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DUKE ENERGY®

June 12, 2017

VIA ELECTRONIC FILING

M. Lynn Jarvis
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Carolinas, LLC Application for Certificate of Public Convenience and Necessity – Lincoln County Combustion Turbine Project
Docket No. E-7, Sub 1134

Dear Ms. Jarvis:

Pursuant to N.C. Gen. Stat. §62-110.1 and Commission Rule R8-61(b), I enclose Duke Energy Carolinas, LLC's ("DEC") Application for Certificate of Public Convenience and Necessity to construct and operate the Lincoln County Combustion Turbine Project at the Lincoln Combustion Turbine Station in Lincoln County, along with the testimony and exhibits of Matthew R. Kalemba and Mark E. Landseidel (collectively the "Application"), for filing in connection with the referenced matter. Pursuant to N.C. Gen. Stat. §62-300(a)(5), DEC has submitted to the Clerk's Office a check for $250 to process this application.

Portions of the Application are being filed under seal, and DEC respectfully requests that they be treated confidentially pursuant to N.C. Gen. Stat. §132-1.2. Kalemba Confidential Exhibit 1A, the DEC 2016 IRP, contains confidential information that should be protected from public disclosure. Pages 144 through 147 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 158 and 159) contain information concerning DEC's wholesale contracts. Public disclosure of this information would harm DEC's and/or its counterparties' ability to negotiate in the wholesale market.

Portions of Kalemba Confidential Exhibit 1B, pages 11 and 12 of Mr. Kalemba's testimony, and Landseidel Confidential Exhibit 3 contain projected capital costs and operating expenses for the project. Portions of Landseidel Confidential Exhibit 4 contain information about the Engineering, Procurement and Construction ("EPC") agreement including the vendor's technology development and commercial arrangements, which are proprietary and commercially sensitive. Public disclosure of this confidential information would harm the vendor and is protected by a confidentiality provision in the EPC agreement. DEC will make the confidential information available to parties to this proceeding upon the execution of an appropriate confidentiality agreement.

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

Sincerely,

Lawrence B. Somers

Enclosures

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's Application for Certificate of Public Convenience and Necessity, in Docket No. E-7, Sub 1134, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to the following parties:

David Drooz
Public Staff
North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, NC 27699-4300
david.drooz@psncuc.nc.gov

This the 12th day of June, 2017.

By: ______________________

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1134

In the Matter of Application of Duke Energy Carolinas, LLC for Approval to Construct a 402 MW Natural Gas-Fired Combustion Turbine Electric Generating Facility in Lincoln County	)))))))	Duke Energy Carolinas, LLC's Application for Certificate of Public Convenience and Necessity

Pursuant to N.C. Gen. Stat. §62-110.1 and Commission Rule R8-61(b), Duke Energy Carolinas, LLC ("Duke Energy Carolinas," "DEC" or the "Company") submits this Application for a Certificate of Public Convenience and Necessity ("CPCN") to construct and operate a generating plant for the production of electric power and energy at its existing Lincoln County Combustion Turbine ("CT") site, located in Lincoln County, near Stanley, North Carolina. For the purposes of this document, the project will be referred to as the "Lincoln County CT Addition."

The Application is also supported by the testimony of Matthew R. Kalemba, Lead Planning Analyst in Integrated Resource Planning and Analytics - Carolinas, Duke Energy Carolinas; and Mark E. Landseidel, General Manager of Project Development for Duke Energy Corporation, and exhibits. Kalemba Confidential Exhibit 1A contains the 2016 Duke Energy Carolinas Integrated Resource Plan, and Kalemba Confidential Exhibit 1B contains the additional resource planning information required by Commission Rule R8-61(b)(1), and is made part of the Application. Landseidel Exhibit 2 (Siting and Permitting Information), Landseidel Confidential Exhibit 3 (Cost Information) and Landseidel Confidential Exhibit 4 (Construction Information) contain the detailed information required by Commission Rule R8-61(b) and are also incorporated as part of this Application. In further support of the Application, the Company respectfully submits the following:

GENERAL INFORMATION

1. Duke Energy Carolinas is a public utility engaged in the generation, transmission, distribution, and sale of electric energy in the central and western portions of North Carolina and the western portion of South Carolina.

2. Correspondence and communications with respect to this Application should be directed to the following:

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3. The Lincoln County CT Addition will consist of a new nominal 402 MW (winter rating) simple-cycle advanced combustion turbine natural gas-fueled electric generating unit, with fuel oil backup, and related transmission and natural gas pipeline interconnection facilities. This project will provide peaking generating capacity to the Duke Energy Carolinas system. The plant will be the first Siemens advanced-class series test and validation CT unit. The plant is scheduled to begin generating electricity for the benefit of DEC customers in 2020 during an extended commissioning and testing period,

and DEC will take care, custody and control of the unit and begin commercial operation in late 2024. The Company has sixteen existing CTs at the Lincoln County CT site totaling 1,488 MW (winter rating), which provide peaking generation to the Company's customers. The Lincoln County CT Addition will be sited adjacent to the existing CT units.

4. Siemens will manufacture this and future new advanced-class turbines (for U.S. and other 60 Hz markets) at its Charlotte gas turbine and generator facility, thereby providing DEC and the Lincoln County CT Addition with the opportunity to directly enhance economic development in North Carolina and South Carolina. Siemens currently employs approximately 1,700 people in the Charlotte area, and the development of the new advanced-class product line to be enabled by the Lincoln County CT Addition will provide future production work for the Charlotte manufacturing facility.

TECHNOLOGY AND SCHEDULE

5. The simple-cycle generating facility will use a Siemens advanced-class series CT generator to produce electricity. This CT will be designed to compete with other advanced-class "H/J" series CT's being introduced into the market by GE and Mitsubishi. These advanced-class turbines will provide higher efficiency and faster ramp rates than existing large frame gas turbines.

6. Construction would begin in mid 2018, and Siemens will bring the unit online in a series of three versions as part of the comprehensive testing and validation process. Version A will have a nominal winter rating of 369 MW and will begin testing and validation in 2020. Version B will have a nominal winter rating of 382 MW and begin testing and validation in the second quarter of 2022. The final commercial

operation version C will have a nominal winter rating of 402 MW and begin testing and validation in 2023, with Duke Energy Carolinas taking care, custody and control of the unit in late 2024. During the approximately four-year extended testing and validation period, Siemens will determine the timing and nature of operation of the unit; however, Duke Energy Carolinas will receive the capacity at no cost and the energy delivered to the Duke Energy Carolinas grid at only the variable cost of the fuel. Furthermore, Siemens will pay for any inefficient fuel use to the extent the unit is run out of economic merit order.

TRANSMISSION AND FUEL SUPPLY

7. As part of the Lincoln County CT Addition, the existing 230 kV Lincoln County CT substation will be expanded, and the new unit will be connected to the existing substation by a single new 230 kV transmission line of approximately 1,200 feet in length and connected to an expanded 230 kV switchyard. All of the new transmission facilities will be located on existing Duke Energy Carolinas property at the Lincoln County CT site.

8. The Lincoln County CT Addition will operate on natural gas which will be provided by the existing Piedmont Natural Gas pipeline that supplies the existing CT units at the site. The new unit will also have the ability to operate on ultra-low sulfur diesel (fuel oil) for testing and as an emergency backup, should there be a physical interruption in natural gas delivery to the facility, or should there be a temporary spike in the market price of natural gas that makes fuel oil more economic. The existing fuel oil system which serves the existing simple-cycle units, will be expanded to include an additional tank which will be dedicated to the new unit during the testing and

commissioning phase of the project and, prior to commercial operation, will be integrated with the existing fuel oil storage tanks.

ENVIRONMENTAL

9. Operation of the proposed facility will result in the emission of certain pollutants that are regulated by the U.S. Environmental Protection Agency and the State of North Carolina. Operating impacts from these pollutants will be addressed through the North Carolina Division of Air Quality ("DAQ") air quality permit application process. In June 2017, Duke Energy Carolinas plans to submit a permit application to DAQ requesting a permit to authorize construction and operation of the CT units and associated ancillary systems. The application will include all required modeling and analysis to demonstrate compliance with regulatory requirements and air quality standards. The new unit will be designed to control emissions via combustion controls as well as dilution Selective Catalytic Reduction ("SCR") and Carbon Monoxide ("CO") Catalyst to Best Available Control Technology ("BACT"); however, due to the size and efficiency of the unit and expected hours of operations, the application is expected to trigger New Source Review ("NSR") under the Prevention of Significant Deterioration ("PSD") program requirements. Duke Energy Carolinas anticipates that a final air permit should be issued within twelve months of submitting the application. Continuous emission monitoring systems ("CEMS") will be installed on the turbine's exhaust stack.

10. The site has a Publicly Owned Treatment Works ("POTW") permit with Lincoln County Public Works. Preliminary operating plans include installation of an oil/water separator for treatment of all potential oily waste streams and discharge to the POTW. Other liquid waste streams, such as gas turbine wash wastewater, will be

pumped to tank trucks and hauled off-site for treatment. The following permits may be required in addition to those described above: North Carolina Oil Terminal Registration, Department of Environmental Quality ("DEQ") and Lincoln County Storm Water permits, Division of Energy, Mineral and Land Resources ("DEMLR") Erosion and Sedimentation Control permit, Lincoln County Building permit, and Lincoln County Occupancy permit.

NEED AND COST

11. As explained in the testimony of Matthew R. Kalemba filed with this Application, the need for the Lincoln County CT Addition is demonstrated in the Duke Energy Carolinas 2016 Integrated Resource Plan ("IRP") filed with the Commission on September 1, 2016,[1] in Docket No. E-100, Sub 147. The 2016 IRP incorporates a 15-year load forecast, purchased power contracts, existing generation, energy efficiency and demand-side management, new resource additions, and a minimum target planning reserve margin of 17.0%. The comprehensive planning process for the 2016 IRP demonstrates that a combination of renewable resources; energy efficiency and demand-side management programs; and additional baseload, intermediate, and peaking generation are required over the next fifteen years to reliably meet customer demand. After accounting for increased energy efficiency impacts, Duke Energy Carolinas' Spring 2016 forecast shows average annual growth in summer peak demand of 1.2 percent, winter peak demand growth of 1.3 percent, and the average territorial energy growth rate of 1.0 percent.

[1] Administrative corrections to the 2016 DEC IRP were filed on September 30, 2016. That version is being filed with the Application.

12. From a total system perspective, the Duke Energy Carolinas 2016 IRP identifies the need for an additional 1,689 MW of new resources to meet customers' energy needs by 2025 and 3,923 MW by 2031. The Company's IRP planning process includes both quantitative analysis and qualitative considerations. Company management uses all of the perspectives and analyses from the IRP process to ensure that Duke Energy Carolinas will meet short-term and long-term customer needs, while maintaining prudent flexibility.

13. The Duke Energy Carolinas 2016 IRP includes the need for 468 MW of CT capacity in the winter of 2024/2025, which will be substantially met by the Lincoln County CT Addition. Although the Lincoln County CT Addition will begin providing energy for the benefit of Duke Energy Carolinas customers in 2020 during extended testing and validation, Duke Energy Carolinas will not seek to include the costs of the unit in base rates until after the Company assumes care, custody and control of the unit in 2024.

14. As explained in greater detail in the testimony of Mr. Kalemba, the technology selected for the Lincoln County CT Addition will provide enhanced reliability, low turn down, fast ramp, and efficient dispatch for the Duke Energy Carolinas system. The Lincoln County CT Addition will be the most efficient combustion turbine in the Duke Energy Carolinas generation fleet and will be available for economic dispatch with an estimated average capacity factor of 16%.

15. As of December 31, 2016, approximately 500 MW (nameplate) of compliance and non-compliance intermittent renewable generation was interconnected to the Duke Energy Carolinas system. The Duke Energy Carolinas 2016 IRP projects that a

total of approximately 1,800 MW (nameplate) of rated compliance and non-compliance renewable energy resources will be interconnected to the Company's system by 2025, with that figure growing to approximately 2,200 MW (nameplate) by 2031. The load following capability of the Lincoln County CT Addition provides additional system flexibility to help accommodate the impacts resulting from the increasing amounts of intermittent resources being added to the Duke Energy Carolinas system.

16. As explained in more detail in Mr. Kalemba's testimony, Duke Energy Carolinas evaluated the existing wholesale market for alternatives and ascertained that no other advanced frame CTs are currently in service in the Company's balancing authority area. As explained in Mr. Landseidel's testimony, with respect to new construction, Siemens has offered a significant discount compared to market alternatives for the engineering, procurement and construction ("EPC") contractor services including supply of the combustion turbine, as well as technology risk and cost mitigation protections.

17. The projected cost of the Lincoln County CT Addition is confidential and is being filed under seal in Landseidel Confidential Exhibit 3 to the attached Testimony of Mark E. Landseidel. Duke Energy Carolinas requests that this cost information be considered confidential information pursuant to N.C. Gen. Stat. §132-1.2, and that the Commission prohibit the public disclosure of this information. Duke Energy Carolinas will make the information available to intervening parties upon the execution of an appropriate confidentiality agreement.

18. The proposed Lincoln County CT Addition is necessary in order for Duke Energy Carolinas to reliably meet its electric service obligations and is the most cost-effective resource available to serve the Company's North Carolina and South Carolina

customers. Therefore, Duke Energy Carolinas requests that the Commission grant a Certificate of Public Convenience and Necessity authorizing the Company to construct and operate a 402 MW combustion turbine unit at its existing Lincoln County CT site, as set forth herein.

WHEREFORE, Duke Energy Carolinas respectfully requests that the Commission issue a Certificate pursuant to N.C. Gen. Stat. §62-110.1 that the public convenience and necessity require construction of the Lincoln County CT Addition, and requests such further relief as the Commission deems just and proper.

Respectfully submitted this 12th day of June, 2017.

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ATTORNEYS FOR DUKE ENERGY CAROLINAS, LLC

VERIFICATION

STATE OF NORTH CAROLINA)
) DOCKET NO. E-7, SUB 1134
COUNTY OF MECKLENBURG)

Mark E. Landseidel, being first duly sworn, deposes and says:

That he is General Manager of Project Development in the Project Management and Construction Department of Duke Energy Corporation; that he has read the foregoing Application and Exhibits and knows the contents thereof; that the same is true except as to the matters stated therein on information and belief; and as to those matters, he believes them to be true.

Mark E. Landseidel

Sworn to and subscribed before me
this 7th day of June, 2017.

Notary Public

My Commission expires: 7-31-17

THOMAS J. REED-HALL
NOTARY
PUBLIC
GASTON COUNTY, NC

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1134

In the Matter of Application of Duke Energy Carolinas, LLC for Approval to Construct a 400 MW Natural Gas-Fired Combustion Turbine Electric Generating Facility in Lincoln County	))))))))	DIRECT TESTIMONY OF MATTHEW R. KALEMBA FOR DUKE ENERGY CAROLINAS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew R. Kalemba. My business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am currently employed by Duke Energy Carolinas, LLC as Lead Planning Analyst.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES IN YOUR POSITION WITH DUKE ENERGY.

A. I am responsible for contributing to the development of the Integrated Resource Plans ("IRPs") for both Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP"), collectively referred to as the Utilities ("Utilities") or the Companies ("Companies"). In addition to the production of the IRPs, I have responsibility for performing the analytic functions related to resource planning for the Carolinas region. Examples of such analytic functions include unit retirement analysis, the analytical support for applications for certificates of public convenience and necessity ("CPCN") for new generation, and analysis required to support the Utilities' avoided cost calculations that are used in the biennial avoided cost rate proceedings.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. My educational background includes a Bachelor of Science degree in Chemical Engineering from North Carolina State University and a Master of Business Administration from Lake Forest Graduate School of Management in Lake Forest, Illinois. With respect to professional experience, I joined Duke Energy in 2014 in my current position as Lead Planning Analyst. Prior to joining the utility industry, I worked in the petroleum refining industry for 14 years where I held positions in process engineering, supply chain, production and economics planning, and refinery configuration and optimization.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe the need for the proposed construction of the 402 MW Lincoln County Combustion Turbine Project, which I will refer to as the "Lincoln County CT Project" or simply as the "Project." In addition, my testimony will address how Duke Energy Carolinas' most recent biennial Integrated Resource Plan ("IRP") supports the development of the Project as required by North Carolina Utilities Commission Rule R8-61(b)(1).

Q. I SHOW YOU WHAT HAS BEEN MARKED AS KALEMBA EXHIBIT 1A AND KALEMBA EXHIBIT 1B. WOULD YOU PLEASE TELL US

WHAT THESE DOCUMENTS ARE?

A. Yes. Kalemba Exhibit 1A is a copy of the 2016 Duke Energy Carolinas IRP filed September 1, 2016[1] in Commission Docket No. E-100, Sub 147. Kalemba Exhibit 1B contains the additional resource planning information required by Commission Rule R8-61(b)(1). I was a contributor to the preparation of Kalemba Exhibit 1A, and I prepared Kalemba Exhibit 1B.

Q. WHY DID DUKE ENERGY CAROLINAS FILE THIS APPLICATION WITH THE COMMISSION?

A. The Duke Energy Carolinas 2016 IRP identifies the need for an additional 1,689 MW (winter rating) of new resources to meet customers' energy needs by 2025 and 3,923 MW by 2031. The Duke Energy Carolinas 2016 IRP includes the need for 468 MW of CT capacity in the winter of 2024/2025, which will be met by the Lincoln County CT Addition. As is also discussed in greater detail in my testimony below, the Lincoln County CT Project is a key component of Duke Energy Carolinas' portfolio approach to provide reliable, diverse and flexible resources to meet our customers' needs.

Q. PLEASE PROVIDE AN OVERVIEW OF THE INTEGRATED RESOURCE PLANNING PROCESS FOR THE DUKE ENERGY CAROLINAS 2016 IRP.

A. The IRP process seeks to achieve a resource plan that ensures future power reliability at the lowest reasonable cost to consumers while also improving the

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[1] Administrative corrections to the 2016 DEC IRP were filed on September 30, 2016. That version is being filed herein.

environmental footprint of the generation fleet in the Carolinas. The development of the IRP is a multi-step process involving the development of input data, detailed modeling and analysis, and quantitative and qualitative considerations to develop a selected plan. The development of input data includes determining planning inputs and assumptions, preparing a load forecast, identifying cost-effective energy efficiency ("EE") and demand side management ("DSM") options, developing a renewable energy plan, and identifying and economically screening appropriate supply-side resource options. The detailed modeling and analysis step includes integrating the EE, renewable, fossil and nuclear supply-side options with the existing system and electric load forecast to develop potential resource portfolios to meet the desired reserve margin criteria. Performing detailed modeling of potential resource portfolios determines the resource portfolio that exhibits the lowest cost (lowest net present value of revenue requirements) to customers in an effort to minimize price impacts to customers while ensuring long-term reliability of power supply. The quantitative and qualitative considerations include factors such as fuel diversity, the environmental footprint, system flexibility, and cost impacts of selected plans. In addition, scenarios are considered that examine how a plan performs under changing assumptions such as variations in the level of EE and renewables, differing commodity prices, construction costs and potential for future CO_2 prices.

Q. GIVEN THE ANALYSIS CONDUCTED WITH THESE CONSIDERATIONS IN MIND, WHAT WERE THE CONCLUSIONS OF THE 2016 IRP?

A. The 2016 IRP incorporates a 15-year load forecast, purchase power contracts, existing generation, energy efficiency and demand-side management, new resource additions, and a minimum target planning reserve margin of 17.0%. The comprehensive planning process for the 2016 IRP demonstrates that a combination of renewable resources; energy efficiency and demand-side management programs; and additional baseload, intermediate, and peaking generation are required over the next 15 years to reliably meet customer demand. After accounting for increased energy efficiency impacts, Duke Energy Carolinas' Spring 2016 forecast shows average annual growth in summer peak demand of 1.2 percent, winter peak demand growth of 1.3 percent, and the average territorial energy growth rate of 1.0 percent.

The 2016 IRP examined future resource plans under scenarios that did, and did not, include future carbon prices. Under the no carbon Base Case, which consisted of no CO_2 emission costs and no new nuclear generation, the portfolio consisting of 142 MW (2,202 MW nameplate) of compliance and non-compliance renewable generation, 1,221 MW of new natural gas combined cycle capacity, 2,808 MW of new natural gas CT capacity (including the Lincoln County CT Project), 85 MW of nuclear uprates capacity, 669 MW of demand-side management, and 461 MW of energy efficiency was selected over the planning horizon.

Q. WHAT ARE THE KEY IRP ANALYSES INPUTS?

A. Key IRP analyses inputs include: load forecast; planning reserve margin; information on existing resources, including planned retirements and availability; renewable energy mandates and projections; cost and impacts of EE and DSM options; costs and unit characteristics of new resource options; and projected prices for fuel and emission allowances.

Q. PLEASE DISCUSS THE PLANNING RESERVE MARGIN.

A. The 2016 DEC IRP analysis utilized a minimum planning reserve margin of 17.0% based on new resource adequacy studies that DEC and DEP commissioned and that were finalized in 2016. Three main drivers led to the commissioning of these studies including: 1) the high penetration of solar resources that have been connected to the Utilities' transmission and distribution systems in the past two to three years; 2) the high volume of solar resources currently in the Utilities' interconnection queues; and 3) the significant load response to cold weather that was experienced during the 2014 and 2015 winter periods.

Q. WHAT IS THE LOAD FORECAST PROJECTION?

A. The Duke Energy Carolinas Spring 2016 15-year forecast of the needs of the retail and wholesale customer classes, after accounting for increased energy efficiency impacts, shows average annual growth in summer peak demand of 1.2 percent, winter peak demand growth of 1.3 percent, and the average territorial energy growth rate of 1.0 percent. Duke Energy Carolinas' total retail load growth over the planning horizon, 2017-2031, is driven by projected steady increases in the Residential class, 1.2%, and Commercial class, 1.3%, with the

Industrial class growing at 0.9%. In addition to customer growth, plant retirements and expiring purchased power contracts create the need to add incremental resources to allow the Company to meet future customer demand.

Q. WHAT IMPACT DO PLANNED PLANT RETIREMENTS HAVE ON THE NEED FOR THE LINCOLN COUNTY CT PROJECT?

A. As reflected in the 2016 DEC IRP, over the last several years, aging, less efficient coal plants have been replaced with a combination of renewable energy, EE, DSM, and state-of-the-art natural gas generation facilities. Additionally, DEC plans to retire the 1,161 MW Allen Steam Station with Units 1-3 scheduled to retire by December 2024 and Units 4 and 5 in 2028. The combination of load growth and these planned retirements contribute to the need for the Lincoln County CT Project.

Q. HOW WERE PRICES OF FUELS AND EMISSION ALLOWANCES DEVELOPED?

A. Fuel prices represent a composite forecast which utilizes forward market prices in the near term where liquid market quotes are available and a comprehensive fundamental outlook for long-term commodity prices in the absence of liquid market prices. Fuel prices are derived from detailed supply models which balance the demand for these fuels, both domestic and global, with the available North American supply. The future SO_2 and NO_x emission allowance prices were derived from forward market quotes as of March 2016.

Q. IN PARTICULAR, HOW IS THE PRICE OF GAS CONSIDERED WITHIN THE COMPANY'S RESOURCE PLANNING PROCESS?

A. The Company's projection of natural gas prices is an input to the resource planning process. The natural gas price projection represents a combination of market prices and fundamental price projections. The first ten years of natural gas prices are market prices followed by a five-year blend of market and long-term fundamental prices.

Q. NATURAL GAS PRICES ARE CURRENTLY LOW COMPARED TO JUST A FEW YEARS AGO. WHAT HAPPENS IF GAS PRICES RISE CONSIDERABLY IN THE NEAR OR LONG TERM?

A. The new Lincoln County CT will be constructed with dual fuel capability to operate on both natural gas and ultra-low sulfur diesel fuel ("fuel oil"). The Company currently has a firm, long-term Gas Redelivery Agreement with the intrastate pipeline supplier, Piedmont Natural Gas Company, Inc. ("Piedmont"); however, the Company does not plan to procure firm interstate natural gas supply for the CT. Under this arrangement, there is expected to be sufficient natural gas supply to operate the Lincoln County CT Project during all months; however, given the nature of the interstate pipeline, the Lincoln County site is subject to potential natural gas price spikes during extreme temperature events during the winter months. Under this scenario, there may be times where it may be more economical to temporarily operate the unit on fuel oil.

While the IRP itself seeks a balanced portfolio that performs well under multiple fuel price sensitivities, the system capacity and ancillary support that is provided by the new Lincoln County CT is capacity-oriented peaking capability that is expected to run less frequently than intermediate or baseload units. As a result, gas prices have less of an impact on this technology compared to a gas-fired combined cycle that would serve baseload energy needs on the system.

Q. SPECIFICALLY, WHAT DID THE 2016 IRP CONCLUDE AS TO NEED FOR AND TIMING OF NEW GAS-FIRED RESOURCES IN THE 2024/2025 TIMEFRAME?

A. The 2016 planning process revealed the need for peaking gas-fired generation by the winter of 2024/2025 timeframe. The resource options available to meet customer capacity and energy needs include natural gas-fired resources, nuclear, renewable resources, and EE/DSM resources. While a broad mix of these resources is included in the overall plan, the qualitative and quantitative analyses indicate that simple-cycle combustion turbine capacity is the most viable alternative for the 2024 need.

Q. HOW WERE DSM AND EE PROGRAMS ANALYZED WITHIN THE COMPANY'S RESOURCE PLANNING PROCESS?

A. For IRP purposes, 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. DEC also offers a variety of DSM (or demand response) programs that signal customers to reduce electricity use during select peak hours specified by the Company. The IRP treats these "dispatchable" types of programs as a resource option that can be dispatched to meet system capacity needs during periods of peak demand.

To better understand the long-term EE savings potential, DEC commissioned a market potential study by Forefront Economics, Inc. in 2012 that estimated the achievable potential for EE on an annual basis over a 20-year forecast period. The base case EE/DSM savings contained in this IRP were projected by blending near-term program by program planning forecasts into the long-term achievable potential projections from the market potential study. This represents the Company's projection, and commitment, to achieve cost-effective EE and DSM over the planning horizon.

Q. HOW WERE RENEWABLE ENERGY RESOURCES ANALYZED WITHIN THE COMPANY'S RESOURCE PLANNING PROCESS?

A. A portfolio of renewable energy resources is included in the Company's resource plan to reflect renewable compliance obligations, such as the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard ("NC REPS"); and customer product offerings like the Green Source Rider and the South Carolina Distributed Energy Resource Program ("SC DER"). The IRP also includes a projection of renewable resources that will result from Public Utilities Regulatory Policy Act ("PURPA") qualifying facilities ("QFs). This portfolio assumes solar capacity increases from 735 MW in 2017 to 2,168 MW in 2031 (nameplate). Additionally, compliance with NC REPS continues to be met through a combination of solar, other renewables, EE, and REC purchases. Finally, as part of the increase in solar capacity, achievement of the SC DER goal of 120 MW of solar capacity located in the DEC-South Carolina territory was also included in the 2016 IRP.

Q. WHY DIDN'T DUKE ENERGY CAROLINAS SELECT EE, DSM, OR RENEWABLES TO FULFILL THE NEEDS TO BE MET BY THE LINCOLN COUNTY CT PROJECT?

A. With respect to solar, EE and DSM, only DSM (demand response) programs are truly dispatchable. Furthermore, as previously discussed, the Company has already included its estimate of cost-effective EE/DSM and has identified the 2024 need as an incremental need in addition to its investment in EE and DSM. Further, the proposed Lincoln County CT Project will satisfy a critical resource need that provides not only peaking capacity, but also provides generation ancillary service benefits that are becoming increasingly important as more non-dispatchable and intermittent renewable generation is added to the DEC system. As a result, the Lincoln County CT Project helps to provide additional system flexibility required to enable the integration of intermittent renewable resources into the generation portfolio.

Q. IN LIGHT OF THE COMPANY'S ANALYSIS, WHY DID DUKE ENERGY CAROLINAS SELECT THE SIEMENS ADVANCED-CLASS COMBUSTION TURBINE ADDITIONS FOR THE LINCOLN COUNTY CT PROJECT INSTEAD OF OTHER ALTERNATIVES?

A. There are several quantitative reasons Duke Energy Carolinas concluded that the Lincoln County CT Project is the best resource addition for our customers' benefit. First, the Lincoln County CT Project is being offered to the Company at a significant discount to similar advanced technology CTs available in the marketplace. In comparison to other advanced-class technologies, the Utility is receiving an approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END**

CONFIDENTIAL] % total project cost savings. Additionally, in comparison to the less advanced, less efficient F-class CTs, the Utility is receiving an approximate **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** % total project cost savings.

Second, the Utility will not take care, custody, and control of the CT until the fourth quarter of 2024. As such, the Company will not seek to recover the capital costs of the CT in rates until after assuming care, custody and control in 2024; however, the Utilities' customers will benefit from the energy generated by the CT during its extended commissioning period that begins in the third quarter of 2020. As explained in Witness Landseidel's testimony, during the approximately four-year extended testing and validation period, Siemens will determine the timing and nature of operation of the unit; however, DEC will receive the energy delivered to the Company's grid at only the variable cost of the fuel. Furthermore, Siemens will pay for any inefficient fuel use to the extent the unit is run out of economic merit order during this period.

Third, the Lincoln County CT is approximately 6% more fuel efficient than current F-Class options, and is comparable to other suppliers' advanced class gas turbines. As such, the new unit would be DEC's most efficient peaking unit and will be available for economic dispatch with an estimated capacity factor of 16%.

Finally, major maintenance costs associated with the Lincoln County CT Project are deferred until the Company takes care, custody, and control of the unit in late 2024. The long-term major maintenance costs that become DEC's responsibility in 2024 are covered by a long-term service agreement ("LTSA") whose terms are being provided at a significant discount to those associated with the less advanced F-Class CT technologies. A detailed discussion of this topic is contained in Kalemba Exhibit 1B.

Q. WHAT OTHER BENEFITS WILL THE LINCOLN COUNTY CT ADDITION PROVIDE TO THE DEC GENERATION SYSTEM?

A. The technology selected for the Lincoln County CT Project will provide enhanced reliability, low turn down, fast ramp and efficient dispatch for the Duke Energy Carolinas system. As discussed earlier in my testimony, Duke Energy Carolinas currently has approximately 735 MW (nameplate) of compliance and non-compliance intermittent renewable generation interconnected to its system. The Duke Energy Carolinas 2016 IRP projects that a total of approximately 2,168 MW (nameplate) of rated compliance and non-compliance renewable energy resources will be interconnected to the Company's system by 2031. These resources help the Company comply with renewable energy mandates and provide important energy benefits to DEC's customers; however, the inherent intermittency of these resources does not allow the capacity to be dispatched or contribute to reliability in the same manner as a traditional resource such as a combustion turbine. Thus, the load following capability of the Lincoln County CT Project provides additional system flexibility, and reliability, to help accommodate the impacts resulting from the increasing amounts of intermittent resources being added to the Duke Energy Carolinas system.

In addition to these operational benefits, the selection of the Siemen's technology for this application helps to support economic development in North

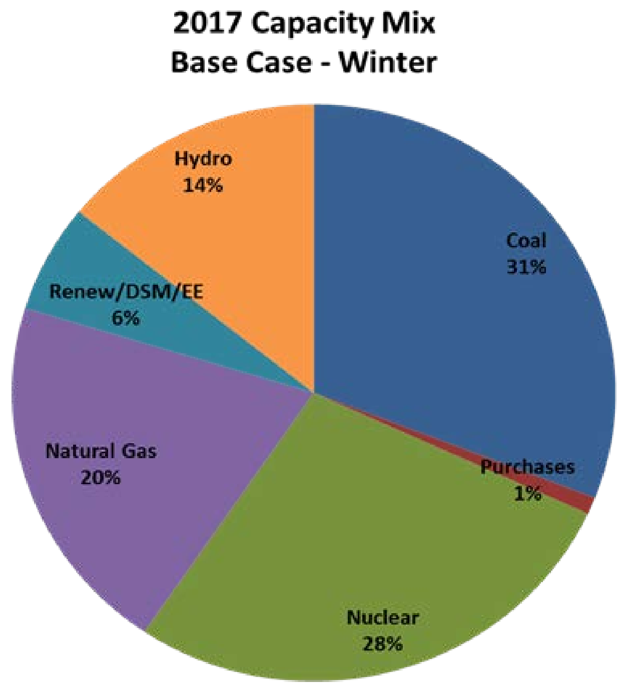
Carolina as both the plant and the manufacturing facility for the major components of the CT are located in North Carolina. With approximately 1,700 people employed by Siemens in the Greater Charlotte area and an additional 150-plus temporary jobs required for the construction, testing, and commissioning of the facility, the Lincoln County CT Project will help support economic growth in the Charlotte region.

Finally, by providing Siemens with the opportunity to test and develop their advanced technology on the grid, DEC is helping to promote competition in the CT manufacturing marketplace which can have long-term benefits for DEC's customers.

Q. PLEASE DESCRIBE DUKE ENERGY CAROLINAS' EXISTING GENERATION RESOURCE PORTFOLIO MIX.

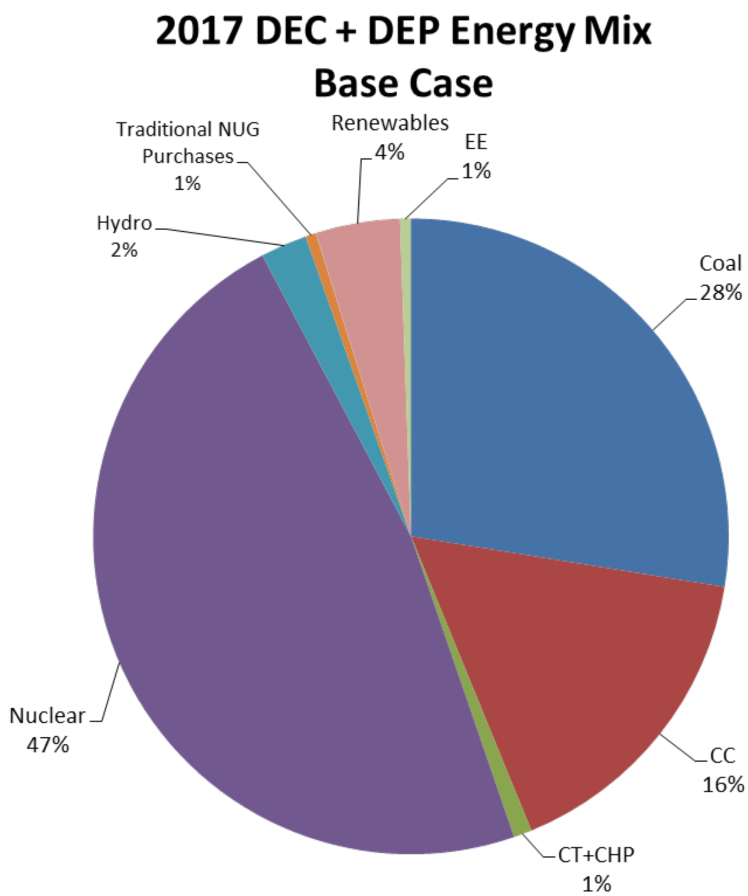
A. Duke Energy Carolinas' generation portfolio is composed of approximately 22,000 MWs of Company-owned generation, EE/DSM, and purchased power capacity. As shown in Kalemba Chart 1 below, DEC's capacity mix consists of approximately 20% gas-fired generation, 28% nuclear generation, 31% coal-fired generation, and the remainder in hydro-electric, renewables, EE/DSM, and other firm power purchases.

Kalemba Chart 1



The following Kalemba Chart 2 illustrates the current energy by fuel type for the combined DEP and DEC systems. This chart incorporates the Joint Dispatch Agreement ("JDA") which represents a non-firm energy only commitment between DEC and DEP. While Duke Energy Carolinas' capacity mix is roughly 20% gas-fired, 28% nuclear, and 31% coal, the energy mix for the combined DEP and DEC systems is roughly 17% gas-fired generation, 47% nuclear generation, and 28% coal-fired generation.

Kalemba Chart 2



Q. HOW WOULD THE ADDITION OF THE LINCOLN COUNTY CT PROJECT CONTRIBUTE TO RESOURCE AND FUEL DIVERSITY?

A. The addition of the Lincoln County CT Project will cause no material increase in the Company's reliance on natural gas resources. As previously mentioned, gas-fired generation makes up approximately 20% of the Company's capacity resources in the form of simple-cycle and combined cycle resources, and only about 17% of the energy mix. With the addition of the Project, the Company's gas-fired generation capacity will increase by less than one percent of the Duke Energy Carolinas portfolio. Also, as noted earlier, the Project will have dual fuel capability with ultra-low sulfur fuel capability in addition to natural gas.

Finally, the Lincoln County CT Project represents the first step into advanced gas-fired technologies (advanced-class) in the Carolinas. The highly efficient and flexible nature of this technology contributes to the overall diversity of the resource mix as the Utility begins to add more resources that have the ability to support operational and grid reliability as more and more intermittent resources are added to the DEC system.

Q. PLEASE DESCRIBE HOW PURCHASED POWER WAS CONSIDERED IN THE PLANNING PROCESS.

A. The IRP defines the least-cost, risk-adjusted generation mix over a variety of potential operating environments. The supply-side options included in the plan reflect generic resource technology additions determined for the base case portfolio. After the type (peaking, baseload, etc.) and timing of the resource addition is identified in the annual planning process, the Company can then consider the best option for obtaining that resource – whether through a purchased power arrangement or a Duke-owned resource. The Duke-owned resource could be obtained from constructing a new generation unit or acquiring an existing generation unit.

Q. DID DUKE ENERGY CAROLINAS EVALUATE THE WHOLESALE MARKET IN CONJUNCTION WITH DETERMINING HOW TO MEET THE CAPACITY AND SYSTEM RELABIILITY NEEDS THAT WILL BE MET WITH THE LINCOLN COUNTY CT PROJECT?

A. As the industry and the Carolinas transition to a more modern and efficient generation fleet, it requires the adoption of the most recent developments in natural gas turbine technologies. When reviewing the wholesale market, it must be noted that no existing advanced frame CTs are currently in service in the Carolinas. With respect to new construction, the opportunity to partner with Siemens in their development of an advanced-class CT was compared to the cost that would be incurred with other suppliers. To perform this comparison, Duke Energy Carolinas contracted with Burns & McDonnell to conduct a screening level capital cost estimate, included as Appendix A in Landseidel Exhibit 3, for a single advanced-class CT at the Lincoln County site. The site specific evaluation of the advanced-class turbine was developed based on recent similar project cost information and Lincoln County site information provided by the Company. Based on this review, it was determined that Siemens has offered a significant discount compared to market alternatives for the EPC contractor services including supply of the CT. Given the discount and advanced nature of the technology, the Company concluded that wholesale resources could not take the place of the Lincoln County CT Project.

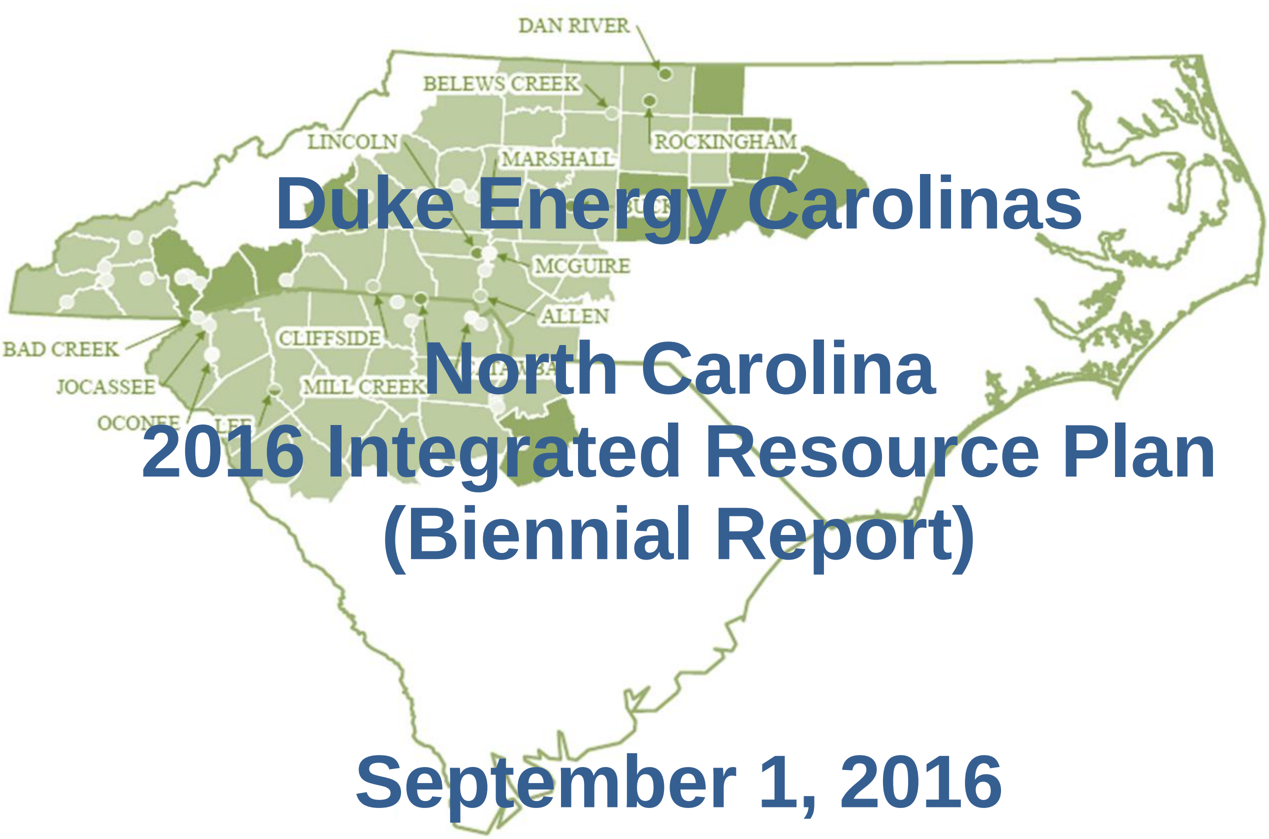
Q. IN CONCLUSION, IS THE LINCOLN COUNTY CT PROJECT NEEDED AND CONSISTENT WITH DUKE ENERGY CAROLINAS' 2016 IRP?

A. Yes. The Project is an important and necessary part of Duke Energy Carolinas' plans for meeting customer capacity and energy needs beginning in the 2024 timeframe. Importantly, the Lincoln County CT Project will be the most efficient and flexible CT in the Carolinas, modernizing the region's generation infrastructure and assisting in the integration of additional renewable resources. There are no other viable, cost-effective resources available as substitutes for this project. For all the reasons stated previously, I believe that Duke Energy Carolinas' comprehensive planning process has identified the need for significant capacity additions over the planning horizon and that a critical portion of these needs can best be met by the Lincoln County CT Project. I believe that Duke Energy Carolinas' application is in the public convenience and necessity, and I ask that the Commission approve it.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

DUKE ENERGY®
CAROLINAS



Duke Energy Carolinas

North Carolina
2016 Integrated Resource Plan
(Biennial Report)

September 1, 2016

PUBLIC

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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 Carolinas (DEC) has provided affordable and reliable electricity to customers in North Carolina (NC) and South Carolina (SC) now totaling more than 2.4 million in number. Each year, as required by the North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC), DEC 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 DEC's entire system.
- Add new resources at the lowest reasonable cost to customers. These resources include a balance of energy efficiency (EE) programs, demand-side management programs (DSM), renewable resources, nuclear facilities, hydro 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, DEC'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, DEC 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 in 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, DEC has now added a winter planning reserve target of 17% to its 2016 IRP.

<u>The Road Ahead— Determining Customer Electricity Needs 2017 – 2031</u>

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 customers is forecasted to be 1.1%. This growth rate is offset by projections for utility-sponsored EE impacts, reducing the projected growth rate by 0.1% for a net growth rate of 1.0% 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 net of EE 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 0.9%.
- Residential class has a projected growth rate of 1.2%.

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, hydro generation and state-of-the art natural gas generation facilities.

The Company recently closed its last coal facility not equipped with advanced emission controls. In April 2015, Lee Steam Station Units 1 and 2 in Anderson County, SC were shuttered. Unit 3 was converted into a natural gas-fired unit. These closings are the most recent in a series of coal unit retirements totaling approximately 1,700 megawatts (MW) (winter/summer) of cumulative retirements. Additionally, the Company plans to retire the 1,161 MW/1,127 MW (winter/summer) Allen Steam Station with Units 1-3 scheduled to retire by December 2024 and Units 4 and 5 in 2028. Finally, DEC has retired approximately 400 MW (summer/winter) of older combustion turbine (CT) units.

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.

Strategy to Meet Customer Needs

Natural Gas

Currently, natural gas resources such as combined cycles (CC) and combustion turbines only make up 20% of the winter generating capacity in DEC. The 2016 IRP identifies the need for additional 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 construction of the 683 MW/653 MW (winter/summer) natural gas combined cycle plant at Lee Steam Station, Anderson County, SC, (Lee CC) expected to be commercially available by the end of 2017. An additional 100 MW of capacity will be purchased by North Carolina Electric Membership Corporation (NCEMC).
- Plan for a 1,221 MW/1,123 MW (winter/summer) natural gas combined cycle in 2023.
- Plan for 468 MW/435 MW (winter/summer) of combustion turbine resources in 2025.

Nuclear Power

The Company expects to receive the Combined Construction and Operating License (COL) for the W.S. Lee Nuclear Station (Lee Nuclear) by the end of 2016. 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. As such, there is uncertainty regarding the ability to receive a license extension, as well as, any costs that may be required to operate an additional 20 years. 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.

Additionally, final resolution of environmental regulations, such as the Environmental Protection Agency's (EPA's) Clean Power Plan (CPP), will significantly impact the Company's generation portfolio. In light of this uncertainty and the historic volatility of natural gas prices, the Company evaluated its resource needs, including new nuclear generation, over a range of reasonable scenarios. The results of this evaluation demonstrated the need for new nuclear generation across the scenarios, though the timing of the need varied from the mid- 2020s to the early 2030s depending upon the assumptions. The Company believes these results demonstrate the value of obtaining the COL for the W.S. Lee Nuclear Station (Lee Nuclear) to the portfolio and customers.

The base planning case in this IRP models commercial operation of the Lee nuclear units in 2026 and 2028. The uncertainties described above may result in a potential accelerated need for Lee Nuclear when compared to the base planning case. The COL application anticipates the need for Lee Nuclear as early as 2024 and 2026 and those dates are reflected in the license application.

The current IRP base plan identifies the following:

- Commercial operation of the first unit at the Lee Nuclear Station by November 2026.
- Review the potential need for additional new nuclear capacity so that it is available in advance of the Oconee license expiration.
- Study the possibility of a license extension from the current 60 years to 80 years at the Oconee Nuclear Station extending its operations until the 2053-2054 time frame.

Renewable Energy and Solar Resources

Renewable mandates, substantial tax subsidies and declining costs make solar energy the Company's primary renewable energy resource in the 2016 IRP. DEC continues to add solar energy to its resource mix through Purchased Power Agreements (PPAs), Renewable Energy Credit (REC) purchases and utility-owned solar generation. The 2016 IRP projects:

- Increasing all solar energy resources from 735 MW in 2017 to 2,168 MW (nameplate) 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.

While the Company is aggressively pursuing 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, hydro and nuclear generation to make up the Company's diverse resource portfolio to ensure system reliability.

<u>Energy Efficiency and Demand-Side Management</u>

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 DEC'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: DEC Projected EE and DSM Energy and Capacity Savings (Winter)

Projected EE and DSM Energy and Capacity Savings		
Year	**Energy (MWh)**	**Capacity (MW)**
2017	600,000	547
2031	3,564,500	1,130

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.

Existing Resources and Alternative Generation

DEC continues to look for opportunities to make enhancements to its existing resources. As such, the Company expects to complete uprates to each unit of its Bad Creek pumped storage facility in the 2020 – 2023 timeframe. Each uprate is expected to provide an additional 46 MW to each unit. These uprates will not only provide valuable capacity to the DEC system, but will also be an important asset for providing support to the transmission system as intermittent sources of energy, such as solar, continue to grow in the Carolinas.

DEC 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 DEC is 109 MW/100 MW (winter/summer) of CHP in the 2018 – 2021 timeframe.

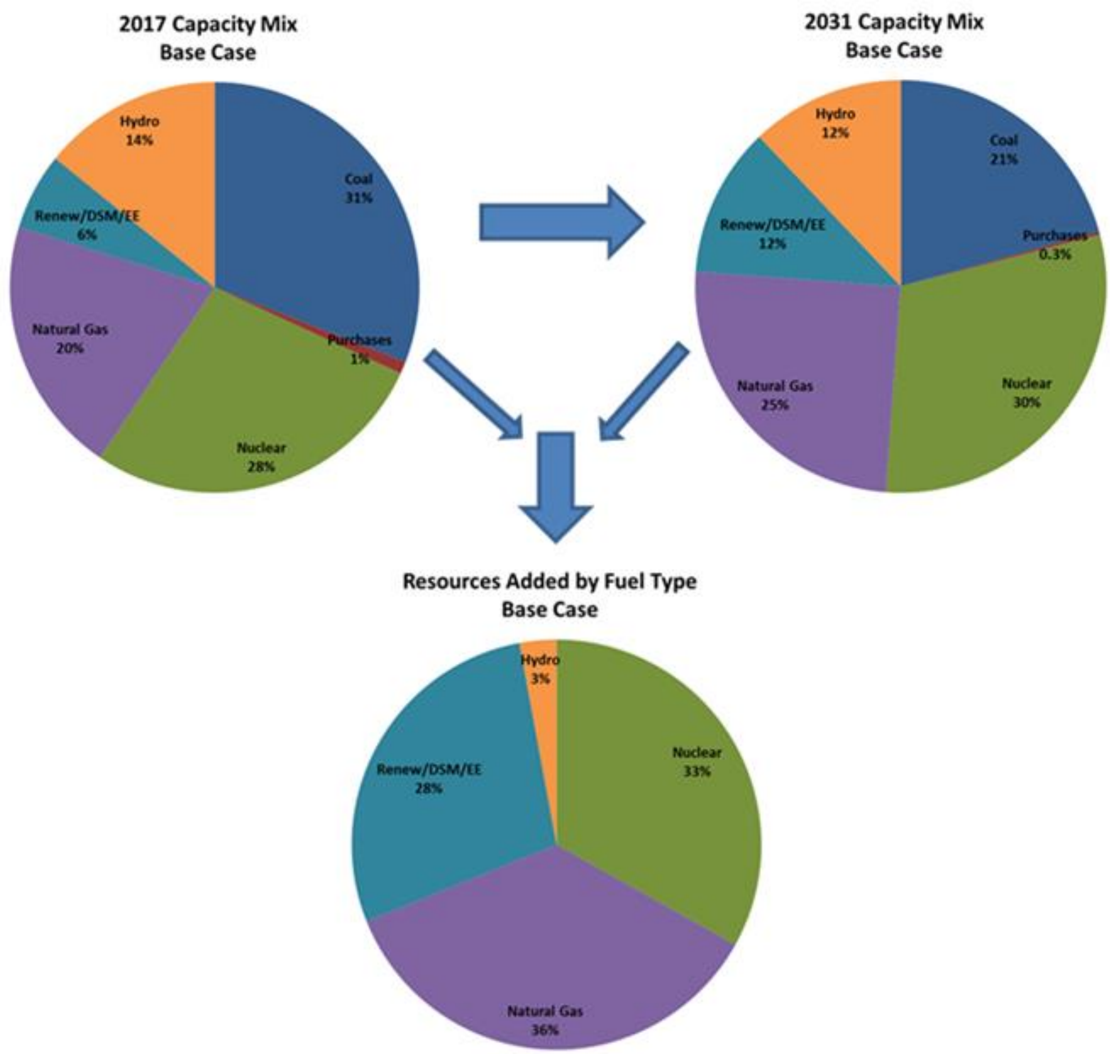
Strong Trend Toward Cleaner, More Environmentally Friendly Generation

When viewed in total, more than 54% of DEC and DEP'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 46% 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 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, DEC'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 winter 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 approximately one-third of the Company's new installed capacity over the study period. The plan also calls for approximately 36% of future new capacity to come from new natural gas generation with the final 33% coming from nuclear 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 and 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, 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

DEC provides electric service to an approximately 24,088-square-mile service area in central and western North Carolina and western South Carolina. In addition to retail sales to approximately 2.48 million customers, the Company also sells wholesale electricity to incorporated municipalities and to public and private utilities. Recent historical values for the number of customers and sales of electricity by customer groupings may be found in Appendix C.

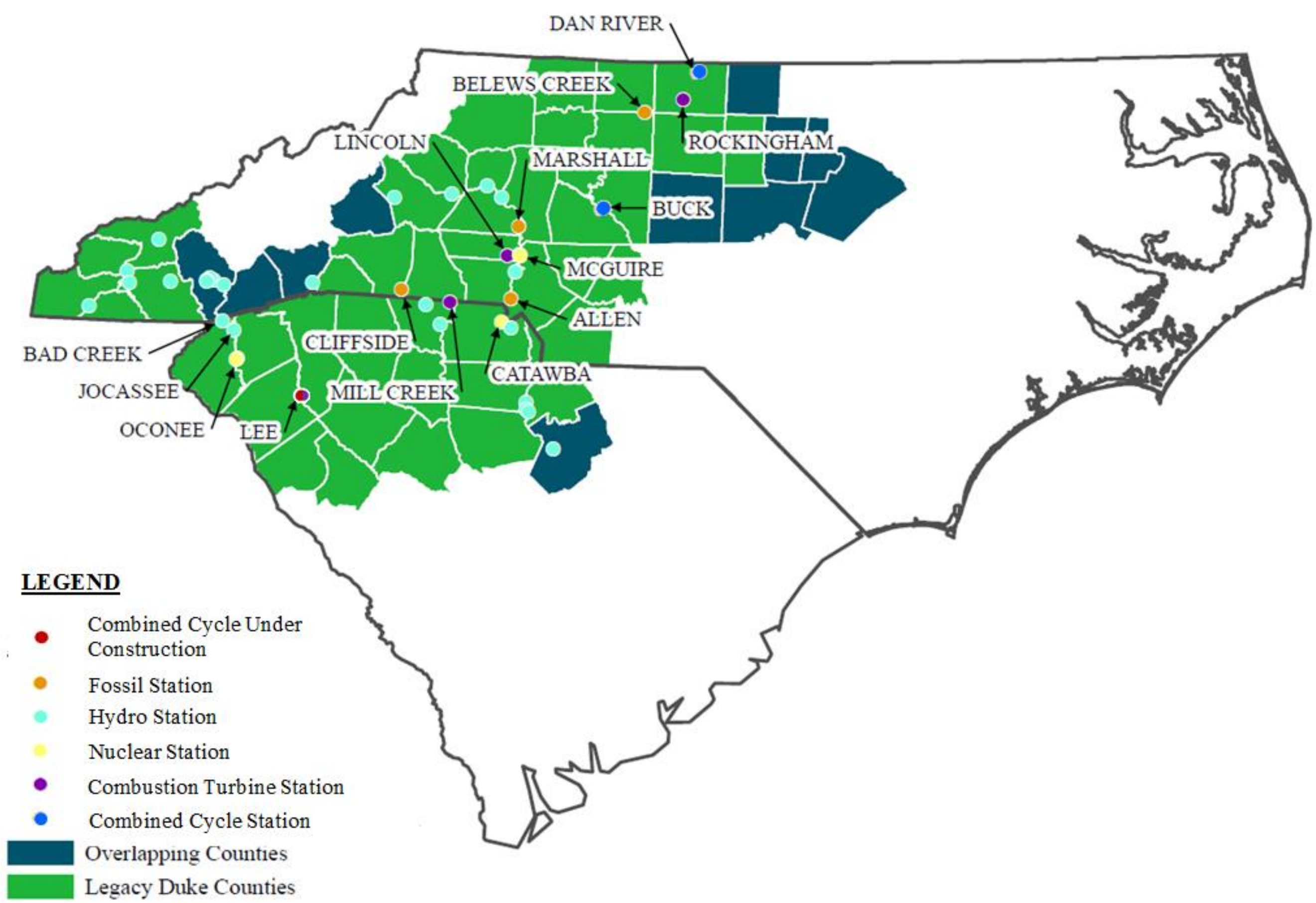
DEC currently meets energy demand, in part, by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets:

- Three nuclear generating stations with a combined capacity of 7,358 MW/7,160 MW (winter/summer)
- Four coal-fired stations with a combined capacity of 6,859 MW/ 6,821 MW (winter/summer)
- 29 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 3,238 MW (winter/summer)
- Four CT stations and two CC stations with a combined capacity of 4,607 MW/4,089 MW (winter/summer)
- 18 utility-owned solar facilities with a combined firm capacity of 3.9 MW
- One natural gas boiler with a capacity of 170 MW (winter/summer)

The Company's power delivery system consists of approximately 103,140 miles of distribution lines and 13,087 miles of transmission lines. The transmission system is directly connected to all of the Transmission Operators that surround the DEC service territory. There are 36 tie-line circuits connecting with nine different Transmission Operators: DEP, PJM Interconnection, LLC (PJM), Tennessee Valley Authority (TVA), Smokey Mountain Transmission, Southern Company, Yadkin, Southeastern Power Administration (SEPA), 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) (formerly Southeastern Electric Reliability Council) and North American Electric Reliability Corporation (NERC).

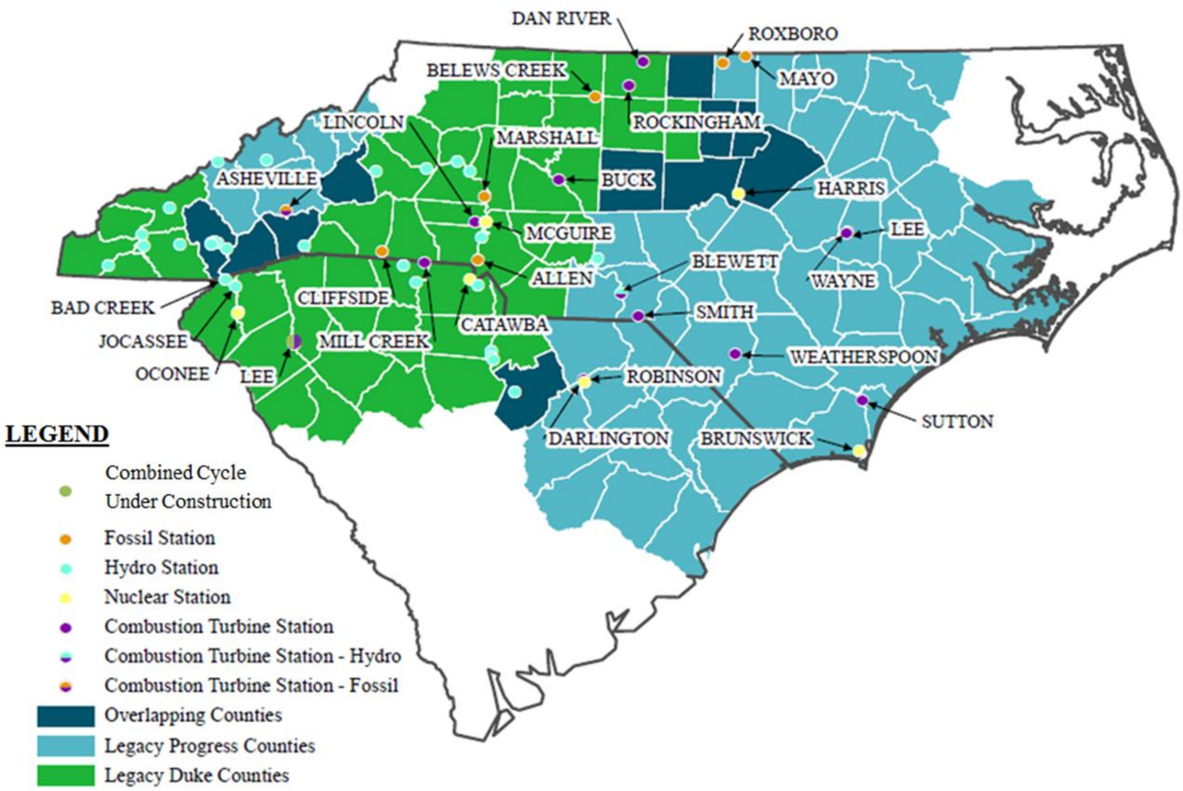
The map on the following page provides a high-level view of the DEC service area.

Chart 2-A Duke Energy Carolinas Service Area



With the closing of the Duke Energy Corporation and Progress Energy Corporation merger, the service territories for both DEC and DEP 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 DEC and DEP Service Area



3. ELECTRIC LOAD FORECAST

The Duke Energy Carolinas' 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 customers 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. DEC has used regression analysis since 1979 and this technique 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 slightly negative to 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 Energy Efficiency (UEE) programs, Solar and Electric Vehicles from 2017-2031 is 1.2%.

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 all 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 0.9% over the forecast horizon, after all adjustments.

Peak Demand and Energy Forecast

If the impacts of new Duke Energy Carolinas UEE[1] programs are included, the projected compound annual growth rate for the summer peak demand is 1.2%, while winter peaks are forecasted to grow at a rate of 1.3%. The forecasted compound annual growth rate for annual energy consumption is 1.0% 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 1.4% in the 2015 forecast versus 1.2% in the new forecast. The Spring 2016 Forecast is lower due to a large Industrial plant closing, strong UEE accomplishments in recent years, and stronger projected Commercial heating and cooling efficiencies. 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	18,729	18,416	97,470
2018	18,948	18,665	98,345
2019	18,916	18,721	98,131
2020	19,127	18,957	99,132
2021	19,362	19,259	99,973
2022	19,562	19,466	100,630
2023	19,804	19,731	101,676
2024	20,046	20,011	102,902
2025	20,321	20,223	103,890
2026	20,581	20,570	105,078
2027	20,842	20,844	106,255
2028	21,146	21,161	107,646
2029	21,427	21,478	108,794
2030	21,723	21,734	110,074
2031	22,028	22,068	111,407

Note: Tables 8-B and 8-C differ from these values due to a 47 MW Piedmont Municipal Power Agency (PMPA) backstand contract through 2020.

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

[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.

4. ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT

DEC is committed to making sure electricity remains available, reliable and affordable and that it is produced in an environmentally sound manner and, therefore, DEC 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 2009, DEC 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. DEC'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.

DEC's EE programs encourage customers to save electricity by installing high efficiency measures and/or changing the way they use their existing electrical equipment. DEC 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. DEC will continue to seek approval from State utility commissions to implement EE and DSM programs that are cost-effective and consistent with DEC's forecasted resource needs over the planning horizon. DEC 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. DEC 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.

In 2011, DEC commissioned an EE market potential study to obtain estimates of the technical, economic and achievable potential for EE savings within the DEC service area. The final report was prepared by Forefront Economics Inc. and H. Gil Peach and Associates, LLC and was completed on February 23, 2012. The results of the 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 DEC's five-year program planning forecast 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 DEC IRP process.

DEC prepared a Base Portfolio savings projection that was based on DEC'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.

DEC also prepared a High Portfolio EE savings projection that assumed that the same types of programs 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, DEC 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 DEC'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 3 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 735 MW in 2017 to 2,168 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 South Carolina Distributed Energy Resource Program goal of 120 MW of solar capacity located in DEC-South Carolina (DEC-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

DEC 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, wind, 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

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

actual renewable energy delivered to the DEC 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 to support NC REPS compliance, DEC will have a need for additional RECs to meet the general compliance requirement in the future without additional resources. DEC is therefore planning to issue a Request for Proposal (RFP) for additional renewable resources in the Fall of 2016 in support of its compliance targets. For details of DEC's NC REPS compliance plan, please reference the NC REPS Compliance Plan attachment.
Additional information on DEC's RFP plans can be found in Chapter 9.

Solar: PURPA and the Interconnection Queue

The rapid growth of new solar facilities continues to dominate the renewable energy market landscape. As discussed above, DEC 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, DEC 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 QF solar purchases relates to the avoided cost rates a utility must pay for this power under PURPA. The utility's avoided cost 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 DEC service territory. Illustrating this trend are these facts:

- DEC had over 300 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, DEC reported another ~140 MW of third-party solar under construction and over 900 MW in the

interconnection queue, including over 200 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 DEC and DEP 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, DEC expects 204 MW-AC of nameplate non-compliance mandated PURPA solar capacity by 2031, some of which could be converted to compliance resources.

Utility-Owned Solar and Integration

DEC continues to evaluate utility-owned solar additions to support its compliance targets and operational flexibility. For example, DEC has two new utility-scale solar projects under construction listed below which should be producing RECs and available for the summer peak of 2017:

- Monroe Solar Facility – 60MW, located in Union County; and
- Mocksville Solar Facility – 15MW, located in Davie County.

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 the Green Source Rider and SC DER. As described in more detail in Appendix A, scenarios where solar was selected required assumptions in which lower installed solar costs 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. DEC 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. DEC 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. DEC expects that it can safely and reliably integrate renewable resources like solar through a combination of utility-owned assets and cooperation with third parties. DEC 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 the Green Source Rider and SC DER. The Green Source Rider allows DEC to procure renewable energy on behalf of the customer. The customer pays for the REC during their project term and DEC may acquire the REC following the contract term. Customers such as Cisco and Google have participated in this program, which is anticipated to grow to 102 MW-AC (nameplate capacity) by 2017. DEC is evaluating additional programs similar to the Green Source Rider 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.

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 40 MW of nameplate solar capacity). The plan calls for a total of ~120MW of solar capacity[3] distributed across three tiers:

- Tier I: 40 MW of solar capacity from facilities each >1 MW and less than 10 MW in size.
- Tier II: 40 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.
- Tier III: Investment by the utility in 40 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 DEC-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.

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.

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 DEC's

[3] 1% of the Company's South Carolina retail peak is equal to approximately 40 MW.

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, Green Source Rider, 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 DEC's expected peak load in the summer, solar's contribution to summer peak (net of solar) load is large enough (46% of nameplate solar capacity) that it may push the time of summer peak 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 DEC Base Case Total Renewables

DEC 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	735	98	833	338	98	436	2016/2017	37	98	135
2018	907	81	989	417	81	499	2017/2018	45	81	127
2019	1088	74	1162	501	74	575	2018/2019	54	74	128
2020	1244	73	1317	572	73	645	2019/2020	62	73	135
2021	1416	70	1486	651	70	722	2020/2021	71	70	141
2022	1542	66	1607	709	66	775	2021/2022	77	66	143
2023	1641	62	1703	755	62	817	2022/2023	82	62	144
2024	1724	62	1786	793	62	855	2023/2024	86	62	148
2025	1801	61	1861	828	61	889	2024/2025	90	61	151
2026	1873	55	1928	862	55	917	2025/2026	94	55	149
2027	1941	49	1990	893	49	942	2026/2027	97	49	146
2028	2004	44	2048	922	44	966	2027/2028	100	44	144
2029	2063	44	2107	949	44	993	2028/2029	103	44	147
2030	2118	44	2161	974	44	1018	2029/2030	106	44	150
2031	2168	34	2202	997	34	1031	2030/2031	108	34	142

* 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 DEC High Case Total Renewables

DEC 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	805	98	903	370	98	468	2016/2017	40	98	138
2018	1057	81	1138	486	81	567	2017/2018	53	81	134
2019	1249	74	1323	575	74	649	2018/2019	62	74	136
2020	1436	73	1509	661	73	734	2019/2020	72	73	145
2021	1609	70	1679	740	70	810	2020/2021	80	70	150
2022	1810	66	1876	832	66	898	2021/2022	90	66	156
2023	1990	62	2052	915	62	977	2022/2023	100	62	162
2024	2140	62	2202	984	62	1046	2023/2024	107	62	169
2025	2281	61	2342	1049	61	1110	2024/2025	114	61	175
2026	2413	55	2468	1110	55	1165	2025/2026	121	55	176
2027	2537	49	2586	1167	49	1216	2026/2027	127	49	176
2028	2654	44	2698	1221	44	1265	2027/2028	133	44	177
2029	2763	44	2807	1271	44	1315	2028/2029	138	44	182
2030	2864	44	2908	1317	44	1361	2029/2030	143	44	187
2031	2957	34	2991	1360	34	1394	2030/2031	148	34	182

* Solar includes 0.5% per year degradation

Table 5-C DEC Low Case Total Renewables

DEC 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	735	98	833	338	98	436	2016/2017	37	98	135
2018	887	81	968	408	81	489	2017/2018	44	81	125
2019	1042	74	1116	479	74	553	2018/2019	52	74	126
2020	1178	73	1251	542	73	615	2019/2020	59	73	132
2021	1334	70	1404	614	70	684	2020/2021	67	70	137
2022	1427	66	1493	656	66	722	2021/2022	71	66	137
2023	1507	62	1569	693	62	755	2022/2023	75	62	137
2024	1574	62	1636	724	62	786	2023/2024	79	62	141
2025	1636	61	1697	753	61	814	2024/2025	82	61	143
2026	1695	55	1750	780	55	835	2025/2026	85	55	140
2027	1750	49	1799	805	49	854	2026/2027	88	49	137
2028	1801	44	1845	828	44	872	2027/2028	90	44	134
2029	1848	44	1892	850	44	894	2028/2029	92	44	136
2030	1892	44	1936	870	44	914	2029/2030	95	44	139
2031	1932	34	1966	889	34	923	2030/2031	97	34	131

* 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 demand side management (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 Carolinas 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 (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
- Renewable – 5 MW Landfill Gas

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 46% 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

DEC's resource plan reflects winter reserve margins ranging from approximately 17% to 22%. Reserves projected in DEC'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 in 2017/18 and 2018/19 as a result of the Lee combined-cycle addition in November 2017. The reserve margin exceeds the minimum target by 3% in 2022/23 and 2023/24 due to the addition of a large combined cycle unit in December 2022. Also, the reserve margin exceeds the minimum target by 3% in 2026/27 due to the addition of a baseload nuclear unit in November 2026.

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 DEC'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, DEC has added a winter planning reserve margin criteria to the IRP process. To meet the future needs of DEC's customers, it is necessary for the Company to adequately understand the load and resource balance. For each year of the planning horizon, DEC 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 DEC considers the non-firm energy purchases and sales associated with the Joint Dispatch Agreement (JDA) with DEP 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, DEC and DEP 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

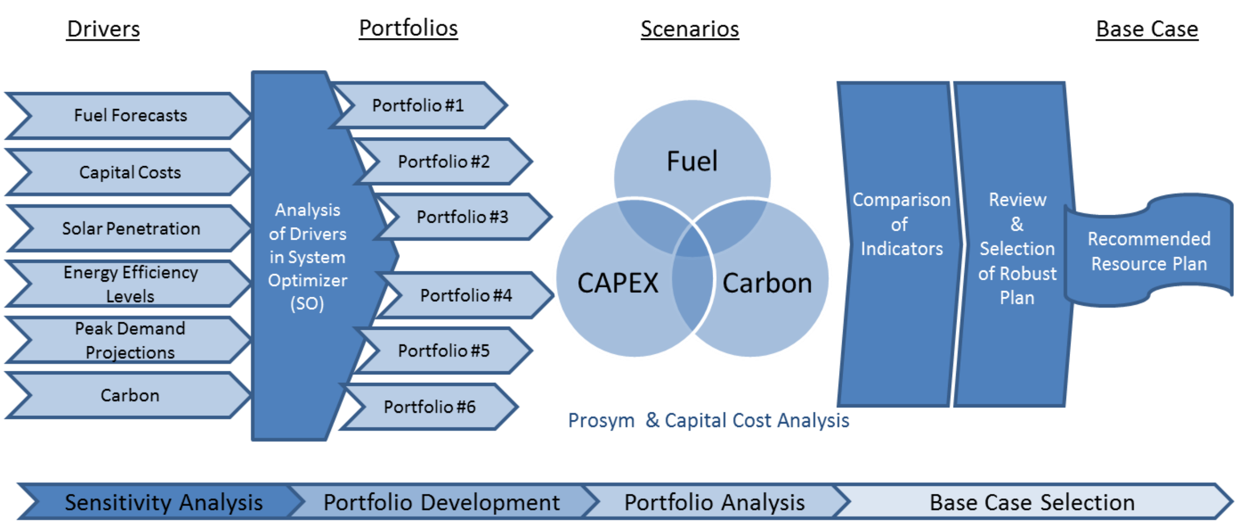
Generation Alternative Screening

DEC 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 DEC 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 DEC system, the potential benefits of sharing capacity within DEC and DEP 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. Three of these portfolios included Lee Nuclear Plant in 2026 and 2028 and varied levels of EE and renewable penetration, while the fourth portfolio replaced Lee Nuclear plant with mainly CC generation.

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 along with construction of the Lee Nuclear Plant in the late 2020s to keep carbon emissions flat to declining.

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_2Tax	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	2	2	2
Portfolio #2 (High Renew)	4	4	4
Portfolio #3 (High EE)	3	3	3
Portfolio #4 (High CC)	1	1	1

While Portfolio #4 had the lowest PVRR due to the absence of Lee Nuclear, Portfolio #4 was not selected as the Base Case because it's carbon footprint would not be sustainable over the long term in a System CO_2 Mass Cap plan if new nuclear generation was not available in the late 2020s. Portfolios 1 through 3 add Lee Nuclear Station in the 2026-2028 timeframe, which leads to a reduction in CO_2 emissions of about 15% to 20% by 2030. Portfolio #1 is the least cost portfolio with Lee Nuclear Station included, but none of these portfolios would meet a System CO_2 Mass Cap scenario unless existing nuclear generation was relicensed or replaced with new nuclear generation.

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 with Lee Nuclear) would keep the Company on track if a System CO_2 Mass Cap were implemented. Of the portfolios that included Lee Nuclear, 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.

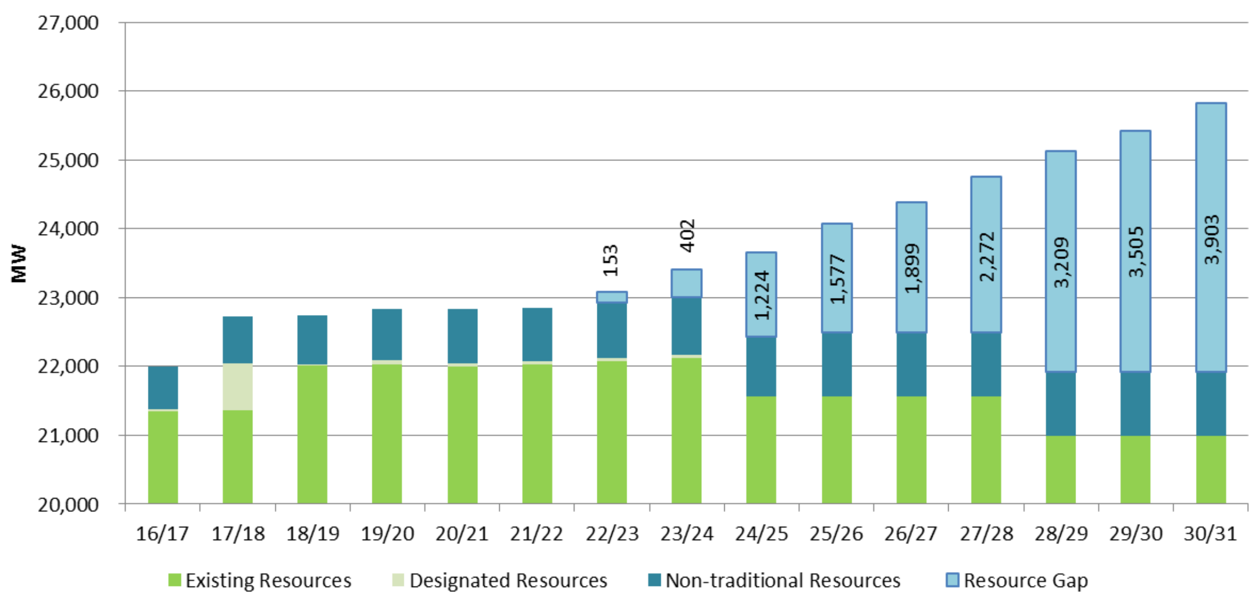
Finally, Portfolios 5 and 6 were evaluated under the Current Trends scenario with a System Mass Cap carbon constraint. Under the Mass Cap carbon paradigm, the high EE and high renewable combination led to a slightly higher PVRR versus the Base Case. The capital costs of the high EE/high renewable portfolio was nearly $1.9B higher than Portfolio #5, however, this was largely offset by approximately $1.7B in system production cost savings. Given the lower cost and 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 DEC and DEP, where appropriate. This case does not take into account the sharing of capacity between DEC and DEP. However, the Base Case incorporates the JDA between DEC and DEP, which represents a non-firm energy only commitment between the Companies. A Joint Planning Case that begins to explore the potential for DEC and DEP 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 DEC 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 2023. As a result, the resource plan analyses described above have determined the most robust plan to meet this resource gap.

Chart 8-A DEC 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	0	153	402
Year	24/25	25/26	26/27	27/28	28/29	29/30	30/31	
Resource Need	1,224	1,577	1,899	2,272	3,209	3,505	3,903	

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

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

Winter Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 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	18,520	18,819	18,916	19,195	19,513	19,764	20,071	20,389	20,638	21,003	21,290	21,609	21,929	22,193	22,530
2	Firm Sale	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Cumulative New EE Programs	(57)	(107)	(148)	(191)	(254)	(298)	(340)	(379)	(415)	(433)	(446)	(447)	(452)	(459)	(461)
4	**Adjusted Duke System Peak**	**18,463**	**18,712**	**18,768**	**19,004**	**19,259**	**19,466**	**19,731**	**20,011**	**20,223**	**20,570**	**20,844**	**21,161**	**21,478**	**21,734**	**22,068**
Existing and Designated Resources																
5	Generating Capacity	21,132	21,141	21,824	21,834	21,900	21,946	21,993	22,039	22,085	21,481	21,481	21,481	21,481	20,924	20,924
6	Designated Additions / Uprates	25	683	10	66	46	46	46	46	-	-	-	-	-	-	-
7	Retirements / Derates	(16)	-	-	-	-	-	-	-	(604)	-	-	-	(557)	-	-
8	**Cumulative Generating Capacity**	**21,141**	**21,824**	**21,834**	**21,900**	**21,946**	**21,993**	**22,039**	**22,085**	**21,481**	**21,481**	**21,481**	**21,481**	**20,924**	**20,924**	**20,924**
Purchase Contracts																
9	**Cumulative Purchase Contracts**	**251**	**261**	**232**	**231**	**141**	**118**	**119**	**120**	**121**	**122**	**117**	**118**	**105**	**106**	**107**
	Non-Compliance Renewable Purchases	33	34	38	39	39	40	40	40	40	40	34	34	34	34	34
	Non-Renewables Purchases	217	227	195	192	101	79	79	80	81	82	83	84	71	72	73
Undesignated Future Resources																
10	Nuclear											1,117		1,117		
11	Combined Cycle							1,221								
12	Combustion Turbine									468						
Renewables																
13	**Cumulative Renewables Capacity**	101	92	91	96	102	103	104	108	111	109	112	109	112	115	108
14	**Combined Heat & Power**	-	43	22	22	22	-	-	-	-	-	-	-	-	-	-
15	**Cumulative Production Capacity**	**21,493**	**22,221**	**22,222**	**22,314**	**22,297**	**22,322**	**23,592**	**23,643**	**23,511**	**23,509**	**24,625**	**24,623**	**25,174**	**25,177**	**25,171**
Demand Side Management (DSM)																
16	**Cumulative DSM Capacity**	**490**	**501**	**513**	**526**	**538**	**535**	**562**	**589**	**616**	**670**	**670**	**669**	**669**	**669**	**669**
17	**Cumulative Capacity w/ DSM**	**21,983**	**22,722**	**22,735**	**22,839**	**22,835**	**22,857**	**24,153**	**24,232**	**24,126**	**24,179**	**25,294**	**25,292**	**25,843**	**25,847**	**25,840**
Reserves w/ DSM																
18	Generating Reserves	3,520	4,010	3,967	3,836	3,577	3,391	4,422	4,221	3,903	3,609	4,450	4,131	4,365	4,113	3,772
19	**% Reserve Margin**	**19%**	**21%**	**21%**	**20%**	**19%**	**17%**	**22%**	**21%**	**19%**	**18%**	**21%**	**20%**	**20%**	**19%**	**17%**

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

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

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Load Forecast															
1 Duke System Peak	18,877	19,159	19,183	19,446	19,685	19,933	20,229	20,521	20,837	21,130	21,405	21,712	21,998	22,297	22,603
2 Firm Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(102)	(164)	(220)	(272)	(323)	(371)	(425)	(475)	(516)	(549)	(564)	(566)	(572)	(574)	(575)
4 Adjusted Duke System Peak	**18,776**	**18,995**	**18,963**	**19,174**	**19,362**	**19,562**	**19,804**	**20,046**	**20,321**	**20,581**	**20,842**	**21,146**	**21,427**	**21,723**	**22,028**
Existing and Designated Resources															
5 Generating Capacity	20,394	20,378	21,031	21,086	21,138	21,185	21,231	21,278	21,278	20,693	20,693	20,693	20,151	20,151	20,151
6 Designated Additions / Uprates	0	653	55	52	46	46	46	0	0	0	0	0	0	0	0
7 Retirements / Derates	(16)	0	0	0	0	0	0	0	(585)	0	0	(542)	0	0	0
8 Cumulative Generating Capacity	**20,378**	**21,031**	**21,086**	**21,138**	**21,185**	**21,231**	**21,278**	**21,278**	**20,693**	**20,693**	**20,693**	**20,151**	**20,151**	**20,151**	**20,151**
Purchase Contracts															
9 Cumulative Purchase Contracts	**348**	**367**	**365**	**371**	**292**	**275**	**275**	**276**	**276**	**277**	**272**	**272**	**259**	**260**	**261**
Non-Compliance Renewable Purchases	137	146	176	185	192	197	196	196	195	195	189	189	188	188	188
Non-Renewables Purchases	211	221	189	186	100	79	79	80	81	82	83	84	71	72	73
Undesignated Future Resources															
10 Nuclear											1,117	1,117			
11 Combined Cycle							1,123								
12 Combustion Turbine									435						
Renewables															
13 **Cumulative Renewables Capacity**	299	353	398	460	530	578	621	659	694	722	753	777	804	830	843
14 **Combined Heat & Power**	0	40	20	20	20	0	0	0	0	0	0	0	0	0	0
15 Cumulative Production Capacity	**21,025**	**21,791**	**21,909**	**22,049**	**22,107**	**22,184**	**23,397**	**23,435**	**23,321**	**23,349**	**24,492**	**25,092**	**25,106**	**25,132**	**25,147**
Demand Side Management (DSM)															
16 Cumulative DSM Capacity	**1,057**	**1,090**	**1,119**	**1,148**	**1,156**	**1,154**	**1,181**	**1,208**	**1,235**	**1,289**	**1,290**	**1,290**	**1,290**	**1,290**	**1,290**
17 Cumulative Capacity w/ DSM	**22,082**	**22,880**	**23,028**	**23,197**	**23,263**	**23,339**	**24,578**	**24,644**	**24,556**	**24,639**	**25,782**	**26,381**	**26,396**	**26,422**	**26,436**
Reserves w/ DSM															
18 Generating Reserves	3,306	3,885	4,065	4,024	3,901	3,777	4,775	4,598	4,235	4,058	4,940	5,235	4,969	4,699	4,408
19 % Reserve Margin	**18%**	**20%**	**21%**	**21%**	**20%**	**19%**	**24%**	**23%**	**21%**	**20%**	**24%**	**25%**	**23%**	**22%**	**20%**

DEC - 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 tables. All values are MW (winter ratings) except where shown as a Percent.

1. Planning is done for the peak demand for the Duke Energy Carolinas System including Nantahala.

   A firm wholesale backstand agreement for 47 MW between Duke Energy Carolinas and Piedmont Municipal Power Agency (PMPA) starts on 1/1/2014 and continues through the end of 2020. This backstand is included in Line 1.

2. No additional firm sales are included.

3. Cumulative new 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 101 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for North Carolina Municipal Power Agency #1 (NCMPA1) firm capacity sale.

6. Capacity Additions include:

   Includes runner upgrades on each of the four Bad Creek pumped storage units. Each upgrade is expected to be 46.4 MW and are projected in the 2021 – 2024 timeframe. One unit will be upgraded per year.

   Lee Combined Cycle is reflected in 2018 (683 MW). This is the DEC capacity net of 100 MW to be owned by NCEMC.

   Capacity Additions include Duke Energy Carolinas hydro units scheduled to be repaired and returned to service. The units are returned to service in the 2017-2020 timeframe and total 16 MW.

   Also included is a 85 MW capacity increase due to nuclear uprates at Catawba and Oconee. Timing of these uprates is shown from 2017-2020.

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

7. A planning assumption for coal retirements has been included in the 2016 IRP.

   Allen Steam Station Units 1-3 (604 MW) are assumed to retire in December 2024.

   Allen Steam Station Units 4-5 (557 MW) are assumed to retire in June 2028.

   Nuclear Stations are assumed to retire at the end of their current license extension. However, no nuclear facilities have license expiries in the 15 year study period.

   The Hydro facilities for which Duke has submitted an application to Federal Energy Regulatory Commission (FERC) for license renewal are assumed to continue operation through the planning horizon.

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

8. Sum of lines 5 through 7.

9. Cumulative Purchase Contracts including purchased capacity from PURPA Qualifying Facilities, an 86 MW Cherokee County Cogeneration Partners contract which began in June 1998 and expires June 2020 and miscellaneous other QF projects.

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

   Renewable resources 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.

    Addition of 1,117 MW Lee Nuclear Unit additions assumed in November 2026 and May 2028.

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

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

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 2022.

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 online December 2024.

13. Resources to comply with NC REPS along with solar customer product offerings such as Green Source and SC DER were input as existing resources. Solar resources reflect 5% of nameplate capacity contribution at the time of winter peak demand and 46% of nameplate capacity contribution at the time of summer peak demand.

14. New 21.7 MW (winter) combined heat and power units included in 2018 (2x), 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 Response 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 winter 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 DEC Base Case

Duke Energy Carolinas Resource Plan (1)
Base Case - Winter

Year	Resource			MW		
2017	Nuclear Uprates			25		
2018	Lee CC	CHP		683	43	
2019	Hydro Refurb Return to Service	CHP		10	22	
2020	Nuclear Uprates	CHP	Hydro Refurb Return to Service	60	22	6
2021	Bad Creek Uprate	CHP		46.4	22	
2022	Bad Creek Uprate			46.4		
2023	Bad Creek Uprate	New CC		46.4	1221	
2024	Bad Creek Uprate			46.4		
2025	New CT			468		
2026						
2027	New Nuclear			1117		
2028						
2029	New Nuclear			1117		
2030						
2031						

Notes: (1) Table includes both designated and undesignated capacity additions
Future additions of renewables, EE and DSM not included
(2) Lee CC capacity is net of NCEMC ownership of 100 MW
(3) Rocky Creek Units currently offline for refurbishment; these are expected return to service dates
(4) Lee Nuclear in service dates are assumed to be Nov 2026 and May 2028

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

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

DEC Base Case Resources
Cumulative Winter Totals - 2017 - 2031

Nuclear	2319
CC	1904
CT	468
Hydro	202
CHP	109
Total	5002

The following charts illustrate both the current and forecasted capacity by fuel type for the DEC system, as projected by the Base Case. As demonstrated in Chart 8-B, the capacity mix for the DEC system changes with the passage of time. In 2031, the Base Case projects that DEC will have a smaller reliance on coal and a higher reliance on gas-fired resources, nuclear, 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 735 MW in 2017 to 2,168 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 37 MW in 2017 to 108 MW by 2031.

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

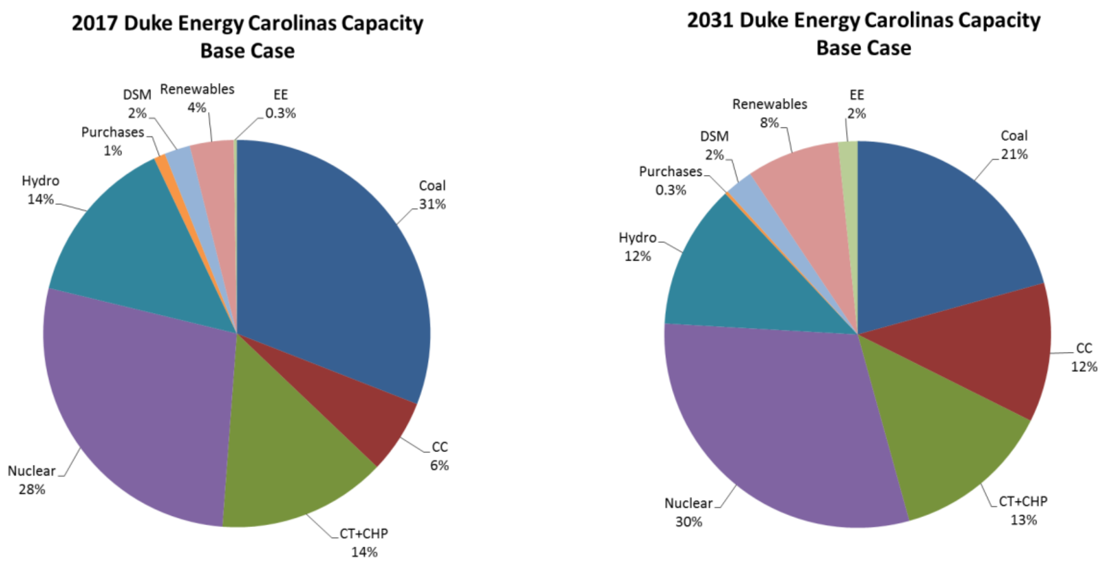
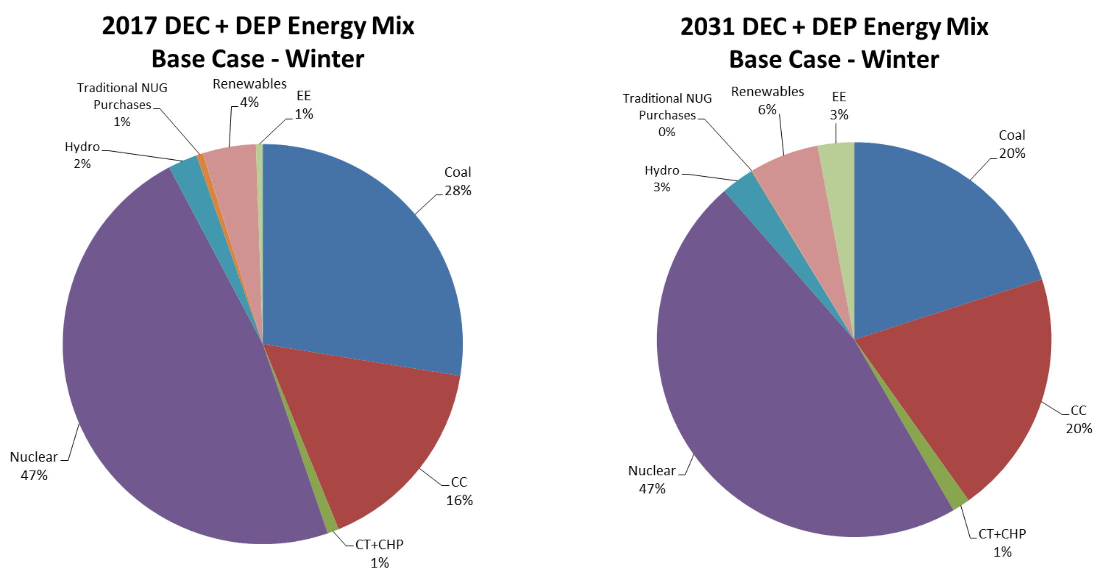


Chart 8-C represents the energy of the DEC and DEP base cases by fuel type. These energy charts represent both the DEC and DEP Base Cases. Due to the joint dispatch agreement (JDA), it is prudent to combine the energy of both utilities to develop a meaningful Base Case energy chart. From 2017 to 2031, 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] All capacity based on winter ratings except renewables which are based on nameplate.

