Candler	NC	Solar	Intermediate	Yes	10.13
Facility 2555	Garner	NC	Solar	Intermediate	Yes	4.92
Facility 2556	Roxboro	NC	Solar	Intermediate	Yes	2.907
Facility 2557	Apex	NC	Solar	Intermediate	Yes	4.1
Facility 2558	Clayton	NC	Solar	Intermediate	Yes	6.62
Facility 2559	West End	NC	Solar	Intermediate	Yes	4.2
Facility 2560	Princeton	NC	Solar	Intermediate	Yes	3.99
Facility 2561	Siler City	NC	Solar	Intermediate	Yes	6.51
Facility 2562	Elm City	NC	Solar	Intermediate	Yes	4975
Facility 2563	Raleigh	NC	Solar	Intermediate	Yes	2.46
Facility 2564	Vass	NC	Solar	Intermediate	Yes	3.66
Facility 2565	New Hill	NC	Solar	Intermediate	Yes	5.47
Facility 2566	Chapel Hill	NC	Solar	Intermediate	Yes	3.98
Facility 2567	Biltmore Lakes	NC	Solar	Intermediate	Yes	5.46
Facility 2568	Clayton	NC	Solar	Intermediate	Yes	6.452
Facility 2569	Leland	NC	Solar	Intermediate	Yes	5.813
Facility 2570	Cary	NC	Solar	Intermediate	Yes	3.05
Facility 2571	Wilmington	NC	Solar	Intermediate	Yes	2.946
Facility 2572	Chapel Hill	NC	Solar	Intermediate	Yes	5.83
Facility 2573	Raleigh	NC	Solar	Intermediate	Yes	2.07
Facility 2574	Wilmington	NC	Solar	Intermediate	Yes	3.72
Facility 2575	Albertson	NC	Solar	Intermediate	Yes	5000
Facility 2576	Weaverville	NC	Solar	Intermediate	Yes	6.18
Facility 2577	Raleigh	NC	Solar	Intermediate	Yes	5.422
Facility 2578	Holly Springs	NC	Solar	Intermediate	Yes	7.83
Facility 2579	Fuquay Varina	NC	Solar	Intermediate	Yes	9.57
Facility 2580	Apex	NC	Solar	Intermediate	Yes	5.084
Facility 2581	Arden	NC	Solar	Intermediate	Yes	4.47
Facility 2582	Fuquay Varina	NC	Solar	Intermediate	Yes	5.3
Facility 2583	Cary	NC	Solar	Intermediate	Yes	7.58
Facility 2584	Cary	NC	Solar	Intermediate	Yes	3.7
Facility 2585	Blanch	NC	Solar	Intermediate	Yes	5000
Facility 2586	Blanch	NC	Solar	Intermediate	Yes	4950
Facility 2587	Blanch	NC	Solar	Intermediate	Yes	4975
Facility 2588	Clinton	NC	Solar	Intermediate	Yes	4.44
Facility 2589	Cary	NC	Solar	Intermediate	Yes	6.78
Facility 2590	Zebulon	NC	Solar	Intermediate	Yes	8.13
Facility 2591	Fletcher	NC	Solar	Intermediate	Yes	7
Facility 2592	Wilmington	NC	Solar	Intermediate	Yes	5.53
Facility 2593	Wake Forest	NC	Solar	Intermediate	Yes	2.79
Facility 2594	Apex	NC	Solar	Intermediate	Yes	6
Facility 2595	Cary	NC	Solar	Intermediate	Yes	3.85
Facility 2596	Raleigh	NC	Solar	Intermediate	Yes	5.477
Facility 2597	Asheville	NC	Solar	Intermediate	Yes	7.6
Facility 2598	Fuquay Varina	NC	Solar	Intermediate	Yes	5.006
Facility 2599	Morehead City	NC	Solar	Intermediate	Yes	3.25

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2600	Roxboro	NC	Solar	Intermediate	Yes	11.919
Facility 2601	Wilmington	NC	Solar	Intermediate	Yes	4.483
Facility 2602	Raleigh	NC	Solar	Intermediate	Yes	5.46
Facility 2603	Red Springs	NC	Solar	Intermediate	Yes	4998
Facility 2604	Red Springs	NC	Solar	Intermediate	Yes	4998
Facility 2605	New Bern	NC	Biomass	Intermediate	Yes	48000
Facility 2606	Southport	NC	Biomass	Intermediate	Yes	80000
Facility 2607	Roxboro	NC	Biomass	Intermediate	Yes	42000

Note: Data provided in Table H-3 reflects nameplate capacity for the facility as of June 30, 2016.

Table H-4 Non-Utility Generation – South Carolina

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
South Carolina Generators:						
Facility 1	Pageland	SC	Solar	Intermediate	Yes	140
Facility 2	Rembert	SC	Solar	Intermediate	Yes	50
Facility 3	Florence	SC	Solar	Intermediate	Yes	13.6
Facility 4	Latta	SC	Solar	Intermediate	Yes	5.58
Facility 5	Marion	SC	Solar	Intermediate	Yes	6.993
Facility 6	Darlington	SC	Solar	Intermediate	Yes	4.2
Facility 7	Florence	SC	Solar	Intermediate	Yes	10
Facility 8	Darlington	SC	Solar	Intermediate	Yes	17.4
Facility 9	Dillon	SC	Solar	Intermediate	Yes	4.73
Facility 10	Florence	SC	Solar	Intermediate	Yes	10
Facility 11	Nichols	SC	Solar	Intermediate	Yes	4.9
Facility 12	Nichols	SC	Solar	Intermediate	Yes	6.1
Facility 13	Lake City	SC	Solar	Intermediate	Yes	2.49
Facility 14	Lamar	SC	Solar	Intermediate	Yes	8
Facility 15	Latta	SC	Solar	Intermediate	Yes	5.59
Facility 16	Bishopville	SC	Solar	Intermediate	Yes	10
Facility 17	Cheraw	SC	Solar	Intermediate	Yes	5
Facility 18	New Hill	SC	Solar	Intermediate	Yes	2.9
Facility 19	Cheraw	SC	Solar	Intermediate	Yes	2.7
Facility 20	Sumter	SC	Solar	Intermediate	Yes	2.64
Facility 21	Hartsville	SC	Solar	Intermediate	Yes	9
Facility 22	Mc Bee	SC	Solar	Intermediate	Yes	5
Facility 23	Elgin	SC	Solar	Intermediate	Yes	6.25
Facility 24	Sumter	SC	Solar	Intermediate	Yes	11.4
Facility 25	Sumter	SC	Solar	Intermediate	Yes	2.5
Facility 26	Sumter	SC	Solar	Intermediate	Yes	3.01
Facility 27	Florence	SC	Solar	Intermediate	Yes	6
Facility 28	Latta	SC	Solar	Intermediate	Yes	4.73
Facility 29	Johnsonville	SC	Solar	Intermediate	Yes	5.59
Facility 30	Florence	SC	Solar	Intermediate	Yes	1.5
Facility 31	Sumter	SC	Solar	Intermediate	Yes	2.58
Facility 32	Sumter	SC	Biogas	Intermediate	Yes	1546
Facility 33	Sumter	SC	Solar	Intermediate	Yes	10
Facility 34	Florence	SC	Solar	Intermediate	Yes	2.5
Facility 35	Bethune	SC	Solar	Intermediate	Yes	3
Facility 36	Sumter	SC	Solar	Intermediate	Yes	1.92
Facility 37	Elgin	SC	Solar	Intermediate	Yes	2.5
Facility 38	Rembert	SC	Solar	Intermediate	Yes	18
Facility 39	McColl	SC	Solar	Intermediate	Yes	4.341
Facility 40	Florence	SC	Solar	Intermediate	Yes	1.72
Facility 41	Florence	SC	Biomass	Intermediate	Yes	10000

Note: Data provided in Table H-4 reflects nameplate capacity for the facility as of June 30, 2016.

Table H-5 DEP QF Interconnection Queue

Qualified Facilities contribute to the current and future resource mix of the Company. QFs that are under contract are captured as designated resources in the base resource plan. QFs that are not yet under contract but in the interconnection queue may contribute to the undesignated additions identified in the resource plans. It is not possible to precisely estimate how much of the interconnection queue will come to fruition, however the current queue clearly supports solar generation's central role in DEP's NC REPS compliance plan.

Below is a summary of the interconnection queue as of June 30, 2016:

Utility	FacilityState	Energy Source Type	Number of Pending Projects	Pending Capacity (MW AC)
DEP	**NC**	Biomass	4	50.8
		Diesel	7	3.2
		Natural Gas	2	530.0
		Other	2	1.2
		Solar	380	2654.5
DEP	**NC Total**		**395**	**3239.6**
	SC	Diesel	1	0.4
		Solar	101	1220.9
DEP	**SC Total**		**102**	**1221.3**
DEP Total			**497**	**4460.9**

Note: (1) Above table includes all QF projects that are in various phases of the interconnection queue and not yet generating energy.
(2) Table does not include net metering interconnection requests.

APPENDIX I: TRANSMISSION PLANNED OR UNDER CONSTRUCTION

This appendix lists the planned transmission line additions. A discussion of the adequacy of DEP's transmission system is also included. Table I-1 lists the transmission line projects that are planned to meet reliability needs. This appendix also provides information pursuant to the North Carolina Utility Commission Rule R8-62.

Table I-1: DEP Transmission Line Additions

	Location		Capacity	Voltage	
Year	**From**	**To**	**MVA**	**KV**	**Comments**
2016	Asheboro	Asheboro East South Line	307	115	Upgrade
2016	Ft Bragg Woodruff St	Manchester	307	115	Upgrade
2018	Sutton Plant	Castle Hayne North Line	239	115	Upgrade
2018	Vanderbilt	West Asheville	307	115	Upgrade
2018	Richmond	Raeford	1195	230	Relocate, new
2018	Ft. Bragg Woodruff St.	Raeford	1195	230	Relocate, new
2019	Asheboro	Asheboro East North Line	307	115	Upgrade
2020	Jacksonville	Grants Creek	1195	230	New
2020	Newport	Harlowe	681	230	New

Rule R8-62: Certificates of environmental compatibility and public convenience and necessity for the construction of electric transmission lines in North Carolina.

(p) Plans for the construction of transmission lines in North Carolina (161 kV and above) shall be incorporated in filings made pursuant to Commission Rule R8-60. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(1) For existing lines, the information required on FERC Form 1, pages 422, 423, 424, and 425, except that the information reported on pages 422 and 423 may be reported every five years.

Please refer to the Company's FERC Form No. 1 filed with NCUC in April, 2015.

(p) Plans for the construction of transmission lines in North Carolina (161 kV and above) shall be incorporated in filings made pursuant to Commission Rule R8-60. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(2) For lines under construction, the following:
a. Commission docket number;
b. Location of end point(s);
c. length;
d. range of right-of-way width;
e. range of tower heights;
f. number of circuits;
g. operating voltage;
h. design capacity;
i. date construction started;
j. projected in-service date;

The following pages represent those projects in response to Rule R8-62 parts (1) and (2).

DEP has no transmission line projects, 161 kV and above, currently under construction

(p) Plans for the construction of transmission lines in North Carolina (161 kV and above) shall be incorporated in filings made pursuant to Commission Rule R8-60. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(3) For all other proposed lines, as the information becomes available, the following:

a. county location of end point(s);
b. approximate length;
c. typical right-of-way width for proposed type of line;
d. typical tower height for proposed type of line;
e. number of circuits;
f. operating voltage;
g. design capacity;
h. estimated date for starting construction (if more than 6 month delay from last report, explain); and
i. estimated in-service date (if more than 6-month delay from last report, explain). (NCUC Docket No. E-100, Sub 62, 12/4/92; NCUC Docket No. E-100, Sub 78A, 4/29/98.)