Chart 8-C DEC and DEP Energy by Fuel Type – Base Case[5]



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 late 2020s to mid-2030s. To this point, Lee Nuclear plant is assumed to be available in November 2026 and May 2028, and additional new nuclear generation is required coincident with the retirement of Oconee Nuclear Plant in 2034. Additionally, incremental solar generation begins to be economically selected in the early 2030s as shown in Table 8-G. It should be noted that the expansion planning model does not incorporate incremental solar integration costs when selecting

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[5] All capacity based on winter ratings except renewables which are based on nameplate.

resources, however these costs are added later when calculating the total PVRR of the resource plan.[6]

Table 8-G DEC System Carbon Mass Cap Case

Duke Energy Carolinas Resource Plan (1) System Mass Cap - Winter						
Year	**Resource**			**MW**		
2017	Nuclear Uprates			25		
2018	Lee CC	CHP		683	43	
2019	Hydro Refurb Return to Service	CHP		10	22	
2020	Nuclear Uprates	CHP	Hydro Refurb Return to Service	66	22	6
2021	Bad Creek Uprate	CHP		46.4	22	
2022	Bad Creek Uprate			46.4		
2023	Bad Creek Uprate	New CT		46.4	468	
2024	Bad Creek Uprate			46.4		
2025	New CC			1221		
2026						
2027	New Nuclear			1117		
2028						
2029	New Nuclear			1117		
2030						
2031	New Solar			232		

Notes: (1) Table includes both designated and undesignated capacity additions
Future additions of renewables, EE and DSM not included
(2) Lee CC capacity is net of NCEMC ownership of 100 MW
(3) Rocky Creek Units currently offline for refurbishment; these are expected return to service dates
(4) Lee Nuclear in service dates are assumed to be Nov 2026 and May 2028

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

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

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

DEC System Mass Cap Resources Cumulative Winter Totals - 2017 - 2031	
Nuclear	2325
CC	1904
CT	468
Hydro	202
CHP	109
Solar	232
Total	5240

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 DEC and DEP 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 DEC and DEP 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 DEC and DEP winter Base Cases as compared to the Joint Planning Case. The plan contains the undesignated additions for DEC and DEP 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 DEC and DEP 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	New CT	468
2027	New Nuclear	1117
2028	New CT	468
2029	New Nuclear / New CT	1117 / 468
2030		
2031	New CT	1404

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

Delay & Combine

Delay

Delay & Combine

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

A comparison of both the DEC and DEP 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

DEC and DEP Combined Base Case Resources Cumulative Winter Totals - 2017 - 2031	
Nuclear	2234
CC	2442
CT	3744
Total	8420

DEC and DEP 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 Reserve Margins

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 DEC and DEP 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 DEC 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

DEC is committed to full compliance with NC REPS in North Carolina and is actively exploring incremental renewable resource additions contemplated under the recently passed South Carolina legislation. 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, DEC continues to procure renewable purchase power resources, when economically viable, as part of its Compliance Plan. DEC is also pursuing the addition of new utility-owned solar on the DEC system.

In 2015, DEC 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 40 MW of nameplate solar capacity). The first tier of SC DER is comprised of a combination of utility scale PPAs 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 DEC contemplates doing in 2019.

DEC continues to evaluate market options for renewable generation and procure capacity, as appropriate. PPAs have been signed with developers of solar PV, landfill gas and wind resources. 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.

<u>Continue to Find Opportunities to Enhance Existing Clean Resources</u>

DEC is committed to continually looking for opportunities to improve and enhance its existing resources. DEC has committed to the replacement of the runners on each of its four Bad Creek pumped storage units. Each replacement is expected to gain approximately 46 MW of capacity. The first replacement is projected to be in 2020, available for the 2021 winter peak. The remaining units will be replaced at the rate of one per year for availability in the winter peaks from 2022 – 2024.

<u>Continue to Pursue New Nuclear</u>

As part of the 2016 IRP, new nuclear resources continue to be supported in the resource plan in the 2024 to 2030 timeframe, depending on the scenario. Given the time it takes to receive a Combined Construction and Operating License from the Nuclear Regulatory Commission (NRC) and the significant reduction in lead time and risk to build a new nuclear facility with a COL in hand, Duke Energy views the receipt of a COL as a valuable asset for its customers.

DEC remains on course to obtain the COL for the Lee Nuclear facility in 2016. The following is a summary of the activities relative to the COL for the Lee Nuclear facility. There are three primary milestones that a project must complete to receive a COL: Final Environmental Impact Statement (FEIS), Final Safety Evaluation Report (FSER), and a Mandatory Hearing. On Dec. 23, 2013, the NRC issued the FEIS for Lee Nuclear, and on Jan. 2, 2014, the South Carolina Department of Health and Environmental Control (SC DHEC) issued the final Water Quality Certification. With the National Pollutant Discharge Elimination System (NPDES)[7] permit, which was issued in July 2013, all of the major, required environmental permits and certifications required for the COL have been received. The NRC issued the FSER on August 1, 2016 and the Mandatory Hearing for the Lee COL is scheduled for October 5, 2016. Receipt of the Lee COL is expected by December 2016. The schedule for receipt of the Lee COL supports the earliest projected need date for Lee Unit 1 in 2024 and Unit 2 in 2026.

Addition of Clean Natural Gas Resources

- Continue construction of the Lee combined cycle plant at the Lee Steam Station site located in Anderson, SC. As demonstrated in recent IRP plans, a capacity need was identified in 2017/2018 to allow DEC to meet its customers' load demands. After evaluating multiple bids in an RFP to address the 2017/2018 capacity need, the Company determined the most economical alternative to meet the need was to construct a new natural gas combined cycle facility at the Lee Steam Station site in Anderson County SC. The Company received a Certificate of Environmental Compatibility and Public Convenience and Necessity (CECPCN) in an order dated May 2, 2014, to move forward with the construction of the Lee CC.

- Lee Steam Station Unit 3 was converted from coal to clean-burning natural gas fuel in 2015.

Continued Focus on Environmental Compliance and Wholesale

- Retire older coal generation. As of April 2015, approximately 1,700 MW (winter/summer) of older coal generation has been retired and replaced with clean-burning natural gas, renewable energy resources or energy efficiency. The final older, un-

[7] The Section 402 NPDES permit and the Section 401 Water Quality Certification are part of the Clean Water Act.

scrubbed coal units at Lee Steam Station were retired in November 2014. Currently, Duke Energy Carolinas has no remaining older, un-scrubbed coal units in operation.[8]

- 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.

- 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 Base Case 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.

[8] 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.

Table 9-A DEC Short-Term Action Plan

Duke Energy Carolinas Short-Term Action Plan (1)						
			Compliance Renewable Resources (Cumulative Nameplate MW)			
Year	Retirements	Additions	Solar (2)	Biomass/Hydro	EE	DSM (3)
2017		25 MW Nuc	483	77	57	490
2018		683 MW Lee CC(4)	635	60	107	501
2019		10 MW Hydro Refurb(5)	751	53	148	513
2020		60 MW Nuc 6 MW Hydro Refurb(5)	887	52	191	526
2021		46 MW Bad Creek	1044	50	254	538

Notes:

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

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

(3) Includes impacts of grid modernization.

(4) 683 MW is net of NCEMC portion of Lee CC

(5) Rocky Creek is currently offline for refurbishment. Hydro Refurb MW in table represent expected return to service date.

DEC Request for Proposal (RFP) Activity

Supply-Side

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

Renewable Energy

Duke Energy Distributed Energy Resource Solar RFP – South Carolina

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 DEC and DEP 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 DEC or DEP 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.

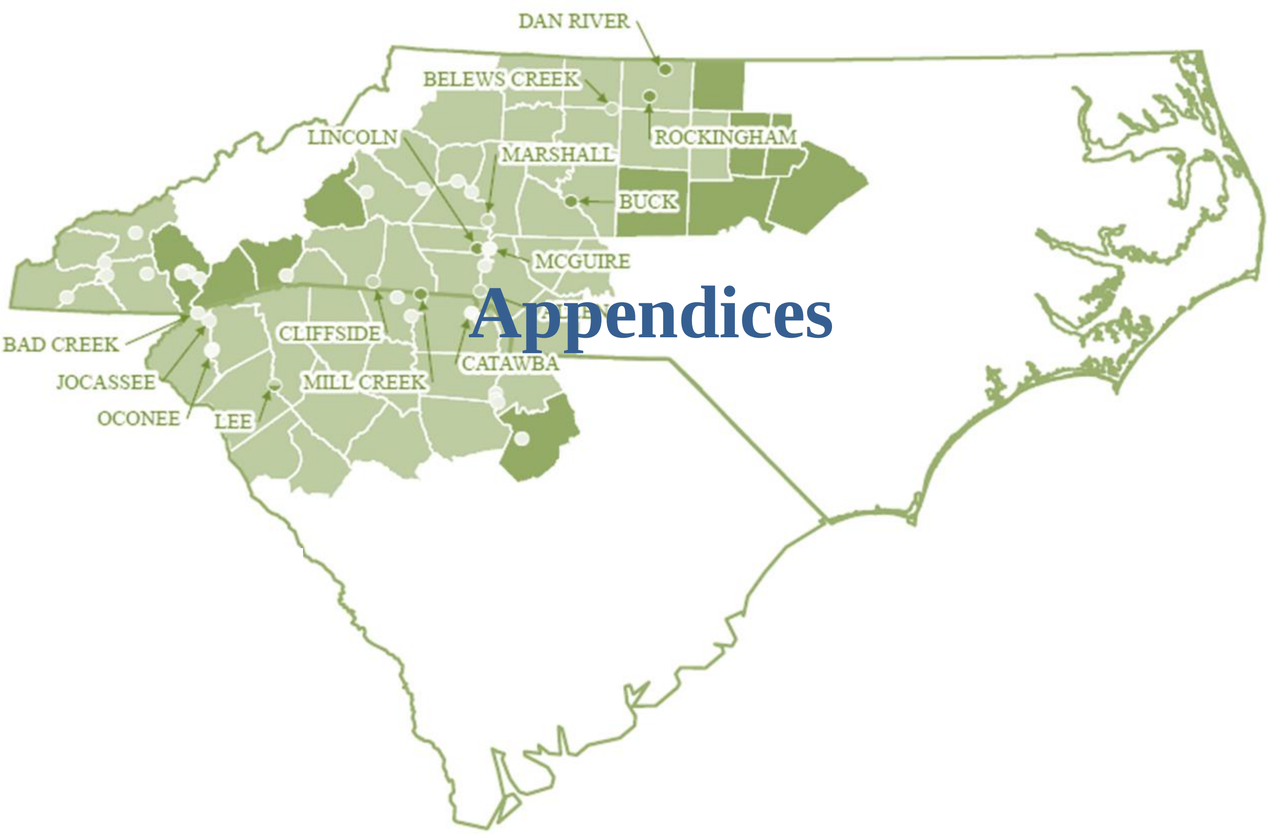
Proposals of interest were allowed to refresh bid pricing following the completion of DEC/DEP estimated interconnection costs. Proposals of interest are currently in varying stages of negotiations and contract execution.

Duke Energy Carolinas – General Compliance RFP

Under this RFP, DEC will be soliciting proposals to procure renewable resources to meet the general compliance under the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS) while expanding DECs emission free, diversified distributed generation portfolio. This RFP will seek up to 750,000 megawatt-hours (MWh) of energy and associated renewable energy certificates for projects that will achieve commercial operation within the 2017/2018 timeframe. Proposal structures allowed must be in the form of Purchased Power Agreements or Engineering, Procurement & Construction/Turnkey projects. All projects must be located in DEC's retail service territory in the state of North Carolina. There will be a preference for operational projects or projects in late stage of development.

DUKE ENERGY® CAROLINAS

Appendices



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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 DEC and DEP independently. However, an additional case representative of jointly planning future capacity on a DEC/DEP 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 1.0% after the impacts of energy efficiency programs are included.
- Generation
    - Completion of the 683 MW Lee CC in November of 2017
    - Runner upgrades totaling 185 MW between 2020 and 2024 at Bad Creek Pumped-Storage Generating Station
    - Expected nuclear up-rates of 85 MW by 2020
- Retirements - Retirement of 604 MW at Allen Steam Station (Units 1 – 3) in December 2024 and the remaining 557 MW at Allen Steam Station in June 2028 (Units 4 and 5)
- 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

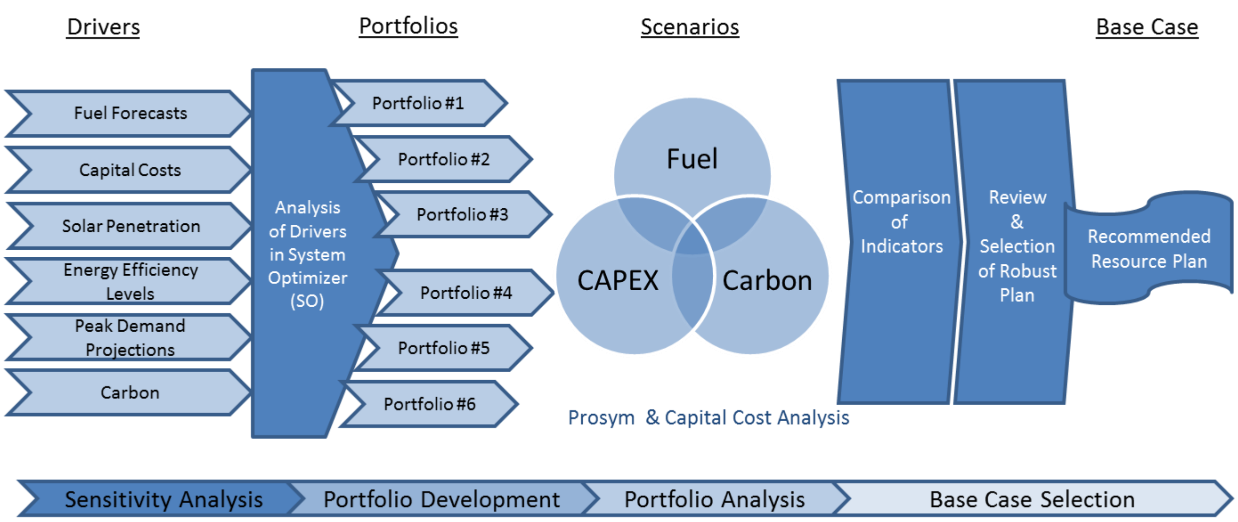
EE and DSM programs continue to be an important part of Duke Energy Carolinas' system mix. The Company considered both EE and DSM programs in the IRP analysis. As described in Appendix D, EE and DSM measures are compared to generation alternatives to identify cost-effective EE and DSM programs.

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[9]. 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 aim is 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 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:

[9] 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.

- 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.

- 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, Allen Steam Station Units 4 and 5 were retired in 2028. Allen Steam Station Units 1-3 were retired in 2024 based on the New Source Review (NSR) consent decree announced in September 2015.

  - Nuclear assets – Oconee Nuclear Station's current operating license has been extended to 60 years and expires in 2033. To date, no nuclear units in the United States have received a license extension beyond 60 years. For the purpose of this IRP, the Oconee Station is assumed to be retired in 2033.

    - 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.

- 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 Costs
  - 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 impacted 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 CO2 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.[10]

- 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 C. By 2031, this accounts for an additional 262 MW reduction in total winter load.

- Nuclear Selection – Three different options were evaluated with regards to the selection of nuclear.

  - Carbon Tax - Lee Nuclear Station was assumed to be operational in November 2026 for Unit 1 and May 2028 for Unit 2. The model allowed additional nuclear units to be economically selected through 2061.

    - A sensitivity was performed without Lee Nuclear fixed in the plan.

  - System Mass Cap - Lee Nuclear Station was assumed to be operational in November 2026 for Unit 1 and May 2028 for Unit 2. The model allowed additional nuclear units to be economically selected through 2061.

    - 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). The purpose of the sensitivity was to determine the impact on additional economically selected nuclear generation after Lee Nuclear.

  - No CO_2 regulations – Lee Nuclear Station was assumed to be operational in November 2026 for Unit 1 and May 2028 for Unit 2.

    - A sensitivity was performed without Lee Nuclear fixed in the plan.

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

- 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 DEC and DEP 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

The first two resource needs after the Lee CC Station with base EE and renewable assumptions are in 2023 and 2025. In the Carbon Tax paradigm, CC generation was selected optimally in 2023 and CT generation was selected in 2025. The CC continued to be selected in 2023 in the high fuel, high load, high capital, high EE and high renewable sensitivities. However in the low fuel and low capital sensitivities, CT generation was selected in 2023 and the CC generation was selected in 2025. Only in the load low and no CO_2 sensitivities was CC generation not selected in the 2023 to 2025 timeframe.

- 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 DEC and DEP 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 emissions continue to increase into the future. Lee Nuclear Station was input in November 2026 and May 2028 to provide an option for base load carbon free generation in the 2030 timeframe in the event of more stringent carbon regulation or in the event license extensions are not granted to existing nuclear generation. This is evident in the System Mass Cap constrained cases where Lee Nuclear and additional generic nuclear is needed in the 2032 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 that 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 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 beginning in the early 2030s until 10% of the total energy was met with solar generation.

- *High Renewables* - A sensitivity was performed using the High Renewables case in the Carbon Tax paradigm. The inclusion of the 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 2025 CT need to 2026. The inclusion of the increased implementation cost associated with the 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. Lee Nuclear was still needed by 2030 and additional generic nuclear generation was still required in the early to mid-2030's. The increased EE and Renewables did reduce the number of CCs required over the planning horizon.

Gas Firing Technology Options – In general, the first need was shown best met with CC generation, followed by CT generation through 2030. If Lee Nuclear Station is delayed additional CC generation would be selected in the 2025 timeframe.

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 Portfolios 1 – 4 would not meet a 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 also includes Lee Nuclear in November 2026 and May 2028, along with base EE and renewable assumptions.

Portfolio 2 (High Renewables, Lee Nuclear, Base EE)

This portfolio includes high renewables capacity through the planning period. In DEC, the high renewables assumption has the effect of delaying the first CT need by one year in the 15 year planning horizon. Beyond the 15 year horizon, additional CTs are delayed by one to two years with increased renewable capacity. This portfolio also includes Lee Nuclear in November 2026 and May 2028, along with base EE assumptions.

Portfolio 3 (High EE, Lee Nuclear, Base Renewables)

This portfolio includes high EE targets through the planning period. Similar to Portfolio #2, the high EE assumption has the effect of delaying the first CT need by one year in the 15 year planning horizon. Beyond the 15 year horizon, additional CTs are delayed by one to two years with increased EE targets. This portfolio also includes Lee Nuclear in November 2026 and May 2028, along with base renewable assumptions.

Portfolio 4 (CC Centric, No Lee Nuclear, Base EE/Renewables)

This portfolio replaces Lee Nuclear with two CCs; the first in November 2026 and the second in May 2028. This portfolio includes base renewable and base EE assumptions.

Portfolio 5 (System Mass Cap – Lee Nuclear + 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 2031, however from 2031 to 2040, one new nuclear plant replaces Oconee in DEC and one new nuclear plant is also required in DEP. Additionally, CT resources are replaced with CC resources in order 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 – Lee Nuclear + 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 the initial CC need to a CT need, and one new nuclear plant replaces Oconee in DEC and one new nuclear plant is also required in DEP in order to meet the carbon constraint. This portfolio also includes additional economically selected solar in the 2030s.

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 DEC 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						
2022	1123 MW CC	1123 MW CC	1123 MW CC	1123 MW CC	435 MW CT	435 MW CT
2023						
2024	435 MW CT			435 MW CT	1123 MW CC	870 MW CT
2025		435 MW CT	435 MW CT			
2026	1117 MW Lee Nuc 1	1117 MW Lee Nuc 1	1117 MW Lee Nuc 1	1123 MW CC	1117 MW Lee Nuc 1	1117 MW Lee Nuc 1
2027						
2028	1117 MW Lee Nuc 2	1117 MW Lee Nuc 2	1117 MW Lee Nuc 2	1123 MW CC	1117 MW Lee Nuc 2	1117 MW Lee Nuc 2
2029						
2030					500 Incremental Solar	
2031	435 MW CT	435 MW CT	435 MW CT	870 MW CT	435 MW CT 500 Incremental Solar	435 MW CT
2017 - 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 870 MW CT 1117 MW Lee Nuc 1 1117 MW Lee Nuc 2 0 Generic Nuclear 0 Incremental Solar	1123 MW CC 870 MW CT 1117 MW Lee Nuc 1 1117 MW Lee Nuc 2 0 Generic Nuclear 0 Incremental Solar	3369 MW CC 1305 MW CT 0 MW Lee Nuc 1 0 MW Lee Nuc 2 0 Generic Nuclear 0 Incremental Solar	1123 MW CC 870 MW CT 1117 MW Lee Nuc 1 1117 MW Lee Nuc 2 0 Generic Nuclear 1000 Incremental Solar	0 MW CC 1740 MW CT 1117 MW Lee Nuc 1 1117 MW Lee Nuc 2 0 Generic Nuclear 0 Incremental Solar

*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.

Table A-2 DEC Cumulative Solar Summary (Nameplate MWs)

Year	Portfolio #1	Portfolio #2	Portfolio #3	Portfolio #4	Portfolio #5	Portfolio #6
2017	735	805	735	735	735	805
2018	907	1,057	907	907	907	1,057
2019	1,088	1,249	1,088	1,088	1,088	1,249
2020	1,244	1,436	1,244	1,244	1,244	1,436
2021	1,416	1,609	1,416	1,416	1,416	1,609
2022	1,542	1,810	1,542	1,542	1,542	1,810
2023	1,641	1,990	1,641	1,641	1,641	1,990
2024	1,724	2,140	1,724	1,724	1,724	2,140
2025	1,801	2,281	1,801	1,801	1,801	2,281
2026	1,873	2,413	1,873	1,873	1,873	2,413
2027	1,941	2,537	1,941	1,941	1,941	2,537
2028	2,004	2,654	2,004	2,004	2,004	2,654
2029	2,063	2,763	2,063	2,063	2,063	2,763
2030	2,118	2,864	2,118	2,118	2,618	2,864
2031	2,168	2,957	2,168	2,168	3,168	2,957

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	CO2	CAPEX
1	Current Trends	Base	CO2 Tax	Base
2	Economic Recession	Low Fuel	No CO2 Tax	Low
3	Economic Expansion	High Fuel	CO2 Tax	High

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

	System Mass Cap Scenarios[2]	Fuel	CO2	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 – 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 PVRR of each portfolio compared to Portfolio #1 over the range of scenarios and sensitivities.

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

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

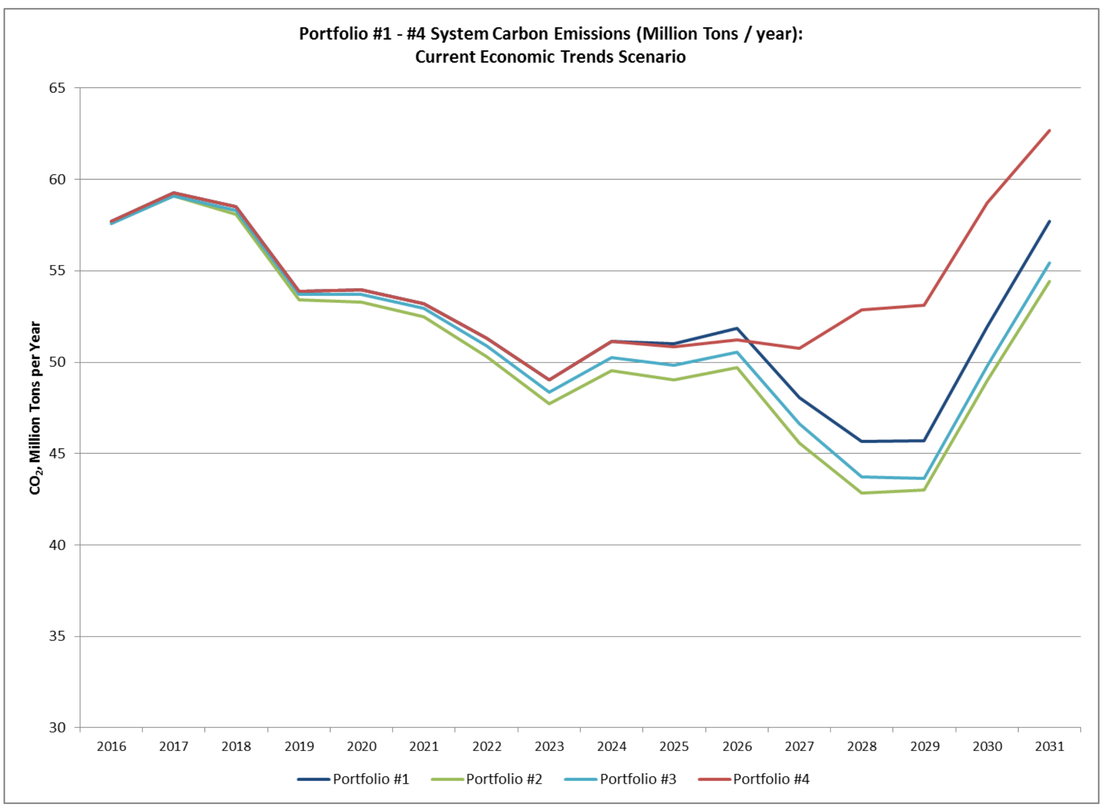
Portfolio	Scenario #1 (Current Trends)	Scenario #2 (Economic Recession)	Scenario #3 (Economic Expansion)
Portfolio #1 (Base Case)	$0	$0	$0
Portfolio #2 (High Renew)	$322	$464	$430
Portfolio #3 (High EE)	$69	$335	$22
Portfolio #4 (High CC)	-$4,992	-$6,077	-$6,212

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

In the three scenarios, Portfolio #4 (CC Centric, No Lee Nuclear) was the lowest cost portfolio due to the absence of Lee Nuclear in the expansion plan. However, Portfolio #4 had the highest total system CO2 emissions of the four portfolios. In the portfolios that included the Lee Nuclear Plant, 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. 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.

Without the addition of new nuclear in the late 2020s, or relicensing or replacement of retiring nuclear units in the early 2030s, the CO_2 emissions increase significantly beginning in the 2028 timeframe. Figure A–2 illustrates this point by comparing the total cumulative DEC and DEP 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 in DEP, all Portfolios experience increased carbon emissions.

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



Portfolio 5 and 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

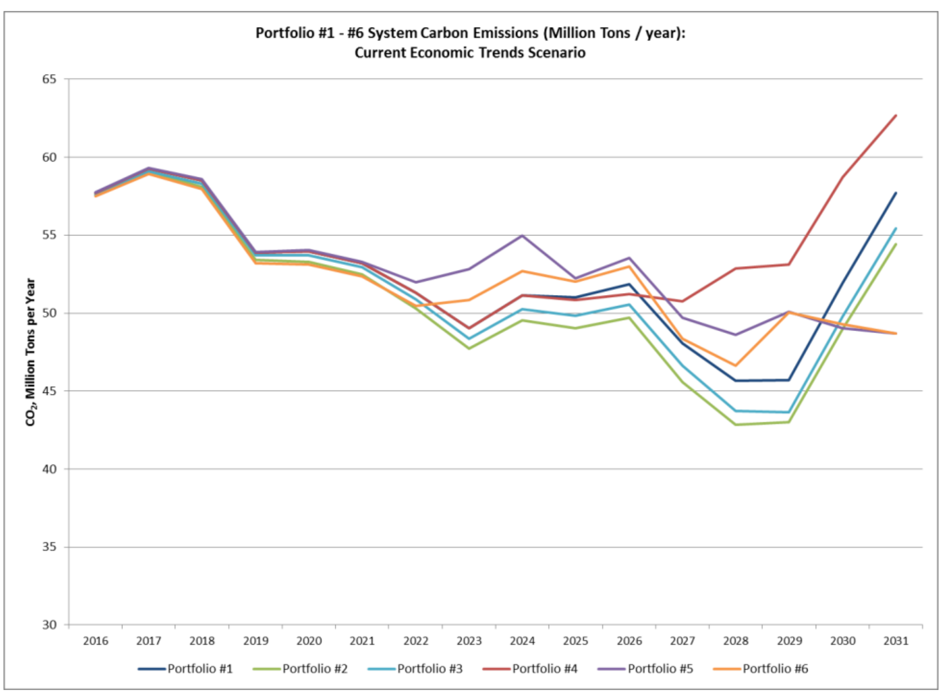
Delta PVRR 2016 - 2061, $Millions compared to Portfolio #5

Portfolio	Scenario #1 (Current Trends)
Portfolio #5 (System Mass Cap Base)	$0
Portfolio #6 (High EE / Renew)	$184

The high EE and high renewable combination led to a slightly higher PVRR versus the Base Case under a System Mass Cap carbon plan. The capital cost of the high EE/high renewable portfolio was nearly $1.9B higher than Portfolio #5, and this was mostly offset by approximately $1.7B in system production cost savings.

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

Figure A-3 Cumulative DEC & DEP 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 #4 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 plan if new nuclear generation was not available in the late 2020s to early 2030s. Portfolios 1 through 3 add Lee Nuclear Station in the 2026-2028 timeframe which leads to a reduction in CO_2 emissions of about 15% to 20% by 2030. Portfolio #1 is the least cost portfolio with Lee Nuclear Station included, but none of these portfolios would meet a System CO_2 Mass Cap scenario unless existing nuclear generation was relicensed or replaced with new nuclear generation. By 2034, approximately 3,300 MW of existing nuclear generation will be retired in DEC and DEP 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 with Lee Nuclear included 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 DEC and DEP 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 DEC and DEP to a combined Joint Planning Case in which existing and future capacity resources could be shared between DEC and DEP 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 DEC and DEP) 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 DEC and DEP 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 DEC and DEP 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 2022 through 2031. The lower reserve margin in the Joint Planning Case indicates that DEC and DEP 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 2022 to meet the minimum reserve margin requirement in the winter of 2023. 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 CO2 Mass Cap future as identified in Portfolios 5 & 6. In the 15-year planning horizon, the addition of the Lee Nuclear Station in the 2026 to 2028 timeframe and 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 CAROLINAS OWNED GENERATION

Duke Energy Carolinas' 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 Carolinas-owned generation, as well as purchased power, is evaluated on a real-time basis in order to select and dispatch the lowest-cost resources to meet system load requirements. In 2015, Duke Energy Carolinas' nuclear, coal-fired and gas-fired generating units met the vast majority of customer needs by providing 61%, 27% and 11%, respectively, of Duke Energy Carolinas' energy from generation.Hydro-electric generation, solar generation, long term PPAs, and economical purchases from the wholesale market supplied the remainder.

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

Existing Generating Units and Ratings [a, b, c, d]
All Generating Unit Ratings are as of January 1, 2016

Coal						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Allen	1	167	162	Belmont, N.C.	Coal	Peaking
Allen	2	167	162	Belmont, N.C.	Coal	Peaking
Allen	3	270	261	Belmont, N.C.	Coal	Peaking
Allen	4	282	276	Belmont, N.C.	Coal	Peaking
Allen	5	275	266	Belmont, N.C.	Coal	Peaking
Belews Creek	1	1110	1110	Belews Creek, N.C.	Coal	Base
Belews Creek	2	1110	1110	Belews Creek, N.C.	Coal	Base
Cliffside	5	556	552	Cliffside, N.C.	Coal	Peaking
Cliffside	6	844	844	Cliffside, N.C.	Coal	Intermediate
Marshall	1	380	380	Terrell, N.C.	Coal	Intermediate
Marshall	2	380	380	Terrell, N.C.	Coal	Intermediate
Marshall	3	658	658	Terrell, N.C.	Coal	Base
Marshall	4	660	660	Terrell, N.C.	Coal	Base
Total Coal		6859	6821			

Combustion Turbines						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Lee	7C	41	41	Pelzer, S.C.	Natural Gas/Oil-Fired	Peaking
Lee	8C	41	41	Pelzer, S.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	1	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	2	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	3	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	4	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	5	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	6	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	7	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	8	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	9	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	10	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	11	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	12	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	13	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	14	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	15	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	16	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	1	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	2	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	3	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	4	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	5	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	6	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	7	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	8	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	1	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	2	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	3	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	4	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	5	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Total NC		2,383	2,092			
Total SC		821	677			
Total CT		3,204	2,770			

Natural Gas Fired Boiler						
		Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Lee	3	170.0	170.0	Pelzer, N.C.	Nat. Gas	Peaking
Total Nat. Gas		170.0	170.0			

Combined Cycle						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Buck	CT11	190.7	176.3	Salisbury, N.C.	Natural Gas	Base
Buck	CT12	189.8	175.1	Salisbury, N.C.	Natural Gas	Base
Buck	ST10	316.8	316.8	Salisbury, N.C.	Natural Gas	Base
Buck CTCC		697.3	668.2			
Dan River	CT8	193.0	165.0	Eden, N.C.	Natural Gas	Base
Dan River	CT9	193.0	166.0	Eden, N.C.	Natural Gas	Base
Dan River	ST7	320.0	320.0	Eden, N.C.	Natural Gas	Base
Dan River CTCC		706.0	651.0			
Total CTCC		1,403.3	1,319.2			

Pumped Storage						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Jocassee	1	195	195	Salem, S.C.	Pumped Storage	Peaking
Jocassee	2	195	195	Salem, S.C.	Pumped Storage	Peaking
Jocassee	3	195	195	Salem, S.C.	Pumped Storage	Peaking
Jocassee	4	195	195	Salem, S.C.	Pumped Storage	Peaking
Bad Creek	1	340	340	Salem, S.C.	Pumped Storage	Peaking
Bad Creek	2	340	340	Salem, S.C.	Pumped Storage	Peaking
Bad Creek	3	340	340	Salem, S.C.	Pumped Storage	Peaking
Bad Creek	4	340	340	Salem, S.C.	Pumped Storage	Peaking
Total Pump Stor		2,140	2,140			

Hydro						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
99 Islands	1	2.4	2.4	Blacksburg, S.C.	Hydro	Peaking
99 Islands	2	2.4	2.4	Blacksburg, S.C.	Hydro	Peaking
99 Islands	3	2.4	2.4	Blacksburg, S.C.	Hydro	Peaking
99 Islands	4	2.4	2.4	Blacksburg, S.C.	Hydro	Peaking
99 Islands	5	0	0	Blacksburg, S.C.	Hydro	Peaking
99 Islands	6	0	0	Blacksburg, S.C.	Hydro	Peaking
Bear Creek	1	9.5	9.5	Tuckasegee, N.C.	Hydro	Peaking
Bridgewater	1	15	15	Morganton, N.C.	Hydro	Peaking
Bridgewater	2	15	15	Morganton, N.C.	Hydro	Peaking
Bridgewater	3	1.5	1.5	Morganton, N.C.	Hydro	Peaking
Bryson City	1	0	0	Whittier, N.C.	Hydro	Peaking
Bryson City	2	0	0	Whittier, N.C.	Hydro	Peaking
Cedar Cliff	1	6.4	6.4	Tuckasegee, N.C.	Hydro	Peaking
Cedar Cliff	2	0.4	0.4	Tuckasegee, N.C.	Hydro	Peaking
Cedar Creek	1	15	15	Great Falls, S.C.	Hydro	Peaking
Cedar Creek	2	15	15	Great Falls, S.C.	Hydro	Peaking
Cedar Creek	3	15	15	Great Falls, S.C.	Hydro	Peaking
Cowans Ford	1	81.3	81.3	Stanley, N.C.	Hydro	Peaking
Cowans Ford	2	81.3	81.3	Stanley, N.C.	Hydro	Peaking
Cowans Ford	3	81.3	81.3	Stanley, N.C.	Hydro	Peaking
Cowans Ford	4	81.3	81.3	Stanley, N.C.	Hydro	Peaking
Dearborn	1	14	14	Great Falls, S.C.	Hydro	Peaking
Dearborn	2	14	14	Great Falls, S.C.	Hydro	Peaking
Dearborn	3	14	14	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	1	11	11	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	2	9.5	9.5	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	3	9.5	9.5	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	4	11	11	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	5	8	8	Great Falls, S.C.	Hydro	Peaking
Franklin	1	0.5	0.5	Franklin, N.C.	Hydro	Peaking
Franklin	2	0.5	0.5	Franklin, N.C.	Hydro	Peaking
Gaston Shoals	3	0	0	Blacksburg, S.C.	Hydro	Peaking
Gaston Shoals	4	1	1	Blacksburg, S.C.	Hydro	Peaking
Gaston Shoals	5	1	1	Blacksburg, S.C.	Hydro	Peaking
Gaston Shoals	6	0	0	Blacksburg, S.C.	Hydro	Peaking

Hydro cont.						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Great Falls	1	3	3	Great Falls, S.C.	Hydro	Peaking
Great Falls	2	3	3	Great Falls, S.C.	Hydro	Peaking
Great Falls	3	0	0	Great Falls, S.C.	Hydro	Peaking
Great Falls	4	0	0	Great Falls, S.C.	Hydro	Peaking
Great Falls	5	3	3	Great Falls, S.C.	Hydro	Peaking
Great Falls	6	3	3	Great Falls, S.C.	Hydro	Peaking
Great Falls	7	0	0	Great Falls, S.C.	Hydro	Peaking
Great Falls	8	0	0	Great Falls, S.C.	Hydro	Peaking
Keowee	1	76	76	Seneca, S.C.	Hydro	Peaking
Keowee	2	76	76	Seneca, S.C.	Hydro	Peaking
Lookout Shoals	1	9.3	9.3	Statesville, N.C.	Hydro	Peaking
Lookout Shoals	2	9.3	9.3	Statesville, N.C.	Hydro	Peaking
Lookout Shoals	3	9.3	9.3	Statesville, N.C.	Hydro	Peaking
Mission	1	0.6	0.6	Murphy, N.C.	Hydro	Peaking
Mission	2	0.6	0.6	Murphy, N.C.	Hydro	Peaking
Mission	3	0	0	Murphy, N.C.	Hydro	Peaking
Mountain Island	1	14	14	Mount Holly, N.C.	Hydro	Peaking
Mountain Island	2	14	14	Mount Holly, N.C.	Hydro	Peaking
Mountain Island	3	17	17	Mount Holly, N.C.	Hydro	Peaking
Mountain Island	4	17	17	Mount Holly, N.C.	Hydro	Peaking
Nantahala	1	50	50	Topton, N.C.	Hydro	Peaking
Oxford	1	20	20	Conover, N.C.	Hydro	Peaking
Oxford	2	20	20	Conover, N.C.	Hydro	Peaking
Queens Creek	1	1.4	1.4	Topton, N.C.	Hydro	Peaking
Rhodhiss	1	9.5	9.5	Rhodhiss, N.C.	Hydro	Peaking
Rhodhiss	2	11.5	11.5	Rhodhiss, N.C.	Hydro	Peaking
Rhodhiss	3	12.4	12.4	Rhodhiss, N.C.	Hydro	Peaking
Rocky Creek	1	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	2	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	3	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	4	0	0	Great Falls, S.C.	Hydro	Peaking

Hydro cont.						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Rocky Creek	5	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	6	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	7	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	8	0	0	Great Falls, S.C.	Hydro	Peaking
Tuxedo	1	3.2	3.2	Flat Rock, N.C.	Hydro	Peaking
Tuxedo	2	3.2	3.2	Flat Rock, N.C.	Hydro	Peaking
Tennessee Creek	1	9.8	9.8	Tuckasegee, N.C.	Hydro	Peaking
Thorpe	1	19.7	19.7	Tuckasegee, N.C.	Hydro	Peaking
Tuckasegee	1	2.5	2.5	Tuckasegee, N.C.	Hydro	Peaking
Wateree	1	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	2	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	3	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	4	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	5	17	17	Ridgeway, S.C.	Hydro	Peaking
Wylie	1	18	18	Fort Mill, S.C.	Hydro	Peaking
Wylie	2	18	18	Fort Mill, S.C.	Hydro	Peaking
Wylie	3	18	18	Fort Mill, S.C.	Hydro	Peaking
Wylie	4	18	18	Fort Mill, S.C.	Hydro	Peaking
Total NC		628.3	628.3			
Total SC		468.6	468.6			
Total Hydro		1,096.9	1,096.9			

Solar						
		Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
NC Solar		3.87	3.87	N.C.	Solar	Intermittent
Total Solar		3.87	3.87			

Nuclear						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
McGuire	1	1199.0	1158.0	Huntersville, N.C.	Nuclear	Base
McGuire	2	1187.2	1157.6	Huntersville, N.C.	Nuclear	Base
Catawba	1	1173.7	1140.1	York, S.C.	Nuclear	Base
Catawba	2	1179.8	1150.1	York, S.C.	Nuclear	Base
Oconee	1	865	847	Seneca, S.C.	Nuclear	Base
Oconee	2	872	848	Seneca, S.C.	Nuclear	Base
Oconee	3	881	859	Seneca, S.C.	Nuclear	Base
Total NC		2,386.2	2,315.6			
Total SC		4,971.5	4,844.2			
Total Nuclear		7,357.7	7,159.8			

Total Generation Capability		
	Winter Capacity (MW)	Summer Capacity (MW)
TOTAL DEC SYSTEM - N.C.	13,664	13,180
TOTAL DEC SYSTEM – S.C.	8,571	8,300
TOTAL DEC SYSTEM	22,235	21,480

Note a: Unit information is provided by State, but resources are dispatched on a system-wide basis.

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

Note c: Catawba Units 1 and 2 capacity reflects 100% of the station's capability, and does not factor in NCMPA#1's decision to sell or utilize its 832 MW retained ownership in Catawba.

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

Catawba Owner	Percent Of Ownership
Duke Energy Carolinas	19.246%
North Carolina Electric Membership Corporation (NCEMC)	30.754%
NCMPA#1	37.5%
PMPA	12.5%

Planned Uprates			
Unit	Date	Winter MW	Summer MW
Catawba 1[a,b]	June 2016	25	20
Oconee 1[b]	March 2019	20	15
Oconee 2[b]	March 2019	20	15
Oconee 3[b]	March 2019	20	15

Note a: The capacity represented in this table is the total operating capacity addition and is not adjusted for the Joint Exchange Agreement for Catawba and McGuire. The adjusted values are utilized in the resource plan.

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

Planned Additions			
Unit	Date	Winter MW	Summer MW
Lee CC[a]	Nov 2017	783	753
Bad Creek 1[c]	June 2023	46.4	46.4
Bad Creek 2[c]	June 2020	46.4	46.4
Bad Creek 3[c]	June 2021	46.4	46.4
Bad Creek 4[c]	June 2022	46.4	46.4
Gaston Shoals 6[b]	8/1/2016	1.7	1.7
Mission 3[b]	7/1/2016	.6	.6
Bryson City 1[b]	5/1/2016	.5	.5
Bryson City 2[b]	5/1/2016	.5	.5

Note a: Includes 100 MW ownership by NCEMC.
Note b: Units expected to return to service.
Note c: Order of Bad Creek uprates subject to change.

Retirements				
Unit & Plant Name	Location	Capacity (MW) Winter / Summer	Fuel Type	Retirement Date
Buck 3[a]	Salisbury, N.C.	76/75	Coal	05/15/11
Buck 4[a]	Salisbury, N.C.	39/38	Coal	05/15/11
Cliffside 1[a]	Cliffside, N.C.	39/38	Coal	10/1/11
Cliffside 2[a]	Cliffside, N.C.	39/38	Coal	10/1/11
Cliffside 3[a]	Cliffside, N.C.	62/61	Coal	10/1/11
Cliffside 4[a]	Cliffside, N.C.	62/61	Coal	10/1/11
Dan River 1[a]	Eden, N.C.	69/67	Coal	04/1/12
Dan River 2[a]	Eden, N.C.	69/67	Coal	04/1/12
Dan River 3[a]	Eden, N.C.	145/142	Coal	04/1/12
Buzzard Roost 6C[b]	Chappels, S.C.	20/20	Combustion Turbine	10/1/12
Buzzard Roost 7C[b]	Chappels, S.C.	20/20	Combustion Turbine	10/1/12
Buzzard Roost 8C	Chappels, S.C.	20/20	Combustion Turbine	10/1/12
Buzzard Roost 9C[b]	Chappels, S.C.	20/20	Combustion Turbine	10/1/12
Buzzard Roost 10C[b]	Chappels, S.C.	16/16	Combustion Turbine	10/1/12
Buzzard Roost 11C[b]	Chappels, S.C.	16/16	Combustion Turbine	10/1/12
Buzzard Roost 12C[b]	Chappels, S.C.	16/16	Combustion Turbine	10/1/12
Buzzard Roost 13C[b]	Chappels, S.C.	16/16	Combustion Turbine	10/1/12
Buzzard Roost 14C[b]	Chappels, S.C.	16/16	Combustion Turbine	10/1/12
Buzzard Roost 15C[b]	Chappels, S.C.	16/16	Combustion Turbine	10/1/12
Riverbend 8C[b]	Mt. Holly, N.C.	20/20	Combustion Turbine	10/1/12
Riverbend 9C[b]	Mt. Holly, N.C.	30/22	Combustion Turbine	10/1/12
Riverbend 10C[b]	Mt. Holly, N.C.	30/22	Combustion Turbine	10/1/12
Riverbend 11C[b]	Mt. Holly, N.C.	30/20	Combustion Turbine	10/1/12
Buck 7C[b]	Spencer, N.C.	30/25	Combustion Turbine	10/1/12
Buck 8C[b]	Spencer, N.C.	30/25	Combustion Turbine	10/1/12
Buck 9C[b]	Spencer, N.C.	16/12	Combustion Turbine	10/1/12
Dan River 4C[b]	Eden, N.C.	31/24	Combustion Turbine	10/1/12
Dan River 5C[b]	Eden, N.C.	31/24	Combustion Turbine	10/1/12
Dan River 6C[b]	Eden, N.C.	31/24	Combustion Turbine	10/1/12
Riverbend 4[a]	Mt. Holly, N.C.	96/94	Coal	04/1/13
Riverbend 5[a]	Mt. Holly, N.C.	96/94	Coal	04/1/13
Riverbend 6[c]	Mt. Holly, N.C.	136/133	Coal	04/1/13
Riverbend 7[c]	Mt. Holly, N.C.	136/133	Coal	04/1/13
Buck 5[c]	Spencer, N.C.	131/128	Coal	04/1/13
Buck 6[c]	Spencer, N.C.	131/128	Coal	04/1/13
Lee 1[d]	Pelzer, S.C.	100/100	Coal	11/6/14
Lee 2[d]	Pelzer, S.C.	102/100	Coal	11/6/14
Lee 3[e]	Pelzer, S.C.	173/170	Coal	05/12/15*
	Total	2,156 MW / 2,037 MW		

Note a: Retirement assumptions associated with the conditions in the NCUC Order in Docket No. E-7, Sub 790, granting a CPCN to build Cliffside Unit 6.

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

Note c: The decision was made to retire Buck 5 & 6 and Riverbend 6 & 7 early on April 1, 2013. The original expected retirement date was April 15, 2015.

Note d: Lee Steam Units 1 and 2 were retired November 6, 2014.

Note e: The conversion of the Lee 3 coal unit to a natural gas unit was effective March 12, 2015.

Planning Assumptions – Unit Retirements

Unit & Plant Name	Location	Winter Capacity (MW)	Summer Capacity (MW)	Fuel Type	Expected Retirement
Allen 1[a]	Belmont, NC	167	162	Coal	12/2024
Allen 2[a]	Belmont, NC	167	162	Coal	12/2024
Allen 3[a]	Belmont, NC	270	261	Coal	12/2024
Allen 4[a]	Belmont, NC	282	276	Coal	6/2028
Allen 5[a]	Belmont, NC	275	266	Coal	6/2028
Oconee 1[b,c]	Seneca, SC	865	847	Nuclear	5/2033
Oconee 2[b,c]	Seneca, SC	872	848	Nuclear	5/2033
Oconee 3[b,c]	Seneca, SC	881	859	Nuclear	5/2033
Total		3,779	3,681		

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: Oconee capacity includes scheduled uprates (15 MW/unit).

Operating License Renewal

Operating License Renewal				
Plant & Unit Name	Location	Original Operating License Expiration	Date of Approval	Operating License Expiration
Catawba Unit 1	York, SC	12/6/2024	12/5/2003	12/5/2043
Catawba Unit 2	York, SC	2/24/2026	12/5/2003	12/5/2043
McGuire Unit 1	Huntersville, NC	6/12/2021	12/5/2003	6/12/2041
McGuire Unit 2	Huntersville, NC	3/3/2023	12/5/2003	3/3/2043
Oconee Unit 1	Seneca, SC	2/6/2013	5/23/2000	2/6/2033
Oconee Unit 2	Seneca, SC	10/6/2013	5/23/2000	10/6/2033
Oconee Unit 3	Seneca, SC	7/19/2014	5/23/2000	7/19/2034
Bad Creek (PS)(1-4)	Salem, SC	N/A	8/1/1977	7//31/2027
Jocassee (PS) (1-4)	Salem, SC	N/A	9/1/2016	8/31/2046
Cowans Ford (1-4)	Stanley, NC	8/31/2008	11/1/2015	10/31/2055
Keowee (1&2)	Seneca, SC	N/A	9/1/2016	8/31/2046
Rhodhiss (1-3)	Rhodhiss, NC	8/31/2008	11/1/2015	10/31/2055
Bridge Water (1-3)	Morganton, NC	8/31/2008	11/1/2015	10/31/2055
Oxford (1&2)	Conover, NC	8/31/2008	11/1/2015	10/31/2055
Lookout Shoals (1-3)	Statesville, NC	8/31/2008	11/1/2015	10/31/2055
Mountain Island (1-4)	Mount Holly, NC	8/31/2008	11/1/2015	10/31/2055
Wylie (1-4)	Fort Mill, SC	8/31/2008	11/1/2015	10/31/2055
Fishing Creek (1-5)	Great Falls, SC	8/31/2008	11/1/2015	10/31/2055
Great Falls (1-8)	Great Falls, SC	8/31/2008	11/1/2015	10/31/2055
Dearborn (1-3)	Great Falls, SC	8/31/2008	11/1/2015	10/31/2055
Rocky Creek (1-8)	Great Falls, SC	8/31/2008	11/1/2015	10/31/2055
Cedar Creek (1-3)	Great Falls, SC	8/31/2008	11/1/2015	10/31/2055
Wateree (1-5)	Ridgeway, SC	8/31/2008	11/1/2015	10/31/2055
Gaston Shoals (3-6)	Blacksburg, SC	12/31/1993	6/1/1996	5/31/2036
Tuxedo (1&2)	Flat Rock, NC	N/A	N/A	N/A
Ninety Nine (1-6)	Blacksburg, SC	12/31/1993	6/1/1996	5/31/2036
Cedar Cliff (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Bear Creek (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Tennessee Creek (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Nantahala (1)	Topton, NC	2/28/2006	2/1/2012	1/31/2042

Planned Operating License Renewal cont.				
Plant & Unit Name	Location	Original Operating License Expiration	Date of Approval	Extended Operating License Expiration
Queens Creek (1)	Topton, NC	9/30/2001	3/1/2002	2/29/2032
Thorpe (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Tuckasegee (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Bryson City (1&2)	Whittier, NC	7/31/2005	7/1/2011	6/30/2041
Franklin (1&2)	Franklin, NC	7/31/2005	9/1/2011	8/31/2041
Mission (1-3)	Murphy, NC	7/31/2005	10/1/2011	9/30/2041

APPENDIX C: ELECTRIC LOAD FORECAST

Methodology

The Duke Energy Carolinas' 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 represent 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. DEC has used regression analysis since 1979 and this technique 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 slightly negative to 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 1.2%.

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 all 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 0.9% 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 51 counties that comprise the DEC 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 rends 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 DEC's Spring 2016 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 DEC 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 DEC customers and sales are given. As a note, the values in Table C-2 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	2,452

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

	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential	27,459	27,335	27,273	30,049	28,323	26,279	26,895	27,976	27,916
Commercial	27,433	27,288	26,977	27,968	27,593	27,476	27,765	28,421	28,700
Industrial	23,948	22,634	19,204	20,618	20,783	20,978	21,070	21,577	22,136
Other	278	284	287	287	287	290	293	303	305
Total Retail	79,118	77,541	73,741	78,922	76,985	75,022	78,035	78,278	79,057
Wholesale	2,454	3,525	3,788	5,166	4,866	5,176	5,824	6,559	6,560
Total System	81,572	81,066	77,528	84,088	81,851	80,199	83,859	84,837	85,617

Utility Energy Efficiency

A new process for reflecting the impacts of UEE on the forecast was introduced in Spring 2015. The Spring 2016 Forecast continued this process. 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	98,044	3,148	573	0	573	97,470
2018	99,287	3,472	942	0	942	98,345
2019	99,409	3,782	1,278	0	1,278	98,131
2020	100,736	4,087	1,605	0	1,605	99,132
2021	101,902	4,392	1,929	0	1,929	99,973
2022	102,883	4,697	2,253	0	2,253	100,630
2023	104,249	5,002	2,576	3	2,573	101,676
2024	105,784	5,307	2,897	15	2,882	102,902
2025	107,033	5,613	3,205	62	3,143	103,890
2026	108,442	5,918	3,499	135	3,365	105,078
2027	109,734	6,223	3,793	314	3,480	106,255
2028	111,136	6,528	4,099	608	3,490	107,646
2029	112,299	6,833	4,404	899	3,504	108,794
2030	113,596	7,138	4,709	1,187	3,522	110,074
2031	114,949	7,444	5,014	1,472	3,542	111,407

Results

A tabulation of class forecasts of customers and sales are given in Table C-4 and Table C-5. The sales forecasts are after all adjustments for UEE, Solar and Electric Vehicles, and are at the customer meter, excluding Wholesale.

A tabulation of the utility's forecasts, 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-6 and C-7. These projections are at generation and include Wholesale. Load duration curves, with and without UEE programs are shown as Charts C-1 and C-2.

The values in these tables reflect the loads that Duke Energy Carolinas 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 Carolinas 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 Carolinas UEE programs are included, the projected compound annual growth rate for the summer peak demand is 1.2%, while winter peaks are forecasted to grow at a rate of 1.3%. The forecasted compound annual growth rate for energy is 1.0% after the impacts of UEE programs are subtracted.

The peaks and sales in the tables and charts below are at generation, except for the Class sales forecast, which is at meter.

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

	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2017	2,171	355	6	15	2,547
2018	2,197	359	6	16	2,578
2019	2,223	363	6	16	2,608
2020	2,247	368	6	16	2,637
2021	2,272	372	6	16	2,667
2022	2,297	377	6	16	2,696
2023	2,322	381	6	16	2,726
2024	2,347	386	6	17	2,755
2025	2,369	390	6	17	2,783
2026	2,392	395	6	17	2,811
2027	2,415	400	6	17	2,838
2028	2,438	404	6	17	2,866
2029	2,461	409	6	17	2,893
2030	2,483	414	6	18	2,921
2031	2,506	418	6	18	2,949

Note: Table 8.C differs from these values due to a 47 MW PMPA backstand contract through 2020.

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

	Residential	Commercial	Industrial	Other	Retail
	Gwh	Gwh	Gwh	Gwh	Gwh
2017	27,797	28,710	22,430	298	79,235
2018	28,011	28,935	22,634	294	79,874
2019	28,266	29,193	22,842	289	80,591
2020	28,617	29,544	23,046	284	81,491
2021	28,880	29,881	23,218	277	82,256
2022	29,207	30,232	23,409	271	83,119
2023	29,565	30,611	23,606	265	84,046
2024	29,967	31,076	23,827	258	85,128
2025	30,296	31,462	24,013	252	86,024
2026	30,699	31,896	24,222	247	87,064
2027	31,095	32,354	24,401	241	88,091
2028	31,549	32,877	24,630	235	89,292
2029	31,917	33,331	24,815	230	90,293
2030	32,316	33,828	25,037	225	91,406
2031	32,719	34,366	25,262	223	92,569

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

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2017	18,830	18,473	98,044
2018	19,112	18,772	99,287
2019	19,136	18,869	99,409
2020	19,399	19,148	100,736
2021	19,685	19,513	101,902
2022	19,933	19,764	102,883
2023	20,229	20,071	104,249
2024	20,521	20,389	105,784
2025	20,837	20,638	107,033
2026	21,130	21,003	108,442
2027	21,405	21,290	109,734
2028	21,712	21,609	111,136
2029	21,998	21,929	112,299
2030	22,297	22,193	113,596
2031	22,603	22,530	114,949

Chart C-1
Load Duration Curve without Energy Efficiency Programs and Before Demand Reduction Programs

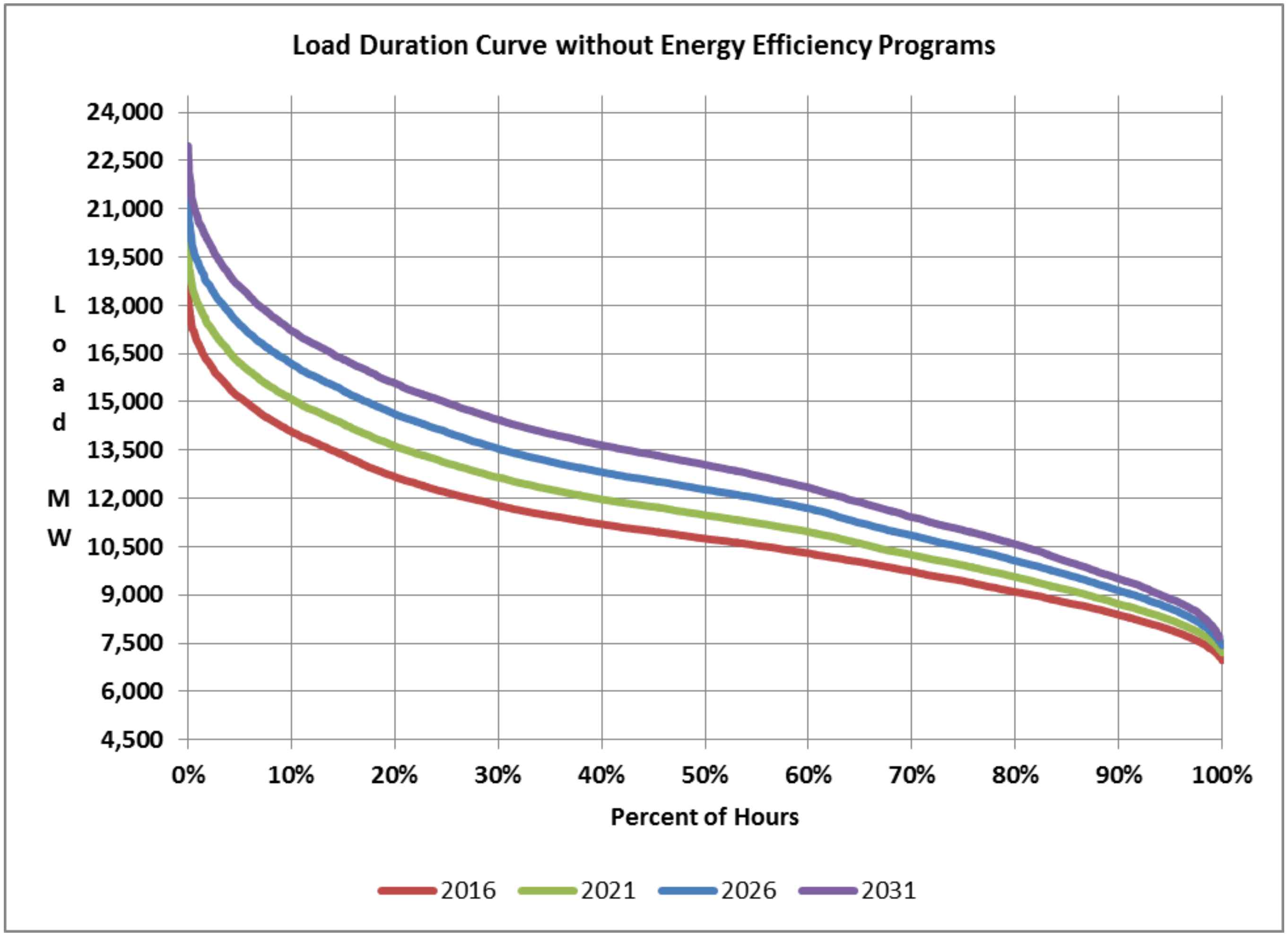
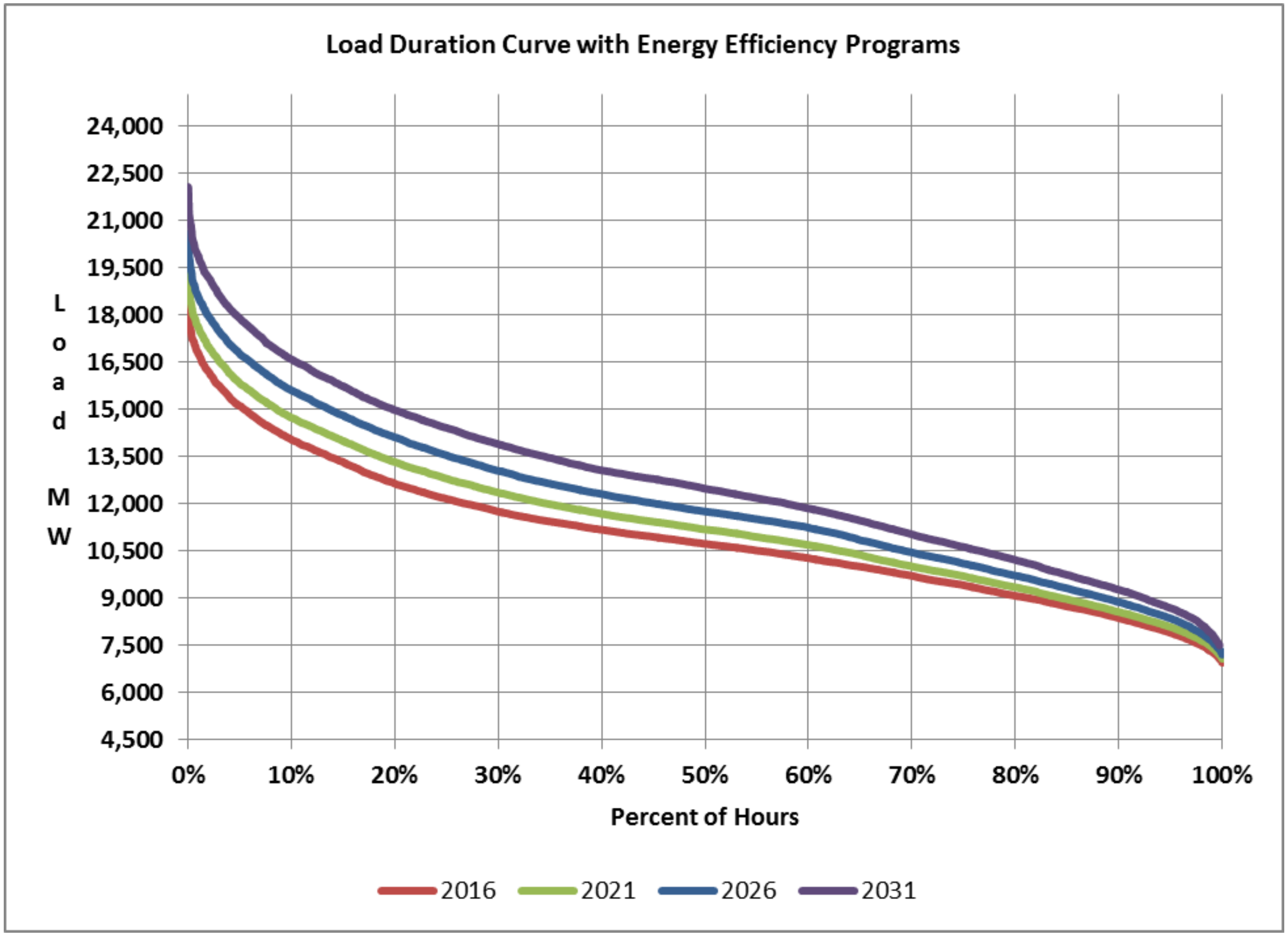


Table C-7
Load Forecast with Energy Efficiency Programs and Before Demand Reduction Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2017	18,729	18,416	97,470
2018	18,948	18,665	98,345
2019	18,916	18,721	98,131
2020	19,127	18,957	99,132
2021	19,362	19,259	99,973
2022	19,562	19,466	100,630
2023	19,804	19,731	101,676
2024	20,046	20,011	102,902
2025	20,321	20,223	103,890
2026	20,581	20,570	105,078
2027	20,842	20,844	106,255
2028	21,146	21,161	107,646
2029	21,427	21,478	108,794
2030	21,723	21,734	110,074
2031	22,028	22,068	111,407

Chart C-2
Load Duration Curve with Energy Efficiency Programs & Before Demand Reduction Programs



APPENDIX D: ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT

Current Energy Efficiency and Demand-Side Management Programs

DEC 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 available through DEC as of December 31, 2015:

Residential Customer Programs

- Appliance Recycling Program
- Energy Assessments Program
- Energy Efficiency Education Program
- Energy Efficient Appliances and Devices
- Heating, Ventilation and Air Conditioning (HVAC) Energy Efficiency Program
- Multi-Family Energy Efficiency Program
- My Home Energy Report
- Income-Qualified Energy Efficiency and Weatherization Program
- Power Manager

Non-Residential Customer Programs

- Non-Residential Smart $aver® Energy Efficient Food Service Products Program
- Non-Residential Smart $aver® Energy Efficient HVAC Products Program
- Non-Residential Smart $aver® Energy Efficient IT Products Program
- Non-Residential Smart $aver ®Energy Efficient Lighting Products Program
- Non-Residential Smart $aver® Energy Efficient Process Equipment Products Program
- Non-Residential Smart $aver® Energy Efficient Pumps and Drives Products Program
- Non-Residential Smart $aver® Custom Program
- Non-Residential Smart $aver® Custom Energy Assessments Program
- Small Business Energy Saver
- Smart Energy in Offices
- PowerShare®

- PowerShare® CallOption
- EnergyWise[SM] for Business

In addition, based on feedback from stakeholders, the Company has developed a pilot program for non-residential customers that has received Commission approval and the expected impacts are included in this IRP analysis.

Pilot Program

- Business Energy Report Pilot

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[11]) 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 DEC's existing EE programs:

<u>Residential Programs</u>

Appliance Recycling Program promotes the removal and responsible disposal of operating refrigerators and freezers from DEC residential customers. The 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 2016 were not included in this IRP analysis.

[11] "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.

Appliance Recycling Program			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	30,827	31,549	4,314

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.

Residential Energy Assessments			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	50,246	49,715	7,926

Two previously offered Residential Energy Assessment measures were no longer offered in the new portfolio effective January 1, 2014. The historical performance of these measures through December 31, 2013 is included below.

Personalized Energy Report			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2013	86,333	24,502	2,790

Online Home Energy Comparison Report			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2013	12,902	3,547	387

Energy Efficiency Education Program is designed to educate students in grades K-12 about energy and the impact they can have by becoming more energy efficient and using energy more wisely. In conjunction with teachers and administrators, the Company will provide educational materials and curriculum for targeted schools and grades that meet grade-appropriate state education standards. The curriculum and engagement method may vary over time to adjust to market conditions, but currently utilizes theatre to deliver the program into the school. Enhancing the message with a live theatrical production truly captures the children's attention and reinforces the classroom and take-home assignments. Students learn about EE measures in the Energy Efficiency Starter Kit and then implement these energy saving measures in their homes. Students are sharing what they have learned with their parents and helping their entire households learn how to save more energy.

Energy Efficiency Education Program			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	128,507	32,708	5,513

Energy Efficient Appliances and Devices Program (formerly part of Residential Smart $aver® program) provides incentives to residential customers for installing energy efficient appliances and devices to drive reductions in energy usage. The program includes the following measures:

- Energy Efficient Pool Equipment: This measure encourages the purchase and installation of energy efficient equipment and controls. Initially, the measure will focus on variable speed pumps, but the pool equipment offerings may evolve with the marketplace to include additional equipment options and control devices that reduce energy consumption and/or demand.
- Energy Efficient Lighting: This measure encourages the installation of energy efficient lighting products and controls. The product examples may include, but are not limited to the following: standard compact fluorescent light bulbs (CFLs), specialty CFLs, A lamp light emitting diodes (LEDs), specialty LEDs, CFL fixtures, LED fixtures, 2X

incandescent, LED holiday lighting, motion sensors, photo cells, timers, dimmers and daylight sensors.

- Energy Efficient Water Heating and Usage: This measure encourages the adoption of heat pump water heaters, insulation, temperature cards and low flow devices.
- Other Energy Efficiency Products and Services: Other cost-effective measures may be added to in-home installations, purchases, enrollments and events. Examples of additional measures may include, without limitation, outlet gaskets, switch gaskets, weather stripping, filter whistles, fireplace damper seals, caulking, smart strips and energy education tools/materials.

Residential Smart $aver® Program – Residential CFLs

Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2015	31,424,759	1,267,996	135,691

Residential Smart $aver® Program – Specialty Lighting

Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2015	1,175,317	51,027	6,195

Residential Smart $aver® Program – Water Measures

Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2015	414,788	32,271	3,163

Residential Smart $aver® Program – Pool Equipment

Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2015	469	1,167	294

Heating, Ventilation, and Air Conditioning (HVAC) Energy Efficiency Program (formerly part of Residential Smart $aver® program) provides residential customers with opportunities to lower their home's electric use through maintenance and improvements to their central HVAC system(s) as well as the structure of their home's building envelope and duct system(s). This program reaches Duke Energy Carolinas customers during the decision-making process for measures included in the program. Each measure offered through the program will have a prescribed incentive associated with successful completion by an approved contractor. The prescriptive and a-la-carte design of the program allows customers to implement individual, high priority measures in their homes without having to commit to multiple measures and higher price tags. The measures eligible for incentives through the program are:

- Central Air Conditioner
- Heat Pump
- Attic Insulation and Air Sealing
- Duct Sealing
- Duct Insulation
- Central Air Conditioner Tune Up
- Heat Pump Tune Up

As of the time of the analysis for this IRP, the cost effectiveness of this program had declined below the allowable threshold and, as a result, projected impacts from this program were not included in the analysis for this IRP. However, work is underway to improve the cost effectiveness and a proposal was submitted and approved by the NC Public Staff (NCPS) and the SC Office of Regulatory Staff (ORS) to implement a revised program design, subject to evaluation of the results after the first year of the program.

Residential Smart $aver® Program -- HVAC			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2015	71,446	54,295	16,031

Residential Smart $aver® Program -- Tune and Seal			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2015	2,361	1,402	441

Multi-Family Energy Efficiency Program provides energy efficient technologies to be installed in multi-family dwellings, which include, but are not limited to, the following:

- Energy Efficient Lighting
- Energy Efficient Water Heating Measures
- Other cost-effective measures may be added to in-home installations, purchases, enrollments and events. Examples of additional measures may include, without limitation, outlet gaskets, switch gaskets, weather stripping, filter whistles, fireplace damper seals, caulking, smart strips and energy education tools/materials.

Residential Smart $aver® Program – Property Manager CFLs			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	1,080,822	46,608	4,800

Residential Smart $aver® Program – Multi Family Water Measures			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	223,812	18,283	1,715

My Home Energy Report Program provides residential customers with a comparative usage report up to twelve times a year that engages and motivates customers by comparing energy use to similar residences in the same geographical area based upon the age, size and heating source of the home. The report also empowers customers to become more efficient by providing them with specific energy saving recommendations to improve the efficiency of their homes. The actionable energy savings tips, as well as measure-specific coupons, rebates or other Company program offers that may be included in a customer's report are based on that specific customer's energy profile.

My Home Energy Report Program			
	Number of	Gross Savings (at plant)	
Capability as of:	Participants	MWh Energy	Peak kW
December 31, 2015	1,045,780	228,776	61,770

Income-Qualified Energy Efficiency and Weatherization Program consists of three distinct components designed to provide EE to different segments of its low income customers:

- The Residential Neighborhood Program (RNP) is available only to individually-metered residences served by Duke Energy Carolinas in neighborhoods selected by the Company, which are considered low-income based on third party and census data, which includes income level and household size. Neighborhoods targeted for participation in this program will typically have approximately 50% or more of the households with income below 200% of the poverty level established by the U.S. Government. This approach allows the Company to reach a larger audience of low income customers than traditional government agency flow-through methods. The program provides customers with the direct installation of measures into the home to increase the EE and comfort level of the home. Additionally, customers receive EE education to encourage behavioral changes for managing energy usage and costs.
- The Company recognizes the existence of customers whose EE needs surpass the standard low cost measure offerings provided through RNP. In order to accommodate customers needing this more substantial assistance, the Company will also offer the following two programs that are deployed in conjunction with the existing government-funded North Carolina Weatherization Assistance Program when feasible. Collaborating with these programs will result in a reduction of overhead and administration costs.
- The Refrigerator Replacement Program (RRP) includes, but is not limited to, replacement of inefficient operable refrigerators in low income households. The program will be available to homeowners, renters, and landlords with income qualified tenants that own a qualified appliance. Income eligibility for RRP will mirror the income eligibility standards for the North Carolina Weatherization Assistance Program.

Income Qualified Energy Efficiency and Weatherization Program			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	32,122	14,343	2,341

Non-Residential

The Non-Residential Smart $aver® programs are listed separately below by technology but for the purpose of reporting the historical performance, all of the historical impacts are combined into a single Non-Residential Smart $aver® total.

Non-Residential Smart $aver® Energy Efficient Food Service Products Program provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency food service equipment in new and existing non-residential establishments and repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, commercial refrigerators and freezers, steam cookers, pre-rinse sprayers, vending machine controllers, and anti-sweat heater controls.

Non-Residential Smart $aver® Energy Efficient HVAC Products Program provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficient HVAC equipment in new and existing non-residential establishments and efficiency-directed repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, chillers, unitary and rooftop air conditioners, programmable thermostats, and guest room energy management systems.

Non-Residential Smart $aver® Energy Efficient Information Technologies (IT) Products Program provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of high efficiency new IT equipment in new and existing non-residential establishments and efficiency-directed repairs to maintain or enhance efficiency levels in currently-installed equipment. Measures include, but are not limited to, Energy Star-rated desktop computers and servers, PC power management from network, server virtualization, variable frequency drives (VFD) for computer room air conditioners and VFD for chilled water pumps.

Non-Residential Smart $aver® Energy Efficient Lighting Products Program provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency lighting equipment in new and existing non-residential establishments and the efficiency-directed repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, interior and exterior LED lamps and fixtures, reduced wattage and high performance T8 systems, T8 and T5 high bay fixtures, and occupancy sensors.

Non-Residential Smart $aver® Energy Efficient Process Equipment Products Program provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency equipment in new and existing non-residential establishments and efficiency-directed repairs to maintain or enhance high efficiency levels in currently installed equipment. Measures include, but are not limited to, VFD air compressors, barrel wraps, and pellet dryer insulation.

Non-Residential Smart $aver® Energy Efficient Pumps and Drives Products Program provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency equipment in new and existing non-residential establishments and efficiency-directed repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, pumps and VFD on HVAC pumps and fans.

Non-Residential Smart $aver® Custom Program provides custom incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency equipment in new and existing non-residential establishments. This program allows for eligible customers to apply for and the Company to provide custom incentives in the amount up to 75% of the installed cost difference between standard equipment and new higher efficiency equipment or efficiency-directed repair activities in order to cover measures and efficiency-driven activities that are not offered in the various Non-Residential Smart $aver prescriptive programs.

Non-Residential Smart $aver® Custom Energy Assessments Program provides customers who may be unaware of EE opportunities at their facilities with a custom incentive payment in the amount up to 50% of the costs of a qualifying energy assessment. The purpose of this component of the program is to overcome financial barriers by off-setting a customer's upfront costs to identify and evaluate EE projects that will lead to the installation of energy efficient measures. The scope of an energy assessment may include but is not limited to a facility energy audit, a new construction/renovation energy performance simulation, a system energy study and retro-commissioning service. After the energy assessment is complete, program participants may receive an additional custom incentive payment in the amount of up to 75% of the installed cost difference between standard equipment and higher efficiency equipment or efficiency-directed repair activities.

Non-Residential Smart $aver® Program			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2015	6,296,781	1,261,051	203,580

Small Business Energy Saver Program is designed to reduce energy usage by improving energy efficiency through the offer and installation of eligible energy efficiency measures. Program measures address major end-uses in lighting, refrigeration, and HVAC applications. The Program is available to existing non-residential establishments served on a Duke Energy Carolinas general service or industrial rate schedule from the Duke Energy Carolinas' retail distribution system that are not opted-out of the EE portion of Rider EE. Program participants must have an average annual demand of 100 kW or less per active account. Participants may be owner-occupied or tenant facilities with owner permission.

Small Business Energy Saver Program			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	67,564,358	71,127	15,603

Smart Energy in Offices Program is designed to increase the energy efficiency of targeted customers by engaging building occupants, tenants, property managers and facility teams with information, education, and data to drive behavior change and reduce energy consumption. This Program leverages communities to target owners and managers of potential participating accounts by providing participants with detailed information on the account/building's energy usage, support to launch energy saving campaigns, information to make comparisons between their building's energy performance and others within their community and actionable recommendations to improve their energy performance. The Program is available to existing non-residential accounts located in eligible commercial buildings served on a Duke Energy Carolinas' general service rate schedule from the Duke Energy Carolinas' retail distribution system that are not opted out of the EE portion of the Rider EE.

Smart Energy in Offices Program			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	65,027,594	69,071	14,376

In addition, the impacts from the Smart Energy Now Pilot program are included below:

Smart Energy Now Pilot			
	Number of Participants	Gross Savings (at plant)	
Cumulative as of:		MWh Energy	Peak kW
December 31, 2015	70	25,093	804

Pilot

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.

Demand Side Management Programs

DEC's current DSM programs will be presented in two sections: Demand Response Direct Load Control Programs and Demand Response Interruptible Programs and Related Rate Tariffs.

Demand Response – Direct Load Control Programs

These programs can be dispatched by the utility and have the highest level of certainty due to the participant not having to directly respond to an event. DEC's current direct load control programs are:

Residential

Power Manager® provides residential customers a voluntary demand response program that allows Duke Energy Carolinas to limit the run time of participating customers' central air conditioning (cooling) systems to reduce electricity demand. Power Manager® may be used to completely interrupt service to the cooling system when the Company experiences capacity problems. In addition, the Company may intermittently interrupt (cycle) service to the cooling system. For their participation in Power Manager®, customers receive bill credits during the billing months of June through September.

Power Manager® provides DEC with the ability to reduce and shift peak loads, thereby enabling a corresponding deferral of new supply-side peaking generation and enhancing system reliability.

Participating customers are impacted by (1) the installation of load control equipment at their residence, (2) load control events which curtail the operation of their air conditioning unit for a period of time each hour, and (3) the receipt of bill credits from DEC in exchange for allowing DEC the ability to control their electric equipment.

Power Manager® Program			
Cumulative as of:	**Participants (customers)**	**Devices (switches)**	**Summer 2015 Capability (MW)**
December 31, 2015	179,017	213,030	487

The following table shows Power Manager® program activations that were <u>not</u> for testing purposes from June 1, 2014 through December 31, 2015.

Power Manager® Program Activations*			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
September 2, 2014 – 2:30 PM	September 2, 2014 – 6:00 PM	210	194
September 11, 2014 – 2:30 PM	September 11, 2014 – 6:00 PM	210	194
September 16, 2014 – 2:30 PM	September 16, 2014 – 6:00 PM	210	202
June 16, 2015 – 2:30 PM	June 16, 2015 – 6:00 PM	210	228
June 23, 2015 – 2:30 PM	June 23, 2015 – 6:00 PM	210	228
July 20, 2015 – 3:30 PM	July 20, 2015 – 6:00 PM	150	168
August 5, 2015 – 2:30 PM	August 5, 2015 – 6:00 PM	210	232

<u>Non-Residential</u>

Demand Response – Interruptible Programs and Related Rate Structures

These programs rely either on the customer's ability to respond to a utility-initiated signal requesting curtailment, or on rates with price signals that provide an economic incentive to reduce or shift load. Timing, frequency, and nature of the load response depend on customers' actions after notification of an event or after receiving pricing signals. Duke Energy Carolinas' current interruptible and time-of-use rate programs include:

Interruptible Power Service (IS) (North Carolina Only) **-** Participants agree contractually to reduce their electrical loads to specified levels upon request by DEC. If customers fail to do so during an interruption, they receive a penalty for the increment of demand exceeding the specified level.

IS Program		
Cumulative as of:	**Participants**	**Summer 2015 Capability (MW)**
December 31, 2015	53	166

The following table shows IS program activations that were not for testing purposes from July 1, 2014 through December 31, 2015.

IS Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
January 8, 2015 5:00 AM	January 8, 2015 10:00 AM	300	124
January 9, 2015 5:00 AM	January 9, 2015 8:00 AM	180	138
February 19, 2015 6:00 AM	February 19, 2015 8:30 AM	150	127
February 20, 2015 6:00 AM	February 20, 2015 8:30 AM	150	109

Standby Generator Control (SG) (North Carolina Only) **-** Participants agree contractually to transfer electrical loads from the DEC source to their standby generators upon request of the Company. The generators in this program do not operate in parallel with the DEC system and therefore, cannot "backfeed" (i.e., export power) into the DEC system.

Participating customers receive payments for capacity and/or energy, based on the amount of capacity and/or energy transferred to their generators.

SG Program		
Cumulative as of:	**Participants**	**Summer 2015 Capability (MW)**
December 31, 2015	29	22

The following table shows SG program activations that were not for testing purposes from July 1, 2014 through December 31, 2015.

SG Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
January 8, 2015 5:00 AM	January 8, 2015 10:00 AM	300	18
January 9, 2015 5:00 AM	January 9, 2015 8:00 AM	180	18
February 19, 2015 6:00 AM	February 19, 2015 8:30 AM	150	18
February 20, 2015 6:00 AM	February 20, 2015 8:30 AM	150	18

PowerShare® is a non-residential curtailment program consisting of four options: an emergency only option for curtailable load (PowerShare® Mandatory), an emergency only option for load curtailment using on-site generators (PowerShare® Generator), an economic based voluntary option (PowerShare® Voluntary) and a combined emergency and economic option that allows for increased notification time of events (PowerShare® CallOption).

PowerShare® Mandatory: Participants in this emergency only option will receive capacity credits monthly based on the amount of load they agree to curtail during utility-initiated emergency events. Participants also receive energy credits for the load curtailed during events. Customers enrolled may also be enrolled in PowerShare® Voluntary and eligible to earn additional credits.

PowerShare® Mandatory Program		
Cumulative as of:	**Participants**	**Summer 2015 Capability (MW)**
December 31, 2015	168	371

The following table shows PowerShare® Mandatory program activations that were not for testing purposes from July 1, 2014 through December 31, 2105.

PowerShare® Mandatory Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
January 8, 2015 5:00 AM	January 8, 2015 10:00 AM	300	333
January 9, 2015 5:00 AM	January 9, 2015 8:00 AM	180	313
February 19, 2015 6:00 AM	February 19, 2015 8:30 AM	150	311
February 20, 2015 6:00 AM	February 20, 2015 8:30 AM	150	310

PowerShare® Generator: Participants in this emergency only option will receive capacity credits monthly based on the amount of load they agree to curtail (i.e. transfer to their on-site generator) during utility-initiated emergency events and their performance during monthly test hours. Participants also receive energy credits for the load curtailed during events.

PowerShare® Generator Statistics		
As of:	**Participants**	**Summer 2015 Capability (MW)**
December 31, 2015	41	49

The following table shows PowerShare® Generator program activations that were not for testing purposes from July 1, 2014 through December 31, 2015.

PowerShare® Generator Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
February 20, 2015 6:00 AM	February 20, 2015 8:00 AM	120	31

In response to EPA regulations finalized January 2013, the manner in which PowerShare® Generator was dispatched was modified as of May 1, 2014 to allow customers with emergency generators to continue participation in demand response programs. To comply with the new rule, dispatch of the PowerShare® Generator program had to be limited to NERC Level II (EEA2) except for the monthly readiness tests. 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 a majority of existing PowerShare® Generator participants to continue participation as of May 1, 2016.

PowerShare® Voluntary: Enrolled customers will be notified of pending emergency or economic events and can log on to a website to view a posted energy price for that particular event. Customers will then have the option to participate in the event and will be paid the posted energy credit for load curtailed. Since this is a voluntary event program, no capacity benefit is recognized for this program and no capacity incentive is provided. The values below represent participation in PowerShare® Voluntary only and do not double count the participants in PowerShare® Mandatory that also participate in PowerShare® Voluntary.

PowerShare® Voluntary Program		
As of:	**Participants**	**Summer 2015 Capability (MW)**
December 31, 2015	3	N/A

The following table shows PowerShare® Voluntary program activations that were not for testing purposes from July 1, 2014 through December 31, 2015.

PowerShare® Voluntary Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
January 8, 2015 5:00 AM	January 8, 2015 10:00 AM	300	0
January 9, 2015 5:00 AM	January 9, 2015 10:00 AM	300	0
February 19, 2015 6:00 AM	February 19, 2015 10:00 AM	240	0
February 20, 2015 6:00 AM	February 20, 2015 10:00 AM	240	0

PowerShare® CallOption: This program offers a participating customer the ability to receive credits when the customer agrees, at the Company's request, to reduce and maintain its load by a minimum of 100 kW during Emergency and/or Economic Events. Credits are paid for the load available for curtailment, and charges are applicable when the customer fails to reduce load in accordance with the participation option it has selected. Participants are obligated to curtail load during emergency events. CallOption offers four participation options to customers: PS 0/5, PS 5/5, PS 10/5 and PS 15/5. All options include a limit of five Emergency Events and set a limit for Economic Events to 0, 5, 10 and 15 respectively.

PowerShare® CallOption Program		
As of:	**Participants**	**Summer 2015 Capability (MW)**
December 31, 2015	0	0

The PowerShare® CallOption program was not activated during the period from July 1, 2014 through December 31, 2015.

PowerShare® CallOption 200: This CallOption offering is targeted at customers with very flexible load and curtailment potential of up to 200 hours of economic load curtailment each year. This option will function essentially in the same manner as the Company's other CallOption offers.

However, customers who participate would experience considerably more requests for load curtailment for economic purposes. Participants remain obligated to curtail load during up to 5 emergency events.

PowerShare® CallOption 200 Program		
As of:	**Participants**	**Summer 2015 Capability (MW)**
December 31, 2015	0	0

The PowerShare® CallOption 200 program was not activated during the period from July 1, 2014 through December 31, 2015.

EnergyWise℠ for Business: is both an energy efficiency and demand response program for non-residential customers that allows DEC 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, DEC 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 DEC. 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 the upcoming conservation periods.

The DEC EnergyWise℠ for Business program was implemented in South Carolina in December 2015, followed by North Carolina in January 2016.

EnergyWise[SM] for Business Program			
		MW Capability	
Cumulative as of:	Participants	Summer	Winter
December 31, 2015	27	0.085	---

Future EE and DSM Programs

DEC is continually seeking to enhance its EE and DSM portfolio by: (1) adding new programs or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new 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 uses the DSMore model to evaluate the costs, benefits, and risks of EE and DSM programs and measures. DSMore is a financial analysis tool designed to estimate of the capacity and energy values of EE and DSM measures at an hourly level across distributions of weather conditions and/or energy costs or prices. By examining projected program performance and cost effectiveness over a wide variety of weather and cost conditions, the Company is in a better position to measure the risks and benefits of employing EE and DSM measures versus traditional generation capacity additions, and further, to ensure that DSM resources are compared to supply side resources on a level playing field.

The analysis of energy efficiency 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. DSMore provides the results of those tests for any type of EE or DSM program.

- 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 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 approval of the 2014 Integrated Resource Plans and REPS Compliance Plans 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.

<u>Forecast Methodology</u>

In 2011, DEC commissioned a new EE market potential study to obtain new estimates of the technical, economic and achievable potential for EE savings within the DEC service area. The final report was prepared by Forefront Economics Inc. and H. Gil Peach and Associates, LLC and was completed on February 23, 2012 and included an achievable potential for planning year 5 and an economic potential for planning year 20.

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 DEC 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 DEC IRP process.

DEC prepared a Base Portfolio savings projection that was based on DEC's five year program plan for years 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 2032. For periods beyond 2032, DEC 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, DEC 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 Case projected MWh load impacts of all DEC EE programs implemented since the approval of the save-a-watt recovery mechanism in 2009 on a Gross and Net of Free Riders basis. 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 2032, 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 3,260 gigawatt-hour (GWh) of energy. The projections also do not include savings from DEC's proposed Integrated Voltage-VAR Control (IVVC) program, which will be discussed later in this document.