The following pages represent those projects in response to Rule R8-62 part (3).

Richmond – Raeford 230 kV Line loop-in

Project Description: Loop-In the existing 230 kV transmission line from the Richmond 230 kV Substation in Richmond County to the Ft. Bragg Woodruff St 230 kV Substation in Cumberland County at Raeford 230 kV Substation in Hoke County.

a. County location of end point(s); Hoke County
b. Approximate length; 5 miles
c. Typical right-of-way width for proposed type of line; 125 feet
d. Typical tower height for proposed type of line; 80 -120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 1195 MVA
h. Estimated date for starting construction; July 2017
i. Estimated in-service date; June 2018

Ft. Bragg Woodruff St – Raeford 230 kV Line loop-in

Project Description: Loop-In the existing 230 kV transmission line from the Richmond 230 kV Substation in Richmond County to the Ft. Bragg Woodruff St 230 kV Substation in Cumberland County at Raeford 230 kV Substation in Hoke County.

a. County location of end point(s); Hoke County
b. Approximate length; 5 miles
c. Typical right-of-way width for proposed type of line; 125 feet
d. Typical tower height for proposed type of line; 80 – 120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 1195 MVA
h. Estimated date for starting construction; July 2017
i. Estimated in-service date; June 2018

Jacksonville – Grants Creek 230 kV Line

Project Description: Construct new 230 kV transmission line from the Jacksonville 230 kV Substation in Onslow County to the Grants Creek 230 kV Substation in Onslow County.

a. County location of end point(s); Onslow County
b. Approximate length; 15 miles
c. Typical right-of-way width for proposed type of line; 125 feet
d. Typical tower height for proposed type of line; 80 – 120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 1195 MVA
h. Estimated date for starting construction; January 2018
i. Estimated in-service date; June 2020

Newport – Harlowe 230 kV Line

Project Description: Construct new 230 kV transmission line from the Newport 230 kV Substation in Carteret County to the Harlowe 230 kV Substation in Carteret County.

a. County location of end point(s); Carteret County
b. Approximate length; 8 miles
c. Typical right-of-way width for proposed type of line; 125 feet
d. Typical tower height for proposed type of line; 80 – 120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 681 MVA
h. Estimated date for starting construction; March 2019
i. Estimated in-service date; June 2020

DEP Transmission System Adequacy

Duke Energy Progress (DEP) monitors the adequacy and reliability of its transmission system and interconnections through internal analysis and participation in regional reliability groups. Internal transmission planning looks 10 years ahead at available generating resources and projected load to identify transmission system upgrade and expansion requirements. Corrective actions are planned and implemented in advance to ensure continued cost-effective and high-quality service. The DEP transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability. DEP works with DEC, NCEMC and ElectriCities to develop an annual NC Transmission Planning Collaborative (NCTPC) plan for the DEP and DEC systems in both North and South Carolina. In addition, transmission planning is coordinated with neighboring systems including South Carolina Electric & Gas (SCE&G) and Santee Cooper under a number of mechanisms including legacy interchange agreements between SCE&G, Santee Cooper, DEP, and DEC.

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with DEP's Transmission Planning Summary guidelines for voltage and thermal loading. The annual screening uses methods that comply with SERC policy and NERC Reliability Standards and the screening results identify the need for future transmission system expansion and upgrades. The transmission system is planned to ensure that no equipment overloads and adequate voltage is maintained to provide reliable service. The most stressful scenario is typically at projected peak load with certain equipment out of service. A thorough screening process is used to analyze the impact of potential equipment failures or other disturbances. As problems are identified, solutions are developed and evaluated.

Transmission planning and requests for transmission service and generator interconnection are interrelated to the resource planning process. DEP currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning Summary guidelines and the FERC Open Access Transmission Tariff (OATT). The Company performs studies to ensure transfer capability is acceptable to meet reliability needs and customers' expected use of the transmission system. Generator interconnection requests are studied in accordance with the Large and Small Generator Interconnection Procedures in the OATT and the North Carolina and South Carolina Interconnection Procedures.

SERC Reliability Corporation (SERC) audits DEP every three years for compliance with NERC Reliability Standards. Specifically, the audit requires DEP to demonstrate that its transmission planning practices meet NERC standards and to provide data supporting the Company's annual

compliance filing certifications. SERC conducted a NERC Reliability Standards compliance audit of DEP in the fall of 2014. DEP received "No Findings" from the audit team.

DEP participates in a number of regional reliability groups to coordinate analysis of regional, sub-regional and inter-balancing authority area transfer capability and interconnection reliability. Each reliability group's purpose is to:

- Assess the interconnected system's capability to handle large firm and non-firm transactions for purposes of economic access to resources and system reliability;
- Ensure that planned future transmission system improvements do not adversely affect neighboring systems; and
- Ensure interconnected system compliance with NERC Reliability Standards.

Regional reliability groups evaluate transfer capability and compliance with NERC Reliability Standards for the upcoming peak season and five- and ten-year periods. The groups also perform computer simulation tests for high transfer levels to verify satisfactory transfer capability.

Application of the practices and procedures described above ensures that DEP's transmission system continues to provide reliable service to its native load and firm transmission customers.

APPENDIX J: ECONOMIC DEVELOPMENT

Customers Served Under Economic Development

In the NCUC Order issued in Docket No. E-100, Sub 73 dated November 28, 1994, the NCUC ordered North Carolina utilities to review the combined effects of existing economic development rates within the approved IRP process and file the results in its short-term action plan. The incremental load (demand) for which customers are receiving credits under economic development rates and/or self-generation deferral rates (Rider EC), as well as economic redevelopment rates (Rider ER) as of June 2016 is:

Rider EC:
33 MW for North Carolina
10 MW for South Carolina

Rider ER:
0.6 MW for North Carolina
0 MW for South Carolina

APPENDIX K: ROXBORO RETROFIT ANALYSIS PER DOCKET E-2, SUB 1089

The following discussion is concerning the analysis of Roxboro coal plant retrofits for North Carolina Department of Environmental Quality (NC DEQ) Draft Rule "Standards of Performance for Existing Electric Generating Units Under Clean Air Act Section 111(d)"

Introduction

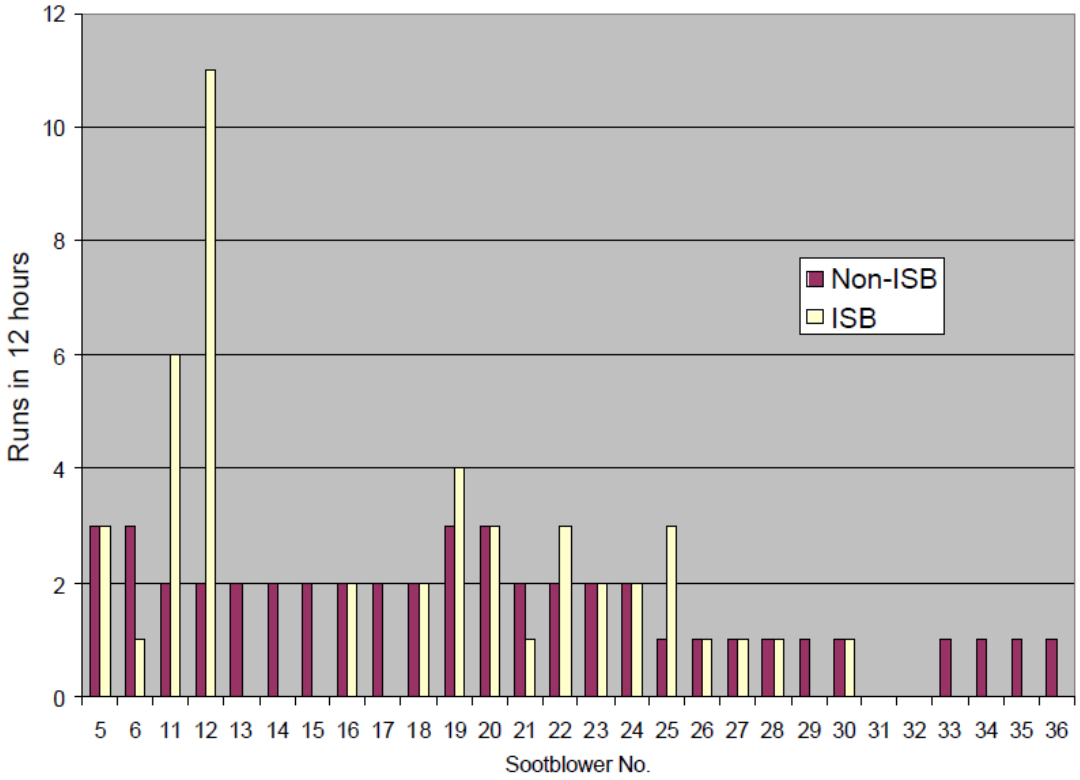
The November 16, 2015, NC DEQ draft rule entitled "Standards of Performance for Existing Electric Generating Units Under Clean Air Act Section 111(d)," proposed retrofitting the four Roxboro coal-burning power plants as part of the State's State Implementation Plan (SIP) for complying with the Environmental Protection Agency's (EPA) proposed Clean Power Plan (CPP). Duke Energy Progress (DEP) evaluated two technologies, (1) Intelligent Sootblowing, or ISB and (2) Variable Frequency Drive , or VFD. A description of the technologies, their costs, and potential benefits are summarized below.

Intelligent Sootblowing (ISB)

The use of Intelligent Sootblowers system (ISB) can improve system efficiency. The ISB system functions by monitoring both furnace exhaust gas temperatures and steam temperatures. A sophisticated ISB will receive various inputs from the boiler system, which are then digitally processed to evaluate real-time performance. The ISB system then interacts with the control system, historical data, or other data acquisition systems, to optimize online boiler cleaning location, duration and frequency in specific areas to remove ash buildup. Traditional sootblowing systems depend on power plant operator directions and generally are used on a specified-time basis. Overuse of sootblowers can erode the boiler tubing and reduce efficiency by increasing auxiliary load. Soot blowing improvements affect performance at both full-load and turndown.

Boiler efficiency improvements due to ISB are difficult to predict, DEP's best estimate for the Roxboro units is an approximate heat rate improvement of 0.3% across the load range. The estimated 2016 cost to implement ISB on each of Roxboro Units 2 – 4 is approximately $447,000. The ISB tie in to the DCS must be done during an outage. Installation work can be completed outside of the outage schedule.

Figure K-1: Example of Intelligent Soot Blowing vs Traditional Soot Blowing Soot Blower Operation



Forced Draft (FD) & Induced Draft (ID) Fan Variable Frequency Drive (VFD)

In the past, dampers have been the predominant means for flow control. A potentially more efficient method of flue gas flow control is the use of Variable Frequency Drives (VFDs). The VFD controller can improve fan performance particularly at lower loads. Based on the load profile for Roxboro Unit 2 from 1/1/14 – 5/1/16, VFD's on the FD fans would improve unit heat rate by 0.28%. The use of VFD's would improve net output at full load by approximately 1,300 KW in the winter, and approximately 320 KW in the summer.

Based on the load profile for Unit 2 mentioned above, the VFD's on the ID fans would improve unit heat rate by 0.72%. Also, the use of VFD's would improve net output at full load by approximately 2,625 KW in the winter, but approximately 610 KW in the summer.

The benefits of using VFD's would be greater on the ID fans than on the FD fans, for two reasons. First, the ID fans are doing 3 times as much work as the FD fans. Further, at full load, the inlet vanes are more restricted (~47 – 53% open) on the ID fans compared to the FD fans (~73 – 88% open).

The cost estimate for the combined FD and ID fan VFD project on Roxboro 2 is $10 million in 2016 dollars, excluding AFUDC, overheads, and escalations. O&M costs for drive maintenance would be approximately $60,000 per year. These projects would be multiyear projects spanning approximately three years with an outage for tie in required. Due to scheduling and funding, the earliest estimated implementation schedule would start in 2017 with drives installed in 2020.