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

Base Portfolio MWh Load Impacts of EE Programs

Year	Annual MWh Load Reduction - Gross		Annual MWh Load Reduction - Net	
	Including measures added in 2016 and beyond	Including measures added since 2009	Including measures added in 2016 and beyond	Including measures added since 2009
2009-15		3,260,201		2,908,086
2016	455,532	3,715,733	355,019	3,263,105
2017	922,544	4,182,745	724,529	3,632,615
2018	1,337,250	4,597,451	1,048,922	3,957,008
2019	1,736,531	4,996,732	1,358,414	4,266,500
2020	2,132,744	5,392,945	1,663,582	4,571,668
2021	2,528,958	5,789,159	1,968,750	4,876,836
2022	2,925,171	6,185,372	2,273,918	5,182,004
2023	3,321,385	6,581,586	2,579,086	5,487,172
2024	3,717,598	6,977,799	2,884,254	5,792,340
2025	4,113,812	7,374,013	3,189,422	6,097,508
2026	4,510,026	7,770,226	3,494,590	6,402,676
2027	4,906,239	8,166,440	3,799,758	6,707,844
2028	5,302,453	8,562,653	4,104,927	7,013,013
2029	5,698,666	8,958,867	4,410,095	7,318,181
2030	6,094,880	9,355,081	4,715,263	7,623,349
2031	6,491,093	9,751,294	5,020,431	7,928,517

**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 Case projected MW load impacts of all current and projected DEC DSM programs.

Base Portfolio Load Impacts of DSM Programs

Year	Annual Peak MW Reduction					
	IS	SG	PowerShare	PowerManager	EnergyWise for Business	Total Annual Peak
2016	115	15	374	478	3	985
2017	109	15	380	502	9	1,015
2018	103	14	391	522	18	1,048
2019	98	13	401	540	27	1,079
2020	94	13	412	555	36	1,109
2021	89	12	416	555	45	1,117
2022	88	12	416	555	45	1,115
2023	88	12	416	555	45	1,115
2024	88	12	416	555	45	1,115
2025	88	12	416	555	45	1,115
2026	88	12	416	555	45	1,115
2027	88	12	416	555	45	1,115
2028	88	12	416	555	45	1,115
2029	88	12	416	555	45	1,115
2030	88	12	416	555	45	1,115
2031	88	12	416	555	45	1,115

Note: For DSM programs, Gross and Net are the same.

DEC's approved EE plan is consistent with the requirement set forth in the Cliffside Unit 6 CPCN Order to invest 1% of annual retail electricity revenues in EE and DSM programs, subject to the results of ongoing collaborative workshops and appropriate regulatory treatment.

However, pursuing EE and DSM initiatives is not expected to meet all of the future incremental peak demand for energy. DEC still envisions the need to secure additional generation, including cost-effective renewable generation, but the EE and DSM programs offered by DEC 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 IRPs, the Base Portfolio EE savings forecast of MWh is within 10% of the forecast presented in the 2014 IRP when compared on the cumulative achievements at year 2031 of the forecasts as shown in the table below.

Base Case Comparison to 2014 IRP - Gross

	2014 IRP		2016 IRP		
	Annual MWh Load Reduction		Annual MWh Load Reduction		
Year	Including measures added in 2014 and beyond	Including measures added since 2009	Including measures added in 2016 and beyond	Including measures added since 2009	% Change from 2014 to 2016 IRP
2014	439,799	2,646,334			
2015	845,866	3,052,401		3,260,201	6.8%
2016	1,272,833	3,479,369	455,532	3,715,733	6.8%
2017	1,712,712	3,919,247	922,544	4,182,745	6.7%
2018	2,161,679	4,368,214	1,337,250	4,597,451	5.2%
2019	2,637,421	4,843,957	1,736,531	4,996,732	3.2%
2020	3,119,267	5,325,803	2,132,744	5,392,945	1.3%
2021	3,670,534	5,877,069	2,528,958	5,789,159	-1.5%
2022	4,272,614	6,479,150	2,925,171	6,185,372	-4.5%
2023	4,891,005	7,097,541	3,321,385	6,581,586	-7.3%
2024	5,489,403	7,695,938	3,717,598	6,977,799	-9.3%
2025	6,097,058	8,303,594	4,113,812	7,374,013	-11.2%
2026	6,607,562	8,814,097	4,510,026	7,770,226	-11.8%
2027	7,073,440	9,279,976	4,906,239	8,166,440	-12.0%
2028	7,490,168	9,696,704	5,302,453	8,562,653	-11.7%
2029	7,788,479	9,995,015	5,698,666	8,958,867	-10.4%
2030	8,029,871	10,236,407	6,094,880	9,355,081	-8.6%
2031	8,179,558	10,386,094	6,491,093	9,751,294	-6.1%

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, DEC 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, Business Energy Reports and Smart Energy in Offices). 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. Additionally, 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 DEC's current Commission-approved EE portfolio. More importantly, significantly higher levels of customer participation would need to be generated.

The tables below show the projected High Portfolio savings on both Gross and Net of Free Riders basis.

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

High Portfolio MWh Load Impacts of EE Programs

Year	Annual MWh Load Reduction - Gross		Annual MWh Load Reduction - Net	
	Including measures added in 2016 and beyond	Including measures added since 2009	Including measures added in 2016 and beyond	Including measures added since 2009
2009-15		3,260,201		2,908,086
2016	685,166	3,945,367	537,272	3,445,358
2017	1,381,813	4,642,014	1,089,036	3,997,122
2018	2,026,153	5,286,354	1,595,682	4,503,768
2019	2,655,067	5,915,268	2,087,427	4,995,513
2020	3,280,915	6,541,116	2,574,848	5,482,934
2021	3,906,763	7,166,964	3,062,270	5,970,356
2022	4,532,611	7,792,812	3,549,691	6,457,777
2023	5,158,458	8,418,659	4,037,113	6,945,199
2024	5,784,306	9,044,507	4,524,534	7,432,620
2025	6,410,154	9,670,355	5,011,956	7,920,042
2026	7,036,002	10,296,203	5,499,377	8,407,463
2027	7,661,849	10,922,050	5,986,799	8,894,885
2028	8,287,697	11,547,898	6,474,220	9,382,306
2029	8,913,545	12,173,746	6,961,641	9,869,727
2030	9,539,393	12,799,593	7,449,063	10,357,149
2031	10,165,240	13,425,441	7,936,484	10,844,570

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. DEC 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 Carolinas 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 Carolinas is reviewing an Integrated Volt-Var Control project that will better manage the application and operation of voltage regulators (the Volt) and capacitors (the VAR) on the Duke Energy Carolinas 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.

The deployment of an IVVC program for Duke Energy Carolinas is anticipated to take approximately four years following project approval. The proposed project timeline was adjusted to reflect current strategic priorities and moved out approximately five years. Therefore, the IVVC program is projected to reduce future distribution-only peak needs by 0.20% in 2023, 0.4% in 2024, 0.6% in 2025, 1.0% in 2026 and beyond.

APPENDIX E: FUEL SUPPLY

Duke Energy Carolinas' 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.

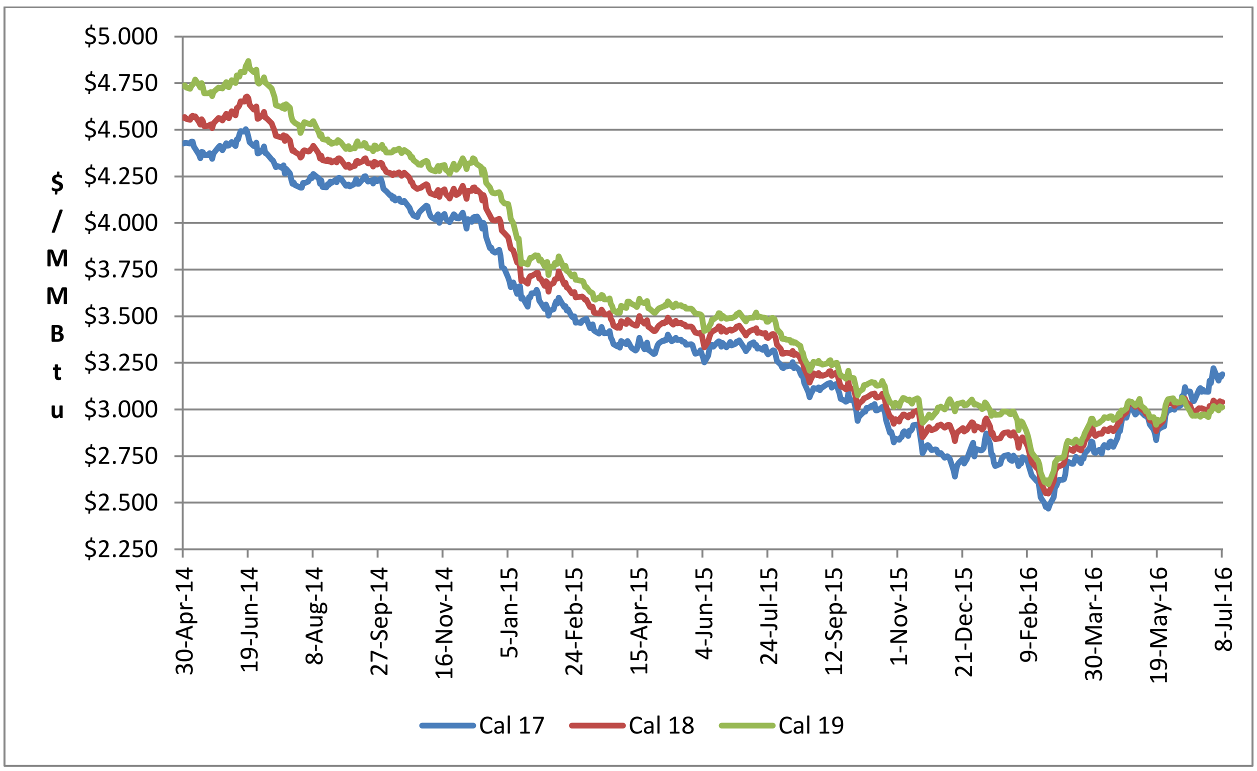
Average daily U.S. net dry production levels of approximately 72.7 BCF/day in the first quarter of 2016 were relatively comparable with 2015 net dry production. Storage ended the winter withdrawal season at a record high of 2.47 per trillion cubic feet (TCF) on March 31, 2016. Lower-48 U.S. demand in 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 a 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 DEC'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 it gas generation fleet as 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, DEC 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, DEC generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

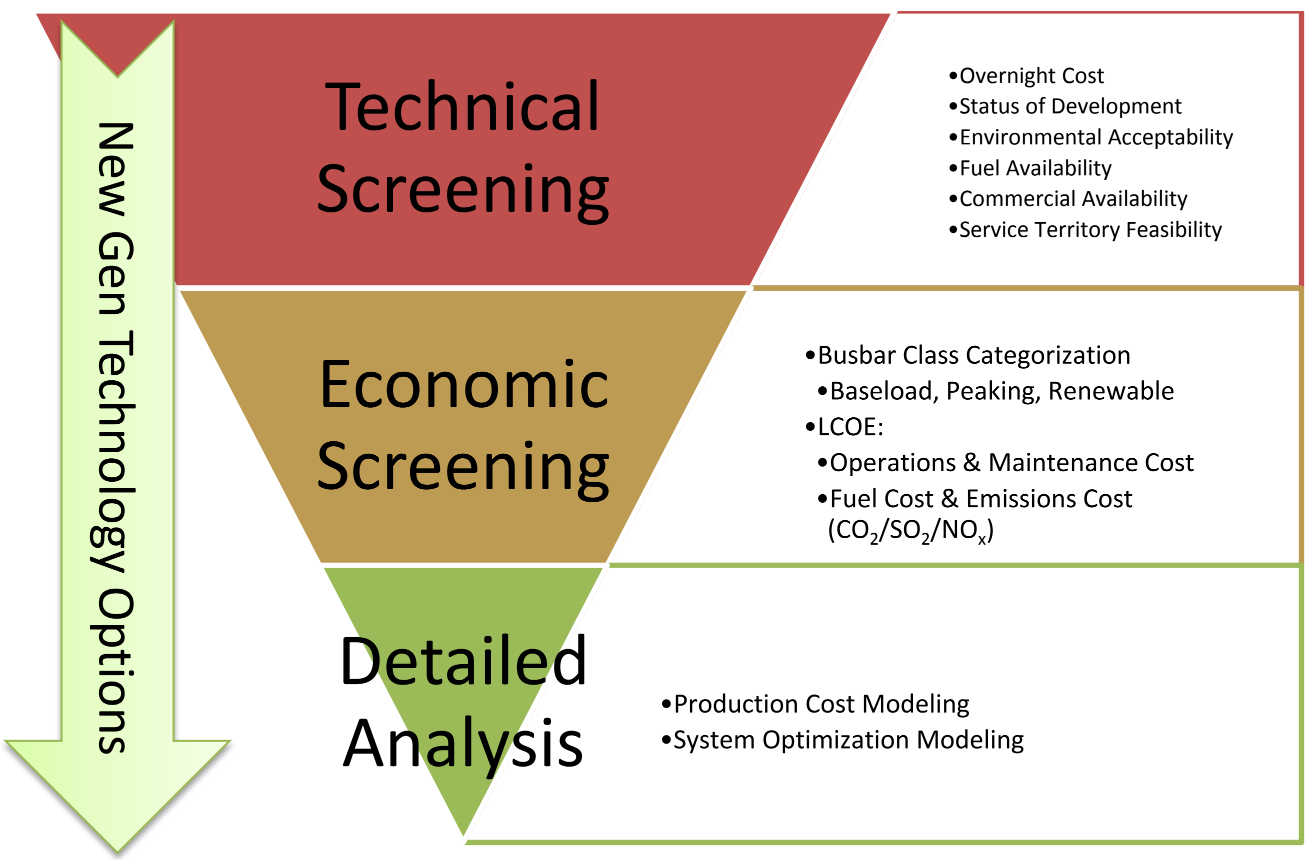
As fuel with a low cost basis is used and lower-priced legacy contracts are replaced with contracts at higher market prices, nuclear fuel expense is expected to increase in the future. Although the costs of certain components of nuclear fuel are expected to increase in future years, nuclear fuel costs 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 Carolinas 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.

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 Carolinas 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, Bad Creek Reservoir and Jocassee Hydro with an approximate combined generating capacity of 2,140 MW.

- **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 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 by 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, making this a low cost grid asset. 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 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 of 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 (DER), 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 regulation may effectively preclude new coal-fired generation, Duke Energy Carolinas has included ultra-supercritical pulverized coal with carbon capture sequestration and integrated gasification combined cycle 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
- 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
- Renewable – 5 MW Landfill Gas

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.

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APPENDIX G: ENVIRONMENTAL COMPLIANCE

Legislative and Regulatory Issues

Duke Energy Carolinas, 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 Carolinas is actively monitoring or engaged in that could potentially influence the Company's existing generation portfolio and choices for new generation resources.

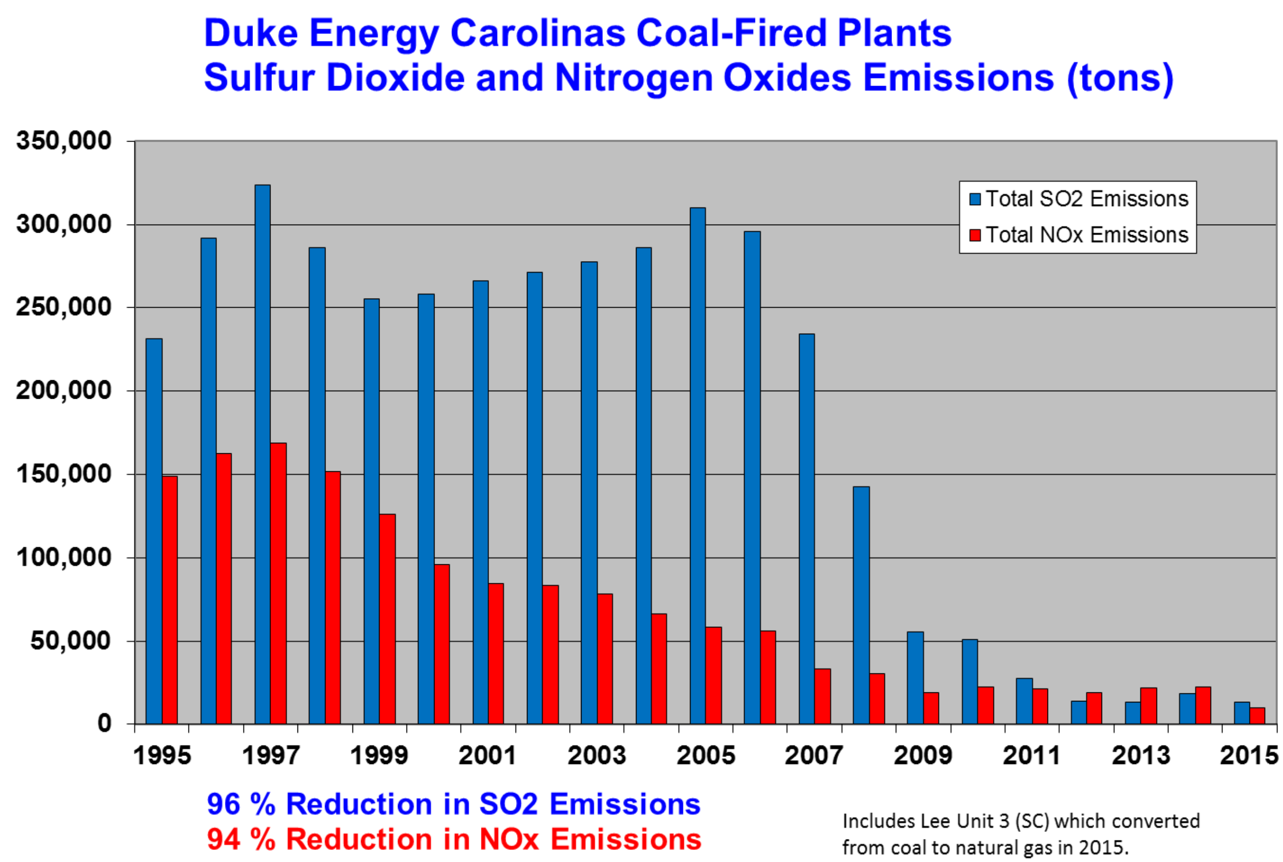
Air Quality

Duke Energy Carolinas is required to comply with numerous State and Federal air emission regulations, including the current Clean Air Interstate Rule (CAIR) NO_X and SO_2 cap-and-trade program and the 2002 North Carolina Clean Smokestacks Act (NC CSA).

As a result of complying with the NC CSA, Duke Energy Carolinas reduced SO_2 emissions by approximately 95% from 2000 to 2013. The law also required additional reductions in NO_X emissions in 2007 and 2009, beyond those required by CAIR, which Duke Energy Carolinas has achieved. This landmark legislation, which was passed by the North Carolina General Assembly in June of 2002, calls for some of the lowest state-mandated emission levels in the nation, and was passed with Duke Energy Carolinas' input and support.

The chart below show the significant downward trend in both NO_X and SO_2 emissions through 2015 as a result of actions taken at DEC facilities.

Chart G-1 DEC 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 Carolinas 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 NOx emissions and ozone season NOx 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 Carolinas 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 NOx 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 NOx program to address interstate transport for the 75 ppb standard. EPA proposed to lower the Phase II ozone season NOx 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 Carolinas 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 Carolinas 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 Carolinas 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 Carolinas Belews Creek, Marshall, and Allen stations using air quality modeling. The modeling analyses must be submitted to EPA by January 13, 2017, and EPA must complete designations of the areas surrounding these three stations by December 31, 2017. 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 Carolinas 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 Carolinas 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 Carolinas. An approved North Carolina state implementation plan would establish the regulatory requirements that would apply to Duke Energy Carolinas. If North Carolina were not to submit an approvable plan, EPA would impose a federal implementation plan on affected Duke Energy Carolinas 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 Carolinas could incur increased fuel, purchased power, operation and maintenance and other costs for replacement generation. However, Duke Energy Carolinas 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 entrained (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 more 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 Carolina 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, 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.

[12] Richmond County(a public water supply system) supplies cooling water to Smith Energy; therefore the rule is not applicable.

The rule requires facilities with a NPDES permit that expires 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 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 DEC'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 DEC 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 DEC coal-fired units either handling fly ash dry during normal operation or are in the process of converting to dry fly ash handling. 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 DEC coal-fired units, except for Rogers / Cliffside 6, will be required to install a closed-loop or a dry bottom ash handling system.
- FGD Wastewater: All DEC coal-fired units, except for Rogers / Cliffside 6 will be required to upgrade or completely replace the existing FGD wastewater treatment system. Even though Allen

and Belews Creek Steam Stations utilize the model technology, which was the basis for the limits, additional treatment is expected to be required to ensure compliance.

— CCR Leachate: The revised limits for CCR leachate from impoundments and landfills are same as the existing limits for low volume waste. Potential impacts are being evaluated on a facility 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 proposed the CCR rule for notice and comment and then published the final rule on April 17, 2015. The CCR rule regulates CCR as a nonhazardous waste under Subtitle D of RCRA and allows for beneficial use of CCR with some restrictions. The effective date of the rule was October 19, 2015.

The CCR rule applies to all new and existing landfills, new and existing surface impoundments receiving CCR and existing surface impoundments that are no longer receiving CCR but contain liquid located at stations currently generating electricity (regardless of fuel source). The rule establishes requirements regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to ensure the safe disposal and management of CCR.

In addition to the requirements of the federal CCR regulation, CCR landfills and surface impoundments will continue to be independently regulated by the state. On September 20, 2014, the North Carolina Coal Ash Management Act of 2014 (CAMA) became law and was amended on June 24, 2015 and amended a second time on July 15, 2016.

CAMA establishes requirements regarding the use of CCR, the closure of existing CCR surface impoundments, the disposal of CCR at active coal plants, and the handling of surface and groundwater impacts from CCR surface impoundments. CAMA requires eight CCR surface impoundments in North Carolina to be closed no later than August 1, 2019. It also required state regulators to provide risk ranking classifications to determine the method and timing for closing the remaining CCR surface impoundments. North Carolina Department of Environmental Quality (NCDEQ) has categorized all remaining CCR surface impoundments as intermediate risk. CAMA also grants NCDEQ the authority to change a impoundment's classification based on dam safety repairs completed or the removal of any threat to drinking water. The impact from both state and federal CCR regulations to Duke Energy Carolinas is significant.

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

[redacted]

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	Charlotte	NC	Solar	Intermediate	Yes	6.119
Facility 2	Elkin	NC	Solar	Intermediate	Yes	5.97
Facility 3	Salisbury	NC	Solar	Intermediate	Yes	7.134
Facility 4	Harrisburg	NC	Solar	Intermediate	Yes	5.301
Facility 5	Hendersonville	NC	Solar	Intermediate	Yes	6.65
Facility 6	Hendersonville	NC	Solar	Intermediate	Yes	10.25
Facility 7	Chapel Hill	NC	Solar	Intermediate	Yes	3
Facility 8	Troutman	NC	Solar	Intermediate	Yes	260
Facility 9	Wilkesboro	NC	Solar	Intermediate	Yes	4.8
Facility 10	Wilkesboro	NC	Solar	Intermediate	Yes	1.92
Facility 11	Lincolnton	NC	Solar	Intermediate	Yes	75
Facility 12	Lincolnton	NC	Solar	Intermediate	Yes	75
Facility 13	Randleman	NC	Solar	Intermediate	Yes	5
Facility 14	Hendersonville	NC	Solar	Intermediate	Yes	4.219
Facility 15	Hillsborough	NC	Solar	Intermediate	Yes	4
Facility 16	Charlotte	NC	Solar	Intermediate	Yes	170
Facility 17	Durham	NC	Solar	Intermediate	Yes	4
Facility 18	Greensboro	NC	Solar	Intermediate	Yes	258
Facility 19	Charlotte	NC	Solar	Intermediate	Yes	30
Facility 20	Kannapolis	NC	Solar	Intermediate	Yes	10.45
Facility 21	Chapel Hill	NC	Solar	Intermediate	Yes	7.1
Facility 22	Chapel Hill	NC	Solar	Intermediate	Yes	2.8
Facility 23	Graham	NC	Solar	Intermediate	Yes	5
Facility 24	Altamahaw	NC	Hydroelectric	Baseload	Yes	240
Facility 25	Winston Salem	NC	Solar	Intermediate	Yes	3.19
Facility 26	Charlotte	NC	Solar	Intermediate	Yes	8.493
Facility 27	Winston Salem	NC	Solar	Intermediate	Yes	5.39
Facility 28	Black Mountain	NC	Solar	Intermediate	Yes	3.42
Facility 29	Durham	NC	Solar	Intermediate	Yes	6
Facility 30	Wilkesboro	NC	Solar	Intermediate	Yes	3.44
Facility 31	Durham	NC	Solar	Intermediate	Yes	3.8
Facility 32	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 33	Denver	NC	Solar	Intermediate	Yes	2.618
Facility 34	Indian Trail	NC	Solar	Intermediate	Yes	60
Facility 35	Greensboro	NC	Solar	Intermediate	Yes	68
Facility 36	Pineville	NC	Solar	Intermediate	Yes	68
Facility 37	High Point	NC	Solar	Intermediate	Yes	60
Facility 38	Harrisburg	NC	Solar	Intermediate	Yes	68
Facility 39	Salisbury	NC	Solar	Intermediate	Yes	312
Facility 40	Salisbury	NC	Solar	Intermediate	Yes	696
Facility 41	Salisbury	NC	Solar	Intermediate	Yes	60
Facility 42	Denver	NC	Solar	Intermediate	Yes	72
Facility 43	Mebane	NC	Solar	Intermediate	Yes	8
Facility 44	Liberty	NC	Solar	Intermediate	Yes	9
Facility 45	Shelby	NC	Solar	Intermediate	Yes	1.72
Facility 46	Chapel Hill	NC	Solar	Intermediate	Yes	5
Facility 47	Charlotte	NC	Solar	Intermediate	Yes	3.696
Facility 48	Sherrills Ford	NC	Solar	Intermediate	Yes	6.5
Facility 49	Fletcher	NC	Solar	Intermediate	Yes	95
Facility 50	Charlotte	NC	Solar	Intermediate	Yes	3.502

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 51	Carrboro	NC	Solar	Intermediate	Yes	5
Facility 52	Gold Hill	NC	Solar	Intermediate	Yes	4.704
Facility 53	Gold Hill	NC	Solar	Intermediate	Yes	4.704
Facility 54	Winston Salem	NC	Solar	Intermediate	Yes	3.57
Facility 55	Durham	NC	Solar	Intermediate	Yes	3.6
Facility 56	Mooresville	NC	Solar	Intermediate	Yes	4.52
Facility 57	Winston Salem	NC	Solar	Intermediate	Yes	2.857
Facility 58	Westfield	NC	Solar	Intermediate	Yes	5
Facility 59	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 60	Forest City	NC	Solar	Intermediate	Yes	3000
Facility 61	Chapel Hill	NC	Solar	Intermediate	Yes	2.75
Facility 62	Harrisburg	NC	Solar	Intermediate	Yes	4.3
Facility 63	Chapel Hill	NC	Solar	Intermediate	Yes	3.8
Facility 64	Mooresville	NC	Solar	Intermediate	Yes	7.37
Facility 65	Huntersville	NC	Solar	Intermediate	Yes	0.86
Facility 66	Nebo	NC	Solar	Intermediate	Yes	3.8
Facility 67	Kannapolis	NC	Solar	Intermediate	Yes	9.476
Facility 68	Hillsborough	NC	Solar	Intermediate	Yes	5
Facility 69	Hendersonville	NC	Solar	Intermediate	Yes	2.1
Facility 70	Summerfield	NC	Solar	Intermediate	Yes	5
Facility 71	Charlotte	NC	Solar	Intermediate	Yes	1.92
Facility 72	Durham	NC	Solar	Intermediate	Yes	1.92
Facility 73	Charlotte	NC	Solar	Intermediate	Yes	1.72
Facility 74	Durham	NC	Solar	Intermediate	Yes	2.5
Facility 75	Charlotte	NC	Solar	Intermediate	Yes	6
Facility 76	Summerfield	NC	Solar	Intermediate	Yes	7
Facility 77	Sylva	NC	Solar	Intermediate	Yes	7.68
Facility 78	Durham	NC	Solar	Intermediate	Yes	2.5
Facility 79	Durham	NC	Solar	Intermediate	Yes	3.465
Facility 80	Charlotte	NC	Solar	Intermediate	Yes	5
Facility 81	Kannapolis	NC	Solar	Intermediate	Yes	6
Facility 82	Winston Salem	NC	Solar	Intermediate	Yes	5.25
Facility 83	Andrews	NC	Solar	Intermediate	Yes	9.6
Facility 84	Charlotte	NC	Solar	Intermediate	Yes	3.8
Facility 85	Wilkesboro	NC	Solar	Intermediate	Yes	7.5
Facility 86	Whittier	NC	Solar	Intermediate	Yes	5.469
Facility 87	Newton	NC	Solar	Intermediate	Yes	5000
Facility 88	Bessemer City	NC	Solar	Intermediate	Yes	2.58
Facility 89	Mooresville	NC	Solar	Intermediate	Yes	3.51
Facility 90	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 91	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 92	Chapel Hill	NC	Solar	Intermediate	Yes	5.299
Facility 93	Chapel Hill	NC	Solar	Intermediate	Yes	4.59
Facility 94	Trinity	NC	Solar	Intermediate	Yes	0.86
Facility 95	Cornelius	NC	Solar	Intermediate	Yes	5.25
Facility 96	Winston Salem	NC	Solar	Intermediate	Yes	3
Facility 97	Matthews	NC	Solar	Intermediate	Yes	0.86
Facility 98	Winston Salem	NC	Solar	Intermediate	Yes	4
Facility 99	Columbus	NC	Solar	Intermediate	Yes	6

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 100	Durham	NC	Solar	Intermediate	Yes	5
Facility 101	Greensboro	NC	Solar	Intermediate	Yes	4.3
Facility 102	Rockwell	NC	Solar	Intermediate	Yes	2.45
Facility 103	Charlotte	NC	Solar	Intermediate	Yes	3.929
Facility 104	Archdale	NC	Solar	Intermediate	Yes	2.88
Facility 105	Charlotte	NC	Solar	Intermediate	Yes	3.5
Facility 106	Durham	NC	Solar	Intermediate	Yes	3
Facility 107	Gastonia	NC	Solar	Intermediate	Yes	6.09
Facility 108	Gastonia	NC	Solar	Intermediate	Yes	14
Facility 109	Charlotte	NC	Solar	Intermediate	Yes	4.525
Facility 110	Claremont	NC	Solar	Intermediate	Yes	17500
Facility 111	Conover	NC	Solar	Intermediate	Yes	20000
Facility 112	Maiden	NC	Solar	Intermediate	Yes	20000
Facility 113	Maiden	NC	Biogas	Intermediate	Yes	5200
Facility 114	Newton	NC	Solar	Intermediate	Yes	4950
Facility 115	Durham	NC	Solar	Intermediate	Yes	4
Facility 116	Mooresville	NC	Solar	Intermediate	Yes	10
Facility 117	Mooresville	NC	Solar	Intermediate	Yes	10
Facility 118	Mount Airy	NC	Solar	Intermediate	Yes	3500
Facility 119	Chapel Hill	NC	Solar	Intermediate	Yes	3.6
Facility 120	Greensboro	NC	Solar	Intermediate	Yes	3.858
Facility 121	Claremont	NC	Solar	Intermediate	Yes	5000
Facility 122	Walkertown	NC	Solar	Intermediate	Yes	4.455
Facility 123	Chapel Hill	NC	Solar	Intermediate	Yes	9.458
Facility 124	Franklin	NC	Wind	Intermediate	Yes	4
Facility 125	Charlotte	NC	Solar	Intermediate	Yes	1.72
Facility 126	Charlotte	NC	Solar	Intermediate	Yes	8.376
Facility 127	Chapel Hill	NC	Solar	Intermediate	Yes	10
Facility 128	Hamptonville	NC	Solar	Intermediate	Yes	4000
Facility 129	Harrisburg	NC	Solar	Intermediate	Yes	5
Facility 130	Durham	NC	Solar	Intermediate	Yes	3
Facility 131	Mebane	NC	Solar	Intermediate	Yes	4.515
Facility 132	Shelby	NC	Solar	Intermediate	Yes	3000
Facility 133	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 134	Charlotte	NC	Solar	Intermediate	Yes	3
Facility 135	Claremont	NC	Solar	Intermediate	Yes	5.829
Facility 136	Charlotte	NC	Solar	Intermediate	Yes	5
Facility 137	Winston Salem	NC	Solar	Intermediate	Yes	15.226
Facility 138	Vale	NC	Solar	Intermediate	Yes	11.486
Facility 139	Charlotte	NC	Solar	Intermediate	Yes	19.68
Facility 140	Hillsborough	NC	Solar	Intermediate	Yes	6
Facility 141	Brevard	NC	Solar	Intermediate	Yes	5
Facility 142	Caroleen	NC	Hydroelectric	Baseload	Yes	325
Facility 143	Charlotte	NC	Solar	Intermediate	Yes	3
Facility 144	Durham	NC	Solar	Intermediate	Yes	5.75
Facility 145	Davidson	NC	Solar	Intermediate	Yes	1.9
Facility 146	Durham	NC	Solar	Intermediate	Yes	5
Facility 147	Gastonia	NC	Solar	Intermediate	Yes	9.283
Facility 148	Charlotte	NC	Solar	Intermediate	Yes	4.418
Facility 149	Jamestown	NC	Solar	Intermediate	Yes	4.341
Facility 150	Hillsborough	NC	Solar	Intermediate	Yes	8.043

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 151	Harmony	NC	Solar	Intermediate	Yes	8.042
Facility 152	Durham	NC	Solar	Intermediate	Yes	2.809
Facility 153	Durham	NC	Solar	Intermediate	Yes	5.889
Facility 154	Eden	NC	Solar	Intermediate	Yes	4.454
Facility 155	Lawndale	NC	Solar	Intermediate	Yes	10
Facility 156	Charlotte	NC	Solar	Intermediate	Yes	9.74
Facility 157	Charlotte	NC	Solar	Intermediate	Yes	1.44
Facility 158	Bryson City	NC	Solar	Intermediate	Yes	3
Facility 159	Clemmon	NC	Solar	Intermediate	Yes	9.178
Facility 160	Taylorsville	NC	Solar	Intermediate	Yes	5.511
Facility 161	Kings Mountain	NC	Solar	Intermediate	Yes	3500
Facility 162	Durham	NC	Solar	Intermediate	Yes	5.043
Facility 163	Durham	NC	Solar	Intermediate	Yes	6.469
Facility 164	RTP	NC	Solar	Intermediate	Yes	15
Facility 165	Charlotte	NC	Solar	Intermediate	Yes	10.059
Facility 166	Lincolnton	NC	Solar	Intermediate	Yes	9.034
Facility 167	Chapel Hill	NC	Solar	Intermediate	Yes	3.49
Facility 168	Archdale	NC	Solar	Intermediate	Yes	28.8
Facility 169	Hendersonville	NC	Solar	Intermediate	Yes	4.788
Facility 170	Charlotte	NC	Solar	Intermediate	Yes	30
Facility 171	Burlington	NC	Solar	Intermediate	Yes	30
Facility 172	Lawndale	NC	Solar	Intermediate	Yes	4000
Facility 173	Durham	NC	Solar	Intermediate	Yes	3.25
Facility 174	High Point	NC	Solar	Intermediate	Yes	4
Facility 175	Conover	NC	Solar	Intermediate	Yes	4
Facility 176	Chapel Hill	NC	Solar	Intermediate	Yes	3
Facility 177	Durham	NC	Solar	Intermediate	Yes	2.205
Facility 178	Lenoir	NC	Solar	Intermediate	Yes	1104
Facility 179	Franklin	NC	Solar	Intermediate	Yes	2.75
Facility 180	Kernersville	NC	Solar	Intermediate	Yes	1.43
Facility 181	King	NC	Solar	Intermediate	Yes	3.028
Facility 182	Julian	NC	Solar	Intermediate	Yes	5000
Facility 183	Charlotte	NC	Solar	Intermediate	Yes	6.534
Facility 184	Madison	NC	Solar	Intermediate	Yes	5.16
Facility 185	Chapel Hill	NC	Solar	Intermediate	Yes	6
Facility 186	Marshville	NC	Solar	Intermediate	Yes	5000
Facility 187	Charlotte	NC	Solar	Intermediate	Yes	3.44
Facility 188	Gibsonville	NC	Solar	Intermediate	Yes	3000
Facility 189	Vale	NC	Solar	Intermediate	Yes	3.686
Facility 190	Hickory	NC	Solar	Intermediate	Yes	4.77
Facility 191	Hickory	NC	Solar	Intermediate	Yes	5
Facility 192	Gastonia	NC	Solar	Intermediate	Yes	1.29
Facility 193	Durham	NC	Solar	Intermediate	Yes	124
Facility 194	Chapel Hill	NC	Solar	Intermediate	Yes	1.851
Facility 195	Hendersonville	NC	Solar	Intermediate	Yes	9
Facility 196	Harrisburg	NC	Solar	Intermediate	Yes	4.422
Facility 197	China Grove	NC	Solar	Intermediate	Yes	2.15
Facility 198	Brevard	NC	Solar	Intermediate	Yes	2.58
Facility 199	Elon	NC	Solar	Intermediate	Yes	20.43

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 200	Elon	NC	Solar	Intermediate	Yes	72.08
Facility 201	Elon	NC	Solar	Intermediate	Yes	40.85
Facility 202	Durham	NC	Solar	Intermediate	Yes	6.394
Facility 203	Durham	NC	Solar	Intermediate	Yes	84
Facility 204	Stanley	NC	Solar	Intermediate	Yes	1560
Facility 205	Charlotte	NC	Solar	Intermediate	Yes	3.025
Facility 206	Burlington	NC	Solar	Intermediate	Yes	0.74
Facility 207	Lincolnton	NC	Solar	Intermediate	Yes	1.35
Facility 208	Durham	NC	Solar	Intermediate	Yes	4.3
Facility 209	Waxhaw	NC	Solar	Intermediate	Yes	1.08
Facility 210	Kernersville	NC	Solar	Intermediate	Yes	2.668
Facility 211	Chapel Hill	NC	Solar	Intermediate	Yes	2.946
Facility 212	Charlotte	NC	Solar	Intermediate	Yes	4.704
Facility 213	Cullowhee	NC	Solar	Intermediate	Yes	3.75
Facility 214	Salisbury	NC	Solar	Intermediate	Yes	5.301
Facility 215	Concord	NC	Solar	Intermediate	Yes	2.821
Facility 216	Durham	NC	Solar	Intermediate	Yes	2.442
Facility 217	Hendersonville	NC	Solar	Intermediate	Yes	9.8
Facility 218	Chapel Hill	NC	Solar	Intermediate	Yes	1.438
Facility 219	Bostic	NC	Solar	Intermediate	Yes	2.422
Facility 220	Mooresville	NC	Solar	Intermediate	Yes	4.8
Facility 221	Old fort	NC	Solar	Intermediate	Yes	7.54
Facility 222	Morganton	NC	Solar	Intermediate	Yes	1.72
Facility 223	Gastonia	NC	Solar	Intermediate	Yes	8.6
Facility 224	Lincolnton	NC	Solar	Intermediate	Yes	6.85
Facility 225	Chapel Hill	NC	Solar	Intermediate	Yes	1.485
Facility 226	Reidsville	NC	Solar	Intermediate	Yes	7.115
Facility 227	Midland	NC	Solar	Intermediate	Yes	2.318
Facility 228	Durham	NC	Solar	Intermediate	Yes	2.7
Facility 229	Charlotte	NC	Solar	Intermediate	Yes	2.943
Facility 230	Hendersonville	NC	Solar	Intermediate	Yes	4.09
Facility 231	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 232	Mt Pleasant	NC	Solar	Intermediate	Yes	7
Facility 233	Brevard	NC	Solar	Intermediate	Yes	1.08
Facility 234	Hillborough	NC	Solar	Intermediate	Yes	10.536
Facility 235	Greensboro	NC	Solar	Intermediate	Yes	4
Facility 236	Chapel Hill	NC	Solar	Intermediate	Yes	5
Facility 237	Greensboro	NC	Solar	Intermediate	Yes	3.36
Facility 238	Greensboro	NC	Solar	Intermediate	Yes	3.8
Facility 239	Chapel Hill	NC	Solar	Intermediate	Yes	3
Facility 240	Mount Pleasant	NC	Solar	Intermediate	Yes	6.08
Facility 241	Charlotte	NC	Solar	Intermediate	Yes	2.45
Facility 242	Charlotte	NC	Solar	Intermediate	Yes	6.678
Facility 243	Greensboro	NC	Solar	Intermediate	Yes	4.62
Facility 244	N. Wilkesboro	NC	Solar	Intermediate	Yes	3.595
Facility 245	Chapel Hill	NC	Solar	Intermediate	Yes	3.564
Facility 246	Maiden	NC	Solar	Intermediate	Yes	3.028
Facility 247	King	NC	Solar	Intermediate	Yes	10.6
Facility 248	Pfafftown	NC	Solar	Intermediate	Yes	5.25
Facility 249	Thomasville	NC	Solar	Intermediate	Yes	3.44
Facility 250	Carrboro	NC	Solar	Intermediate	Yes	9.74

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 251	Durham	NC	Solar	Intermediate	Yes	7
Facility 252	Greensboro	NC	Solar	Intermediate	Yes	3.5
Facility 253	Morrisville	NC	Solar	Intermediate	Yes	5
Facility 254	Chapel Hill	NC	Solar	Intermediate	Yes	3.8
Facility 255	Gold Hill	NC	Solar	Intermediate	Yes	4000
Facility 256	Harrisburg	NC	Solar	Intermediate	Yes	4.418
Facility 257	Durham	NC	Solar	Intermediate	Yes	4.821
Facility 258	Burlington	NC	Hydroelectric	Baseload	Yes	440
Facility 259	Colfax	NC	Solar	Intermediate	Yes	3.596
Facility 260	Greensboro	NC	Solar	Intermediate	Yes	12.058
Facility 261	Taylorsville	NC	Solar	Intermediate	Yes	6.568
Facility 262	Greensboro	NC	Solar	Intermediate	Yes	3.8
Facility 263	Chapel Hill	NC	Solar	Intermediate	Yes	3
Facility 264	Greensboro	NC	Solar	Intermediate	Yes	3
Facility 265	Durham	NC	Solar	Intermediate	Yes	23
Facility 266	Chapel Hill	NC	Solar	Intermediate	Yes	25
Facility 267	Charlotte	NC	Solar	Intermediate	Yes	12.134
Facility 268	Glenville	NC	Solar	Intermediate	Yes	5
Facility 269	Durham	NC	Solar	Intermediate	Yes	4
Facility 270	Charlotte	NC	Solar	Intermediate	Yes	6.3
Facility 271	Charlotte	NC	Solar	Intermediate	Yes	7.68
Facility 272	Troutman	NC	Solar	Intermediate	Yes	2.97
Facility 273	Durham	NC	Solar	Intermediate	Yes	55.2
Facility 274	Waxhaw	NC	Solar	Intermediate	Yes	3.68
Facility 275	Lincolnton	NC	Solar	Intermediate	Yes	1.29
Facility 276	Hickory	NC	Solar	Intermediate	Yes	2.33
Facility 277	Matthews	NC	Solar	Intermediate	Yes	0.86
Facility 278	Salisbury	NC	Solar	Intermediate	Yes	5.301
Facility 279	Durham	NC	Solar	Intermediate	Yes	6.45
Facility 280	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 281	Hendersonville	NC	Solar	Intermediate	Yes	5.927
Facility 282	Troutman	NC	Solar	Intermediate	Yes	13
Facility 283	Winston Salem	NC	Solar	Intermediate	Yes	2.8
Facility 284	Greensboro	NC	Solar	Intermediate	Yes	6.75
Facility 285	Elkin	NC	Solar	Intermediate	Yes	6
Facility 286	Carrboro	NC	Solar	Intermediate	Yes	2
Facility 287	Durham	NC	Solar	Intermediate	Yes	6.72
Facility 288	Ellenboro	NC	Solar	Intermediate	Yes	3.5
Facility 289	Carrboro	NC	Solar	Intermediate	Yes	5
Facility 290	Greensboro	NC	Solar	Intermediate	Yes	5.175
Facility 291	Franklin	NC	Solar	Intermediate	Yes	2.5
Facility 292	Salisbury	NC	Solar	Intermediate	Yes	157
Facility 293	Newton	NC	Landfill Gas	Intermediate	Yes	4000
Facility 294	Salisbury	NC	Solar	Intermediate	Yes	598
Facility 295	Troutman	NC	Solar	Intermediate	Yes	3
Facility 296	Harrisburg	NC	Solar	Intermediate	Yes	3.703
Facility 297	China Grove	NC	Solar	Intermediate	Yes	2.4
Facility 298	Charlotte	NC	Solar	Intermediate	Yes	7.342
Facility 299	Carrboro	NC	Solar	Intermediate	Yes	6

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 300	Charlotte	NC	Solar	Intermediate	Yes	2.72
Facility 301	Burlington	NC	Solar	Intermediate	Yes	3
Facility 302	Monroe	NC	Solar	Intermediate	Yes	6
Facility 303	Harrisburg	NC	Solar	Intermediate	Yes	4.305
Facility 304	Chapel Hill	NC	Solar	Intermediate	Yes	40
Facility 305	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 306	Carrboro	NC	Solar	Intermediate	Yes	16.4
Facility 307	Chapel Hill	NC	Solar	Intermediate	Yes	0.86
Facility 308	Durham	NC	Solar	Intermediate	Yes	5
Facility 309	Charlotte	NC	Solar	Intermediate	Yes	2.4
Facility 310	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 311	Durham	NC	Solar	Intermediate	Yes	6
Facility 312	Durham	NC	Solar	Intermediate	Yes	4.16
Facility 313	Hendersonville	NC	Solar	Intermediate	Yes	4.875
Facility 314	Kings Mountain	NC	Solar	Intermediate	Yes	1.92
Facility 315	Greensboro	NC	Solar	Intermediate	Yes	3.78
Facility 316	Durham	NC	Solar	Intermediate	Yes	5.76
Facility 317	Kernersville	NC	Solar	Intermediate	Yes	0.74
Facility 318	Charlotte	NC	Solar	Intermediate	Yes	6.21
Facility 319	Charlotte	NC	Solar	Intermediate	Yes	1.85
Facility 320	Hillsborough	NC	Solar	Intermediate	Yes	3.84
Facility 321	Elon	NC	Solar	Intermediate	Yes	3
Facility 322	Winston Salem	NC	Solar	Intermediate	Yes	3.84
Facility 323	Oak Ridge	NC	Solar	Intermediate	Yes	4.32
Facility 324	Browns Summit	NC	Solar	Intermediate	Yes	3.84
Facility 325	Stanley	NC	Solar	Intermediate	Yes	3
Facility 326	Cedar Grove	NC	Solar	Intermediate	Yes	2.4
Facility 327	Hendersonville	NC	Solar	Intermediate	Yes	7.6
Facility 328	Julian	NC	Solar	Intermediate	Yes	5000
Facility 329	Forest City	NC	Solar	Intermediate	Yes	5000
Facility 330	Denver	NC	Solar	Intermediate	Yes	10.198
Facility 331	Harrisburg	NC	Solar	Intermediate	Yes	5.301
Facility 332	Kings Mountain	NC	Solar	Intermediate	Yes	15
Facility 333	Cherokee	NC	Solar	Intermediate	Yes	3
Facility 334	Charlotte	NC	Solar	Intermediate	Yes	1.29
Facility 335	Chapel Hill	NC	Solar	Intermediate	Yes	5
Facility 336	Mooresville	NC	Solar	Intermediate	Yes	12.959
Facility 337	Concord	NC	Solar	Intermediate	Yes	0.86
Facility 338	Salisbury	NC	Solar	Intermediate	Yes	4.3
Facility 339	Mooresville	NC	Solar	Intermediate	Yes	8.235
Facility 340	Charlotte	NC	Solar	Intermediate	Yes	6
Facility 341	Sandy Ridge	NC	Solar	Intermediate	Yes	4.94
Facility 342	Durham	NC	Solar	Intermediate	Yes	7.7
Facility 343	Chapel Hill	NC	Solar	Intermediate	Yes	4.18
Facility 344	Charlotte	NC	Solar	Intermediate	Yes	5
Facility 345	Kings Mountain	NC	Solar	Intermediate	Yes	7.5
Facility 346	Harrisburg	NC	Solar	Intermediate	Yes	0.86
Facility 347	Moravian Falls	NC	Solar	Intermediate	Yes	2.4
Facility 348	Mooresville	NC	Solar	Intermediate	Yes	5.865
Facility 349	Monroe	NC	Solar	Intermediate	Yes	5
Facility 350	Gibsonville	NC	Solar	Intermediate	Yes	2

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 351	Greensboro	NC	Solar	Intermediate	Yes	4.8
Facility 352	Belmont	NC	Solar	Intermediate	Yes	5
Facility 353	Hillsborough	NC	Solar	Intermediate	Yes	8
Facility 354	Cornelius	NC	Solar	Intermediate	Yes	4.76
Facility 355	Thomasville	NC	Solar	Intermediate	Yes	2.75
Facility 356	Charlotte	NC	Solar	Intermediate	Yes	4.75
Facility 357	Matthews	NC	Solar	Intermediate	Yes	2.63
Facility 358	Mount Pleasant	NC	Solar	Intermediate	Yes	6.72
Facility 359	Waxhaw	NC	Solar	Intermediate	Yes	3
Facility 360	Chapel Hill	NC	Solar	Intermediate	Yes	7.6
Facility 361	Huntersville	NC	Solar	Intermediate	Yes	6
Facility 362	Sylva	NC	Solar	Intermediate	Yes	9.69
Facility 363	Charlotte	NC	Solar	Intermediate	Yes	4.2
Facility 364	Charlotte	NC	Solar	Intermediate	Yes	4.73
Facility 365	Charlotte	NC	Solar	Intermediate	Yes	9.889
Facility 366	Hendersonville	NC	Solar	Intermediate	Yes	14.752
Facility 367	Research Triangle Park	NC	Solar	Intermediate	Yes	100
Facility 368	Charlotte	NC	Solar	Intermediate	Yes	260.82
Facility 369	Charlotte	NC	Solar	Intermediate	Yes	100
Facility 370	Charlotte	NC	Solar	Intermediate	Yes	8
Facility 371	Greensboro	NC	Solar	Intermediate	Yes	5.16
Facility 372	Greensboro	NC	Solar	Intermediate	Yes	4
Facility 373	Saxapahaw	NC	Solar	Intermediate	Yes	2
Facility 374	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 375	Taylorsville	NC	Solar	Intermediate	Yes	7.626
Facility 376	Mebane	NC	Solar	Intermediate	Yes	8.022
Facility 377	Shelby	NC	Solar	Intermediate	Yes	0.86
Facility 378	Kannapolis	NC	Solar	Intermediate	Yes	0.86
Facility 379	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 380	Charlotte	NC	Biomass	Intermediate	Yes	1600
Facility 381	Durham	NC	Solar	Intermediate	Yes	30
Facility 382	Durham	NC	Wind	Intermediate	Yes	3
Facility 383	Salisbury	NC	Solar	Intermediate	Yes	7
Facility 384	Mooresboro	NC	Hydroelectric	Baseload	Yes	1600
Facility 385	Sylva	NC	Solar	Intermediate	Yes	2.597
Facility 386	Advance	NC	Solar	Intermediate	Yes	4.35
Facility 387	Wilkesboro	NC	Solar	Intermediate	Yes	1.92
Facility 388	Kernersville	NC	Solar	Intermediate	Yes	4.826
Facility 389	Mount Airy	NC	Landfill Gas	Intermediate	Yes	1600
Facility 390	Mint Hill	NC	Solar	Intermediate	Yes	6.3
Facility 391	Statesville	NC	Solar	Intermediate	Yes	1.5
Facility 392	Hendersonville	NC	Solar	Intermediate	Yes	5.756
Facility 393	Reidsville	NC	Solar	Intermediate	Yes	169
Facility 394	Charlotte	NC	Solar	Intermediate	Yes	10.75
Facility 395	Advance	NC	Solar	Intermediate	Yes	10
Facility 396	Concord	NC	Landfill Gas	Intermediate	Yes	11500
Facility 397	Burlington	NC	Solar	Intermediate	Yes	3.696
Facility 398	Brown Summit	NC	Solar	Intermediate	Yes	750
Facility 399	Matthews	NC	Solar	Intermediate	Yes	4.561

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 500	Lawndale	NC	Solar	Intermediate	Yes	2.28
Facility 501	Greensboro	NC	Solar	Intermediate	Yes	4.73
Facility 502	Chapel Hill	NC	Solar	Intermediate	Yes	7.6
Facility 503	China Grove	NC	Solar	Intermediate	Yes	1.72
Facility 504	Claremont	NC	Solar	Intermediate	Yes	3
Facility 505	Charlotte	NC	Solar	Intermediate	Yes	0.7
Facility 506	Greensboro	NC	Solar	Intermediate	Yes	5
Facility 507	China Grove	NC	Solar	Intermediate	Yes	6
Facility 508	China Grove	NC	Wind	Intermediate	Yes	1
Facility 509	Sylva	NC	Solar	Intermediate	Yes	5.46
Facility 510	Matthews	NC	Solar	Intermediate	Yes	3.5
Facility 511	Browns Summit	NC	Solar	Intermediate	Yes	6
Facility 512	Hendersonville	NC	Solar	Intermediate	Yes	3
Facility 513	Chapel Hill	NC	Solar	Intermediate	Yes	2.5
Facility 514	Davidson	NC	Solar	Intermediate	Yes	94.08
Facility 515	Lexington	NC	Landfill Gas	Intermediate	Yes	1600
Facility 516	Chapel Hill	NC	Solar	Intermediate	Yes	3.207
Facility 517	McLeansville	NC	Solar	Intermediate	Yes	6.777
Facility 518	Lewisville	NC	Solar	Intermediate	Yes	0.7
Facility 519	Durham	NC	Solar	Intermediate	Yes	4.452
Facility 520	Charlotte	NC	Solar	Intermediate	Yes	6.067
Facility 521	Browns Summit	NC	Solar	Intermediate	Yes	72
Facility 522	Durham	NC	Solar	Intermediate	Yes	4.174
Facility 523	Cherryville	NC	Solar	Intermediate	Yes	6.051
Facility 524	Burlington	NC	Solar	Intermediate	Yes	6.904
Facility 525	Stokesdale	NC	Solar	Intermediate	Yes	5.2
Facility 526	Oak Ridge	NC	Solar	Intermediate	Yes	6
Facility 527	Kannapolis	NC	Solar	Intermediate	Yes	0.86
Facility 528	Winston Salem	NC	Solar	Intermediate	Yes	3.5
Facility 529	Charlotte	NC	Solar	Intermediate	Yes	2.76
Facility 530	Matthews	NC	Solar	Intermediate	Yes	20
Facility 531	Durham	NC	Solar	Intermediate	Yes	2.5
Facility 532	Durham	NC	Solar	Intermediate	Yes	6.37
Facility 533	Matthews	NC	Solar	Intermediate	Yes	30
Facility 534	China Grove	NC	Solar	Intermediate	Yes	4
Facility 535	Charlotte	NC	Solar	Intermediate	Yes	7.562
Facility 536	Harrisburg	NC	Solar	Intermediate	Yes	9.355
Facility 537	Raleigh	NC	Solar	Intermediate	Yes	7.697
Facility 538	Charlotte	NC	Solar	Intermediate	Yes	6
Facility 539	Stanley	NC	Solar	Intermediate	Yes	1.72
Facility 540	Morrisville	NC	Solar	Intermediate	Yes	30
Facility 541	Mooresville	NC	Solar	Intermediate	Yes	4
Facility 542	Ronda	NC	Solar	Intermediate	Yes	4.16
Facility 543	Whittier	NC	Solar	Intermediate	Yes	3.6
Facility 544	Brevard	NC	Solar	Intermediate	Yes	4
Facility 545	Graham	NC	Solar	Intermediate	Yes	5
Facility 546	Hillsborough	NC	Solar	Intermediate	Yes	3.8
Facility 547	Stanley	NC	Solar	Intermediate	Yes	7.83
Facility 548	Stanfield	NC	Solar	Intermediate	Yes	4.596
Facility 549	Charlotte	NC	Solar	Intermediate	Yes	3.08
Facility 550	Hillsborough	NC	Solar	Intermediate	Yes	5

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 551	Terrell	NC	Solar	Intermediate	Yes	10.05
Facility 552	Hickory	NC	Solar	Intermediate	Yes	2.58
Facility 553	Greensboro	NC	Solar	Intermediate	Yes	6.72
Facility 554	Kannapolis	NC	Solar	Intermediate	Yes	3.44
Facility 555	Charlotte	NC	Solar	Intermediate	Yes	7.937
Facility 556	Mooresville	NC	Solar	Intermediate	Yes	4.3
Facility 557	Charlotte	NC	Solar	Intermediate	Yes	1.29
Facility 558	Greensboro	NC	Solar	Intermediate	Yes	11
Facility 559	Durham	NC	Solar	Intermediate	Yes	101.2
Facility 560	Carrboro	NC	Solar	Intermediate	Yes	1.935
Facility 561	Whittier	NC	Solar	Intermediate	Yes	4.41
Facility 562	Charlotte	NC	Solar	Intermediate	Yes	9
Facility 563	Salisbury	NC	Solar	Intermediate	Yes	5
Facility 564	Moravian Falls	NC	Solar	Intermediate	Yes	2.76
Facility 565	Charlotte	NC	Solar	Intermediate	Yes	1.5
Facility 566	Salisbury	NC	Solar	Intermediate	Yes	2
Facility 567	Charlotte	NC	Solar	Intermediate	Yes	2.15
Facility 568	Pelham	NC	Solar	Intermediate	Yes	5000
Facility 569	Matthews	NC	Solar	Intermediate	Yes	5.394
Facility 570	Clemmons	NC	Solar	Intermediate	Yes	4.8
Facility 571	Charlotte	NC	Solar	Intermediate	Yes	3.75
Facility 572	Elon	NC	Solar	Intermediate	Yes	4.126
Facility 573	Charlotte	NC	Solar	Intermediate	Yes	0.864
Facility 574	Chapel Hill	NC	Solar	Intermediate	Yes	3.87
Facility 575	Greensboro	NC	Solar	Intermediate	Yes	36
Facility 576	Charlotte	NC	Solar	Intermediate	Yes	5
Facility 577	Mooresville	NC	Solar	Intermediate	Yes	7.032
Facility 578	Kings Mountain	NC	Solar	Intermediate	Yes	4000
Facility 579	Concord	NC	Solar	Intermediate	Yes	6.399
Facility 580	Charlotte	NC	Solar	Intermediate	Yes	4.3
Facility 581	Charlotte	NC	Solar	Intermediate	Yes	4
Facility 582	Durham	NC	Solar	Intermediate	Yes	4.77
Facility 583	Chapel Hill	NC	Solar	Intermediate	Yes	6.12
Facility 584	Ararat	NC	Solar	Intermediate	Yes	5
Facility 585	Ararat	NC	Solar	Intermediate	Yes	8
Facility 586	Mount Ulla	NC	Solar	Intermediate	Yes	4
Facility 587	King	NC	Solar	Intermediate	Yes	5
Facility 588	Monroe	NC	Solar	Intermediate	Yes	1.44
Facility 589	Monroe	NC	Solar	Intermediate	Yes	3
Facility 590	Salisbury	NC	Solar	Intermediate	Yes	1.72
Facility 591	Penrose	NC	Solar	Intermediate	Yes	5.76
Facility 592	Summerfield	NC	Solar	Intermediate	Yes	2.58
Facility 593	Charlotte	NC	Solar	Intermediate	Yes	2.65
Facility 594	Charlotte	NC	Solar	Intermediate	Yes	3.8
Facility 595	Mooresville	NC	Solar	Intermediate	Yes	6.02
Facility 596	Franklin	NC	Solar	Intermediate	Yes	4.5
Facility 597	Mooresville	NC	Solar	Intermediate	Yes	10
Facility 598	Charlotte	NC	Solar	Intermediate	Yes	4.06
Facility 599	Winston Salem	NC	Solar	Intermediate	Yes	3.81

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 600	Chapel Hill	NC	Solar	Intermediate	Yes	3
Facility 601	Taylorsville	NC	Solar	Intermediate	Yes	0.7
Facility 602	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 603	Chapel Hill	NC	Solar	Intermediate	Yes	3
Facility 604	Chapel Hill	NC	Solar	Intermediate	Yes	6
Facility 605	Pfafftown	NC	Solar	Intermediate	Yes	3.87
Facility 606	Charlotte	NC	Solar	Intermediate	Yes	1.08
Facility 607	Reidsville	NC	Solar	Intermediate	Yes	1.6
Facility 608	Morganton	NC	Solar	Intermediate	Yes	3
Facility 609	Burlington	NC	Solar	Intermediate	Yes	3
Facility 610	Reidsville	NC	Solar	Intermediate	Yes	3.87
Facility 611	Sherrills Ford	NC	Solar	Intermediate	Yes	6.06
Facility 612	Columbus	NC	Solar	Intermediate	Yes	3.6
Facility 613	Burlington	NC	Solar	Intermediate	Yes	10
Facility 614	Thomasville	NC	Solar	Intermediate	Yes	2.41
Facility 615	Charlotte	NC	Solar	Intermediate	Yes	5.381
Facility 616	Charlotte	NC	Solar	Intermediate	Yes	9.6
Facility 617	Gibsonville	NC	Solar	Intermediate	Yes	3
Facility 618	Franklin	NC	Solar	Intermediate	Yes	10
Facility 619	Winston Salem	NC	Solar	Intermediate	Yes	10.56
Facility 620	Charlotte	NC	Solar	Intermediate	Yes	5
Facility 621	Salisbury	NC	Solar	Intermediate	Yes	7.8
Facility 622	Greensboro	NC	Solar	Intermediate	Yes	5.52
Facility 623	Hickory	NC	Solar	Intermediate	Yes	4500
Facility 624	Durham	NC	Solar	Intermediate	Yes	6.777
Facility 625	Durham	NC	Solar	Intermediate	Yes	5.692
Facility 626	Charlotte `	NC	Solar	Intermediate	Yes	3.801
Facility 627	Mt Holly	NC	Solar	Intermediate	Yes	358.6
Facility 628	Durham	NC	Solar	Intermediate	Yes	40
Facility 629	Durham	NC	Landfill Gas	Intermediate	Yes	3180
Facility 630	Durham	NC	Solar	Intermediate	Yes	3500
Facility 631	Hillsborough	NC	Solar	Intermediate	Yes	10.68
Facility 632	Charlotte	NC	Solar	Intermediate	Yes	4.25
Facility 633	Old fort	NC	Solar	Intermediate	Yes	2.58
Facility 634	Salisbury	NC	Solar	Intermediate	Yes	6
Facility 635	Durham	NC	Solar	Intermediate	Yes	3.25
Facility 636	Harrisburg	NC	Solar	Intermediate	Yes	4.305
Facility 637	Charlotte	NC	Solar	Intermediate	Yes	4.24
Facility 638	Lexington	NC	Other	Intermediate	Yes	0
Facility 639	Cherokee	NC	Solar	Intermediate	Yes	5.16
Facility 640	Cherokee	NC	Solar	Intermediate	Yes	13.72
Facility 641	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 642	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 643	Franklin	NC	Solar	Intermediate	Yes	8.6
Facility 644	Concord	NC	Solar	Intermediate	Yes	1.29
Facility 645	Reidsville	NC	Solar	Intermediate	Yes	6
Facility 646	Burlington	NC	Solar	Intermediate	Yes	5
Facility 647	Mooresville	NC	Solar	Intermediate	Yes	2.4
Facility 648	Mebane	NC	Solar	Intermediate	Yes	5
Facility 649	Chapel Hill	NC	Solar	Intermediate	Yes	3.8
Facility 650	Charlotte	NC	Solar	Intermediate	Yes	0.86

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 651	Chapel Hill	NC	Solar	Intermediate	Yes	3.56
Facility 652	Charlotte	NC	Solar	Intermediate	Yes	3.015
Facility 653	Charlotte	NC	Solar	Intermediate	Yes	5
Facility 654	Charlotte	NC	Solar	Intermediate	Yes	4.578
Facility 655	Matthews	NC	Solar	Intermediate	Yes	0.86
Facility 656	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 657	Chapel Hill	NC	Solar	Intermediate	Yes	5.16
Facility 658	Chapel Hill	NC	Solar	Intermediate	Yes	8.78
Facility 659	Winston Salem	NC	Solar	Intermediate	Yes	2.64
Facility 660	Charlotte	NC	Solar	Intermediate	Yes	3
Facility 661	Pisgah Forest	NC	Solar	Intermediate	Yes	5.39
Facility 662	Pisgah Forest	NC	Solar	Intermediate	Yes	7.54
Facility 663	Chapel Hill	NC	Solar	Intermediate	Yes	5
Facility 664	Chapel Hill	NC	Solar	Intermediate	Yes	7.5
Facility 665	Charlotte	NC	Solar	Intermediate	Yes	4
Facility 666	Chapel Hill	NC	Solar	Intermediate	Yes	3
Facility 667	Durham	NC	Solar	Intermediate	Yes	15
Facility 668	Charltote	NC	Solar	Intermediate	Yes	4.578
Facility 669	Chapel Hill	NC	Solar	Intermediate	Yes	4.95
Facility 670	Charlotte	NC	Solar	Intermediate	Yes	4.003
Facility 671	Burlington	NC	Solar	Intermediate	Yes	3000
Facility 672	Charlotte	NC	Solar	Intermediate	Yes	1.08
Facility 673	Elon	NC	Solar	Intermediate	Yes	5
Facility 674	Greensboro	NC	Solar	Intermediate	Yes	4.8
Facility 675	Huntersville	NC	Solar	Intermediate	Yes	7.96
Facility 676	Winston Salem	NC	Solar	Intermediate	Yes	4.8
Facility 677	Greensboro	NC	Solar	Intermediate	Yes	5
Facility 678	Charlotte	NC	Solar	Intermediate	Yes	3.75
Facility 679	Oak Ridge	NC	Solar	Intermediate	Yes	4.052
Facility 680	Durham	NC	Solar	Intermediate	Yes	3.5
Facility 681	Marion	NC	Solar	Intermediate	Yes	18
Facility 682	Lenoir	NC	Solar	Intermediate	Yes	1.4
Facility 683	Statesville	NC	Solar	Intermediate	Yes	19.153
Facility 684	Durham	NC	Solar	Intermediate	Yes	48
Facility 685	Horse Shoe	NC	Solar	Intermediate	Yes	10.519
Facility 686	Horse Shoe	NC	Solar	Intermediate	Yes	5.064
Facility 687	Matthews	NC	Solar	Intermediate	Yes	4
Facility 688	Dallas	NC	Solar	Intermediate	Yes	3.928
Facility 689	Charlotte	NC	Solar	Intermediate	Yes	6
Facility 690	Durham	NC	Solar	Intermediate	Yes	2.16
Facility 691	Harrisburg	NC	Solar	Intermediate	Yes	1.72
Facility 692	Durham	NC	Solar	Intermediate	Yes	5
Facility 693	Davidson	NC	Solar	Intermediate	Yes	3.84
Facility 694	Raleigh	NC	Solar	Intermediate	Yes	3.8
Facility 695	Hendersonville	NC	Solar	Intermediate	Yes	4.9
Facility 696	Charlotte	NC	Solar	Intermediate	Yes	6
Facility 697	Greensboro	NC	Solar	Intermediate	Yes	634.8
Facility 698	Randleman	NC	Solar	Intermediate	Yes	6
Facility 699	Charlotte	NC	Solar	Intermediate	Yes	4.5

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 700	Nebo	NC	Solar	Intermediate	Yes	3
Facility 701	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 702	Concord	NC	Solar	Intermediate	Yes	0.86
Facility 703	Charlotte	NC	Solar	Intermediate	Yes	2.85
Facility 704	Charlotte	NC	Solar	Intermediate	Yes	9.03
Facility 705	Elon	NC	Solar	Intermediate	Yes	1999
Facility 706	Winston Salem	NC	Solar	Intermediate	Yes	5.75
Facility 707	Greensboro	NC	Solar	Intermediate	Yes	5
Facility 708	Durham	NC	Solar	Intermediate	Yes	5.112
Facility 709	Durham	NC	Solar	Intermediate	Yes	4.05
Facility 710	Winston Salem	NC	Solar	Intermediate	Yes	1.798
Facility 711	Hickory	NC	Solar	Intermediate	Yes	4.844
Facility 712	Brevard	NC	Solar	Intermediate	Yes	8.143
Facility 713	Durham	NC	Solar	Intermediate	Yes	4.483
Facility 714	Winston Salem	NC	Solar	Intermediate	Yes	12.26
Facility 715	Charlotte	NC	Solar	Intermediate	Yes	8.364
Facility 716	Hendersonville	NC	Solar	Intermediate	Yes	10.767
Facility 717	Franklin	NC	Solar	Intermediate	Yes	8.26
Facility 718	Mt. Pleasant	NC	Solar	Intermediate	Yes	7.006
Facility 719	Oakboro	NC	Solar	Intermediate	Yes	4950
Facility 720	Stanley	NC	Solar	Intermediate	Yes	5.953
Facility 721	Conover	NC	Solar	Intermediate	Yes	5000
Facility 722	Charlotte	NC	Solar	Intermediate	Yes	15.68
Facility 723	Greensboro	NC	Solar	Intermediate	Yes	14.4
Facility 724	Clemmons	NC	Solar	Intermediate	Yes	2.38
Facility 725	Marion	NC	Solar	Intermediate	Yes	4
Facility 726	Greensboro	NC	Solar	Intermediate	Yes	2.651
Facility 727	Catawba	NC	Solar	Intermediate	Yes	4.75
Facility 728	Graham	NC	Solar	Intermediate	Yes	2.7
Facility 729	Mount Ulla	NC	Solar	Intermediate	Yes	4.592
Facility 730	Denver	NC	Solar	Intermediate	Yes	5.964
Facility 731	Glen Alpine	NC	Solar	Intermediate	Yes	24
Facility 732	Clemmons	NC	Solar	Intermediate	Yes	2.3
Facility 733	Charlotte	NC	Solar	Intermediate	Yes	6.107
Facility 734	Pisgah Forest	NC	Solar	Intermediate	Yes	3.709
Facility 735	Charlotte	NC	Solar	Intermediate	Yes	17.581
Facility 736	Hickory	NC	Solar	Intermediate	Yes	3.51
Facility 737	Hickory	NC	Solar	Intermediate	Yes	4.5
Facility 738	Chapel Hill	NC	Solar	Intermediate	Yes	5.59
Facility 739	Charlotte	NC	Solar	Intermediate	Yes	0.08
Facility 740	Charlotte	NC	Solar	Intermediate	Yes	11.77
Facility 741	Greensboro	NC	Solar	Intermediate	Yes	2.946
Facility 742	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 743	Salisbury	NC	Solar	Intermediate	Yes	2.88
Facility 744	Franklin	NC	Solar	Intermediate	Yes	18
Facility 745	Columbus	NC	Solar	Intermediate	Yes	5.71
Facility 746	Sylva	NC	Solar	Intermediate	Yes	4.45
Facility 747	Mebane	NC	Solar	Intermediate	Yes	5
Facility 748	Casar	NC	Solar	Intermediate	Yes	6.988
Facility 749	Chapel Hill	NC	Solar	Intermediate	Yes	5
Facility 750	Salisbury	NC	Solar	Intermediate	Yes	82

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 751	Claremont	NC	Solar	Intermediate	Yes	3500
Facility 752	Mebane	NC	Solar	Intermediate	Yes	3000
Facility 753	Charlotte	NC	Solar	Intermediate	Yes	8.373
Facility 754	Charlotte	NC	Solar	Intermediate	Yes	7.952
Facility 755	Claremont	NC	Solar	Intermediate	Yes	10.267
Facility 756	Charlotte	NC	Solar	Intermediate	Yes	72
Facility 757	Hendersonville	NC	Solar	Intermediate	Yes	5
Facility 758	Winston Salem	NC	Solar	Intermediate	Yes	16.759
Facility 759	Greensboro	NC	Solar	Intermediate	Yes	1.75
Facility 760	Pisgah Forest	NC	Solar	Intermediate	Yes	4.38
Facility 761	Tryon	NC	Solar	Intermediate	Yes	3
Facility 762	China Grove	NC	Solar	Intermediate	Yes	3.44
Facility 763	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 764	Pilot Mountain	NC	Solar	Intermediate	Yes	10
Facility 765	Harrisburg	NC	Solar	Intermediate	Yes	5.301
Facility 766	Burlington	NC	Solar	Intermediate	Yes	4.595
Facility 767	Concord	NC	Solar	Intermediate	Yes	3.649
Facility 768	Lincolnton	NC	Solar	Intermediate	Yes	6.593
Facility 769	Durham	NC	Solar	Intermediate	Yes	7.289
Facility 770	Charlotte	NC	Solar	Intermediate	Yes	2.199
Facility 771	Sherrills Ford	NC	Solar	Intermediate	Yes	4.554
Facility 772	Kernersville	NC	Solar	Intermediate	Yes	6.782
Facility 773	Mooresville	NC	Solar	Intermediate	Yes	5.055
Facility 774	Carrboro	NC	Solar	Intermediate	Yes	2.597
Facility 775	Reidsville	NC	Solar	Intermediate	Yes	5
Facility 776	Charlotte	NC	Solar	Intermediate	Yes	1.29
Facility 777	Mount Holly	NC	Solar	Intermediate	Yes	0.86
Facility 778	Durham	NC	Solar	Intermediate	Yes	7.94
Facility 779	Whittier	NC	Solar	Intermediate	Yes	2.58
Facility 780	Concord	NC	Landfill Gas	Intermediate	Yes	5000
Facility 781	Dallas	NC	Landfill Gas	Intermediate	Yes	4800
Facility 782	Durham	NC	Solar	Intermediate	Yes	6.234
Facility 783	Browns Summit	NC	Solar	Intermediate	Yes	2.16
Facility 784	Huntersville	NC	Solar	Intermediate	Yes	7.327
Facility 785	Durham	NC	Solar	Intermediate	Yes	700
Facility 786	Durham	NC	Solar	Intermediate	Yes	1000
Facility 787	Summerfield	NC	Solar	Intermediate	Yes	3.86
Facility 788	Summerfield	NC	Solar	Intermediate	Yes	6.86
Facility 789	Cedar Grove	NC	Solar	Intermediate	Yes	6
Facility 790	Chapel Hill	NC	Solar	Intermediate	Yes	3.06
Facility 791	Mooresville	NC	Solar	Intermediate	Yes	6
Facility 792	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 793	Nebo	NC	Solar	Intermediate	Yes	6
Facility 794	Hendersonville	NC	Solar	Intermediate	Yes	2.82
Facility 795	Charlotte	NC	Solar	Intermediate	Yes	1
Facility 796	Davidson	NC	Solar	Intermediate	Yes	4.3
Facility 797	Rural Hall	NC	Solar	Intermediate	Yes	4.5
Facility 798	Ruffin	NC	Solar	Intermediate	Yes	6
Facility 799	Columbus	NC	Solar	Intermediate	Yes	2.14

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 800	Hillsborough	NC	Solar	Intermediate	Yes	3
Facility 801	Charlotte	NC	Solar	Intermediate	Yes	1.96
Facility 802	Durham	NC	Solar	Intermediate	Yes	3
Facility 803	Franklin	NC	Solar	Intermediate	Yes	1.92
Facility 804	Millers Creek	NC	Solar	Intermediate	Yes	2.58
Facility 805	Bryson City	NC	Solar	Intermediate	Yes	7
Facility 806	Greensboro	NC	Solar	Intermediate	Yes	4.16
Facility 807	Marion	NC	Solar	Intermediate	Yes	2.5
Facility 808	Chapel Hill	NC	Solar	Intermediate	Yes	9.743
Facility 809	Rural Hall	NC	Solar	Intermediate	Yes	5000
Facility 810	Chapel Hill	NC	Solar	Intermediate	Yes	6
Facility 811	Salisbury	NC	Solar	Intermediate	Yes	112
Facility 812	Salisbury	NC	Solar	Intermediate	Yes	90.75
Facility 813	Salisbury	NC	Solar	Intermediate	Yes	84
Facility 814	Charlotte	NC	Solar	Intermediate	Yes	6.236
Facility 815	Charlotte	NC	Solar	Intermediate	Yes	4.05
Facility 816	Charlotte	NC	Solar	Intermediate	Yes	2.907
Facility 817	Mooresville	NC	Solar	Intermediate	Yes	6.98
Facility 818	Chapel Hill	NC	Solar	Intermediate	Yes	1.64
Facility 819	Lewisville	NC	Solar	Intermediate	Yes	1.844
Facility 820	Durham	NC	Solar	Intermediate	Yes	307.43
Facility 821	Cedar Grove	NC	Solar	Intermediate	Yes	5.59
Facility 822	Stanley	NC	Solar	Intermediate	Yes	1.29
Facility 823	Danbury	NC	Solar	Intermediate	Yes	5.76
Facility 824	Hickory	NC	Solar	Intermediate	Yes	1.4
Facility 825	Charlotte	NC	Solar	Intermediate	Yes	1.72
Facility 826	Mills River	NC	Solar	Intermediate	Yes	2.58
Facility 827	Gastonia	NC	Solar	Intermediate	Yes	5.252
Facility 828	Charlotte	NC	Solar	Intermediate	Yes	7.7
Facility 829	Belmont	NC	Solar	Intermediate	Yes	12
Facility 830	Salisbury	NC	Solar	Intermediate	Yes	2.857
Facility 831	Gibsonville	NC	Solar	Intermediate	Yes	2.422
Facility 832	Charlotte	NC	Solar	Intermediate	Yes	4.5
Facility 833	Charlotte	NC	Solar	Intermediate	Yes	3.5
Facility 834	Conover	NC	Solar	Intermediate	Yes	1.851
Facility 835	Columbus	NC	Solar	Intermediate	Yes	2.15
Facility 836	Columbus	NC	Solar	Intermediate	Yes	12.04
Facility 837	Greensboro	NC	Solar	Intermediate	Yes	7.31
Facility 838	Greensboro	NC	Solar	Intermediate	Yes	50
Facility 839	Hendersonville	NC	Solar	Intermediate	Yes	2.88
Facility 840	Winston Salem	NC	Solar	Intermediate	Yes	2.856
Facility 841	Kannapolis	NC	Solar	Intermediate	Yes	3.01
Facility 842	Franklin	NC	Solar	Intermediate	Yes	4.3
Facility 843	Denver	NC	Solar	Intermediate	Yes	0.7
Facility 844	Chapel Hill	NC	Solar	Intermediate	Yes	5
Facility 845	Clemmons	NC	Solar	Intermediate	Yes	8
Facility 846	Stoneville	NC	Solar	Intermediate	Yes	3.808
Facility 847	Kernersville	NC	Solar	Intermediate	Yes	2.907
Facility 848	Charlotte	NC	Solar	Intermediate	Yes	3.677
Facility 849	Greensboro	NC	Solar	Intermediate	Yes	11.995
Facility 850	Waxhaw	NC	Solar	Intermediate	Yes	6.531

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 851	Reidsville	NC	Solar	Intermediate	Yes	5.444
Facility 852	Ellenboro	NC	Solar	Intermediate	Yes	2.58
Facility 853	Hillsborough	NC	Solar	Intermediate	Yes	4.2
Facility 854	Kernersville	NC	Solar	Intermediate	Yes	40
Facility 855	Chapel Hill	NC	Solar	Intermediate	Yes	6
Facility 856	Sylva	NC	Solar	Intermediate	Yes	15.915
Facility 857	Charlotte	NC	Solar	Intermediate	Yes	2.385
Facility 858	Durham	NC	Solar	Intermediate	Yes	5.474
Facility 859	Durham	NC	Solar	Intermediate	Yes	3.32
Facility 860	Chapel Hill	NC	Solar	Intermediate	Yes	9.056
Facility 861	Mount Holly	NC	Solar	Intermediate	Yes	1.862
Facility 862	Taylorsville	NC	Hydroelectric	Baseload	Yes	365
Facility 863	Winston Salem	NC	Solar	Intermediate	Yes	14.8
Facility 864	Charlotte	NC	Solar	Intermediate	Yes	3.356
Facility 865	Dallas	NC	Hydroelectric	Baseload	Yes	820
Facility 866	Charlotte	NC	Solar	Intermediate	Yes	8.126
Facility 867	Whitsett	NC	Solar	Intermediate	Yes	7.5
Facility 868	N Wilkesboro	NC	Solar	Intermediate	Yes	4
Facility 869	Union Mills	NC	Solar	Intermediate	Yes	4.423
Facility 870	Charlotte	NC	Solar	Intermediate	Yes	2
Facility 871	Concord	NC	Solar	Intermediate	Yes	5.2
Facility 872	Horse Shoe	NC	Solar	Intermediate	Yes	5
Facility 873	Connelly Springs	NC	Solar	Intermediate	Yes	1.779
Facility 874	Midland	NC	Solar	Intermediate	Yes	8.771
Facility 875	Charlotte	NC	Solar	Intermediate	Yes	4.596
Facility 876	Charlotte	NC	Solar	Intermediate	Yes	5.964
Facility 877	Saxpahaw	NC	Hydroelectric	Baseload	Yes	1500
Facility 878	Shelby	NC	Solar	Intermediate	Yes	5.22
Facility 879	Lincolnton	NC	Solar	Intermediate	Yes	5000
Facility 880	Greensboro	NC	Solar	Intermediate	Yes	40
Facility 881	Durham	NC	Solar	Intermediate	Yes	3.01
Facility 882	Greensboro	NC	Solar	Intermediate	Yes	2.329
Facility 883	Durham	NC	Solar	Intermediate	Yes	3.485
Facility 884	Thomasville	NC	Solar	Intermediate	Yes	2.318
Facility 885	Clemmons	NC	Solar	Intermediate	Yes	13.6
Facility 886	Albemarle	NC	Solar	Intermediate	Yes	8.989
Facility 887	Charlotte	NC	Solar	Intermediate	Yes	4.525
Facility 888	Chapel Hill	NC	Solar	Intermediate	Yes	3.3
Facility 889	Chapel Hill	NC	Solar	Intermediate	Yes	10.686
Facility 890	Moorrisville	NC	Solar	Intermediate	Yes	7.6
Facility 891	Matthews	NC	Solar	Intermediate	Yes	1.08
Facility 892	China Grove	NC	Solar	Intermediate	Yes	5
Facility 893	Charlotte	NC	Solar	Intermediate	Yes	1.29
Facility 894	Chapel Hill	NC	Solar	Intermediate	Yes	7
Facility 895	Charlotte	NC	Solar	Intermediate	Yes	1.29
Facility 896	Charlotte	NC	Solar	Intermediate	Yes	2.75
Facility 897	Pisgah Forest	NC	Solar	Intermediate	Yes	5.457
Facility 898	Rural Hall	NC	Solar	Intermediate	Yes	4.592
Facility 899	Durham	NC	Solar	Intermediate	Yes	4.379

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 900	Charlotte	NC	Solar	Intermediate	Yes	3.5
Facility 901	Mocksville	NC	Solar	Intermediate	Yes	1.92
Facility 902	Charlotte	NC	Solar	Intermediate	Yes	2.598
Facility 903	Chapel Hill	NC	Solar	Intermediate	Yes	7.2
Facility 904	Chapel Hill	NC	Solar	Intermediate	Yes	5.76
Facility 905	Durham	NC	Solar	Intermediate	Yes	4.576
Facility 906	Charlotte	NC	Other	Intermediate	Yes	0
Facility 907	Greensboro	NC	Solar	Intermediate	Yes	108
Facility 908	Glenville	NC	Solar	Intermediate	Yes	6.635
Facility 909	Concord	NC	Solar	Intermediate	Yes	10.111
Facility 910	Charlotte	NC	Solar	Intermediate	Yes	3.746
Facility 911	Mooresville	NC	Solar	Intermediate	Yes	11
Facility 912	Monroe	NC	Solar	Intermediate	Yes	6.16
Facility 913	Charlotte	NC	Solar	Intermediate	Yes	2.15
Facility 914	Thomasville	NC	Solar	Intermediate	Yes	1.29
Facility 915	Greensboro	NC	Solar	Intermediate	Yes	4.8
Facility 916	Denver	NC	Solar	Intermediate	Yes	4.549
Facility 917	Denver	NC	Solar	Intermediate	Yes	2.247
Facility 918	Winston-Salem	NC	Solar	Intermediate	Yes	3.576
Facility 919	Haw River	NC	Solar	Intermediate	Yes	4
Facility 920	Charlotte	NC	Solar	Intermediate	Yes	5.52
Facility 921	Cornelius	NC	Solar	Intermediate	Yes	4.14
Facility 922	Charlotte	NC	Solar	Intermediate	Yes	2.534
Facility 923	Lincolnton	NC	Solar	Intermediate	Yes	2.15
Facility 924	Cedar Grove	NC	Solar	Intermediate	Yes	3
Facility 925	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 926	Salisbury	NC	Solar	Intermediate	Yes	2.318
Facility 927	Harmony	NC	Solar	Intermediate	Yes	4.682
Facility 928	Midland	NC	Solar	Intermediate	Yes	4998
Facility 929	Charlotte	NC	Solar	Intermediate	Yes	4.366
Facility 930	Charlotte	NC	Solar	Intermediate	Yes	5.847
Facility 931	Advance	NC	Solar	Intermediate	Yes	9.138
Facility 932	Franklin	NC	Solar	Intermediate	Yes	7.579
Facility 933	Mebane	NC	Solar	Intermediate	Yes	4.269
Facility 934	Chapel Hill	NC	Solar	Intermediate	Yes	5.858
Facility 935	Shelby	NC	Solar	Intermediate	Yes	5000
Facility 936	Durham	NC	Solar	Intermediate	Yes	3.157
Facility 937	High Point	NC	Solar	Intermediate	Yes	2.259
Facility 938	Charlotte	NC	Solar	Intermediate	Yes	7.5
Facility 939	Carrboro	NC	Solar	Intermediate	Yes	6
Facility 940	Charlotte	NC	Solar	Intermediate	Yes	7.532
Facility 941	Charlotte	NC	Solar	Intermediate	Yes	790
Facility 942	Summerfield	NC	Solar	Intermediate	Yes	15.207
Facility 943	Haw River	NC	Solar	Intermediate	Yes	8.835
Facility 944	N Wilkesboro	NC	Solar	Intermediate	Yes	63
Facility 945	Chapel Hill	NC	Solar	Intermediate	Yes	5.281
Facility 946	Sylva	NC	Solar	Intermediate	Yes	18
Facility 947	Hendersonville	NC	Solar	Intermediate	Yes	1996.4
Facility 948	Ellenboro	NC	Solar	Intermediate	Yes	1996.4
Facility 949	Hendersonville	NC	Solar	Intermediate	Yes	1981
Facility 950	Bostic	NC	Solar	Intermediate	Yes	1989

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 951	Kings Mountain	NC	Solar	Intermediate	Yes	2500
Facility 952	Hildebran	NC	Solar	Intermediate	Yes	2000
Facility 953	Charlotte	NC	Solar	Intermediate	Yes	3.6
Facility 954	Eden	NC	Hydroelectric	Baseload	Yes	500
Facility 955	Climax	NC	Solar	Intermediate	Yes	8.084
Facility 956	Liberty	NC	Solar	Intermediate	Yes	13.496
Facility 957	Durham	NC	Solar	Intermediate	Yes	4.609
Facility 958	Mooresville	NC	Solar	Intermediate	Yes	3.84
Facility 959	Vale	NC	Solar	Intermediate	Yes	10
Facility 960	Salisbury	NC	Solar	Intermediate	Yes	4
Facility 961	Pfafftown	NC	Solar	Intermediate	Yes	3.63
Facility 962	Chapel Hill	NC	Solar	Intermediate	Yes	3.8
Facility 963	Charlotte	NC	Solar	Intermediate	Yes	2.85
Facility 964	Tobaccoville	NC	Solar	Intermediate	Yes	2.16
Facility 965	Mooresville	NC	Solar	Intermediate	Yes	2.9
Facility 966	Charlotte	NC	Solar	Intermediate	Yes	5.055
Facility 967	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 968	Charlotte	NC	Solar	Intermediate	Yes	4.56
Facility 969	Rutherford College	NC	Solar	Intermediate	Yes	5.907
Facility 970	Greensboro	NC	Solar	Intermediate	Yes	9.6
Facility 971	Hillsborough	NC	Solar	Intermediate	Yes	6.283
Facility 972	Mills River	NC	Solar	Intermediate	Yes	6
Facility 973	Mills River	NC	Solar	Intermediate	Yes	6
Facility 974	Charlotte	NC	Solar	Intermediate	Yes	11.671
Facility 975	Greensboro	NC	Solar	Intermediate	Yes	2.5
Facility 976	Salisbury	NC	Solar	Intermediate	Yes	5
Facility 977	Greensboro	NC	Solar	Intermediate	Yes	3.45
Facility 978	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 979	Chapel Hill	NC	Solar	Intermediate	Yes	9.17
Facility 980	Kannapolis	NC	Solar	Intermediate	Yes	5
Facility 981	Charlotte	NC	Solar	Intermediate	Yes	1.075
Facility 982	Graham	NC	Solar	Intermediate	Yes	2.88
Facility 983	Chapel Hill	NC	Solar	Intermediate	Yes	5
Facility 984	Charlotte	NC	Solar	Intermediate	Yes	5
Facility 985	Charlotte	NC	Solar	Intermediate	Yes	4
Facility 986	Durham	NC	Solar	Intermediate	Yes	4.62
Facility 987	Connelly Springs	NC	Solar	Intermediate	Yes	4
Facility 988	Salisbury	NC	Solar	Intermediate	Yes	1.72
Facility 989	Charlotte	NC	Solar	Intermediate	Yes	5
Facility 990	Saluda	NC	Solar	Intermediate	Yes	5.16
Facility 991	Lewisville	NC	Solar	Intermediate	Yes	2.4
Facility 992	Mount Airy	NC	Solar	Intermediate	Yes	12.26
Facility 993	Lincolnton	NC	Solar	Intermediate	Yes	0.86
Facility 994	Hickory	NC	Solar	Intermediate	Yes	3.01
Facility 995	Charlotte	NC	Solar	Intermediate	Yes	4
Facility 996	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 997	Rockwell	NC	Solar	Intermediate	Yes	2.58
Facility 998	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 999	Carrboro	NC	Solar	Intermediate	Yes	1.5