Economic & CO_2 Emission Analysis

The economic evaluation of the two projects involved the following key assumptions:

- Base case does not include ISB or VFD projects at Roxboro
- Changes cases include ISB or VFD installed and operational beginning 1/1/2020
- Roxboro Units (1-4) retired 12/31/2032 (IRP assumption is Units 1 and 2 in June 2032 and 4&5 in June 2034)
- Carbon Tax beginning in 2022

Based on the estimated costs and process improvements, the two projects had similar Present Value Revenue Requirements (PVRR) benefits as shown in Table 1. However, the payback period for the ISB project would be approximately 1 year, while the payback period for the VFD project would be nearly 8 years.

Table K-1: PVRR & Payback Comparison of ISB and VFD

(PVRR, $M 2016)	Intelligent Soot Blowing (ISB)	Fan Variable Frequency Drive (VFD)
System Production Cost Savings	($4)	($13)
Capital & FOM Costs		
CAPEX	$0.5	$10.2
FOM	$0.4	$0.5
Total PVRR	($3)	($3)
Payback, years	1	8

In terms of CO_2 emissions, the VFD project provides greater reduction in total system CO_2 emissions than the ISB project. Over the 12 year life, the VFD project averages nearly 45,000 tons CO_2/year reduction versus the ISB project which averages nearly 6,000 tons CO_2/year reduction.

APPENDIX L: CROSS-REFERENCE OF IRP REQUIREMENTS AND SUBSEQUENT ORDERS

The following table cross-references IRP regulatory requirements for NC R8-60 in North Carolina identifies where those requirements are discussed in the IRP.

Requirement	Location	Reference	Updated
15-year Forecast of Load, Capacity and Reserves	Ch 8, Tables 8.C & D	NC R8-60 (c) 1	Yes
Comprehensive analysis of all resource options	Ch 4, 5 & 8, App A	NC R8-60 (c) 2	Yes
Assessment of Purchased Power	Table H.1	NC R8-60 (d)	Yes
Assessment of Alternative Supply-Side Energy Resources	Ch 5, App B & D	NC R8-60 (e)	Yes
Assessment of Demand-Side Management	Ch 4, App D	NC R8-60 (f)	Yes
Evaluation of Resource Options	Ch 8, App A, C & F	NC R8-60 (g)	Yes
Short-Term Action Plan	Ch 9	NC R8-60 (h) 3	Yes
REPS Compliance Plan	Attachment	NC R8-60 (h) 4	Yes
Forecasts of Load, Supply-Side Resources, and Demand-Side Resources			
* 10-year History of Customers and Energy Sales	App C	NC R8-60 (i) 1(i)	Yes
* 15-year Forecast w & w/o Energy Efficiency	Ch 3 & App C	NC R8-60 (i) 1(ii)	Yes
* Description of Supply-Side Resources	Ch 6 & App A	NC R8-60 (i) 1(iii)	Yes
Generating Facilities			
* Existing Generation	Ch 2, App B	NC R8-60 (i) 2(i)	Yes
* Planned Generation	Ch 8 & App A	NC R8-60 (i) 2(ii)	Yes
* Non Utility Generation	Ch 5, App H	NC R8-60 (i) 2(iii)	Yes
Reserve Margins	Ch 7, 8, Table 8.D	NC R8-60 (i) 3	Yes
Wholesale Contracts for the Purchase and Sale of Power			
* Wholesale Purchased Power Contracts	App H	NC R8-60 (i) 4(i)	Yes
* Request for Proposal	Ch 9	NC R8-60 (i) 4(ii)	Yes
* Wholesale Power Sales Contracts	App C & H	NC R8-60 (i) 4(iii)	Yes
Transmission Facilities	Ch 2, 7 & App I	NC R8-60 (i) 5	Yes
Energy Efficiency and Demand-Side Management			
* Existing Programs	Ch 4 & App D	NC R8-60 (i) 6(i)	Yes
* Future Programs	Ch 4 & App D	NC R8-60 (i) 6(ii)	Yes
* Rejected Programs	App D	NC R8-60 (i) 4(iii)	Yes
* Consumer Education Programs	App D	NC R8-60 (i) 4(iv)	Yes
Assessment of Alternative Supply-Side Energy Resources			
* Current and Future Alternative Supply-Side Resources	Ch 5, App F	NC R8-60 (i) 7(i)	Yes
* Rejected Alternative Supply-Side Resources	Ch 5, App F	NC R8-60 (i) 7(ii)	Yes
Evaluation of Resource Options (Quantitative Analysis)	App A	NC R8-60 (i) 8	Yes
Levelized Bus-bar Costs	App F	NC R8-60 (i) 9	Yes
Smart Grid Impacts	App D	NC R8-60 (i) 10	Yes
Legislative and Regulatory Issues	App G		Yes
Greenhouse Gas Reduction Compliance Plan	App G		Yes
Other Information (Economic Development)	App J		Yes

The following table cross-references Subsequent Orders for information that is required by the NCUC for inclusion in future IRP documents.

Change	Location	Source (Docket and Order Date)	Updated
DEP shall conduct an investigation on retrofitting its four Roxboro coal-burning power plants as proposed by the NC Department of Environmental Quality in its November 16, 2015 draft rule entitled "Standards of Performance for Existing Electric Generating Units Under Clean Air Act Section 111(d), "and submit a report to the Commission in the Company's 2016 Integrated Resource Planning regarding the feasibility and cost-effectiveness of conducting such retrofits.	App K	E-2, Sub 1089 Order Granting Application in Part, with Conditions, and Denying Application in Part, dated 3/28/16, ordering paragraph 7	Yes
Future IRP filings by all IOUs shall continue to include a detailed explanation of the basis and justification for the appropriateness of the level of the respective utility's projected reserve margins.	Ch 7 & App K	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 4	Yes
Duke will review reserve margins in 2015, in response to the recent winter peak loads experienced and the interconnection of increasing amounts of intermittent renewable resources to the DEC and DEP systems. Pending the results of that study, the Companies may update their required planning reserve margin target.	Ch 7 & App K	No new reporting requirements, but NCUC stated its expectation that Duke would make additional changes to future IRPs as discussed in Duke's 4/20/15 reply comments (p. 9) in E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15 (p. 39)	Yes
Future IRP filings by all IOUs shall continue to include a copy of the most recently completed FERC Form 715, including all attachments and exhibits.	Filed Under Seal	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 5	Yes
Future IRP filings by all IOUs shall continue to: (1) provide the amount of load and projected load growth for each wholesale customer under contract on a year-by-year basis through the terms of the current contract, segregate actual and projected growth rates of retail and wholesale loads, and explain any difference in actual and projected growth rates between retail and wholesale loads, and (2) for any amount of undesignated load, detail each potential customer's current supply arrangements and explain the basis for the utility's reasonable expectation for serving each such customer.	App C & App H	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 6 E-100, Sub 1118 and Sub 124, Order Approving Integrated Resource Plans and REPS Compliance Plans (2008-09), dated 8/10/10, ordering paragraph 6	Yes

Change	Location	Source (Docket and Order Date)	Updated
IOUs should continue to monitor and report any changes of more than 10% in the energy and capacity savings derived from DSM and EE between successive IRPs, and evaluate and discuss any changes on a program-specific basis. Any issues impacting program deployment should be thoroughly explained and quantified in future IRPs.	App D	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 7 E-100, Sub 128, Order Approving 2011 Annual Updates to 2010 IRPs and 2011 REPS Compliance Plans, dated 5/30/12, ordering paragraph 8	Yes
Each IOU shall continue to include a discussion of the status of EE market potential studies or updates in their future IRPs.	App D	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 8 E-100, Sub 128, Order Approving 2011 Annual Updates to 2010 IRPs and 2011 REPS Compliance Plans, dated 5/30/12, ordering paragraph 9	Yes
All IOUs shall include in future IRPs a full discussion of the drivers of each class' load forecast, including new or changed demand of a particular sector or sub-group.	Ch 3, App C	E-100, Sub 141, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/26/15, ordering paragraph 9 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 9 E-100, Sub 133, Order Denying Rulemaking Petition (Allocation Methods), dated 10/30/12, ordering paragraph 4	Yes
To the extent an IOU selects a preferred resource scenario based on fuel diversity, the IOU should provide additional support for its decision based on the costs and benefits of alternatives to achieve the same goals.	N/A	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 13 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 13 E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 16	N/A

Change	Location	Source (Docket and Order Date)	Updated
Future IRP filings by DEP and DEC shall continue to provide information on the number, resource type and total capacity of the facilities currently within the respective utility's interconnection queue as well as a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.	Ch 5 App A App H	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 14 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 14	Yes
Consistent with the Commission's May 7, 2013 Order in M-100, Sub 135, the IOUs shall include with their 2014 IRP submittals verified testimony addressing natural gas issues, as detailed in the body of that Order.	App E	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 15 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 15 E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 17	Yes
Duke plans to diligently review the business case for relicensing existing nuclear units, and if relicensing is in the best interest of customers, pursue second license renewal.	Exec Summ	No new reporting requirements, but NCUC stated its expectation that Duke would make additional changes to future IRPs as discussed in Duke's 4/20/15 reply comments (p. 7) in E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15 (p. 39)	Yes
Duke will include Li-ion battery storage technology in the economic supply-side screening process as part of the IRP.	App F	No new reporting requirements, but NCUC stated its expectation that Duke would make additional changes to future IRPs as discussed in Duke's 4/20/15 reply comments (p. 19) in E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15 (p. 39)	Yes
DEP and DNCP shall provide additional details and discussion of projected alternative supply side resources similar to the information provided by DEC.	Ch 5, 6 & App B, D, F	E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 14	Yes

Change	Location	Source (Docket and Order Date)	Updated
DEC and DEP should consider additional resource scenarios that include larger amounts of renewable energy resources similar to DNCP's Renewable Plan, and to the extent those scenarios are not selected, discuss why the scenario was not selected.	Ch 5, Ch 8, App A	E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 15	Yes
DEP, DEC and DNCP shall annually review their REPS compliance plans from four years earlier and disclose any redacted information that is no longer a trade secret. [This is filed in the docket of the prior IRP rather than the new IRP.]	Attached NC REPS Compliance Plan	E-100, Sub 137, Order Granting in Part and Denying in Part Motion for Disclosure, dated 6/3/13, ordering paragraph 3	Yes
[2013] Duke shall show the peak demand and energy savings impacts of each measure/option in the Program separately from each other, and separately from the impacts of its other existing PowerShare DSM program options in its future IRP and DSM filings, and in its evaluation, measurement, and verification reports for each measure of the Program. [2011] Duke shall show the impacts of the Program separately from the impacts of its existing PowerShare DSM options in future IRP and DSM filings, and Duke shall conduct and present separate M&V of the Program's impacts.	App D	E-7, Sub 953, Order Approving Amended Program, dated 1/24/13, ordering paragraph 4 (PowerShare Call Option Nonresidential Load and Curtailment Program) E-7, Sub 953, Order Approving Program, dated 3/31/11, ordering paragraph 4	Yes
DEP will incorporate into future IRPs any demand and energy savings resulting from the Energy Efficiency Education Program, My Home Energy Report Program, Multi-Family Energy Efficiency Program, Small Business Energy Saver Program, and Residential New Construction Program.	App D	E-2, Sub 1060, Order Approving Program, dated 12/18/14, p. 2 E-2, Sub 1059, Order Approving Program, dated 12/18/14, p. 2 E-2, Sub 989, Order Approving Program, dated 12/18/14, p. 3 E-2, Sub 1022, Order Approving Program, dated 11/5/12, footnote 2 (Small Business Energy Saver) E-2, Sub 1021, Order Approving Program, dated 10/2/12, footnote 3 (Residential New Construction Program)	Yes
Each utility shall include in each biennial report potential impacts of smart grid technology on resource planning and load forecasting: a present and five-year outlook – see R8-60(i)(10).	App D	E-100, Sub 126, Order Amending Commission Rule R8-60 and Adopting Commission Rule R8-60.1, dated 4/11/12	Yes