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1000	Durham	NC	Solar	Intermediate	Yes	3.6
Facility 1001	Matthews	NC	Solar	Intermediate	Yes	3.6
Facility 1002	Mooresville	NC	Solar	Intermediate	Yes	7.6
Facility 1003	Germanton	NC	Solar	Intermediate	Yes	2.58
Facility 1004	Greensboro	NC	Solar	Intermediate	Yes	5
Facility 1005	Charlotte	NC	Solar	Intermediate	Yes	1.72
Facility 1006	Charlotte	NC	Solar	Intermediate	Yes	1.72
Facility 1007	Winston Salem	NC	Solar	Intermediate	Yes	6.38
Facility 1008	Highlands	NC	Solar	Intermediate	Yes	3
Facility 1009	Highlands	NC	Solar	Intermediate	Yes	3
Facility 1010	High Point	NC	Solar	Intermediate	Yes	5.04
Facility 1011	Hillsborough	NC	Solar	Intermediate	Yes	6
Facility 1012	Salisbury	NC	Solar	Intermediate	Yes	2.4
Facility 1013	Salisbury	NC	Solar	Intermediate	Yes	6
Facility 1014	Winston Salem	NC	Solar	Intermediate	Yes	2.856
Facility 1015	Charlotte	NC	Solar	Intermediate	Yes	1.25
Facility 1016	Durham	NC	Solar	Intermediate	Yes	4
Facility 1017	Charlotte	NC	Solar	Intermediate	Yes	1.75
Facility 1018	Durham	NC	Solar	Intermediate	Yes	3.75
Facility 1019	Monroe	NC	Solar	Intermediate	Yes	5
Facility 1020	Chapel Hill	NC	Solar	Intermediate	Yes	3.571
Facility 1021	King	NC	Solar	Intermediate	Yes	2.58
Facility 1022	Harrisburg	NC	Solar	Intermediate	Yes	6
Facility 1023	Saluda	NC	Solar	Intermediate	Yes	6.645
Facility 1024	Kannapolis	NC	Solar	Intermediate	Yes	5
Facility 1025	Pinnacle	NC	Solar	Intermediate	Yes	4
Facility 1026	Millers Creek	NC	Solar	Intermediate	Yes	2
Facility 1027	Carrboro	NC	Solar	Intermediate	Yes	2
Facility 1028	Kernersville	NC	Solar	Intermediate	Yes	1.5
Facility 1029	Hillsborough	NC	Solar	Intermediate	Yes	4
Facility 1030	Mebane	NC	Solar	Intermediate	Yes	2
Facility 1031	Liberty	NC	Solar	Intermediate	Yes	4.9
Facility 1032	Concord	NC	Solar	Intermediate	Yes	4
Facility 1033	Durham	NC	Solar	Intermediate	Yes	2.205
Facility 1034	Durham	NC	Solar	Intermediate	Yes	5.29
Facility 1035	Charlotte	NC	Solar	Intermediate	Yes	1.4
Facility 1036	Charlotte	NC	Solar	Intermediate	Yes	5
Facility 1037	Salisbury	NC	Solar	Intermediate	Yes	6
Facility 1038	Durham	NC	Solar	Intermediate	Yes	3.84
Facility 1039	Concord	NC	Solar	Intermediate	Yes	1.92
Facility 1040	Chapel Hill	NC	Solar	Intermediate	Yes	5
Facility 1041	Salisbury	NC	Solar	Intermediate	Yes	2.5
Facility 1042	Reidsville	NC	Solar	Intermediate	Yes	0.76
Facility 1043	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 1044	Cullowhee	NC	Solar	Intermediate	Yes	2.58
Facility 1045	Union Mills	NC	Solar	Intermediate	Yes	4.18
Facility 1046	Monroe	NC	Solar	Intermediate	Yes	4.2
Facility 1047	Climax	NC	Solar	Intermediate	Yes	4.8
Facility 1048	Durham	NC	Solar	Intermediate	Yes	2.205
Facility 1049	Mooresville	NC	Solar	Intermediate	Yes	7.96
Facility 1050	Mooresville	NC	Solar	Intermediate	Yes	4.3

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1051	Charlotte	NC	Solar	Intermediate	Yes	6.138
Facility 1052	Cornelius	NC	Solar	Intermediate	Yes	6.02
Facility 1053	Shelby	NC	Solar	Intermediate	Yes	3.3
Facility 1054	Wilkesboro	NC	Solar	Intermediate	Yes	4.2
Facility 1055	Pisgah Forest	NC	Solar	Intermediate	Yes	0.7
Facility 1056	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 1057	Charlotte	NC	Solar	Intermediate	Yes	1.08
Facility 1058	Winston Salem	NC	Solar	Intermediate	Yes	2.86
Facility 1059	Durham	NC	Solar	Intermediate	Yes	5
Facility 1060	Hendersonville	NC	Solar	Intermediate	Yes	4
Facility 1061	Durham	NC	Solar	Intermediate	Yes	13.5
Facility 1062	Charlotte	NC	Solar	Intermediate	Yes	2.38
Facility 1063	Winston Salem	NC	Solar	Intermediate	Yes	3
Facility 1064	Mayodan	NC	Solar	Intermediate	Yes	1.2
Facility 1065	Chapel Hill	NC	Solar	Intermediate	Yes	3
Facility 1066	Durham	NC	Solar	Intermediate	Yes	2.48
Facility 1067	Mount Ulla	NC	Solar	Intermediate	Yes	5.301
Facility 1068	Charlotte	NC	Solar	Intermediate	Yes	3
Facility 1069	Harrisburg	NC	Solar	Intermediate	Yes	5.81
Facility 1070	Durham	NC	Solar	Intermediate	Yes	1.25
Facility 1071	Greensboro	NC	Solar	Intermediate	Yes	4.3
Facility 1072	Hillsborough	NC	Solar	Intermediate	Yes	5
Facility 1073	Lenoir	NC	Solar	Intermediate	Yes	6.45
Facility 1074	Durham	NC	Solar	Intermediate	Yes	3.23
Facility 1075	Chapel Hill	NC	Solar	Intermediate	Yes	4.08
Facility 1076	Morrisville	NC	Solar	Intermediate	Yes	3.812
Facility 1077	Durham	NC	Solar	Intermediate	Yes	6.45
Facility 1078	Charlotte	NC	Solar	Intermediate	Yes	3.6
Facility 1079	Germantown	NC	Solar	Intermediate	Yes	2.36
Facility 1080	Browns Summit	NC	Solar	Intermediate	Yes	4.719
Facility 1081	Morrisville	NC	Solar	Intermediate	Yes	5.344
Facility 1082	Terrell	NC	Solar	Intermediate	Yes	4.3
Facility 1083	Graham	NC	Solar	Intermediate	Yes	2
Facility 1084	Pisgah Forest	NC	Solar	Intermediate	Yes	8.061
Facility 1085	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1086	Connellys Springs	NC	Solar	Intermediate	Yes	6.88
Facility 1087	McLeansville	NC	Solar	Intermediate	Yes	2.856
Facility 1088	Mooresville	NC	Solar	Intermediate	Yes	2.4
Facility 1089	Concord	NC	Solar	Intermediate	Yes	3.8
Facility 1090	Durham	NC	Solar	Intermediate	Yes	5
Facility 1091	Cullowhee	NC	Solar	Intermediate	Yes	3
Facility 1092	Salisbury	NC	Solar	Intermediate	Yes	1.72
Facility 1093	Matthews	NC	Solar	Intermediate	Yes	2.88
Facility 1094	Chapel Hill	NC	Solar	Intermediate	Yes	4.15
Facility 1095	Greensboro	NC	Solar	Intermediate	Yes	2.15
Facility 1096	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 1097	Concord	NC	Solar	Intermediate	Yes	3
Facility 1098	Kannapolis	NC	Solar	Intermediate	Yes	2.7
Facility 1099	Efland	NC	Solar	Intermediate	Yes	7.6

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1100	Granite Falls	NC	Solar	Intermediate	Yes	6.45
Facility 1101	Browns Summit	NC	Solar	Intermediate	Yes	5
Facility 1102	Durham	NC	Solar	Intermediate	Yes	3
Facility 1103	Chapel Hill	NC	Solar	Intermediate	Yes	10
Facility 1104	Thomasville	NC	Solar	Intermediate	Yes	6
Facility 1105	Maiden	NC	Solar	Intermediate	Yes	2.58
Facility 1106	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1107	High Point	NC	Solar	Intermediate	Yes	4.5
Facility 1108	Charlotte	NC	Solar	Intermediate	Yes	5.194
Facility 1109	Brevard	NC	Solar	Intermediate	Yes	7.56
Facility 1110	Burlington	NC	Solar	Intermediate	Yes	3.24
Facility 1111	Burlington	NC	Solar	Intermediate	Yes	2.5
Facility 1112	Burlington	NC	Solar	Intermediate	Yes	2.88
Facility 1113	Greensboro	NC	Solar	Intermediate	Yes	2.38
Facility 1114	Old fort	NC	Solar	Intermediate	Yes	3.01
Facility 1115	Marble	NC	Solar	Intermediate	Yes	7.6
Facility 1116	Hillsborough	NC	Solar	Intermediate	Yes	2.58
Facility 1117	Greensboro	NC	Solar	Intermediate	Yes	4.32
Facility 1118	Winston Salem	NC	Solar	Intermediate	Yes	3.99
Facility 1119	Durham	NC	Solar	Intermediate	Yes	2.5
Facility 1120	Concord	NC	Solar	Intermediate	Yes	9.8
Facility 1121	Charlotte	NC	Solar	Intermediate	Yes	6
Facility 1122	Charlotte	NC	Solar	Intermediate	Yes	6
Facility 1123	Monroe	NC	Solar	Intermediate	Yes	0.86
Facility 1124	Durham	NC	Solar	Intermediate	Yes	3.896
Facility 1125	Hendersonville	NC	Solar	Intermediate	Yes	4
Facility 1126	Graham	NC	Solar	Intermediate	Yes	2
Facility 1127	Hickory	NC	Solar	Intermediate	Yes	4
Facility 1128	Durham	NC	Solar	Intermediate	Yes	5
Facility 1129	Randleman	NC	Solar	Intermediate	Yes	4
Facility 1130	Browns Summit	NC	Solar	Intermediate	Yes	6
Facility 1131	Salisbury	NC	Solar	Intermediate	Yes	6
Facility 1132	Denver	NC	Solar	Intermediate	Yes	1.29
Facility 1133	Carrboro	NC	Solar	Intermediate	Yes	6.81
Facility 1134	Charlotte	NC	Solar	Intermediate	Yes	3.75
Facility 1135	Pfafftown	NC	Solar	Intermediate	Yes	9.45
Facility 1136	Hillsborough	NC	Solar	Intermediate	Yes	4
Facility 1137	Jonesville	NC	Solar	Intermediate	Yes	3.42
Facility 1138	Elon	NC	Solar	Intermediate	Yes	4.905
Facility 1139	Jonesville	NC	Solar	Intermediate	Yes	4
Facility 1140	Gastonia	NC	Solar	Intermediate	Yes	4.389
Facility 1141	Shelby	NC	Wind	Intermediate	Yes	1.2
Facility 1142	Durham	NC	Solar	Intermediate	Yes	3.6
Facility 1143	Lewisville	NC	Solar	Intermediate	Yes	3.247
Facility 1144	Durham	NC	Solar	Intermediate	Yes	3
Facility 1145	Charlotte	NC	Solar	Intermediate	Yes	3.04
Facility 1146	Durham	NC	Solar	Intermediate	Yes	3.44
Facility 1147	Gibsonville	NC	Solar	Intermediate	Yes	2
Facility 1148	Durham	NC	Solar	Intermediate	Yes	2.82
Facility 1149	Rural Hall	NC	Solar	Intermediate	Yes	2.85
Facility 1150	Chapel Hill	NC	Solar	Intermediate	Yes	9

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1151	Forest City	NC	Solar	Intermediate	Yes	5
Facility 1152	Charlotte	NC	Solar	Intermediate	Yes	4.95
Facility 1153	Liberty	NC	Solar	Intermediate	Yes	2
Facility 1154	Durham	NC	Solar	Intermediate	Yes	3.6
Facility 1155	Chapel Hill	NC	Solar	Intermediate	Yes	3.84
Facility 1156	Chapel Hill	NC	Solar	Intermediate	Yes	5.76
Facility 1157	Greensboro	NC	Solar	Intermediate	Yes	1.57
Facility 1158	Lewisville	NC	Solar	Intermediate	Yes	2.85
Facility 1159	Greensboro	NC	Solar	Intermediate	Yes	2.58
Facility 1160	Mills River	NC	Solar	Intermediate	Yes	6.45
Facility 1161	Mills River	NC	Solar	Intermediate	Yes	10
Facility 1162	Charlotte	NC	Solar	Intermediate	Yes	1.29
Facility 1163	Carrboro	NC	Solar	Intermediate	Yes	3
Facility 1164	Charlotte	NC	Solar	Intermediate	Yes	3.2
Facility 1165	Charlotte	NC	Solar	Intermediate	Yes	8.765
Facility 1166	Durham	NC	Solar	Intermediate	Yes	3.782
Facility 1167	Charlotte	NC	Solar	Intermediate	Yes	4.366
Facility 1168	Waxhaw	NC	Solar	Intermediate	Yes	3.623
Facility 1169	Chapel Hill	NC	Solar	Intermediate	Yes	7.8
Facility 1170	Oak Ridge	NC	Solar	Intermediate	Yes	15
Facility 1171	Saluda	NC	Solar	Intermediate	Yes	4.32
Facility 1172	Mills River	NC	Solar	Intermediate	Yes	7.31
Facility 1173	Waxhaw	NC	Solar	Intermediate	Yes	3
Facility 1174	Greensboro	NC	Solar	Intermediate	Yes	27
Facility 1175	Hendersonville	NC	Solar	Intermediate	Yes	2.58
Facility 1176	Charlotte	NC	Solar	Intermediate	Yes	3.87
Facility 1177	Chapel Hill	NC	Solar	Intermediate	Yes	5
Facility 1178	Tobaccoville	NC	Solar	Intermediate	Yes	3.3
Facility 1179	Rockwell	NC	Solar	Intermediate	Yes	6
Facility 1180	Winston Salem	NC	Solar	Intermediate	Yes	7.68
Facility 1181	Charlotte	NC	Solar	Intermediate	Yes	5.25
Facility 1182	Durham	NC	Solar	Intermediate	Yes	4.25
Facility 1183	Marion	NC	Solar	Intermediate	Yes	3.92
Facility 1184	Spindale	NC	Solar	Intermediate	Yes	4.18
Facility 1185	Hays	NC	Solar	Intermediate	Yes	2.624
Facility 1186	Hillsborough	NC	Solar	Intermediate	Yes	3.858
Facility 1187	Walnut Cove	NC	Solar	Intermediate	Yes	7.192
Facility 1188	Marshville	NC	Solar	Intermediate	Yes	6.106
Facility 1189	Charlotte	NC	Solar	Intermediate	Yes	3.4
Facility 1190	Summerfield	NC	Solar	Intermediate	Yes	3.9
Facility 1191	Charlotte	NC	Solar	Intermediate	Yes	7
Facility 1192	Salisbury	NC	Solar	Intermediate	Yes	8.8
Facility 1193	Mooresville	NC	Solar	Intermediate	Yes	3.3
Facility 1194	Tobaccoville	NC	Solar	Intermediate	Yes	6
Facility 1195	Charlotte	NC	Solar	Intermediate	Yes	2.58
Facility 1196	East Bend	NC	Solar	Intermediate	Yes	4.73
Facility 1197	Durham	NC	Solar	Intermediate	Yes	5
Facility 1198	Durham	NC	Solar	Intermediate	Yes	4
Facility 1199	Charlotte	NC	Solar	Intermediate	Yes	1.63

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1200	Gold Hill	NC	Solar	Intermediate	Yes	4.3
Facility 1201	Gold Hill	NC	Solar	Intermediate	Yes	9.3
Facility 1202	Mooresville	NC	Solar	Intermediate	Yes	250
Facility 1203	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1204	Concord	NC	Solar	Intermediate	Yes	9
Facility 1205	N Wilkesboro	NC	Solar	Intermediate	Yes	4.73
Facility 1206	Greensboro	NC	Solar	Intermediate	Yes	3
Facility 1207	Durham	NC	Solar	Intermediate	Yes	4.77
Facility 1208	Burlington	NC	Solar	Intermediate	Yes	5
Facility 1209	Catawba	NC	Solar	Intermediate	Yes	15.2
Facility 1210	Catawba	NC	Solar	Intermediate	Yes	6
Facility 1211	Greensboro	NC	Solar	Intermediate	Yes	8.64
Facility 1212	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 1213	Charlotte	NC	Solar	Intermediate	Yes	1.72
Facility 1214	Charlotte	NC	Solar	Intermediate	Yes	4
Facility 1215	Newton	NC	Solar	Intermediate	Yes	0.86
Facility 1216	Durham	NC	Solar	Intermediate	Yes	2.442
Facility 1217	Durham	NC	Solar	Intermediate	Yes	6.62
Facility 1218	Cherryville	NC	Solar	Intermediate	Yes	3.36
Facility 1219	Marion	NC	Solar	Intermediate	Yes	0.76
Facility 1220	Marion	NC	Solar	Intermediate	Yes	3.92
Facility 1221	Chapel Hill	NC	Solar	Intermediate	Yes	5.305
Facility 1222	Durham	NC	Solar	Intermediate	Yes	5
Facility 1223	Robbinsville	NC	Solar	Intermediate	Yes	4.3
Facility 1224	Durham	NC	Solar	Intermediate	Yes	4.05
Facility 1225	Kernersville	NC	Solar	Intermediate	Yes	5
Facility 1226	Greensboro	NC	Solar	Intermediate	Yes	5.59
Facility 1227	Forest City	NC	Solar	Intermediate	Yes	0.86
Facility 1228	Germanton	NC	Solar	Intermediate	Yes	4.3
Facility 1229	Clemmons	NC	Solar	Intermediate	Yes	3
Facility 1230	Charlotte	NC	Solar	Intermediate	Yes	4.2
Facility 1231	Winston Salem	NC	Solar	Intermediate	Yes	
Facility 1232	Chapel Hill	NC	Solar	Intermediate	Yes	3
Facility 1233	Brevard	NC	Solar	Intermediate	Yes	3
Facility 1234	Chapel Hill	NC	Solar	Intermediate	Yes	1.2
Facility 1235	Charlotte	NC	Solar	Intermediate	Yes	3.01
Facility 1236	Durham	NC	Solar	Intermediate	Yes	2.55
Facility 1237	Charlotte	NC	Solar	Intermediate	Yes	8
Facility 1238	Mooresville	NC	Solar	Intermediate	Yes	2.58
Facility 1239	Hendersonville	NC	Solar	Intermediate	Yes	3.5
Facility 1240	Charlotte	NC	Solar	Intermediate	Yes	8.416
Facility 1241	Hendersonville	NC	Solar	Intermediate	Yes	2.28
Facility 1242	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1243	Winston Salem	NC	Solar	Intermediate	Yes	7.65
Facility 1244	Reidsville	NC	Solar	Intermediate	Yes	4.3
Facility 1245	Harrisburg	NC	Solar	Intermediate	Yes	4.305
Facility 1246	Midland	NC	Solar	Intermediate	Yes	5.515
Facility 1247	Winston Salem	NC	Solar	Intermediate	Yes	5.358
Facility 1248	Sylva	NC	Solar	Intermediate	Yes	6
Facility 1249	Salisbury	NC	Solar	Intermediate	Yes	6
Facility 1250	Nebo	NC	Solar	Intermediate	Yes	2

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1251	Old fort	NC	Solar	Intermediate	Yes	3
Facility 1252	Chapel Hill	NC	Solar	Intermediate	Yes	2.58
Facility 1253	King	NC	Solar	Intermediate	Yes	5
Facility 1254	Durham	NC	Solar	Intermediate	Yes	3.25
Facility 1255	Hendersonville	NC	Solar	Intermediate	Yes	0.76
Facility 1256	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 1257	Lewisville	NC	Solar	Intermediate	Yes	2.35
Facility 1258	Greensboro	NC	Solar	Intermediate	Yes	3
Facility 1259	Durham	NC	Solar	Intermediate	Yes	4.583
Facility 1260	Whittier	NC	Solar	Intermediate	Yes	3.526
Facility 1261	Chapel Hill	NC	Solar	Intermediate	Yes	2
Facility 1262	Mount Ulla	NC	Solar	Intermediate	Yes	10
Facility 1263	Winston Salem	NC	Solar	Intermediate	Yes	6.168
Facility 1264	Ronda	NC	Solar	Intermediate	Yes	10
Facility 1265	Ronda	NC	Solar	Intermediate	Yes	14.5
Facility 1266	Burlington	NC	Solar	Intermediate	Yes	7.68
Facility 1267	Hillsborough	NC	Solar	Intermediate	Yes	6
Facility 1268	Charlotte	NC	Solar	Intermediate	Yes	2.5
Facility 1269	Tobaccoville	NC	Solar	Intermediate	Yes	3.8
Facility 1270	Franklin	NC	Solar	Intermediate	Yes	1.44
Facility 1271	Franklin	NC	Wind	Intermediate	Yes	1
Facility 1272	Mount Holly	NC	Solar	Intermediate	Yes	3.896
Facility 1273	Dobson	NC	Solar	Intermediate	Yes	7.95
Facility 1274	Brevard	NC	Solar	Intermediate	Yes	3.8
Facility 1275	Summerfield	NC	Solar	Intermediate	Yes	7.6
Facility 1276	Harrisburg	NC	Solar	Intermediate	Yes	4.32
Facility 1277	Mooresville	NC	Solar	Intermediate	Yes	4
Facility 1278	Morrisville	NC	Solar	Intermediate	Yes	7.829
Facility 1279	Winston Salem	NC	Solar	Intermediate	Yes	2.373
Facility 1280	Durham	NC	Solar	Intermediate	Yes	6.523
Facility 1281	Greensboro	NC	Solar	Intermediate	Yes	3
Facility 1282	Charlotte	NC	Solar	Intermediate	Yes	18.13
Facility 1283	Charlotte	NC	Solar	Intermediate	Yes	6.96
Facility 1284	Chapel Hill	NC	Solar	Intermediate	Yes	3
Facility 1285	Mount Airy	NC	Solar	Intermediate	Yes	4.6
Facility 1286	Durham	NC	Solar	Intermediate	Yes	3.78
Facility 1287	Hendersonville	NC	Solar	Intermediate	Yes	1.92
Facility 1288	Durham	NC	Solar	Intermediate	Yes	7.307
Facility 1289	Charlotte	NC	Solar	Intermediate	Yes	4.135
Facility 1290	Nebo	NC	Solar	Intermediate	Yes	5.307
Facility 1291	Chapel Hill	NC	Solar	Intermediate	Yes	13.33
Facility 1292	Hickory	NC	Solar	Intermediate	Yes	445
Facility 1293	Durham	NC	Solar	Intermediate	Yes	5.464
Facility 1294	Charlotte	NC	Solar	Intermediate	Yes	9
Facility 1295	Greensboro,	NC	Solar	Intermediate	Yes	8.296
Facility 1296	Charlotte	NC	Solar	Intermediate	Yes	5.515
Facility 1297	Burlington	NC	Solar	Intermediate	Yes	280
Facility 1298	Winston Salem	NC	Solar	Intermediate	Yes	280
Facility 1299	Chapel Hill	NC	Solar	Intermediate	Yes	5.181

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1300	Sylva	NC	Solar	Intermediate	Yes	8.084
Facility 1301	Salisbury	NC	Solar	Intermediate	Yes	7.325
Facility 1302	Charlotte	NC	Solar	Intermediate	Yes	5
Facility 1303	Hillsborough	NC	Solar	Intermediate	Yes	7.6
Facility 1304	Mills River	NC	Solar	Intermediate	Yes	7.6
Facility 1305	Durham	NC	Solar	Intermediate	Yes	7.6
Facility 1306	Concord	NC	Solar	Intermediate	Yes	4
Facility 1307	Chapel Hill	NC	Solar	Intermediate	Yes	3.749
Facility 1308	Morrisville	NC	Solar	Intermediate	Yes	8.099
Facility 1309	Hickory	NC	Solar	Intermediate	Yes	3.44
Facility 1310	Andrews	NC	Solar	Intermediate	Yes	5
Facility 1311	Lewisville	NC	Solar	Intermediate	Yes	3.44
Facility 1312	Mt Holly	NC	Solar	Intermediate	Yes	6
Facility 1313	Charlotte	NC	Solar	Intermediate	Yes	1.851
Facility 1314	Charlotte	NC	Solar	Intermediate	Yes	7.479
Facility 1315	Kannapolis	NC	Solar	Intermediate	Yes	34
Facility 1316	Shelby	NC	Solar	Intermediate	Yes	2000
Facility 1317	Mooresville	NC	Solar	Intermediate	Yes	180
Facility 1318	Charlotte	NC	Solar	Intermediate	Yes	6.467
Facility 1319	Winston-Salem	NC	Solar	Intermediate	Yes	6.359
Facility 1320	Catawba	NC	Solar	Intermediate	Yes	2.768
Facility 1321	Durham	NC	Solar	Intermediate	Yes	2.438
Facility 1322	Durham	NC	Solar	Intermediate	Yes	2.681
Facility 1323	Durham	NC	Solar	Intermediate	Yes	2.681
Facility 1324	Durham	NC	Solar	Intermediate	Yes	2.438
Facility 1325	Denver	NC	Solar	Intermediate	Yes	3
Facility 1326	Sylva	NC	Solar	Intermediate	Yes	19.3
Facility 1327	Andrews	NC	Solar	Intermediate	Yes	3.01
Facility 1328	Charlotte	NC	Solar	Intermediate	Yes	4.808
Facility 1329	Durham	NC	Solar	Intermediate	Yes	4.205
Facility 1330	Chapel Hill	NC	Solar	Intermediate	Yes	6.398
Facility 1331	Marion	NC	Solar	Intermediate	Yes	3.57
Facility 1332	Ellenboro	NC	Solar	Intermediate	Yes	2.15
Facility 1333	Belmont	NC	Solar	Intermediate	Yes	8.25
Facility 1334	Valdese	NC	Solar	Intermediate	Yes	2.58
Facility 1335	Greensboro	NC	Solar	Intermediate	Yes	2.8
Facility 1336	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1337	High Point	NC	Solar	Intermediate	Yes	2.38
Facility 1338	Winston Salem	NC	Solar	Intermediate	Yes	5.76
Facility 1339	Franklin	NC	Solar	Intermediate	Yes	21.12
Facility 1340	Sylva	NC	Solar	Intermediate	Yes	5.7
Facility 1341	Carrboro	NC	Solar	Intermediate	Yes	5
Facility 1342	Durham	NC	Solar	Intermediate	Yes	7.658
Facility 1343	Winston Salem	NC	Solar	Intermediate	Yes	1.844
Facility 1344	Hendersonville	NC	Solar	Intermediate	Yes	3.031
Facility 1345	Durham	NC	Solar	Intermediate	Yes	6.118
Facility 1346	Charlotte	NC	Solar	Intermediate	Yes	1.08
Facility 1347	Durham	NC	Solar	Intermediate	Yes	3.8
Facility 1348	Durham	NC	Solar	Intermediate	Yes	2.5
Facility 1349	Charlotte	NC	Solar	Intermediate	Yes	7.5
Facility 1350	Kannapolis	NC	Solar	Intermediate	Yes	2.15

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1351	Mount Pleasant	NC	Solar	Intermediate	Yes	4.5
Facility 1352	Charlotte	NC	Solar	Intermediate	Yes	7.857
Facility 1353	Durham	NC	Solar	Intermediate	Yes	7
Facility 1354	Greensboro	NC	Solar	Intermediate	Yes	3.68
Facility 1355	Carrboro	NC	Solar	Intermediate	Yes	2.597
Facility 1356	Charlotte	NC	Solar	Intermediate	Yes	0.22
Facility 1357	Carrboro	NC	Solar	Intermediate	Yes	2.888
Facility 1358	Charlotte	NC	Solar	Intermediate	Yes	4.5
Facility 1359	Salisbury	NC	Solar	Intermediate	Yes	2
Facility 1360	Durham	NC	Solar	Intermediate	Yes	4
Facility 1361	Charlotte	NC	Solar	Intermediate	Yes	5
Facility 1362	Durham	NC	Solar	Intermediate	Yes	5
Facility 1363	McLeansville	NC	Solar	Intermediate	Yes	3.376
Facility 1364	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1365	Woodleaf	NC	Solar	Intermediate	Yes	2.096
Facility 1366	Indian Trail	NC	Solar	Intermediate	Yes	1.075
Facility 1367	Salisbury	NC	Solar	Intermediate	Yes	2.318
Facility 1368	Durham	NC	Solar	Intermediate	Yes	3.44
Facility 1369	Pfafftown	NC	Solar	Intermediate	Yes	4.2
Facility 1370	Charlotte	NC	Solar	Intermediate	Yes	3.44
Facility 1371	Concord	NC	Solar	Intermediate	Yes	0.86
Facility 1372	Greensboro	NC	Solar	Intermediate	Yes	35.475
Facility 1373	Taylorsville	NC	Solar	Intermediate	Yes	1.94
Facility 1374	Greensboro	NC	Solar	Intermediate	Yes	2.32
Facility 1375	Carrboro	NC	Solar	Intermediate	Yes	4
Facility 1376	Raleigh	NC	Solar	Intermediate	Yes	6.867
Facility 1377	Tobaccoville	NC	Solar	Intermediate	Yes	6
Facility 1378	Charlotte	NC	Solar	Intermediate	Yes	1.075
Facility 1379	Summerfield	NC	Solar	Intermediate	Yes	4.905
Facility 1380	Stanley	NC	Solar	Intermediate	Yes	5
Facility 1381	Stanley	NC	Solar	Intermediate	Yes	0.86
Facility 1382	Elon	NC	Solar	Intermediate	Yes	4.752
Facility 1383	Matthews	NC	Solar	Intermediate	Yes	40.25
Facility 1384	Chapel Hill	NC	Solar	Intermediate	Yes	5.299
Facility 1385	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1386	Charlotte	NC	Solar	Intermediate	Yes	6
Facility 1387	Newton	NC	Solar	Intermediate	Yes	0.86
Facility 1388	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1389	Maiden	NC	Solar	Intermediate	Yes	3.01
Facility 1390	Mooresville	NC	Solar	Intermediate	Yes	2.88
Facility 1391	Chapel Hill	NC	Solar	Intermediate	Yes	5.948
Facility 1392	Durham	NC	Solar	Intermediate	Yes	3.84
Facility 1393	East Bend	NC	Solar	Intermediate	Yes	5
Facility 1394	Lawndale	NC	Solar	Intermediate	Yes	9
Facility 1395	Charlotte	NC	Solar	Intermediate	Yes	1.72
Facility 1396	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1397	Charlotte	NC	Solar	Intermediate	Yes	4.977
Facility 1398	Charlotte	NC	Solar	Intermediate	Yes	0.77
Facility 1399	Winston Salem	NC	Solar	Intermediate	Yes	3.44

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1400	Greensboro	NC	Solar	Intermediate	Yes	3.87
Facility 1401	Charlotte	NC	Solar	Intermediate	Yes	3.5
Facility 1402	Gerton	NC	Hydroelectric	Baseload	Yes	6
Facility 1403	Mebane	NC	Solar	Intermediate	Yes	6.622
Facility 1404	Charlotte	NC	Solar	Intermediate	Yes	36
Facility 1405	Monroe	NC	Solar	Intermediate	Yes	0.86
Facility 1406	Salisbury	NC	Solar	Intermediate	Yes	3
Facility 1407	Salisbury	NC	Solar	Intermediate	Yes	2.88
Facility 1408	Thomasville	NC	Solar	Intermediate	Yes	4.928
Facility 1409	Davidson	NC	Solar	Intermediate	Yes	7.9
Facility 1410	Miller Creek	NC	Solar	Intermediate	Yes	2.5
Facility 1411	Raleigh	NC	Solar	Intermediate	Yes	240
Facility 1412	Kannapolis	NC	Solar	Intermediate	Yes	9.192
Facility 1413	Conover	NC	Solar	Intermediate	Yes	6.1
Facility 1414	Elon	NC	Solar	Intermediate	Yes	4000
Facility 1415	Salisbury	NC	Solar	Intermediate	Yes	14
Facility 1416	Matthews	NC	Solar	Intermediate	Yes	1.08
Facility 1417	Greensboro	NC	Solar	Intermediate	Yes	3
Facility 1418	Browns Summit	NC	Solar	Intermediate	Yes	3.84
Facility 1419	Union Mills	NC	Solar	Intermediate	Yes	1.935
Facility 1420	Mount Airy	NC	Solar	Intermediate	Yes	4.3
Facility 1421	Pisgah Forest	NC	Solar	Intermediate	Yes	6
Facility 1422	Durham	NC	Solar	Intermediate	Yes	3.84
Facility 1423	Hillsborough	NC	Solar	Intermediate	Yes	3.8
Facility 1424	Hillsborough	NC	Solar	Intermediate	Yes	4
Facility 1425	Ronda	NC	Solar	Intermediate	Yes	3.49
Facility 1426	Winston Salem	NC	Solar	Intermediate	Yes	1.72
Facility 1427	Indian Trail	NC	Solar	Intermediate	Yes	15.787
Facility 1428	Charlotte	NC	Solar	Intermediate	Yes	7.965
Facility 1429	Charlotte	NC	Solar	Intermediate	Yes	5
Facility 1430	Clemmons	NC	Solar	Intermediate	Yes	2.58
Facility 1431	Kings Mountain	NC	Solar	Intermediate	Yes	135
Facility 1432	Indian Trail	NC	Solar	Intermediate	Yes	3.494
Facility 1433	Kernersville	NC	Solar	Intermediate	Yes	6.02
Facility 1434	Kernersville	NC	Solar	Intermediate	Yes	6.02
Facility 1435	Kernersville	NC	Solar	Intermediate	Yes	6.02
Facility 1436	Kernersville	NC	Solar	Intermediate	Yes	6.02
Facility 1437	Kernersville	NC	Solar	Intermediate	Yes	3.87
Facility 1438	Durham	NC	Solar	Intermediate	Yes	2.15
Facility 1439	Summerfield	NC	Solar	Intermediate	Yes	5.674
Facility 1440	Belmont	NC	Solar	Intermediate	Yes	9
Facility 1441	Huntersville	NC	Solar	Intermediate	Yes	4.91
Facility 1442	Durham	NC	Solar	Intermediate	Yes	2.831
Facility 1443	Winston Salem	NC	Solar	Intermediate	Yes	2.88
Facility 1444	Charlotte	NC	Solar	Intermediate	Yes	4.2
Facility 1445	Mebane	NC	Solar	Intermediate	Yes	2.88
Facility 1446	Kannapolis	NC	Solar	Intermediate	Yes	6.534
Facility 1447	Charlotte	NC	Solar	Intermediate	Yes	4.582
Facility 1448	Winston Salem	NC	Solar	Intermediate	Yes	3.84
Facility 1449	Durham	NC	Solar	Intermediate	Yes	3.174
Facility 1450	Chapel Hill	NC	Solar	Intermediate	Yes	3

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1451	Charlotte	NC	Solar	Intermediate	Yes	4.32
Facility 1452	Wingate	NC	Solar	Intermediate	Yes	5
Facility 1453	Charlotte	NC	Solar	Intermediate	Yes	5.064
Facility 1454	Hillsborough	NC	Solar	Intermediate	Yes	3.56
Facility 1455	Charlotte	NC	Solar	Intermediate	Yes	4
Facility 1456	Chapel Hill	NC	Solar	Intermediate	Yes	4.866
Facility 1457	Durham	NC	Solar	Intermediate	Yes	2.31
Facility 1458	Lincolnton	NC	Solar	Intermediate	Yes	3
Facility 1459	Chapel Hill	NC	Solar	Intermediate	Yes	3.6
Facility 1460	Hillsborough	NC	Solar	Intermediate	Yes	2.58
Facility 1461	Hickory	NC	Solar	Intermediate	Yes	2.4
Facility 1462	Graham	NC	Solar	Intermediate	Yes	2.1
Facility 1463	Clemmons	NC	Solar	Intermediate	Yes	1.075
Facility 1464	Matthews	NC	Solar	Intermediate	Yes	6.75
Facility 1465	Salisbury	NC	Solar	Intermediate	Yes	1.72
Facility 1466	Chapel Hill	NC	Solar	Intermediate	Yes	5
Facility 1467	China Grove	NC	Solar	Intermediate	Yes	2.58
Facility 1468	Durham	NC	Solar	Intermediate	Yes	5.2
Facility 1469	Wilkesboro	NC	Solar	Intermediate	Yes	5.16
Facility 1470	Chapel Hill	NC	Solar	Intermediate	Yes	2.4
Facility 1471	Marion	NC	Solar	Intermediate	Yes	3.36
Facility 1472	Chapel Hill	NC	Solar	Intermediate	Yes	5.56
Facility 1473	China Grove	NC	Solar	Intermediate	Yes	1.7
Facility 1474	Waxhaw	NC	Solar	Intermediate	Yes	2.94
Facility 1475	Advance	NC	Solar	Intermediate	Yes	7.848
Facility 1476	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 1477	Saluda	NC	Solar	Intermediate	Yes	3.655
Facility 1478	Clemmons	NC	Solar	Intermediate	Yes	3.87
Facility 1479	Durham	NC	Solar	Intermediate	Yes	5.16
Facility 1480	Charlotte	NC	Solar	Intermediate	Yes	6
Facility 1481	Penrose	NC	Solar	Intermediate	Yes	8.88
Facility 1482	Otto	NC	Solar	Intermediate	Yes	2.58
Facility 1483	Stokesdale	NC	Solar	Intermediate	Yes	4
Facility 1484	Charlotte	NC	Solar	Intermediate	Yes	3.75
Facility 1485	Salisbury	NC	Solar	Intermediate	Yes	12
Facility 1486	Salisbury	NC	Solar	Intermediate	Yes	2
Facility 1487	Harrisburg	NC	Solar	Intermediate	Yes	6.66
Facility 1488	Durham	NC	Solar	Intermediate	Yes	3
Facility 1489	Charlotte	NC	Solar	Intermediate	Yes	1.4
Facility 1490	Lexington	NC	Solar	Intermediate	Yes	3.45
Facility 1491	Charlotte	NC	Solar	Intermediate	Yes	2.58
Facility 1492	Reidsville	NC	Solar	Intermediate	Yes	4950
Facility 1493	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 1494	Shelby	NC	Solar	Intermediate	Yes	4.7
Facility 1495	Davidson	NC	Solar	Intermediate	Yes	3.5
Facility 1496	Durham	NC	Solar	Intermediate	Yes	3.87
Facility 1497	Marshville	NC	Solar	Intermediate	Yes	4950
Facility 1498	Chapel Hill	NC	Solar	Intermediate	Yes	6.366
Facility 1499	Brevard	NC	Solar	Intermediate	Yes	3.92

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1500	Chapel Hill	NC	Solar	Intermediate	Yes	1.92
Facility 1501	Charlotte	NC	Solar	Intermediate	Yes	1.72
Facility 1502	Huntersville	NC	Solar	Intermediate	Yes	4
Facility 1503	Mooresville	NC	Solar	Intermediate	Yes	60
Facility 1504	Charlotte	NC	Solar	Intermediate	Yes	6.98
Facility 1505	Conover	NC	Solar	Intermediate	Yes	4.75
Facility 1506	Durham	NC	Solar	Intermediate	Yes	2.205
Facility 1507	Randleman	NC	Solar	Intermediate	Yes	2.58
Facility 1508	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 1509	Charlotte	NC	Solar	Intermediate	Yes	1.72
Facility 1510	Charlotte	NC	Solar	Intermediate	Yes	2.695
Facility 1511	Clemmons	NC	Solar	Intermediate	Yes	14
Facility 1512	Mills River	NC	Solar	Intermediate	Yes	1.5
Facility 1513	Mebane	NC	Solar	Intermediate	Yes	3.11
Facility 1514	Hillsborough	NC	Solar	Intermediate	Yes	5
Facility 1515	Snow Camp	NC	Solar	Intermediate	Yes	6
Facility 1516	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1517	Durham	NC	Solar	Intermediate	Yes	4.32
Facility 1518	Winston Salem	NC	Solar	Intermediate	Yes	3.15
Facility 1519	Franklin	NC	Solar	Intermediate	Yes	5
Facility 1520	Hendersonville	NC	Solar	Intermediate	Yes	2.7
Facility 1521	Chapel Hill	NC	Solar	Intermediate	Yes	1.948
Facility 1522	Charlotte	NC	Solar	Intermediate	Yes	5.494
Facility 1523	Durham	NC	Solar	Intermediate	Yes	4.501
Facility 1524	Jamestown	NC	Solar	Intermediate	Yes	5.18
Facility 1525	Clemmons	NC	Solar	Intermediate	Yes	7.31
Facility 1526	Durham	NC	Solar	Intermediate	Yes	2.205
Facility 1527	Winston Salem	NC	Solar	Intermediate	Yes	9.72
Facility 1528	Charlotte	NC	Solar	Intermediate	Yes	9.46
Facility 1529	Mebane	NC	Solar	Intermediate	Yes	5.16
Facility 1530	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1531	Charlotte	NC	Solar	Intermediate	Yes	3.15
Facility 1532	Clemmons	NC	Solar	Intermediate	Yes	3.36
Facility 1533	Chapel Hill	NC	Solar	Intermediate	Yes	4.8
Facility 1534	Charlotte	NC	Solar	Intermediate	Yes	3.44
Facility 1535	Concord	NC	Solar	Intermediate	Yes	4.73
Facility 1536	East Bend	NC	Solar	Intermediate	Yes	2.314
Facility 1537	Charlotte	NC	Solar	Intermediate	Yes	5.91
Facility 1538	Taylorsville	NC	Solar	Intermediate	Yes	3.98
Facility 1539	Morganton	NC	Solar	Intermediate	Yes	3.5
Facility 1540	Browns Summit	NC	Solar	Intermediate	Yes	2.25
Facility 1541	Chapel Hill	NC	Solar	Intermediate	Yes	2.36
Facility 1542	Chapel Hill	NC	Solar	Intermediate	Yes	7.5
Facility 1543	Charlotte	NC	Solar	Intermediate	Yes	0.7
Facility 1544	Harrisburg	NC	Solar	Intermediate	Yes	1.92
Facility 1545	Mt Airy	NC	Solar	Intermediate	Yes	1000
Facility 1546	Mayodan	NC	Hydroelectric	Baseload	Yes	951
Facility 1547	Mayodan	NC	Hydroelectric	Baseload	Yes	1275
Facility 1548	High Point	NC	Solar	Intermediate	Yes	3.077
Facility 1549	Franklin	NC	Solar	Intermediate	Yes	8.77
Facility 1550	Charlotte	NC	Solar	Intermediate	Yes	3.677

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1551	Durham	NC	Solar	Intermediate	Yes	2.962
Facility 1552	Durham	NC	Solar	Intermediate	Yes	5.829
Facility 1553	Hendersonville	NC	Solar	Intermediate	Yes	4.029
Facility 1554	Zirconia	NC	Solar	Intermediate	Yes	11.58
Facility 1555	Durham	NC	Solar	Intermediate	Yes	6.449
Facility 1556	Mount Airy	NC	Solar	Intermediate	Yes	4.658
Facility 1557	Hickory	NC	Solar	Intermediate	Yes	8.17
Facility 1558	Charlotte	NC	Solar	Intermediate	Yes	49
Facility 1559	Charlotte	NC	Solar	Intermediate	Yes	12
Facility 1560	Kernersville	NC	Solar	Intermediate	Yes	8.584
Facility 1561	Charlotte	NC	Solar	Intermediate	Yes	6.204
Facility 1562	Morrisville	NC	Solar	Intermediate	Yes	6.479
Facility 1563	Huntersville	NC	Solar	Intermediate	Yes	4
Facility 1564	Clemmons	NC	Solar	Intermediate	Yes	2.96
Facility 1565	Durham	NC	Solar	Intermediate	Yes	2.31
Facility 1566	Charlotte	NC	Solar	Intermediate	Yes	4
Facility 1567	Durham	NC	Solar	Intermediate	Yes	7
Facility 1568	Charlotte	NC	Solar	Intermediate	Yes	5.221
Facility 1569	Randelman	NC	Solar	Intermediate	Yes	6.639
Facility 1570	Charlotte	NC	Solar	Intermediate	Yes	5.576
Facility 1571	Durham	NC	Solar	Intermediate	Yes	1.42
Facility 1572	Mooresville	NC	Solar	Intermediate	Yes	1.938
Facility 1573	Randleman	NC	Solar	Intermediate	Yes	4.8
Facility 1574	Hendersonville	NC	Solar	Intermediate	Yes	1.72
Facility 1575	Durham	NC	Solar	Intermediate	Yes	4.305
Facility 1576	Union Mills	NC	Solar	Intermediate	Yes	1.96
Facility 1577	Salisbury	NC	Solar	Intermediate	Yes	4.805
Facility 1578	Winston Salem	NC	Solar	Intermediate	Yes	2.2
Facility 1579	Charlotte	NC	Solar	Intermediate	Yes	5.76
Facility 1580	Chapel Hill	NC	Solar	Intermediate	Yes	3.25
Facility 1581	Charlotte	NC	Solar	Intermediate	Yes	12
Facility 1582	King	NC	Solar	Intermediate	Yes	2.64
Facility 1583	Stanfield	NC	Solar	Intermediate	Yes	6
Facility 1584	Chapel Hill	NC	Solar	Intermediate	Yes	1.32
Facility 1585	Elon	NC	Solar	Intermediate	Yes	5.16
Facility 1586	Yadkinville	NC	Solar	Intermediate	Yes	14.2
Facility 1587	Charlotte	NC	Solar	Intermediate	Yes	1.53
Facility 1588	Charlotte	NC	Solar	Intermediate	Yes	1.89
Facility 1589	Glenville	NC	Solar	Intermediate	Yes	2.76
Facility 1590	Charlotte	NC	Solar	Intermediate	Yes	2.15
Facility 1591	Durham	NC	Solar	Intermediate	Yes	5
Facility 1592	Charlotte	NC	Solar	Intermediate	Yes	5
Facility 1593	Charlotte	NC	Solar	Intermediate	Yes	8.8
Facility 1594	Charlotte	NC	Solar	Intermediate	Yes	1.72
Facility 1595	Old fort	NC	Solar	Intermediate	Yes	3.84
Facility 1596	Union Mills	NC	Solar	Intermediate	Yes	1.94
Facility 1597	Charlotte	NC	Solar	Intermediate	Yes	4.905
Facility 1598	Belmont	NC	Solar	Intermediate	Yes	3.44
Facility 1599	Hickory	NC	Solar	Intermediate	Yes	4.8

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1600	Mooresville	NC	Solar	Intermediate	Yes	2.795
Facility 1601	Mount Ulla	NC	Solar	Intermediate	Yes	7.714
Facility 1602	Davidson	NC	Solar	Intermediate	Yes	4
Facility 1603	Yadkinville	NC	Solar	Intermediate	Yes	6
Facility 1604	Salisbury	NC	Solar	Intermediate	Yes	2.88
Facility 1605	Winston Salem	NC	Solar	Intermediate	Yes	3.84
Facility 1606	Greensboro	NC	Solar	Intermediate	Yes	5.787
Facility 1607	Charlotte	NC	Solar	Intermediate	Yes	3
Facility 1608	Durham	NC	Solar	Intermediate	Yes	5
Facility 1609	Lexington	NC	Solar	Intermediate	Yes	4.32
Facility 1610	Lake Lure	NC	Solar	Intermediate	Yes	3
Facility 1611	Oak Ridge	NC	Solar	Intermediate	Yes	3.36
Facility 1612	Salisbury	NC	Solar	Intermediate	Yes	2.58
Facility 1613	Salisbury	NC	Solar	Intermediate	Yes	4.3
Facility 1614	Chapel Hill	NC	Solar	Intermediate	Yes	54
Facility 1615	Durham	NC	Solar	Intermediate	Yes	3.23
Facility 1616	Franklin	NC	Solar	Intermediate	Yes	1.44
Facility 1617	Columbus	NC	Solar	Intermediate	Yes	2.782
Facility 1618	Mooresville	NC	Solar	Intermediate	Yes	1500
Facility 1619	Whitsett	NC	Solar	Intermediate	Yes	7.6
Facility 1620	Carrboro	NC	Solar	Intermediate	Yes	4.539
Facility 1621	Hickory	NC	Solar	Intermediate	Yes	5.055
Facility 1622	Concord	NC	Solar	Intermediate	Yes	3.322
Facility 1623	Randleman	NC	Solar	Intermediate	Yes	4998
Facility 1624	Charlotte	NC	Solar	Intermediate	Yes	3.201
Facility 1625	High Shoals	NC	Hydroelectric	Baseload	Yes	1800
Facility 1626	Burlington	NC	Solar	Intermediate	Yes	3000
Facility 1627	Charlotte	NC	Solar	Intermediate	Yes	2
Facility 1628	Graham	NC	Solar	Intermediate	Yes	3000
Facility 1629	Durham	NC	Solar	Intermediate	Yes	2.345
Facility 1630	Township of Ridenhour	NC	Solar	Intermediate	Yes	4998
Facility 1631	Advance	NC	Solar	Intermediate	Yes	4.704
Facility 1632	Mocksville	NC	Solar	Intermediate	Yes	5000
Facility 1633	Durham	NC	Solar	Intermediate	Yes	3
Facility 1634	Graham	NC	Solar	Intermediate	Yes	3
Facility 1635	Salisbury	NC	Solar	Intermediate	Yes	3.36
Facility 1636	Charlotte	NC	Solar	Intermediate	Yes	0.96
Facility 1637	Hickory	NC	Solar	Intermediate	Yes	2.673
Facility 1638	Brevard	NC	Solar	Intermediate	Yes	5.76
Facility 1639	Reidsville	NC	Solar	Intermediate	Yes	4950
Facility 1640	Summerfield	NC	Solar	Intermediate	Yes	4.341
Facility 1641	Pfafftown	NC	Solar	Intermediate	Yes	1.862
Facility 1642	Durham	NC	Solar	Intermediate	Yes	3.758
Facility 1643	Germanton	NC	Solar	Intermediate	Yes	3.01
Facility 1644	Moravian Falls	NC	Solar	Intermediate	Yes	6.586
Facility 1645	Stanley	NC	Solar	Intermediate	Yes	8.771
Facility 1646	Salisbury	NC	Solar	Intermediate	Yes	4.977
Facility 1647	Brevard	NC	Solar	Intermediate	Yes	5.947
Facility 1648	Salisbury	NC	Solar	Intermediate	Yes	24
Facility 1649	Harrisburg	NC	Solar	Intermediate	Yes	4.305
Facility 1650	Clemmons	NC	Solar	Intermediate	Yes	7.374

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1651	Harrisburg	NC	Solar	Intermediate	Yes	8.816
Facility 1652	Tryon	NC	Solar	Intermediate	Yes	0.86
Facility 1653	Charlotte	NC	Solar	Intermediate	Yes	4.8
Facility 1654	Durham	NC	Solar	Intermediate	Yes	4.339
Facility 1655	Stanley	NC	Solar	Intermediate	Yes	6
Facility 1656	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1657	Durham	NC	Solar	Intermediate	Yes	2.58
Facility 1658	Harrisburg	NC	Solar	Intermediate	Yes	5.743
Facility 1659	Chapel Hill	NC	Solar	Intermediate	Yes	5.52
Facility 1660	Burlington	NC	Solar	Intermediate	Yes	4.3
Facility 1661	Haw River	NC	Solar	Intermediate	Yes	3.87
Facility 1662	Graham	NC	Solar	Intermediate	Yes	5.5
Facility 1663	Charlotte	NC	Solar	Intermediate	Yes	3.8
Facility 1664	Matthews	NC	Solar	Intermediate	Yes	2.58
Facility 1665	Charlotte	NC	Solar	Intermediate	Yes	4.861
Facility 1666	Newton	NC	Solar	Intermediate	Yes	5
Facility 1667	Charlotte	NC	Solar	Intermediate	Yes	35
Facility 1668	Gastonia	NC	Solar	Intermediate	Yes	635
Facility 1669	Charlotte	NC	Solar	Intermediate	Yes	30
Facility 1670	Charlotte	NC	Solar	Intermediate	Yes	3.447
Facility 1671	Research Triangle Park	NC	Solar	Intermediate	Yes	28
Facility 1672	Hickory	NC	Solar	Intermediate	Yes	15.2
Facility 1673	Chapel Hill	NC	Solar	Intermediate	Yes	6.044
Facility 1674	Troutman	NC	Solar	Intermediate	Yes	7.601
Facility 1675	Durham	NC	Solar	Intermediate	Yes	4.669
Facility 1676	Shelby	NC	Solar	Intermediate	Yes	1990
Facility 1677	Durham	NC	Solar	Intermediate	Yes	4.475
Facility 1678	Durham	NC	Solar	Intermediate	Yes	3.19
Facility 1679	Conover	NC	Solar	Intermediate	Yes	135
Facility 1680	Chapel Hill	NC	Solar	Intermediate	Yes	3.6
Facility 1681	Monroe	NC	Solar	Intermediate	Yes	2.318
Facility 1682	Monroe	NC	Solar	Intermediate	Yes	2.819
Facility 1683	Wilkesboro	NC	Solar	Intermediate	Yes	12
Facility 1684	Liberty	NC	Solar	Intermediate	Yes	5000
Facility 1685	Hickory	NC	Solar	Intermediate	Yes	2.58
Facility 1686	Charlotte	NC	Solar	Intermediate	Yes	5
Facility 1687	Pisgah Forest	NC	Solar	Intermediate	Yes	4.73
Facility 1688	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1689	Charlotte	NC	Solar	Intermediate	Yes	12.174
Facility 1690	Charlotte	NC	Solar	Intermediate	Yes	6.325
Facility 1691	Wingate	NC	Solar	Intermediate	Yes	2.63
Facility 1692	Salem	NC	Solar	Intermediate	Yes	1
Facility 1693	Hendersonville	NC	Solar	Intermediate	Yes	6
Facility 1694	Gibsonville	NC	Solar	Intermediate	Yes	3.33
Facility 1695	Concord	NC	Solar	Intermediate	Yes	4
Facility 1696	Durham	NC	Solar	Intermediate	Yes	5.847
Facility 1697	Kannapolis	NC	Solar	Intermediate	Yes	10
Facility 1698	Mill Springs	NC	Hydroelectric	Baseload	Yes	5500
Facility 1699	Brevard	NC	Solar	Intermediate	Yes	6.626

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1700	Reidsville	NC	Solar	Intermediate	Yes	3.028
Facility 1701	Charlotte	NC	Solar	Intermediate	Yes	6.3
Facility 1702	Mebane	NC	Solar	Intermediate	Yes	221.76
Facility 1703	Hillsborough	NC	Solar	Intermediate	Yes	18.48
Facility 1704	Reidsville	NC	Solar	Intermediate	Yes	3.888
Facility 1705	Hillsborough	NC	Solar	Intermediate	Yes	18.48
Facility 1706	Thomasville	NC	Solar	Intermediate	Yes	1500
Facility 1707	Monroe	NC	Solar	Intermediate	Yes	5000
Facility 1708	Cornelius	NC	Solar	Intermediate	Yes	4
Facility 1709	Charlotte	NC	Solar	Intermediate	Yes	5.59
Facility 1710	Salisbury	NC	Solar	Intermediate	Yes	7.5
Facility 1711	Charlotte	NC	Solar	Intermediate	Yes	7.7
Facility 1712	Mooresville	NC	Solar	Intermediate	Yes	7.613
Facility 1713	Charlotte	NC	Solar	Intermediate	Yes	8.4
Facility 1714	Charlotte	NC	Solar	Intermediate	Yes	33.88
Facility 1715	Durham	NC	Solar	Intermediate	Yes	5.642
Facility 1716	Lincolnton	NC	Solar	Intermediate	Yes	5000
Facility 1717	Harrisburg	NC	Solar	Intermediate	Yes	5.301
Facility 1718	Carrboro	NC	Solar	Intermediate	Yes	5.3
Facility 1719	Charlotte	NC	Solar	Intermediate	Yes	5
Facility 1720	Charlotte	NC	Wind	Intermediate	Yes	3
Facility 1721	Salisbury	NC	Solar	Intermediate	Yes	5.977
Facility 1722	Carrboro	NC	Solar	Intermediate	Yes	4.5
Facility 1723	Durham	NC	Solar	Intermediate	Yes	3.209
Facility 1724	Valdese	NC	Solar	Intermediate	Yes	9.09
Facility 1725	Chapel Hill	NC	Solar	Intermediate	Yes	6
Facility 1726	Morrisville	NC	Solar	Intermediate	Yes	6.209
Facility 1727	Hickory	NC	Solar	Intermediate	Yes	4.807
Facility 1728	China Grove	NC	Solar	Intermediate	Yes	2.318
Facility 1729	Harrisburg	NC	Solar	Intermediate	Yes	5.301
Facility 1730	Durham	NC	Solar	Intermediate	Yes	4.341
Facility 1731	Charlotte	NC	Solar	Intermediate	Yes	4.91
Facility 1732	Salisbury	NC	Solar	Intermediate	Yes	5.301
Facility 1733	Charlotte	NC	Solar	Intermediate	Yes	6.66
Facility 1734	Charlotte	NC	Solar	Intermediate	Yes	9.67
Facility 1735	Durham	NC	Solar	Intermediate	Yes	3
Facility 1736	Mooresville	NC	Solar	Intermediate	Yes	18.9
Facility 1737	Charlotte	NC	Solar	Intermediate	Yes	4.25
Facility 1738	Summerfield	NC	Solar	Intermediate	Yes	1.72
Facility 1739	Durham	NC	Solar	Intermediate	Yes	3.5
Facility 1740	Old fort	NC	Solar	Intermediate	Yes	4.68
Facility 1741	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1742	Monroe	NC	Solar	Intermediate	Yes	1.08
Facility 1743	McLeansville	NC	Solar	Intermediate	Yes	3.6
Facility 1744	Oak Ridge	NC	Solar	Intermediate	Yes	3.01
Facility 1745	Stokesdale	NC	Solar	Intermediate	Yes	6
Facility 1746	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1747	Durham	NC	Solar	Intermediate	Yes	6
Facility 1748	Kings Mountain	NC	Solar	Intermediate	Yes	81.08
Facility 1749	Charlotte	NC	Solar	Intermediate	Yes	4
Facility 1750	Monroe	NC	Solar	Intermediate	Yes	0.86

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1751	Mooresville	NC	Solar	Intermediate	Yes	7.032
Facility 1752	Charlotte	NC	Solar	Intermediate	Yes	3.746
Facility 1753	Morrisville	NC	Solar	Intermediate	Yes	6.209
Facility 1754	High Point	NC	Solar	Intermediate	Yes	2.856
Facility 1755	Salisbury	NC	Solar	Intermediate	Yes	7.7
Facility 1756	Charlotte	NC	Solar	Intermediate	Yes	1.72
Facility 1757	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1758	Franklin	NC	Solar	Intermediate	Yes	1.92
Facility 1759	Lawndale	NC	Solar	Intermediate	Yes	5.76
Facility 1760	Chapel Hill	NC	Solar	Intermediate	Yes	3.78
Facility 1761	Lewisville	NC	Solar	Intermediate	Yes	7.68
Facility 1762	Salisbury	NC	Solar	Intermediate	Yes	4.2
Facility 1763	Rockwell	NC	Solar	Intermediate	Yes	3.44
Facility 1764	Clemmons	NC	Solar	Intermediate	Yes	7.68
Facility 1765	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 1766	Graham	NC	Solar	Intermediate	Yes	2
Facility 1767	Gibsonville	NC	Solar	Intermediate	Yes	3.44
Facility 1768	Lincolnton	NC	Solar	Intermediate	Yes	0.86
Facility 1769	Durham	NC	Solar	Intermediate	Yes	5
Facility 1770	Whitsett	NC	Solar	Intermediate	Yes	15
Facility 1771	Durham	NC	Solar	Intermediate	Yes	3.627
Facility 1772	Charlotte	NC	Solar	Intermediate	Yes	9.02
Facility 1773	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1774	Midland	NC	Solar	Intermediate	Yes	7.562
Facility 1775	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1776	Jamestown	NC	Solar	Intermediate	Yes	5.426
Facility 1777	Concord	NC	Other	Intermediate	Yes	0
Facility 1778	Morrisville	NC	Solar	Intermediate	Yes	3.855
Facility 1779	Charlotte	NC	Solar	Intermediate	Yes	2.422
Facility 1780	Jonesville	NC	Solar	Intermediate	Yes	3.93
Facility 1781	Kannapolis	NC	Solar	Intermediate	Yes	6.534
Facility 1782	Mooresville	NC	Solar	Intermediate	Yes	6.593
Facility 1783	Tryon	NC	Solar	Intermediate	Yes	3.84
Facility 1784	Durham	NC	Solar	Intermediate	Yes	3.85
Facility 1785	Durham	NC	Solar	Intermediate	Yes	4.3
Facility 1786	Denver	NC	Solar	Intermediate	Yes	9.18
Facility 1787	Greensboro	NC	Solar	Intermediate	Yes	2.7
Facility 1788	Winston Salem	NC	Solar	Intermediate	Yes	6
Facility 1789	Burlington	NC	Solar	Intermediate	Yes	3
Facility 1790	Butner	NC	Solar	Intermediate	Yes	5.1
Facility 1791	Durham	NC	Solar	Intermediate	Yes	3.36
Facility 1792	Charlotte	NC	Solar	Intermediate	Yes	6.494
Facility 1793	Kernersville	NC	Solar	Intermediate	Yes	3.709
Facility 1794	Durham	NC	Solar	Intermediate	Yes	4.792
Facility 1795	Charlotte	NC	Solar	Intermediate	Yes	6.117
Facility 1796	Ellenboro	NC	Solar	Intermediate	Yes	5
Facility 1797	Ellenboro	NC	Solar	Intermediate	Yes	3.68
Facility 1798	Brevard	NC	Solar	Intermediate	Yes	3
Facility 1799	Salisbury	NC	Solar	Intermediate	Yes	2.58

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1800	Charlotte	NC	Solar	Intermediate	Yes	7.6
Facility 1801	Shelby	NC	Hydroelectric	Baseload	Yes	600
Facility 1802	Greensboro	NC	Solar	Intermediate	Yes	1.8
Facility 1803	Sylva	NC	Solar	Intermediate	Yes	9
Facility 1804	Stem	NC	Solar	Intermediate	Yes	7.6
Facility 1805	Durham	NC	Solar	Intermediate	Yes	4.269
Facility 1806	Mocksville	NC	Solar	Intermediate	Yes	5.97
Facility 1807	Mount Pleasant	NC	Solar	Intermediate	Yes	3.549
Facility 1808	Conover	NC	Solar	Intermediate	Yes	7.554
Facility 1809	Hickory	NC	Solar	Intermediate	Yes	5.932
Facility 1810	Greensboro	NC	Solar	Intermediate	Yes	4.592
Facility 1811	Chapel Hill	NC	Solar	Intermediate	Yes	5.98
Facility 1812	Mills River	NC	Solar	Intermediate	Yes	2.571
Facility 1813	Chapel Hill	NC	Solar	Intermediate	Yes	5
Facility 1814	Charlotte	NC	Solar	Intermediate	Yes	7.6
Facility 1815	Salisbury	NC	Solar	Intermediate	Yes	4.32
Facility 1816	Mooresville	NC	Solar	Intermediate	Yes	7.773
Facility 1817	Durham	NC	Solar	Intermediate	Yes	248.4
Facility 1818	Mooresboro	NC	Solar	Intermediate	Yes	4.682
Facility 1819	Cleveland	NC	Solar	Intermediate	Yes	6.056
Facility 1820	Durham	NC	Solar	Intermediate	Yes	6.262
Facility 1821	Charlotte	NC	Solar	Intermediate	Yes	33.12
Facility 1822	Harrisburg	NC	Solar	Intermediate	Yes	14.618
Facility 1823	Charlotte	NC	Solar	Intermediate	Yes	52.47
Facility 1824	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1825	Charlotte	NC	Solar	Intermediate	Yes	2.38
Facility 1826	Charlotte	NC	Solar	Intermediate	Yes	4.545
Facility 1827	Horse Shoe	NC	Solar	Intermediate	Yes	0.19
Facility 1828	Hendersonville	NC	Solar	Intermediate	Yes	14
Facility 1829	Glenville	NC	Solar	Intermediate	Yes	4
Facility 1830	Charlotte	NC	Solar	Intermediate	Yes	8.8
Facility 1831	Hillsborough	NC	Solar	Intermediate	Yes	3
Facility 1832	Charlotte	NC	Solar	Intermediate	Yes	8.61
Facility 1833	Charlotte	NC	Solar	Intermediate	Yes	4.385
Facility 1834	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 1835	Walnut Cove	NC	Solar	Intermediate	Yes	1.89
Facility 1836	Charlotte	NC	Solar	Intermediate	Yes	2.7
Facility 1837	Durham	NC	Solar	Intermediate	Yes	7
Facility 1838	Charlotte	NC	Solar	Intermediate	Yes	7.6
Facility 1839	Summerfield	NC	Solar	Intermediate	Yes	2.45
Facility 1840	Charlotte	NC	Solar	Intermediate	Yes	4.1
Facility 1841	Vale	NC	Solar	Intermediate	Yes	2.845
Facility 1842	Vale	NC	Solar	Intermediate	Yes	5.719
Facility 1843	Vale	NC	Solar	Intermediate	Yes	19.374
Facility 1844	Charlotte	NC	Solar	Intermediate	Yes	2.58
Facility 1845	Chapel Hill	NC	Solar	Intermediate	Yes	1.2
Facility 1846	Salisbury	NC	Solar	Intermediate	Yes	3.44
Facility 1847	Rutherfordton	NC	Solar	Intermediate	Yes	3.44
Facility 1848	Cary	NC	Solar	Intermediate	Yes	5.841
Facility 1849	Hendersonville	NC	Solar	Intermediate	Yes	3.322
Facility 1850	Winston Salem	NC	Solar	Intermediate	Yes	4.385

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1851	Charlotte	NC	Solar	Intermediate	Yes	4.373
Facility 1852	Charlotte	NC	Solar	Intermediate	Yes	7
Facility 1853	Mocksville	NC	Solar	Intermediate	Yes	10
Facility 1854	Mocksville	NC	Solar	Intermediate	Yes	336
Facility 1855	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 1856	Charlotte	NC	Solar	Intermediate	Yes	2
Facility 1857	Durham	NC	Solar	Intermediate	Yes	4.86
Facility 1858	Rutherfordton	NC	Solar	Intermediate	Yes	5.76
Facility 1859	Tryon	NC	Solar	Intermediate	Yes	5.18
Facility 1860	Chapel Hill	NC	Solar	Intermediate	Yes	3
Facility 1861	Marion	NC	Solar	Intermediate	Yes	7
Facility 1862	Chapel Hill	NC	Solar	Intermediate	Yes	1.71
Facility 1863	Durham	NC	Solar	Intermediate	Yes	1.2
Facility 1864	Concord	NC	Solar	Intermediate	Yes	9.117
Facility 1865	Winston Salem	NC	Solar	Intermediate	Yes	3
Facility 1866	Columbus	NC	Solar	Intermediate	Yes	1.72
Facility 1867	Charlotte	NC	Solar	Intermediate	Yes	18.06
Facility 1868	Hillsborough	NC	Solar	Intermediate	Yes	1.949
Facility 1869	Cleveland	NC	Solar	Intermediate	Yes	2000
Facility 1870	Chapel Hill	NC	Solar	Intermediate	Yes	5.991
Facility 1871	Lewisville	NC	Solar	Intermediate	Yes	5.258
Facility 1872	Carrboro	NC	Solar	Intermediate	Yes	3.85
Facility 1873	Charlotte	NC	Solar	Intermediate	Yes	8.6
Facility 1874	Durham	NC	Solar	Intermediate	Yes	4.776
Facility 1875	East Bend	NC	Solar	Intermediate	Yes	3.545
Facility 1876	Charlotte	NC	Biomass	Intermediate	Yes	1900
Facility 1877	Chapel Hill	NC	Solar	Intermediate	Yes	7
Facility 1878	Harmony	NC	Solar	Intermediate	Yes	2
Facility 1879	Hendersonville	NC	Solar	Intermediate	Yes	2.5
Facility 1880	Charlotte	NC	Solar	Intermediate	Yes	3
Facility 1881	Ellenboro	NC	Solar	Intermediate	Yes	1.29
Facility 1882	Salisbury	NC	Solar	Intermediate	Yes	6
Facility 1883	Winston Salem	NC	Solar	Intermediate	Yes	1.94
Facility 1884	Carrboro	NC	Solar	Intermediate	Yes	5
Facility 1885	Hendersonville	NC	Solar	Intermediate	Yes	3.8
Facility 1886	Huntersville	NC	Solar	Intermediate	Yes	9
Facility 1887	Kernersville	NC	Solar	Intermediate	Yes	3.377
Facility 1888	Randleman	NC	Solar	Intermediate	Yes	2.3
Facility 1889	Pinnacle	NC	Solar	Intermediate	Yes	4.5
Facility 1890	Charlotte	NC	Solar	Intermediate	Yes	3
Facility 1891	Hillsborough	NC	Solar	Intermediate	Yes	3.57
Facility 1892	Chapel Hill	NC	Solar	Intermediate	Yes	3.06
Facility 1893	Hillsborough	NC	Solar	Intermediate	Yes	5
Facility 1894	Durham	NC	Solar	Intermediate	Yes	4
Facility 1895	Otto	NC	Solar	Intermediate	Yes	3.6
Facility 1896	Mount Holly	NC	Solar	Intermediate	Yes	5
Facility 1897	Chapel Hill	NC	Solar	Intermediate	Yes	6
Facility 1898	Gold Hill	NC	Solar	Intermediate	Yes	6
Facility 1899	Norwood	NC	Solar	Intermediate	Yes	5.17

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1900	Indian Trail	NC	Solar	Intermediate	Yes	6.79
Facility 1901	Charlotte	NC	Solar	Intermediate	Yes	3.45
Facility 1902	Chapel Hill	NC	Solar	Intermediate	Yes	3
Facility 1903	Winston Salem	NC	Solar	Intermediate	Yes	4.3
Facility 1904	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 1905	Purlear	NC	Solar	Intermediate	Yes	6.748
Facility 1906	Forest City	NC	Solar	Intermediate	Yes	6
Facility 1907	Hickory	NC	Solar	Intermediate	Yes	2.946
Facility 1908	Moravian FLS	NC	Solar	Intermediate	Yes	3.675
Facility 1909	Hickory	NC	Solar	Intermediate	Yes	36
Facility 1910	Clemmons	NC	Solar	Intermediate	Yes	4.8
Facility 1911	Greensboro	NC	Solar	Intermediate	Yes	2.58
Facility 1912	Greensboro	NC	Solar	Intermediate	Yes	5.59
Facility 1913	Salisbury	NC	Solar	Intermediate	Yes	5
Facility 1914	Efland	NC	Solar	Intermediate	Yes	6
Facility 1915	Charlotte	NC	Solar	Intermediate	Yes	4.7
Facility 1916	Durham	NC	Solar	Intermediate	Yes	3.78
Facility 1917	Durham	NC	Solar	Intermediate	Yes	3.78
Facility 1918	Chapel Hill	NC	Solar	Intermediate	Yes	5
Facility 1919	Glenville	NC	Solar	Intermediate	Yes	5
Facility 1920	Greensboro	NC	Solar	Intermediate	Yes	2.4
Facility 1921	Charlotte	NC	Solar	Intermediate	Yes	2.5
Facility 1922	Waxhaw	NC	Solar	Intermediate	Yes	4
Facility 1923	Harrisburg	NC	Solar	Intermediate	Yes	3.225
Facility 1924	Hendersonville	NC	Solar	Intermediate	Yes	4
Facility 1925	Burlington	NC	Solar	Intermediate	Yes	6
Facility 1926	Chapel Hill	NC	Solar	Intermediate	Yes	3.5
Facility 1927	Julian	NC	Solar	Intermediate	Yes	1.1
Facility 1928	Charlotte	NC	Solar	Intermediate	Yes	5.25
Facility 1929	Harrisburg	NC	Solar	Intermediate	Yes	3.36
Facility 1930	Kernersville	NC	Solar	Intermediate	Yes	2.88
Facility 1931	Mount Holly	NC	Solar	Intermediate	Yes	0.86
Facility 1932	Saluda	NC	Solar	Intermediate	Yes	5.16
Facility 1933	Charlotte	NC	Solar	Intermediate	Yes	2.35
Facility 1934	Hillsborough	NC	Solar	Intermediate	Yes	5.1
Facility 1935	Horse Shoe	NC	Solar	Intermediate	Yes	3.01
Facility 1936	Gold Hill	NC	Solar	Intermediate	Yes	0.86
Facility 1937	Franklin	NC	Other	Intermediate	Yes	2.58
Facility 1938	Gastonia	NC	Solar	Intermediate	Yes	8
Facility 1939	Clemmons	NC	Solar	Intermediate	Yes	5.28
Facility 1940	Greensboro	NC	Solar	Intermediate	Yes	4
Facility 1941	Charlotte	NC	Solar	Intermediate	Yes	4.32
Facility 1942	Charlotte	NC	Solar	Intermediate	Yes	0.96
Facility 1943	Charlotte	NC	Solar	Intermediate	Yes	5
Facility 1944	Charlotte	NC	Solar	Intermediate	Yes	1.29
Facility 1945	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 1946	Durham	NC	Solar	Intermediate	Yes	5
Facility 1947	Valdese	NC	Solar	Intermediate	Yes	3.75
Facility 1948	Hendersonville	NC	Solar	Intermediate	Yes	0.76
Facility 1949	Pisgah Forest	NC	Solar	Intermediate	Yes	7.579

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 1950	Madison	NC	Landfill Gas	Intermediate	Yes	800
Facility 1951	Rockwell	NC	Solar	Intermediate	Yes	3480
Facility 1952	Indian Trail	NC	Solar	Intermediate	Yes	1
Facility 1953	Troutman	NC	Solar	Intermediate	Yes	2.88
Facility 1954	Mooresville	NC	Solar	Intermediate	Yes	2.4
Facility 1955	Sylva	NC	Solar	Intermediate	Yes	4.571
Facility 1956	Harrisburg	NC	Solar	Intermediate	Yes	5.674
Facility 1957	Pittsboro	NC	Solar	Intermediate	Yes	6
Facility 1958	Graham	NC	Solar	Intermediate	Yes	5.52
Facility 1959	Norwood	NC	Solar	Intermediate	Yes	5
Facility 1960	Charlotte	NC	Solar	Intermediate	Yes	4.94
Facility 1961	Salisbury	NC	Solar	Intermediate	Yes	6.45
Facility 1962	Waxhaw	NC	Solar	Intermediate	Yes	7
Facility 1963	Waxhaw	NC	Solar	Intermediate	Yes	2.48
Facility 1964	Hendersonville	NC	Solar	Intermediate	Yes	1.72
Facility 1965	Hendersonville	NC	Solar	Intermediate	Yes	6
Facility 1966	Burlington	NC	Solar	Intermediate	Yes	3
Facility 1967	Franklin	NC	Solar	Intermediate	Yes	5.94
Facility 1968	Randleman	NC	Solar	Intermediate	Yes	4.8
Facility 1969	Claremont	NC	Solar	Intermediate	Yes	1.92
Facility 1970	Wilkesboro	NC	Hydroelectric	Baseload	Yes	200
Facility 1971	Grover	NC	Solar	Intermediate	Yes	5000
Facility 1972	Pisgah Forest	NC	Solar	Intermediate	Yes	5.59
Facility 1973	Charlotte	NC	Solar	Intermediate	Yes	8
Facility 1974	Chapel Hill	NC	Solar	Intermediate	Yes	7.093
Facility 1975	Durham	NC	Solar	Intermediate	Yes	4.992
Facility 1976	Reidsville	NC	Solar	Intermediate	Yes	3.494
Facility 1977	Mooresville	NC	Solar	Intermediate	Yes	3
Facility 1978	Charlotte	NC	Solar	Intermediate	Yes	2.743
Facility 1979	Mooresville	NC	Other	Intermediate	Yes	0
Facility 1980	Salisbury	NC	Solar	Intermediate	Yes	16.2
Facility 1981	Salisbury	NC	Solar	Intermediate	Yes	42
Facility 1982	Durham	NC	Solar	Intermediate	Yes	4.452
Facility 1983	Winston Salem	NC	Solar	Intermediate	Yes	4.73
Facility 1984	Carrboro	NC	Solar	Intermediate	Yes	5
Facility 1985	Durham	NC	Solar	Intermediate	Yes	3.75
Facility 1986	Hendersonville	NC	Solar	Intermediate	Yes	9
Facility 1987	Midland	NC	Solar	Intermediate	Yes	9.883
Facility 1988	Hendersonville	NC	Solar	Intermediate	Yes	5.16
Facility 1989	Durham	NC	Solar	Intermediate	Yes	3.8
Facility 1990	Kernersville	NC	Solar	Intermediate	Yes	2.4
Facility 1991	Mooresville	NC	Solar	Intermediate	Yes	2.94
Facility 1992	Brevard	NC	Solar	Intermediate	Yes	3
Facility 1993	Charlotte	NC	Solar	Intermediate	Yes	2.597
Facility 1994	Matthews	NC	Solar	Intermediate	Yes	0.86
Facility 1995	Charlotte	NC	Solar	Intermediate	Yes	4.91
Facility 1996	Carrboro	NC	Solar	Intermediate	Yes	3.57
Facility 1997	Charlotte	NC	Solar	Intermediate	Yes	7.6
Facility 1998	Charlotte	NC	Solar	Intermediate	Yes	255
Facility 1999	Winston Salem	NC	Landfill Gas	Intermediate	Yes	4750

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2000	Chapel Hill	NC	Solar	Intermediate	Yes	3.8
Facility 2001	Durham	NC	Solar	Intermediate	Yes	5
Facility 2002	Charlotte	NC	Solar	Intermediate	Yes	4.73
Facility 2003	Charlotte	NC	Solar	Intermediate	Yes	10.8
Facility 2004	Charlotte	NC	Solar	Intermediate	Yes	7.63
Facility 2005	Durham	NC	Solar	Intermediate	Yes	5.89
Facility 2006	Carrboro	NC	Solar	Intermediate	Yes	3.75
Facility 2007	Elon	NC	Solar	Intermediate	Yes	3.44
Facility 2008	Elon	NC	Solar	Intermediate	Yes	2.4
Facility 2009	Durham	NC	Solar	Intermediate	Yes	6
Facility 2010	Rutherfordton	NC	Solar	Intermediate	Yes	3.6
Facility 2011	Lincolnton	NC	Solar	Intermediate	Yes	0.86
Facility 2012	Waxhaw	NC	Solar	Intermediate	Yes	2.15
Facility 2013	Albemarle	NC	Solar	Intermediate	Yes	0.86
Facility 2014	Winston-Salem	NC	Solar	Intermediate	Yes	3.974
Facility 2015	McLeansville	NC	Solar	Intermediate	Yes	24
Facility 2016	Belews Creek	NC	Solar	Intermediate	Yes	7.6
Facility 2017	Chapel Hill	NC	Solar	Intermediate	Yes	2.58
Facility 2018	Durham	NC	Solar	Intermediate	Yes	4
Facility 2019	Pelham	NC	Solar	Intermediate	Yes	2.82
Facility 2020	Midland	NC	Solar	Intermediate	Yes	2.857
Facility 2021	Pineville	NC	Solar	Intermediate	Yes	20
Facility 2022	Pineville	NC	Solar	Intermediate	Yes	20
Facility 2023	Mills River	NC	Solar	Intermediate	Yes	8.64
Facility 2024	Tryon	NC	Solar	Intermediate	Yes	2.58
Facility 2025	Hillsborough	NC	Solar	Intermediate	Yes	2.4
Facility 2026	Durham	NC	Solar	Intermediate	Yes	4.5
Facility 2027	Burlington	NC	Solar	Intermediate	Yes	5.141
Facility 2028	Durham	NC	Solar	Intermediate	Yes	4.433
Facility 2029	Highpoint	NC	Solar	Intermediate	Yes	5.788
Facility 2030	Carrboro	NC	Solar	Intermediate	Yes	3.226
Facility 2031	Concord	NC	Solar	Intermediate	Yes	7.912
Facility 2032	Greensboro	NC	Solar	Intermediate	Yes	5.46
Facility 2033	Chapel Hill	NC	Solar	Intermediate	Yes	4.636
Facility 2034	Conover	NC	Solar	Intermediate	Yes	2.58
Facility 2035	Charlotte	NC	Solar	Intermediate	Yes	4.25
Facility 2036	Chapel Hill	NC	Solar	Intermediate	Yes	2.58
Facility 2037	Durham	NC	Solar	Intermediate	Yes	5
Facility 2038	Chapel Hill	NC	Solar	Intermediate	Yes	7.6
Facility 2039	Marion	NC	Solar	Intermediate	Yes	1.02
Facility 2040	Chapel Hill	NC	Solar	Intermediate	Yes	3.8
Facility 2041	Chapel Hill	NC	Solar	Intermediate	Yes	6
Facility 2042	Charlotte	NC	Solar	Intermediate	Yes	9.29
Facility 2043	Stanley	NC	Solar	Intermediate	Yes	6.398
Facility 2044	Rockwell	NC	Solar	Intermediate	Yes	6.593
Facility 2045	Durham	NC	Solar	Intermediate	Yes	3.5
Facility 2046	Charlotte	NC	Solar	Intermediate	Yes	1.72
Facility 2047	Greensboro	NC	Solar	Intermediate	Yes	5.991
Facility 2048	Charlotte	NC	Solar	Intermediate	Yes	7
Facility 2049	Carrboro	NC	Solar	Intermediate	Yes	3.8
Facility 2050	Charlotte	NC	Solar	Intermediate	Yes	0.86

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2051	Concord	NC	Solar	Intermediate	Yes	4.5
Facility 2052	Concord	NC	Solar	Intermediate	Yes	3
Facility 2053	Whittier	NC	Solar	Intermediate	Yes	1.72
Facility 2054	Reidsville	NC	Solar	Intermediate	Yes	5.76
Facility 2055	Hillsborough	NC	Solar	Intermediate	Yes	4
Facility 2056	Concord	NC	Solar	Intermediate	Yes	2.541
Facility 2057	Sylva	NC	Solar	Intermediate	Yes	6
Facility 2058	Shelby	NC	Solar	Intermediate	Yes	1990
Facility 2059	Mooresville	NC	Solar	Intermediate	Yes	7.83
Facility 2060	Durham	NC	Solar	Intermediate	Yes	4
Facility 2061	Hendersonville	NC	Solar	Intermediate	Yes	5
Facility 2062	Taylorsville	NC	Solar	Intermediate	Yes	2.58
Facility 2063	Chapel Hill	NC	Solar	Intermediate	Yes	4.869
Facility 2064	Durham	NC	Solar	Intermediate	Yes	5.225
Facility 2065	Durham	NC	Solar	Intermediate	Yes	4.269
Facility 2066	Marion	NC	Solar	Intermediate	Yes	3
Facility 2067	Statesville	NC	Solar	Intermediate	Yes	4.4
Facility 2068	Greensboro	NC	Solar	Intermediate	Yes	2.58
Facility 2069	Indian Trail	NC	Solar	Intermediate	Yes	0.86
Facility 2070	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 2071	Charlotte	NC	Solar	Intermediate	Yes	11.11
Facility 2072	Concord	NC	Solar	Intermediate	Yes	4500
Facility 2073	Durham	NC	Solar	Intermediate	Yes	101.2
Facility 2074	Shelby	NC	Solar	Intermediate	Yes	4875
Facility 2075	China Grove	NC	Solar	Intermediate	Yes	0.86
Facility 2076	Mooresville	NC	Solar	Intermediate	Yes	17.635
Facility 2077	Fletcher	NC	Biogas	Intermediate	Yes	400
Facility 2078	Fletcher	NC	Solar	Intermediate	Yes	600
Facility 2079	Newton	NC	Solar	Intermediate	Yes	4950
Facility 2080	Charlotte	NC	Solar	Intermediate	Yes	8.846
Facility 2081	Greensboro	NC	Solar	Intermediate	Yes	12
Facility 2082	Salisbury	NC	Solar	Intermediate	Yes	6.625
Facility 2083	Winston Salem	NC	Solar	Intermediate	Yes	10
Facility 2084	Durham	NC	Solar	Intermediate	Yes	6.339
Facility 2085	Durham	NC	Solar	Intermediate	Yes	4.39
Facility 2086	Trinity	NC	Solar	Intermediate	Yes	2.946
Facility 2087	Matthews	NC	Solar	Intermediate	Yes	4.408
Facility 2088	Cherryville	NC	Solar	Intermediate	Yes	6.4
Facility 2089	Burlington	NC	Solar	Intermediate	Yes	24
Facility 2090	Marshville	NC	Solar	Intermediate	Yes	6.056
Facility 2091	Charlotte	NC	Solar	Intermediate	Yes	4
Facility 2092	Chapel Hill	NC	Solar	Intermediate	Yes	6.523
Facility 2093	Rockwell	NC	Solar	Intermediate	Yes	4.366
Facility 2094	Charlotte	NC	Solar	Intermediate	Yes	2.58
Facility 2095	Winston Salem	NC	Solar	Intermediate	Yes	3.447
Facility 2096	Durham	NC	Solar	Intermediate	Yes	3.824
Facility 2097	Durham	NC	Solar	Intermediate	Yes	4.821
Facility 2098	Hickory	NC	Solar	Intermediate	Yes	440
Facility 2099	Charlotte	NC	Solar	Intermediate	Yes	3.687

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2100	Winston-Salem	NC	Solar	Intermediate	Yes	5.96
Facility 2101	Mooresboro	NC	Solar	Intermediate	Yes	4500
Facility 2102	Winston Salem	NC	Solar	Intermediate	Yes	4998
Facility 2103	Cooleemee	NC	Hydroelectric	Baseload	Yes	1500
Facility 2104	Mount Airy	NC	Solar	Intermediate	Yes	9.87
Facility 2105	Charlotte	NC	Solar	Intermediate	Yes	5.834
Facility 2106	Gastonia	NC	Hydroelectric	Baseload	Yes	560
Facility 2107	Pfafftown	NC	Solar	Intermediate	Yes	4
Facility 2108	Greensboro	NC	Solar	Intermediate	Yes	2.88
Facility 2109	Durham	NC	Solar	Intermediate	Yes	3
Facility 2110	Elkin	NC	Solar	Intermediate	Yes	5
Facility 2111	Durham	NC	Solar	Intermediate	Yes	6.056
Facility 2112	Durham	NC	Solar	Intermediate	Yes	3.261
Facility 2113	Winston Salem	NC	Solar	Intermediate	Yes	8
Facility 2114	Hillsborough	NC	Solar	Intermediate	Yes	3.85
Facility 2115	Charlotte	NC	Solar	Intermediate	Yes	4.423
Facility 2116	Chapel Hill	NC	Solar	Intermediate	Yes	8.6
Facility 2117	Stanley	NC	Solar	Intermediate	Yes	5
Facility 2118	Durham	NC	Solar	Intermediate	Yes	5000
Facility 2119	Chapel Hill	NC	Solar	Intermediate	Yes	7.668
Facility 2120	Mt Pleasant	NC	Solar	Intermediate	Yes	8.838
Facility 2121	Charlotte	NC	Solar	Intermediate	Yes	3.87
Facility 2122	Pleasant Garden	NC	Solar	Intermediate	Yes	3.709
Facility 2123	Charlotte	NC	Solar	Intermediate	Yes	243
Facility 2124	Charlotte	NC	Solar	Intermediate	Yes	208
Facility 2125	Mebane	NC	Solar	Intermediate	Yes	10.754
Facility 2126	Charlotte	NC	Solar	Intermediate	Yes	4.5
Facility 2127	Salisbury	NC	Solar	Intermediate	Yes	4.32
Facility 2128	Salisbury	NC	Solar	Intermediate	Yes	1.72
Facility 2129	Durham	NC	Solar	Intermediate	Yes	3.66
Facility 2130	Charlotte	NC	Solar	Intermediate	Yes	3.36
Facility 2131	Lincolnton	NC	Solar	Intermediate	Yes	0.86
Facility 2132	Durham	NC	Solar	Intermediate	Yes	2.04
Facility 2133	Durham	NC	Solar	Intermediate	Yes	3.87
Facility 2134	Oak Ridge	NC	Solar	Intermediate	Yes	6.48
Facility 2135	Morganton	NC	Solar	Intermediate	Yes	3.04
Facility 2136	Reidsville	NC	Solar	Intermediate	Yes	5
Facility 2137	Statesville	NC	Solar	Intermediate	Yes	1.51
Facility 2138	Durham	NC	Solar	Intermediate	Yes	3.44
Facility 2139	Charlotte	NC	Solar	Intermediate	Yes	9.74
Facility 2140	Charlotte	NC	Solar	Intermediate	Yes	3.84
Facility 2141	Charlotte	NC	Solar	Intermediate	Yes	1.72
Facility 2142	Summerfield	NC	Solar	Intermediate	Yes	5
Facility 2143	Durham	NC	Solar	Intermediate	Yes	4
Facility 2144	Whittier	NC	Solar	Intermediate	Yes	3.44
Facility 2145	Whittier	NC	Solar	Intermediate	Yes	0.43
Facility 2146	Reidsville	NC	Solar	Intermediate	Yes	10
Facility 2147	Reidsville	NC	Solar	Intermediate	Yes	4.73
Facility 2148	Pfafftown	NC	Solar	Intermediate	Yes	5
Facility 2149	Lincolnton	NC	Hydroelectric	Baseload	Yes	750
Facility 2150	Hickory	NC	Solar	Intermediate	Yes	4.41

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2151	Durham	NC	Solar	Intermediate	Yes	4.4
Facility 2152	Charlotte	NC	Solar	Intermediate	Yes	2
Facility 2153	Greensboro	NC	Solar	Intermediate	Yes	2.4
Facility 2154	Greensboro	NC	Solar	Intermediate	Yes	8
Facility 2155	Cedar Grove	NC	Solar	Intermediate	Yes	5
Facility 2156	Chapel Hill	NC	Solar	Intermediate	Yes	5.17
Facility 2157	Mount Pleasant	NC	Solar	Intermediate	Yes	4.3
Facility 2158	Snow Camp	NC	Solar	Intermediate	Yes	2.85
Facility 2159	Snow Camp	NC	Solar	Intermediate	Yes	2.85
Facility 2160	Chapel Hill	NC	Solar	Intermediate	Yes	9
Facility 2161	Mooresville	NC	Solar	Intermediate	Yes	1.728
Facility 2162	Durham	NC	Solar	Intermediate	Yes	1.5
Facility 2163	Brevard	NC	Solar	Intermediate	Yes	3.36
Facility 2164	Hiddenite	NC	Solar	Intermediate	Yes	5000
Facility 2165	Waxhaw	NC	Solar	Intermediate	Yes	7
Facility 2166	Bostic	NC	Solar	Intermediate	Yes	1.938
Facility 2167	Durham	NC	Solar	Intermediate	Yes	4.792
Facility 2168	Elkin	NC	Solar	Intermediate	Yes	5.908
Facility 2169	Newton	NC	Solar	Intermediate	Yes	7.915
Facility 2170	Stoneville	NC	Solar	Intermediate	Yes	9
Facility 2171	Kernersville	NC	Solar	Intermediate	Yes	2.422
Facility 2172	Mebane	NC	Solar	Intermediate	Yes	4500
Facility 2173	Greensboro	NC	Solar	Intermediate	Yes	5.788
Facility 2174	Durham	NC	Solar	Intermediate	Yes	3.998
Facility 2175	Winston Salem	NC	Solar	Intermediate	Yes	6
Facility 2176	Mebane	NC	Solar	Intermediate	Yes	3
Facility 2177	Charlotte	NC	Solar	Intermediate	Yes	9
Facility 2178	Durham	NC	Solar	Intermediate	Yes	2.741
Facility 2179	Summerfield	NC	Solar	Intermediate	Yes	21.4
Facility 2180	Charlotte	NC	Solar	Intermediate	Yes	5
Facility 2181	Charlotte	NC	Solar	Intermediate	Yes	115
Facility 2182	Lexington	NC	Solar	Intermediate	Yes	15500
Facility 2183	Durham	NC	Solar	Intermediate	Yes	4.825
Facility 2184	Pisgah Forest	NC	Solar	Intermediate	Yes	6
Facility 2185	Franklin	NC	Solar	Intermediate	Yes	6
Facility 2186	Chapel Hill	NC	Solar	Intermediate	Yes	4.3
Facility 2187	Hillsborough	NC	Solar	Intermediate	Yes	7.6
Facility 2188	Chapel Hill	NC	Solar	Intermediate	Yes	9.24
Facility 2189	Advance	NC	Solar	Intermediate	Yes	5.4
Facility 2190	Chapel Hill	NC	Solar	Intermediate	Yes	4.41
Facility 2191	Charlotte	NC	Solar	Intermediate	Yes	5
Facility 2192	Durham	NC	Solar	Intermediate	Yes	2.205
Facility 2193	Mount Ulla	NC	Solar	Intermediate	Yes	0.86
Facility 2194	Conover	NC	Solar	Intermediate	Yes	4.76
Facility 2195	Durham	NC	Solar	Intermediate	Yes	1.92
Facility 2196	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 2197	Gastonia	NC	Solar	Intermediate	Yes	1.14
Facility 2198	Greensboro	NC	Solar	Intermediate	Yes	3.84
Facility 2199	Charlotte	NC	Solar	Intermediate	Yes	1.962

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2200	Chapel Hill	NC	Solar	Intermediate	Yes	5
Facility 2201	Reidsville	NC	Solar	Intermediate	Yes	2.8
Facility 2202	Durham	NC	Solar	Intermediate	Yes	5
Facility 2203	Monroe	NC	Solar	Intermediate	Yes	6
Facility 2204	Davidson	NC	Solar	Intermediate	Yes	4
Facility 2205	Carrboro	NC	Solar	Intermediate	Yes	4.3
Facility 2206	Reidsville	NC	Solar	Intermediate	Yes	2.23
Facility 2207	Winston Salem	NC	Solar	Intermediate	Yes	5
Facility 2208	Mooresville	NC	Solar	Intermediate	Yes	4.2
Facility 2209	Morganton	NC	Solar	Intermediate	Yes	7.053
Facility 2210	Bryson City	NC	Solar	Intermediate	Yes	5
Facility 2211	Charlotte	NC	Solar	Intermediate	Yes	7.44
Facility 2212	Denver	NC	Solar	Intermediate	Yes	1.851
Facility 2213	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 2214	Durham	NC	Solar	Intermediate	Yes	2.8
Facility 2215	Research Triangle Park	NC	Solar	Intermediate	Yes	5
Facility 2216	Charlotte	NC	Solar	Intermediate	Yes	3.44
Facility 2217	Burlington	NC	Solar	Intermediate	Yes	8.6
Facility 2218	Lincolnton	NC	Solar	Intermediate	Yes	6.02
Facility 2219	Carrboro	NC	Solar	Intermediate	Yes	3.89
Facility 2220	Greensboro	NC	Solar	Intermediate	Yes	2.15
Facility 2221	Mooresville	NC	Solar	Intermediate	Yes	6.298
Facility 2222	Durham	NC	Solar	Intermediate	Yes	2.5
Facility 2223	Charlotte	NC	Solar	Intermediate	Yes	7.7
Facility 2224	Charlotte	NC	Solar	Intermediate	Yes	3.5
Facility 2225	Matthews	NC	Solar	Intermediate	Yes	0.86
Facility 2226	Winston Salem	NC	Solar	Intermediate	Yes	324
Facility 2227	Wesley Chapel	NC	Solar	Intermediate	Yes	360
Facility 2228	Charlotte	NC	Solar	Intermediate	Yes	360
Facility 2229	Charlotte	NC	Solar	Intermediate	Yes	360
Facility 2230	Charlotte	NC	Solar	Intermediate	Yes	360
Facility 2231	Charlotte	NC	Solar	Intermediate	Yes	644
Facility 2232	Hickory	NC	Solar	Intermediate	Yes	396
Facility 2233	Claremont	NC	Solar	Intermediate	Yes	5.59
Facility 2234	Waxhaw	NC	Solar	Intermediate	Yes	6
Facility 2235	Archdale	NC	Solar	Intermediate	Yes	20
Facility 2236	Archdale	NC	Solar	Intermediate	Yes	52
Facility 2237	Greensboro	NC	Solar	Intermediate	Yes	5
Facility 2238	Greensboro	NC	Solar	Intermediate	Yes	175
Facility 2239	Greensboro	NC	Solar	Intermediate	Yes	6
Facility 2240	Julian	NC	Solar	Intermediate	Yes	4.8
Facility 2241	Chapel Hill	NC	Solar	Intermediate	Yes	0.74
Facility 2242	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 2243	Greensboro	NC	Solar	Intermediate	Yes	4.32
Facility 2244	Charlotte	NC	Solar	Intermediate	Yes	1.12
Facility 2245	Mooresville	NC	Solar	Intermediate	Yes	3
Facility 2246	Oak Ridge	NC	Solar	Intermediate	Yes	2.15
Facility 2247	Pfafftown	NC	Solar	Intermediate	Yes	1.72
Facility 2248	Mills River	NC	Other	Intermediate	Yes	6
Facility 2249	Kannapolis	NC	Solar	Intermediate	Yes	1.72
Facility 2250	Durham	NC	Solar	Intermediate	Yes	13.77

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2251	Durham	NC	Solar	Intermediate	Yes	2.58
Facility 2252	Winston Salem	NC	Solar	Intermediate	Yes	4.944
Facility 2253	Graham	NC	Solar	Intermediate	Yes	5.056
Facility 2254	Harrisburg	NC	Solar	Intermediate	Yes	4.305
Facility 2255	Carrboro	NC	Solar	Intermediate	Yes	26.8
Facility 2256	Charlotte	NC	Solar	Intermediate	Yes	4.6
Facility 2257	Charlotte	NC	Solar	Intermediate	Yes	250
Facility 2258	Hickory	NC	Solar	Intermediate	Yes	4.7
Facility 2259	Hickory	NC	Solar	Intermediate	Yes	4.7
Facility 2260	Greensboro	NC	Solar	Intermediate	Yes	0.96
Facility 2261	Greensboro	NC	Solar	Intermediate	Yes	0.96
Facility 2262	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 2263	Durham	NC	Solar	Intermediate	Yes	2.28
Facility 2264	Davidson	NC	Solar	Intermediate	Yes	1.72
Facility 2265	Columbus	NC	Solar	Intermediate	Yes	6
Facility 2266	Burlington	NC	Solar	Intermediate	Yes	1.9
Facility 2267	Mooresville	NC	Solar	Intermediate	Yes	4.678
Facility 2268	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 2269	Black Mountain	NC	Solar	Intermediate	Yes	10
Facility 2270	Durham	NC	Solar	Intermediate	Yes	4.58
Facility 2271	Charlotte	NC	Solar	Intermediate	Yes	2.58
Facility 2272	Hendersonville	NC	Solar	Intermediate	Yes	1.935
Facility 2273	Indian Trail	NC	Solar	Intermediate	Yes	4.3
Facility 2274	Stokesdale	NC	Solar	Intermediate	Yes	3.44
Facility 2275	Liberty	NC	Solar	Intermediate	Yes	3.98
Facility 2276	Winston Salem	NC	Solar	Intermediate	Yes	5
Facility 2277	Concord	NC	Solar	Intermediate	Yes	4
Facility 2278	Concord	NC	Solar	Intermediate	Yes	3.08
Facility 2279	Bryson City	NC	Solar	Intermediate	Yes	6
Facility 2280	Bryson City	NC	Solar	Intermediate	Yes	2.52
Facility 2281	Charlotte	NC	Solar	Intermediate	Yes	7.5
Facility 2282	Bostic	NC	Solar	Intermediate	Yes	2.8
Facility 2283	Charlotte	NC	Solar	Intermediate	Yes	6.24
Facility 2284	Burlington	NC	Solar	Intermediate	Yes	7.02
Facility 2285	Charlotte	NC	Solar	Intermediate	Yes	2.4
Facility 2286	Iron Station	NC	Solar	Intermediate	Yes	5.16
Facility 2287	Chapel Hill	NC	Solar	Intermediate	Yes	5
Facility 2288	Carrboro	NC	Solar	Intermediate	Yes	6
Facility 2289	Charlotte	NC	Solar	Intermediate	Yes	4.945
Facility 2290	Charlotte	NC	Solar	Intermediate	Yes	5.75
Facility 2291	Pittsboro	NC	Solar	Intermediate	Yes	5
Facility 2292	Charlotte	NC	Solar	Intermediate	Yes	9.085
Facility 2293	Carrboro	NC	Solar	Intermediate	Yes	3.801
Facility 2294	Hillsborough	NC	Solar	Intermediate	Yes	4.743
Facility 2295	Chapel Hill	NC	Solar	Intermediate	Yes	7.115
Facility 2296	Burlington	NC	Solar	Intermediate	Yes	4.818
Facility 2297	Winston-Salem	NC	Solar	Intermediate	Yes	3.209
Facility 2298	Greensboro	NC	Solar	Intermediate	Yes	4.087
Facility 2299	Haw River	NC	Solar	Intermediate	Yes	14.8

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2300	Chapel Hill	NC	Solar	Intermediate	Yes	2.808
Facility 2301	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 2302	Hickory	NC	Solar	Intermediate	Yes	5.59
Facility 2303	Charlotte	NC	Solar	Intermediate	Yes	2.782
Facility 2304	Durham	NC	Solar	Intermediate	Yes	4.945
Facility 2305	Waxhaw	NC	Solar	Intermediate	Yes	1.29
Facility 2306	Chapel Hill	NC	Solar	Intermediate	Yes	1.48
Facility 2307	Randleman	NC	Solar	Intermediate	Yes	2.5
Facility 2308	Randleman	NC	Solar	Intermediate	Yes	4
Facility 2309	Waxhaw	NC	Solar	Intermediate	Yes	4
Facility 2310	Chapel Hill	NC	Solar	Intermediate	Yes	9
Facility 2311	Chapel Hill	NC	Solar	Intermediate	Yes	9
Facility 2312	Hillsborough	NC	Solar	Intermediate	Yes	4.3
Facility 2313	Matthews	NC	Solar	Intermediate	Yes	0.86
Facility 2314	Durham	NC	Solar	Intermediate	Yes	7
Facility 2315	King	NC	Solar	Intermediate	Yes	5
Facility 2316	Burlington	NC	Solar	Intermediate	Yes	4
Facility 2317	Davidson	NC	Solar	Intermediate	Yes	2
Facility 2318	Carrboro	NC	Solar	Intermediate	Yes	4
Facility 2319	Saluda	NC	Solar	Intermediate	Yes	3.84
Facility 2320	Reidsville	NC	Solar	Intermediate	Yes	5
Facility 2321	Browns Summit	NC	Solar	Intermediate	Yes	2.32
Facility 2322	Carrboro	NC	Solar	Intermediate	Yes	4.37
Facility 2323	Charlotte	NC	Solar	Intermediate	Yes	3.29
Facility 2324	Morganton	NC	Solar	Intermediate	Yes	2.58
Facility 2325	Kannapolis	NC	Solar	Intermediate	Yes	8
Facility 2326	Rockwell	NC	Solar	Intermediate	Yes	4
Facility 2327	Greensboro	NC	Solar	Intermediate	Yes	2.88
Facility 2328	Concord	NC	Solar	Intermediate	Yes	1.29
Facility 2329	Nebo	NC	Solar	Intermediate	Yes	4.41
Facility 2330	Lincolnton	NC	Solar	Intermediate	Yes	9
Facility 2331	Winston Salem	NC	Solar	Intermediate	Yes	6.522
Facility 2332	Mooresville	NC	Solar	Intermediate	Yes	1.726
Facility 2333	Chapel Hill	NC	Solar	Intermediate	Yes	3.8
Facility 2334	Lake Lure	NC	Hydroelectric	Baseload	Yes	3600
Facility 2335	Sylva	NC	Solar	Intermediate	Yes	5
Facility 2336	Cornelius	NC	Solar	Intermediate	Yes	14.7
Facility 2337	Kannapolis	NC	Solar	Intermediate	Yes	14.02
Facility 2338	Durham	NC	Solar	Intermediate	Yes	3.01
Facility 2339	Charlotte	NC	Solar	Intermediate	Yes	0.86
Facility 2340	Mooresville	NC	Solar	Intermediate	Yes	5.853
Facility 2341	Mount Pleasant	NC	Solar	Intermediate	Yes	2.909
Facility 2342	Hickory	NC	Solar	Intermediate	Yes	4.596
Facility 2343	Greensboro	NC	Solar	Intermediate	Yes	30
Facility 2344	Durham	NC	Solar	Intermediate	Yes	27.6
Facility 2345	Whittier	NC	Solar	Intermediate	Yes	7.367
Facility 2346	Hickory	NC	Solar	Intermediate	Yes	3.8
Facility 2347	Morrisville	NC	Solar	Intermediate	Yes	4.885
Facility 2348	Charlotte	NC	Solar	Intermediate	Yes	18
Facility 2349	Salisbury	NC	Solar	Intermediate	Yes	3.84
Facility 2350	Summerfield	NC	Solar	Intermediate	Yes	2.16

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2351	Durham	NC	Solar	Intermediate	Yes	4
Facility 2352	Durham	NC	Solar	Intermediate	Yes	16
Facility 2353	Mills River	NC	Solar	Intermediate	Yes	5.868
Facility 2354	Durham	NC	Solar	Intermediate	Yes	6.818
Facility 2355	Charlotte	NC	Solar	Intermediate	Yes	1.5
Facility 2356	Catawba	NC	Solar	Intermediate	Yes	10.111
Facility 2357	Charlotte	NC	Solar	Intermediate	Yes	480
Facility 2358	Hickory	NC	Solar	Intermediate	Yes	5000
Facility 2359	Charlotte	NC	Solar	Intermediate	Yes	2.373
Facility 2360	Conover	NC	Solar	Intermediate	Yes	1.72
Facility 2361	Charlotte	NC	Solar	Intermediate	Yes	4.8
Facility 2362	Wingate	NC	Solar	Intermediate	Yes	9.03
Facility 2363	Chapel Hill	NC	Solar	Intermediate	Yes	20
Facility 2364	Chapel Hill	NC	Landfill Gas	Intermediate	Yes	1059
Facility 2365	Greensboro	NC	Solar	Intermediate	Yes	3
Facility 2366	Haw River	NC	Solar	Intermediate	Yes	56
Facility 2367	Yadkinville	NC	Solar	Intermediate	Yes	750
Facility 2368	Winston Salem	NC	Solar	Intermediate	Yes	31.327
Facility 2369	Chapel Hill	NC	Solar	Intermediate	Yes	80
Facility 2370	Conover	NC	Solar	Intermediate	Yes	301.95
Facility 2371	RTP	NC	Solar	Intermediate	Yes	3000
Facility 2372	RTP	NC	Solar	Intermediate	Yes	51
Facility 2373	RTP	NC	Solar	Intermediate	Yes	112
Facility 2374	Durham	NC	Solar	Intermediate	Yes	4
Facility 2375	Winston Salem	NC	Solar	Intermediate	Yes	95.2
Facility 2376	Troutman	NC	Solar	Intermediate	Yes	4.093
Facility 2377	Durham	NC	Solar	Intermediate	Yes	50
Facility 2378	Durham	NC	Solar	Intermediate	Yes	30
Facility 2379	Durham	NC	Solar	Intermediate	Yes	75
Facility 2380	Durham	NC	Solar	Intermediate	Yes	52.9
Facility 2381	Mount Airy	NC	Solar	Intermediate	Yes	14
Facility 2382	Chapel Hill	NC	Solar	Intermediate	Yes	2.7
Facility 2383	Mocksville	NC	Solar	Intermediate	Yes	4.136
Facility 2384	Charlotte	NC	Solar	Intermediate	Yes	4.408
Facility 2385	Summerfield,	NC	Solar	Intermediate	Yes	4.582
Facility 2386	Monroe	NC	Solar	Intermediate	Yes	4.822
Facility 2387	Jamestown	NC	Solar	Intermediate	Yes	3
Facility 2388	Winston Salem	NC	Solar	Intermediate	Yes	0.426
Facility 2389	Mooresville	NC	Solar	Intermediate	Yes	8.45
Facility 2390	Mooresville	NC	Solar	Intermediate	Yes	12.2
Facility 2391	King	NC	Solar	Intermediate	Yes	9.602
Facility 2392	Concord	NC	Solar	Intermediate	Yes	5
Facility 2393	Hillsborough	NC	Solar	Intermediate	Yes	4
Facility 2394	Salisbury	NC	Solar	Intermediate	Yes	8.54
Facility 2395	Elon	NC	Solar	Intermediate	Yes	2.58
Facility 2396	Winston Salem	NC	Solar	Intermediate	Yes	2.58
Facility 2397	Indian Trail	NC	Solar	Intermediate	Yes	2.5
Facility 2398	Oak Ridge	NC	Solar	Intermediate	Yes	8
Facility 2399	Charlotte	NC	Solar	Intermediate	Yes	4

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2400	Elon	NC	Solar	Intermediate	Yes	6.02
Facility 2401	Hillsborough	NC	Solar	Intermediate	Yes	5.714
Facility 2402	Lincolnton	NC	Solar	Intermediate	Yes	1.29
Facility 2403	Charlotte	NC	Solar	Intermediate	Yes	6
Facility 2404	Charlotte	NC	Solar	Intermediate	Yes	5.81
Facility 2405	Reidsville	NC	Solar	Intermediate	Yes	800.4
Facility 2406	Durham	NC	Solar	Intermediate	Yes	5.078
Facility 2407	Charlotte	NC	Solar	Intermediate	Yes	3.08
Facility 2408	Winston Salem	NC	Solar	Intermediate	Yes	1.92
Facility 2409	Charlotte	NC	Solar	Intermediate	Yes	27.47
Facility 2410	Eden	NC	Biomass	Intermediate	Yes	700
Facility 2411	Chapel Hill	NC	Solar	Intermediate	Yes	14.51
Facility 2412	Durham	NC	Solar	Intermediate	Yes	3.937
Facility 2413	Kings Mountain	NC	Solar	Intermediate	Yes	4950
Facility 2414	Conover	NC	Solar	Intermediate	Yes	3
Facility 2415	Winston Salem	NC	Solar	Intermediate	Yes	9.36
Facility 2416	Sylva	NC	Solar	Intermediate	Yes	2.765
Facility 2417	Charlotte	NC	Solar	Intermediate	Yes	2.88
Facility 2418	Newton	NC	Solar	Intermediate	Yes	3.926
Facility 2419	Salisbury	NC	Solar	Intermediate	Yes	150
Facility 2420	Gibsonville	NC	Solar	Intermediate	Yes	14.04
Facility 2421	Walkertown	NC	Solar	Intermediate	Yes	6
Facility 2422	Summerfield	NC	Solar	Intermediate	Yes	2
Facility 2423	Salisbury	NC	Solar	Intermediate	Yes	12.4
Facility 2424	Statesville	NC	Solar	Intermediate	Yes	1.4
Facility 2425	McLeansville	NC	Solar	Intermediate	Yes	8.008
Facility 2426	Andrews	NC	Solar	Intermediate	Yes	8.2
Facility 2427	Harrisburg	NC	Solar	Intermediate	Yes	5.301
Facility 2428	Chapel Hill	NC	Solar	Intermediate	Yes	4.32
Facility 2429	Greensboro	NC	Solar	Intermediate	Yes	4
Facility 2430	Durham	NC	Solar	Intermediate	Yes	4.707
Facility 2431	Boone	NC	Landfill Gas	Intermediate	Yes	186
Facility 2432	Concord	NC	Biomass	Intermediate	Yes	1942
Facility 2433	Taylorsville	NC	Solar	Intermediate	Yes	3.976
Facility 2434	Chapel Hill	NC	Solar	Intermediate	Yes	4.341
Facility 2435	Mt Pleasant	NC	Solar	Intermediate	Yes	8.718
Facility 2436	Elkin	NC	Solar	Intermediate	Yes	3
Facility 2437	Greensboro	NC	Solar	Intermediate	Yes	5
Facility 2438	Carrboro	NC	Solar	Intermediate	Yes	5.194
Facility 2439	Mocksville	NC	Solar	Intermediate	Yes	0.7
Facility 2440	Winston Salem	NC	Solar	Intermediate	Yes	6.068
Facility 2441	Charlotte	NC	Solar	Intermediate	Yes	7.7
Facility 2442	Robbinsville	NC	Solar	Intermediate	Yes	7.62
Facility 2443	Lincolton	NC	Solar	Intermediate	Yes	4.4
Facility 2444	Moravian Falls	NC	Solar	Intermediate	Yes	2.85
Facility 2445	Efland	NC	Solar	Intermediate	Yes	6
Facility 2446	McLeansville	NC	Solar	Intermediate	Yes	1.44
Facility 2447	Chapel Hill	NC	Solar	Intermediate	Yes	4
Facility 2448	Durham	NC	Solar	Intermediate	Yes	6.209
Facility 2449	Mooresville	NC	Solar	Intermediate	Yes	2.58
Facility 2450	Charlotte	NC	Solar	Intermediate	Yes	6

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 2451	Hendersonville	NC	Solar	Intermediate	Yes	2.58
Facility 2452	Ellenboro	NC	Solar	Intermediate	Yes	2.65
Facility 2453	Shelby	NC	Solar	Intermediate	Yes	0.86
Facility 2454	Salisbury	NC	Solar	Intermediate	Yes	4998
Facility 2455	Carrboro	NC	Solar	Intermediate	Yes	18.6
Facility 2456	Carrboro	NC	Solar	Intermediate	Yes	9.61
Facility 2457	Durham	NC	Solar	Intermediate	Yes	4.059
Facility 2458	Kernersville	NC	Solar	Intermediate	Yes	4.823
Facility 2459	Chapel Hill	NC	Solar	Intermediate	Yes	5000
Facility 2460	Saluda	NC	Solar	Intermediate	Yes	5
Facility 2461	Brevard	NC	Solar	Intermediate	Yes	0.65
Facility 2462	Taylorsville	NC	Solar	Intermediate	Yes	23.776
Facility 2463	Saluda	NC	Solar	Intermediate	Yes	5.885
Facility 2464	Mount Ulla	NC	Solar	Intermediate	Yes	6.051
Facility 2465	Charlotte	NC	Solar	Intermediate	Yes	6.63
Facility 2466	Summerfield	NC	Solar	Intermediate	Yes	4.983
Facility 2467	Summerfield	NC	Solar	Intermediate	Yes	4.983
Facility 2468	Durham	NC	Solar	Intermediate	Yes	6.829
Facility 2469	N Wilkesboro	NC	Wind	Intermediate	Yes	2.4
Facility 2470	Wilkesboro	NC	Landfill Gas	Intermediate	Yes	70
Facility 2471	Rural Hall	NC	Solar	Intermediate	Yes	6.913
Facility 2472	Greensboro	NC	Solar	Intermediate	Yes	4.52
Facility 2473	Lawndale	NC	Solar	Intermediate	Yes	2.5
Facility 2474	Chapel Hill	NC	Solar	Intermediate	Yes	2.3
Facility 2475	Chapel Hill	NC	Solar	Intermediate	Yes	5
Facility 2476	Durham	NC	Solar	Intermediate	Yes	4.32
Facility 2477	Matthews	NC	Solar	Intermediate	Yes	2.41
Facility 2478	Chapel Hill	NC	Solar	Intermediate	Yes	6
Facility 2479	Jamestown	NC	Solar	Intermediate	Yes	2.4
Facility 2480	Wingate	NC	Solar	Intermediate	Yes	2.58
Facility 2481	Salisbury	NC	Solar	Intermediate	Yes	7.68
Facility 2482	Highlands	NC	Solar	Intermediate	Yes	3
Facility 2483	Franklin	NC	Solar	Intermediate	Yes	2.58
Facility 2484	Winston Salem	NC	Solar	Intermediate	Yes	5.16
Facility 2485	Snow Camp	NC	Solar	Intermediate	Yes	4.5
Facility 2486	Greensboro	NC	Solar	Intermediate	Yes	5.1
Facility 2487	Winston Salem	NC	Solar	Intermediate	Yes	2.94
Facility 2488	Durham	NC	Solar	Intermediate	Yes	2
Facility 2489	Concord	NC	Solar	Intermediate	Yes	2.75
Facility 2490	McLeansville	NC	Solar	Intermediate	Yes	2.88
Facility 2491	Oak Ridge	NC	Solar	Intermediate	Yes	6.5
Facility 2492	Chapel Hill	NC	Solar	Intermediate	Yes	2
Facility 2493	Greensboro	NC	Solar	Intermediate	Yes	4.8

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	Greenville	SC	Solar	Intermediate	Yes	21
Facility 2	Edgemoor	SC	Solar	Intermediate	Yes	10.95
Facility 3	Clemson	SC	Solar	Intermediate	Yes	12.6
Facility 4	Greenville	SC	Solar	Intermediate	Yes	8
Facility 5	Spartanburg	SC	Solar	Intermediate	Yes	0.86
Facility 6	Greenville	SC	Solar	Intermediate	Yes	8
Facility 7	Greer	SC	Solar	Intermediate	Yes	15
Facility 8	Spartanburg	SC	Solar	Intermediate	Yes	0.76
Facility 9	Greenville	SC	Solar	Intermediate	Yes	6
Facility 10	Travelers Rest	SC	Solar	Intermediate	Yes	15.25
Facility 11	Simpsonville	SC	Solar	Intermediate	Yes	3.66
Facility 12	Spartanburg	SC	Solar	Intermediate	Yes	4.3
Facility 13	Lyman	SC	Solar	Intermediate	Yes	7.2
Facility 14	Moore	SC	Solar	Intermediate	Yes	15.25
Facility 15	Boiling Springs	SC	Solar	Intermediate	Yes	6
Facility 16	Fort Mill	SC	Solar	Intermediate	Yes	3
Facility 17	Clover	SC	Solar	Intermediate	Yes	8
Facility 18	Taylors	SC	Solar	Intermediate	Yes	7.6
Facility 19	Anderson	SC	Solar	Intermediate	Yes	7
Facility 20	Greenville	SC	Solar	Intermediate	Yes	6
Facility 21	Duncan	SC	Solar	Intermediate	Yes	4
Facility 22	Rock Hill	SC	Solar	Intermediate	Yes	3.25
Facility 23	Williamston	SC	Solar	Intermediate	Yes	1.72
Facility 24	Tega Cay	SC	Solar	Intermediate	Yes	3.25
Facility 25	Williamston	SC	Solar	Intermediate	Yes	10
Facility 26	Ware Shoals	SC	Hydroelectric	Baseload	Yes	6300
Facility 27	Piedmont	SC	Hydroelectric	Baseload	Yes	600
Facility 28	Taylors	SC	Solar	Intermediate	Yes	5
Facility 29	Gaffney	SC	Solar	Intermediate	Yes	3
Facility 30	Greenville	SC	Solar	Intermediate	Yes	5
Facility 31	Gaffney	SC	Solar	Intermediate	Yes	6.01
Facility 32	Duncan	SC	Solar	Intermediate	Yes	10
Facility 33	Pelzer	SC	Solar	Intermediate	Yes	13.25
Facility 34	Fort Mill	SC	Solar	Intermediate	Yes	15.25
Facility 35	Greenville	SC	Solar	Intermediate	Yes	7.6
Facility 36	Cowpens	SC	Solar	Intermediate	Yes	3
Facility 37	Greenville	SC	Solar	Intermediate	Yes	11
Facility 38	Fort Mill	SC	Solar	Intermediate	Yes	8.49
Facility 39	Fountain Inn	SC	Solar	Intermediate	Yes	5.16
Facility 40	Greenville	SC	Solar	Intermediate	Yes	5.25
Facility 41	Chesnee	SC	Solar	Intermediate	Yes	2.58
Facility 42	Pickens	SC	Solar	Intermediate	Yes	2.15
Facility 43	Clemson	SC	Solar	Intermediate	Yes	2.35
Facility 44	Greenwood	SC	Solar	Intermediate	Yes	3.66
Facility 45	Inman	SC	Solar	Intermediate	Yes	4.357
Facility 46	Lyman	SC	Solar	Intermediate	Yes	94.08
Facility 47	Moore	SC	Solar	Intermediate	Yes	3
Facility 48	Fort Mill	SC	Solar	Intermediate	Yes	6.75
Facility 49	Greenwood	SC	Solar	Intermediate	Yes	3.655
Facility 50	Piedmont	SC	Solar	Intermediate	Yes	0.86

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 51	Spartanburg	SC	Solar	Intermediate	Yes	12
Facility 52	Piedmont	SC	Solar	Intermediate	Yes	10
Facility 53	Greenville	SC	Solar	Intermediate	Yes	4.32
Facility 54	Spartanburg	SC	Solar	Intermediate	Yes	0.76
Facility 55	Clover	SC	Solar	Intermediate	Yes	10
Facility 56	Chester	SC	Solar	Intermediate	Yes	4.5
Facility 57	Simpsonville	SC	Solar	Intermediate	Yes	2.15
Facility 58	Starr	SC	Solar	Intermediate	Yes	7
Facility 59	Lancaster	SC	Solar	Intermediate	Yes	13.52
Facility 60	Seneca	SC	Solar	Intermediate	Yes	10
Facility 61	Greenville	SC	Solar	Intermediate	Yes	7.2
Facility 62	Taylors	SC	Solar	Intermediate	Yes	3.84
Facility 63	Greenville	SC	Solar	Intermediate	Yes	5
Facility 64	Greer	SC	Solar	Intermediate	Yes	1.68
Facility 65	Greer	SC	Solar	Intermediate	Yes	5.52
Facility 66	Simpsonville	SC	Solar	Intermediate	Yes	6
Facility 67	Tega Cay	SC	Solar	Intermediate	Yes	9.141
Facility 68	Clover	SC	Solar	Intermediate	Yes	2.8
Facility 69	Lancaster	SC	Solar	Intermediate	Yes	5
Facility 70	Greenville	SC	Solar	Intermediate	Yes	1.72
Facility 71	Simpsonville	SC	Solar	Intermediate	Yes	6
Facility 72	Lyman	SC	Solar	Intermediate	Yes	5
Facility 73	Liberty	SC	Solar	Intermediate	Yes	6
Facility 74	Anderson	SC	Solar	Intermediate	Yes	7.6
Facility 75	Campobello	SC	Wind	Intermediate	Yes	10
Facility 76	Easley	SC	Solar	Intermediate	Yes	11
Facility 77	Campobello	SC	Solar	Intermediate	Yes	16
Facility 78	Simpsonville	SC	Solar	Intermediate	Yes	2.88
Facility 79	Honea Path	SC	Solar	Intermediate	Yes	11
Facility 80	Liberty	SC	Solar	Intermediate	Yes	7.975
Facility 81	Gaffney	SC	Solar	Intermediate	Yes	5
Facility 82	Chesnee	SC	Solar	Intermediate	Yes	2.5
Facility 83	Ridgeway	SC	Solar	Intermediate	Yes	2.4
Facility 84	Gaffney	SC	Natural Gas	Intermediate	Yes	100000
Facility 85	Blacksburg	SC	Hydroelectric	Baseload	Yes	4140
Facility 86	Campobello	SC	Solar	Intermediate	Yes	12
Facility 87	Anderson	SC	Solar	Intermediate	Yes	7.5
Facility 88	Easley	SC	Solar	Intermediate	Yes	4
Facility 89	Greenwood	SC	Solar	Intermediate	Yes	1.5
Facility 90	Anderson	SC	Solar	Intermediate	Yes	3
Facility 91	Lancaster	SC	Solar	Intermediate	Yes	5.25
Facility 92	Hodges	SC	Solar	Intermediate	Yes	7.5
Facility 93	Greenville	SC	Solar	Intermediate	Yes	1.8
Facility 94	Clemson	SC	Solar	Intermediate	Yes	42
Facility 95	Seneca	SC	Solar	Intermediate	Yes	7.2
Facility 96	Gray Court	SC	Solar	Intermediate	Yes	6
Facility 97	Greenville	SC	Solar	Intermediate	Yes	3.2
Facility 98	Greenville	SC	Solar	Intermediate	Yes	6.2
Facility 99	Taylors	SC	Solar	Intermediate	Yes	5

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 100	Mauldin	SC	Solar	Intermediate	Yes	9.6
Facility 101	Greenwood	SC	Solar	Intermediate	Yes	12
Facility 102	Clover	SC	Solar	Intermediate	Yes	27
Facility 103	Anderson	SC	Solar	Intermediate	Yes	2.075
Facility 104	Greenwood	SC	Solar	Intermediate	Yes	20
Facility 105	Spartanburg	SC	Solar	Intermediate	Yes	7
Facility 106	Spartanburg	SC	Hydroelectric	Baseload	Yes	1250
Facility 107	Ninety Six	SC	Solar	Intermediate	Yes	12
Facility 108	Travelers Rest	SC	Solar	Intermediate	Yes	4.95
Facility 109	Greenville	SC	Solar	Intermediate	Yes	4.532
Facility 110	Clemson	SC	Solar	Intermediate	Yes	4.5
Facility 111	Gray Court	SC	Solar	Intermediate	Yes	0.76
Facility 112	Tega Cay	SC	Solar	Intermediate	Yes	15.2
Facility 113	Greenville	SC	Solar	Intermediate	Yes	3
Facility 114	Taylors	SC	Solar	Intermediate	Yes	2.28
Facility 115	Hodges	SC	Solar	Intermediate	Yes	5.712
Facility 116	Seneca	SC	Solar	Intermediate	Yes	5
Facility 117	Simpsonville	SC	Solar	Intermediate	Yes	2
Facility 118	Greenville	SC	Solar	Intermediate	Yes	0.83
Facility 119	Belton	SC	Solar	Intermediate	Yes	2
Facility 120	Piedmont	SC	Solar	Intermediate	Yes	18
Facility 121	Greenville	SC	Solar	Intermediate	Yes	10.5
Facility 122	Campobello	SC	Solar	Intermediate	Yes	3.01
Facility 123	Spartanburg	SC	Solar	Intermediate	Yes	9.2
Facility 124	Fountain Inn	SC	Solar	Intermediate	Yes	11
Facility 125	Landrum	SC	Solar	Intermediate	Yes	7
Facility 126	Boiling Springs	SC	Solar	Intermediate	Yes	3
Facility 127	Greenville	SC	Solar	Intermediate	Yes	2.856
Facility 128	Greenville	SC	Solar	Intermediate	Yes	7
Facility 129	Pendleton	SC	Solar	Intermediate	Yes	6
Facility 130	Greenville	SC	Solar	Intermediate	Yes	11
Facility 131	Seneca	SC	Solar	Intermediate	Yes	6.25
Facility 132	Greer	SC	Solar	Intermediate	Yes	7
Facility 133	Greer	SC	Solar	Intermediate	Yes	3.5
Facility 134	Inman	SC	Solar	Intermediate	Yes	6.6
Facility 135	Simpsonville	SC	Solar	Intermediate	Yes	10
Facility 136	Anderson	SC	Solar	Intermediate	Yes	1
Facility 137	Wellford	SC	Solar	Intermediate	Yes	15.25
Facility 138	Spartanburg	SC	Solar	Intermediate	Yes	11.4
Facility 139	Greenville	SC	Solar	Intermediate	Yes	1.5
Facility 140	Greenville	SC	Solar	Intermediate	Yes	4.5
Facility 141	Taylors	SC	Solar	Intermediate	Yes	8.8
Facility 142	Clover	SC	Solar	Intermediate	Yes	2.85
Facility 143	Greenville	SC	Solar	Intermediate	Yes	20
Facility 144	Greenwood	SC	Solar	Intermediate	Yes	2.76
Facility 145	Inman	SC	Solar	Intermediate	Yes	6
Facility 146	Fort Mill	SC	Solar	Intermediate	Yes	7.6
Facility 147	Anderson	SC	Solar	Intermediate	Yes	2.75
Facility 148	Greer	SC	Solar	Intermediate	Yes	3.02
Facility 149	Blacksburg	SC	Solar	Intermediate	Yes	2.4
Facility 150	Travelers Rest	SC	Solar	Intermediate	Yes	7.6

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 151	Cowpens	SC	Solar	Intermediate	Yes	0.74
Facility 152	Greenville	SC	Solar	Intermediate	Yes	6
Facility 153	Taylors	SC	Solar	Intermediate	Yes	2
Facility 154	Fountain Inn	SC	Solar	Intermediate	Yes	6
Facility 155	Marietta	SC	Solar	Intermediate	Yes	4.5
Facility 156	Fort Mill	SC	Solar	Intermediate	Yes	4.52
Facility 157	Liberty Hill	SC	Solar	Intermediate	Yes	7.7
Facility 158	Roebuck	SC	Solar	Intermediate	Yes	6
Facility 159	Fountain Inn	SC	Solar	Intermediate	Yes	2.53
Facility 160	Simponville	SC	Solar	Intermediate	Yes	0.86
Facility 161	Greenwood	SC	Solar	Intermediate	Yes	5
Facility 162	Lancaster	SC	Solar	Intermediate	Yes	3.6
Facility 163	Lancaster	SC	Solar	Intermediate	Yes	1.64
Facility 164	Greenville	SC	Solar	Intermediate	Yes	10.5
Facility 165	Spartanburg	SC	Solar	Intermediate	Yes	2.8
Facility 166	Easley	SC	Solar	Intermediate	Yes	7.6
Facility 167	Simpsonville	SC	Solar	Intermediate	Yes	1.44
Facility 168	Travelers Rest	SC	Solar	Intermediate	Yes	4.357
Facility 169	Greenville	SC	Solar	Intermediate	Yes	7.74
Facility 170	Tega Cay	SC	Solar	Intermediate	Yes	7.358
Facility 171	Chesnee	SC	Solar	Intermediate	Yes	15.4
Facility 172	Moore	SC	Solar	Intermediate	Yes	8
Facility 173	Simpsonville	SC	Solar	Intermediate	Yes	5
Facility 174	Sunset	SC	Solar	Intermediate	Yes	9
Facility 175	Clover	SC	Solar	Intermediate	Yes	8
Facility 176	Piedmont	SC	Solar	Intermediate	Yes	7
Facility 177	Lyman	SC	Solar	Intermediate	Yes	8
Facility 178	Travelers Rest	SC	Solar	Intermediate	Yes	4.2
Facility 179	Greenville	SC	Solar	Intermediate	Yes	13.6
Facility 180	Spartanburg	SC	Solar	Intermediate	Yes	13.25
Facility 181	Simpsonville	SC	Solar	Intermediate	Yes	6.5
Facility 182	Greenville	SC	Solar	Intermediate	Yes	14
Facility 183	Mauldin	SC	Solar	Intermediate	Yes	5
Facility 184	Clemson	SC	Solar	Intermediate	Yes	4
Facility 185	Spartanburg	SC	Solar	Intermediate	Yes	0.86
Facility 186	Spartanburg	SC	Solar	Intermediate	Yes	6
Facility 187	Spartanburg	SC	Solar	Intermediate	Yes	3.75
Facility 188	Williamston	SC	Solar	Intermediate	Yes	6.752
Facility 189	Greer	SC	Solar	Intermediate	Yes	8.033
Facility 190	Taylors	SC	Solar	Intermediate	Yes	0.76
Facility 191	Gaffney	SC	Solar	Intermediate	Yes	9.443
Facility 192	Seneca	SC	Solar	Intermediate	Yes	10.08
Facility 193	Duncan	SC	Solar	Intermediate	Yes	5
Facility 194	Greenville	SC	Solar	Intermediate	Yes	4.25
Facility 195	Taylors	SC	Solar	Intermediate	Yes	4.3
Facility 196	Anderson	SC	Solar	Intermediate	Yes	10.5
Facility 197	Greenville	SC	Solar	Intermediate	Yes	6
Facility 198	Spartanburg	SC	Solar	Intermediate	Yes	8.75
Facility 199	Greenville	SC	Solar	Intermediate	Yes	3.8

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 200	Gaffney	SC	Other	Intermediate	Yes	0
Facility 201	Greenville	SC	Solar	Intermediate	Yes	29.826
Facility 202	Pelzer	SC	Solar	Intermediate	Yes	10
Facility 203	Inman	SC	Solar	Intermediate	Yes	10.6
Facility 204	Greenville	SC	Solar	Intermediate	Yes	4.6
Facility 205	Greenville	SC	Solar	Intermediate	Yes	6
Facility 206	Fort Mill	SC	Solar	Intermediate	Yes	7.6
Facility 207	York	SC	Solar	Intermediate	Yes	0.86
Facility 208	Cleveland	SC	Solar	Intermediate	Yes	3.12
Facility 209	Greenville	SC	Solar	Intermediate	Yes	100
Facility 210	Greenville	SC	Solar	Intermediate	Yes	9
Facility 211	Greenville	SC	Solar	Intermediate	Yes	20
Facility 212	Greenville	SC	Solar	Intermediate	Yes	4.3
Facility 213	Campobello	SC	Solar	Intermediate	Yes	2.15
Facility 214	Taylors	SC	Solar	Intermediate	Yes	6
Facility 215	Greenville	SC	Solar	Intermediate	Yes	4.528
Facility 216	Spartanburg	SC	Solar	Intermediate	Yes	4.29
Facility 217	Greenville	SC	Solar	Intermediate	Yes	7
Facility 218	Greenville	SC	Solar	Intermediate	Yes	6
Facility 219	Gray Court	SC	Solar	Intermediate	Yes	5.64
Facility 220	Simpsonville	SC	Solar	Intermediate	Yes	9.25
Facility 221	Greenville	SC	Solar	Intermediate	Yes	6
Facility 222	Greenville	SC	Solar	Intermediate	Yes	6
Facility 223	Greenville	SC	Solar	Intermediate	Yes	6
Facility 224	Moore	SC	Solar	Intermediate	Yes	3
Facility 225	Greenville	SC	Solar	Intermediate	Yes	4.53
Facility 226	Edgemoore	SC	Solar	Intermediate	Yes	7.6
Facility 227	Greenville	SC	Solar	Intermediate	Yes	24
Facility 228	Greer	SC	Landfill Gas	Intermediate	Yes	3200
Facility 229	Greenville	SC	Solar	Intermediate	Yes	30.1
Facility 230	Greenville	SC	Solar	Intermediate	Yes	2.58
Facility 231	Williamston	SC	Solar	Intermediate	Yes	3.44
Facility 232	Inman	SC	Solar	Intermediate	Yes	1
Facility 233	Anderson	SC	Solar	Intermediate	Yes	7
Facility 234	Fort Mill	SC	Solar	Intermediate	Yes	8.492
Facility 235	Greenville	SC	Solar	Intermediate	Yes	10.238
Facility 236	Simpsonville	SC	Solar	Intermediate	Yes	6
Facility 237	Lancaster	SC	Solar	Intermediate	Yes	9.339
Facility 238	Greenville	SC	Solar	Intermediate	Yes	7.2
Facility 239	Piedmont	SC	Solar	Intermediate	Yes	7.5
Facility 240	Williamston	SC	Solar	Intermediate	Yes	6.88
Facility 241	Greenville	SC	Solar	Intermediate	Yes	5.16
Facility 242	Belton	SC	Solar	Intermediate	Yes	14
Facility 243	Glendale	SC	Solar	Intermediate	Yes	2.4
Facility 244	Greenville	SC	Solar	Intermediate	Yes	4.6
Facility 245	Walhalla	SC	Solar	Intermediate	Yes	3.38
Facility 246	Fort Mill	SC	Solar	Intermediate	Yes	
Facility 247	Greenwood	SC	Solar	Intermediate	Yes	9.6
Facility 248	Anderson	SC	Solar	Intermediate	Yes	12
Facility 249	Greenville	SC	Solar	Intermediate	Yes	4.357
Facility 250	Lyman	SC	Solar	Intermediate	Yes	12

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 251	Greenville	SC	Solar	Intermediate	Yes	10
Facility 252	Taylors	SC	Solar	Intermediate	Yes	10
Facility 253	Moore	SC	Solar	Intermediate	Yes	7.2
Facility 254	Enoree	SC	Hydroelectric	Baseload	Yes	1600
Facility 255	Fountain Inn	SC	Solar	Intermediate	Yes	49
Facility 256	West Union	SC	Solar	Intermediate	Yes	56.7
Facility 257	Chester	SC	Solar	Intermediate	Yes	3.5
Facility 258	Pelzer	SC	Solar	Intermediate	Yes	1.944
Facility 259	Simpsonville	SC	Solar	Intermediate	Yes	3.75
Facility 260	Seneca	SC	Solar	Intermediate	Yes	5
Facility 261	Fort Mill	SC	Solar	Intermediate	Yes	8.816
Facility 262	Greenville	SC	Solar	Intermediate	Yes	7.6
Facility 263	Taylors	SC	Solar	Intermediate	Yes	5.5
Facility 264	Salem	SC	Solar	Intermediate	Yes	10.32
Facility 265	Chesnee	SC	Solar	Intermediate	Yes	1.44
Facility 266	Fort Mill	SC	Solar	Intermediate	Yes	7.6
Facility 267	Central	SC	Solar	Intermediate	Yes	8.5
Facility 268	Greenville	SC	Solar	Intermediate	Yes	4.3
Facility 269	Clover	SC	Solar	Intermediate	Yes	2.1
Facility 270	Spartanburg	SC	Solar	Intermediate	Yes	13.8
Facility 271	Moore	SC	Solar	Intermediate	Yes	4.3
Facility 272	Greer	SC	Solar	Intermediate	Yes	2.5
Facility 273	Moore	SC	Solar	Intermediate	Yes	3.44
Facility 274	Simpsonville	SC	Solar	Intermediate	Yes	3.01
Facility 275	Spartanburg	SC	Solar	Intermediate	Yes	0.76
Facility 276	Donalds	SC	Solar	Intermediate	Yes	10
Facility 277	Hodges	SC	Solar	Intermediate	Yes	12
Facility 278	Heath Springs	SC	Solar	Intermediate	Yes	6
Facility 279	Clover	SC	Solar	Intermediate	Yes	20
Facility 280	Greenville	SC	Solar	Intermediate	Yes	18.06
Facility 281	Greenville	SC	Solar	Intermediate	Yes	11.5
Facility 282	Anderson	SC	Solar	Intermediate	Yes	9.6
Facility 283	Ninety Six	SC	Solar	Intermediate	Yes	8
Facility 284	Maudlin	SC	Solar	Intermediate	Yes	4.3
Facility 285	Gaffney	SC	Solar	Intermediate	Yes	6.48
Facility 286	Boiling Springs	SC	Solar	Intermediate	Yes	5
Facility 287	Spartanburg	SC	Solar	Intermediate	Yes	0.19
Facility 288	Greenville	SC	Solar	Intermediate	Yes	3.44
Facility 289	Salem	SC	Solar	Intermediate	Yes	4
Facility 290	Piedmont	SC	Solar	Intermediate	Yes	2.5
Facility 291	Central	SC	Solar	Intermediate	Yes	9
Facility 292	Moore	SC	Solar	Intermediate	Yes	1
Facility 293	Greenwood	SC	Solar	Intermediate	Yes	2.58
Facility 294	Fountain Inn	SC	Solar	Intermediate	Yes	18
Facility 295	Piedmont	SC	Solar	Intermediate	Yes	6.75
Facility 296	Greenville	SC	Solar	Intermediate	Yes	3
Facility 297	Greenville	SC	Solar	Intermediate	Yes	9
Facility 298	Greer	SC	Solar	Intermediate	Yes	12
Facility 299	Gaffney	SC	Solar	Intermediate	Yes	4.3

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 300	Anderson	SC	Solar	Intermediate	Yes	5
Facility 301	Greenville	SC	Solar	Intermediate	Yes	12.74
Facility 302	Mauldin	SC	Solar	Intermediate	Yes	4.25
Facility 303	Chester	SC	Solar	Intermediate	Yes	15.2
Facility 304	Ware Shoals	SC	Solar	Intermediate	Yes	1.94
Facility 305	Clemson	SC	Solar	Intermediate	Yes	7.6
Facility 306	Greenville	SC	Solar	Intermediate	Yes	
Facility 307	Taylors	SC	Solar	Intermediate	Yes	6
Facility 308	Inman	SC	Solar	Intermediate	Yes	7.75
Facility 309	Six Mile	SC	Solar	Intermediate	Yes	1.05
Facility 310	Easley	SC	Solar	Intermediate	Yes	19
Facility 311	Greer	SC	Solar	Intermediate	Yes	1
Facility 312	Travelers Rest	SC	Solar	Intermediate	Yes	15.2
Facility 313	Greenville	SC	Solar	Intermediate	Yes	8.75
Facility 314	Greenville	SC	Solar	Intermediate	Yes	4.32
Facility 315	Simpsonville	SC	Solar	Intermediate	Yes	10.56
Facility 316	Greenville	SC	Solar	Intermediate	Yes	5.886
Facility 317	Tega Cay	SC	Solar	Intermediate	Yes	5.41
Facility 318	Central	SC	Solar	Intermediate	Yes	13
Facility 319	Startex	SC	Solar	Intermediate	Yes	7.5
Facility 320	Fort Mill	SC	Solar	Intermediate	Yes	7.5
Facility 321	Williamston	SC	Solar	Intermediate	Yes	7.7
Facility 322	Greenville	SC	Solar	Intermediate	Yes	7.75
Facility 323	Fountain Inn	SC	Solar	Intermediate	Yes	7.75
Facility 324	Piedmont	SC	Solar	Intermediate	Yes	8
Facility 325	Piedmont	SC	Solar	Intermediate	Yes	4.84
Facility 326	Greenville	SC	Solar	Intermediate	Yes	3
Facility 327	Greenville	SC	Solar	Intermediate	Yes	8.5
Facility 328	Spartanburg	SC	Solar	Intermediate	Yes	10.75
Facility 329	Boiling Springs	SC	Solar	Intermediate	Yes	15.5
Facility 330	Tega Cay	SC	Solar	Intermediate	Yes	3.7
Facility 331	Mcconnells	SC	Solar	Intermediate	Yes	4
Facility 332	Ninety Six	SC	Solar	Intermediate	Yes	6
Facility 333	Belton	SC	Solar	Intermediate	Yes	5
Facility 334	Greenville	SC	Solar	Intermediate	Yes	5
Facility 335	Greer	SC	Solar	Intermediate	Yes	11.4
Facility 336	Pacolet	SC	Solar	Intermediate	Yes	1.12
Facility 337	Inman	SC	Solar	Intermediate	Yes	2.9
Facility 338	Simpsonville	SC	Solar	Intermediate	Yes	3.44
Facility 339	Inman	SC	Solar	Intermediate	Yes	13.25
Facility 340	Central	SC	Solar	Intermediate	Yes	4.2
Facility 341	Ware Shoals	SC	Solar	Intermediate	Yes	3.96
Facility 342	Central	SC	Solar	Intermediate	Yes	12.6
Facility 343	Central	SC	Solar	Intermediate	Yes	2.62
Facility 344	Clover	SC	Solar	Intermediate	Yes	5
Facility 345	Salem	SC	Solar	Intermediate	Yes	6.85
Facility 346	Mcconnells	SC	Solar	Intermediate	Yes	13.6
Facility 347	Sharon	SC	Solar	Intermediate	Yes	2.99
Facility 348	Anderson	SC	Solar	Intermediate	Yes	4.2
Facility 349	Greenville	SC	Solar	Intermediate	Yes	5.89
Facility 350	Greenville	SC	Solar	Intermediate	Yes	3.36

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 351	Seneca	SC	Solar	Intermediate	Yes	5
Facility 352	Simpsonville	SC	Solar	Intermediate	Yes	8.58
Facility 353	Six Mile	SC	Solar	Intermediate	Yes	4
Facility 354	Piedmont	SC	Solar	Intermediate	Yes	1.5
Facility 355	Pelzer	SC	Solar	Intermediate	Yes	2.94
Facility 356	Greenville	SC	Solar	Intermediate	Yes	6.665
Facility 357	Greenville	SC	Solar	Intermediate	Yes	3.8
Facility 358	Greenville	SC	Solar	Intermediate	Yes	7.1
Facility 359	Ridgeway	SC	Solar	Intermediate	Yes	10
Facility 360	Anderson	SC	Solar	Intermediate	Yes	9.5
Facility 361	Fort Mill	SC	Solar	Intermediate	Yes	5
Facility 362	Piedmont	SC	Solar	Intermediate	Yes	1.727
Facility 363	Gaffney	SC	Solar	Intermediate	Yes	10
Facility 364	Pickens	SC	Solar	Intermediate	Yes	15.6
Facility 365	Greenville	SC	Solar	Intermediate	Yes	6.6
Facility 366	Pelzer	SC	Solar	Intermediate	Yes	1.944
Facility 367	York	SC	Solar	Intermediate	Yes	17
Facility 368	Simpsonville	SC	Solar	Intermediate	Yes	10.75
Facility 369	Greenville	SC	Solar	Intermediate	Yes	6.6
Facility 370	Fort Mill	SC	Solar	Intermediate	Yes	7.6
Facility 371	Boiling Springs	SC	Solar	Intermediate	Yes	6.6
Facility 372	Greenville	SC	Solar	Intermediate	Yes	14
Facility 373	Tega Cay	SC	Solar	Intermediate	Yes	7.6
Facility 374	Greenville	SC	Solar	Intermediate	Yes	5
Facility 375	Fort Mill	SC	Solar	Intermediate	Yes	6.522
Facility 376	Fountain Inn	SC	Solar	Intermediate	Yes	12
Facility 377	Lancaster	SC	Solar	Intermediate	Yes	7.7
Facility 378	Williamston	SC	Solar	Intermediate	Yes	18
Facility 379	Greenville	SC	Solar	Intermediate	Yes	16.34
Facility 380	Walhalla	SC	Solar	Intermediate	Yes	4.3
Facility 381	Walhalla	SC	Solar	Intermediate	Yes	8.385
Facility 382	Roebuck	SC	Solar	Intermediate	Yes	7.6
Facility 383	Spartanburg	SC	Solar	Intermediate	Yes	4.75
Facility 384	Mauldin	SC	Solar	Intermediate	Yes	10
Facility 385	Greenville	SC	Solar	Intermediate	Yes	6
Facility 386	Greer	SC	Solar	Intermediate	Yes	20
Facility 387	Clover	SC	Solar	Intermediate	Yes	7.6
Facility 388	Woodruff	SC	Solar	Intermediate	Yes	13.55
Facility 389	Lancaster	SC	Solar	Intermediate	Yes	2
Facility 390	Lancaster	SC	Solar	Intermediate	Yes	9
Facility 391	Lyman	SC	Solar	Intermediate	Yes	8
Facility 392	Hodges	SC	Solar	Intermediate	Yes	13.08
Facility 393	Gaffney	SC	Solar	Intermediate	Yes	3
Facility 394	Inman	SC	Solar	Intermediate	Yes	12.6
Facility 395	Greenville	SC	Solar	Intermediate	Yes	1.296
Facility 396	Simpsonsville	SC	Solar	Intermediate	Yes	1.935
Facility 397	Enoree	SC	Biomass	Intermediate	Yes	3200
Facility 398	Pacolet	SC	Hydroelectric	Baseload	Yes	800
Facility 399	Lockhart	SC	Other	Intermediate	Yes	800

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 400	Pacolet	SC	Hydroelectric	Baseload	Yes	
Facility 401	Wellford	SC	Landfill Gas	Intermediate	Yes	1600
Facility 402	Simpsonville	SC	Solar	Intermediate	Yes	11
Facility 403	Campobello	SC	Solar	Intermediate	Yes	3.85
Facility 404	Campobello	SC	Solar	Intermediate	Yes	5.59
Facility 405	Taylors	SC	Solar	Intermediate	Yes	5.5
Facility 406	Greenville	SC	Solar	Intermediate	Yes	3.44
Facility 407	Boiling Springs	SC	Solar	Intermediate	Yes	8
Facility 408	Simpsonville	SC	Solar	Intermediate	Yes	4
Facility 409	Fort Mill	SC	Solar	Intermediate	Yes	7.7
Facility 410	Gaffney	SC	Solar	Intermediate	Yes	9.365
Facility 411	Chesnee	SC	Solar	Intermediate	Yes	0.86
Facility 412	Moore	SC	Solar	Intermediate	Yes	6.25
Facility 413	Pelzer	SC	Solar	Intermediate	Yes	4
Facility 414	Inman	SC	Solar	Intermediate	Yes	15
Facility 415	Piedmont	SC	Solar	Intermediate	Yes	1.5
Facility 416	Greenville	SC	Solar	Intermediate	Yes	7.5
Facility 417	Greenville	SC	Solar	Intermediate	Yes	6
Facility 418	Gray Court	SC	Solar	Intermediate	Yes	8.6
Facility 419	Greenville	SC	Solar	Intermediate	Yes	17.52
Facility 420	Spartanburg	SC	Solar	Intermediate	Yes	2.85
Facility 421	Greenville	SC	Solar	Intermediate	Yes	10
Facility 422	Seneca	SC	Solar	Intermediate	Yes	2
Facility 423	Greenville	SC	Solar	Intermediate	Yes	7.6
Facility 424	Woodruff	SC	Solar	Intermediate	Yes	7.68
Facility 425	Simpsonville	SC	Solar	Intermediate	Yes	6.5
Facility 426	Lyman	SC	Solar	Intermediate	Yes	8.5
Facility 427	Gaffney	SC	Solar	Intermediate	Yes	8
Facility 428	Greenville	SC	Solar	Intermediate	Yes	11.25
Facility 429	Moore	SC	Solar	Intermediate	Yes	2.37
Facility 430	Taylors	SC	Solar	Intermediate	Yes	10
Facility 431	Simpsonville	SC	Solar	Intermediate	Yes	5.25
Facility 432	Clover	SC	Solar	Intermediate	Yes	4
Facility 433	Greenville	SC	Solar	Intermediate	Yes	3
Facility 434	Honea Path	SC	Solar	Intermediate	Yes	3.82
Facility 435	Greenville	SC	Solar	Intermediate	Yes	7.6
Facility 436	Anderson	SC	Solar	Intermediate	Yes	12.25
Facility 437	Catawba	SC	Solar	Intermediate	Yes	2.612
Facility 438	Fountain Inn	SC	Solar	Intermediate	Yes	8.682
Facility 439	Greenville	SC	Solar	Intermediate	Yes	14.7
Facility 440	Spartanburg	SC	Solar	Intermediate	Yes	6.5
Facility 441	Greenville	SC	Solar	Intermediate	Yes	6.6
Facility 442	Greenville	SC	Solar	Intermediate	Yes	15
Facility 443	Greenville	SC	Solar	Intermediate	Yes	11.4
Facility 444	Spartanburg	SC	Solar	Intermediate	Yes	0.19
Facility 445	Greenville	SC	Solar	Intermediate	Yes	4.3
Facility 446	Duncan	SC	Solar	Intermediate	Yes	6
Facility 447	Greenwood	SC	Solar	Intermediate	Yes	9.6
Facility 448	Greenville	SC	Solar	Intermediate	Yes	8.25
Facility 449	Mauldin	SC	Solar	Intermediate	Yes	6.75
Facility 450	Spartanburg	SC	Solar	Intermediate	Yes	0.86

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 451	Spartanburg	SC	Solar	Intermediate	Yes	1
Facility 452	Simpsonville	SC	Solar	Intermediate	Yes	10
Facility 453	Simpsonville	SC	Solar	Intermediate	Yes	10
Facility 454	Spartanburg	SC	Solar	Intermediate	Yes	1.92
Facility 455	Anderson	SC	Solar	Intermediate	Yes	13.8
Facility 456	Spartanburg	SC	Solar	Intermediate	Yes	8
Facility 457	Anderson	SC	Solar	Intermediate	Yes	0.96
Facility 458	Clover	SC	Solar	Intermediate	Yes	10
Facility 459	Travelers Rest	SC	Solar	Intermediate	Yes	8.33
Facility 460	Williamston	SC	Solar	Intermediate	Yes	2.5
Facility 461	Campobello	SC	Solar	Intermediate	Yes	4.25
Facility 462	Inman	SC	Solar	Intermediate	Yes	3.78
Facility 463	Piedmont	SC	Solar	Intermediate	Yes	1.04
Facility 464	Pendleton	SC	Solar	Intermediate	Yes	4.357
Facility 465	Belton	SC	Solar	Intermediate	Yes	6.144
Facility 466	Lyman	SC	Solar	Intermediate	Yes	0.74
Facility 467	Fountain Inn	SC	Solar	Intermediate	Yes	8
Facility 468	Spartanburg	SC	Solar	Intermediate	Yes	8
Facility 469	Duncan	SC	Solar	Intermediate	Yes	6.75
Facility 470	Greenville	SC	Solar	Intermediate	Yes	4.15
Facility 471	Seneca	SC	Solar	Intermediate	Yes	11.4
Facility 472	Fort Mill	SC	Solar	Intermediate	Yes	6
Facility 473	Greenville	SC	Solar	Intermediate	Yes	5
Facility 474	Greenville	SC	Solar	Intermediate	Yes	10
Facility 475	Greenville	SC	Solar	Intermediate	Yes	14
Facility 476	Laurens	SC	Hydroelectric	Baseload	Yes	1500
Facility 477	Belton	SC	Hydroelectric	Baseload	Yes	3500
Facility 478	Greenville	SC	Hydroelectric	Baseload	Yes	2400
Facility 479	Spartanburg	SC	Solar	Intermediate	Yes	10.95
Facility 480	Taylors	SC	Solar	Intermediate	Yes	6.6
Facility 481	Piedmont	SC	Solar	Intermediate	Yes	11.75
Facility 482	Sharon	SC	Solar	Intermediate	Yes	2.5
Facility 483	Simpsonville	SC	Solar	Intermediate	Yes	18
Facility 484	Taylors	SC	Solar	Intermediate	Yes	1.72
Facility 485	Greenville	SC	Solar	Intermediate	Yes	3.655
Facility 486	Greenville	SC	Solar	Intermediate	Yes	5
Facility 487	Greenville	SC	Solar	Intermediate	Yes	3.8
Facility 488	Cleveland	SC	Solar	Intermediate	Yes	4.8
Facility 489	Greenville	SC	Solar	Intermediate	Yes	3.01
Facility 490	Ninety Six	SC	Solar	Intermediate	Yes	7.52
Facility 491	Seneca	SC	Solar	Intermediate	Yes	10
Facility 492	Spartanburg	SC	Solar	Intermediate	Yes	8
Facility 493	Gaffney	SC	Solar	Intermediate	Yes	4
Facility 494	Greenville	SC	Solar	Intermediate	Yes	5.71
Facility 495	Williamston	SC	Hydroelectric	Baseload	Yes	3300
Facility 496	Anderson	SC	Hydroelectric	Baseload	Yes	2020
Facility 497	Salem	SC	Solar	Intermediate	Yes	2.15
Facility 498	Spartanburg	SC	Solar	Intermediate	Yes	5.5
Facility 499	Simpsonville	SC	Solar	Intermediate	Yes	3.1

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 500	Simpsonville	SC	Solar	Intermediate	Yes	10.32
Facility 501	Gaffney	SC	Solar	Intermediate	Yes	1.72
Facility 502	Greenville	SC	Solar	Intermediate	Yes	1.72
Facility 503	Easley	SC	Solar	Intermediate	Yes	6.58
Facility 504	Rock Hill	SC	Solar	Intermediate	Yes	6.522
Facility 505	Greenville	SC	Solar	Intermediate	Yes	2.38
Facility 506	Boiling Springs	SC	Solar	Intermediate	Yes	3.84
Facility 507	Anderson	SC	Solar	Intermediate	Yes	5
Facility 508	Roebuck	SC	Solar	Intermediate	Yes	4
Facility 509	Chesnee	SC	Solar	Intermediate	Yes	1.47
Facility 510	Fountain Inn	SC	Solar	Intermediate	Yes	6.8
Facility 511	Greenville	SC	Solar	Intermediate	Yes	6
Facility 512	Spartanburg	SC	Solar	Intermediate	Yes	11.6
Facility 513	Simpsonville	SC	Solar	Intermediate	Yes	10.316
Facility 514	Greenville	SC	Solar	Intermediate	Yes	4
Facility 515	Spartanburg	SC	Solar	Intermediate	Yes	13.2
Facility 516	Greenville	SC	Solar	Intermediate	Yes	15.75
Facility 517	Inman	SC	Solar	Intermediate	Yes	2.88
Facility 518	Chester	SC	Solar	Intermediate	Yes	7
Facility 519	Fort Mill	SC	Solar	Intermediate	Yes	10.97
Facility 520	Greenville	SC	Solar	Intermediate	Yes	6.72
Facility 521	Sharon	SC	Solar	Intermediate	Yes	2.5
Facility 522	Piedmont	SC	Solar	Intermediate	Yes	4
Facility 523	Spartanburg	SC	Solar	Intermediate	Yes	14
Facility 524	Catawba	SC	Solar	Intermediate	Yes	2.5
Facility 525	Anderson	SC	Solar	Intermediate	Yes	11
Facility 526	Greenville	SC	Solar	Intermediate	Yes	6
Facility 527	Travelers Rest	SC	Solar	Intermediate	Yes	9.46
Facility 528	Roebuck	SC	Solar	Intermediate	Yes	5
Facility 529	Spartanburg	SC	Solar	Intermediate	Yes	2.5
Facility 530	Laurens	SC	Solar	Intermediate	Yes	10
Facility 531	Travelers Rest	SC	Solar	Intermediate	Yes	3.01
Facility 532	Williamston	SC	Solar	Intermediate	Yes	2.38
Facility 533	Mauldin	SC	Solar	Intermediate	Yes	9
Facility 534	Greer	SC	Solar	Intermediate	Yes	7
Facility 535	Duncan	SC	Solar	Intermediate	Yes	6
Facility 536	Spartanburg	SC	Solar	Intermediate	Yes	6.25
Facility 537	Simpsonville	SC	Solar	Intermediate	Yes	7
Facility 538	Cowpens	SC	Solar	Intermediate	Yes	4
Facility 539	Simpsonville	SC	Solar	Intermediate	Yes	8
Facility 540	Greer	SC	Solar	Intermediate	Yes	4
Facility 541	Anderson	SC	Solar	Intermediate	Yes	7
Facility 542	Anderson	SC	Solar	Intermediate	Yes	4.25
Facility 543	Rock Hill	SC	Solar	Intermediate	Yes	10
Facility 544	Boiling Spgs	SC	Solar	Intermediate	Yes	4
Facility 545	Chesnee	SC	Solar	Intermediate	Yes	6
Facility 546	Fort Mill	SC	Solar	Intermediate	Yes	4.72
Facility 547	Taylors	SC	Solar	Intermediate	Yes	8
Facility 548	Taylors	SC	Solar	Intermediate	Yes	13
Facility 549	York	SC	Solar	Intermediate	Yes	2.58
Facility 550	Chester	SC	Solar	Intermediate	Yes	2.47

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 551	Fort Mill	SC	Solar	Intermediate	Yes	5.16
Facility 552	Greenville	SC	Solar	Intermediate	Yes	18
Facility 553	Greer	SC	Solar	Intermediate	Yes	10
Facility 554	Clover	SC	Solar	Intermediate	Yes	3.75
Facility 555	Greenville	SC	Solar	Intermediate	Yes	11.4
Facility 556	Spartanburg	SC	Solar	Intermediate	Yes	5
Facility 557	Anderson	SC	Solar	Intermediate	Yes	12.25
Facility 558	Greenville	SC	Solar	Intermediate	Yes	6.75
Facility 559	Fort Lawn	SC	Solar	Intermediate	Yes	8.75
Facility 560	Pendelton	SC	Solar	Intermediate	Yes	20.65
Facility 561	Mauldin	SC	Solar	Intermediate	Yes	10
Facility 562	Fountain Inn	SC	Solar	Intermediate	Yes	9.25
Facility 563	Greenville	SC	Solar	Intermediate	Yes	9.25
Facility 564	Greer	SC	Solar	Intermediate	Yes	8.49
Facility 565	Greenville	SC	Solar	Intermediate	Yes	11.75
Facility 566	Duncan	SC	Solar	Intermediate	Yes	7.36
Facility 567	Taylors	SC	Solar	Intermediate	Yes	9
Facility 568	Greer	SC	Solar	Intermediate	Yes	6.665
Facility 569	Campobello	SC	Solar	Intermediate	Yes	9
Facility 570	Belton	SC	Solar	Intermediate	Yes	5.5
Facility 571	Greenville	SC	Solar	Intermediate	Yes	5.5
Facility 572	Greenville	SC	Solar	Intermediate	Yes	7.5
Facility 573	Boiling Springs	SC	Solar	Intermediate	Yes	3
Facility 574	Lyman	SC	Solar	Intermediate	Yes	5
Facility 575	Spartanburg	SC	Solar	Intermediate	Yes	10
Facility 576	Duncan	SC	Solar	Intermediate	Yes	2
Facility 577	Greenville	SC	Solar	Intermediate	Yes	4.68
Facility 578	Clover	SC	Solar	Intermediate	Yes	0.7
Facility 579	Marietta	SC	Solar	Intermediate	Yes	7
Facility 580	Fort Mill	SC	Solar	Intermediate	Yes	7.221
Facility 581	Greenville	SC	Solar	Intermediate	Yes	4.2
Facility 582	Spartanburg	SC	Solar	Intermediate	Yes	10
Facility 583	Ridgeway	SC	Solar	Intermediate	Yes	2.5
Facility 584	Boling Spgs	SC	Solar	Intermediate	Yes	3.3
Facility 585	Simpsonville	SC	Solar	Intermediate	Yes	2.5
Facility 586	Greenville	SC	Solar	Intermediate	Yes	6.25
Facility 587	Greenville	SC	Solar	Intermediate	Yes	4.3
Facility 588	Cowpens	SC	Solar	Intermediate	Yes	11.6
Facility 589	Spartanburg	SC	Solar	Intermediate	Yes	5.16
Facility 590	Inman	SC	Solar	Intermediate	Yes	7.6
Facility 591	Greenville	SC	Solar	Intermediate	Yes	2.5
Facility 592	Piedmont	SC	Solar	Intermediate	Yes	19.4
Facility 593	Reidville	SC	Solar	Intermediate	Yes	2.2
Facility 594	Reidville	SC	Wind	Intermediate	Yes	1.2
Facility 595	Chesnee	SC	Hydroelectric	Baseload	Yes	1000
Facility 596	Ridgeway	SC	Solar	Intermediate	Yes	11.4
Facility 597	Seneca	SC	Solar	Intermediate	Yes	5
Facility 598	Taylors	SC	Solar	Intermediate	Yes	6.25
Facility 599	Mauldin	SC	Solar	Intermediate	Yes	10.25

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 600	Laurens	SC	Solar	Intermediate	Yes	3.5
Facility 601	Moore	SC	Solar	Intermediate	Yes	13.25
Facility 602	Simpsonville	SC	Solar	Intermediate	Yes	12.94
Facility 603	Lancaster	SC	Solar	Intermediate	Yes	5
Facility 604	Greenville	SC	Solar	Intermediate	Yes	15
Facility 605	Simpsonville	SC	Solar	Intermediate	Yes	5
Facility 606	Greer	SC	Solar	Intermediate	Yes	6
Facility 607	Greenville	SC	Solar	Intermediate	Yes	9.75
Facility 608	Greer	SC	Solar	Intermediate	Yes	8
Facility 609	Lyman	SC	Solar	Intermediate	Yes	6
Facility 610	Greenville	SC	Solar	Intermediate	Yes	0.76
Facility 611	Spartanburg	SC	Solar	Intermediate	Yes	0.86
Facility 612	Simpsonville	SC	Solar	Intermediate	Yes	5.75
Facility 613	Campobello	SC	Solar	Intermediate	Yes	6
Facility 614	Greer	SC	Solar	Intermediate	Yes	3
Facility 615	Chesnee	SC	Solar	Intermediate	Yes	10
Facility 616	Greenville	SC	Solar	Intermediate	Yes	16
Facility 617	Greenville	SC	Solar	Intermediate	Yes	9
Facility 618	Greenvillle	SC	Solar	Intermediate	Yes	6.6
Facility 619	Spartanburg	SC	Solar	Intermediate	Yes	5
Facility 620	Taylors	SC	Solar	Intermediate	Yes	13.5
Facility 621	Chesnee	SC	Solar	Intermediate	Yes	10.2
Facility 622	Seneca	SC	Solar	Intermediate	Yes	3.6
Facility 623	Greer	SC	Solar	Intermediate	Yes	20
Facility 624	Anderson	SC	Solar	Intermediate	Yes	5.75
Facility 625	Greenville	SC	Solar	Intermediate	Yes	4
Facility 626	Greer	SC	Solar	Intermediate	Yes	3.5
Facility 627	Chester	SC	Solar	Intermediate	Yes	4.2
Facility 628	Spartanburg	SC	Solar	Intermediate	Yes	7.6
Facility 629	Simpsonville	SC	Solar	Intermediate	Yes	5.16
Facility 630	Travelers Rest	SC	Solar	Intermediate	Yes	10
Facility 631	Rock Hill	SC	Solar	Intermediate	Yes	2.5
Facility 632	Moore	SC	Solar	Intermediate	Yes	12
Facility 633	Clover	SC	Solar	Intermediate	Yes	7
Facility 634	Greenville	SC	Solar	Intermediate	Yes	2.541
Facility 635	Moore	SC	Solar	Intermediate	Yes	1.4
Facility 636	Cleveland	SC	Solar	Intermediate	Yes	8.5
Facility 637	Spartanburg	SC	Solar	Intermediate	Yes	5.078
Facility 638	Inman	SC	Solar	Intermediate	Yes	1.52
Facility 639	Spartanburg	SC	Solar	Intermediate	Yes	6.117
Facility 640	Taylors	SC	Solar	Intermediate	Yes	12.2
Facility 641	Lyman	SC	Solar	Intermediate	Yes	7.2
Facility 642	Rock Hill	SC	Solar	Intermediate	Yes	8.09
Facility 643	Greer	SC	Solar	Intermediate	Yes	9.46
Facility 644	Greenville	SC	Solar	Intermediate	Yes	1.8
Facility 645	Clover	SC	Solar	Intermediate	Yes	2.5
Facility 646	Campobello	SC	Solar	Intermediate	Yes	10
Facility 647	Greenville	SC	Solar	Intermediate	Yes	4.2
Facility 648	Belton	SC	Solar	Intermediate	Yes	2.142
Facility 649	Rock Hill	SC	Solar	Intermediate	Yes	21
Facility 650	Greenville	SC	Solar	Intermediate	Yes	4.15

Facility Name	City/County	State	Primary Fuel Type	Designation	Inclusion in Utility's Resources	Capacity (AC kW)
Facility 651	Greenville	SC	Solar	Intermediate	Yes	9.5
Facility 652	Simpsonville	SC	Solar	Intermediate	Yes	17.75
Facility 653	Simpsonville	SC	Solar	Intermediate	Yes	6
Facility 654	Greenville	SC	Solar	Intermediate	Yes	16.34
Facility 655	Landrum	SC	Solar	Intermediate	Yes	4
Facility 656	Piedmont	SC	Solar	Intermediate	Yes	8.25
Facility 657	Six Mile	SC	Solar	Intermediate	Yes	19
Facility 658	Moore	SC	Solar	Intermediate	Yes	5.232
Facility 659	Greenwood	SC	Solar	Intermediate	Yes	2.49
Facility 660	Spartanburg	SC	Solar	Intermediate	Yes	36
Facility 661	Landrum	SC	Solar	Intermediate	Yes	2.1
Facility 662	Travelers Rest	SC	Solar	Intermediate	Yes	5.16
Facility 663	Taylors	SC	Solar	Intermediate	Yes	5.16
Facility 664	Travelers Rest	SC	Solar	Intermediate	Yes	2.5
Facility 665	Fountain Inn	SC	Solar	Intermediate	Yes	7.6
Facility 666	Pelzer	SC	Solar	Intermediate	Yes	5.4
Facility 667	Belton	SC	Solar	Intermediate	Yes	6
Facility 668	Simpsonville	SC	Solar	Intermediate	Yes	7.2
Facility 669	Williamston	SC	Solar	Intermediate	Yes	2.38
Facility 670	Roebuck	SC	Solar	Intermediate	Yes	2.49
Facility 671	Anderson	SC	Solar	Intermediate	Yes	10.75
Facility 672	Simpsonville	SC	Solar	Intermediate	Yes	12.07
Facility 673	Belton	SC	Solar	Intermediate	Yes	3.4
Facility 674	Whitmire	SC	Solar	Intermediate	Yes	1.92
Facility 675	Fort Lawn	SC	Solar	Intermediate	Yes	16.75
Facility 676	Spartanburg	SC	Solar	Intermediate	Yes	12.6
Facility 677	Taylors	SC	Solar	Intermediate	Yes	5
Facility 678	Fountain Inn	SC	Solar	Intermediate	Yes	9.25
Facility 679	Inman	SC	Solar	Intermediate	Yes	7.6
Facility 680	Greenville	SC	Solar	Intermediate	Yes	23.54
Facility 681	Richburg	SC	Solar	Intermediate	Yes	4.5

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

Table H-5 DEC 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 DEC'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)
DEC	**NC**	Biogas	4	6.3
		Biomass	4	7.1
		Diesel	1	1.5
		Hydroelectric	1	4.0
		Landfill Gas	2	3.0
		Solar	175	709.4
DEC	**NC Total**		**187**	**731.3**
	SC	Landfill Gas	1	4.8
		Solar	80	536.1
DEC	**SC Total**		**81**	**540.9**
DEC Total			**268**	**1272.2**

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 and discusses the adequacy of DEC's transmission system. Table I-1 lists the 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: DEC Transmission Line Additions

	Location		Capacity	Voltage	
Year	**From**	**To**	**MVA**	**KV**	**Comments**
2016	Peach Valley Tie	Riverview Switching Station	N/A	230	Install a switchable 3% series reactor on the Peach Valley – Riverview 230 kV transmission line.
2017	Ripp Switching Station	Riverbend Steam Station	N/A	230	Install new switching station along the Ripp - Riverbend 230kV transmission line to tie in new NTE generation.
2022	Central Tie	Shady Grove Tie	930	230	Reconductor approximately 18 miles of the Central – Shady Grove 230 kV transmission line with bundled 954 ACSR at 120°C.

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, 2016.

(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;

There are presently no new lines, 161 kV and above, under construction in DEC's service area.

DEC Transmission System Adequacy

Duke Energy Carolinas monitors the adequacy and reliability of its transmission system and interconnections through internal analysis and participation in regional reliability groups. Internal transmission planning looks 10 years ahead at available generating resources and projected load to identify transmission system upgrade and expansion requirements. Corrective actions are planned and implemented in advance to ensure continued cost-effective and high-quality service. The DEC transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability. DEC works with DEP, NCEMC and ElectriCities to develop an annual NC Transmission Planning Collaborative (NCTPC) plan for the DEC and DEP 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 DEC's Transmission Planning Guidelines for voltage and thermal loading. The annual screening uses methods that comply with SERC policy and NERC Reliability Standards and the screening results identify the need for future transmission system expansion and upgrades.

Transmission planning and requests for transmission service and generator interconnection are interrelated to the resource planning process. DEC currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning 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.

Southeastern Reliability Corporation (SERC) audits DEC every three years for compliance with NERC Reliability Standards. Specifically, the audit requires DEC 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 DEC in May 2014. The scope of this audit included standards impacting the Transmission Planning area. DEC received "No Findings" from the audit team in the Transmission Planning area.

DEC 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. The reliability groups' 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 have ensured DEC's transmission system is expected to continue 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:
235 MW for North Carolina
60 MW for South Carolina

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

APPENDIX K: CARBON NEUTRAL PLAN

Greenhouse Gas Reduction Compliance Plan – Cliffside Unit 6

On January 29, 2008, the NCDAQ issued the Air Quality Permit to Duke Energy Carolinas for the Cliffside Unit 6. The Permit specifically requires that Duke Energy Carolinas implement a Greenhouse Gas Reduction Plan (Greenhouse Plan), and specifically obligates Duke Energy Carolinas to take the following actions in recognition of NCDAQ's issuance of the Permit for Cliffside Unit 6: (1) retire 800 MW of coal capacity in North Carolina in accordance with the schedule set forth in Table K-1, which is in addition to the retirement of Cliffside Units 1 – 4; (2) accommodate, to the extent practicable, the installation and operations of future carbon control technology; and (3) take additional actions to make Cliffside Unit 6 carbon neutral by 2018.

With regard to obligation (1) identified above, as shown in Table K-1 below, Duke Energy Carolinas has retired 1,299 MW at the following generating units to satisfy the required retirement schedule set forth in the Greenhouse Plan.

Table K-1 - Cumulative Coal Plant Retirements

	Greenhouse Plan Retirement Schedule Capacity in MW	IRP Retirement Schedule Capacity in MW (Appendix B)[1]	Description for IRP Retirement Schedule
by end of 2011		113	Buck 3 & 4
by end of 2012		389	Dan River 1-3
by end of 2013		1099	Riverbend 4 - 7, Buck 5 & 6
by end of 2015	350	1299	Lee 1&2; Note [2]
by end of 2018	800	1299	

[1] In the 2016 IRP, this data appears in Appendix B. References have been updated to match the 2016 IRP.
[2] The IRP Retirement Schedule indicates that the retirements would exceed the Greenhouse Plan by close to 50%.

With respect to obligation (2) listed above, the requirement to build Cliffside Unit 6 to accommodate future carbon technologies has been met by allocating space at the 1100 acre site for this equipment and incorporating practical energy efficiency designs into the plant.

With respect to obligation (3) to render Cliffside Unit 6 carbon neutral by 2018, the proposed plan to achieve this requirement is set forth below. The Greenhouse Gas Reduction Plan states that the plan for carbon neutrality:

may include energy efficiency, carbon free tariffs, purchase of credits, domestic and international offsets, additional retirements or reduction in fossil fuel usage as carbon free generation becomes available, and carbon reduction through the development of smart grid, plug in hybrid electric vehicles or other carbon mitigation projects. Such actions will be included in plans to be filed with the NCUC and will be subject to NCUC approval, including appropriate cost recovery of such actions. In addition, the plans shall be submitted to the Division of Air Quality, which will evaluate the effect of the plans on carbon, and provide its conclusions to the NCUC.

Duke Energy Carolinas included the plan for carbon neutrality in the 2011 IRP in order to satisfy the requirement to file and seek approval of the plan from the NCUC as required by the NC Department of Air Quality Air Permit. The NCUC's Order Approving 2011 Annual Updates to 2010 Biennial Resource Plans and 2011 REPS Compliance Plans issued on May 30, 2012, states that "the Commission is approving the Plan itself as a reasonable path for Duke's compliance with the carbon emission reduction standards of the air quality permit and is not approving any individual specific activities nor expenditures for any activities shown in the Plan."

The estimated emissions reductions required to render Cliffside Unit 6 carbon neutral in 2018 are approximately 5.3 million tons of carbon dioxide (the Emission Reduction Requirement). The Company calculated the estimated emission reductions by estimating the actual tons of carbon dioxide emissions that will be released per year from Cliffside Unit 6 less 681,954 tons of carbon dioxide emissions that was historically generated from Cliffside Units 1 – 4 and will be eliminated by the retirement of these units. (See Table K-2 below.)

Table K-2 - Emission Reduction Requirement

Actions	**Tons of CO_2 Equivalent Emissions**	**Notes**
Cliffside Unit 6	6,000,000	Expected Annual Emissions (based on an approximate 90% capacity factor)
Less Cliffside Units 1 – 4	(681,954)	Average of emissions in 2007 & 2008[1]
Total Increase	**5,318,046**	**Emissions Reduction Requirement**

[1]The emissions attributable to coal plant retirements are identified as the highest two year average CO_2 emissions for the five years prior to the operations of Unit 6 in 2012, consistent with the methodology for calculating emissions for major modification under the Clean Air Act Prevention of Significant Deterioration regulations.

The Company's plan for meeting the Emissions Reductions Requirements includes actions from multiple categories and associated methodologies for determining the offset value known as "Qualifying Actions" (defined below and as further indicated in Table K-3).

For 2018, the Company has identified approximately 8.8 million annual tons of carbon dioxide emissions reductions and a lifetime credit of 600,000 tons of carbon dioxide bio-sequestration as eligible Qualifying Actions (See Table K-3). The Qualifying Actions include the avoidance of carbon dioxide emission releases from coal plant retirements, addition of renewable resources, implementation of energy efficiency measures, nuclear and hydropower capacity upgrades. This also includes the retirement of coal-fired operations at Lee Units 1, 2 and 3 in South Carolina in 2015. In addition, carbon dioxide bio-sequestration offsets from the Greentrees program, which sequesters carbon as trees grow, is identified as a Qualifying Action.

While the reductions associated with retirements for each of the coal plants shall be the same each year, the reductions for the remaining Qualifying Actions will vary based on actual results for each of the categories and the then current system carbon intensity factor. The system carbon intensity factor shall be equal to the actual carbon dioxide emissions of all Company-owned generation dedicated for Duke Energy Carolina customers divided by the megawatt hours generated by those same resources (the "Conversion Factor").

Table K-3 - Qualifying Actions for carbon dioxide emission reductions

Categories	Tons of CO_2 Equivalent Emissions	Methodology Description
Buck 3	216,202	Average of emissions in 2007 & 2008[1]
Buck 4	139,429	Average of emissions in 2007 & 2008[1]
Buck 5	606,837	Average of emissions in 2007 & 2008[1]
Buck 6	653,860	Average of emissions in 2007 & 2008[1]
Riverbend 4	462,314	Average of emissions in 2007 & 2008[1]
Riverbend 5	435,895	Average of emissions in 2007 & 2008[1]
Riverbend 6	684,010	Average of emissions in 2007 & 2008[1]
Riverbend 7	710,023	Average of emissions in 2007 & 2008[1]
Dan River 1	249,900	Average of emissions in 2007 & 2008[1]
Dan River 2	282,944	Average of emissions in 2007 & 2008[1]
Dan River 3	677,334	Average of emissions in 2007 & 2008[1]
Lee 1 [5]	335,583	Average of emissions in 2007 & 2008[1]
Lee 2 [5]	390,965	Average of emissions in 2007 & 2008[1]
Lee 3 [5]	783,658	Average of emissions in 2007 & 2008[1]
Conservation	383.280	In 2018, 958,200 MWH "Conservation and Demand Side Management Programs"[2] is multiplied by a Conversion Factor of 0.40.
Renewable Energy[6]	876.876	In 2018, 989 MW per the Table 5-A.1 "MW Nameplate Capacity".[3] Is multiplied by an assumed 30% (wind), 20% (solar), and 85% (biomass) capacity factor and a Conversion Factor of 0.40.
Bridgewater Hydro	7,997	Indicates 8.75 MW increase in capacity. This is multiplied by a 26% capacity factor and a Conversion Factor of 0.40.
Nuclear Uprates	608,631	Assumed 189 MW of nuclear uprates by June of 2018.[4] Assumed a 92% capacity factor and a Conversion Factor of 0.40.
Total Annual	8,505,738	

[1] The emissions attributable to coal plant retirements are identified as the highest two year average CO_2 emissions for the five years prior to the operations of Unit 6 in 2012, consistent with the methodology for calculating emissions for major modifications under the Clean Air Act Prevention of Significant Deterioration regulations. Company reserves the right to use any credits for reduction of nitrogen oxide, sulfur dioxide and carbon dioxide emissions generated by retirement of units retired under the plan consistent with provisions of State and Federal law.
[2] Conservation Data is from Appendix C of the 2016 IRP. DSM from PROSYM Base Case.
[3] Data is from the Table 5-A.1 of the 2016 IRP. Actual nameplate capacity is 989 MW.
[4] Data is a portion of the total capacity addition on Appendix B of 2014 IRP prior to June 2018.