Change	Location	Source (Docket and Order Date)	Updated
DEP shall reflect plant retirements and address its progress in retiring its unscrubbed coal units by updates in its annual IRP filings.	Exec Summ, App B	E-2, Sub 960, Order Approving Plan, dated 1/28/10, ordering paragraph 2 (Wayne County CCs CPCN)	Yes
One-time requirement: Each IOU and EMC shall investigate the value of activating DSM resources during times of high system load as a means of achieving lower fuel costs by not having to dispatch peaking units with their associated higher fuel costs if it is less expensive to activate DSM resources. This issue shall be addressed as a specific item in their 2012 biennial IRP reports. [Note: the 10/14/13 Order in E-100, Sub 137 did not include this requirement for future IRPs; FoF 5 stated "The IOUs and EMCs included a full discussion of their DSM programs and their use of these resources a required by Rule R8-60(i)(6)."]	N/A	E-100, Sub 128, Order Approving 2010 Biennial Integrated Resource Plans and 2010 REPS Compliance Plans, dated 10/26/11, ordering paragraph 12	N/A
One-time requirement: DEP and DEC shall prepare a comprehensive reserve margin requirements study and include it as part of its 2012 biennial IRP report. DEP and DEC shall keep the Public Staff updated as they develop the parameters of the studies. [Study was included in 2012 IRP, as required.]	N/A	E-100, Sub 128, Order Approving 2010 Biennial Integrated Resource Plans and 2010 REPS Compliance Plans, dated 10/26/11, ordering paragraph 13	N/A
All utilities shall, for any amount of undesignated load, detail each potential customer's current supply arrangements and explain the basis for the utility's reasonable expectation for serving each such customer.	App H	E-100, Sub 118 and Sub 124, Order Approving Integrated Resource Plans and REPS Compliance Plans (2008-09), dated 8/10/10, ordering paragraph 6	Yes

The Duke Energy Progress

NC Renewable Energy & Energy Efficiency Portfolio Standard (NC REPS) Compliance Plan

September 1, 2016

NC REPS Compliance Plan
Table of Contents

I. INTRODUCTION

Duke Energy Progress, LLC (DEP or the Company) submits its annual Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS or REPS) Compliance Plan (Compliance Plan) in accordance with NC Gen. Stat. § 62-133.8 and North Carolina Utilities Commission (the Commission) Rule R8-67(b). This Compliance Plan, set forth in detail in Section II and Section III, provides the required information and outlines the Company's projected plans to comply with NC REPS for the period 2016 to 2018 (the Planning Period). Section IV addresses the cost implications of the Company's REPS Compliance Plan.

In 2007, the North Carolina General Assembly enacted Session Law 2007-397 (Senate Bill 3), codified in relevant part as NC Gen. Stat. § 62-133.8, in order to:

- Diversify the resources used to reliably meet the energy needs of consumers in the State;
- Provide greater energy security through the use of indigenous energy resources available within the State;
- Encourage private investment in renewable energy and energy efficiency; and
- Provide improved air quality and other benefits to energy consumers and citizens of the State.

As part of the broad policy initiatives listed above, Senate Bill 3 established the NC REPS, which requires the investor-owned utilities, electric membership corporations or co-operatives, and municipalities to procure or produce renewable energy, or achieve energy efficiency savings, in amounts equivalent to specified percentages of their respective retail megawatt-hour (MWh) sales from the prior calendar year.

Duke Energy Progress seeks to advance these State policies and comply with its REPS obligations through a diverse portfolio of cost-effective renewable energy and energy efficiency resources. Specifically, the key components of Duke Energy Progress' 2016 Compliance Plan include: (1) purchases of renewable energy certificates (RECs); (2) constructing and operating Company-owned renewable facilities; (3) energy efficiency programs that will generate savings that can be counted towards the Company's REPS obligation; and (4) research studies to enhance the Company's ability to comply with its future REPS obligations. The Company believes that these actions yield a diverse portfolio of qualifying resources and allow a flexible mechanism for compliance with the requirements of NC Gen. Stat. § 62-133.8.

In addition, the Company has undertaken, and will continue to undertake, specific regulatory and operational initiatives to support REPS compliance, including: (1) submission of regulatory applications to pursue reasonable and appropriate renewable energy and energy efficiency initiatives in support of the

Company's REPS compliance needs; (2) solicitation, review, and analysis of proposals from renewable energy suppliers offering RECs and diligent pursuit of the most attractive opportunities, as appropriate; and (3) development and implementation of administrative processes to manage the Company's REPS compliance operations, such as procuring and managing renewable resource contracts, accounting for RECs, safely interconnecting renewable energy suppliers, reporting renewable generation to the North Carolina Renewable Energy Tracking System (NC-RETS), and forecasting renewable resource availability and cost in the future.

The Company believes these actions collectively constitute a thorough and prudent plan for compliance with NC REPS and demonstrate the Company's commitment to pursue its renewable energy and energy efficiency strategies for the benefit of its customers.

II. REPS COMPLIANCE OBLIGATION

Duke Energy Progress calculates its NC REPS Compliance Obligations[13] for 2016, 2017, and 2018 based on interpretation of the statute (NC Gen. Stat. § 62-133.8), the Commission's rules implementing Senate Bill 3 (Rule R8-67), and subsequent Commission orders, as applied to the Company's actual or forecasted retail sales in the Planning Period, as well as the actual and forecasted retail sales of those wholesale customers for whom the Company is supplying REPS compliance services. The Company's wholesale customers for whom it supplies REPS compliance services are the Town of Sharpsburg, the Town of Stantonsburg, the Town of Lucama, the Town of Black Creek, and the Town of Winterville (collectively referred to as Wholesale or Wholesale Customers)[14]. Table 1 below shows the Company's retail and Wholesale customers' REPS Compliance Obligation.

[13] For the purposes of this Compliance Plan, Compliance Obligation is more specifically defined as the sum of Duke Energy Progress' native load obligations for both the Company's retail sales and for wholesale native load priority customers' retail sales for whom the Company is supplying REPS compliance. All references to the respective Set-Aside requirements, the General Requirements, and REPS Compliance Obligation of the Company include the aggregate obligations of both Duke Energy Progress and the Wholesale Customers. Also, for purposes of this Compliance Plan, all references to the compliance activities and plans of the Company shall encompass such activities and plans being undertaken by Duke Energy Progress on behalf of the Wholesale Customers.

[14] For purposes of this Compliance Plan, Retail Sales is defined as the sum of Duke Energy Progress' retail sales and the retail sales of the Wholesale Customers for whom the company is supplying REPS compliance.

Table 1: Duke Energy Progress' NC REPS Compliance Obligation

Compliance Year	Previous Year DEP Retail Sales (MWhs)	Previous Year Wholesale Retail Sales (MWhs)	Total Retail sales for REPS Compliance (MWhs)	Solar Set-Aside (RECs)	Swine Set-Aside (RECs)	Poultry Set-Aside (RECs)	REPS Requirement (%)	Total REPS Compliance Obligation (RECs)
2016	37,455,301	117,344	37,572,645	52,605	26,303	197,939	6%	2,254,364
2017	37,291,020	118,075	37,409,094	52,373	26,186	254,493	6%	2,244,546
2018	37,518,731	118,606	37,637,337	75,275	52,692	254,493	10%	3,763,734

Note: Obligation is determined by prior-year MWh sales. Thus, retail sales figures for compliance years 2017 and 2018 are estimates.

As shown in Table 1, the Company's requirements in the Planning Period include the solar energy resource requirement (Solar Set-Aside), swine waste resource requirement (Swine Waste Set-Aside), and poultry waste resource requirement (Poultry Waste Set-Aside). In addition, the Company must also ensure that, in total, the RECs that it produces or procures, combined with energy efficiency savings, is an amount equivalent to 6% of its prior-year retail sales in compliance years 2016 and 2017 and 10% of its prior-year retail sales in compliance year 2018. The Company refers to this as its Total Obligation. For clarification, the Company refers to its Total Obligation, net of the Solar, Swine Waste, and Poultry Waste Set-Aside requirements, as its General Requirement.

III. REPS COMPLIANCE PLAN

In accordance with Commission Rule R8-67b(1)(i), the Company describes its planned actions to comply with the Solar, Swine Waste, and Poultry Waste Set-Asides, as well as the General Requirement below. The discussion first addresses the Company's efforts to meet the Set-Aside requirements and then outlines the Company's efforts to meet its General Requirement in the Planning Period.

A. SOLAR ENERGY RESOURCES

Pursuant to NC Gen. Stat. § 62-133.8(d), the Company must produce or procure solar RECs equal to a minimum of 0.14% of the prior year's total electric energy in megawatt-hours (MWh) sold to retail customers in North Carolina in 2016 and 2017, and 0.20% of the prior year's total electric energy in megawatt-hours (MWh) sold to retail customers in North Carolina in 2018.

Based on the Company's actual retail sales in 2015, the Solar Set-Aside is 52,605 RECs in 2016. Based on forecasted retail sales, the Solar Set-Aside is projected to be approximately 52,373 RECs in 2017 and 75,275 RECs in 2018.

The Company has fully satisfied and vastly exceeded the minimum Solar Set-Aside requirements in the Planning Period through a combination of Power Purchase Agreements and Company-owned

solar facilities, including those listed below. The Company is now using solar energy to meet the General Requirement obligation.

- Camp Lejeune Solar Facility – 13MW, located in Onslow County, placed in service in November 2015;
- Warsaw Solar Facility – 65MW, located in Duplin County, placed in service in December 2015;
- Fayetteville Solar Facility – 23MW, located in Bladen County, placed in service in December 2015; and
- Elm City Solar Facility – 40MW, located in Wilson County, placed in service in March 2016.

Additional details with respect to the REC purchase agreements are set forth in Exhibit A.

B. SWINE WASTE-TO-ENERGY RESOURCES

Pursuant to NC Gen. Stat. § 62-133.8(e), as amended by the NCUC *Order Modifying the Swine and Poultry Waste Set-Aside Requirement and Providing Other Relief,* Docket No. E-100, Sub 113 (December 2015), for compliance years 2016 and 2017, at least 0.07%, and in 2018, at least 0.14%, of prior-year total retail electric energy sold in aggregate by utilities in North Carolina must be supplied by energy derived from swine waste. The Company's Swine Waste Set-Aside is estimated to be 26,303 RECs in 2016, 26,186 RECs in 2017, and 52,692 RECs in 2018.

Swine waste-to-energy compliance challenges have been numerous and varied. Three paths to the creation of swine waste-to-energy RECs have been identified, although each faces unique challenges.

1. On-farm generation

Projects consisting of digestion and generation on a single farm or tight cluster of farms often face gas production and feedstock agreement challenges, as well as interconnection difficulties. The Company understands that many farms in NC are contract growers and have only limited term agreements with the integrators. Accordingly, many contract growers are not in a position to provide a firm supply of waste sufficient to support project financing. The Company is exploring ways to overcome such risks.

2. Centralized digestion

This type of system would benefit farmers that cannot individually construct and operate an anaerobic digester manure handling system on their own due to the capital expense or just don't have the number of animals required to operate a digester successfully or cost effectively. Farms located close to each other could share the cost of the centrally located digester system. The centralized digester operated by an individual or private company would carry out the operation and maintenance of the digester and its mechanical systems. It would have the same advantages as on-farm digesters of odor reduction, pathogen and weed seed destruction, biogas production and a stable effluent ready to fertilize fields and crops.