[5] Lee Units 1, 2 and 3 retired April 15, 2015. Alternatively, Duke Energy converted Lee 3 to natural gas to allow continued operation for peak generation demand only (at a low annual capacity factor). Any CO_2 from operating with natural gas would be subtracted from the reductions shown in the table, but would likely be very small.
[6] The renewable resources used in this calculation only include those utilized for compliance as well as the renewable QF purchases not used for compliance.

As the proposed Plan methodology has been approved, Duke Energy Carolinas shall provide a compliance report in the 2019 IRP filing indicating what Qualifying Actions were used to meet the Emission Reduction Requirement in 2018. The expected Qualifying Actions total 8.5 million tons of emission reductions by 2018. The Company's proposed Qualifying Actions clearly demonstrate that identified reductions can more than exceed the Required Emissions Reduction estimate of 5.3 million tons.

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 and 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
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

Change	Location	Source (Docket and Order Date)	Updated
DEC shall continue to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit.	App L	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 11 E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 12	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
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

Change	Location	Source (Docket and Order Date)	Updated
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
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 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
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

Change	Location	Source (Docket and Order Date)	Updated
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

NCUC DOCKET NO. E-7, SUB 1134
LINCOLN COUNTY CT ADDITION PROJECT CPCN

Exhibit 1B: Statement of Need

PARTIALLY CONFIDENTIAL

PROJECT DESCRIPTION

The Lincoln County Combustion Turbine ("CT") Addition Project will consist of a new, state-of-the-art 402 MW (expected winter rating) simple-cycle natural gas-fueled electric generating unit, with fuel oil backup, and associated transmission and natural gas pipeline interconnection facilities. The new CT has been offered to Duke Energy Carolinas ("DEC") at a significant discount by Siemens Energy ("Siemens") in exchange for Siemens to have the opportunity to test and validate its advanced-class gas turbine (the "Advanced Turbine") under real market grid conditions. While DEC will not take care, custody and control of the Advanced Turbine Plant until October 2024, DEC and its customers will benefit from the energy produced by the generating unit beginning in 3Q 2020 as the Advanced Turbine begins an extended commissioning and testing period. The 16 existing dual fuel CT units, totaling 1,488 MW, located at the Lincoln County site will remain in operation. Additionally, and aside from the operating benefits of the new unit, providing Siemens the facility for testing and validating this Advanced Turbine will promote job and economic growth in North Carolina, both at the site in Lincoln County and at the Siemens gas turbine and generator manufacturing facility in Charlotte, NC.

1.1 BIENNIAL AND ANNUAL REPORTS

DEC's 2016 Integrated Resource Plan Biennial Report ("IRP") is included as Exhibit 1A. The 2016 IRP includes an undesignated 468 MW CT need in the winter of 2024/2025 (required in service by December 2024) in order to maintain adequate system reserve margins for reliable operation of the DEC system. Previous IRPs envisioned the Lee Nuclear Plant during this time frame. With the subsequent postponement of the Lee Nuclear Plant to the late 2020s in the most recently filed IRP, the generating need in the mid-2020s remained.

1.2 PROPOSED FACILITY CONFORMANCE WITH BIENNIAL AND ANNUAL REPORTS

The 402 MW Siemens Advanced Turbine will serve to meet the undesignated generating need in the winter of 2024/2025, and will thus lead to system reserve margins above the 17% threshold described in the 2016 IRP.

1.3 RESOURCE AND FUEL DIVERSITY

The new Siemens Advanced Turbine will operate on natural gas which will be provided by the existing Piedmont Natural Gas Company, Inc. ("Piedmont") pipeline that supplies the existing CT units at the site. The new unit will also have the ability to operate on ultra-low sulfur diesel (fuel oil) for testing and as an emergency backup, should there be a physical interruption in natural gas delivery to the facility or a temporary price spike that makes natural gas more expensive than fuel oil. The existing fuel oil system which serves the existing simple-cycle units will be expanded to include an additional tank which will be dedicated to the new unit during the testing and commissioning phase of the project. At Commercial

Operation, a system will be put in place to allow transfer of oil between the existing two tanks and the new tank. With the expansion, there will be fuel oil storage for three days of continuous operation of the new and the existing simple-cycle units.

The addition of the Advanced Turbine is the latest in a series of highly flexible, planned generating units in DEC that provide needed capacity and energy to the system, as well as the ability to aid the system in managing increasing levels of intermittent, non-dispatchable resources in DEC. The Advanced Turbine, along with the recently announced upgrades at the Bad Creek Pumped Storage Facility and the conversion of Cliffside Units 5 & 6 to dual fuel optionality, are examples of diverse resources that will help maintain reliable and efficient operation of the DEC system.

1.4 STATEMENT OF NEED

The 2016 IRP identifies a need for generation by the winter of 2024/2025 in order to maintain adequate system reserve requirements. The Siemens Advanced Turbine, which will begin providing firm capacity in late 2024, meets that need. Additionally, given the forward-looking design aspects of the Siemens Advanced Turbine, the unit will begin extended commissioning and testing in July 2020. During the commissioning period, any energy generated by the new asset will be delivered to DEC at or below the marginal cost of energy at that time. In that manner, the Advanced Turbine will begin providing low cost energy to DEC and its customers several years before DEC assumes care, custody and control of the unit in 2024.

Furthermore, given Siemens' desire to test and operate this Advanced Turbine under "real world" grid conditions in order to maintain their competitive position in the industry, Siemens is providing the new CT to DEC at a significant discount to similar frame turbine technologies. The approximate **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** % discount on the Engineering, Procurement and Construction (EPC) price, including the Advanced Turbine, along with the projected energy benefits of the new unit, provide an efficient and economically attractive means for meeting DEC's future energy and capacity needs.

Economic Justification for the Lincoln CT Addition

The economic justification for the Lincoln CT Addition Project is developed by comparing the Present Value Rate of Return (PVRR) for the Lincoln CT Addition (Change Case) to the 2016 IRP "No CO_2 Legislation" resource plan. The "No CO_2 Legislation" resource plan is the same resource plan that was used in the E-100 Sub 148 Avoided Cost filing in 2016. Partially confidential Table 1 details the key variables in the Base Case and the Change Case.

Table 1: Comparison of Key Variables between Base Case and Change Case (2017$, Winter Ratings)

	Base Case (2016 IRP No CO_2 Case)	Change Case (Lincoln CT Addition)
2024/2025 New Generating Asset	468 MW Generic F-Class CT Located at Lincoln County Site	402 MW Siemens advanced-class CT Located at Lincoln County Site[1]

[BEGIN CONFIDENTIAL]

Capital Cost of New Generating Asset w/ AFUDC, $/kw	$[redacted]	$[redacted]
Variable Operations & Maintenance (VOM) Rate, $/MWh[2]	$[redacted]	$[redacted]
Start Costs, $/MW-Start[3]	$[redacted]	$[redacted]

[END CONFIDENTIAL]

In addition to the key variables listed above, the extended commissioning of the Advanced Turbine is expected to occur over three stages: Version A, Version B, and Version C, whereby Siemens expects to progressively improve the gas turbine's performance through increased output and improved heat rate. The expected performance assumed for each version is as follows in confidential Table 2:

[BEGIN CONFIDENTIAL]

Table 2: Comparison of Version A, B, and C Operating Parameters

	Lincoln CT		
	Version A	Version B	Version C
Capacity (Winter/Summer), MW	369 / 335	382 / 347	402 / 365
Heat Rate (Winter/Summer), HHV	[redacted]	[redacted]	[redacted]

[END CONFIDENTIAL]

The Advanced Turbine is allowed to operate beginning in July 2020; however, the following operation availability assumptions in Table 3 were modelled based on the testing and validation schedule of each phase of the project:

[1] A 66 MW Generic F-Class CT is required to balance the MW between the base and change cases. The "balance" CT is assumed to be located at a generic greenfield site with full Fixed Operating and Maintenance (FOM) and other costs associated with a greenfield site.
[2] VOM costs for Generic F-Class CT are based on 2016 IRP Generic Unit Summary VOM assumptions without inclusion of a Selective Catalytic Reducer ("SCR"). VOM costs for the Lincoln CT Addition are assumed to be the same as the F-Class CT VOM from the Generic Unit Summary, plus the NH3 requirements for the SCR associated with the new unit.
[3] Converted $/Gas Turbine-Starts to $/MW-Start using Start Costs for Generic F-Class CT from 2016 IRP Generic Unit Summary, and Start Costs for New Lincoln CT based on LTSA cost and terms negotiated with Siemens

Table 3: Assumed Operational Availability During Commissioning

	Start	End
Version A	7/31/2020	4/1/2021
Version B	3/1/2022	11/30/2022
Version C	11/1/2023	5/1/2024
Version C (Final)	10/1/2024	10/1/2059

As detailed in Confidential Table 4, based on a PVRR analysis, the Lincoln County CT Addition Project is a lower cost alternative versus the base case.

Table 4: PVRR Results of the New Lincoln County CT Addition Project

[BEGIN CONFIDENTIAL]

	PVRR ($K, 2017)
System Production Costs	
Reduced System Variable Costs	[redacted]
Subtotal	[redacted]
Lincoln Advanced Turbine Capital & FOM Costs	
Capital Costs beginning in 2025	[redacted]
FOM Costs	[redacted]
Subtotal	[redacted]
Generic F-Class CT Capital & FOM Costs (66 MW Balance CT)	
Capital Costs beginning in 2025	[redacted]
FOM Costs	[redacted]
Subtotal	[redacted]
Avoided F-Class CT Capital & FOM Costs at Lincoln	
Avoided Capital Costs beginning in 2025	[redacted]
Avoided FOM Costs	[redacted]
Subtotal	[redacted]
TOTAL PROJECT BENEFIT(-) / COST (+)	[redacted]

[END CONFIDENTIAL]

The main economic benefits of the Lincoln County CT Addition Project are:

1. Reduced fuel and operating costs with more efficient Siemens Advanced Turbine versus F-Class CT;
2. Approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** % capital

cost savings on the Siemens Advanced Turbine versus the avoided F-Class CT; and

3. Lower long-term major maintenance costs versus F-Class CT service agreements.

Additionally, as the Advanced Turbine begins an extended commissioning phase in 3Q 2020, and DEC does not take care, custody, and control of the CT until 4Q 2024, the operating benefits from the unit contribute to a lower PVRR several years before costs associated with the capital and major maintenance of the unit begin.

Economic Sensitivity Analysis

Several sensitivities were developed to test the robustness of the Lincoln County CT Project economics. The results of the sensitivities described below are included in Table 5:

1. *No CO_2 cost scenario with gas prices decreased by 25%* (Decrease natural gas prices by 25% throughout the study period): In this scenario gas prices are 25% lower than the gas prices in the base scenario. Lower gas prices lead to increased utilization of the Advanced Turbine, thereby slightly increasing the benefits of the Advanced Turbine.

2. *No CO_2 cost scenario with gas prices increased by 25%* (Increase natural gas prices by 25% throughout the study period): In this scenario gas prices are 25% higher than the gas prices in the base scenario. Higher gas prices lead to decreased utilization of the Advanced Turbine, thereby slightly reducing the benefits of the Advanced Turbine.

3. *IRP base case w/ Lee Nuclear and CO_2 tax* (2016 IRP Base Case): This scenario represents the 2016 IRP Base Case with Lee Nuclear on line beginning in 2026. In addition, this scenario includes a CO_2 Tax levied on carbon emissions beginning in 2022. While the Advanced Turbine shows greater value with the inclusion of a carbon tax, this scenario shows lower system production cost savings overall as the Advanced Turbine is pushed further down the operating stack with the addition of Lee Nuclear in the late 2020s, thereby reducing the operating benefits of the CT.

In all scenarios, the sensitivity analysis demonstrates that the New Lincoln CT Project is economically favorable to the alternative plan as shown in Confidential Table 5 below.

Table 5: PVRR Sensitivity Analysis of the New Lincoln County CT Project ***($K, 2017)***

[BEGIN CONFIDENTIAL]

	Base Scenario	Sensitivity 1 (Low Gas)	Sensitivity 2 (High Gas)	Sensitivity 3 (Carbon Tax / Lee Nuclear)
System Production Costs				
Reduced System Variable Costs	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal	[redacted]	[redacted]	[redacted]	[redacted]
Advanced CT Capital & FOM Costs				
Capital Costs beginning 2025	[redacted]	[redacted]	[redacted]	[redacted]
FOM Costs	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal	[redacted]	[redacted]	[redacted]	[redacted]
Generic F-Class CT Capital & FOM Costs (66 MW Balance CT)				
Capital Costs beginning 2025	[redacted]	[redacted]	[redacted]	[redacted]
FOM Costs	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal	[redacted]	[redacted]	[redacted]	[redacted]
Avoided F-Class CT Capital & FOM Costs at Lincoln				
Avoided Capital Costs beginning 2025	[redacted]	[redacted]	[redacted]	[redacted]
Avoided FOM Costs	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL PROJECT BENEFIT(-) / COST (+)	[redacted]	[redacted]	[redacted]	[redacted]

[END CONFIDENTIAL]

Additional Benefits of Lincoln County CT Projects

In addition to the PVRR benefits of the project discussed above, there are additional qualitative benefits of the Lincoln County CT Addition Project:

- The Lincoln County CT will be the most efficient and flexible turbine in the DEC fleet. Moving to the latest turbine technology not only provides fuel efficiency but also provides additional fleet flexibility to assist in integrating intermittent renewable resources into the generation portfolio.
- A successful commissioning and operation of the Advanced Turbine will help promote competition among various turbine suppliers by creating a third entrant into the advanced-class gas turbine market.

- Turbine supply, construction, and operation of the Advanced Turbine in North Carolina contributes to economic development in the state.
  - Siemens employs approximately 1,700 people in the Greater Charlotte area.
  - The Advanced Turbine and electrical generator will be manufactured at the Siemens factory in Charlotte, NC, and development of the new product line is critical to maintaining a competitive product line in the gas turbine market which will provide future production work for the factory.
  - As the EPC contractor, Siemens expects to support the local Lincoln County economy with the addition of over 150 temporary construction jobs and 10 operating jobs associated with the testing and commissioning of the facility.
  - Siemens will seek opportunities to partner with local contractors to build the facility in Lincoln County.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1134

In the Matter of		
	)	
Application of Duke Energy Carolinas, LLC for Approval to Construct a 402 MW Natural Gas-Fired Combustion Turbine Electric Generating Facility in Lincoln County	)))))	DIRECT TESTIMONY OF MARK E. LANDSEIDEL FOR DUKE ENERGY CAROLINAS

Q. PLEASE STATE YOUR NAME, ADDRESS, AND POSITION.

A. My name is Mark E. Landseidel. My business address is 400 South Tryon Street, Charlotte, North Carolina. I am General Manager of Project Development in the Project Management and Construction Department of Duke Energy Corporation, and I am responsible for the initiation and development of new generation projects for Duke Energy Carolinas, LLC (hereinafter "Duke Energy Carolinas," "DEC" or the "Company") and Duke Energy Progress, LLC.

Q. PLEASE STATE YOUR EDUCATION, BACKGROUND, AND PROFESSIONAL AFFILIATIONS.

A. I graduated from Colorado State University in May 1982 with a Bachelor of Science in Engineering. I completed the General Manager Program at Harvard Business School in November 2001. I am a certified Project Management Professional.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. I joined Duke Energy Corporation in July 1982 and have worked in a number of departments including plant operations, plant maintenance, plant improvement projects, business development, asset management, and major project management and construction in my 35-year career with Duke Energy Corporation. I have been responsible for project development, project management and construction of a number of new generation major projects since August 1996, including responsibility for the initiation and development of the recent Duke Energy Progress 560 MW Western Carolinas Modernization Combined Cycle Project, as well as the 84 MW Duke Energy Progress Sutton Blackstart Combustion Turbine ("CT") Project, the Duke Energy Carolinas 620 MW Buck and Dan River Combined Cycle projects in North Carolina, and the 750 MW W.S. Lee Combined Cycle Project and the 84 MW W.S. Lee CT Project in South Carolina. I assumed my current position in July 2012.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe the project scope and the combustion turbine technology and environmental controls selected for the new Lincoln County Combustion Turbine Addition Project, which I will refer to as the "Lincoln County CT Project" or simply as the "Project." I will also discuss Duke Energy Carolinas' process to select the generation technology and the site for the Project. In addition, I will discuss the schedule and costs for the Project and provide the status of the various related permits.

Q. I SHOW YOU WHAT HAS BEEN MARKED AS LANDSEIDEL EXHIBIT 2, LANDSEIDEL CONFIDENTIAL EXHIBIT 3, AND LANDSEIDEL CONFIDENTIAL EXHIBIT 4. WOULD YOU PLEASE TELL US WHAT THESE ARE?

A. Yes. Landseidel Exhibit 2 (Siting and Permitting Information), Landseidel Confidential Exhibit 3 (Cost Information) and Landseidel Confidential Exhibit 4 (Construction Information) contain the detailed information required by Commission Rule R8-61(b). Landseidel Confidential Exhibits 3 and 4 contain confidential cost and supplier contract information that is being filed under seal. Appendix A included in Landseidel Exhibit 2 provides additional plant description, equipment and process information. Landseidel Exhibits 2, 3 and 4 were prepared at my direction.

Q. WHY IS THERE NO LANDSEIDEL EXHIBIT 1?

A. Commission Rule R8-61(b) requires that four specifically-numbered exhibits be filed as part of the Lincoln County CT Project. The information required for inclusion in Exhibit 1 under the Commission Rule is contained in Kalemba Exhibits 1A and 1B to Company witness Matthew Kalemba's testimony. In order to have the Kalemba and Landseidel Exhibit numbers align with the Commission Rule, there is no Landseidel Exhibit 1.

Q. PLEASE GENERALLY DESCRIBE THE LINCOLN COUNTY CT

PROJECT.

A. The Lincoln County CT Project will consist of a new nominal 402 MW (winter rating) simple-cycle advanced combustion turbine natural gas-fueled electric generating unit, with fuel oil backup, and related transmission and natural gas pipeline interconnection facilities. The Lincoln County CT Project will be located at the Company's existing Lincoln County CT site in Lincoln County, near Stanley, North Carolina. The Lincoln County CT Project will provide peaking generating capacity to the Duke Energy Carolinas system.

The plant will be a new model Siemens advanced-class series test and validation CT unit. The plant is scheduled to begin generating electricity for the benefit of DEC customers in 2020 during an extended commissioning, testing and validation period, and DEC will take care, custody and control of the unit and begin commercial operation in late 2024. The Company has sixteen existing CTs at the Lincoln County CT site totaling 1,488 MW (winter rating), which provide peaking generation to the Company's customers. The Lincoln County CT Project will be located adjacent to the existing CT units.

Q. PLEASE SUMMARIZE THE COMBUSTION TURBINE TECHNOLOGY SELECTED FOR THE PROJECT AND DETAILED IN LANDSEIDEL EXHIBIT 2 AND LANDSEIDEL EXHIBIT 4.

A. The simple-cycle generating facility will use a Siemens advanced-class series CT generator to produce electricity. This CT will be designed to compete with other advanced-class series CTs being introduced into the market by GE and

Mitsubishi. These advanced-class turbines will provide higher output, improved efficiency and faster ramp rates than existing large frame gas turbines.

Q. FROM A TECHNOLOGY STANDPOINT, HOW DID DUKE ENERGY CAROLINAS EVALUATE POTENTIAL COMBUSTION TURBINE TECHNOLOGY OPTIONS FOR THE PROJECT?

A. In 2016, Siemens approached Duke Energy as part of its efforts to seek a utility customer host site for testing and validation of the new advanced-class gas turbine it is developing. The new Siemens advanced-class turbine will compete with the General Electric HA.02 and the Mitsubishi Hitachi Power Systems J model turbines that currently are being introduced into the U.S. market. Siemens preferred to utilize a U.S. utility customer host site connected directly to the grid as opposed to a new standalone test facility, or their existing testing facility in Berlin. In addition, the proximity of DEC's service territory to Siemens' existing Charlotte gas turbine and generator manufacturing facility presented additional benefits for Siemens as well as economic development benefits of locating a testing and validation unit in Duke Energy Carolinas' service territory. DEC conducted a due diligence evaluation of the Siemens advanced-class turbine design development, including visits to Siemens' turbine manufacturing and test facilities in Germany and Charlotte, in order to evaluate the new turbine technology. As discussed in Mr. Kalemba's testimony, the advanced-class series turbine is also the best option for the approximately 400 MW DEC 2024 CT capacity need that is identified in Kalemba Exhibit 1A which is the 2016 DEC Integrated Resource Plan ("IRP"). Finally, Siemens has offered a significant engineering, procurement and construction ("EPC") price discount for the Project in exchange for the ability to test and validate their technology on the DEC grid.

Q. WHY DID DUKE ENERGY CAROLINAS SELECT THE SIEMENS ADVANCED-CLASS MODEL UNIT FOR THE LINCOLN COUNTY CT PROJECT?

A. The Siemens offer to DEC in 2016 considered normalized capital cost in $/kW, performance (output and heat rate), experience, reliability, operational flexibility, maintenance cost, and contract terms and conditions. Siemens offered the Company very favorable pricing and technology risk guarantees that the Company determined reasonably addressed the potential risks associated with a first of a kind demonstration turbine. Siemens will install its turbine for the Project on an EPC turnkey basis, including start-up, testing and operation from 2020 until DEC assumes care, custody and control of the unit when it goes into commercial operation in 2024. In the unlikely event that the new Siemens advanced turbine does not meet minimum acceptance criteria, Siemens is contractually obligated to install two replacement F-Class gas turbines at no additional cost, thereby insuring against the new technology risk of not meeting DEC and its customers' needs. During the approximately four-year extended testing and validation period, Siemens will determine the timing and nature of operation of the unit; however, DEC will receive the benefits of the capacity and energy delivered to the DEC grid, and Siemens will pay for any fuel costs above the actual system dispatch fuel costs at the time, as well as most fixed and variable maintenance costs. During the extended testing and validation period Siemens will also maintain a spare parts inventory, take parts life risk including in/out costs, and be responsible for all major maintenance costs until the unit goes into commercial operation. Siemens will also provide a full two-year warranty on the entire facility after DEC puts the unit into commercial operation. Siemens has also agreed to favorable long-term parts and maintenance agreement terms, which provide additional cost and risk benefits to DEC and our customers. In addition, by supporting the entry of another market competitor into the advanced-class turbine market, Duke Energy Carolinas, Duke Energy Progress and other Duke Energy and non-Duke Energy electric suppliers should benefit from increased supplier competition for these advanced-class gas turbines. Other gas turbine suppliers are currently introducing CTs into the U.S. market with similar performance characteristics, but the price discount Siemens has offered is a significant benefit to DEC customers compared to these competing alternatives. Additional details about the cost evaluation are contained in Confidential Landseidel Exhibit 3.

Q. PLEASE DESCRIBE THE PROCESS DUKE ENERGY CAROLINAS USED TO DETERMINE WHERE TO SITE THE PROJECT.

A. As discussed in more detail in Landseidel Exhibit 2, DEC conducted a siting study, and the Lincoln County CT Station scored highest on the siting evaluation by a significant margin. On comprehensive site visits and site studies, no significant issues for the addition of a CT unit at the Lincoln County site have been found. In addition to the utilization of the existing switchyard and transmission capacity, the site provides other cost advantages, including existing fuel oil unloading infrastructure and existing natural gas infrastructure. There are also operating cost synergies associated with the adjacent existing CT units.

Q. ARE ANY CHANGES TO TRANSMISSION FACILITIES INCLUDED AS PART OF THE LINCOLN COUNTY CT PROJECT?

A. Yes. The Lincoln County CT Project will be designed with a single 230 kV Generator Step-Up ("GSU") transformer, 230 kV bus line, and interconnected to the existing 230 kV Lincoln County CT electrical switchyard. The preliminary plan is to expand the existing 230 kV switchyard to the south to accommodate the proposed new CT unit connection. The 230 kV bus line from the new unit will be routed to this new switchyard expansion. No new transmission lines are planned to be constructed outside the Lincoln County CT property, and no transmission system upgrades are anticipated.

Q. PLEASE DESCRIBE THE FUEL HANDLING FACILITIES FOR THE LINCOLN COUNTY CT PROJECT.

A. The Project will be dual fuel, capable of burning pipeline natural gas or back-up ultra-low sulfur diesel fuel from on-site storage facilities. The existing Piedmont Natural Gas Company, Inc. ("Piedmont") pipeline from Transco will be modified to provide service to the Project at a location adjacent to the

Project. Duke Energy Carolinas will have an interruptible transportation service agreement with Piedmont to provide gas transportation service for the Project. The plant gas supply will be served initially from Transco utilizing Duke Energy Carolinas' existing gas transportation service agreements and supply portfolio.

The fuel oil unloading and storage facilities built for the existing Lincoln County CTs will be expanded with an additional storage tank. The on-site fuel oil storage will be capable to provide approximately three days of on-site fuel storage for the existing CTs and new unit.

Q. PLEASE DESCRIBE THE EMISSION CONTROLS DESIGNED FOR THE LINCOLN COUNTY CT PROJECT AND AIR PERMIT REQUIREMENTS.

A. Operation of the proposed facility will result in the emission of certain pollutants that are regulated by the US Environmental Protection Agency and the State of North Carolina. Operating impacts from these pollutants will be addressed through the North Carolina Division of Air Quality ("DAQ") air quality permit application process. In June 2017, Duke Energy Carolinas plans to submit a permit application to DAQ requesting a permit to authorize construction and operation of the combustion turbine units and associated ancillary systems. The application will include all required modeling and analysis to demonstrate compliance with regulatory requirements and air quality standards. The new unit will be designed to control emissions via combustion controls as well as a dilution air Selective Catalytic Reduction (“SCR”) and Carbon Monoxide (“CO”) Catalyst to Best Available Control Technology (“BACT”); however, due to the size and efficiency of the unit and expected hours of operations, the application is expected to trigger New Source Review under the Prevention of Significant Deterioration program requirements. Duke Energy Carolinas anticipates that a final air permit should be issued within twelve months of submitting the application. Continuous emission monitoring systems (“CEMS”) will be installed on the turbine's exhaust stack.

Q. WHAT IS THE STATUS OF ANY ADDITIONAL ENVIRONMENTAL PERMITS REQUIRED FOR THE PROJECT?

A. The site has a Publicly Owned Treatment Works (“POTW”) permit with Lincoln County Public Works. Preliminary plans include the installation of an oil/water separator for treatment of all potential oily waste streams and discharge to the POTW. Other liquid waste streams such as gas turbine wash wastewater will be pumped to tank trucks and hauled off-site for treatment. The following permits may be required in addition to those described above: North Carolina Oil Terminal Registration, Department of Environmental Quality and Lincoln County Storm Water permits, Division of Energy, Mineral and Land Resources Erosion and Sedimentation Control permit, Lincoln County Building permit, and Lincoln County Occupancy permit.

Q. HAS DUKE ENERGY CAROLINAS SELECTED ITS PRINCIPAL CONTRACTORS AND SUPPLIERS, AND WHAT IS THE PROCESS FOR MAKING THESE SELECTIONS?

A. Yes. The EPC contract with Siemens includes detailed design, procurement of balance-of-plant items, and construction as well as supply of the combustion turbine, all on a firm fixed price turnkey basis. The Siemens EPC price is at a significant discount to the market in exchange for Siemens' ability to test and validate their technology on the DEC grid at the Lincoln County CT site. As a result, there are considerable benefits to DEC and its customers to utilize this EPC approach with Siemens in order to meet the DEC need for new CT capacity in 2024.

Q. PLEASE SUMMARIZE THE LINCOLN COUNTY CT PROJECT SCHEDULE AND ESTIMATED COSTS.

A. The projected capital costs and operating expenses are confidential and proprietary and have been filed under separate cover as Landseidel Exhibit 3; however, the EPC costs agreed to by Siemens are significantly less than market. Subject to regulatory approvals, construction will begin in mid-2018, and Siemens will bring the unit online in a series of three versions as part of the comprehensive testing and validation process. Version A will have a nominal rating of 369 MW winter and will begin testing and validation in 2020. Version B will have a nominal rating of 382 MW winter and will begin testing and validation in 2022. The final commercial operation version C will have a nominal rating of 402 MW winter and will begin testing and validation in 2023, with DEC taking care, custody and control of the unit in the fourth quarter of 2024.

The cost estimate was developed using a firm and fixed EPC price, transmission cost estimates by DEC, gas facility costs by Piedmont Natural Gas and Owner's costs based on in-house experience and data from other projects. Approximately 60% of the project's capital cost is attributable to the EPC fixed price. The EPC cost estimate was compared to a cost estimate for competing advanced technology developed by Burns & McDonnell for the Lincoln County site that validates the estimated Siemens EPC price discount. The Burns & McDonnell evaluation is included as Appendix A to Landseidel Exhibit 3.

Q. DID DUKE ENERGY CAROLINAS CONSIDER CULTURAL RESOURCES, INCLUDING POTENTIAL HISTORIC AND ARCHAEOLOGICAL SITES AS PART OF ITS EVALUATION OF THE SITE FOR THE LINCOLN COUNTY CT PROJECT?

A. Yes. In December of 2016, Brockington conducted a records review and architectural windshield survey within a defined area of potential effect (APE) for the proposed facility (Appendix A). Because of the scale and nature of the undertaking, Brockington defined the APE as a 2-kilometer (1.2-mile) radius around the existing CT station.

Brockington's data review identified seven previously recorded architectural resources that met the National Register of Historic Places ("NRHP") age criterion of 50 years or older. Of those seven resources, two are listed on the NRHP (LN003 "Ingleside" and LN0528 "Mount Welcome"), three are eligible for the NRHP (LN0527 "John R. Asbury House," LN0540 "Kincaid Family House," and LN0573 "Mariposa Road Bridge"), and two are potentially eligible for the NRHP (LN0529 "Mariposa Cotton Mill" and LN0585) (Appendix A). Resource LN0585 could not be located during the field reconnaissance investigation and may have been demolished. Brockington also observed a number of other properties which met the NRHP age criterion of 50 years or older but had not been recorded because of architectural integrity issues, severe alterations to the original structures, and/or lack of architectural significance.

Potential visual impacts as a result of the proposed facility were assessed for each of the seven identified cultural resources. Because mature forest cover provides foreground screening, the proposed facility is not expected to be visible from any of the resources. The NC State Historic Preservation Office concurred with the Brockington's assessment that no historic resources would be affected by the project in the letter included as Appendix B-2 to Landseidel Exhibit 2.

In addition to the cultural resources study, Duke Energy Carolinas conducted a Probable Visual Effect Analysis to characterize the existing visual conditions within five miles of the proposed Project and to determine the future plant's effects on the scenic quality of the area. The analysis determined the Lincoln County CT Project will have minimal effects on the visual resources and scenic quality of the area surrounding the proposed site.

Q. IN CONCLUSION, WHY IS DUKE ENERGY CAROLINAS SEEKING APPROVAL TO CONSTRUCT THE LINCOLN COUNTY CT PROJECT?

A. After conducting technology and siting evaluations, the Company has determined that the selected Siemens advanced-class combustion turbine addition at the Lincoln County CT site will be the best peaking load generation addition for the Duke Energy Carolinas system in the required time frame. The Lincoln County CT site is an existing generating station, with the critical infrastructure already in place and, together with the Siemens EPC price discount and long-term service agreement, will keep construction and operating costs lower and minimize the environmental impacts. Duke Energy Carolinas has a long-established presence in the local community. The Project site is also close to Siemens' Charlotte gas turbine and generator manufacturing facility, where the advanced-class turbines will be built, which provides additional benefits for ongoing operations and maintenance support from Siemens during the extended testing and validation period, as well as after DEC assumes care, custody and control of the unit into long-term commercial operation. For all of the reasons stated in my testimony, and in the testimony of Matthew Kalemba, Duke Energy Carolinas believes that the Commission should approve the construction of the Lincoln County CT Project as required by the public convenience and necessity.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

NCUC DOCKET NO. E-7, SUB 1134
LINCOLN COUNTY CT ADDITION PROJECT CPCN

Exhibit 2: Site and Permitting Information

LINCOLN COUNTY COMBUSTION TURBINE ADDITION PROJECT

Exhibit 2: Site and Permitting Information

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2.8 Seismic
2.9 Water Supply
2.10 Aviation

REFERENCES

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APPENDIX B Literature Review and Windshield Survey of the Proposed Lincoln County CT Addition, Lincoln County, North Carolina
APPENDIX B-1 Archaeological Survey and Testing at the Lowesville Tract, Lincoln County, North Carolina
APPENDIX B-2 North Carolina State Historic Preservation Office Letter of Concurrence
APPENDIX C Lincoln County CT Addition Natural Resources Report
APPENDIX C-1 U.S. Fish & Wildlife Service Letter of Concurrence
APPENDIX D Historic Seismic Activity

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INTRODUCTION

Duke Energy Carolinas (DEC) requests certification to construct a simple-cycle combustion turbine (CT) facility at its existing Lincoln County CT site.

This exhibit provides site and permitting information for construction of the proposed simple-cycle generating facility and for related upgrades to on-site transmission facilities, pursuant to North Carolina Utilities Commission (NCUC) Rule R8-61. All descriptions, illustrations, and information provided herein are based on preliminary engineering and studies, using the most reliable information available to date. The following information is included:

- Facility Layout Map
- Site Location and Address
- Site Ownership
- Site Description
- Site Selection
- Site Analysis
- Site Study Status
- Transmission

PRELIMINARY PLANS AND EXHIBITS

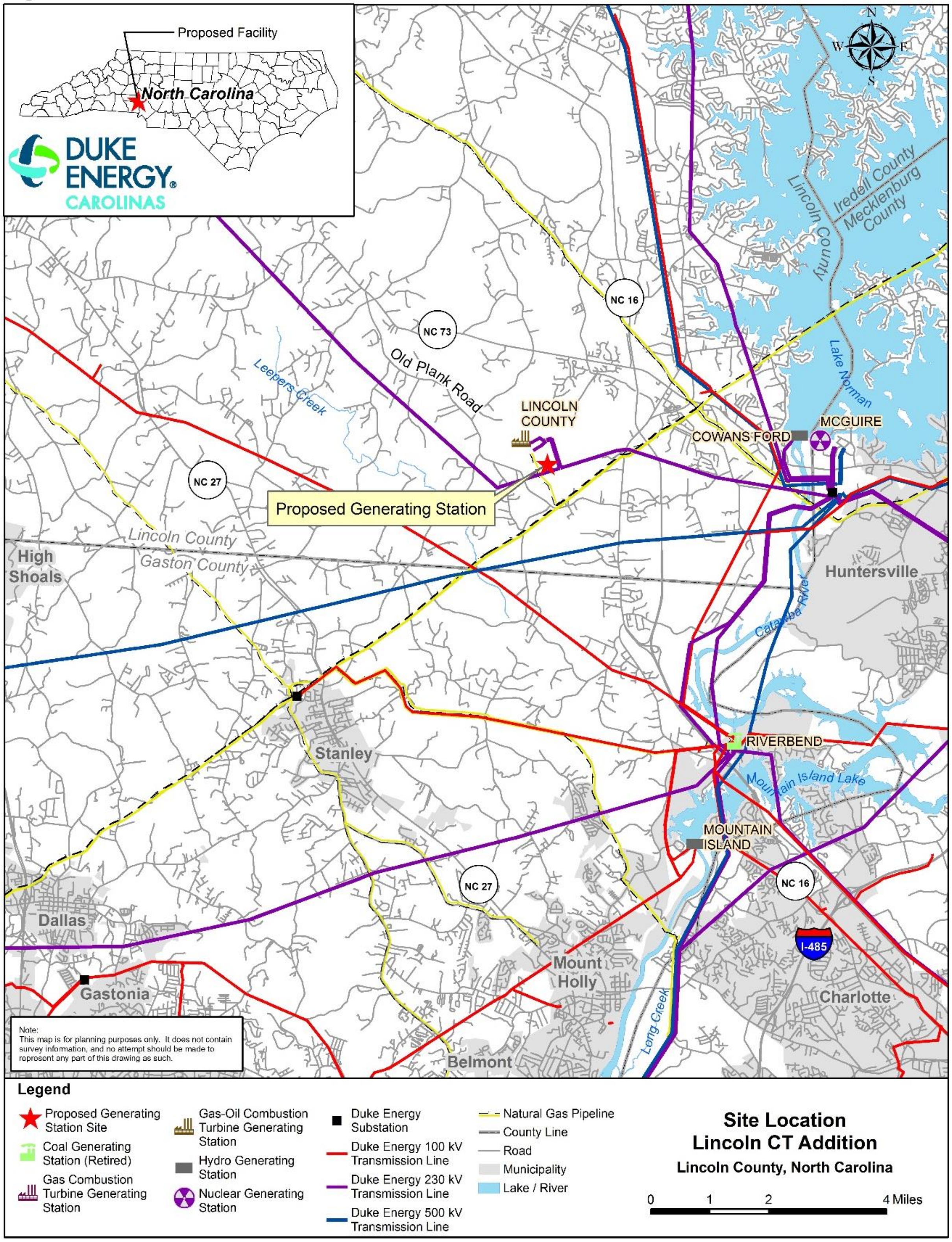
1.0 SITE INFORMATION

DEC contracted with consultants from UC Synergetic (UCS), Brockington & Associates, Inc. (Brockington), terra incognita, HDR, and Stewart Acoustical Consultants (Stewart) to perform research and conduct studies related to the siting of the proposed generating facility, including analyses of local population, area development, visual and auditory resources, aesthetic and cultural resources, geology, ecology, seismicity, water supply, and aviation.

1.1 Site Location, Address, and Ownership

The proposed Lincoln County CT Addition will be owned by DEC and located on DEC-owned property at the Lincoln Combustion Turbine Station (the station) site in southeastern Lincoln County, North Carolina. The proposed facility’s address will be 6769 Old Plank Road, Stanley, North Carolina, 28164; its approximate GPS coordinates are 35° 25' 36.54" north and 81° 02' 07.74" west. Figure 1.1-1 is a map showing the location of the proposed facility.

Figure 1.1-1: Site Location

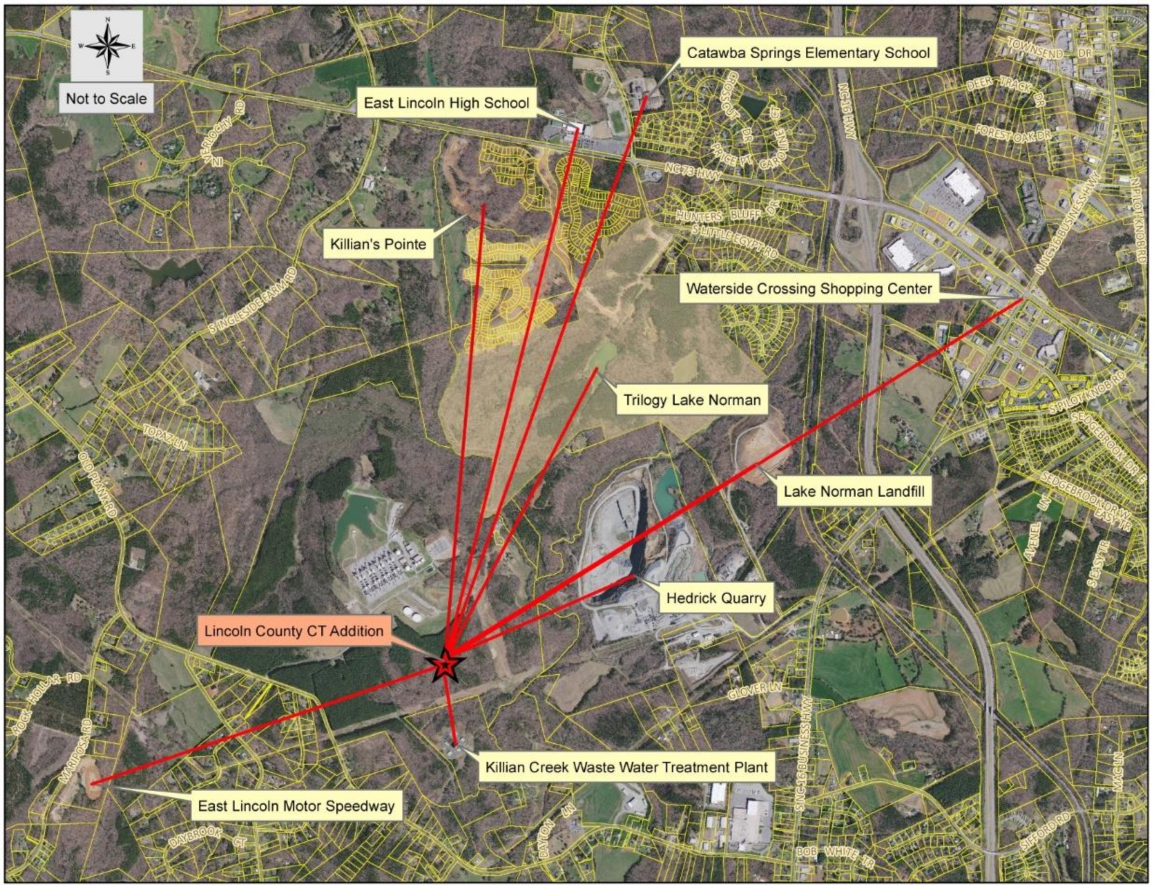


Sources: NCDOT 2016, Hart Energy 2016, Lincoln County GIS/Mapping 2016, Lincoln Count GIS/Mapping (Streets) 2016, Bradley 2016, Gaston County 2016, Iredell County 2016

The area around the station and the proposed facility is a mixture of rural, residential, commercial, and industrial land uses. The existing 1200-megawatt (MW) station has been operating commercially since 1995. Commercial and industrial development in the vicinity includes East Lincoln Motor Speedway (1.2 miles southwest), Hedrick Quarry (0.6 miles east), Killian Creek Waste Water Treatment Plant (0.3 miles southeast), Lake Norman Landfill (1.3 miles northeast), and the Waterside Crossing shopping center at the intersection of North Carolina Highways 16 (Highway 16) and 73 (Highway 73) (2.3 miles northeast). Nearby schools are East Lincoln High School (1.85 miles north) and Catawba Springs Elementary School (2.1 miles north). The communities of Lowesville and Denver are about 1.5 miles to the east and 5.9 miles northwest, respectively; nearby towns include Stanley (5.9 miles south) and Lincolnton (11.5 miles west).

Figure 1.1-2 shows the locations of major commercial, industrial, and residential developments as well as nearby schools.

Figure 1.1-2: Land Use Map



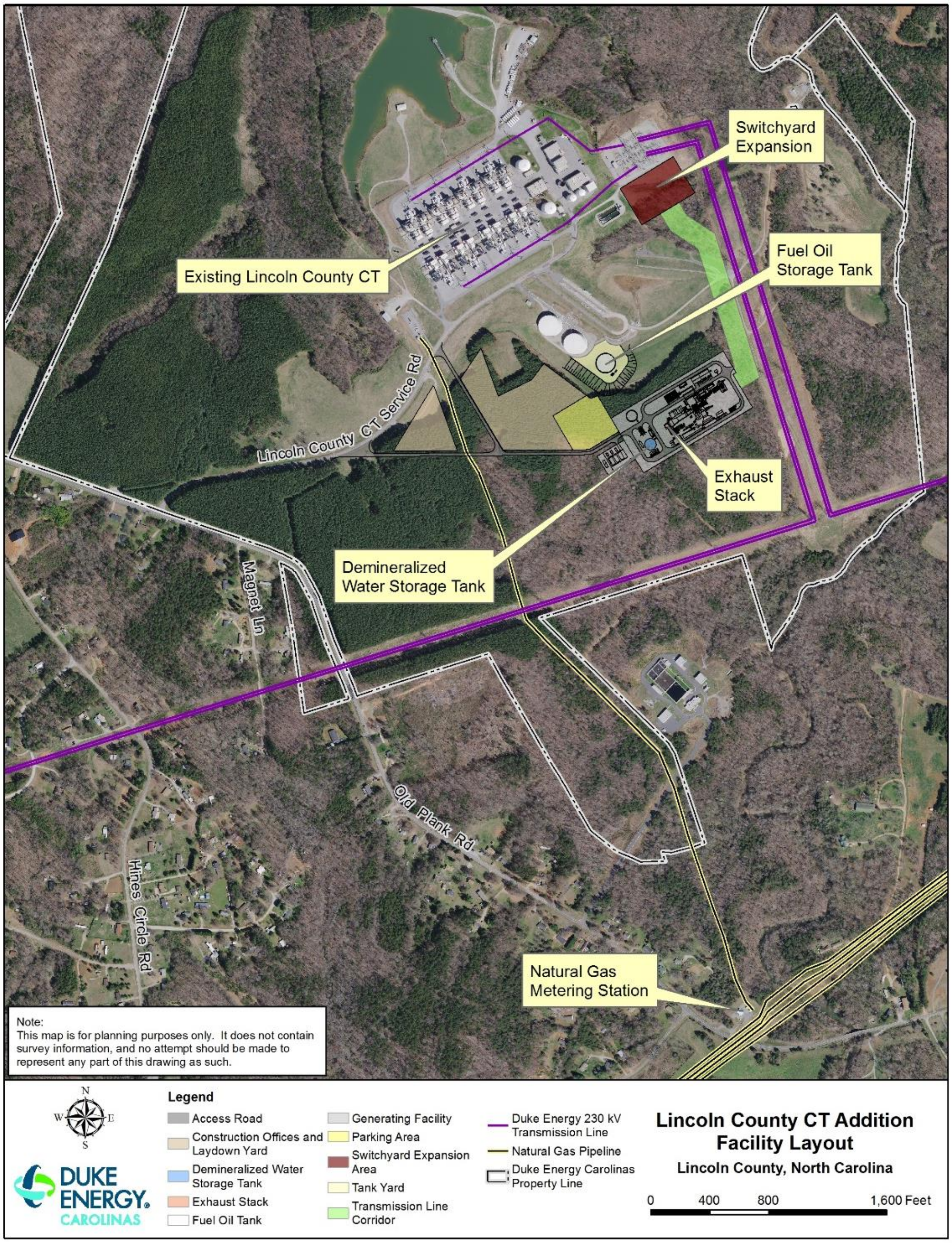
Sources: Lincoln County GIS/Mapping 2016a and 2016b

1.2 Site Description

The plant property encompasses about 746 acres of land, a portion of which is occupied by the existing combustion turbines, an electrical substation, the associated balance of plant facilities, and buffer lands.

Figure 1.2-1 provides an overall view of the proposed facility.

Figure 1.2-1: Facility Layout



Sources: Hart Energy 2016, Lincoln County GIS/Mapping 2016a and 2016b, North Carolina GICC 2015

1.3 Site Selection

1.3.1 Siting Criteria

The site selection was made using a modified Kepner-Tregoe analysis with input from project team members. All of the desired traits of the site were listed and weighted on a scale of one to ten, based on importance. The more important criteria were given a higher weight. After the criteria were established, each site was rated on a one-to-ten scale for each criterion. The score for each site was determined by multiplying each criterion weight by the site score for that criterion. The weighted scores for all criteria were then added to determine each site's total score.

The selected criteria and weighting for the site selection are presented in Table 1.3.1-1 below.

[**BEGIN CONFIDENTIAL**]

Table 1.3.1-1: Site Selection Criteria and Weighting

Criteria	Reason	Weight
Transmission Capacity	Available transmission capacity can provide significant cost-saving opportunities.	8
Natural Gas Capacity	Available natural gas capacity can provide significant cost saving opportunities.	9
Fuel Oil/Water Availability	Existing oil-loading, storage, and water infrastructure provides cost-saving opportunities during the commissioning test and for long-term operation.	3
Long Term Simple Cycle	Site characteristics support long-term operation as a system resource.	10
Combined Cycle Conversion Potential	Site characteristics would support potential conversion to combined cycle at some point in the future.	7
Operational Synergies	Existing sites with gas turbine generation are staffed with personnel with a good understanding of the operation and maintenance of gas turbines.	3
Rail Access	Access to nearby rail lowers cost of turbine and transformer delivery.	3
Proximity to Charlotte	Siemens' manufacturing facility and technical support are located in Charlotte, which would increase efficiency and provide cost-saving opportunities.	3

[**END CONFIDENTIAL**]

1.3.2 Siting Results

All DEC generation sites with existing or planned natural gas infrastructure were considered. Listed below are the sites and the total score for each, based upon the criteria and weights described in Table 1.3.1-1.

• Lincoln (Lincoln County, NC)	416
• Mill Creek (Cherokee County, SC)	293
• Rockingham (Rockingham County, NC)	212
• Dan River (Rockingham County, NC)	208
• Cliffside (Cliffside/Rutherford Counties, NC)	188
• W.S. Lee (Anderson County, SC)	169
• Buck (Rowan County, NC)	133

1.3.3 Recommendation

The Lincoln County CT Station scored highest on the siting evaluation by a significant margin. On a comprehensive site visit, no major issues for the addition of a CT unit at the Lincoln County site were found. Subsequent detailed field work at the Lincoln County site substantiated the preliminary evaluation.

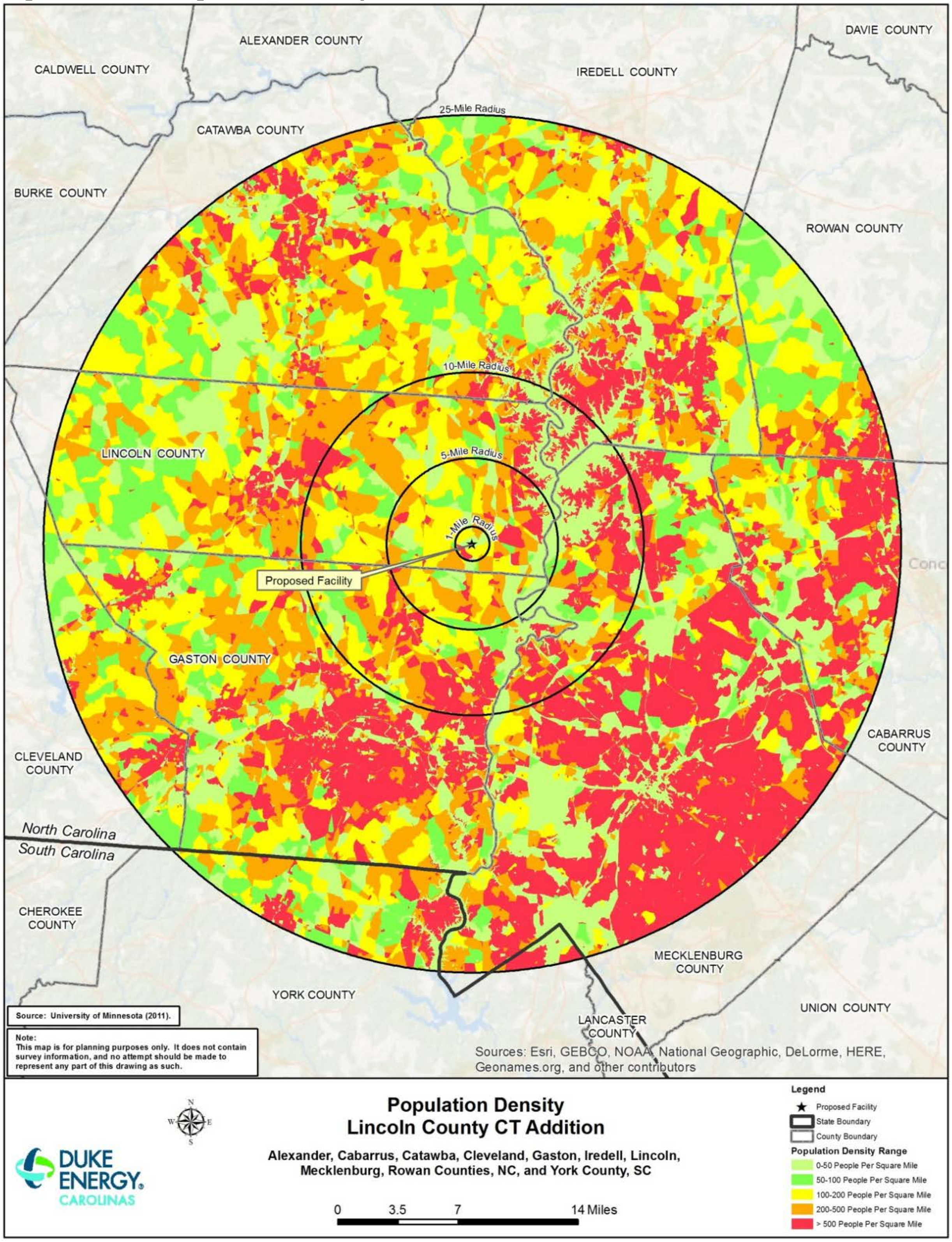
1.4 Site Characteristics

1.4.1 Local Population

According to the U.S. Census Bureau, Lincoln County's 2010 population was 78,265. The towns of Stanley and Lincolnton had 2010 populations of 3,556 and 10,486, respectively. The unincorporated community of Lowesville (a CDP, or census designated place) had a 2010 population of 2,945 (University of Minnesota 2011).

Within a 25-mile radius of the proposed facility, the population is about 1,374,000 (USCB 2015a).

Figure 1.4.1-1: Population Density



Sources: Esri 2016, USCB 2015a, University of Minnesota 2011

1.4.2 Area Development

1.4.2.1 Existing

A UCS representative met with Lincoln County planners on Friday, December 16, 2016, to discuss development in the area. The Trilogy at Lake Norman ([Trilogy], a 606-acre community with a maximum of 1,650 housing units for ages 55+) and the adjacent Killian's Pointe subdivision (all ages), located northeast of the site, are under construction (see Figure 1.1-2). The master plan for Trilogy shows that some units will be about 0.6 miles from the proposed facility (Combs 2016).

The Carrington subdivision has been approved for 87 acres near the intersection of Old NC Highway 16 and Pilot Knob Road, about 1.6 miles east of the proposed facility. This subdivision will have about 302 single-family homes (Combs 2016).

There are scattered rural-residential areas in the vicinity of the proposed facility. Using field reconnaissance, digital data from Lincoln County, and desktop analysis, UCS located approximately 158 single-family and two multi-family residences within one mile. In addition, one church and one community building are located within one mile of the proposed facility.

1.4.2.2 Future

Lincoln and Gaston counties are coordinating future development (industrial/commercial intermixed with conservation and open space) of over 600 acres at a proposed new interchange where new NC Highway 16 crosses the boundary between the two counties, but there are currently no firm plans. The two counties' planning departments developed a "small area plan" for this area, which is about two miles southeast of the proposed facility (Combs 2016).

The 2007 Lincoln County Land Use Plan shows future land uses around the proposed facility as mostly rural, suburban, or mixed residential (Lincoln County 2016). The Gaston County 2035 Comprehensive Land Use Plan, adopted September 27, 2016, shows future land uses south of the proposed facility as suburban development in addition to rural or rural communities (Gaston County Planning 2016).

1.4.3 Visual and Auditory

1.4.3.1 Visual

The degree of visual impact that the proposed generating facility will have on an existing feature (e.g., scenic vista, cultural resource) is directly related to the visual contrast between the proposed facility and the scenic quality of the existing area or region (i.e., the higher the scenic quality, the greater the potential for adverse visual impacts and vice versa). Scenic quality is derived from the interrelationship of multiple factors, including landform, vegetation, water, color, adjacent scenery, scarcity, and cultural modifications.

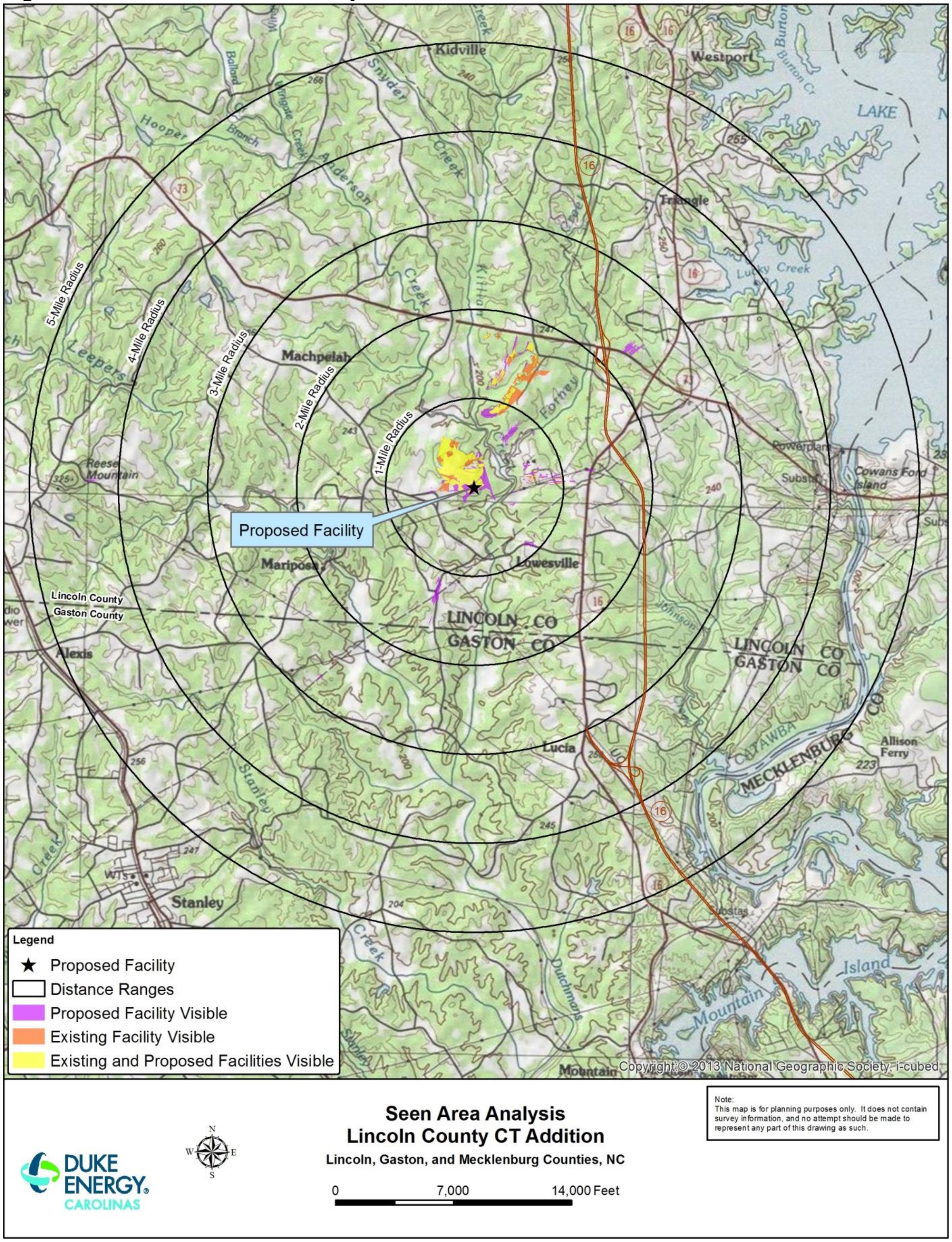
Topographic conditions for the surrounding area are typical of those within the Southern Piedmont Physiographic Province, primarily consisting of rolling to hilly terrain. Opportunities for scenic vistas are limited because there are few topographical high points, and the area is largely forested. Diverse land uses have a direct impact on the scenic quality of the area. Eastern portions of the study area, generally along the Highway 16 corridor, are highly modified by various types of residential, commercial, and industrial development and infrastructure. This area is characterized by a lack of visual definition or connectivity relative to varying land uses, and thus its visual quality relative to other areas has already been diminished. The central and western portions of the study area along Old Plank Road, Mariposa Road, and South Ingleside Farm Road contrast greatly to the highly developed Highway 16 corridor. This area is generally characterized by low-density rural-residential development. Historic resources, such as plantation homes and historic markers, can be discovered along rural tree-lined roads that are intermixed with occasional pockets of pasture. Although there are more contributions to scenic quality in the western portions of the study area than there are along the Highway 16 corridor, the western portions still lack widespread opportunities for scenic enjoyment, such as interesting landscape features.

During a probable visual effects field study, existing residential properties and public roadways were identified as resources with the potential to be most affected by views of the proposed facility, particularly views of the 90-foot-high turbine building and 130-foot-high stack.

Figure 1.4.3.1-1 shows areas within five miles that have a view of the existing simple-cycle plant only, areas with a view of the proposed facility only, and areas predicted to have views of both.

Table 1.4.3.1-1 displays the results of the Seen Area Analysis and Predicted Visual Effects. The data confirms that the proposed facility may be visible from only a minor portion of the surrounding area because of visual obstructions from hills and mature forest cover. Of the total area within five miles of the site (78.54 square miles), the proposed facility will be visible in areas totaling only 0.16 square miles (0.20 percent of the total area) outside the DEC-owned property that is generally inaccessible to the public. UCS further predicts that outside of the DEC-owned property, the future facility will be visible from only 0.11 square miles that do not already have a view of the existing generating facilities (0.14% of the total area).

Figure 1.4.3.1-1: Seen Area Analysis



Sources: ArcGIS 2013, Combs 2016, USDA National Elevation 2016, USDA Orthoimagery 2016

Table 1.4.3.1-1: Seen Area Analysis and Predicted Visual Effects

Visual Effects Probability	View Distance Range from Future Plants (miles)	Total Area (sq. mi.)	Probable Total Area with a View of Only the Existing Plants (sq. mi.) [1]	Probable Total Area with a View of Only the Future Plants (sq. mi.) [1]	Probable Total Area with a View of Both the Existing and Future Plants (sq. mi.) [1]	Probable View Area % of Total Area Where Additional Visual Effects Probability Could Occur[1, 2]
Very High	0.0 - 0.5	0.79	0.00	0.00	0.00	0.00%
High	0.5 - 1.0	2.36	0.01	0.05	0.02	2.12%
Moderate-High	1.0 - 1.5	3.93	0.06	0.03	0.02	0.76%
Moderate	1.5 - 2.0	5.50	0.02	0.01	0.01	0.18%
Low-Moderate	2.0 - 3.0	15.71	0.00	0.02	0.00	0.13%
Low	3.0 - 4.0	21.99	0.00	0.00	0.00	0.00%
Very Low	4.0 - 5.0	28.27	0.00	0.00	0.00	0.00%
Totals	**Totals**	**78.54**	**0.09**	**0.11**	**0.05**	**0.14%**

[1] Visibility not calculated within DEC-owned property.
[2] Areas with additional visual effects were those determined to not have a previous view of the existing Lincoln Plant.

***Very High*:** Plant element(s) will dominate the view because of proximity to the view point and/or the number of elements viewed; because their setting in the landscape commands strong visual attention; or a combination of these factors. Natural landscape elements will be dominated by plant elements.

***High*:** Plant element(s) will be dominant in the view because of their perceived size from the view point or the number of elements viewed; because their setting in the landscape commands strong visual attention; or a combination of these factors. Natural landscape elements will continue to be a moderate influence in the viewshed.

***Moderate-High*:** Plant element(s) will command strong visual attention in the viewshed but will be somewhat mitigated by the influence of the ambient landscape character.

Moderate*:* Plant element(s), though easily recognizable, will be visually subordinate to the ambient landscape character.

Low-Moderate: Plant element(s) will be easily recognized in the ambient landscape setting but command only casual attention in the view.

Low: Plant element(s) will be dominated by the ambient landscape character.

Very Low: Plant element(s) will be totally subordinate to the broader landscape setting and may not command attention from casual viewers.

The visual effects that will result from the addition of the proposed facility will be influenced by several factors, including the following:

- The distance from the viewer to the proposed facility
- The elements of the facility seen (i.e., the emission stack or the entire facility)
- The backgrounds of visible structures (i.e., whether visible structures are seen against backdrops such as vegetation, terrain, or man-made elements, or silhouetted against the skyline)
- The presence or absence of foreground and mid-ground vegetation or man-made elements in the view
- The overall scenic condition (landscape content and quality) of the area from which the facility is viewed

The data derived from the Seen Area Analysis and Predicted Visual Effects were correlated to probable visual effects ranging from Very High to Very Low in Table 1.4.3.1-1.

Using the distance from the viewer to the proposed facility site, UCS predicted (ranked) the visual effects that may occur as a result of the proposed plant. The ranking represents a worst-case scenario, since no attempt was made to reduce the predicted visual effects probability that will inevitably occur when foreground and mid-ground vegetation or backdrops are present. Also, no attempt was made to mitigate predicted view ranking based on existing modifications to natural landscape settings or the fact that only minor plant features may be seen from an area having a probable view. For example, even if only the top segments of the stack (the tallest structure) can be seen from half a mile away, the view effect was ranked as Very High.

1.4.3.1.1 Visibility from Residences

UCS conducted an extensive field investigation to determine the facility's probable visual effects on residential properties within visual proximity. Initial investigations showed that only two residential areas will have potential views of the proposed facility (a few homes near the Old Plank Road and Gold Hill Church Road intersection and the Trilogy residential development along Highway 73). UCS determined that other surrounding areas were sufficiently screened from the existing and proposed facilities by a combination of vegetation and terrain.

Fewer than a dozen homes near the intersection of Old Plank Road and Gold Hill Church Road may have a slight view of the tallest parts of the proposed facility (e.g., the exhaust stack and turbine building) on the horizon. These homes sit on one of only two topographical high points that do not have significant visual obstructions (e.g., tree cover) between the proposed facility's location and the homes (Figure 1.4.3.1.1-1). Although views, if any, will be slight, the visual quality of the area should not be negatively impacted because the distance to the facility (almost a mile) will render the stacks visually inferior to the surrounding environment, which already includes views of commercial development and electrical transmission lines.

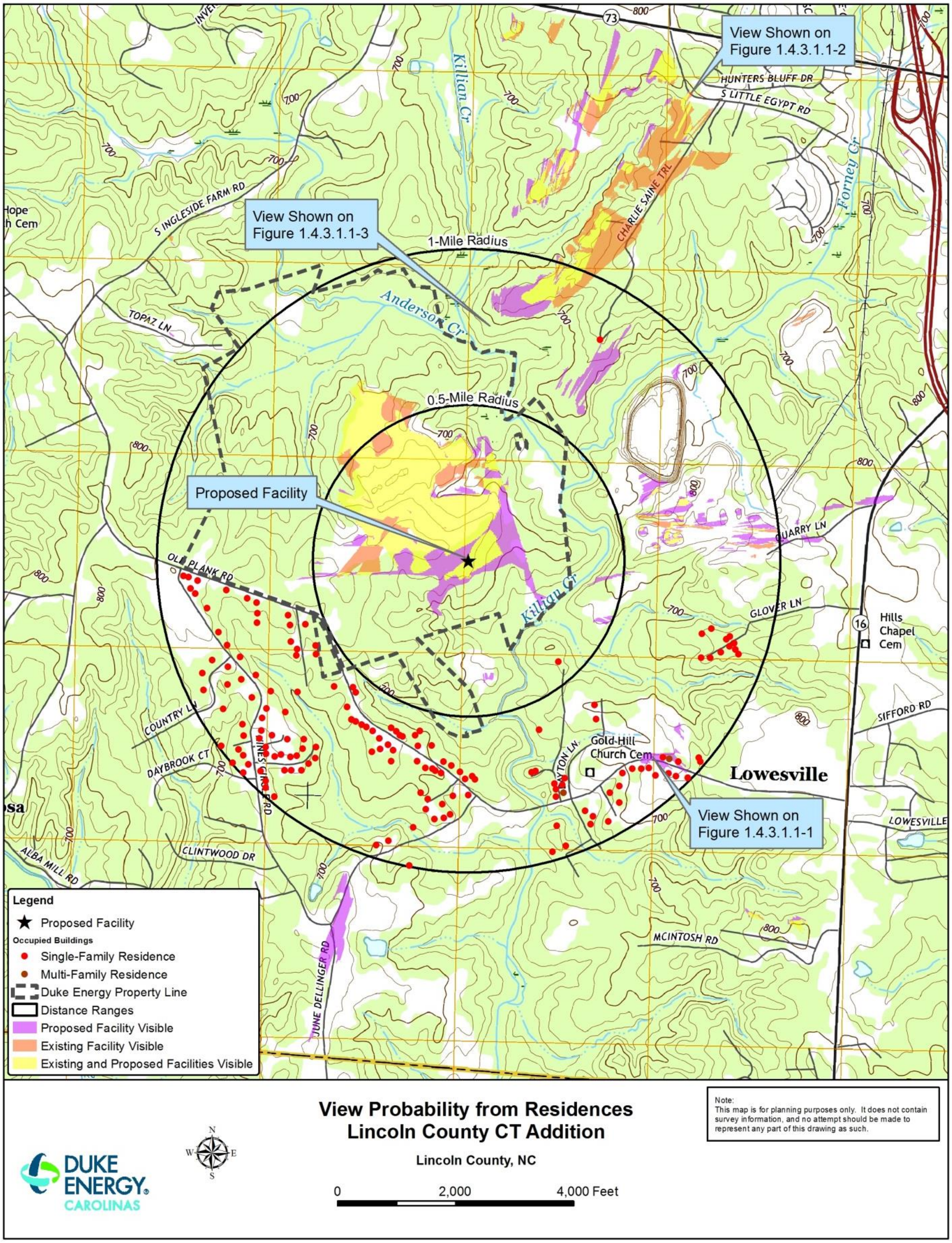
Figure 1.4.3.1.1-1: Old Plank Road Looking Northwest

The Trilogy residential subdivision that is currently being developed along Highway 73 is approximately 1.5 miles north of the proposed facility. This development is located on south-facing slopes that overlook and have open views of the existing station, which are exacerbated by widespread forest clearing within the development (Figure 1.4.3.1.1-2). Although the proposed facility will be visible from parts of the Trilogy property, as the development is built out, new homes and landscaping will provide foreground screening that will mitigate the overall view of the proposed facility.

Figure 1.4.3.1.1-2: S Little Egypt Road Looking South

Figure 1.4.3.1.1-3: Southern Edge of Trilogy Subdivision Looking South

Figure 1.4.3.1.1-4: View Probability from Residences



Sources Combs 2016; Lincoln County GIS/Mapping 2016a, 2016b, and 2016c; USGS 2016, USDA 2016, USDA Orthoimagery 2016

1.4.3.1.2 Visibility from Public Roads

The plant property is surrounded by four arterial or collector roads, including Old Plank Road to the south, South Ingleside Farm Road to the west, Highway 16 and Highway 16 Business to the east, and Highway 73 to the north. Except for a few residential roads within the Trilogy subdivision, only three primary roadways within the area will have a potential view of the proposed facility from any portion of the road. One is Old Plank Road, near its intersection with Gold Hill Church Road. The second is South Ingleside Farm Road, which is designated as a Scenic Byway on Lincoln County's Future Land Use Plan; and the third is Old Lowesville Road-June Dellinger Road, near the intersection with Hines Circle Road. In all of these cases, any views of the tallest parts of the proposed facility's exhaust stack and turbine building will be very slight due to distance and may only be evident momentarily to motorists, if at all.

1.4.3.2 Auditory

DEC contracted with Stewart Acoustical Consultants (Stewart) to conduct a detailed noise study in the vicinity of the proposed facility. A report of the noise study findings is included as Appendix A of this report.

Stewart focused on the following considerations in the study:

1. Existing Community Noise Levels
2. Estimated Sound Levels of Existing CTs and Proposed Addition
3. Estimated Sound Level Propagation of the Existing and Proposed Facilities
4. Anticipated Effects

1.4.3.2.1 Existing Community Noise Levels

Hedrick Quarry, East Lincoln Motor Speedway, Old Plank Road, and overhead aircraft are significant community noise sources. Current noise adjacent to the existing Lincoln CT station is primarily produced by aircraft approaching and leaving Charlotte Douglas International Airport, road traffic noise, mineral processing activities from the nearby quarry, and racecar engines at the speedway. Aircraft noise affects the greatest area around the station during daytime hours, although it drops significantly from midnight to 7:00 in the morning. Charlotte Douglas International Airport is located 18 miles south of the station. The airport's Runway 18C-36C is positioned north-south and nearly in line with the station. Homes near Old Plank Road experience significant levels of road noise due to traffic volume and vehicular speed. Quarry-produced noise (from road grading and machinery startup) can begin as early as 5:30 a.m. and is most significant for neighbors southeast of the station. From late March through September, residences near East Lincoln Motor Speedway experience significant race vehicle noise on Saturday evenings from 7:00 p.m. to 11:00 p.m. Appendix A includes detailed information about sound levels of all these sources.

Sound pressure levels (loudness) are measured by sound level meters in decibels (dB). To account for the relative loudness registered by the human ear (which is less sensitive to low audio frequencies), A-weighting is applied to the dB reading, and the decibel measurements are given as dBA. A quiet classroom or worship space would be about 35 dBA, whereas a normal conversation level would be about 60 dBA. An outdoor condensing fan about 20 feet away could be 50-55 dBA, but a loud siren might be 120 dBA.

The most significant noise levels that are part of the evaluation are shown in Figure 1.4.3.2.4. Although nighttime background noise levels can be as low as 35 dBA in remote locations, several significant existing sources that occur regularly can raise levels substantially. At key locations around the station, many of these sources are 47-60 dBA. Aircraft can generate maximum levels from 62-72 dBA.

1.4.3.2.2 Estimated Sound Levels of Existing CTs and Proposed Addition

Sound power levels are like watts for electricity in a light bulb. They are a measure of how much sound energy is being radiated per second into the air. The brightness of the light depends largely on how far the light is from the receiving location as well as the reflectivity of the surroundings and any objects creating shadows. The loudness of sound (sound pressure level, or sound level for short) generated by the sound power source depends on how far from the source the listener is, density of the ground, topography, and other factors such as blockage by buildings. To understand how much sound is being introduced into a location, one can compare the sound power of an existing source with that of a proposed source.

The anticipated sound level of the proposed facility (123.6 dBA) will be roughly equivalent to the sound level of the existing station's 16 CTs (123.2 dBA), based on estimated sound power levels of the components. Because of the way decibels are added, this leads to an increased total sound power of about 3 dBA. To the human ear, this is a barely noticeable increase.

1.4.3.2.3 Estimated Sound Levels of the Proposed Facility

Sound levels produced by the proposed facility will vary according to location because of distance, topography, and other factors; but no location will experience sound levels greater than 55 dBA with all CTs operating.

Figure 1.4.3.2.3-1 shows sound levels of the 16 existing CTs. Figure 1.4.3.2.3-2 shows sound levels of the proposed addition, and Figure 1.4.3.2.3-3 shows sound levels of both the existing CTs and the proposed CT. Because the combustion turbines will not be located at the exact same area of the Duke site, some neighbors will experience a larger increase than others. The greatest increase is to the southeast, where sound levels from the existing CTs are quite low; these will increase to about 52 dBA at the nearest house and 55 dBA at the nearest property line, a 10-11 dBA increase in Duke CT sound levels. Neighbors to the west should have no measurable sound level change. Neighbors to the southwest will have generally a 3-4 dBA increase (a barely noticeable difference), with one location having a 6 dBA increase (clearly noticeable difference) due to proximity to the proposed CT addition. Neighbors to the north (at the Trilogy property) will see less than a 2 dBA increase from the proposed CT (which is not noticeable to most people).

Figure 1.4.3.2.3-1: Noise Levels from Existing 16 CTs at the Lincoln CT Station

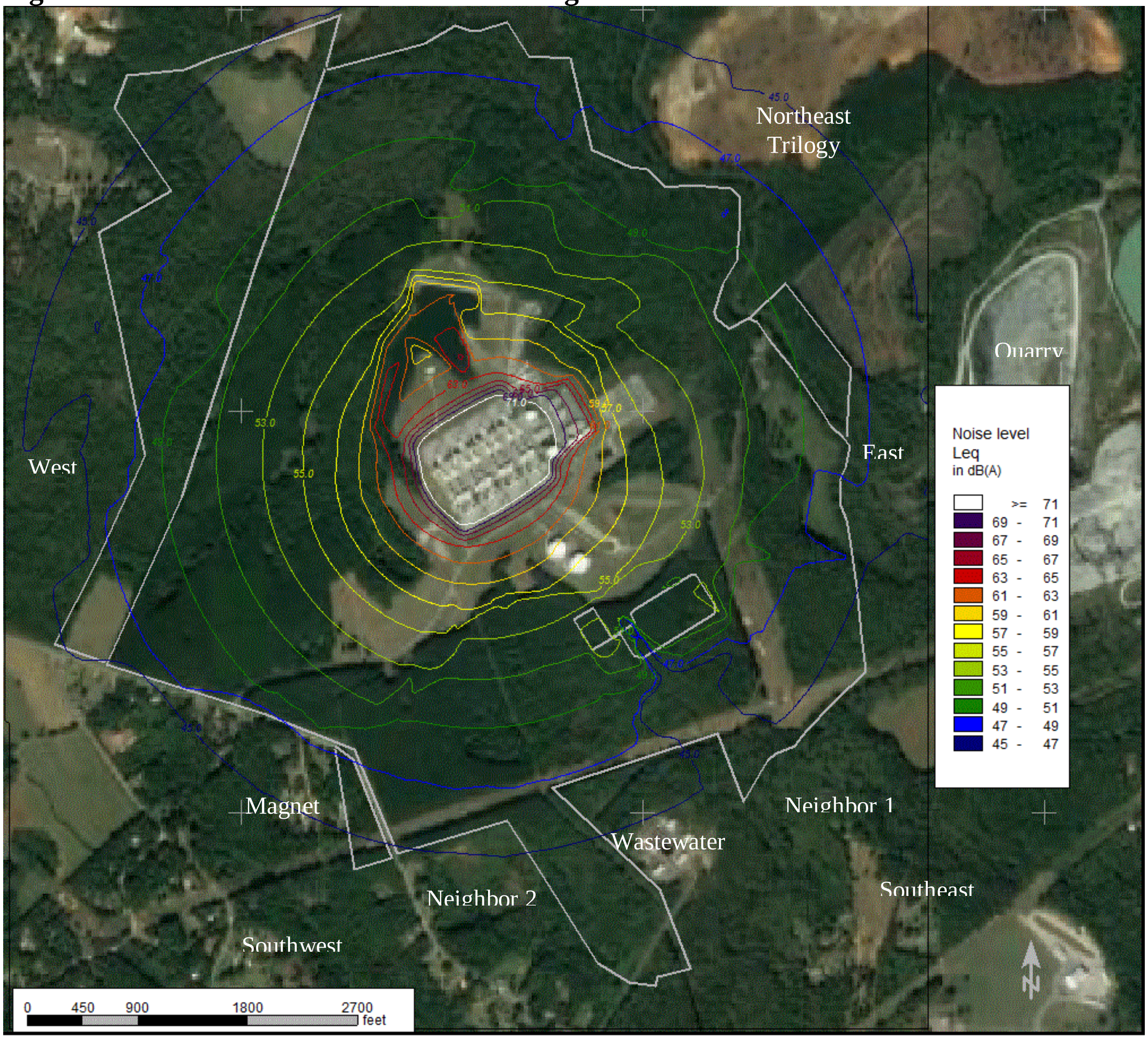


Figure 1.4.3.2.3-2: Noise Levels from the Proposed Facility

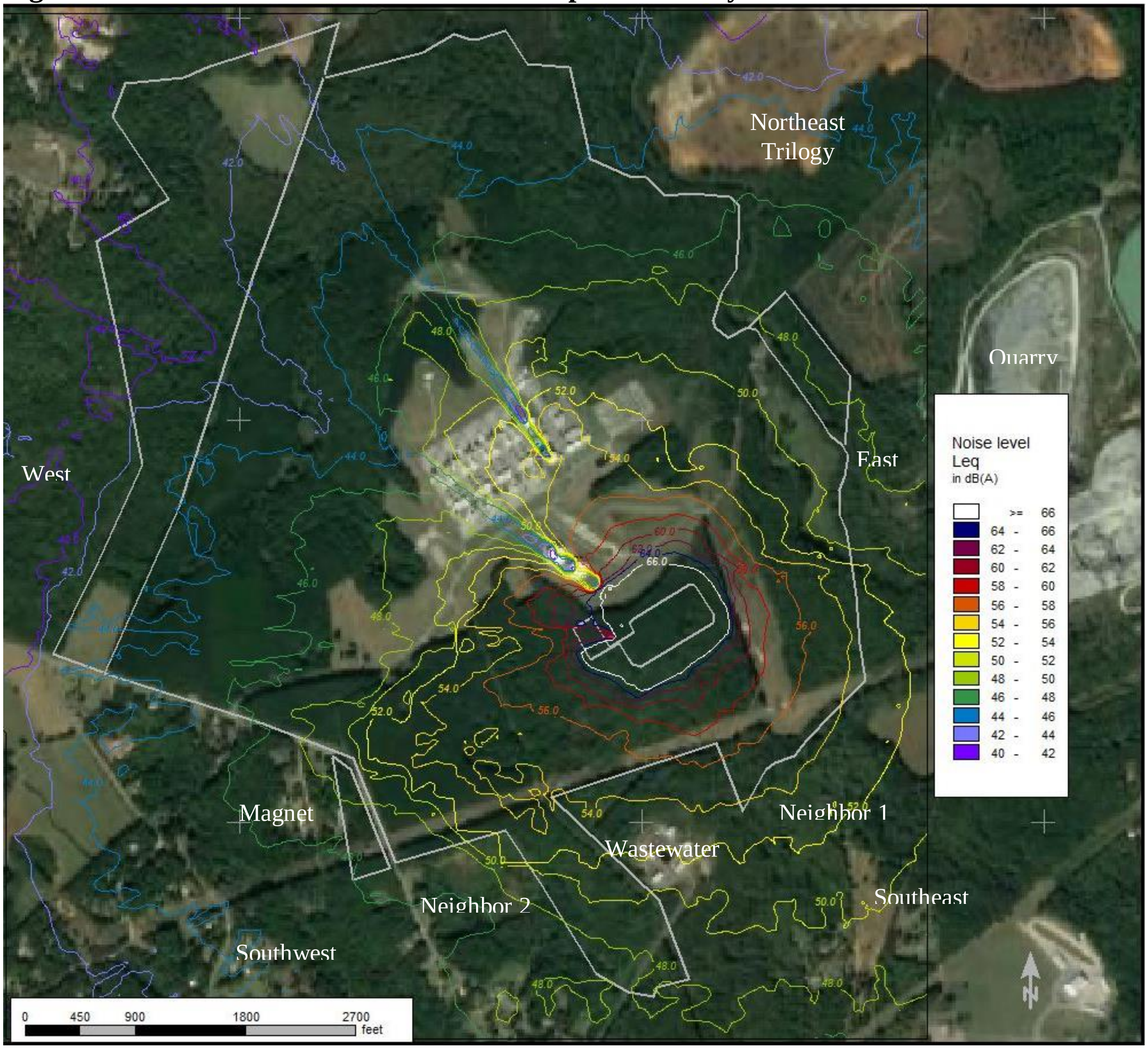
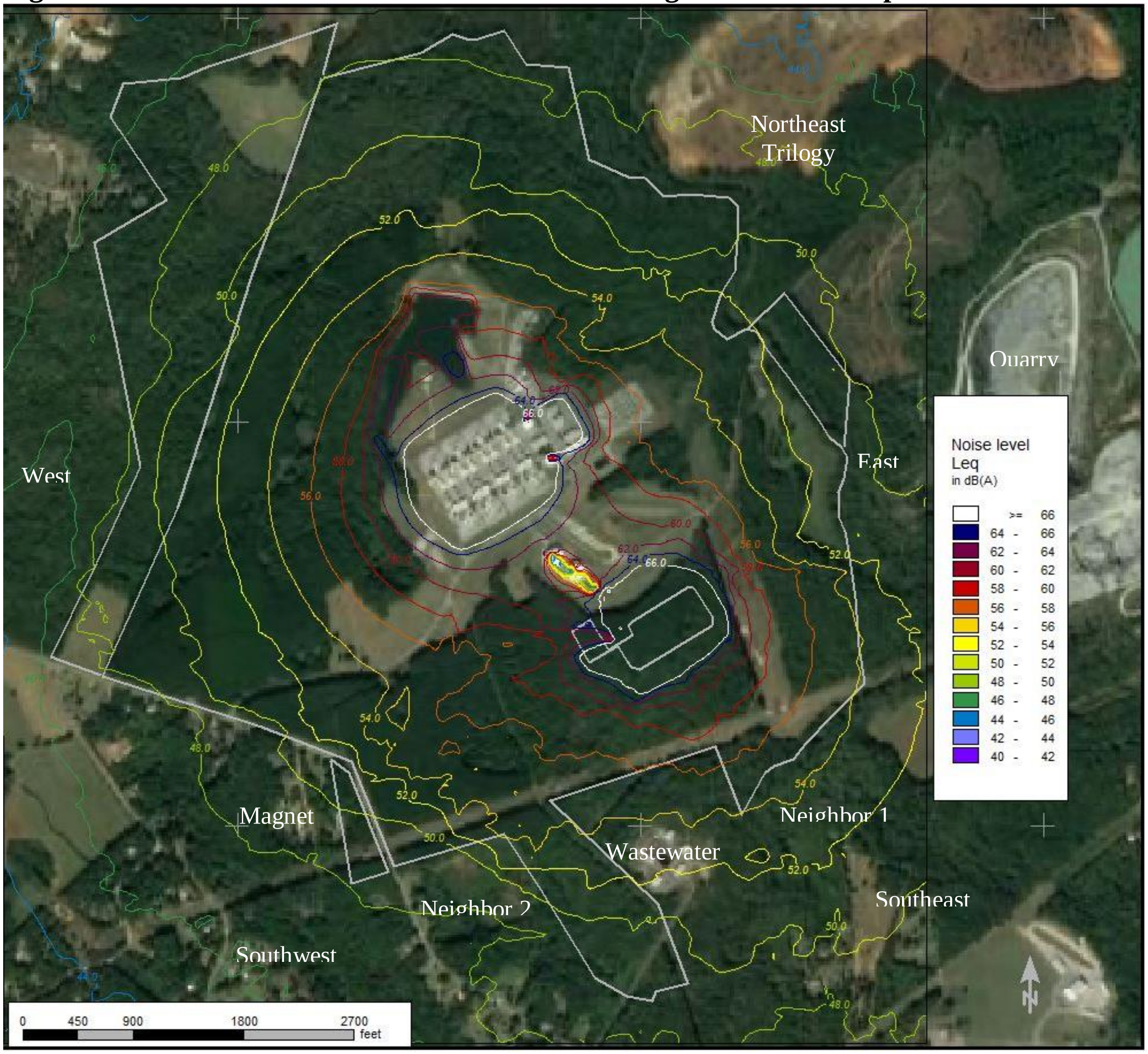


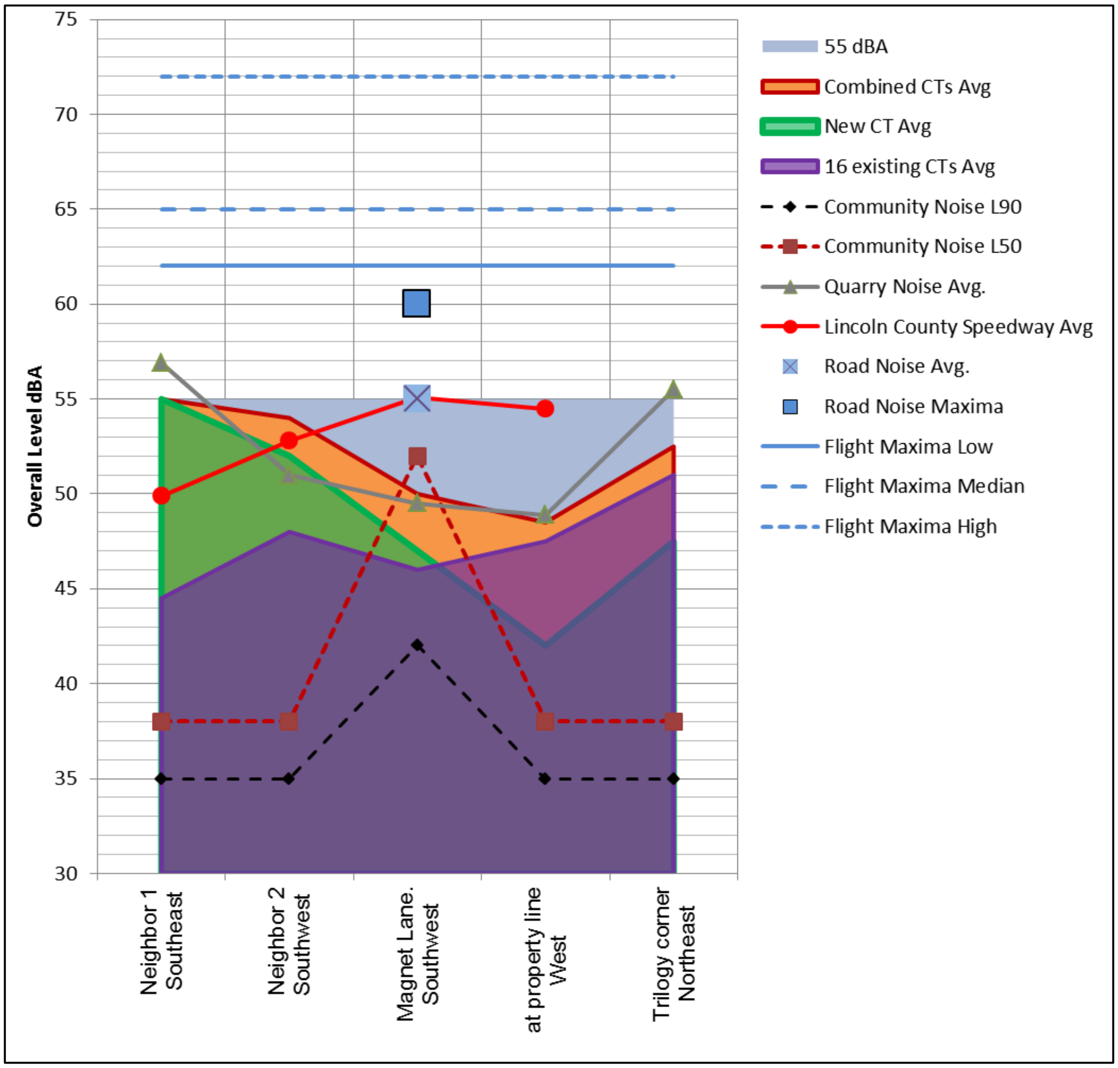
Figure 1.4.3.2.3-3: Combined Noise Levels of Existing 16 CTs and Proposed CT Addition



1.4.3.2.4 Anticipated Effects

Lincoln County's noise ordinance has no specified decibel limits, but it does prohibit noise from "becoming a nuisance to adjacent single-family detached and two-family houses and residential districts" (Unified Development Ordinance 2016). The Unified Development Ordinance does limit noise from race tracks. At night, 10-minute average levels cannot exceed 55 dBA for this kind of source. Stewart used these limits to draw some comparisons.