The Company recognizes that NIMBY ("Not In My Back Yard") issues may scuttle some developers' plans for overcoming fuel supply and interconnection problems faced by more rural, on-farm projects.

3. Directed biogas

In theory, directed biogas[15] reduces costs by using large, efficient, centralized generation in the place of smaller, less-efficient reciprocating engines typical of other projects. However, practically, the Company has found such solutions in North Carolina to be economically challenged, in part due to additional gas clean-up requirements prior to injection and the general lack of physical proximity between clusters of farms and pipeline infrastructure.

The Company continues to explore directed biogas opportunities and has entered into two contracts to purchase swine waste-derived directed biogas from projects in North Carolina. The directed biogas will be transported via intrastate pipelines and used for fuel in the Company's H.F. Lee or Sutton combined cycle plants.

In an effort to meet compliance with the Swine Waste Set Aside, the Company (1) continues direct negotiations for additional supplies of both in-state and out-of-state resources; (2) works diligently to understand the technological, permitting, and operational risks associated with various methods of producing qualifying swine RECs to aid developers in overcoming those risks; when those risks cannot be overcome, the Company works with developers via contract amendments to adjust for outcomes that the developers believe are achievable based on new experience; (3) explores and is engaging in modification of current biomass and set-asides contracts by working with developers to

[3] "Directed Biogas" is defined as pipeline quality methane, injected into the pipeline system, and nominated to Duke Energy Progress generating facilities; this methane is biogenically derived from Swine Waste, Poultry Waste, and general Biomass sources.

add swine waste to their fuel mix; (4) continues pursuit of swine-derived directed biogas from North Carolina facilities to be directed to DEP's combined cycle plants for combustion and generation of zero emission renewable electricity; (5) utilizes the Company's REC trader to search the broker market for out-of-state swine RECs available in the market; and (6) engages the North Carolina Pork Council ("NCPC") in a project evaluation collaboration effort that will allow the Company and the NCPC to discuss project viability, as appropriate with respect to the Company's obligations to keep certain sensitive commercial information confidential.

In spite of Duke Energy Progress' active and diligent efforts to secure resources to comply with its Swine Waste Set-Aside requirements, the Company will not be able to procure sufficient volumes of RECs to meet its pro-rata share of the Swine Waste Set-Aside requirements in 2016. The Company remains actively engaged in seeking additional resources and continues to make every reasonable effort to comply with the swine waste set-aside requirements.

The Company's ability to comply in 2017 and 2018 remains subject to multiple variables, particularly related to counterparty achievement of projected delivery requirements and commercial operation milestones. Additional details with respect to the Company's compliance efforts and REC purchase agreements are set forth in Exhibit A and the Company's semiannual progress reports, filed confidentially in Docket No. E-100 Sub113A.

Due to its expected non-compliance in 2016, the Company has submitted a motion to the Commission for approval of a request to relieve the Company from compliance with the Swine Waste Set-Aside requirements until calendar year 2017 by delaying the compliance obligation for a one year period.

C. POULTRY WASTE-TO-ENERGY RESOURCES

Pursuant to NC Gen. Stat. § 62-133.8(f), as amended by NCUC *Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief*, Docket No. E-100, Sub 113 (December 2015), for calendar year 2016, at least 700,000 MWhs, and for 2017 and 2018, at least 900,000 MWhs, or an equivalent amount of energy, shall be produced or procured each year from poultry waste, as defined per the Statute and additional clarifying Orders. As the Company's retail sales share of the State's total retail megawatt-hour sales is approximately 28%, the Company's Poultry Waste Set-Aside is estimated to be 197,939 RECs in 2016, 254,493 RECs in 2017, and 254,493 in 2018.

In an effort to meet compliance with the Poultry Waste Set-Aside, the Company (1) continues direct negotiations for additional supplies of both in-state and out-of-state resources with multiple counterparties; (2) works diligently to understand the technological, permitting, and operational risks associated with various methods of producing qualifying poultry RECs to aid developers in overcoming those risks; when those risks cannot be overcome, the Company works with developers

via contract amendments to adjust for more realistic outcomes; (3) explores leveraging current biomass contracts by working with developers to add poultry waste to their fuel mix; (4) explores adding thermal capabilities to current poultry sites to bolster REC production; (5) explores poultry-derived directed biogas at facilities located in North Carolina and directing such biogas to DEP's combined cycle plants for combustion and generation of zero emission renewable electricity; and (6) utilizes the Company's REC trader to search the broker market for out-of-state poultry RECs available in the market.

In spite of Duke Energy Progress' active and diligent efforts to secure resources to comply with its Poultry Waste Set-Aside requirements, poultry waste-to-energy compliance remains a challenge for the Company. The Company will not be able to procure sufficient volumes of RECs to meet its pro-rata share of the Poultry Waste Set-Aside requirements in 2016, and the Company's ability to comply in 2017 and 2018 remains uncertain and largely subject to counterparty performance. To date, only a handful of poultry projects are operating and online in North Carolina. Ramping up to meet the increased compliance targets for 2016 - 2018 has been problematic because other suppliers have either delayed projects or lowered the volume of RECs to be produced. The Company is, nevertheless, encouraged by the growing use of thermal poultry RECs and the proposals that it has recently received from developers. In addition, the Company recently signed a contract to purchase poultry waste-derived directed biogas from a project in North Carolina. The directed biogas will be transported via intrastate pipelines and used for fuel in the Company's H.F. Lee or Sutton combined cycle plants. The Company remains actively engaged in seeking additional resources and continues to make every reasonable effort to comply with the Poultry Waste Set-Aside requirements.

Additional details with respect to the Company's compliance efforts and REC purchase agreements are set forth in Exhibit A and the Company's semiannual progress reports, filed confidentially in Docket No. E-100 Sub113A.

Due to its expected non-compliance in 2016, the Company has submitted a motion to the Commission for approval of a request to reduce the 2016 poultry-waste requirement to 170,000 MWh, maintaining the level of the 2014 and 2015 state-wide requirements and delaying the increase to 700,000 MWh until 2017.

D. GENERAL REQUIREMENT RESOURCES

Pursuant to NC Gen. Stat. § 62-133.8, DEP is required to comply with its Total Obligation in 2016 and 2017, by submitting for retirement a total volume of RECs equivalent to 6% of prior-year retail sales in North Carolina; in 2018, the requirement jumps to 10% of prior-year retail sales in North Carolina. Based on the Company's actual retail sales in 2015, the Total Requirement is 2,254,364 RECs in 2016. Based on forecasted retail sales, the Total Requirement is projected to be approximately 2,244,546 RECs

in 2017, and 3,763,734 RECs in 2018. This requirement, net of the Solar, Swine Waste, and Poultry Waste Set-Aside requirements, is estimated to be 1,977,517 RECs in 2016, 1,911,494 RECs in 2017, and 3,381,274 RECs in 2018. The various resource options available to the Company to meet the General Requirement are discussed below, as well as the Company's plan to meet the General Requirement with these resources.

1. Energy Efficiency

During the Planning Period, the Company plans to meet up to 25% of the Total Obligation with Energy Efficiency (EE) savings, which is the maximum allowable amount under NC Gen. Stat. § 62-133.7(b)(2)c. The Company continues to develop and offer its customers new and innovative EE programs that will deliver savings and count towards its future NC REPS requirements. The Company has attached a list of those EE measures that it plans to use toward REPS compliance, including projected impacts, as Exhibit B.

2. Hydroelectric Power

Duke Energy Progress plans to use hydroelectric power from two sources to meet a portion of the General Requirement in the Planning Period: (1) Wholesale Customers' Southeastern Power Administration (SEPA) allocations; and (2) hydroelectric generation suppliers whose facilities have received Qualifying Facility (QF or QF Hydro) status. Wholesale Customers may also bank and utilize hydroelectric resources arising from their full allocations of SEPA. When supplying compliance for the Wholesale Customers, the Company will ensure that hydroelectric resources do not comprise more than 30% of each Wholesale Customers' respective compliance portfolio, pursuant to NC Gen. Stat. § 62-133.8(c)(2)c. In addition, RECs from QF Hydro facilities will be used towards the General Requirements of Duke Energy Progress' retail and wholesale customers. Please see Exhibit A for more information on these contracts.

3. Biomass Resources

Duke Energy Progress plans to meet a portion of the General Requirement through a variety of biomass resources, including landfill gas to energy, combined heat and power, and direct combustion of biomass fuels. The Company is purchasing RECs from multiple biomass facilities in the Carolinas, including landfill gas to energy facilities and biomass-fueled combined heat and power facilities, all of which qualify as renewable energy facilities. Please see Exhibit A for more information on each of these contracts.

Duke Energy Progress notes, however, that reliance on direct-combustion biomass remains limited in long-term planning horizons, in part due to continued uncertainties around the developable potential of

such resources in the Carolinas and the projected availability of other forms of renewable resources to offset the need for biomass.

4. Wind

While the Company may rely upon wind resources for future REPS compliance, the extent and timing will depend on deliverability, policy changes and market prices. Additional opportunities may exist to transmit wind energy resources into the Carolinas from other regions, which could supplement the amount of wind that could be developed within the Carolinas.

5. Use of Solar Resources for General Requirement

Duke Energy Progress plans to meet a significant portion of the General Requirement with RECs from solar facilities. Solar energy has emerged as a predominant renewable energy resource in the Southeast, and the Company views the downward trend in solar equipment and installation costs over the past several years as a positive development. Additionally, new solar facilities also benefit from generous supportive Federal policies that will be in place beyond 2016. The Company is using solar resources to contribute to our compliance efforts beyond the Solar Set-Aside minimum threshold for NC REPS, and will continue to do so during the Planning Period.

6. Review of Company's General Requirement Plan

The Company has contracted for, or otherwise procured, sufficient resources to meet its General Requirement in the Planning Period. Based on the known information available at the time of this filing, the Company is confident that it will meet this General Requirement during the Planning Period, and well beyond, and submits that the actions and plans described herein represent a reasonable and prudent plan for meeting the General Requirement.

E. SUMMARY OF RENEWABLE RESOURCES

The Company has evaluated, procured, and/or developed a variety of types of renewable energy and energy efficiency resources to meet its NC REPS requirements within the compliance Planning Period. As noted above, several risks and uncertainties exist across the various types of resources and the associated parameters of the NC REPS requirements. The Company continues to carefully monitor opportunities and unexpected developments across all facets of its compliance requirements. Duke Energy Progress submits that it has crafted a prudent, reasonable plan with a diversified balance of renewable resources that will allow the Company to comply with its NC REPS obligation over the Planning Period.

IV. COST IMPLICATIONS OF REPS COMPLIANCE PLAN

A. CURRENT AND PROJECTED AVOIDED COST RATES

The Current Avoided Energy and Capacity costs included in the table below represent key data elements used to determine the PP-1 tariff rates approved in the Commission's *Order Establishing Avoided Cost Rates for DEC and DEP*, issued in Docket No. E-100, Sub 140 (March 10, 2016). The "Energy" columns reflect the cost of fuel and variable O&M per kwh embedded in the approved tariff energy rates. The "Capacity" column is based on the installed cost and capacity rating of a combustion turbine unit as reflected in the approved tariff capacity rates.

The Projected Avoided Energy and Capacity Costs included below reflect updated estimates of the same data elements provided with the current costs. The projected costs contained herein are subject to change, including (but not limited to) fuel price projections, variable O&M estimates, turbine costs and equipment capability.