Figure 1.4.3.2.4: Comparison of Sound Levels at Critical Site Locations



Anticipated noise levels are similar to those of existing sources, meaning a minimal impact to most people. Figure 1.4.3.2.4 below displays various DEC and community noise source levels at the most critical site locations and the 55-dBA limit. Sound levels at most neighbor locations are below 55 dBA; only one location (the property line of Neighbor 1 to the southeast) is as much as 55 dBA. It should be noted, however, that the Neighbor 1 property was sold to Hedrick Quarry in 2016; and the zoning for the property is now listed as Residential Transitional.

For the Neighbor 1/Hedrick Quarry property to the southeast, noise levels from the quarry and race track are estimated to be 57 dBA and 50 dBA respectively. Aircraft from Charlotte Douglas International Airport produce slow A-weighted maximum levels of 62-72 dBA. Although clearly the noise source will be new and thus noticed, it is not more than 55 dBA, and is not more than other sources affecting this property.

Other homes to the southwest show a clear increase from DEC sources, from 50 to 54 dBA with all CTs (existing and proposed) operating (a 3-6 dBA increase); by comparison, racetrack noise levels are estimated to be 53-55 dBA. Sound levels along Plank Road were measured at about 55 dBA.

Sound levels for property to the west and north (Trilogy) are not noticeably changed from those of the existing station, and most of the property is below 50 dBA.

For these reasons, it is anticipated that noise impacts to most of the surrounding neighbors will be minimal. Neighbor 1/Hedrick Quarry and Neighbor 2 will have a clearly noticeable increase in DEC sound levels, but total levels do not exceed 55 dBA; and other sources are generating similar levels at these properties. Thus impacts should not be significant.

1.4.4 Aesthetic/Cultural Resources

The federal government's official list of cultural resources, which includes districts, archaeological sites, aboveground sites (buildings), and objects deemed worthy of preservation, is the National Register of Historic Places (NRHP). The NRHP was established with the passage of the National Historic Preservation Act (NHPA) of 1966 as amended, and traditionally uses four classifications for cultural resources: NRHP Listed, NRHP Eligible, Potentially Eligible, and Not Eligible. Cultural resources consist of historic and archaeological resources (USDA 2015, U.S. Department of the Interior 1983).

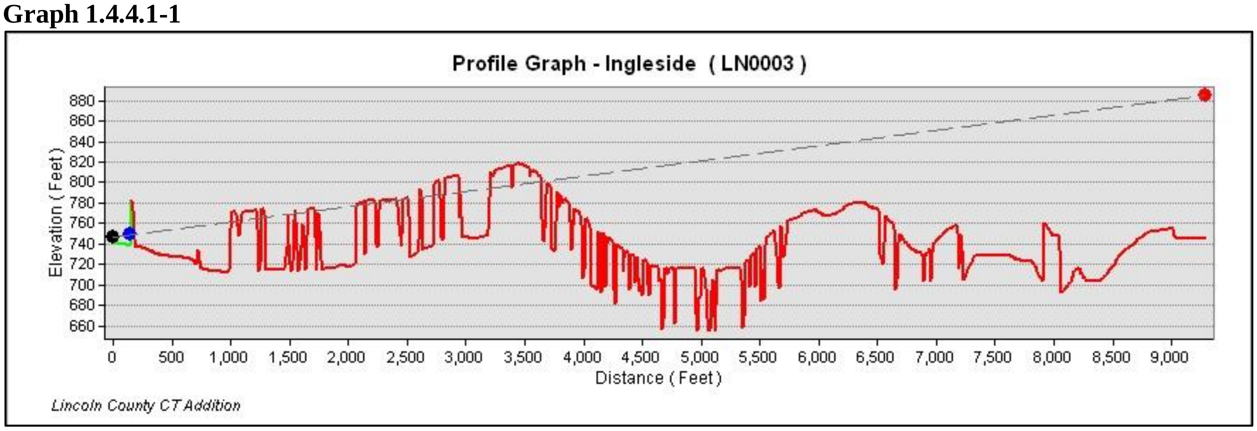
1.4.4.1 Historic Resources

In December 2016, Brockington conducted a records review and architectural windshield survey within a defined area of potential effect (APE) for the proposed facility (Appendix B). Because of the scale and nature of the undertaking, the APE was a 2.5-kilometer (1.5-mile) radius around the proposed CT station.

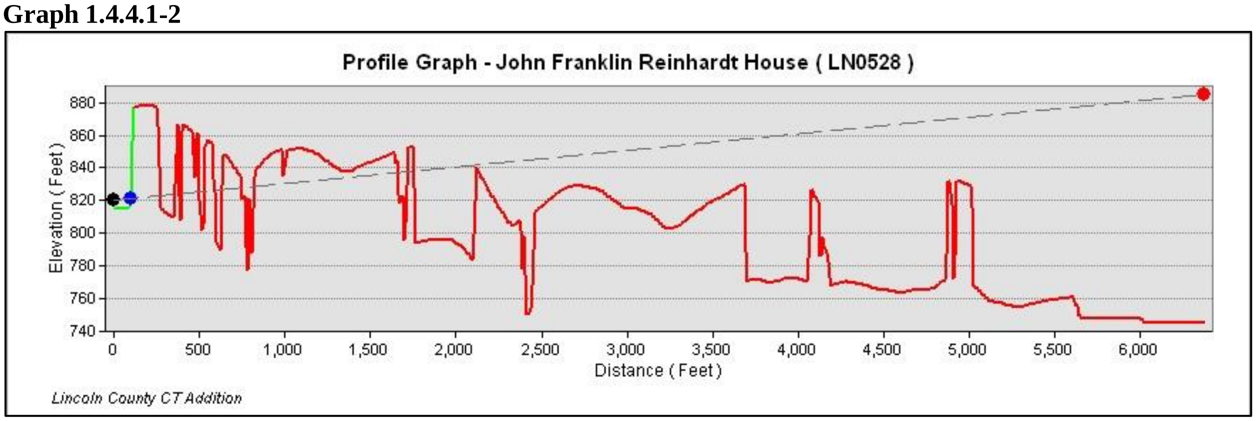
Brockington's data review identified seven previously recorded architectural resources that met the NRHP age criterion of 50 years or older. Of those seven resources, two are listed on the NRHP (LN003 "Ingleside" and LN0528 "John Franklin Reinhardt House/Mount Welcome"), three are eligible for the NRHP (LN0527 "John R. Asbury House", LN0540 "Kincaid Family House", and LN0573 "Mariposa Road Bridge"), and two are potentially eligible for the NRHP (LN0529 "Mariposa Cotton Mill" and LN0585) (Appendix B). Resource LN0585 could not be located during the field reconnaissance investigation and may have been demolished. Brockington also observed a number of other properties which met the NRHP age criterion of 50 years or older but had not been recorded because of architectural integrity issues, severe alterations to the original structures, and/or lack of architectural significance.

Potential visual impacts as a result of the proposed facility were assessed for each of the six identified cultural resources. Because mature forest cover provides foreground screening and because of the distance of 1-2 miles between the resources and the proposed facility, the proposed facility is not expected to be visible from five of the six located resources, as confirmed by the profile graphs below. Viewshed modeling indicates that the John R. Asbury House could have a slight view of the tallest parts of the facility from the adjacent road. Because of the distance (1.5 miles) to the proposed plant and the density of foreground and mid-ground screening provided by mature tree cover, the proposed plant facility will be visually subordinate to the surrounding landscape and thus will have no negative visual impacts on the John R. Asbury House.

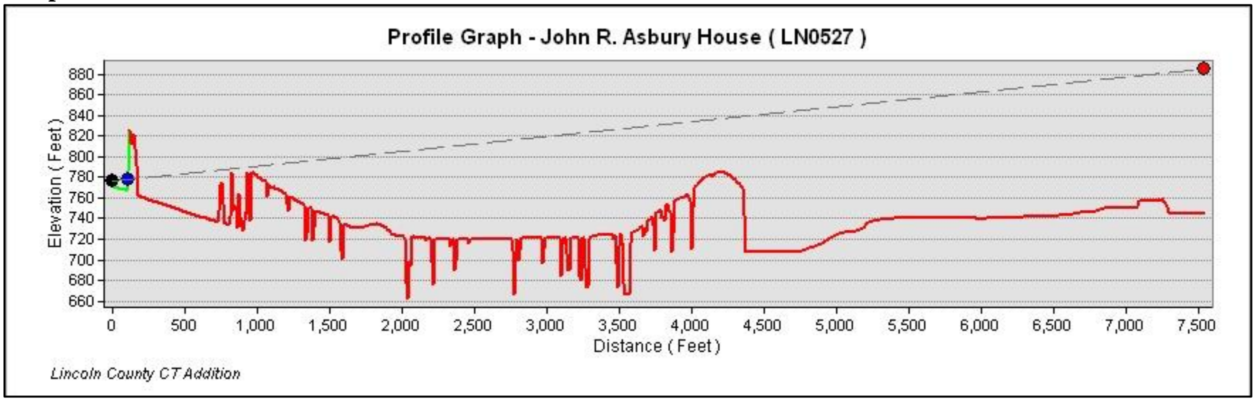
Graph 1.4.4.1-1



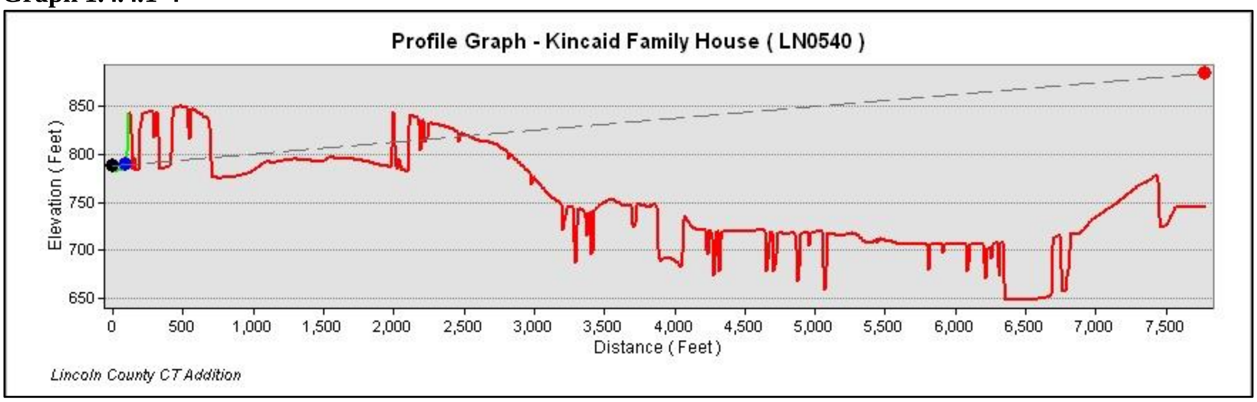
Graph 1.4.4.1-2



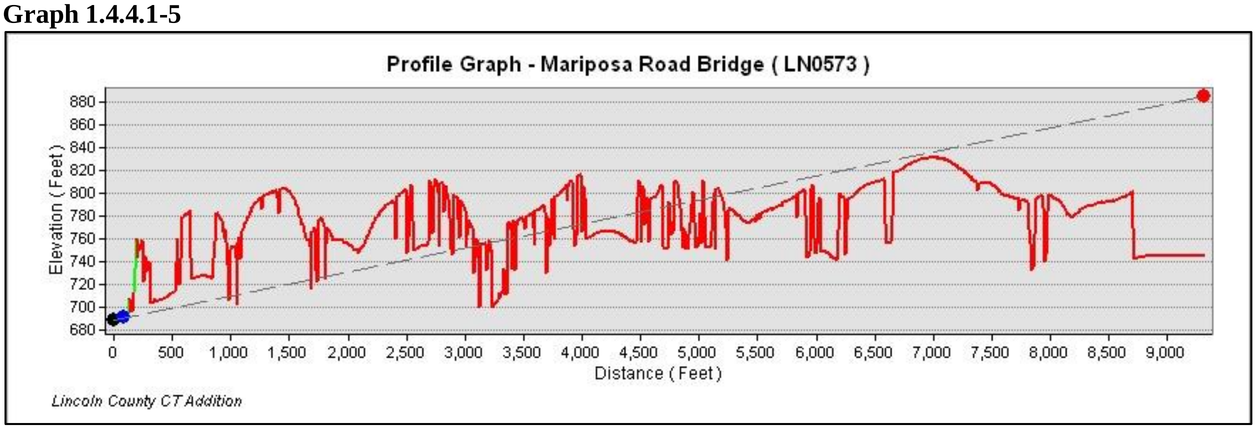
Graph 1.4.4.1-3



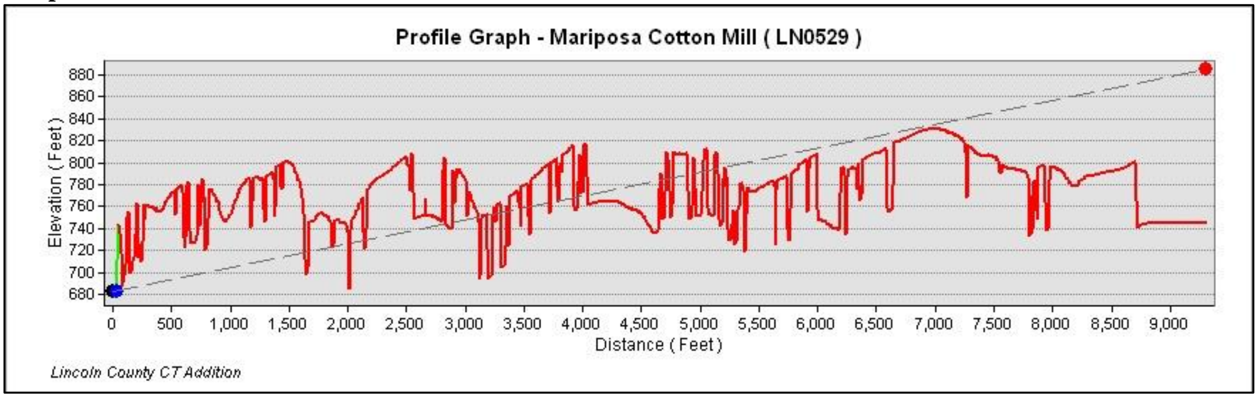
Graph 1.4.4.1-4



Graph 1.4.4.1-5



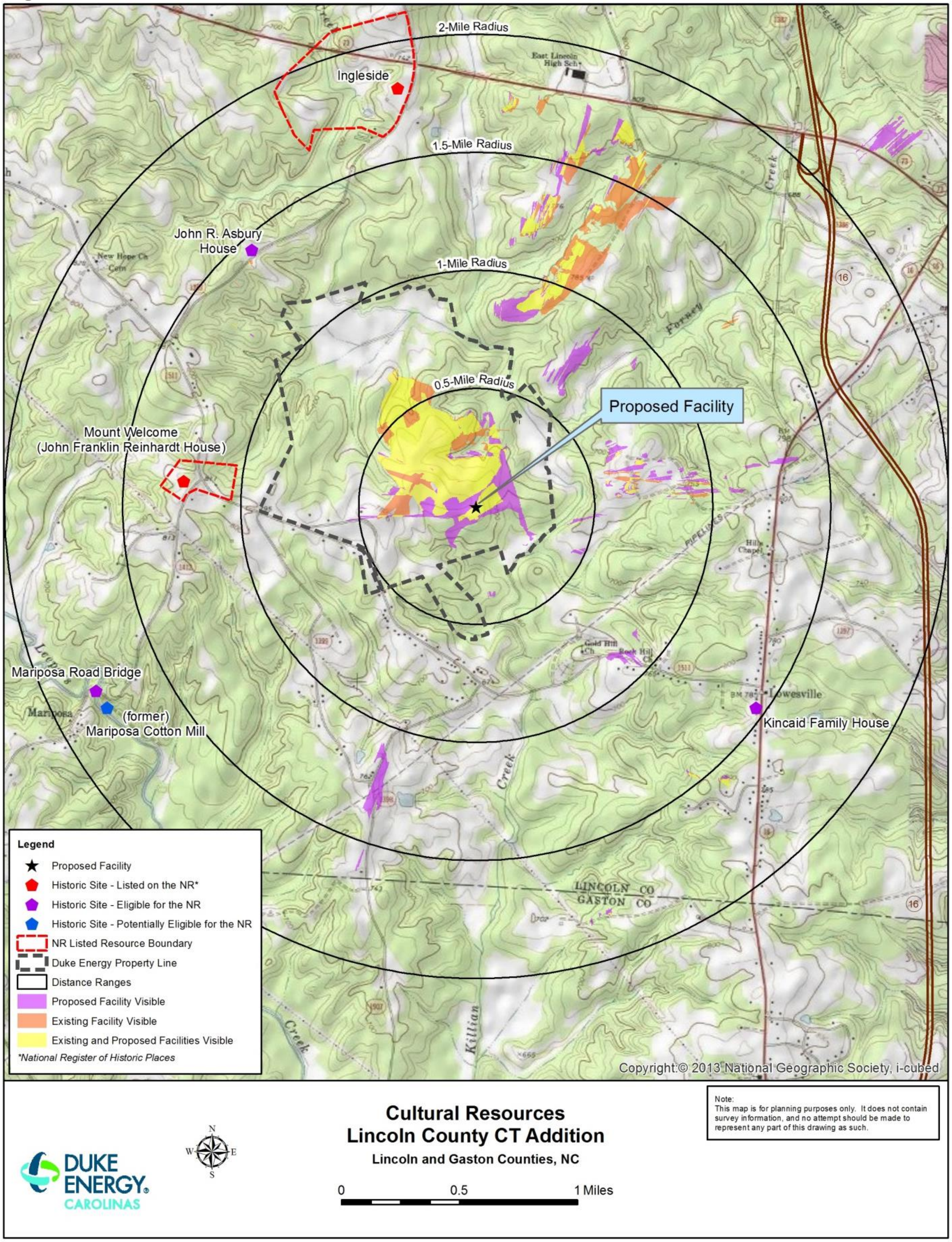
Graph 1.4.4.1-6



Profile Graph Legend

Green line	Probable Visible Terrain/Vegetative Surfaces from the Viewpoint
Red line	Probable Not Visible Terrain/Vegetative Surfaces from the Viewpoint
Black dot	Viewpoint at the Resource
Blue dot	Screening Element (Terrain or Vegetation) on the Line-of-Sight From the Viewpoint to the Top of Proposed Plant Emission Stack
Green dot	Top of Proposed Plant Emission Stack Seen
Red dot	Top of Proposed Plant Emission Stack Not Seen

Figure 1.4.4.1-1: Cultural Resources



Sources: Topographic Maps 2013, Combs 2016, Lincoln County GIS/Mapping 2016a and 2016b, USDA 2016, USDA Orthoimagery 2016

1.4.4.2 Archaeological Sites

Brockington also visited the North Carolina Office of State Archaeology in Raleigh to conduct a literature review of previous reports and site files for known archaeological resources. Of note, Brockington conducted a 1990 archaeological survey of the Duke Energy Combustion Turbine plant site ("Lowesville Tract") in advance of construction of the present-day station (Appendix B-1). Through this and other previous surveys as well as independent investigations, 48 archaeological sites have been recorded within the APE. One of these sites (Site 31LN78) was determined eligible; however, it was mitigated through data recovery and does not need consideration for planning purposes. Two sites are categorized as "unassessed" and, as they have no formal determination of eligibility, they should be considered potentially eligible. None of the noted unassessed archaeological sites are located within the proposed facility's footprint. The remaining 45 sites are noted on their respective site forms as not eligible for the NRHP.

For specific information concerning cultural resources in the vicinity of the proposed facility, see Brockington's reports (included as Appendix B, Literature Review and Windshield Survey of the Proposed Lincoln County CT Addition, Lincoln County, North Carolina and Appendix B-1, Archaeological Survey and Testing at the Lowesville Tract, Lincoln County, North Carolina).

A request for concurrence with the findings of the Brockington report was sent to the North Carolina State Historic Preservation Office (SHPO), and SHPO responded that, because they are unaware of any historic properties that would be affected by the proposed project, they have no comment (Appendix B-2).

1.4.5 Geological

The study area for the geological assessment is comprised of a five-acre plot of land adjacent to the switchyard of the existing station and an approximately 95-acre plot south of the station, the areas where the proposed transmission switchyard and CT facility, respectively, would be located.

1.4.5.1 Geology and Geologic History

The eastern United States consists of three major physiographic regions: the Blue Ridge Mountain region, the Piedmont region, and the Coastal Plain region. The proposed facility will be located in the Piedmont region, which extends from New Jersey to central Alabama and sits between the Atlantic Coastal Plain and the Blue Ridge and Appalachian Mountains. This approximately 80,000-square-mile region is characterized by undulating hills with broad, semi-dissected valleys; and surface relief typically varies from 200 to 800 feet above mean sea level.

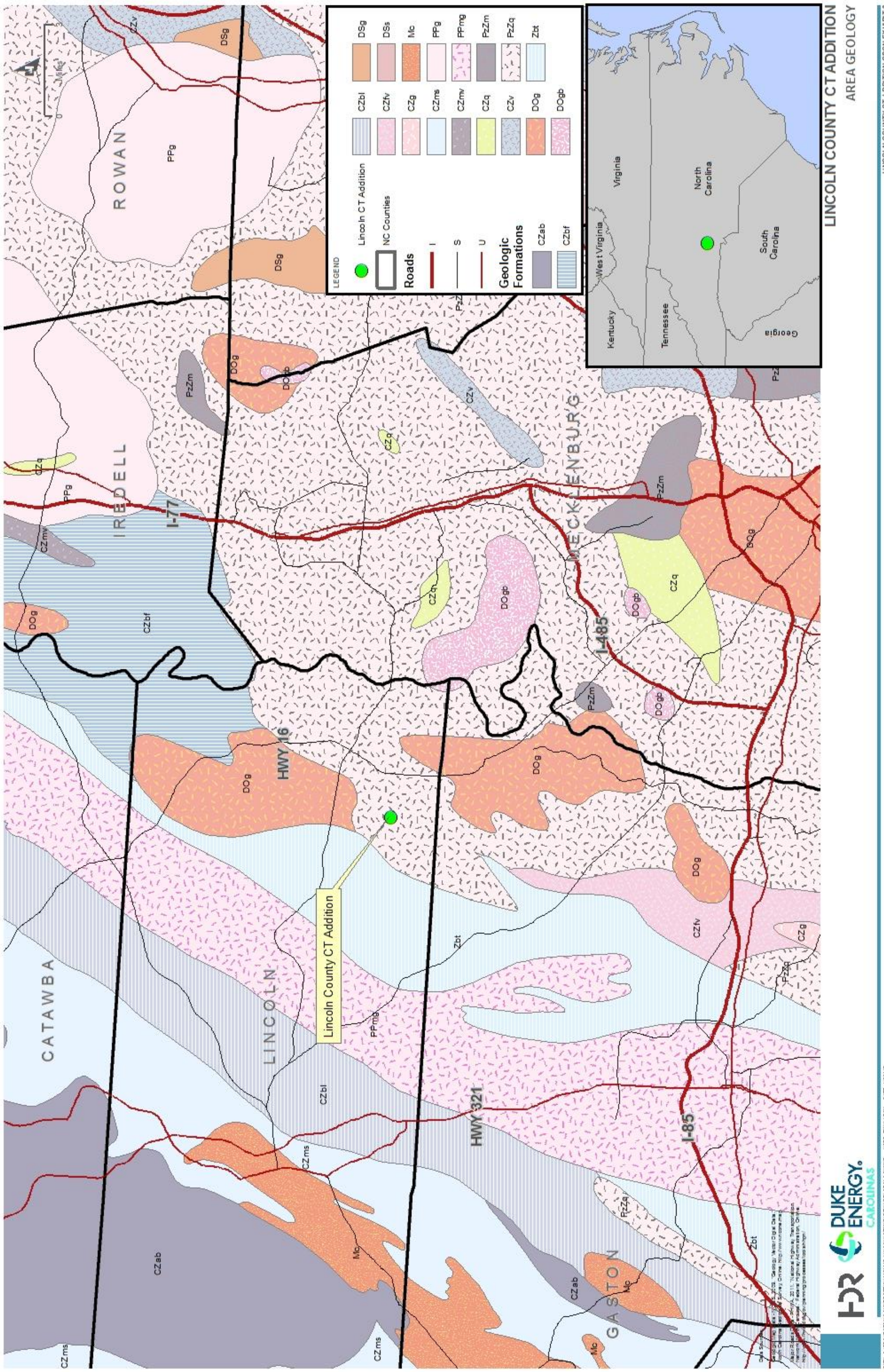
The geology of the region is complex. During the earliest Paleozoic Era (541–252 million years ago [MYA]), North America was situated near the equator, and the current-day Appalachian region was submerged beneath shallow seas. During this time, terrigenous and carbonate sediment was deposited, which later transformed into extensive layers of sedimentary and carbonate rock through lithification. The first significant mountain building event, or orogeny, occurred around 440–480 MYA, and thus the early Appalachian mountain chain began to form. During this event, as well as subsequent mountain-building events, the Appalachian region was folded, faulted, intruded by magma, sheared, uplifted, and metamorphosed. Both the Blue Ridge and Piedmont regions were transported over 100 miles west, telescoping into a series of folded, thrusted crustal sheets.

As a result of continental collision, rocks were accreted onto the present-day North American continent as a patchwork of volcanic islands and fragments of land and former ocean-bottom sediments. This led to the formation of distinct geologic belts, or terranes, that currently trend northeast-southwestward (Hibbard et al. 2002; Secor et al. 1983). The study area is located in the Charlotte terrane of the Inner Piedmont zone, just east of the Kings Mountain belt (see the geologic map shown on Figure 1.4.5.1-1 [NCGS 2009]). The Charlotte terrane is composed of medium- to high-grade metamorphic rocks, including gneiss, schist, amphibolite, diorite, minor quartzite, and aluminosilicate schist. Units are intruded by a variety of pre-and post-kinematic (granitic) plutons (Overstreet and Bell 1965). The Kings Mountain belt is a narrow (10- to 20-mile) elongated area trending northeast-southwest; it is comprised mostly of metasedimentary rocks with some granite gneiss, biotite gneiss, metamorphosed quartz diorite, and intrusive granitic bodies. Also present are other resistant rocks (e.g., quartzite, kyanite, and conglomerate) which form a chain of hills (e.g., Crowders Mountain and Kings Mountain) less than 30 miles west and southwest of the site of the proposed facility.

The bedrock underlying the site is typical of the rocks of the Charlotte terrane (see Figure 1.4.5.1-1, Area Geology). The study area is underlain by intruded, foliated to massive metamorphosed quartz diorite bedrock (PzZq). Locally, there are intrusions of pinkish-gray granitic rock, which may be massive to weakly foliated (DOg); Horneblende is typically present in these granitic intrusive rocks. To the northeast there are additional granitic intrusive rocks (PPg) of Pennsylvanian to Permian age (265–325 MYA), which are typically megacrystic to equigranular. Named intrusions include the Churchland, Landis, and Mooresville intrusives. To the west are metamorphic rocks of the Kings Mountain belt, including the Battleground (Zbt) Formation (quartz-sericite schist with metavolcanics) and the Blacksburg (CZbl) Formation (sericite schist, with graphite, phyllite and banded marble), with strongly foliated fine-grained biotite gneiss (CZbf) to the north of the study area. Additional intrusions in the Kings Mountain belt include the Mississippian-age (351 MYA) Cherryville Granite (Mc), which is massive to weakly foliated with pegmatites, and granitic rocks (PPmg) of Pennsylvanian to Permian age (270–230 MYA) (i.e., High Shoals Granite).

On-site exploratory drilling has been completed in the areas expected to include structures and roads. The study area's depth to bedrock varies between 3 and 10 meters (m) thick, and the average thickness of the overlying saprolite layer in the region is between 15 to 30 meters (m) thick.

Figure 1.4.5.1-1: Area Geology



1.4.5.2 Dominant Soil Types

Shallow subsurface material of the Inner Piedmont typically consists of thick saprolite (i.e., residual soil) units (15–30m) overlaying fractured bedrock. Saprolite consists of mostly red to brown, clayey subsoils. HDR located, identified, and classified soils within the study area using the U.S. Department of Agriculture Natural Resources Conservation Service (NRCS) Gridded Soil Survey Geographic (gSSURGO) Database (Figure 1.4.5.2-1) (NRCS 2016). Based on the soil data (NRCS Gridded Soil Survey 2016), the proposed facility foundation material in the shallow subsurface consists primarily of soils within the Lloyd series (sandy clay loam) and the Pacolet series (sandy clay loam).

The approximately 95-acre plot of the study area consists of Lloyd sandy clay loam (LdB2 and LdC2), accounting for 89.6 percent of the profile, with a very minor percentage of Wynott-Winnsboro-Rowan complex (WyD) (5.2 percent) (Figure 1.4.5.2-1). The difference between the two types of Lloyd series soils is the typical range in slopes: LdB2 typically has slopes of 2 to 8 percent, whereas LdC2 has slopes of 8 to 15 percent. Soils of the Lloyd series are usually deep, well drained, moderately permeable, moderately eroded soils that have formed as the residuum of intermediate and mafic igneous rocks and medium to high-grade metamorphic rocks. This saprolite is typically derived from a diorite, gabbro, diabase, and/or gneiss parent rock. The typical soil profile of the Lloyd series soils is included in Table 1.4.5.2-1.

The five-acre plot is underlain by both LdC2 (2.3 percent) and Pacolet sandy loam (PaD) (2.7 percent). The soils of the Pacolet series consist of very deep, well drained, moderately permeable soils that form in residuum primarily from felsic igneous and metamorphic rocks (granite or gneiss). The PaD series has average slopes ranging from 15 to 25 percent. The typical soil profile is provided in Table 1.4.5.2-1.

Pacolet sandy clay loam (PeC2) comprises a very minor portion (0.2 percent) of the southwest corner of the approximately 95-acre plot and has a slightly different soil profile from that of PaD as well as steeper slopes (8 to 15 percent). PeC2 is usually weathered from granite, gneiss, and/or schist and the soil profile is included in Table 1.4.5.2-1.

WyD soil units typically have slopes of 15 to 25 percent and are derived from diorite, gabbro, diabase, and/or gneiss parent material. They are well drained soils; and because the soil series is comprised of three individual types (i.e., Wynott, Winnsboro, Rowan), all three typical profiles are included in Table 1.4.5.2-2.

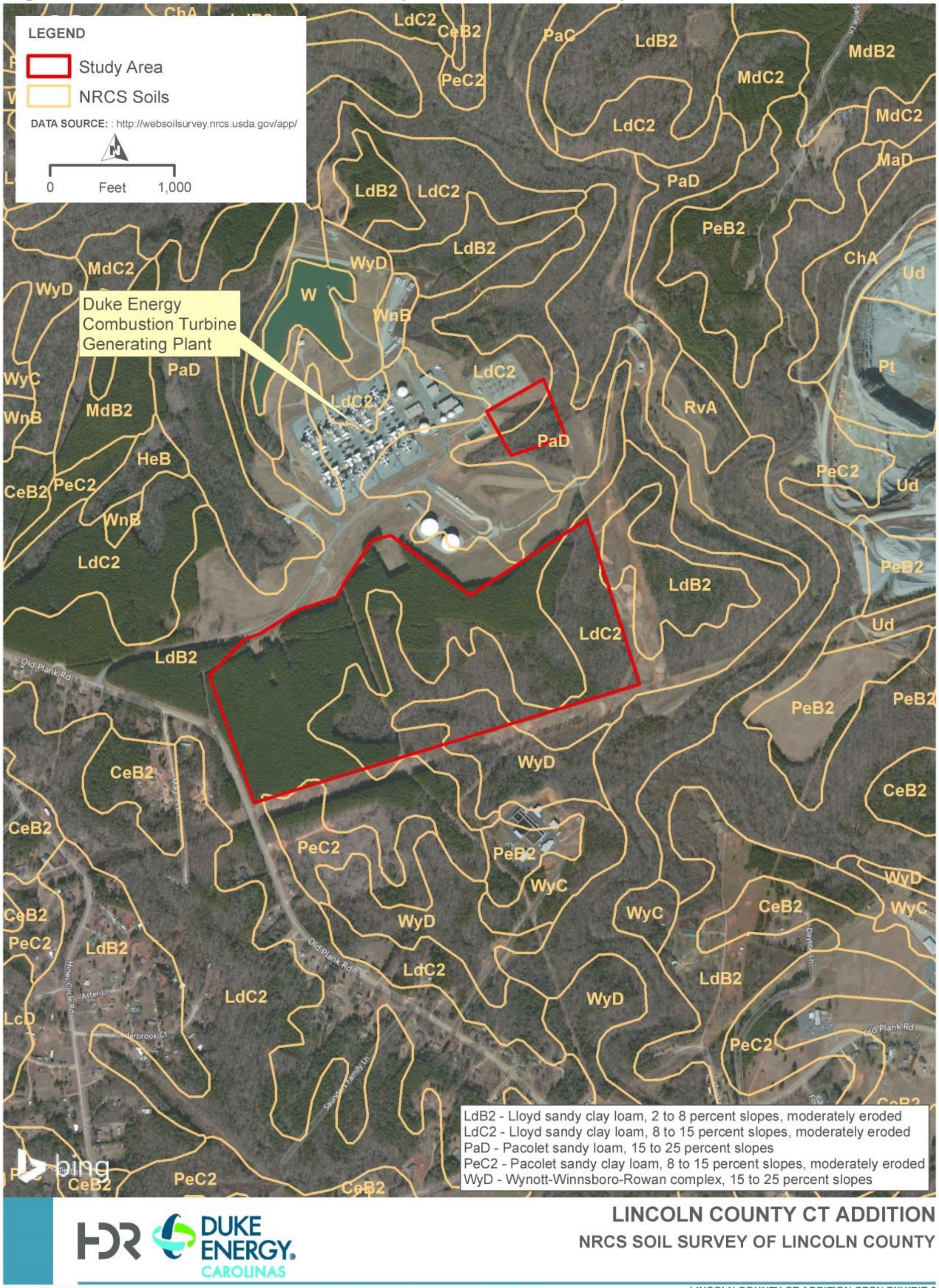
Table 1.4.5.2-1: Typical Subsurface Soil Profiles of the Site (Source: USDA Gridded Soil Survey 2016)

Lloyd Sandy Clay Loam (LdB2 and LdC2)		Pacolet Sandy Loam (PaD)		Pacolet Sandy Clay Loam (PeC2)	
Depth (inch)	**Description**	**Depth (inch)**	**Description**	**Depth (inch)**	**Description**
0-7	Clay loam	0-6	Sandy loam	0-7	Sandy clay loam
7-58	Clay	6-38	Clay	7-24	Clay
58-73	Clay loam	38-80	Sandy clay loam	24-33	Sandy clay loam
73-80	Loam			33-80	Loam

Table 1.4.5.2-2: Typical Subsurface Soil Profiles for Wynott-Winnsboro-Rowan Series (Source: USDA Gridded Soil Survey 2016)

Wynott (WyD)		Winnsboro (WyD)		Rowan (WyD)	
Depth (inch)	**Description**	**Depth (inch)**	**Description**	**Depth (inch)**	**Description**
0-4 4-14	Sandy loam Sandy loam	0-8 8-11	Fine sandy loam Clay loam	0-6 6-20	Sandy loam Clay loam
14-24	Clay	11-32	Clay	20-25	Sandy loam
24-28 28-80	Sandy clay loam Weathered bedrock	32-37 37-60	Clay loam Loam	25-80	Loamy sand

Figure 1.4.5.2-1: NRCS Soil Survey of Lincoln County



Settlement and proper foundation support are concerns that will be assessed by site-specific exploration. Potential settlement of project structures and appropriate foundation support of infrastructure under static and dynamic (earthquake, machinery, etc.) loading will be addressed as part of preliminary and final design for the project structures.

1.4.6 Ecological

The ecological study area for the Lincoln County CT Addition includes a five-acre tract upon which the switchyard expansion will be located and an approximately 95-acre tract where the proposed facility and its associated components will be located. This heavily forested area is surrounded by agricultural, maintained open areas, residential properties, and forested undeveloped lands. Detailed information on the ecological resources of the proposed facility can be found in Appendix C of this report.

1.4.6.1 Terrestrial Resources

1.4.6.1.1 Botanical

Based upon the Classification of the Natural Communities of North Carolina – Fourth Approximation (Schafale 2012), one distinct natural community can be classified as Mesic Mixed Hardwood Forest (Piedmont Subtype); it is located in uplands along the existing drainage areas within the study area. The remaining forested areas are managed planted pine forests. Below is a description of plant species identified during HDR's site visit in each forest community type.

<u>Mesic Mixed Hardwood Forest (Piedmont Subtype)</u>

This community is comprised of mature woody, herbaceous, and vine species including black oak (*Quercus velutina*), northern red oak (*Quercus rubra*), scarlet oak (*Quercus coccinea*), water oak (*Quercus nigra*), white oak (*Quercus alba*), American sycamore (*Platanus occidentalis*), American beech (*Fagus grandifolia*), American elm (*Ulmus americana*), loblolly pine (*Pinus taeda*), shortleaf pine (*Pinus echinata*), mockernut hickory (*Carya tomentosa*), sweetgum (*Liquidambar styraciflua*), tulip poplar (*Liriodendron tulipifera*), red maple (*Acer rubra*), American holly (*Ilex opaca*), black cherry (*Prunus serotina*), ironwood (*Carpinus caroliniana*), flowering dogwood (*Cornus florida*), possumhaw holly (*Ilex decidua*), redcedar (*Juniperus virginiana*), greenbrier (*Smilax rotundifolia*), Japanese honeysuckle (*Lonicera japonica*), crossvine (*Bignonia capreolata*), strawberry bush (*Euonymus americanus*), lopseed (*Phryma leptostachya*), spotted pipsissewa (*Chimaphila maculata*), Christmas fern (*Polystichum acrostichoides*), ebony spleenwort (*Asplenium platyneuron*), cutleaf grapefern (*Botrychium dissectum*), and arrow-leaved heartleaf (*Hexastylis arifolia*).

Planted Pines

This forested community is dominated by a loblolly pine canopy. Midstory woody species, vines, and herbs are scarce and include immature sweetgum, redcedar, winged elm (*Ulmus alata*), Japanese honeysuckle, and Christmas fern. Routinely maintained open areas and utility line rights-of-way are located along the perimeter of the study area.

Wetlands and Jurisdictional Waters of the U.S.

On December 8, 2016, HDR biologists surveyed the study area for wetlands and jurisdictional waters of the U.S. under Section 404 of the Clean Water Act (CWA). The study area was examined according to the methodology described in the U.S. Army Corps of Engineers (USACE) 1987 Wetland Delineation Manual, USACE Post-Rapanos guidance, USACE Eastern

Mountains and Piedmont Regional Supplement, and North Carolina Division of Water Resources (NCDWR) Methodology for Identification of Intermittent and Perennial Streams and Their Origins (Version 4.11). HDR mapped waters of the U.S. in the field using a Trimble Geo7x GPS unit capable of sub-meter accuracy.

On-site reconnaissance activities revealed that two jurisdictional streams and one jurisdictional wetland occur within the study area. For a summary of delineated jurisdictional waters of the U.S. and figures, see the attached Natural Resources Report (Appendix C). DEC does not anticipate that the construction of the new facility will impact these areas.

<u>Federally Protected Plant Species</u>

HDR obtained and reviewed a list of federally protected plant species for Lincoln County from the U.S. Fish and Wildlife Service (USFWS) website (USFWS 2015), which was last updated on April 2, 2015. HDR's on-site survey also served to identify potential habitat and possible individuals of federally protected species listed for Lincoln County. HDR consulted the North Carolina Natural Heritage Programs (NCNHP) Element Occurrence database for protected plant species distribution and proximity to the site of the proposed facility. The NCNHP database revealed that there are no known occurrences of federally protected species within the study area.

The survey findings indicate that there are a few locations within the study area that have preferred habitat requirements for the federally listed dwarf-flowered heartleaf (*Hexastylis naniflora*), and HDR did identify plants belonging to the *Hexastylis* genus in the five-acre plot during the site visit.

DEC contracted with terra incognita to perform a site inventory for the possible presence of dwarf-flowered heartleaf and other federally listed plant species. The site visit was conducted on February 22, 2017, and the *Hexastylis* species present within the study area was identified as arrow-leaved heartleaf, not dwarf-flowered heartleaf. Arrow-leaved heartleaf is common throughout the Piedmont region of North Carolina, and the juvenile leaves sometimes resemble those of dwarf-flowered heartleaf. Because the federally listed species is not present in the study area, no impacts to dwarf-flowered heartleaf are anticipated.

No habitat was present for the remaining federally listed plant species known to occur in Lincoln County (Appendix C).

The USFWS provided DEC a letter concurring that no federally protected plants or animals are found within the study area, and therefore none would be impacted by the project (Appendix C-1). Furthermore, it is anticipated that neither construction nor operation of the facility will significantly affect the botanical resources of adjacent areas.

1.4.6.1.2 Wildlife

Terrestrial communities in the study area are primarily comprised of forested habitats that may support a diverse number of wildlife species. Representative mammal, bird, reptile, and amphibian species commonly occurring in these habitats are listed below. Individual species and/or evidence of species observed during HDR's field survey are indicated with an asterisk (*). Information on species that typically use these habitats in the Southern Outer Piedmont ecoregion was obtained from relevant literature, mainly the Biodiversity of the Southeastern United States, Upland Terrestrial Communities (Martin et al. 1993).

Mammal species that commonly occur in these habitats include eastern cottontail (*Sylvilagus floridanus*); gray squirrel (*Sciurus carolinensis*)*; various vole, rat, and mice species; raccoon (*Procyon lotor*)*; Virginia opossum (*Didelphis virginiana*); groundhog (*Marmota monax*); white-tailed deer (*Odocoileus virginianus*)*; gray fox (*Urocyon cinereoargenteus*); and red fox (*Vulpes vulpes*). Bird species that commonly use these habitats include American Crow (*Corvus brachyrhynchos*)*, American Robin (*Turdus migratorius*), Blue Jay (*Cyanocitta cristata*)*, Carolina Chickadee (*Poecile carolinensis*)*, Carolina Wren (*Thryothorus ludovicianus*)*, Gray Catbird (*Dumetella carolinensis*), Brown Thrasher (*Toxostoma rufum*), Red-eyed Vireo (*Vireo olivaceus*), Yellow-throated Vireo (*Vireo flavifrons*), Northern Mockingbird (*Mimus polyglottos*)*, Scarlet Tanager (*Piranga olivacea*), Wood Thrush (*Hylocichla mustelina*), Pileated Woodpecker (*Dryocopus pileatus*), Northern Flicker (*Colaptes auratus*)*, Red-bellied Woodpecker (*Melanerpes carolinus*)*, Red-headed Woodpecker* (*M. erythrocephalus*), Downy Woodpecker (*Picoides pubescens*)*, and Hairy Woodpecker (*Picoides villosus*). Raptors in the study area may include Red-shouldered Hawk (*Buteo lineatus*), Red-tailed Hawk (*Buteo jamaicensis*)*; owl species, and Turkey Vulture (*Cathartes aura*)*.

Reptile and amphibian species that may use this terrestrial community include the eastern black rat snake (*Pantherophis alleghaniensis*), eastern corn snake (*P. guttatus*), eastern hognose snake (*Heterodon platirhinos*), copperhead (*Agkistrodon contortrix*), spotted salamander (*Ambystoma maculatum*), slimy salamander (*Plethodon glutinosus*), southern dusky salamander (*Desmognathus auriculatus*), American toad (*Anaxyrus americanus*), Fowlers toad (*A. fowleri*), gray treefrog (*Hyla versicolor*), eastern box turtle (*Terrapene carolina carolina*)*, eastern fence lizard (*Sceloporus undulatus*), five-lined skink (*Plestiodon fasciatus*), and spring peeper (*Pseudacris crucifer*).

Construction of the proposed facility will require removal of existing intact forested areas and thus will displace wildlife. During construction, wildlife is expected to migrate to adjacent undeveloped forested areas of the property that will provide suitable replacement habitat for game and non-game species. The proposed construction activities are not anticipated to impact the diversity or number of species or interfere with the movement of any resident or migratory species. DEC does not anticipate that daily plant operations, including noise from equipment and vehicle traffic, will affect wildlife beyond the proposed facility's footprint.

Additional information on wildlife that can be found at the proposed facility can be found in Appendix C of this report.

Federally Protected Animal Species

HDR obtained and reviewed a list of federally protected animal species for Lincoln County from the USFWS website (USFWS 2015), which was last updated on April 2, 2015. The northern long-eared bat (*Myotis septentrionalis*) was the only listed animal species. Several mature trees (greater than 12 inches in diameter) that exhibit exfoliating bark (i.e., hickories and oaks) and dead tree snags were observed within the mixed hardwood forest portion of the study area and may serve as potential roosting habitat for the northern long-eared bat. According to the NCNHP database, no known occurrences including hibernacula and/or maternity roost trees have been documented within or within close proximity to the study area. In addition, the proposed facility is located outside any North Carolina USFWS northern long-eared bat consultation area (USFWS 2015).

A USFWS letter concurring with the findings of no federally protected plants or animals found in the study area is attached as Appendix C-1. DEC will endeavor to observe the recommended USFWS June 1 – July 31 cutting moratorium in areas that could be habitat for northern long-eared bat to further reduce the probability of any effect on this species. Thus the proposed project will not impact any federally protected species with its construction and operation.

1.4.6.2 Aquatic Resources

HDR identified two jurisdictional streams within the study area. One tributary to Killian Creek exhibits perennial flow, and fish and macroinvertebrates were identified during the on-site visit. The remaining tributary to Killian Creek exhibits intermittent surface water flow and lacks instream habitat. This system is not likely to support populations of fish and macroinvertebrates year-round. No federally protected aquatic species or critical habitats have been identified in Lincoln County (USFWS 2015). A jurisdictional determination of the jurisdictional resources within the study area has been sent to the U.S. Army Corps of Engineers. As of the time of this report, the determination is pending.

During construction, potential effects related to runoff from the site will be minimized through the implementation of best management practices under an approved, comprehensive erosion-control plan to protect water quality and aquatic resources. Construction of the proposed facility is not anticipated to adversely affect macroinvertebrate or fish communities.

The proposed facility will use a municipal water supply during testing operations. If needed, backup water could be provided from currently permitted withdrawals from Killian Creek; there will be no withdrawals from other area waterbodies. Prior to commercial operations, the existing filtered water system which is sourced from Killian Creek will be cross-connected to the new facility. There will be no thermal issues associated with discharge from the proposed facility, and thus operations of the proposed facility are not anticipated to adversely affect macroinvertebrate or fish communities.

Low-volume wastewater streams will tie into the existing wastewater system and discharge to the Lincoln County Wastewater Treatment Plant adjacent to the site via the existing Publicly Owned Treatment Works (POTW) permitted discharge. Oily water separators will be constructed according to a Duke Energy-approved design. CT water wash wastewater will be contained for off-site disposal. Oil-filled transformer containments will be designed to contain the oil and the firefighting water that would be used in the event of a transformer failure and/or fire.

1.4.7 Meteorological

1.4.7.1 Climatology

The site of the proposed Lincoln County CT Addition is in the Piedmont region of North Carolina, with the Appalachian Mountains to the west and the Atlantic Ocean to the east. Both of these features play important roles in the climatological conditions of the site. The National Weather Service reporting station at Charlotte, NC (KCLT), located approximately 15 miles south-southeast, is representative of the climate conditions at the proposed facility site.

This region traditionally features a temperate climate in the winter. The proximity of the Atlantic Ocean provides some moderating effects, and the Appalachian Mountains block any direct impact from Arctic air masses approaching from the north and west. In rare instances, however, this location can still be subjected to extreme cold. The record low at KCLT, -5° F, has occurred twice, most recently on January 21, 1985. Typical winter minimums for the area are much milder: the normal daily minimum in January (the coldest month of the year) is 29.6° F, while the normal high is 50.7° F. Overall, 65 days a year on average see minimums of 32° F or below, but only about one day a year will see a daily maximum at or below 32° F (Fuhrmann 2007).

Winter precipitation events are typically either migratory low-pressure systems which move northeast from the Gulf of Mexico and cross the region from southwest to northeast or low pressure systems that form off the Carolinas' coast and move off to the northeast. Fronts crossing the region from the northwest are also common in winter, but these typically provide much less rainfall because the mountains block a portion of the moisture from reaching the lee side. Rain is the dominant precipitation type in the winter, averaging about 3.25 inches per month at KCLT from December to February (Fuhrmann 2007).

Snowfall can occur between November and March, but the average annual snowfall at KCLT is only 4.3 inches per year. In fact, this region averages only about one day of snowfall greater than 1 inch every year. Heavy snowfalls are possible but rare. The heaviest 24-hour snowfall at KCLT was 12.1 inches in January of 1988 (Fuhrmann 2007).

Sleet and freezing rain are also a winter risk for this region. A phenomenon called "cold air damming" (CAD) commonly occurs when cold, dense air banks against the Appalachian Mountains during times of high pressure to the north of the region. This causes cold air to become trapped at the earth's surface, which can cause freezing rain or sleet if precipitation occurs. CAD events can occur any time of the year but are most frequent in fall and winter. In some instances, this setup can lead to significant ice storms for the region, such as the major ice storms experienced across the region in 2002 and 2005. Based on a climatology study of winters between 1948 and 2003, KCLT has an annual probability of 56% for a 0.25-inch ice event. The probability falls to 26% for a 0.50-inch event (Fuhrmann 2007).

Sub-tropical "Bermuda" high pressure systems dominate the weather in summer, causing a maritime tropical climate characterized by warm, humid days and convectively driven precipitation events. The normal July daily minimum temperature is 68.1° F, and the normal July daily maximum temperature is 89° F. Daytime maximum temperatures can reach or exceed 100° F, though this is relatively uncommon. The record high of 104° F was most recently reached in July 2012. About 35 days per year reach or exceed 90° F.

Summer precipitation is typically driven by air mass thunderstorms caused by diurnal heating. Showers and thunderstorms often form in the mountain and foothills just to the west of the site in the afternoon and move into the region in the late afternoon and evening. KCLT averages 40 thunderstorm days annually, with 71% of these occurring between May and August. The months of June, July and August each average just below 4 inches of precipitation per month.

Spring and autumn are transitional seasons. Spring is characterized by warming temperatures and a transition from winter stratiform rainfall events to summer events driven by convection. Autumn is characterized by the breakdown of the Bermuda high pressure system and an increasing frequency of cold fronts and intrusions of cool air masses (U.S. Climate Data 2016).

Tornadoes have been recorded in all four seasons across the Carolinas. Spring is the typical peak, although a secondary peak associated with tropical systems and stronger cold fronts occurs in the fall. Since 1970, 18 tornadoes have been reported in Lincoln County, with the most recent in 2010. Fewer than 20 percent of all tornadoes observed since 1950 in North Carolina have been F2/EF2 or higher. Lincoln County statistics are similar to this state-wide value. Four of these 18 tornadoes (22%) were reported as F2/EF2 or higher. The strongest was a F4 tornado that passed through the county on May 5, 1989—to date, the only tornado rated greater than F2 to pass through Lincoln County (NCSU Tornadoes 2016).

Annual precipitation in the region is relatively constant year-round. August is the wettest month of the year (4.22 inches), and April is typically the driest (3.04 inches) because of the transition from winter's coastal low-pressure systems before the convective-based activity of the summer. The months of September through November can be dry compared to the rest of the year if there is a dearth of tropical storms. The annual normal precipitation at KCLT is 41.6 inches. Table 1.4.7.1-1 shows average seasonal climate data for the region (NCEI 2015).

Table 1.4.7.1-1: Average Seasonal Climate Data (NCEI 2015)

Climate Indicator	Winter (Dec-Feb)	Spring (March-May)	Summer (June-Aug)	Autumn (Sept-Nov)
Average Temperature (ºF)	42.13	59.33	77.03	60.63
Average precipitation (inches)	3.33	3.41	3.88	3.26
Total Precipitation (inches)	9.98	10.23	11.64	9.78

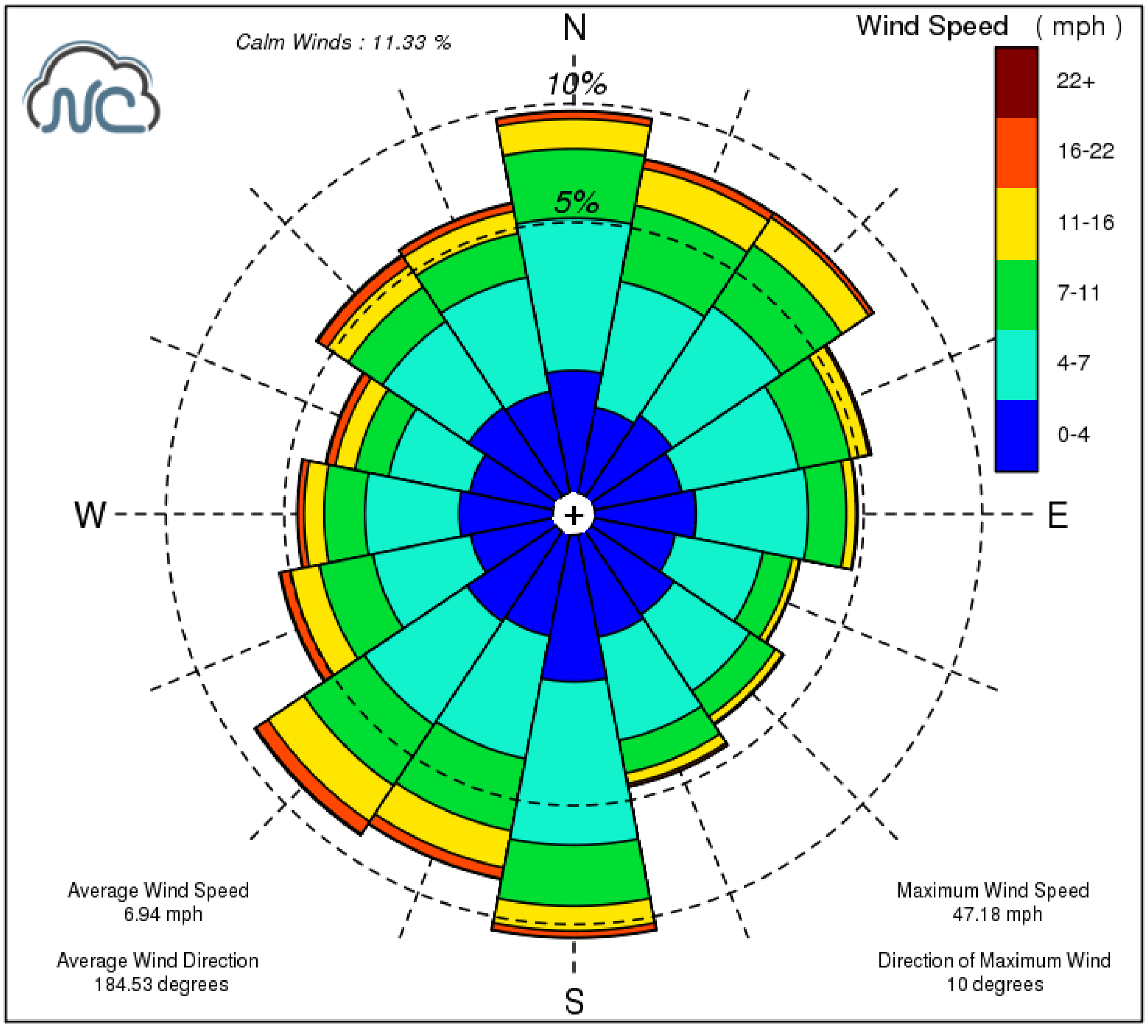
The air dispersion of pollutants in the region is a product of the overall weather pattern combined with the impacts of being near the Appalachian Mountains. Given the right pattern, the mountains can enhance sinking air across the Piedmont, leading to stagnant conditions, mostly in the summer and fall. Afternoon mixing heights decrease significantly from the summer to the fall. Table 1.4.7.1-2 shows the seasonal mixing heights (representing the height at which the atmosphere is mixed due to turbulence) for Charlotte based on data from 1987-2006 (NCDC 2007).

Table 1.4.7.1-2: Seasonal Mixing Heights (in meters) for Charlotte, NC

	Spring	**Summer**	**Fall**	**Winter**
Morning (minimum)	642	620	510	561
Afternoon (maximum)	1717	1799	1284	1027

In terms of plume transport, winds at KCLT (10-meter level) since 1950 are most frequently from the north and south sectors. A wind rose (a graphic tool used to show wind speed and direction for a particular location over a specified time period) is provided in Figure 1.4.7.1-1.

Figure 1.4.7.1-1: Wind Rose for Charlotte Douglas International Airport (KCLT) January 1, 1950 – January 1, 2015



Source: NCSU Windrose 2016

1.4.7.2 Air Quality

National Ambient Air Quality Standards (NAAQS) have been established by the U.S. Environmental Protection Agency (USEPA) and adopted by the N.C. Department of Environmental Quality (NCDEQ), formerly the N.C. Department of Environment and Natural Resources. These standards, outlined in Chapter 15A of the North Carolina Administrative Code (NCAC), Subchapter 2D (Air Pollution Control Requirements), Section .0400, establish certain maximum limits on parameters of air quality considered necessary for the preservation and enhancement of the state's air resources (USEPA 2016a).

The six criteria air pollutants regulated by the NCDEQ through NAAQS include the following:

- Ozone (O_3)
- Particulate Matter ($PM_{2.5}$ and PM_{10})
- Carbon Monoxide (CO)
- Sulfur Dioxide (SO_2)
- Nitrogen Dioxide (NO_2) and
- Lead (Pb).

The entire state of North Carolina has reached attainment and continues to satisfy the attainment criteria for each of the six listed pollutants. In the past, portions of North Carolina (e.g., Charlotte metropolitan area) have experienced intermittent non-attainment designations for ozone; however, this is not uncommon in larger cities during the warmest periods of the year. Ground-level ozone limits may be exceeded in metropolitan areas and large suburbs during the summer due to increased chemical reactions between vehicle emissions and ultraviolet radiation and sunlight, resulting in (temporarily) increased ozone levels.

The proposed facility's operations will be permitted as part of the Lincoln County Combustion Turbine Station. DEC expects the air permit application to be submitted in the summer of 2017. Potential emissions from the equipment indicate that the facility will be permitted as a "major" modification for the purposes of Prevention of Significant Deterioration (PSD) permitting. As part of the permitting process, the facility will be required to evaluate Best Available Control Technology (BACT) and perform a dispersion modeling analysis. DEC will use Continuous Emissions Monitoring Systems (CEMS) to ensure compliance with the New Source Performance Standards (NSPS) and allowance trading programs such as the Cross-State Air Pollution Rule.

During construction, the proposed facility may be subject to air permitting requirements, depending on the type of equipment used (such as portable generators) and the associated level of air emissions. The primary air quality issue during construction will be fugitive dust—dust from non-point sources, such as earthwork and construction traffic on unpaved roads. Water trucks will be used to suppress dust as required. Fugitive dust impact is expected to be equivalent to a normal construction project of this magnitude.

Other potential sources of pollutants during construction are mobile internal combustion engines (e.g., earth moving equipment and cranes), temporary sources (e.g., portable generators and air compressors), and increased vehicle traffic by construction workers. Emissions from these sources should have little impact. Any emissions from sources during construction will be addressed through the North Carolina Division of Air Quality's air quality permit application process.

1.4.8 Seismic

1.4.8.1 Seismic Character and Seismic Hazards

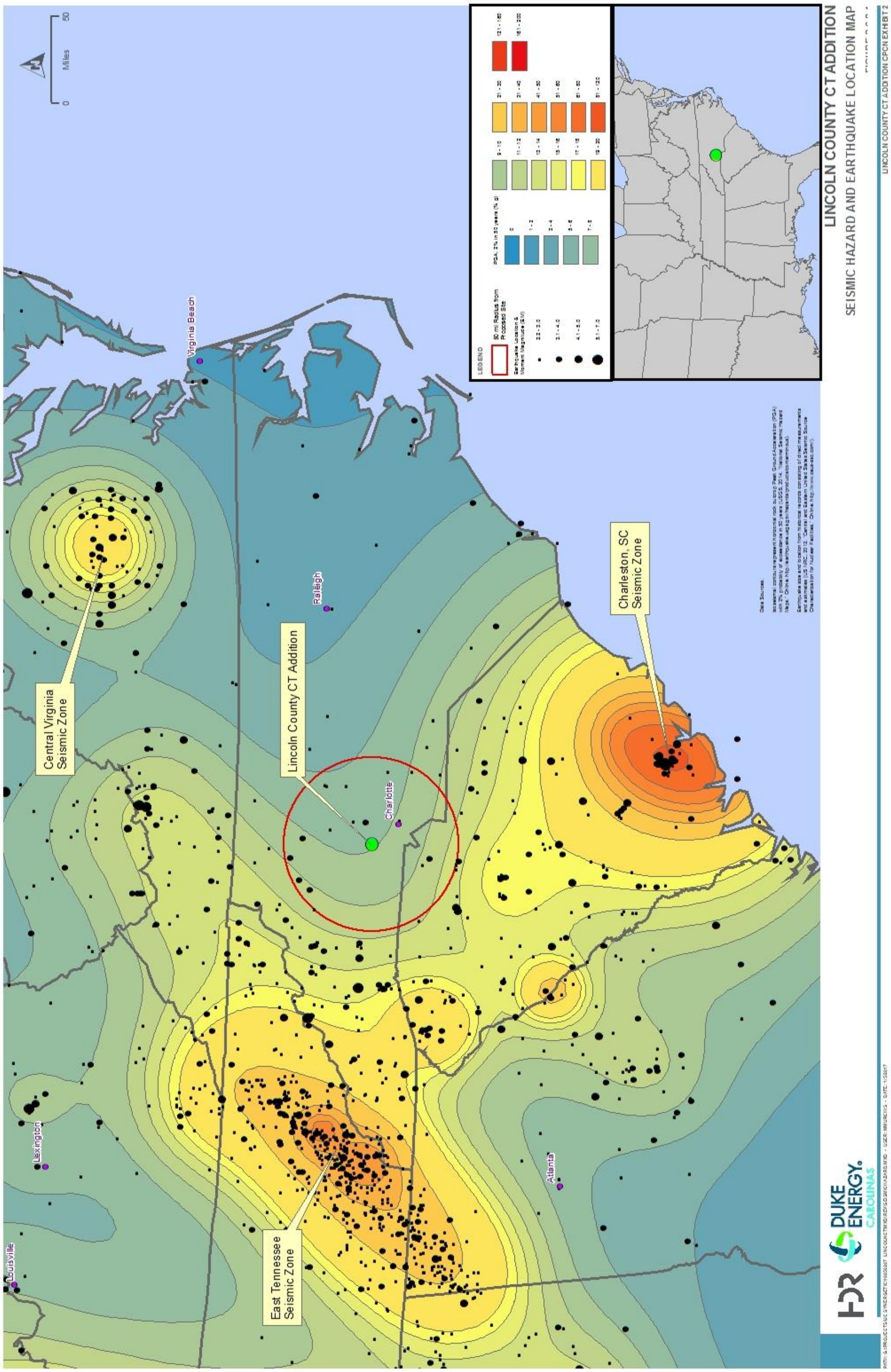
Earthquakes that originate in North Carolina are primarily intraplate earthquakes (i.e., earthquakes that occur in the interior of a tectonic plate) and in most cases, occur along existing structural faults. The orientation of these structures within the current-day stress field in the southeast is northeast-southwest. The eastern United States has a low relative recurrence interval for strong earthquakes; however, the rigid and largely intact basement rock enables seismic energy to travel significant distances. Because the type and condition of local and regional geology plays a significant role in earthquake attenuation, even structures in areas of low seismicity should be designed to withstand surface movement.

Tectonism describes the movement of tectonic plates that causes earthquakes, faults, volcanoes, uplift, subsidence, or a number of combinations thereof. Because earthquakes that are felt in North Carolina are typically the result of regional tectonism, they are not associated with the movement of tectonic plates and the significant changes and loss of property that can accompany these seismic events. Intraplate earthquakes, however, are not well understood, and the hazards associated with them are difficult to quantify. A seismic hazard is the probability that an earthquake will generate an amount of ground motion exceeding the specified reference level in a certain period of time, generally 50 years. Although intraplate earthquakes are typically of low magnitude (M) on the Richter scale, which is a base-10 logarithmic numeric scale used to express the magnitude of an earthquake based on seismograph oscillations, there have been several major intraplate earthquakes that have affected the central and eastern United States. Examples include the Mineral, Virginia, earthquake in 2011; the Charleston, South Carolina, earthquake in 1886; and the New Madrid, Missouri, earthquakes in 1811 and 1812. A more comprehensive discussion of historic seismic activity is included in Appendix D.

The seismic hazard for a particular site or location is based on: (1) the magnitude of and distance from the potential earthquake, (2) the frequency with which those potential earthquakes are likely to occur, and (3) the amount of shaking that is expected to occur as a result of those earthquakes. The Peak Ground Acceleration (PGA) for the study area has been estimated using the U.S. Geological Survey (USGS) National Seismic Hazard Mapping database (2016b). The site of the proposed facility has an estimated value of 0.08 peak ground acceleration, which is expressed as a fraction of standard gravity (g), and has a two percent probability of exceedance in 50 years (USGS 2016a). Figure 1.4.8.1-1 shows the location of the site, the two percent probability of exceedance in 50 years, PGA contours, regional earthquake source information, and the 50-mile radius from the proposed project site. The probability that there would be an earthquake with a magnitude of greater than 5.0 on the Richter scale within 100 years within 30 miles of the study area is very small (0.02 – 0.03%) (USGS 2016b).

Induced seismicity, which has increased in frequency over recent years in the eastern United States, has been linked to an increase in wastewater injection into deep wells. These activities are not accounted for in the estimated hazards presented above. Because the proposed facility will be in an area of relatively low potential seismic activity and overlies stable basement rock, it should perform satisfactorily in the event of an earthquake if appropriate considerations are made during preliminary and final design.

Figure 1.4.8.1-1: Seismic Hazard and Earthquake Locations



1.4.8.2 Seismic Zones and Magnitude

Three major seismic zones exist in the central and eastern United States: (1) the Charleston, South Carolina, seismic zone, (2) the East Tennessee seismic zone, and (3) the Central Virginia seismic zone (see Figure 1.4.8.1-1). These zones are located approximately 180, 190, and 240 miles from the proposed facility, respectively. Figure 1.4.8.1-1 indicates these three zones; and the clusters of variable-sized black circles represent the locations of previous earthquakes and their respective magnitude on the Richter scale. The magnitude of an earthquake can be expressed as the amount of energy released (in gigajoules). For example, an earthquake with a magnitude of 5.0 is equivalent to a release of 2,000 gigajoules of energy. An earthquake with a magnitude of 2.5 to 5.4 causes minor damage; there are around 30,000 of these each year world-wide. An earthquake with a magnitude of 8.0 is considered a great earthquake and can completely destroy communities near the epicenter. There are, on average, less than five great earthquakes per year world-wide.

The closest recorded earthquake (>4.0 M) to the study area occurred in 1916 near Skyland, North Carolina, in Buncombe County, which is approximately 100 miles west of the study area. This earthquake was estimated to be 5.2 M and was most likely associated with the East Tennessee seismic zone. In more recent history, the largest earthquake that was felt in North Carolina was the earthquake that originated near Richmond, Virginia, in 2011. This earthquake was associated with the Central Virginia Seismic Zone and registered as a 5.8 M on the Richter scale (USGS 2016a). Both the Charleston and East Tennessee seismic zones are considered areas of high seismic hazard by the USGS. More details regarding the history of earthquakes in the region are included in Appendix D.

It is likely that the East Tennessee seismic zone presents the greatest known risk to the site area, but the risk is considered small. The facility's structures will be designed in accordance with the applicable code, using ground motion data consistent with the required loading.

1.4.9 Water Supply

The study area is located within the Upper Catawba River Basin (HUC 03050101). According to the North Carolina Division of Water Quality's 2010 Catawba River Basin Plan, the land cover within this hydrologic unit code (HUC) is mostly forested (62%) with significant areas of agriculture (17%) and developed land (16%). Agriculture is spread out across the subbasin; the largest urban areas include Morganton, Lenoir, the northern portion of Hickory, Huntersville, Gastonia, and outlying areas northwest of Charlotte (NCDEQ 2010a).

The study area does not occur within a water supply watershed. It drains to Killian Creek, which is classified by the NCDEQ as a Class C water. Class C waters are protected for uses such as secondary recreation, fishing, wildlife, fish consumption, aquatic life (including propagation, survival and maintenance of biological integrity), and agriculture. Secondary recreation includes wading, boating, and other uses involving human body contact with water where such activities take place in an infrequent, unorganized, or incidental manner.

1.4.10 Aviation

Title 14, Code of Federal Regulations, Part 77 (Safe, Efficient Use, and Preservation of the Navigable Airspace) establishes standards for protecting navigable airspace and sets forth requirements for Federal Aviation Administration (FAA) notification of proposed construction that could potentially affect the navigable airspace. Specifically, the notification "triggers" set out in Part 77 that are, or possibly could be, applicable to construction of the Lincoln County CT Addition facility include the following:

- If requested by the FAA, or if any of the following types of construction or alteration are proposed, a notice must be filed with the FAA:

a) Any construction or alteration that is more than 200 feet above ground line at its site

b) Any construction or alteration that exceeds an imaginary surface extending outward and upward from the aviation facility at any of the following imaginary surface slopes:

   i) 100 to 1 for a horizontal distance of 20,000 feet from the nearest point of the nearest runway of each public-use airport listed in the Airport/Facility Directory with its longest runway more than 3,200 feet in actual length, excluding heliports

   ii) 50 to 1 for a horizontal distance of 10,000 feet from the nearest point of the nearest runway of each public use airport listed in the Airport/Facility Directory with its longest runway no more than 3,200 feet in actual length, excluding heliports

   iii) 25 to 1 for a horizontal distance of 5,000 feet from the nearest point of the nearest landing and takeoff area of each heliport (U.S. Government Publishing Office 2004)

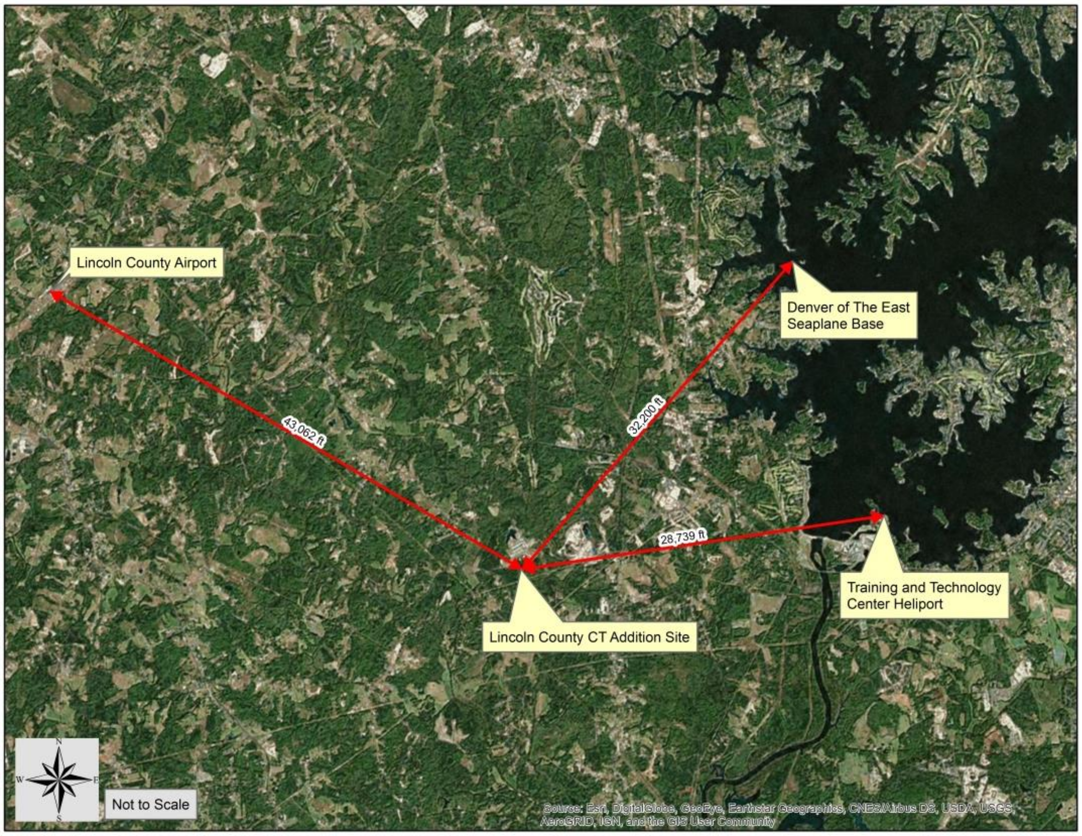
With these notification triggers in mind, UCS identified two aviation facilities (Esri 2017) in the region of the proposed plant site (see Figure 1.4.10-1):

- The Denver of the East Seaplane Base, private, approximately 32,000 (6.1 miles) to the northeast
- Lincoln County Airport, public, approximately 43,000 (8.1 miles) feet to the northwest

UCS has determined that none of the above notification criteria are met, based on distances to the aviation facilities and preliminary engineering of the proposed Lincoln County plant.

UCS used the online FAA Notification Criteria Tool to enter the proposed plant coordinates (latitude/longitude), plant grade elevation, and stack height (140 feet) to determine whether FAA notification would be required. The results from the tool asked that notification Form 7460-1 be filed with the FAA before plant construction because, even though it did not meet the filing criteria listed above, the plant structure "may impact the assurance of navigation signal reception" in relation to the Lincoln County Airport (FAA 2017). Otherwise, the proposed facility should have no impacts on aviation in the area.

Figure 1.4.10-1: Airfield Locations



1.5 Site Study Status

All necessary studies have been conducted.

1.6 Transmission

The location of the existing Lincoln County CT electrical substation is shown in Figure 1.2-1.

The proposed CT unit will be designed with a single high voltage output breaker and interconnected to the existing 230 kV Lincoln County CT electrical substation. The preliminary plan is to expand the existing substation to the south to accommodate the proposed new CT unit. The high voltage line from the unit will be routed to this new location. Two new circuit breakers will be required at the substation, and as many as seven existing circuit breakers may be replaced, if required by the Interconnect Agreement. No new transmission lines will be constructed outside the Lincoln County CT property, and no transmission upgrades are anticipated.

DEC has filed an application and will conduct studies for the interconnection in accordance with the DEC Open Access Transmission Tariff. The System Impact Study results are expected in the summer of 2017, and the Facility Study results are expected in the fall of 2017. Final design will be determined after the studies have been completed.

1.7 Unit Capacity

The net capacity of the unit at 30° F is 402 megawatts.

2.0 METHODOLOGY

2.1 Population

Total 2010 population numbers for Lincoln County and the nearby towns and communities listed in Section 1.4.1 were derived from information downloaded from the U.S. Census Bureau website. The smallest geographic unit of digital 2010 census data available directly from the U.S. Census Bureau is the census tract. A third-party vendor (University of Minnesota 2011) has contracted with the U.S. Census Bureau to publish and make available census data geographic files and population tables at the block level. This is the finest detail of population data that the U.S. Census Bureau collects. This report analyzes population data to the census block level.

UCS downloaded census block geographic files and population statistical tables for the entire states of North Carolina and South Carolina. ArcGIS was then used to extract census block polygons within a radius of 25 miles from the proposed simple-cycle facility from the two statewide data sets and combine the geographic polygons with the attributes. The resultant file contained an array of population data for each census block polygon. The total population value and geographic area for each census block was then used to calculate the population density, as reported in Section 1.4.1.

It should be noted that for the purposes of this study, UCS assumed that the total population for each census block was evenly distributed throughout its geographic area. Thus, for the census blocks that were split into two parts based on distance, a percentage of the entire block acreage was calculated for each piece (after-split acreage divided by pre-split acreage). This decimal fraction was then multiplied by the total population number for the entire block to assign the population figure to each piece.

2.2 Area Development

UCS researched existing area development through intensive field reconnaissance, desktop mapping (using current aerial photography along with county tax parcel and other digital data), and contacts with governmental officials.

To ascertain future development plans in the vicinity of the proposed facility, UCS consulted planning officials for Lincoln and Gaston counties (Combs 2016). Future land use documents and mapping were also researched online for both Lincoln and Gaston counties (Gaston County 2016).

2.3 Visual and Auditory

2.3.1 Visual

The Visual Effects Analysis was conducted in three steps.

- First, a comprehensive field study was conducted to identify sensitive visual resources and characterize existing visual conditions. During the Probable Visual Effects field study, existing residential properties and public roadways were identified as resources with the potential to be most affected by views of the proposed plant.

- Second, using National Elevation Dataset (NED) tiles, UCS built a computer-generated Seen Area Analysis model (Figure 1.1.3.1-1) that predicts areas within five miles that will likely have a view of the proposed facility.

  UCS delineated tree cover by using the ArcGIS system to classify georeferenced aerial photography and extract a raster image of tree cover. This digital raster image was converted to polygons representing tree locations. Where these polygons overlapped the NEDs, UCS added 60 feet (an assumed average tree height) to the NED elevations. This information was used to create a five-mile visual probability model that accounts for the screening effects of topography and vegetation. UCS assumed that forested areas were opaque in building viewshed models.

  Next, using the ArcGIS 3-D Analyst module, UCS developed a viewshed map to predict the visibility within five miles of the existing and future facility. A height of 60 feet was used for the emission stacks of the existing 16 simple-cycle units. UCS used the following equipment heights for the proposed facility in the viewshed analysis.

• Generation Building	90 Feet
• Gas Turbine Inlet Filter	95 Feet
• Dilution Selective Catalytic Reactor (DSCR)	56 Feet
• DSCR Stack	140 Feet
• Demineralized Water Tank	30 Feet
• Closed Cooling Water Fin-Fan Cooling Tower	20 Feet
• Administrative Building	20 Feet

- Third, UCS interpreted and analyzed the information and data developed during the first and second steps, taking into account the fact that any visual effects of the proposed plant would be influenced by such factors as distance, the parts of the proposed facility that would be seen, the backgrounds of visible structures, any foreground or mid-ground vegetation in the view, and the scenic condition of the area from which the facility would be viewed.

  The data derived from the Seen Area Analysis and Predicted Visual Effects (Table 1.4.3.1-1) were correlated to probable visual effects ranging from Very High to Very Low.

  Using the distance from the viewer to the proposed plant, UCS predicted (ranked) the visual effects that may occur as a result of the proposed structure. The ranking (Table 1.4.3.1-1) represents a worst-case scenario, since UCS made no attempt to reduce the predicted visual effects probability that will inevitably occur when foreground and mid-ground vegetation or backdrops are present. Also, no attempt was made to mitigate predicted view ranking based on existing modifications to natural landscape settings or the fact that only minor plant features may be seen from an area having a probable view. For example, even if only the top segment of the emission stack can be seen from within one-half mile, the view effect was ranked as Very High.

  UCS conducted an extensive field investigation to determine the probable visual effects of the proposed facility on residential properties and public roadways.

2.3.2 Auditory

Stewart used a Casella 633C sound analyzer to measure current sound levels along the perimeter of the station and in the surrounding neighborhoods and to document the existing sounds at various community locations. Measurements for this study were made during one 42-hour period with two long-term monitors (Larson Davis 831s). Samples were taken on Tuesday, March 28, 2017, from 9:00 a.m. to 10:00 a.m. and on Thursday, March 30, from 1:00 a.m. to 2:00 a.m. Shorter, five-minute samples were made on Friday, March 24, during the initial site visit and on Saturday evening, March 25, during a Lincoln County Speedway event. Atmospheric conditions varied over the measurement period. Temperature, relative humidity, and wind conditions at the nearby airport were recorded from online sources to allow some evaluation of these effects on the noise distribution. The sound was measured in octave bands as well as the overall A-weighted level to provide a better understanding of the noise situation. Statistical sampling was used to see the variation within each measurement period.

Existing and proposed combustion turbine equipment sound power levels were estimated.

- DEC provided information about the existing CT units (which could not be operated during the noise survey phase) to estimate their sound power levels. Stewart considered the distribution of sources, the sound level specification that the equipment supplier met for one and all 16 units, the layout of the units, and spectral information of similar combustion turbines at another site. From this, the sound power of each unit in each octave band could be reasonably estimated.
- The proposed turbine is a new model size that has not yet been constructed, and therefore no field measurements are available. The manufacturer, Siemens, estimated the sound power of each piece of equipment and provided CadnaA (sound propagation analysis software) drawings to illustrate the location and size of each sound source and building that could impact sound radiation. Stewart then reconstructed the

proposed CT SoundPlan, using the CadnaA plot, drawings, and sound power data.

- Stewart modeled the acoustical hardness/softness and general topography of the ground, other major pieces of equipment, and existing and proposed sound sources in SoundPlan. Then sound level results from the computer sound propagation modeling software were computed for the DEC sources. This included three plots of sound levels (overall A-weighted sound pressure level [dBA]): one plot with all 16 existing combustion turbines running, another plot with only the proposed CT addition running, and a final plot with both existing and proposed CTs running. For Soundplan, ISO 9613-2:1996 is employed, which considers ground effects, distance, barrier effects, reflection, etc., in a standardized approach.
- Stewart evaluated the anticipated DEC-generated noise levels by comparing existing DEC-site noise levels, community noise levels, and available Lincoln County regulations.

2.4 Cultural Resources

The cultural resources identification survey for the project included identification of architectural historic resources and archaeological resources. Brockington designed the survey to identify all architectural and archaeological resources that may be present in the project area and to obtain sufficient information to make recommendations based on their potential eligibility to the NRHP. To accomplish this, Brockington conducted documentary research and architectural survey work in compliance with the NHPA of 1966 (NHPA-PL89-665); the Archaeological and Historic Preservation Act of 1974, Executive Order 11593; and relevant sections of 36CFR60 and 36CFR800. Because comprehensive archaeological field testing was conducted in 1990 before the existing generating facility was constructed (see Appendix B-1), Brockington did not repeat field testing for this study. The archaeological and architectural investigations were conducted with reference to state and federal guidelines (Secretary of the Interior's *Standards and Guidelines for Archaeology and Historic Preservation* [United States Department of the Interior 1983]) for conducting archaeological and architectural investigations. This report was prepared in accordance with the Office of State Archaeology's (OSA) *Guidelines for Preparation of Archaeological Survey Reports in North Carolina* (North Carolina DNCR 1988).

Prior to architectural fieldwork, Brockington consulted architectural data and tax records from the North Carolina State Historic Preservation Office's (NCSHPO) online database and architectural data housed in the NCSHPO's Raleigh, North Carolina, office for properties located within the 2.5-kilometer (1.5-mile) APE to determine which buildings met the NRHP 50 years or older age criteria as of 2016. Background research also focused on relevant sources of local historical information and available historical maps, which were examined to provide historical context for the study area and to check for any buildings and other cultural features present within the APE.

With consideration to the background research, Brockington conducted an architectural windshield survey within the APE of the proposed facility. This entailed a survey of each resource 50 years or older within the defined APE. Resources which retained architectural integrity, were representative of type, and/or differed from resources within the APE were recorded photographically. Resources which retained little architectural integrity or were severely altered were not recorded. Due to private property issues, resources not visible from public rights-of-way and resources located down private roads posted with "No Trespassing" signs were also not surveyed.

UCS utilized Seen Area Analysis modeling data as described in Section 2.3.1 to further assess visual impacts to architectural resources within the APE. Line-of-sight graphs were prepared to display any obstructions, or lack thereof, that lie in the visual path of the proposed facility. The graphs also show the elevation, distance, and amount of elements contributing to screening as well as areas where additional screening elements could be implemented to mitigate any negative visual effects incurred by the construction of the facility.

2.5 Geological

HDR geologists performed a review of existing germane literature regarding the geology and geologic history of the southeastern Piedmont region. Data generated from the published geologic map of North Carolina was obtained from the North Carolina Geological

Survey and evaluated for site-specific bedrock type, terrane, structural features, formations, and presence of intrusions. Finally, site-specific data reports were generated from the United States Department of Agriculture Natural Resources Conservation Service database for soil types, soil conditions, and soil profiles typical of the study area.

2.6 Ecological

HDR provided Duke Energy with a detailed Natural Resources Assessment Report for the Lincoln CT Addition Project (Appendix C). This study involved a desktop review of publicly available data and an on-site investigation that included surveys for jurisdictional wetlands and waters of the U.S., federally protected species habitat, and classification of natural/vegetation communities.

On December 8, 2016, HDR biologists surveyed the study area for jurisdictional wetlands and waters of the U.S. under Section 404 of the CWA. The study area was examined according to the methodology described in the USACE 1987 Wetland Delineation Manual, USACE Post-Rapanos guidance, USACE Eastern Mountains and Piedmont Regional Supplement, and NCDWR Methodology for Identification of Intermittent and Perennial Streams and Their Origins (Version 4.11). Results of the jurisdictional wetlands and waters survey are provided in the Natural Resources Assessment Report (Appendix C).

Existing vegetative communities are described in the Natural Resources Assessment Report based on the Classification of the Natural Communities of North Carolina – Fourth Approximation (Schafale 2012).

2.7 Meteorological

DEC conducted an extensive online review of pertinent reports from the National Climatic Data Center, the Environmental Protection Agency, North Carolina State University, and the State Climate Office of North Carolina.

2.8 Seismic

HDR geologists reviewed the United States Geological Survey National Seismic Hazard Mapping database to obtain current seismic data as well the estimated Peak Ground Acceleration (PGA) for the study area. The USGS Probabilistic Seismic Hazard Analysis

Model, which is part of the Seismic Hazard Mapping program, was used to predict the probability of an earthquake (>5.0 M) near the study area. The USGS Earthquake Track website was accessed to identify and compile documented historic and recent earthquakes, the distance of earthquake epicenters from the study area, the depth of the earthquake from the surface, and magnitude of the individual event. USGS publications (Open File Reports and Research Letters) were also reviewed for information regarding seismic character in the southeastern United States.

2.9 Water Supply

HDR reviewed information from the North Carolina Department of Environmental Quality to compile the information on water quality.

2.10 Aviation

UCS reviewed aerial photographs; Lincolnton East, NC, Lowesville, NC, and Lake Norman South, NC, United States Geological Survey 7.5-minute Quadrangle Maps (USGS 2013); aeronautical charts; and airport diagrams to determine the locations of airfields in the region surrounding the proposed facility. Two airfields were located, and records for each were reviewed. A preliminary assessment was conducted for each site.

The airports are located approximately 32,000 feet to the northeast and 43,000 feet to the northwest of the proposed facility.

FAA notification criteria were reviewed. The plant location coordinates, pad elevation, and stack height were also entered into the FAA Notice Criteria Tool on the FAA website (Federal Aviation Administration 2017).

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APPENDIX A

Lincoln County Combustion Turbine Plant CT Addition CPCN Noise Impact Study

Lincoln County Combustion Turbine Plant CT addition
CPCN Noise Impact Study

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Executive Summary

The four major aspects of this noise report are:

1. Current community and environmental noise levels at areas surrounding the Lincoln County Combustion Turbine plant.
2. Estimation of existing and proposed combustion turbine equipment sound power levels.
3. Sound Level results from computer sound propagation modeling of Duke Energy sources - existing and with the future CT addition (sound levels).
4. Evaluation of the noise impact.

In this summary we will only discuss the important conclusions from each portion of the report.

Existing Community Noise Levels

The existing quarry, speedway, aircraft and Old Plank Road are significant community noise sources. Current noise adjacent to the CT plant is primarily produced by aircraft approaching and leaving Charlotte Douglas airport, road traffic noise, mineral processing activities from a nearby quarry and race vehicles at a nearby speedway. Aircraft noise affects the greatest area around the CT plant during the day hours. Aircraft noise drops significantly from midnight to 7 AM. The Charlotte Douglas airport is located 18 miles south of the CT plant. Runway 18C-36C at the Charlotte Douglas airport runway is orientated north-south and nearly in line with the CT plant. Homes near Old Plank Road experience significant levels of road noise due to volume of traffic and speed of vehicle. Quarry produced noise is heard starting near 5:30 AM to 8:30 AM. Quarry noise is due to road grading and machinery startup. Noise is most significant from the quarry at neighbors to the southeast of the Duke Energy plant. Residences in the vicinity of the East Lincoln Motor Speedway will experience significant race vehicle noise on Saturday evening from 7 pm to 11 pm from late March through the end of September. Levels from all these sources are reported in great detail in the report.

These most significant noise levels are part of the evaluation section. Although the background noise levels can be as low as 35 dBA during the night in remote locations, these existing sources occur regularly and raise levels substantially when they are occurring. Many of these sources are 47-60 dBA at key locations around the plant. Aircraft events have maximum levels from 62-72 dBA.

Sound Power Levels of Duke Existing CT's and Proposed simple cycle CT addition

The new simple cycle CT Addition only increases the total sound power from the plant 3 dBA. Sound power is similar to watts for electricity in a light bulb. It is a measure of how much sound energy is being radiated per second into the air. The brightness of the light for a bulb is largely dependent on how far the receiving location is from the light, and the reflectivity of the surrounds and any objects creating shadows. The loudness of sound (sound pressure level or sound level for short) generated by the sound power source (the bulb) is dependent on how far from the source you are, how soft the ground is, the land topography, and other factors such as blockage by buildings. However, a quick comparison of how much sound is being introduced into a location is to compare the sound power of the existing source and the proposed source.

The existing 16 Combustion Turbines (CTs) and proposed single CT have an approximately equivalent sound power level (overall) (123.2 for the existing CTs and 123.6 dBA for the addition) based on estimated sound power levels of the components. Due to the way decibels are added, this leads to an increased total sound power of about 3 dBA. Due to the way humans hear this is a barely noticeable increase.