Table 2: Current and Projected Avoided Cost Rates Table

[BEGIN CONFIDENTIAL]

CURRENT AVOIDED ENERGY AND CAPACITY COST(from E-100 Sub 140)			
	On-Peak Energy[1] ($/MWh)	Off-Peak Energy[1] ($/MWh)	[redacted]
2017	38.43	34.04	
2018	38.32	34.87	
2019	37.78	36.03	
PROJECTED AVOIDED ENERGY AND CAPACITY COST [3]			
	On-Peak Energy ($/MWh)	Off-Peak Energy ($/MWh)	[redacted]
2017	26.64	25.24	
2018	33.43	30.68	
2019	32.97	31.01	

Notes: (1) On-peak and off-peak energy rates based on Option B hours and information derived using methodology approved in Docket No. E-100, Sub 140
(2) Capacity Cost column provides the installed CT cost with AFUDC /summer capacity rating based on the Memorandum of Understanding between Duke Energy Progress, Duke Energy Carolinas, the NC Public Staff and other parties agreed to in Docket No. E-100, Sub 140
(3) The capacity cost shown is a placeholder based on previous avoided cost filing and is subject to change in upcoming filings..

[END CONFIDENTIAL]

B. PROJECTED TOTAL NORTH CAROLINA RETAIL AND WHOLESALE SALES AND YEAR-END NUMBER OF CUSTOMER ACCOUNTS BY CLASS

The tables below reflect the inclusion of the Wholesale Customers in the Compliance Plan.

Table 3: Retail Sales for Retail and Wholesale Customers

	2015 Actual	2016 Forecast	2017 Forecast	2018 Forecast
Retail MWh Sales	37,455,301	37,291,020	37,518,731	37,777,458
Wholesale MWh Sales	206,694	118,075	118,606	119,140
Total MWh Sales	37,661,995	37,409,094	37,637,337	37,896,597

Note: The MWh sales reported above are those applicable to REPS compliance years 2016 – 2019, and represent actual MWh sales for 2015, and projected MWh sales for 2016 – 2018.

Table 4: Retail and Wholesale Year-end Number of Customer Accounts

	2015 (Actual)	2016 (Projected)	2017 (Projected)	2018 (Projected)
Residential Accts	1,185,648	1,201,323	1,217,139	1,231,874
General Accts	193,497	195,602	197,724	200,062
Industrial Accts	2,031	2,028	2,025	2,031

Note: The number of accounts reported above are those applicable to the cost caps for compliance years 2016 – 2019, and represent the actual number of accounts for year-end 2015, and the projected number of accounts for year-end 2016 – 2018.

C. PROJECTED ANNUAL COST CAP COMPARISON OF TOTAL AND INCREMENTAL COSTS, REPS RIDER AND FUEL COST IMPACT

Projected compliance costs for the Planning Period are presented in the cost tables below by calendar year. The cost cap data is based on the number of accounts as reported above.

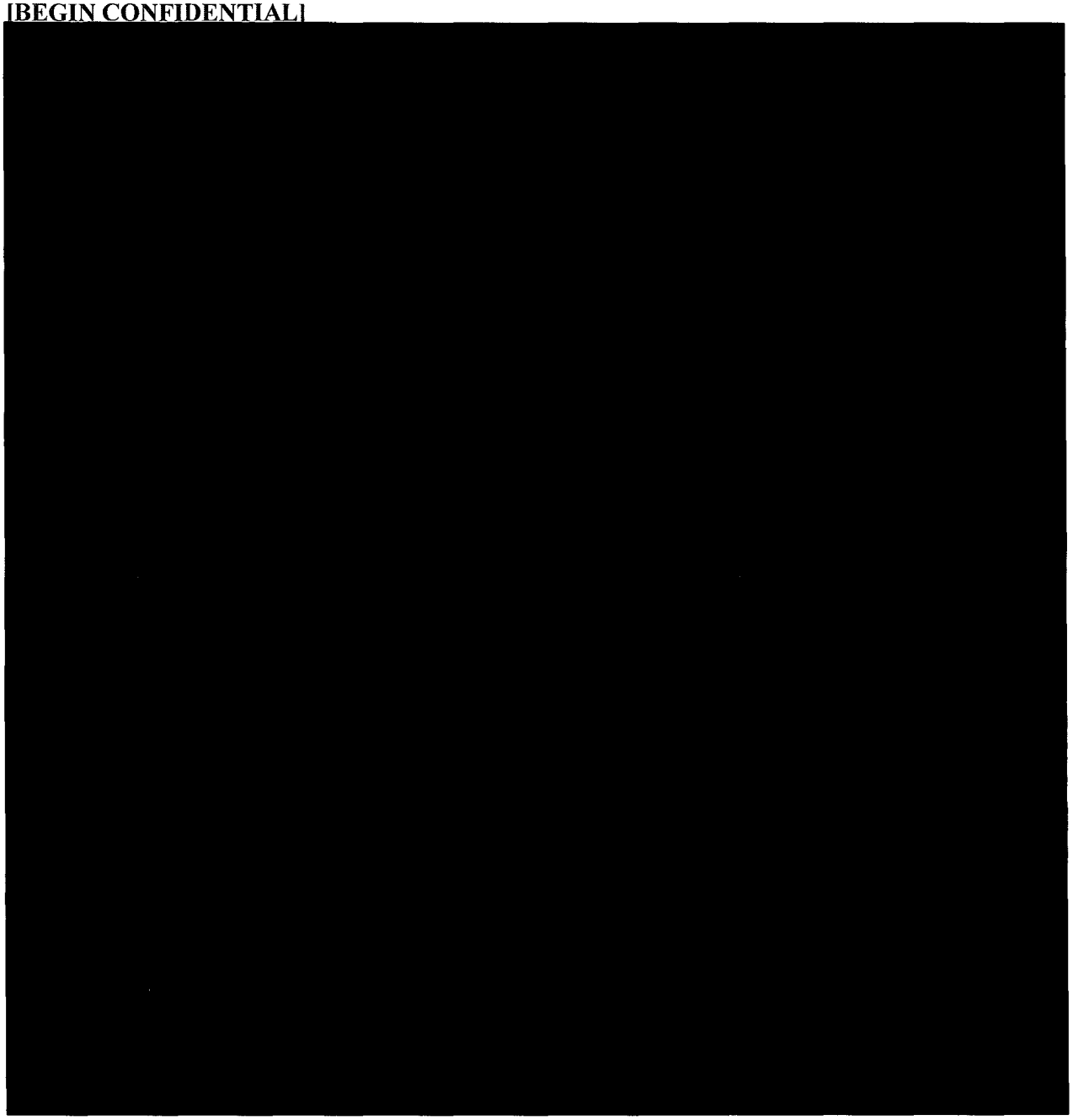
Table 5: Projected Annual Cost Caps and Fuel Related Cost Impact

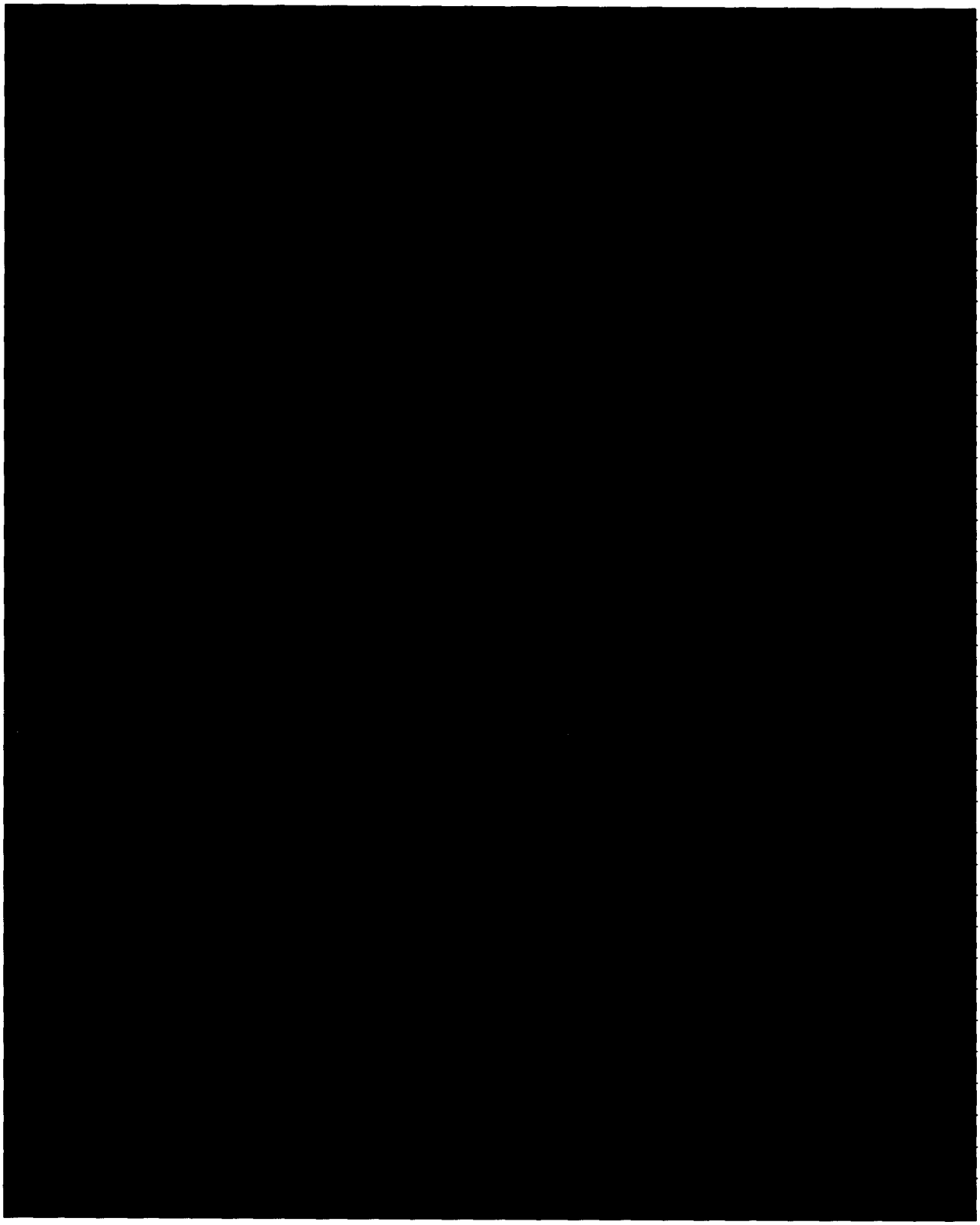
	2016	2017	2018
Total projected REPS compliance costs	$183,504,411	$221,520,983	$ 212,742,960
Recovered through the Fuel Rider	$150,132,764	$172,103,253	$ 163,127,444
Total incremental costs (REPS Rider)	$ 33,371,647	$ 49,417,730	$ 49,615,516
Total including Regulatory Fee	$ 33,418,433	$ 49,487,012	$ 49,685,075
Projected Annual Cost Caps (REPS Rider)	$ 71,367,582	$ 72,213,282	$ 73,066,326

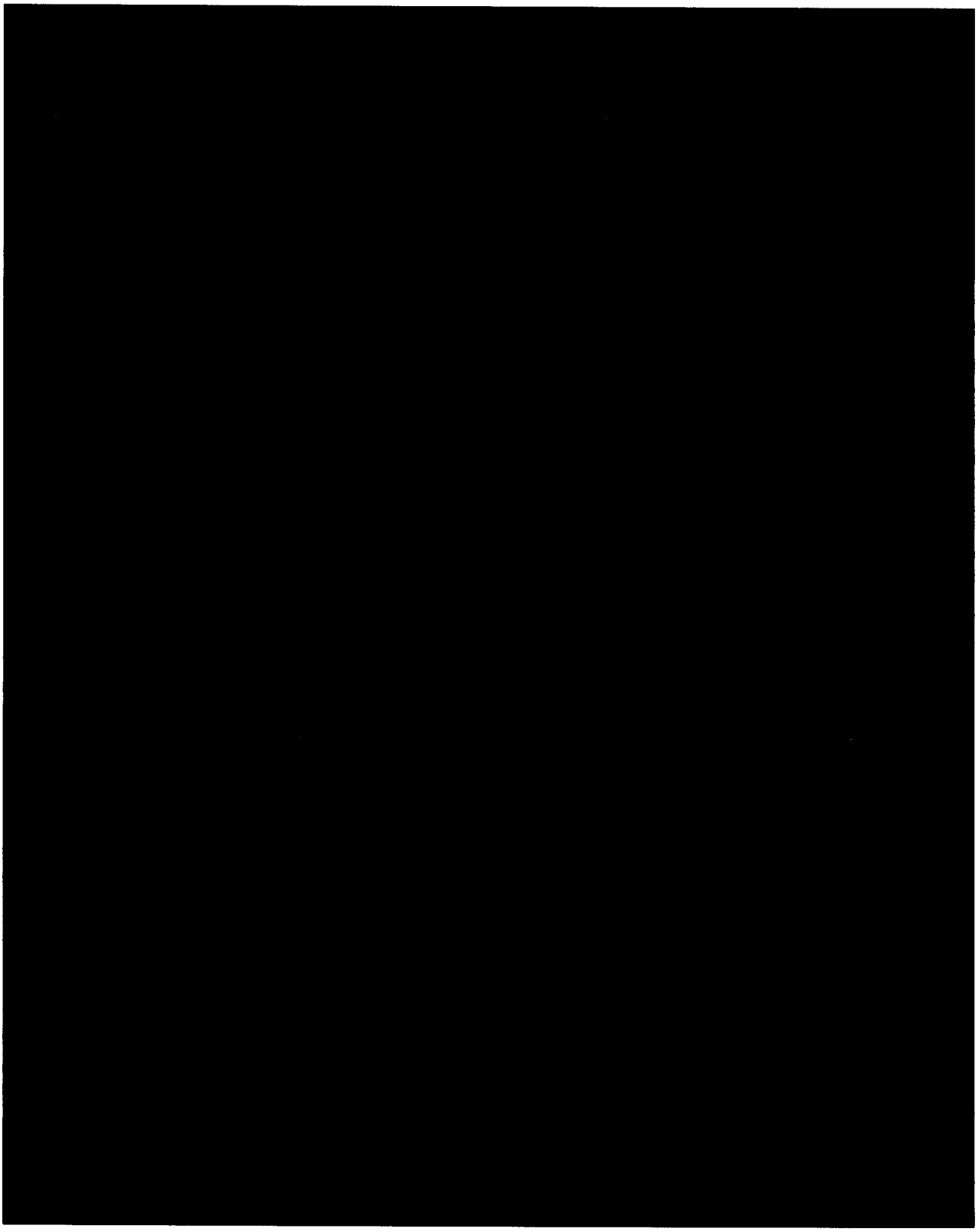
EXHIBIT A

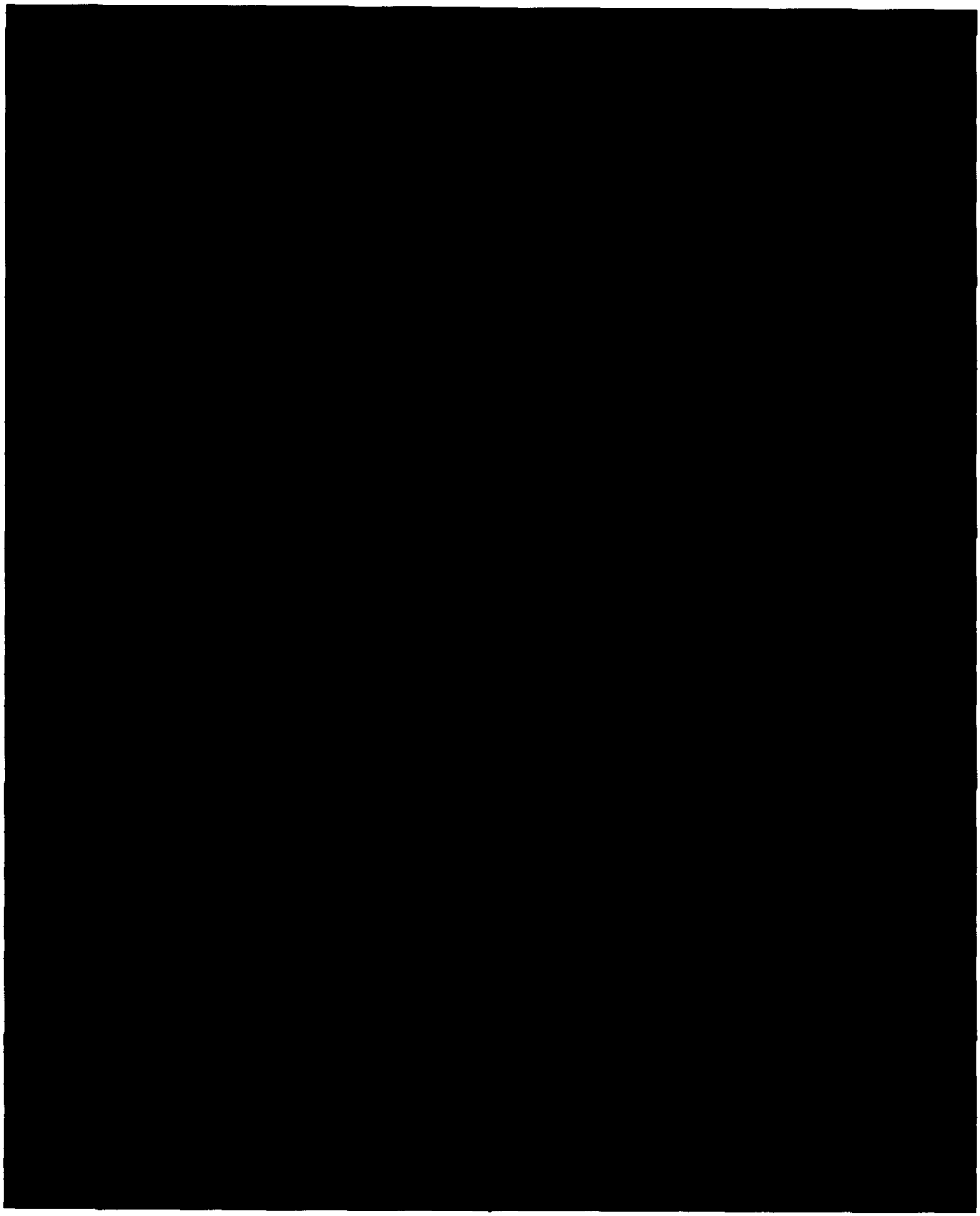
Duke Energy Progress, LLC's 2015 REPS Compliance Plan
Duke Energy Progress' Renewable Resource Procurement from 3rd Parties
(signed contracts as of June 30, 2016)

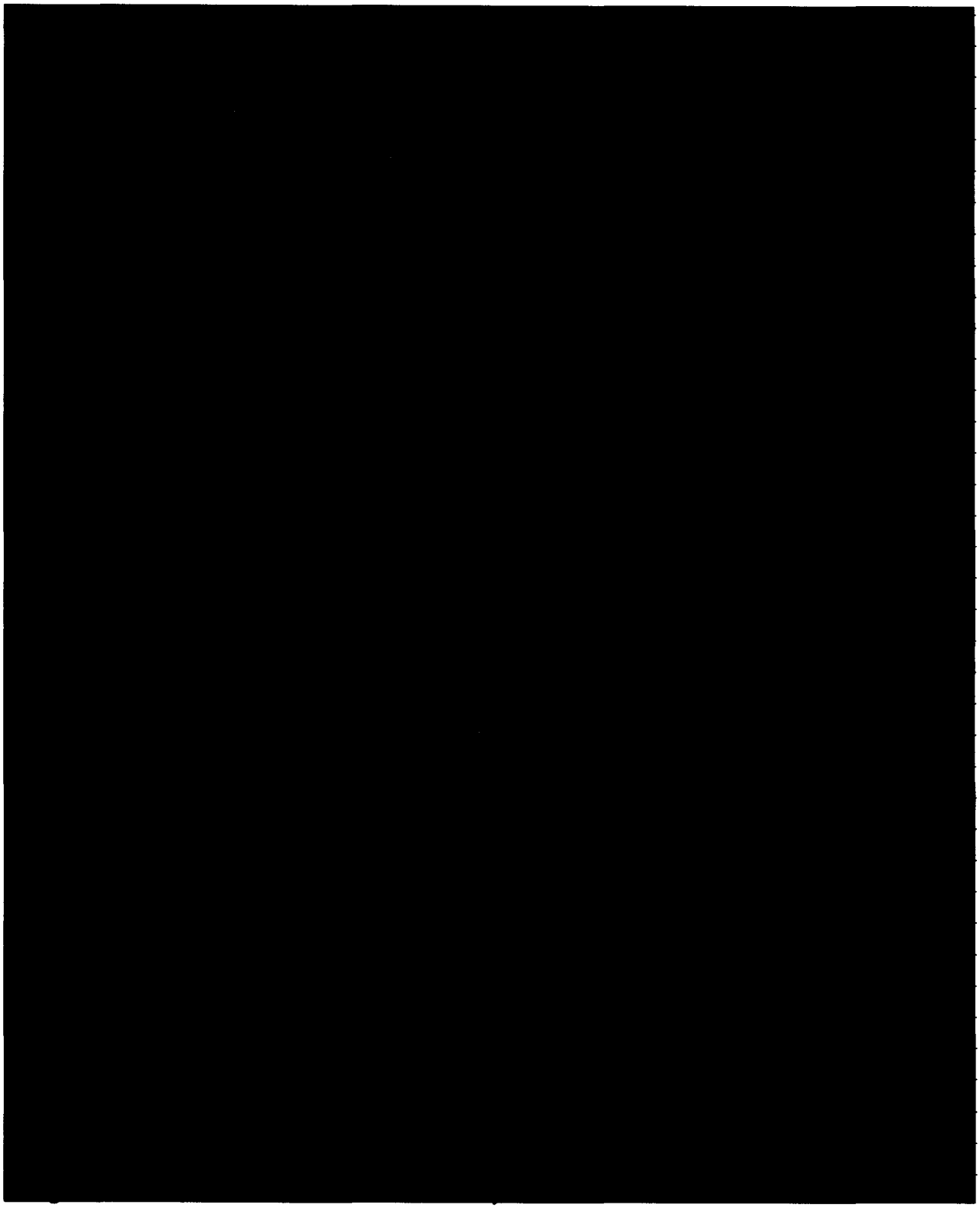
[BEGIN CONFIDENTIAL]

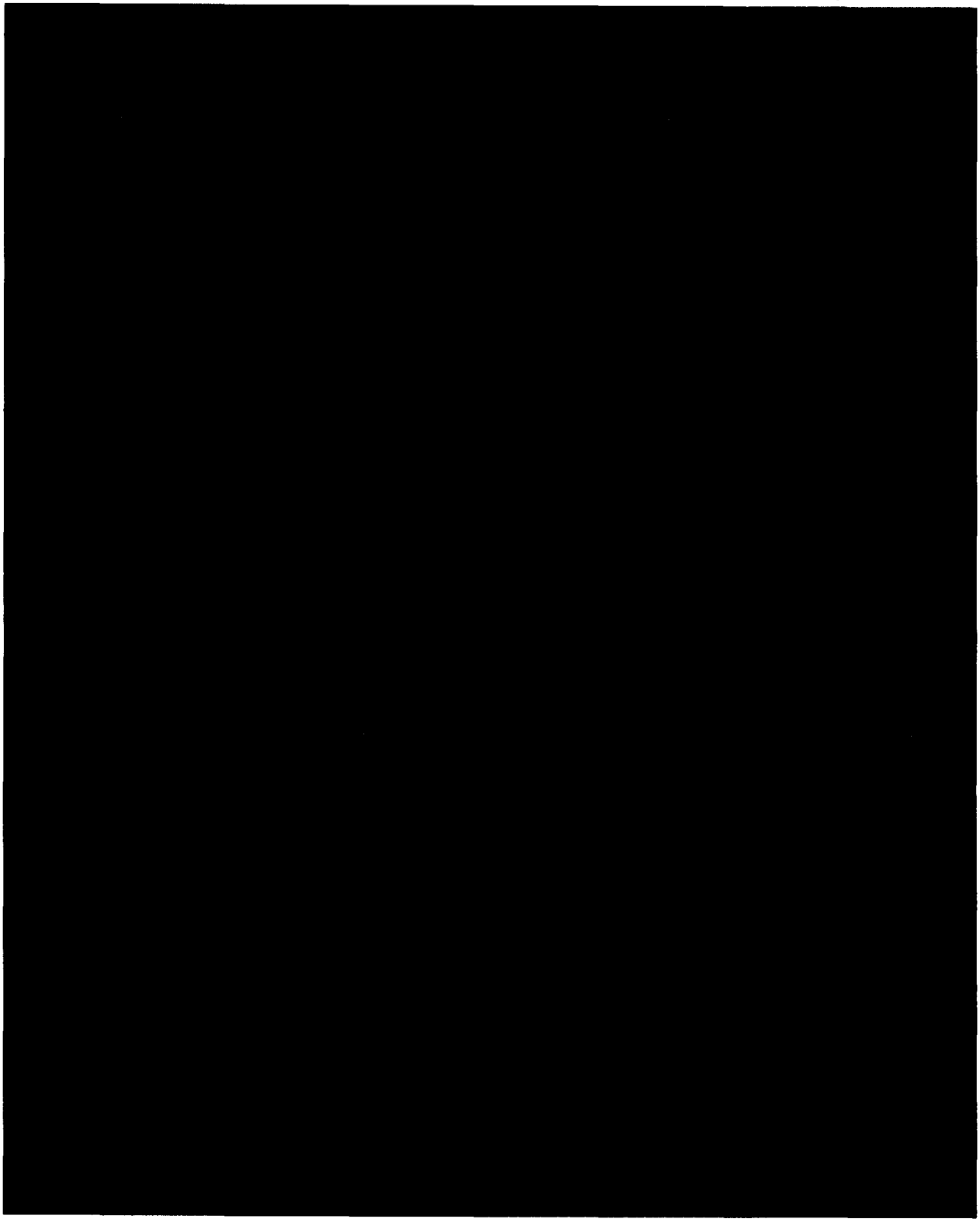


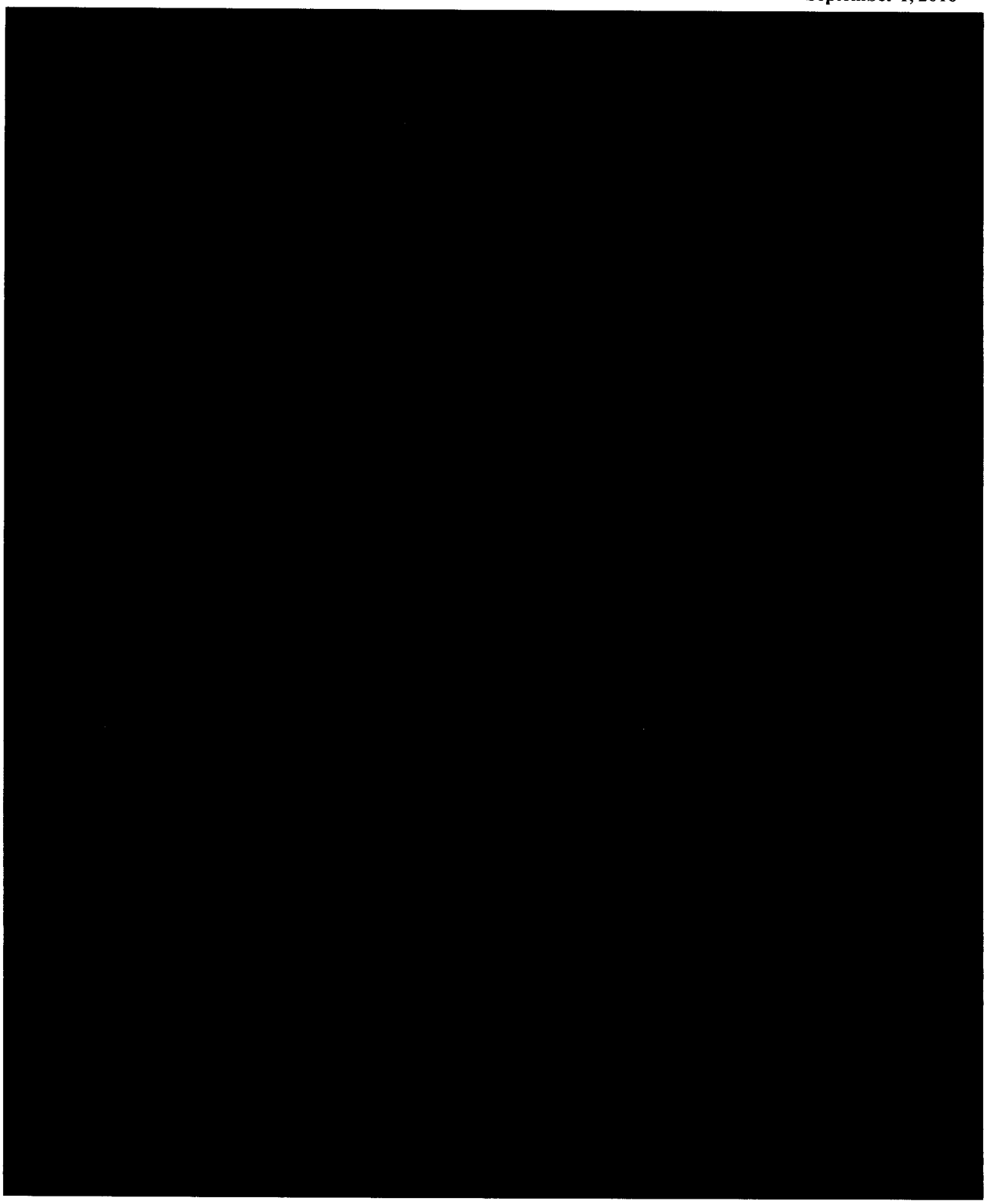


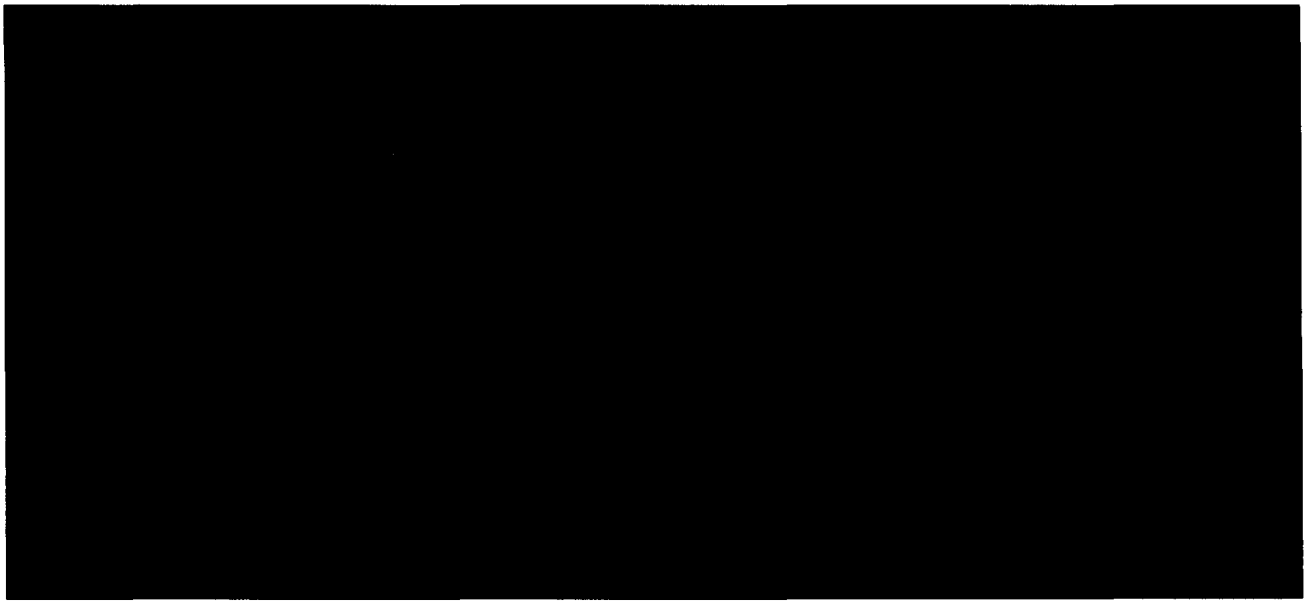












[END CONFIDENTIAL]

EXHIBIT B

Duke Energy Progress, LLC's 2015 REPS Compliance Plan
Duke Energy Progress, LLC's EE Programs and Projected REPS Impacts

Forecast Annual Energy Efficiency Impacts for the REPS Compliance Planning Period 2016-2018 (MWhs)

Residential Programs	**2016**	**2017**	**2018**
Appliance Recycling	-	-	-
HEIP	14,671	18,016	18,019
K-12	1,707	1,707	1,707
Multi Family	7,484	7,110	5,442
MyHER	7,364	(6,337)	0
Neighborhood Energy Saver	1,548	1,548	1,548
Residential Lighting	89,488	83,255	82,529
Residential New Construction	9,997	11,393	5,940
Sub Total	**132,259**	**116,692**	**115,185**
Non Residential Programs	**2016**	**2017**	**2018**
Business Energy Report	3,776	(272)	(251)
EEB	61,242	64,304	67,519
Non-Res Custom	14,548	15,038	15,546
Small Business Energy Saver	36,036	32,151	27,342
Sub Total	**115,602**	**111,221**	**110,156**
Total	**247,861**	**227,913**	**225,342**

Ann L. Warren
Associate General Counsel
Duke Energy Corporation
550 South Tryon Street
Charlotte, NC 28202
Phone: 704.382.2108
Ann.Warren@duke-energy.com

PUBLIC VERSION

April 1, 2016

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
Form No. 715
888 First Street, N. E.
Washington, DC 20426

Re: FERC Form No. 715

Dear Secretary Bose:

I am submitting the FERC Form No. 715, "Annual Transmission Planning and Evaluation Report," on behalf of Duke Energy Progress, LLC. Due to the critical energy infrastructure information (CEII) contained in Parts 2, 3, 4, 5 and 6 of the report, I am requesting that these sections be exempt from public disclosure, pursuant to 18 CFR § 388.112. Part 1 is enclosed for public disclosure, and Parts 2 through 6 are being filed confidentially as CEII documents.

You may contact the undersigned with questions regarding the privileged treatment of this report.

Very truly yours,

/s/

Ann L. Warren
Associate General Counsel

ALW/hms
Enclosures

ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT

April 1, 2016

Part 1: Identification and Certification

1. Transmitting Utility Name and Mailing Address:

   Duke Energy Progress, LLC
   P. O. Box 1551
   Raleigh NC 27602-1551

2. Contact Person:

   Name: **A. Mark Byrd**
   Title: **Manager, Transmission Planning**

   Telephone Number: **(919) 546-7937**
   Facsimile Number: **(919) 546-3321**

3. Certifying Official: I certify that the information provided herein is true and accurate to the best of my knowledge.

   Name: A. Mark Byrd
   Title: Manager, Transmission Planning
   E-mail: mark.byrd@duke-energy.com

   Signature: A. Mark Byrd Date: 3/29/16