Future Sound Levels from the proposed CT addition

Future sound levels and resulting change varies by location but sound levels are not more than 55 dBA with all CT's operating at any adjoining property lines. The sources (existing CTs and proposed CT addition) are not located at the exact same area of the Duke site and therefore we have some neighbors that will see a much larger increase than others. The greatest increase is to the southeast where currently levels from the existing CTs are quite low, and will now be about 52 dBA at the nearest house and 55 dBA at the nearest property line. (Note: Hedrick Quarry purchased this property in 2016.) Neighbors to the west will see no measureable change. Neighbors to the southwest will see generally a 3-4 dB increase (a barely noticeable difference), with one location seeing a 6 dB increase (clearly noticeable difference) due to proximity to the new CT addition. Neighbors to the north at the Trilogy property will see less than a 2 dB increase with the new CTs (which is not noticeable to most).

Evaluation of Future Duke Energy generated noise levels by comparing to existing Duke site noise levels, community noise levels, and the Lincoln County race track night-time noise limits.

Lincoln County's noise ordinance has no specified decibel limits, but does prohibit noise from "becoming a nuisance to adjacent single-family detached and two-family houses and residential districts" (Lincoln County 2016). The unified development ordinance does have limits that apply to race tracks. At night time, 10-minute average levels cannot exceed 55 dBA at the receiving residential property for this kind of source. These limits were used to draw some comparisons.

Future noise levels are similar to sound levels of existing sources, meaning a minimal impact to most. Most neighbor locations are below 55 dBA with only one location right at 55 dBA (property line of one neighbor to the southeast).

Noise levels from the quarry and race track at the neighbor to the southeast (Neighbor 1) are estimated to be 57 dBA and 50 dBA respectively. Aircraft events from CLT have slow A-weighted maximum levels of 62-72 dBA. Although clearly the noise source will be new and thus noticed, it is not more than 55 dBA (level used to regulate race tracks at night in Lincoln county), and is not more than other sources affecting this property.

Other homes showing a clear increase from Duke Energy sources to the southwest are 50-54 dBA with all CT's (existing and proposed) operating (3-6 dB increase), but race track noise levels are estimated to be 53-55 dBA and are thus similar. Also, noise from Old Plank Road (for those homes in close proximity to the road) is generating sound levels of about 55 dBA.

Property to the west and north (Trilogy property) are not noticeably changed in sound levels from the Duke Energy plant and most of the property is below 50 dBA.

It is our opinion that noise impacts are minimal to most of the surrounding neighbors. Neighbors 1 and 2 will see a clearly noticeable increase in Duke Energy levels, but total levels do not exceed 55 dBA and other sources are generating similar levels at these properties, thus impacts should not be significant.

Measurement Methodology

Introduction - Goals for noise analysis

The proposed new combustion turbine will be capable of producing up to 500 megawatts of electricity compared to 80 megawatts electricity for each of the current 16 combustion turbines now existing at the plant. It is the goal of this study to determine the noise impact of the new proposed CT addition and the combined noise impact of the current 16 CTs with the new proposed CT addition.

It is also a goal of this report to document measured community noise levels and compare to predicted noise levels of the existing and proposed combustion turbines. Noise measurements were made at properties adjacent and in the surrounding neighborhood to the Lincoln County Duke Energy site.

Background on sound and sound levels

Sound is produced by rapid fluctuation in air pressure on top of barometric pressure. Sound strength, whether pressure or power, is measured in decibels (dB) which is a way of expressing the ratio of any two "power-like" quantities as a logarithmic ratio. By choosing a standardized reference value, absolute values of sound level can be expressed in decibels. A pressure of 1 Pascal (Pa) is equivalent to 94dB sound pressure level and 20 µPa is the reference for 0dB. We should note that each change of 10 dB indicates 10 times as much sound present and a doubling of sound present is only 3 dB. A sound that is 60 dB louder than another, for example, has a million times as much sound energy. Note that the human hearing system does not respond proportionately to the "amount" of sound present or changes in stimulus frequency. A 3 dB change in level means twice or half as much actual sound, but is generally just barely noticeable unless there is something else different about the sound. A 5-6 dB change is three to four times as much sound and is very clearly noticeable even if the sound is otherwise the same. A 10 dB change is dramatically noticeable, judged at least twice as loud, and is 10 times as much sound present. The human hearing system does not respond to very low or high pitched sounds as well as those sounds in the speech range. We make up for this in the measurements we collect by employing frequency weighting filters. The most popular in use is the A-weighting filter. When an A weighting filter is used we usually report the results labeled as dBA.

Typical speech at a distance of 1 meter is around 60 dBA, typical office ventilation sound 35-45 dBA, and most North Carolina residential communities are in the range of 40-50 dBA but can be below 40 dBA at times, especially in less densely populated areas or above 50dBA in more densely populated areas or near highways.

Instantaneous sound levels are measured with "fast" or "slow" time weighting. Fast corresponds to a 125 millisecond time constant. Slow corresponds to a 1 second time constant. This can be visualized as how fast the needle on a meter can move. Fast response corresponds better to perception when levels are changing rapidly, but a slow response setting is easier to read on a manual meter and corresponds better to slower moving changes in the sound in terms of analysis results.

Sound levels over a period can be "average levels" and they can also be analyzed to look at maximum levels. Analyzing sound by assigning percentiles to levels exceeded for specific percentages of a time period can be used to get an idea of how steady the sound is. We sometimes use 1%, and 10% levels to indicate higher intermittent levels from the average value and 90 or 99 % to indicate the steady part of the sound. "Fast" or "slow" response is chosen as part of all these measurements. These measurements are often labeled L% so the level exceeded 90% of the time would be labeled L90.

When we contemplate studying sound propagation over distance, the first factor we generally look at is that the sound level from a point source drops 6dB per doubling of distance. This is derived from the inverse square law which applies to sound (intensity) and light and gravity as well. Interaction with soft ground can further reduce the sound level when the sound travels from source to a receiver ear close to ground – but when listeners are very high above the ground there is less effect. Over long distances, atmospheric absorption reduces primarily the high frequency part of the sound. This is an effect of a number of dB per 1000 feet. Beyond 1000 feet or so, this effect overcomes the inverse square effect so the higher frequencies are typically not significant. Another consideration is terrain. The presence of changes in topography can create shadow zones where sound is attenuated some from a sound source because the line of sight is blocked. The extent of the effect depends on how well the source is blocked and the size of the blocking object or terrain. It also depends on how close the source or receiver is to the element creating the shadow.

Sound levels are significantly reduced on sunny afternoons when air near ground is warmer than air higher in the sky and the sound curves upward. The loudest time for sound beyond the first few hundred feet is at sunset until an hour or so after sunrise. During this period or if downwind, sound that starts upward will curve back downward, often not passing through intervening trees etc. As one might expect, sound levels can be significantly reduced upwind from a source. Another factor is trees. 300 feet of trees can reduce levels about 5 dB if sound passes through them. Over long distances sound can pass over the top of the trees due to the atmospheric curvature effect, so the benefit is obtained only from trees nearest the source and receivers.

When using SoundPLAN for environmental noise modelling, ISO 9613-2:1996 is employed which considers ground effects, distance, barrier effects, reflection etc. in a standardized approach.

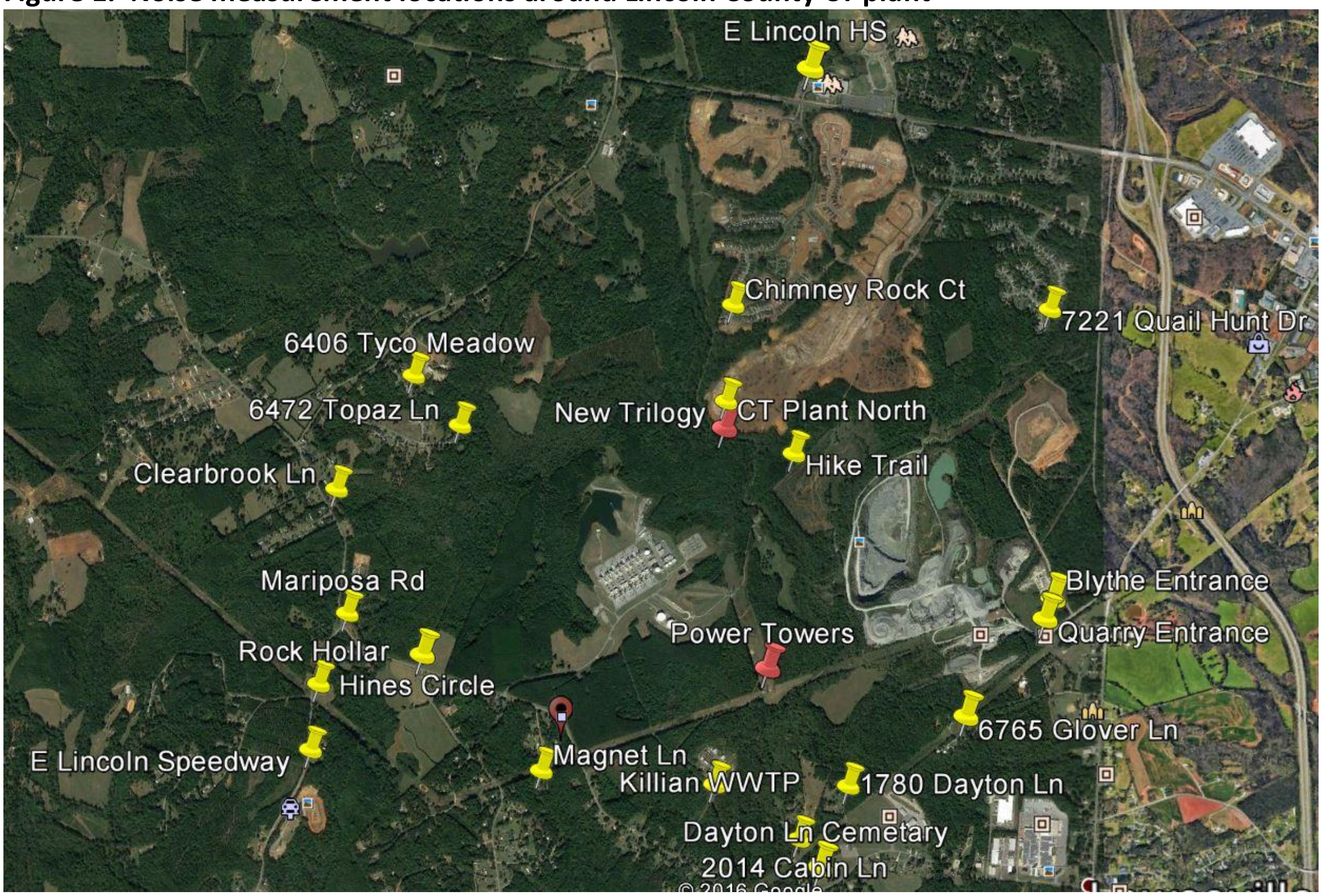
Noise Measurement Goals and Procedures

Current sound levels were measured in the surrounding neighborhood and along the plant perimeter of the Duke Energy Lincoln County combustion turbine plant. The purpose of the sound measurements was to document the existing sound at various community locations. The sound will vary with time of day, time of year, atmospheric conditions, and plant operating conditions. This study was limited to measurements made during one 42-hour period for long term monitors from Tuesday 9-10 AM on March 28 to Thursday 1-2 AM on March 30, and shorter 5 minute samples made on Friday, March 24 during the initial site visit and Saturday evening, March 25 during a Lincoln County Speedway event. Atmospheric conditions varied over the measurement period. Temperature, relative humidity, and wind conditions at the nearby airport were recorded from online sources to allow some evaluation of these effects on the noise distribution. The sound was measured in octave bands as well as the overall A-weighted level to provide a better understanding of the noise situation. Statistical sampling was used to see the variation within each measurement period.

Current noise levels at locations around current CT and proposed CT addition

Figure 1 provides an aerial view of the Duke Energy Lincoln County Combustion Turbine plant and adjacent properties. The yellow thumbtacks indicate noise measurement locations obtained over a five minute time period at various dates and times of day. The two red thumbtacks provide locations where 42 hour noise monitoring occurred. **Table 1** provides the sound measurements obtained on Friday, March 24 from 11:45 AM to 5:00 PM. **Table 2** provides the sound measurements obtained on Saturday, March 25 from 7:00 PM to 8:00 PM. **Table 3** provides the sound measurements obtained on Tuesday, March 28 from 2:00 PM to 3:00 PM. **Tables 1, 2 and 3** provides sound measurement location (refer to figure 1), GPS coordinates, the measurement file number, average level (L_{Aeq}), maximum sound level (L_{ASmax}), level exceeded 10%, 50% and 90% of the time (L_{10}, L_{50} , L_{90}). Also given in **tables 1, 2 and 3** is anything significant to note during the sound measurements.

Figure 1. Noise measurement locations around Lincoln County CT plant



Sound measurements identified by the yellow thumbtacks were obtained with a Casella 633C sound analyzer, SN 3148034. The Casella 633C was calibrated with a B&K 4230 sound calibrator, SN 1576946. The red thumbtacks were obtained with Larson Davis 831 sound analyzers (long term monitoring), SN 2544 and SN 3542. The LD 831 were calibrated by a Larson Davis CAL200 sound calibrator, SN 13269.

Table 1. Sound measurements obtained Friday, March 24, 11:45 AM to 5 PM.

Location	GPS N	GPS W	File	Time	L_{Aeq}	L_{Asmax}	L_{10}	L_{50}	L_{90}	Note
Blythe Entrance	35° 25' 45.66"	81° 0' 48.58"	381	11:57	57.9	64.4	60.0	57.5	54.5	Truck noise
Quarry Entrance	35° 25' 42.29"	81° 0' 50.23"	382	12:09	71.2	87	73.5	61.5	53.5	Truck noise
6765 Glover Ln	35° 25' 25.99"	81° 1' 6.34"	384	12:20	48.1	51.6	50.5	48.0	45.5	Birds, Jets
Dayton Ln Cemetery	35° 25' 0.84"	81° 1' 36.11"	385	12:42	65.3	80.4	69.5	53.0	45.0	Jets, Cars,
1780 Dayton Ln	35° 25' 14.66"	81° 1' 30.29"	386	12:52	57.5	75.4	53.0	44.5	39.5	
2014 Cabin Ln	35° 25' 5.78"	81° 1' 40.38"	387	13:09	57.6	67.6	63.5	51	46.5	Jet, Bird
Killian WWTP	35° 25' 14.88"	81° 1' 57.66"	388	13:21	41.6	49.4	43.5	41.5	39.5	
Magnet Ln	35° 25' 30.31"	81° 2' 33.05"	389	13:36	61	74.5	65	51.5	42.5	Road noise
Hines Circle	35° 25' 36.34"	81° 2' 57.41"	390	13:45	48.2	57.3	52.5	44	42	Road noise
Mariposa Rd	35° 26' 43.53"	81° 3' 12.65"	391	13:53	56.2	65.3	61.5	50	45	Road noise
Clearbrook Ln	35° 26' 4.23"	81° 3' 14.98"	392	14:04	68.4	83.4	72.5	56.5	48.5	Traffic noise
6472 Topaz Ln	35° 26' 14.97"	81° 2' 49.99"	393	14:15	43.4	55	46.5	43	40.5	
6406 Tyco Meadows	35° 26' 23.31"	81° 2' 59.51"	394	14:28	43.1	56.1	46.5	41	38.5	Motorcycle, Chimes
Chimney Rock Ct	35° 26' 35.24"	81° 1' 53.83"	395	15:06	52.1	58.8	55.5	50.5	47.5	Construct Equip, Jet
E. Lincoln HS	35° 27' 14.31"	81° 1' 38.18"	396	15:17	60.9	63.1	62.5	60.5	57.5	
7221 Quail Hunt Dr.	35° 26' 34.43"	81° 0' 48.58"	397	15:28	53.6	65.9	57.5	46.5	42	
Blythe Entrance	35° 25' 45.66"	81° 0' 48.58"	398	15:42	50.3	54.6	53	49.5	46.5	381
Quarry Entrance	35° 25' 42.29"	81° 0' 50.23"	399	15:48	47.3	55.7	49	46.5	45	382
6765 Glover Ln	35° 25' 25.99"	81° 1' 6.34"	400	15:55	42.9	50.8	45	42.5	40.5	384
Dayton Ln Cemetery	35° 25' 0.84"	81° 1' 36.11"	401	16:06	65.1	73.7	71	57.5	46.5	385 Road noise
1780 Dayton Ln	35° 25' 14.66"	81° 1' 30.29"	402	16:13	43.3	55.1	45	42.5	39.5	386
2014 Cabin Ln	35° 25' 5.78"	81° 1' 40.38"	403	16:17	58.1	68	65	46	44.5	387 jet
Killian WWTP	35° 25' 14.88"	81° 1' 57.66"	404	16:26	60.3	69.8	64.5	56	50.5	388 near Old Plank
Magnet Ln	35° 25' 30.31"	81° 2' 33.05"	405	16:32	55.9	65.1	60.5	52	39	389
Hines Circle	35° 25' 36.34"	81° 2' 57.41"	406	16:36	54.1	64.8	57.5	49.5	39	390 Jet
Mariposa Rd	35° 26' 43.53"	81° 3' 13.65"	407	16:41	60.2	68.7	64.5	56	42	391
Clearbrook Ln	35° 26' 4.23"	81° 3' 14.98"	408	16:48	63.6	74.2	69.5	54	46.5	392 Road noise
6472 Topaz Ln	35° 26' 14.97"	81° 2' 49.99"	409	16:53	44	51	48	43	39	393 Jet, Bird

Table 2. Sound measurements obtained Saturday, March 25, 7 PM to 8 PM.

Location	GPS N	GPS W	File	Time	L_{Aeq}	L_{Asmax}	L_{10}	L_{50}	L_{90}	Distance Speedway (ft)	Note
Hines Circle	35^0 25' 36.34"	81^0 2' 57.41"	410	19:07	51.6	57.8	55	50.5	46	2700-3100	Cars
Mariposa Rd	35^0 26' 43.53"	81^0 3' 13.65"	411	19:15	61.5	68.7	65.5	58.5	55.5	2840-3390	Motorcycle, Gunshots
Rock Hollar	35^0 25' 31.78"	81^0 3' 18.37"	412	19:20	48.7	53.9	51.5	48	46.5	1680-2300	
Speedway	35^0 25' 20.88"	81^0 3' 19.95"	413	19:28	70.2	77.1	73.5	69.5	66	385-900	Engines revving
Speedway	35^0 25' 20.88"	81^0 3' 19.95"	414	19:31	67.2	74	70.5	65.5	62.5	385-900	Engines revving
Speedway	35^0 25' 20.88"	81^0 3' 19.95"	415	19:35	71.7	81.7	76	66	61	385-900	Engines revving
Speedway	35^0 25' 20.88"	81^0 3' 19.95"	416	19:41	71.1	81	76	64	59	385-900	Engines revving

Table 3. . Sound measurements obtained Tuesday, March 28, 2 PM to 3 PM.

Location	GPS N	GPS W	File	Time	L_{Aeq}	L_{Asmax}	L_{10}	L_{50}	L_{90}	Note
Hiking trail	35^0 26' 10.18"	81^0 1' 41.36"	418	14:14	36.5	49.2	38.5	34	32.5	
New Trilogy	35^0 26' 19.00"	81^0 1' 55.30"	419	14:51	44.1	53.5	49.5	38	33	Jet, chainsaw
New Trilogy	35^0 26' 19.00"	81^0 1' 55.30"	420	14:58	35.1	41.2	37.5	34	32	very quiet

Observations of five minute noise measurements

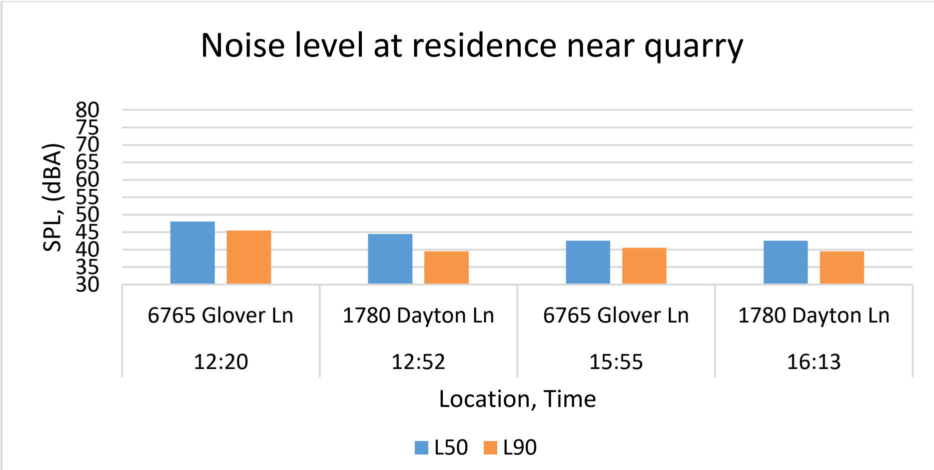
Quarry noise

Sound measurements made down Quarry lane near the Blythe Construction and Lake Norman Quarry entrances indicated maximum sound levels of 64.4 dBA and 87 dBA respectively. The primary source of the noise was dump trucks traveling to and from the quarry. The Blythe and Quarry measurement locations were 100 feet and 10 feet from the quarry gravel road that the dump trucks traveled on. While there, the frequency of trucks entering or leaving the quarry was about two minutes. **Table 4** provides the measured sound pressure levels of residences closest to the quarry. Because the quarry is a large area, the closest (minimum) and farthest (maximum) distances from the two residences to the quarry are given in **table 4**. From **table 4** and **figure 2,** it is seen that the L_{90} is near 40 dBA, or stated differently, 90% of the time, the sound level at these two residence will be louder than 40 dBA. From **table 4** and **figure 2** the average noise level (L_{50}) for these two residences without jet flyover is from 42.5 dBA to 44.5 dBA. During the time of day that these sound measurements were obtained (12:15 PM to 1 PM and from 3:45 PM to 4:15 PM), the quarry noise was not dominant.

Table 4. Residences closest to quarry

Location	GPS N	GPS W	Min Dist. (ft)	Max Dist. (ft)	Time	L_{50}	L_{90}	Note
6765 Glover Ln	35^{0}25' 25.99"	81^0 1' 6.34"	530	4200	12:20	48.0	45.5	Birds, Jet
1780 Dayton Ln	35^{0}25' 14.66"	81^0 1' 30.29"	3000	5750	12:52	44.5	39.5	
6765 Glover Ln	35^{0}25' 25.99"	81^0 1' 6.34"	530	4200	15:55	42.5	40.5	
1780 Dayton Ln	35^{0}25' 14.66"	81^0 1' 30.29"	3000	5750	16:13	42.5	39.5	

Figure 2. Noise level at residence near quarry



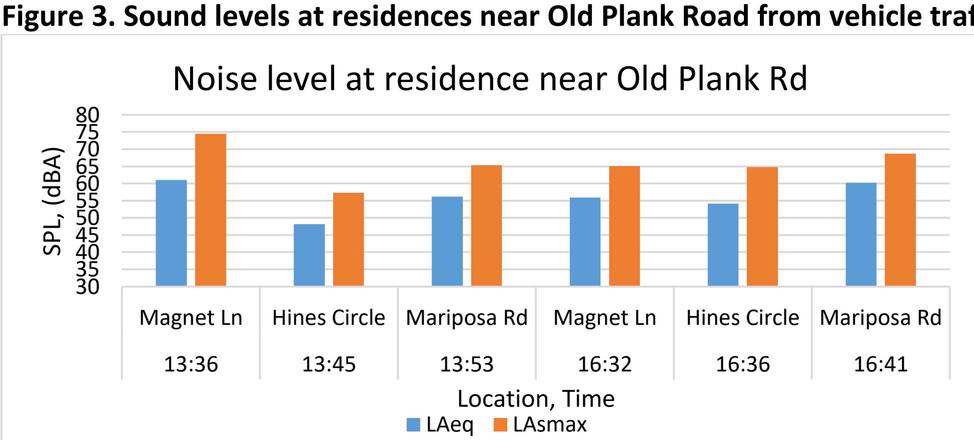
Noise near residences by Old Plank Road

Sound measurements were made near residences close to Old Plank Road. Old Plank Road has a 45 mph speed limit and hence, vehicles are frequently traveling at a relatively high rate of speed. Residences on the streets just off of Old Plank Road are Magnet Lane, Hines Circle and Mariposa Road. **Table 5** and **Figure 3** provides the average and maximum sound levels obtained at these locations. The average noise levels from vehicle noise ranged from 48 dBA to 61 dBA. The maximum noise levels due to vehicle noise ranged from 57.3 dBA to 74.5 dBA. People living just off of Old Plank Road will experience average levels from 48 dBA to 61 dBA and maximum levels up to 74.5 dBA

Table 5. Sound levels at residences near Old Plank Road from vehicle traffic.

Location	GPS N	GPS W	File	Time	L_{Aeq}	L_{Asmax}	Note
Magnet Ln	35^{0}25' 30.31"	81^0 2' 33.05"	389	13:36	61	74.5	Road noise
Hines Circle	35^{0}25' 36.34"	81^0 2' 57.41"	390	13:45	48.2	57.3	Road noise
Mariposa Rd	35^{0}26' 43.53"	81^0 3' 12.65"	391	13:53	56.2	65.3	Road noise
Magnet Ln	35^{0}25' 30.31"	81^0 2' 33.05"	405	16:32	55.9	65.1	
Hines Circle	35^{0}25' 36.34"	81^0 2' 57.41"	406	16:36	54.1	64.8	Jet
Mariposa Rd	35^{0}26' 43.53"	81^0 3' 13.65"	407	16:41	60.2	68.7	

Figure 3. Sound levels at residences near Old Plank Road from vehicle traffic.

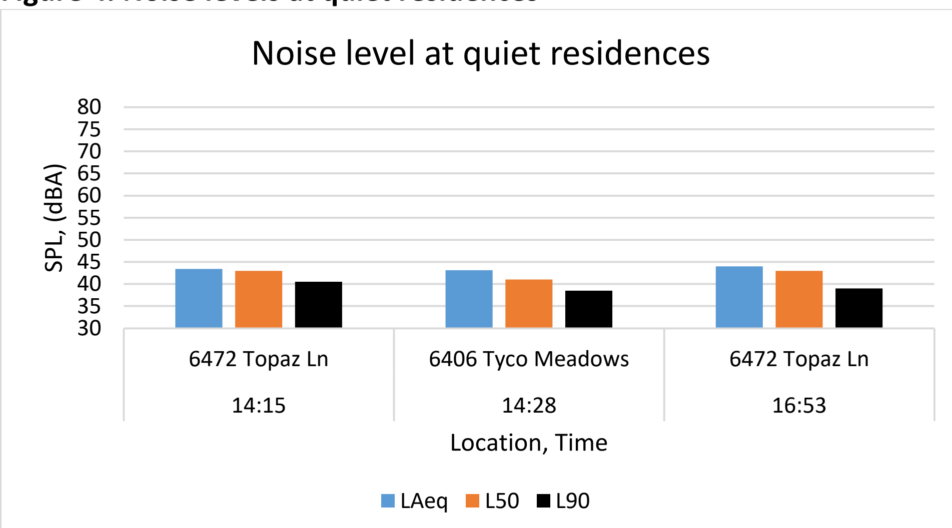


Measurements were also made at residences that were down non-outlet roads. These non-outlet road locations were 6472 Topaz Lane and 6406 Tyco Meadows. The average noise levels at these two locations were 43 dBA and 41 dBA respectively. The residences on Topaz and Tyco Meadows currently are not experiencing high noise levels from non-combustion turbine noise sources such as racetrack noise and quarry noise.

Table 6. Noise levels at quiet residences

Location	GPS N	GPS W	File	Time	L_{Aeq}	L_{50}	L_{90}	Note
6472 Topaz Ln	35^0 26' 14.97"	81^0 2' 49.99"	393	14:15	43.4	43	40.5	
6406 Tyco Meadows	35^0 26' 23.31"	81^0 2' 59.51"	394	14:28	43.1	41	38.5	Motorcycle, Chimes
6472 Topaz Ln	35^0 26' 14.97"	81^0 2' 49.99"	409	16:53	44	43	39	393 Jet, Bird

Figure 4. Noise levels at quiet residences



<u>East Lincoln Motor Speedway noise</u>

The East Lincoln Motor Speedway is approximately 1 mile from the proposed combustion turbine site. The 2017 schedule for the speedway is on Saturday night from 7 pm to 11 pm. Sound measurements were made Saturday evening, March 25 from 7 pm to 8 pm. The closest sound measurement location to the racetrack was 385 feet. At a distance of 385 feet from the racetrack, racetrack maximum sound levels exceeded 81 dBA. Average sound levels at a distance of 385 feet from the racetrack were from 64 to 69.5 dBA. The racetrack noise contained a high content of low frequency rumble. From sound pressure levels at the 385 distance from the race track, the sound power level of a race car was estimated. The equation used for the estimation of the race car sound power and sound pressure levels at other locations is taken from International Electrotechnical Commission IEC TS 61973:2012. The estimate assumed hemi-spherical sound spreading and that the noise was created by four vehicles distributed at different locations on the racetrack. Calculated estimates of sound pressure levels at three locations were made (**table 7)**. The three locations were the intersections of Mariposa and Rock Hollar, Mariposa and Old Plank, and Hines Circle and Old Plank Rd. In addition, racetrack noise predictions were made at locations near the proposed CT turbine addition (**table 8**).

Table 8 shows that at a distance of near 7400 feet from the center of the racetrack, the sound pressure levels from racetrack noise decrease to 50 dBA.

Table 7. Estimate of sound pressure level at locations from East Lincoln Speedway

Location	GPS N	GPS W	Distance Speedway (ft)	L_{Aeq}	L_{Asmax}	L_{10}	L_{50}	L_{90}
Hines Circle & Old Plank	35^0 25' 36.34"	81^0 2' 57.41"	2700-3100	56.3	66.3	61.3	53.3	49.3
Mariposa Rd & Old Plank	35^0 26' 43.53"	81^0 3' 13.65"	2840-3390	55.8	65.8	60.8	52.8	48.8
Rock Hollar & Mariposa	35^0 25' 31.78"	81^0 3' 18.37"	1680-2300	59.7	69.7	64.7	56.7	52.7

Table 8. Estimate of sound level at locations from East Lincoln Speedway nearer proposed CT Plant

Location	GPS N	GPS W	Distance Speedway (ft)	L_{Aeq}
Magnet Lane & Old Plank Rd	35^0 25' 30.31"	81^0 2' 33.05"	4058	55.1
Killian WWTP	35^0 25' 14.88"	81^0 1' 57.66"	6705	51.6
Neighbor 1 from sound modeling	35^0 25' 30.95"	81^0 1' 45.15"	7392	49.9
Neighbor 2 from sound modeling	35^0 25' 25.93"	81^0 2' 11.85"	5280	52.8
West Placement from sound modeling	35^0 25' 22.69"	81^0 2' 26.27"	4334	54.5
South Placement from sound modeling	35^0 25' 14.81"	81^0 1' 45.47"	7656	49.6

Trilogy community under construction

Sound measurements were made in the Trilogy community under development located north of the CT plant. Two locations were measured, one was on the hiking trail in the woods on the east side of the housing and the other was on the far south edge of the housing construction. During sound measurements, construction was not being undertaken. The average sound pressure levels on the hiking trail and south housing were 34 dBA respectively. A chainsaw was heard farther south of the housing development down a slope towards the creek bed. During that operation of the chainsaw, the average sound pressure level increased to 38 dBA.

Forty-two-hour noise monitoring

Two LD 831 noise monitors were set up on the Lincoln CT plant boundaries. The locations are shown in figure 1 at the two red thumbtacks. The first location was just south of the proposed new CT addition at the intersection of the east-west power tower clearing and north-south power tower clearing. The second location was on the north property line 20 feet between the creek bed separating the south edge of the Trilogy property from the north end of the CT plant property. The LD 831s were configured to audio record loud sounds so that the sounds could be listened to and identified. **Figures 5 and 6** provides the L_{Aeq} and L_{Asmax} time histories at the power towers and north property line respectively. **Figures 7 and 8** provides the L_{10}, L_{50} and L_{90} time histories at the power towers and north property line respectively.

Figure 5. LA_{eq} and LA_{smax} time histories at the power towers

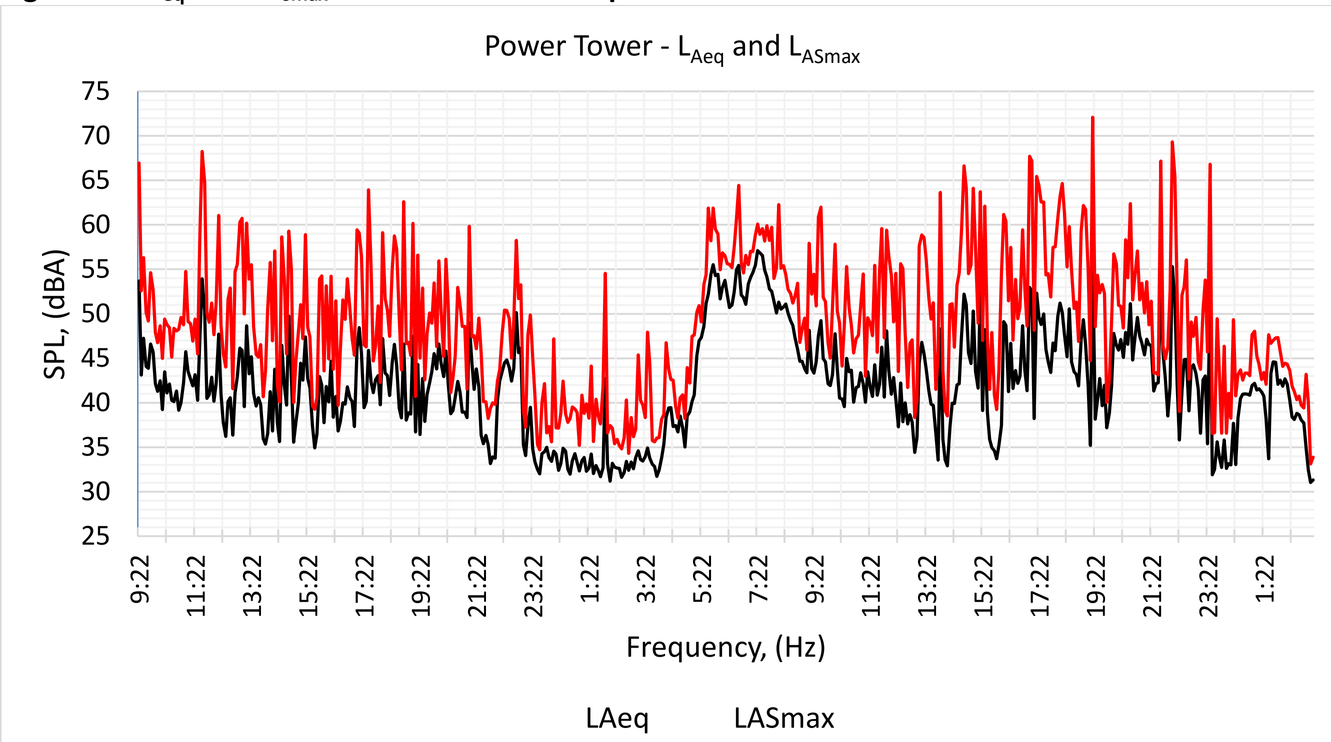


Figure 6. LA_{eq} and LA_{smax} time histories at the north property line

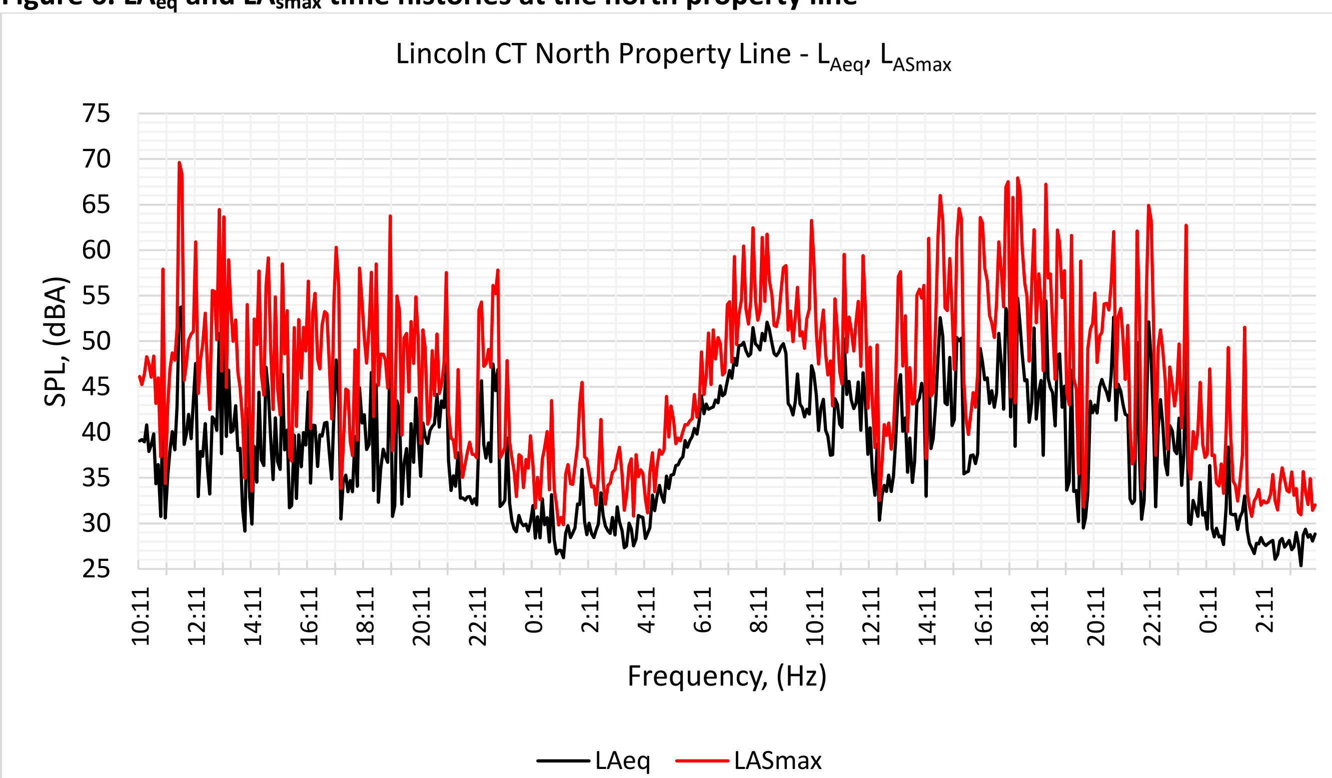


Figure 7. L_{10}, L_{50} and L_{90} time histories at the power towers

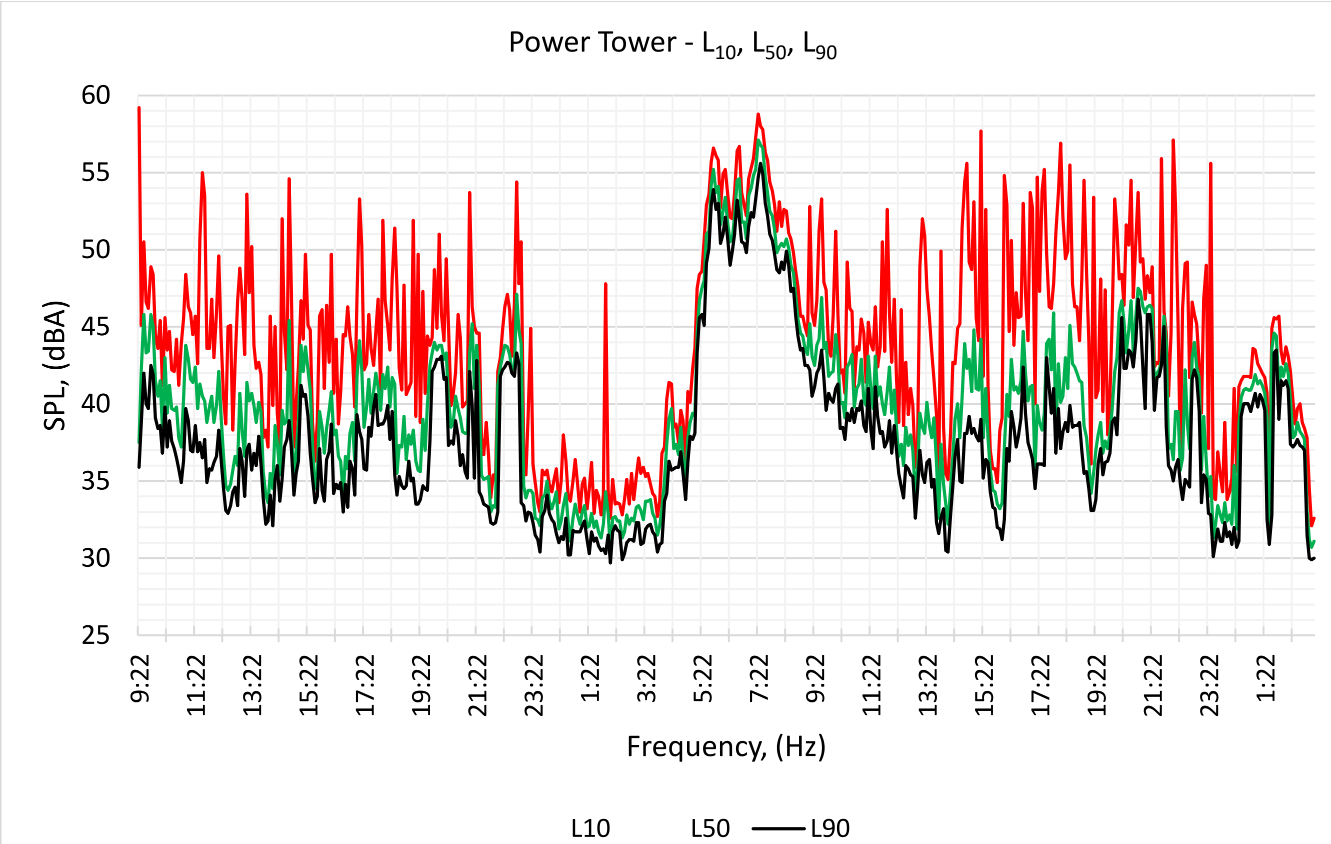
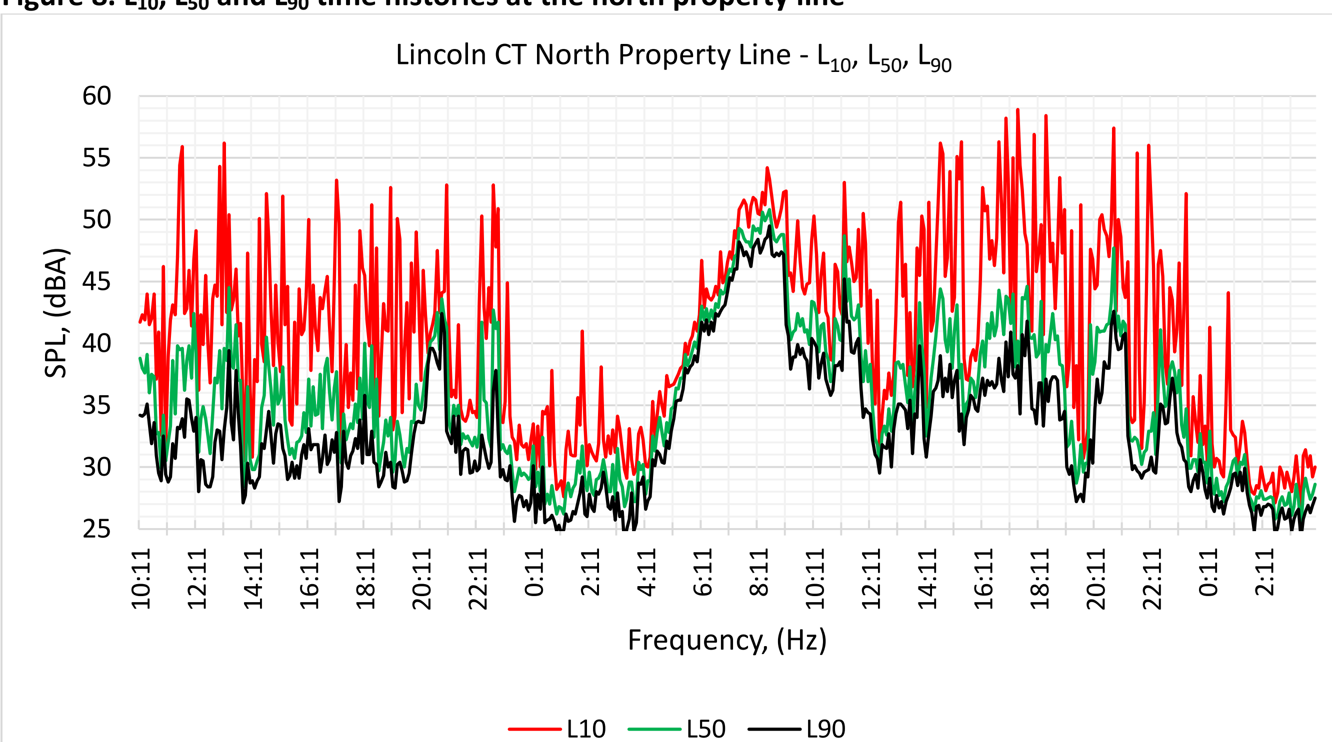


Figure 8. L_{10}, L_{50} and L_{90} time histories at the north property line



Power lines location- General noise

At the power lines, the most frequent source of high noise levels was aircraft flyover. Aircraft flyover noise occurred from 7:30 AM to midnight. At midnight, there appeared to be an abrupt halt of aircraft noise that was from flights originating or terminating at Charlotte Douglas airport until 7:30 AM. However, on Wednesday morning at 1:57 AM there was a high altitude flyover that appears in figure 5 and 7. In figure 7 starting near 1 AM and continuing to 2:15 AM there is a low level constant noise that was below the audio recording trigger level of the sound level meter. Hence it is unknown what was occurring from 1 AM to 2:15 near the power towers. Generally speaking average noise levels will be in the mid 40 decibels when sound propagation conditions are not favorable and there is absence of aircraft flyover noise.

Power lines location – Quarry noise

At the power towers other sources of high noise levels were birds and quarry machinery such as equipment backup alarms and construction vehicle tracks. On Wednesday morning, March 29, quarry noise was most prevalent from 5:30 AM to 8:30 AM and had average noise levels in the range of 53 to 57 dBA. After 8:30 AM, the average sound pressure levels dropped to 50 dBA or less. **Table 9** provides the calculated estimated sound pressure level from 5:30 AM to 8:30 AM when atmospheric conditions are favorable to sound propagation for the two residences close to the quarry (Glover Ln and Dayton Ln) and for two locations used for sound modeling prediction designated as neighbor 1 and neighbor 3. Also provided in **table 9** is the estimated distance from the quarry that will produce a sound pressure level of 50 dBA during the hours of 5:30 AM and 8:30 AM when atmospheric conditions are favorable. At a distance of 6400 feet from the quarry, under favorable sound propagation conditions, the sound pressure level due to quarry noise will be near 50 dBA.

Table 9. Estimated closest neighbors to quarry L_{Aeq} during 5:30 AM to 8:30 AM

Location	GPS N	GPS W	Dist. (ft)	Estimate L_{Aeq} 5:30 AM-8:30 AM
6765 Glover Ln	35^0 25' 25.99"	81^0 1' 6.34"	2022	60.0
1780 Dayton Ln	35^0 25' 14.66"	81^0 1' 30.29"	3550	55.1
Neighbor 1	35^0 25' 30.95"	81^0 1' 45.15"	2904	56.9
Neighbor 3	35^0 26' 03.55"	81^0 1' 50.88"	3387	55.5
50 dBA Contour			6400	50

North property line location – General noise

At the north property line of the CT plant, the most frequent source of high noise levels was aircraft flyover. Like the power tower location other high level noise sources at the north property line were birds, quarry noise and banging. The banging occurred near 5 pm on Wednesday, March 29. The banging may have been related to repair of a foot bridge over a small creek.

Power towers and North property line location - Aircraft flyover noise

Maximum noise levels at the power towers were caused by aircraft flyover with over 21 occurrences of maximum noise levels between 62 to 72 dBA over the 42 hour time period of monitoring. Maximum noise levels at the CT plant north property line were caused by aircraft flyover with over 25 occurrences of maximum noise levels between 62 to 70 dBA over the 42 hour time period of monitoring. Otherwise, average noise levels are in the 45 dBA range.

Sound Power Estimation

Sound Power Estimation for the Existing Turbine Plant

There was limited information available for the 16 existing combustion turbines (CTs) at the Duke Energy Carolinas Lincoln County Plant. **Figure 9** shows the levels that had to be met for the initial CT units. This included 61 dBA maximum level for a single unit measured 400 ft from the perimeter of the single unit, and a 65 dBA maximum level for all 16 units measured 400 ft from the nearest CT.

Figure 9 - Existing CT Sound Level Specification

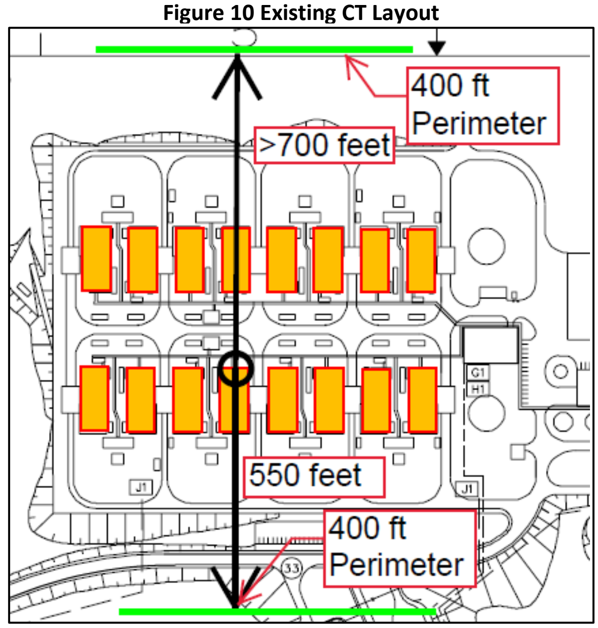
25.2.4.5.2 A maximum far field A-weighted sound emission (400 ft. from the perimeter of the nearest CT) of 61 dB for a single unit, in accordance with paragraph 2.3 of ANSI B133.8-1977, "Gas Turbine Installation Sound Emissions."

25.2.4.5.3 A maximum far field sound emission (400 ft. from the perimeter of the nearest CT) of 81 dB at 31.5 Hz for a single unit, in accordance with paragraph 2.3 of ANSI B133.8-1977.

25.2.4.5.4 A maximum far field A-weighted sound emission (400 ft. from the perimeter of the nearest CT) of 65 dB for a sixteen (16) unit site when arranged in a back-to-back fashion, with the centerlines of the compressor inlet flanges 270 ± 30 ft. apart, in accordance with paragraph 2.3 of ANSI B133.8-1977.

25.2.4.5.5 A maximum far field sound emission (400 ft. from the perimeter of the nearest CT) of 90 dB at 31.5 Hz for a sixteen (16) unit site when arranged in a back-to-back fashion, with the centerlines of the compressor inlet flanges 270 ± 30 ft. apart, in accordance with paragraph 2.3 of ANSI B133.8-1977.

Figure 10 Existing CT Layout



According to Figure 9, this means going from 1 to 16 units only increases maximum levels 4 dBA. If we could take all 16 CT sources and place them at the exact same distance from the measuring location and could have the same noise directed in that direction, they would be 12 dB louder than one unit or 73 dBA at 400 ft. So how is it, that it is only 4 dB (not 12 dB) louder? This is an 8 dB difference. The key wording here is "when arranged in a back-to-back fashion with the centerlines of the compressor inlet flanges 270 ft (+/- 30 ft) apart". The basic fact that the sources are distributed accounts for a 4-5 dB of this difference. A majority of the units are significantly further away than the closest units and do not contribute as much. This is both because of arranging them in two rows, and the arrangement in a line. We also believe the back to back arrangement means the noisier side of the unit is farthest from the perimeter and has some shielding/source directivity benefits. In other words, with the expanded perimeter we are no longer 400 feet from the inlet when all 16 are running. Instead we are over 700 feet from the back side in the unshielded direction and nearly 550 feet in shielded direction. This provides the remaining 3-4 dB of benefit. The layout is illustrated in Figure 10.

All of this is important, because to project noise to greater distances, we must know the sound source properties of the 16 units and translate these requirements to sources we can model. For purposes of this study, we took these effects into account and computed a point source equivalent CT sound power level (dBA) for a single CT and modeled 16 point sources. The A-weighted sound power we estimated for a single unit is about 111 dBA. The spectral frequency shape of the sound power was derived from work performed on the CTs at the Asheville site when those CTs were added in the mid 90's. The results are shown in **Figure 11**.

Figure 11 – Existing CT Estimated Individual Sound Power Levels

Sound Power	31 Hz	63 Hz	125 Hz	250 Hz	500 Hz	1 KHz	2 KHz	4 KHz	8 KHz	Overall
Unweighted	119.6	114.0	115.4	112.4	110.7	105.0	95.9	91.0	97.2	dBA
A-weighted	80.2	87.8	99.3	103.8	107.5	105.0	97.1	92.0	96.1	111.2

This sound power information is then added to our SoundPLAN outdoor propagation model in the form of 16 point sources. Since our concern was accuracy at a greater distance, there is no directivity assigned to each individual CT.

Estimation of Sound Power Levels for the new Siemens combined cycle CT

This particular combined cycle unit has not been produced yet. Therefore, it was necessary for Siemens to use a similar program (CadnA) to model all of the various source components, enclosures, silencers, barriers, and structures and provide estimates of sound power for each component. These are educated engineering judgments in some cases where the particular noise source has never been built on that particular scale before, and in other cases known sound power levels of individual pieces of equipment.

The equipment drawing in **Figure 12** shows the Siemens CadnaA results and how they modeled sources. **Figure 14** has the Siemens estimated sound power levels assumed for over 20 different types of sources. The buildings and other blocking elements were also modeled that provided shielding. This helps one get a sense of the complexity of the estimation process Siemens has used and that we replicated in SoundPLAN. Each component was identified, dimensioned, and sound power assigned per the Siemen's estimates provided.

The equipment layout and sound power level estimates are after agreed upon noise control measures (between Siemens and Duke Energy) were implemented and design changes fine-tuned.

Figure 12 – Siemens CadnaA Modeling

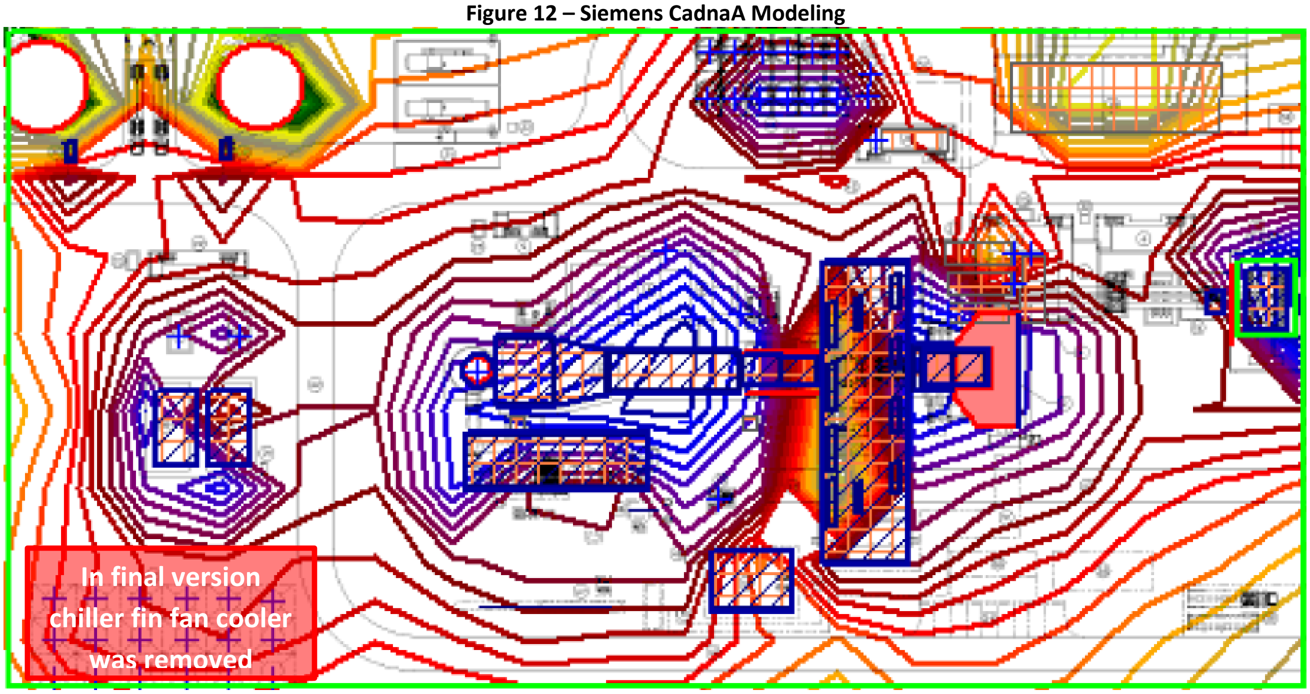
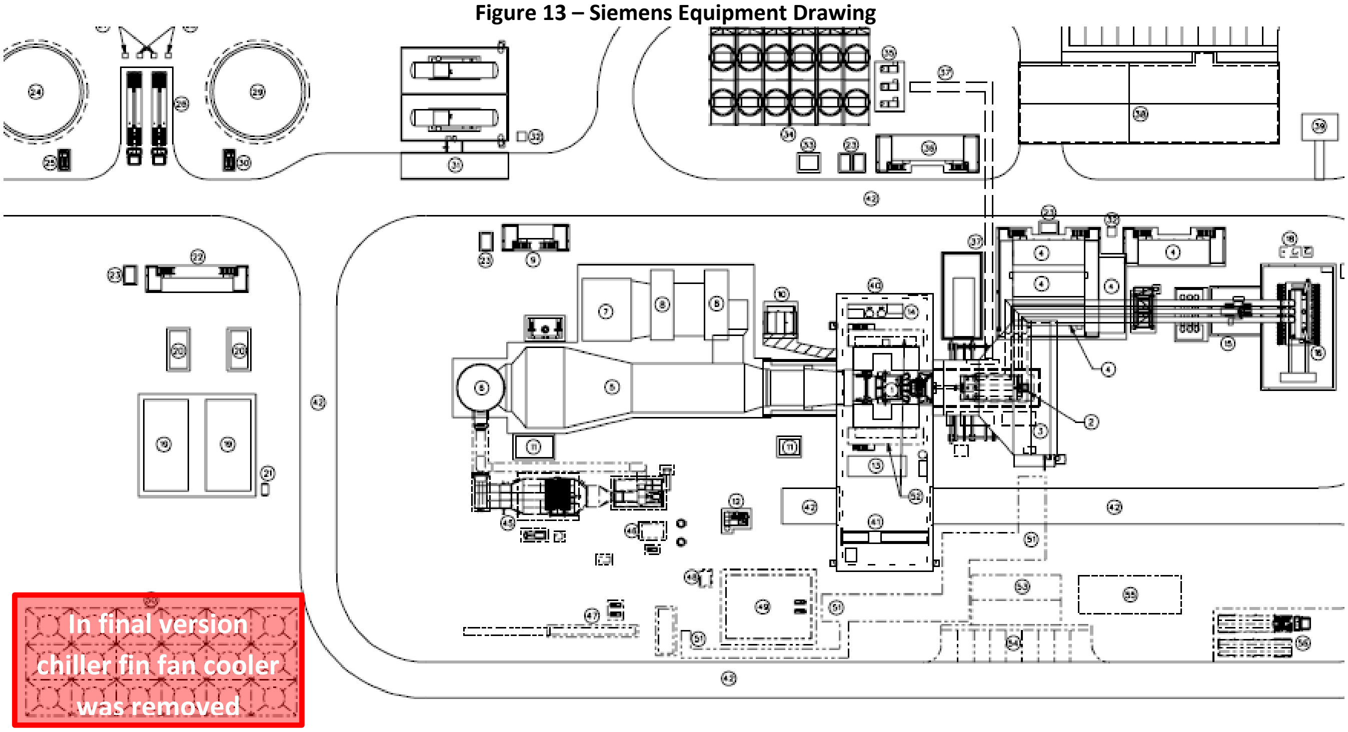


Figure 13 – Siemens Equipment Drawing



Strictly looking at the loudest sound levels at 400 ft for Siemens, the resulting sound level maximum was 64 dBA, averaging closer to 62-63 dBA. This maximum is only 3 dB higher than from a single CT existing unit maximum of 61 dBA. At large distances the 16 existing CTs have a combined sound power output of 123.2 dBA. The new combined cycle CT has an equivalent sound power output estimated at 123.6 dBA. This is essentially the same as the existing equipment at large distances.

Figure 14 – Siemens Estimated Sound Power Levels of Proposed CT addition Equipment

Name	Sound Power Level PWL Day (dB(A))									
	31.5	63.0	125.0	250.0	500.0	1000.0	2000.0	4000.0	8000.0	A-weighted overall level
GT Inlet Filter Face (h=18m)	88.1	92.0	98.6	98.0	90.8	102.0	85.5	102.0	106.6	109.8
Inlet filter casing outdoor	68.5	76.1	85.7	82.1	83.9	106.1	100.3	96.1	89.1	107.5
Inlet filter chiller	85.3	94.5	87.7	87.8	82.0	78.4	77.0	62.6	45.3	96.6
GT building, in all	89.1	102.1	95.9	98.3	98.4	102.9	103.7	103.5	101.2	110.5
HVAC	62.8	83.1	81.9	90.3	94.7	99.1	103.0	102.8	100.9	108.1
Building (h=30m)	89.1	102.0	95.7	97.5	96.0	100.6	95.4	95.1	90.0	106.9
S-Gen6-3000W Generator (h=6m)	77.6	103.7	108.2	111.0	113.2	114.6	113.2	111.3	103.1	120.4
GT Exhaust Diffuser Duct (h=6m)	85.5	98.7	100.8	102.3	106.7	110.9	103.1	95.9	65.8	113.6
Dilution SCR, in all	95.0	109.1	106.1	105.9	107.1	105.7	98.7	94.4	74.2	114.2
Transition duct (h=6m)	84.9	96.1	96.2	96.7	100.1	102.3	94.5	87.3	59.2	106.4
Inlet duct (h=8m) and main Body (h=24m)	89.2	99.2	99.4	98.8	99.7	100.7	96.1	92.9	68.8	107.2
DSRC Stack	90.5	108.1	89.2	74.6	74.9	77.1	73.3	70.1	46.0	108.2
DSRC Stack Outlet (h=43m)	89.5	96.9	104.3	104.2	105.0	99.4	86.1	83.5	72.5	110
DSCR Forced draft fans, in all	74.4	87.6	95.7	100.2	101.6	102.8	101.0	93.8	86.7	108
Exhaust gas heat exchanger	36.4	61.6	80.7	96.2	100.6	101.8	106.0	106.8	87.7	110.8
GT Transformer, in all	63.7	81.8	95.9	93.6	108.9	93.8	92.3	84.3	77.1	109.4
Auxiliary	47.6	60.8	74.9	79.4	90.8	86.0	77.2	72.0	63.9	92.5
GSU	63.6	81.8	95.9	93.4	108.8	93.0	92.2	84.0	76.9	109.3
Rotor Air Cooler Fin Fan	67.6	78.8	83.9	87.4	90.8	89.0	86.2	84.0	77.9	95.6
Fuel gas heater	65.5	74.7	86.8	84.3	83.7	84.9	86.1	82.9	76.8	92.9
Inlet filter air heater	71.7	80.9	93.0	90.5	89.9	91.1	92.3	89.1	83.0	99.2
Fuell gas final filter	38.6	54.8	69.9	77.4	83.9	90.0	92.2	95.0	82.0	98
Closed cooling water fin fan cooler, in all	72.8	73.4	90.9	94.4	101.4	101.3	96.0	91.4	90.0	105.8
Closed cooling water pump skid	48.6	63.8	75.9	89.4	92.8	92.0	90.0	88.0	83.9	98
Compressor fin fan cooler, in all	63.6	76.8	89.9	89.4	95.8	94.0	93.2	89.0	83.9	100.6
Fuel gas compressor, in all	77.4	85.6	96.7	100.2	103.6	98.8	94.0	101.8	101.7	108.9
Water Forwarding Pumps, in all	51.6	58.8	68.9	79.4	91.8	98.0	100.2	96.0	85.9	103.6

Predicted Noise Levels from Plant

Existing Lincoln Duke Energy Carolinas CT Noise Levels (SoundPLAN estimated)

Figure 15 shows the Existing CT noise level predicted with all 16 operating.

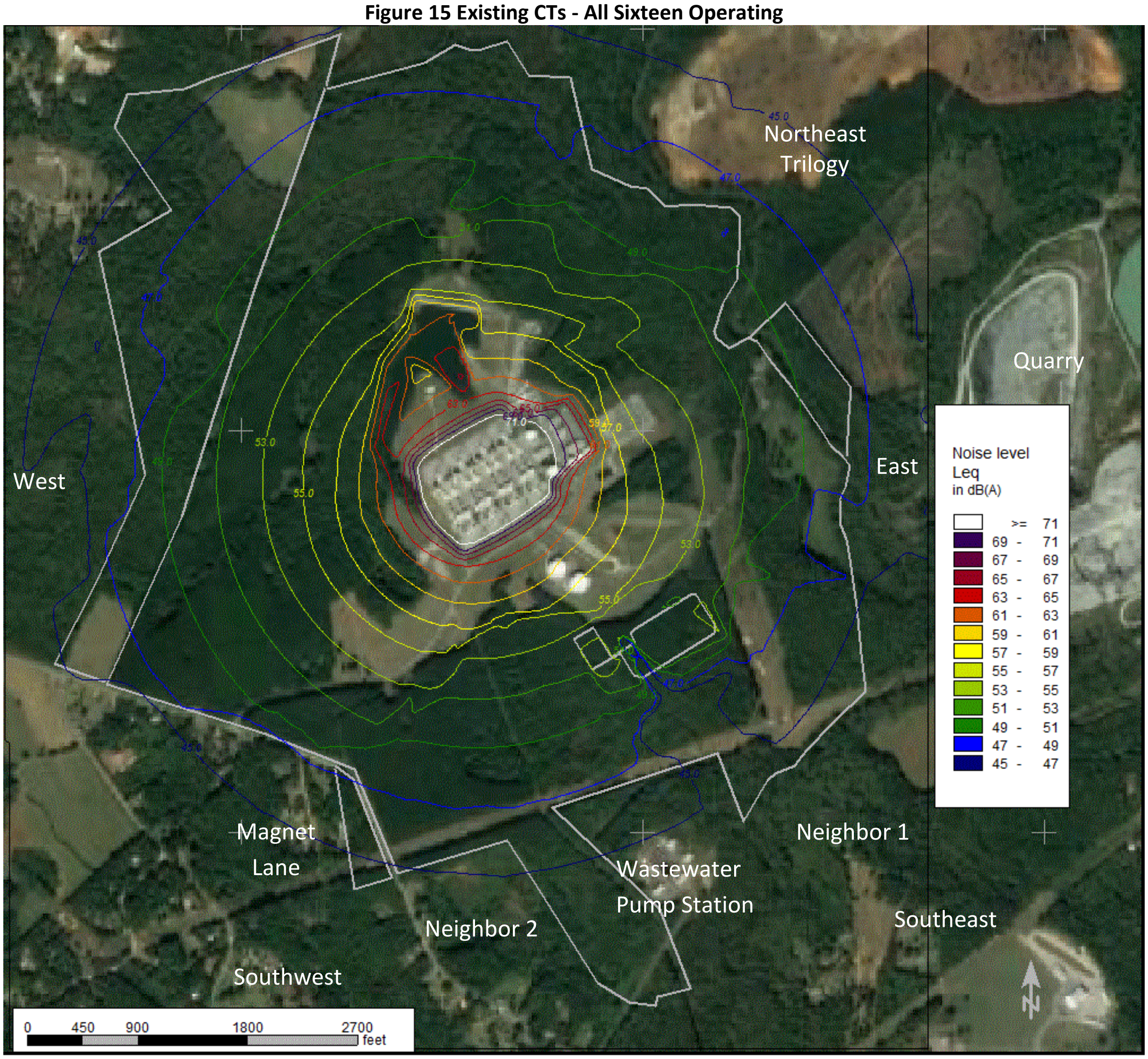
To the Southeast - The level at neighbor 1 to the southeast just under 45 dBA. Topography is adding some benefit. To the southeast, the contour lines are closer in than to the southwest. It appears the hill itself is obstructing some of the sound energy, and the new CT buildings some as well.

To the Southwest - The closest neighbors to the southwest are seeing levels approaching 48 dBA. Most of these neighbors are closer to 47 dBA. Neighbor 2 is where it increases and rises to 48 dBA in the nearest corner. Just across Old Plank Road near Magnet Lane levels are around 45-47 dBA.

To the West – Levels do not exceed 48 dBA to the west at adjoining properties and are generally less.

To the North – The future Trilogy Property to the Northeast is estimated to have noise levels of 47- 48 dBA at the property line when all sixteen are running, and falling off from there. One small corner of the property approaches 51 dBA. The topography is reducing levels a couple dB for some of the shared Trilogy property line as can be seen by the reduced radius for the 49 dBA contour line.

Figure 15 Existing CTs - All Sixteen Operating



New CT Addition Noise Levels

The location of this unit is on a hill, and more complex modeling of buildings and sources leads to less smooth contour lines and more minor movements as these effects slightly change propagation results.

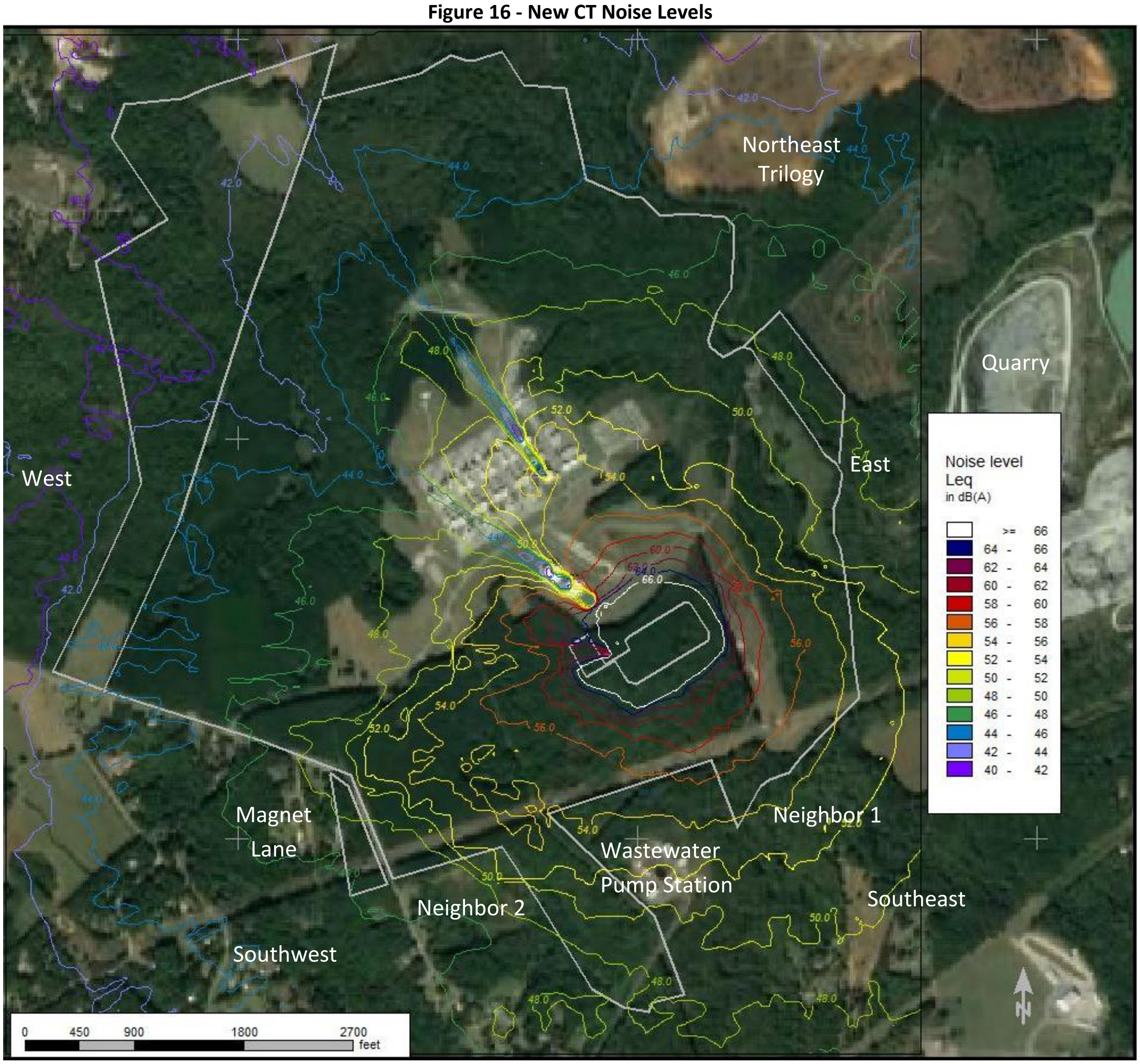
To the Southeast - Levels at neighbor 1 peak at 55 dBA. At the nearest home on that property levels are 52 dBA. The next home is around 50 dBA.

To the Southwest - Properties to the Southwest are in the mid 40's, except at neighbor 2 where it increases and rises to 52 dBA in the nearest corner. Also, just across Old Plank Road near Magnet Lane levels are around 46-48 dBA.

To the West – Levels do not exceed 45 dBA to the west at adjoining properties.

To the North – The Trilogy property has one small corner where levels approach 48 dBA in the one corner, with most of the property line below 46 dBA, and dropping to around 45 dBA and below for the cleared area on the Trilogy property.

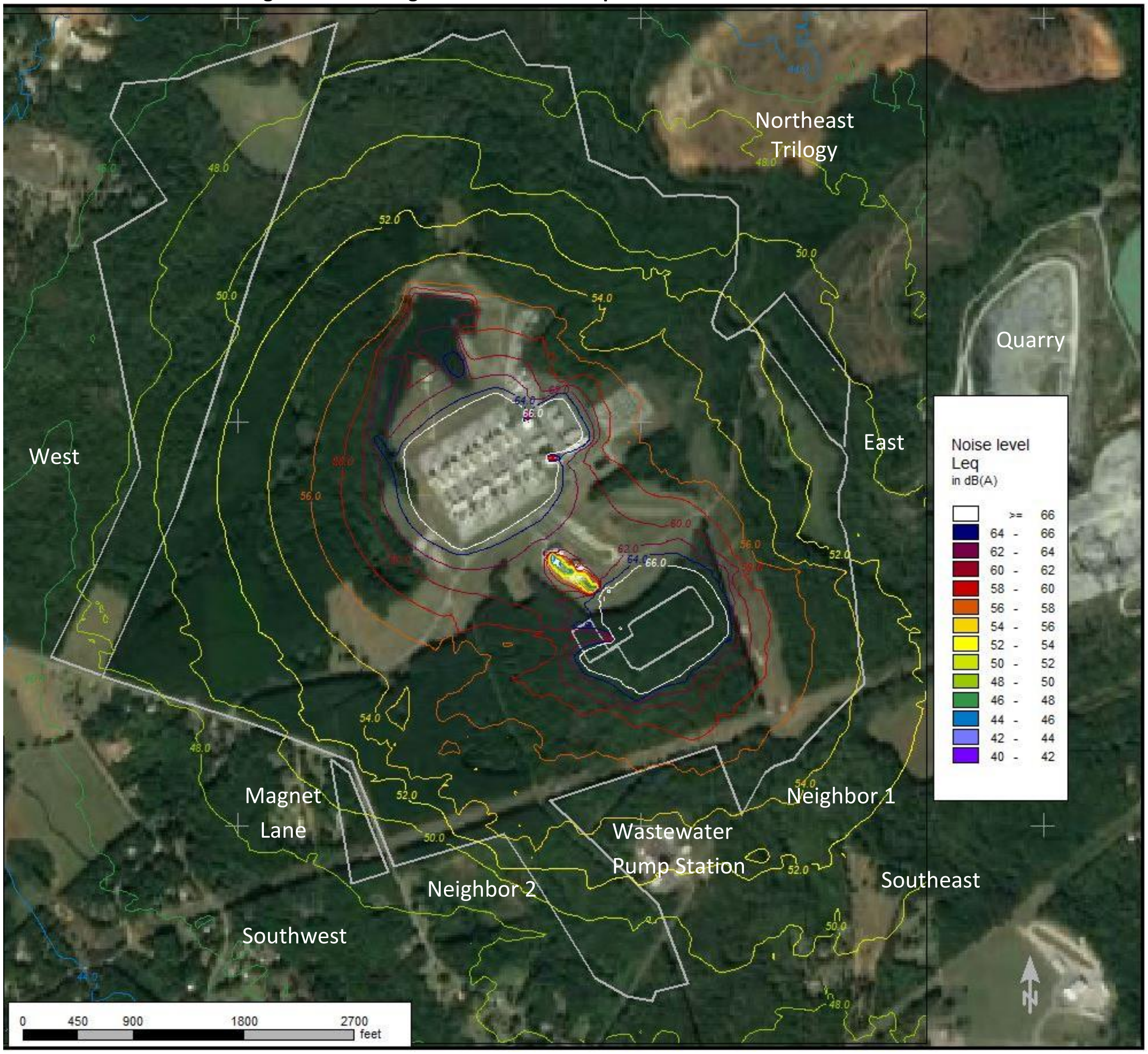
Figure 16 - New CT Noise Levels



Both existing CTs and proposed CT Addition

The levels for both existing and proposed CT's are shown in Figure 17.

Figure 17 - Existing Sixteen CTs and Proposed CT Combined Noise Levels



To the Southeast - Levels are essentially the same as with just the proposed CT which makes sense given there is an 10-11 dB difference in the individual sound levels from these two sources. 8-9 dB of this difference in sound levels from the two sources at this location is due to proximity. The source strength is essentially the same for the two source groups. The remaining minor difference appears to be a combination of the benefit of greater ground attenuation and shielding by the hill between this neighbor and the existing CT's than the new unit receives from the topography. This neighbor will of course therefore see an increase in noise from Duke Energy of 10-11 dB at the property line when the proposed CT operates. However, levels will be 52-55 dBA, just meeting the same night time limits that are currently in use for the specific use of race tracks in Lincoln County. There are currently no specific requirements for a project of this type. However, this shows Duke Energy approximately meets requirements the county has imposed on a specific type it has chosen to apply a limit. The existing noise sources affecting this property are in the same range as these levels. It is estimated from our measurements of the quarry that quarry operations are about 57 dBA and operates in the early morning hours. The race track is less in level but still around 50 dBA. Aircraft flyovers of course can be louder (we measured 62 dBA to 72 dBA maximum sound levels), but do not last as long. Although there is no doubt that this will be a new source of sound, it is estimated to be no louder than other currently occurring sources on this property.

<u>To the Southwest</u> –neighbor 2 and others on Magnet Lane are more equidistant from the existing and proposed CT's and thus levels are essentially the same. At neighbor 2 levels are 54 dBA with both sources on, with 52 dBA from the new CT and 48 dBA from the existing CTs. At Magnet Lane we have 47 dBA from existing CTs, and 46-48 dBA from the new CT. Thus overall levels are about 50 dBA there. Again, there will be an increase of Duke Energy generated noise in this direction of about 3 dBA on Magnet Lane and 6 dBA at the 'neighbor 2' worst case location in this direction. Levels from the race track are estimated to be 53-55 dBA at neighbor 2 and Magnet Lane respectively. Road noise from Old Plank Road at residences for Magnet Lane were reported in the mid 50's (and some higher). Therefore, this increase is on par with other noise sources in this direction, and is under 55 dBA.

<u>To the Northeast</u> – The Trilogy property has one small corner where sound levels approach 53 dBA; sound levels on most of the property are below 50 dBA. Existing CTs were 51 dBA in the one corner and 47-48 dBA mostly elsewhere. Therefore the increase of less than 2 dB is not a clearly noticeable change and is well below 55 dBA.

<u>To the West</u> – The difference in sound levels between both old and new CTs running versus only the Existing CTs is a fraction of a dB. This is due to the proximity effect of being significantly closer to the existing CTs than the new proposed CT. Therefore, there is no measurable increase in noise levels in this direction with the new CTs.

Noise Impact Evaluation

Methodology of Evaluation

An evaluation of the future Duke Energy generated noise levels was made by comparing to existing Duke site noise levels, community noise levels, and the Lincoln County race track night-time noise limits. Lincoln County's noise ordinance has no specified decibel limits, but does prohibit noise from "becoming a nuisance to adjacent single-family detached and two-family houses and residential districts" (Lincoln County 2016). The unified development ordinance does have limits that apply to race tracks. At night time, 10 minute average levels cannot exceed 55 dBA at the receiving residential property for this kind of source. Thus these limits were used to draw some comparisons.

§4.4.14 Racetrack

A. The maximum sound level at the property boundary shall remain at or below the limits set herein for the following receiving land use districts when measured at the boundary or at any point within the property affected by the noise. dB(A) shall remain at or below the maximum sound level maximum. dB(A) shall be calculated on a 10-minute average.

Table of Maximum Permitted Sound Level [dB(A)]		
Receiving Use District	Day (7 a.m.-10 p.m.)	Night (10 p.m.-7 a.m.)
Residential	60	55
Commercial	65	60
Industrial	75	75

Noise impacts on a community are based on the amount of increase in noise levels compared to other existing noise sources present in the community (including existing noise from the noise producer who is adding a noise source), the general level of the noise source, and many other factors (nature of the source – speech or music, impulsive, tonal, time of day, periodic nature, whether neighbors are already concerned, or are supportive of the noise producer to name a few). Where noise levels from the plant are not increasing more than 3 or 4 dB, the impact will not be clearly noticeable. Where noise levels from the plant will increase 5 or more decibels, then the other community noise sources present are a more significant factor, as is the overall sound level. In the end, individual responses will vary to a new noise source. We can only provide an opinion of what the reaction may be based on the character, frequency, and level of existing noise sources versus the new noise source and its overall level.

Results

Figure 18 illustrates the current levels being experienced by the community from itself, nearby roads, aircraft, quarry, and a nearby speedway. It also shows the levels of the existing CTs at the Lincoln plant, and estimated future noise levels with the new proposed CT. Future noise levels are similar to sound levels of existing sources, meaning a minimal impact to most. Most neighbor locations are below 55 dBA with only one location right at 55 dBA (property line of one neighbor to the southeast).

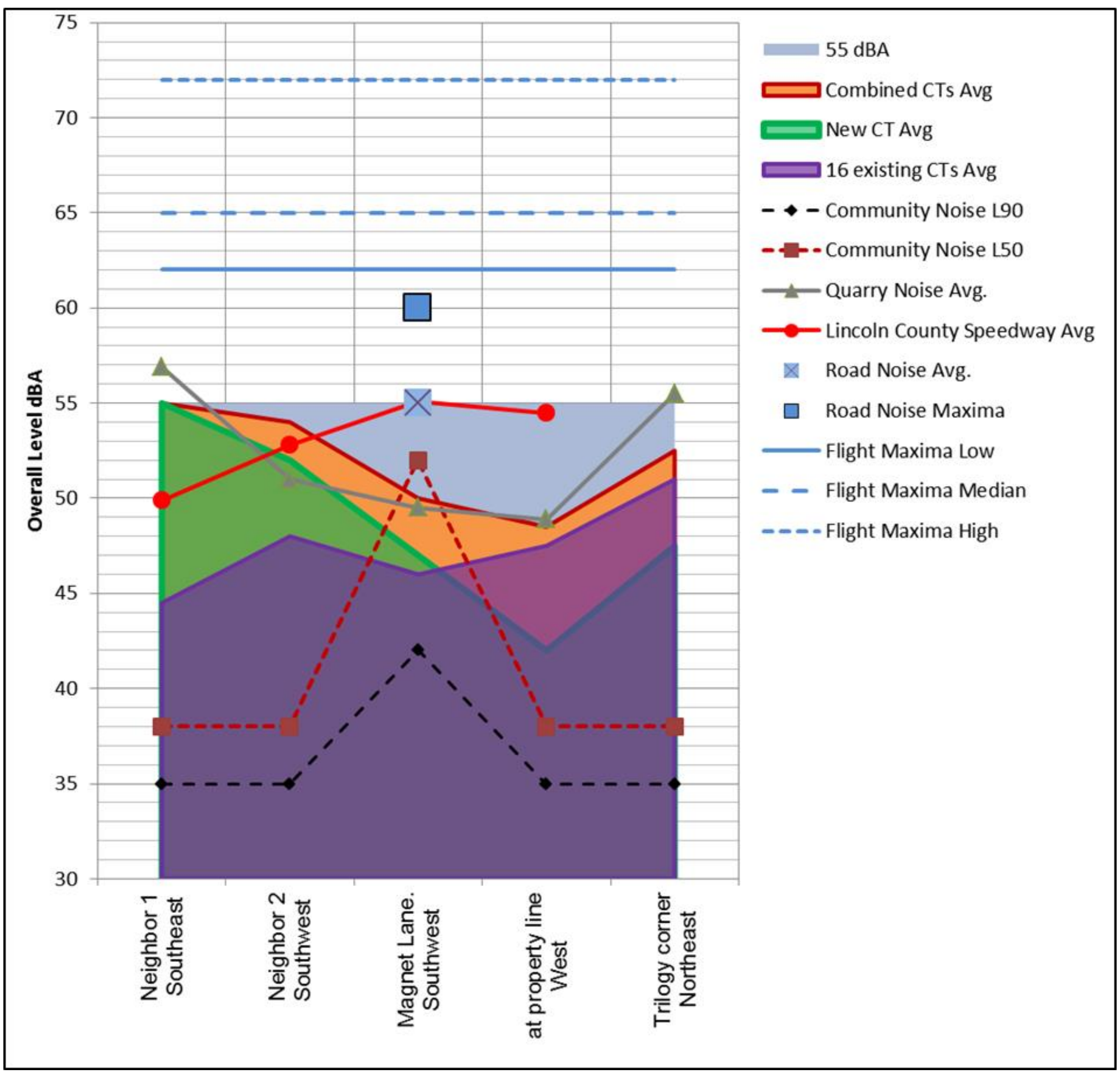
Noise levels from the quarry and race track at the neighbor to the southeast (Neighbor 1) are estimated to be 57 dBA and 50 dBA respectively. Aircraft events from CLT have slow A-weighted maximum levels of 62-72 dBA. Although clearly the noise source will be new and thus noticed, it is not more than 55 dBA (level used to regulate race tracks at night in Lincoln county), and is not more than other sources affecting this property.

Other homes showing a clear increase from Duke Energy sources to the southwest are 50-54 dBA with all CT's (existing and proposed) operating (3-6 dB increase), but race track noise levels are estimated to be 53-55 dBA and are thus similar. Also, noise from Old Plank Road (for those homes in close proximity to the road) is generating sound levels of about 55 dBA.

Property to the west and north (Trilogy property) are not noticeably changed in sound levels from the Duke Energy plant and most of the property is below 50 dBA.

It is our opinion that noise impacts are minimal to most of the surrounding neighbors. Neighbors 1 and 2 will see a clearly noticeable increase in Duke Energy levels, but total levels do not exceed 55 dBA. Thus impacts should not be significant. It should be noted that the Neighbor 1 property was sold to Hedrick Quarry in 2016; and the zoning for the property is now listed as Residential Transitional.

Figure 18 - Summary of Community Noise, Existing and Proposed Duke Lincoln CT Noise Levels



APPENDIX B

Literature Review and Windshield Survey of the Proposed Lincoln County CT Addition, Lincoln County, North Carolina

Mr. Henry Jenkins
UC Synergetic, LLC
123 North White Street
Fort Mill, SC 29715

April 5, 2016

Re: Literature Review and Windshield Survey of the Proposed Lincoln County CT Addition, Lincoln County, North Carolina

Dear Mr. Jenkins:

On December 7, 2016, UC Synergetic, LLC (UCS) contracted with Brockington and Associates, Inc. (Brockington) to conduct a literature review and windshield survey for the proposed Lincoln County CT Addition in Lincoln County, North Carolina. The project is located in southeastern Lincoln County and, to consider all potential physical and visual effects to cultural resources, we reviewed a broad study area consisting of approximately 10.8 square miles.. This investigation is a due-diligence effort designed for planning purposes in siting the proposed substation so that any potentially significant cultural resources may be considered during the siting process. This level of effort does not constitute fulfilment of more intensive studies that would be required under Section 106 of the National Historic Preservation Act (NHPA), should that law become applicable in this project.

Literature Review for Known Cultural Resources

Archaeological Sites and Surveys

For this literature review, we visited the North Carolina Office of State Archaeology in Raleigh to review previous reports and site files for known archaeological resources. There have been 8 surveys or environmental review projects within the study area. These are digitized in the corresponding GIS data and itemized in Table 1. Of note, there was an archaeological survey of the Duke Energy Combustion Turbine plant site ("Lowesville Tract") in advance of construction of the present-day station. During that survey (Gardner et al. 1990), one archaeological site (31LN78, discussed further below) was determined eligible and later mitigated through data recovery excavation (Gardner 1991). Also during the survey (Gardner et al. 1990), an eligible above-ground resource (The Morrison House) was documented and mitigated through large-format archival photography. The house was later demolished.

Table 1. Previous surveys in the study area.

Survey ID	Date	Report Title (Author)	Notes
BIB 2740	1981	Archaeological reconnaissance survey report for proposed NC 73 connector from NC 16 at Lucia to US 321 near Lincolnton, Gaston and Lincoln county, Project 6.804322, R-207 (Baroody and Padgett)	Total 3 sites recorded (none in study area)

BIB 1151	1982	Archaeological survey of land to be affected by the replacement of Bridge No. 22, on SR 1412 over Leepers Creek, Lincoln County, NC (Baroody)	No additional info
ER 90-8025	1990	Archaeological survey and testing at the Lowesville Tract, Lincoln County, North Carolina (Gardner et al.)	Total 34 sites recorded; one (31LN78) determined eligible and mitigated through Data Recovery. NC Bib Nos 2923, 2731)
ER 94-8949	1994	Cultural resources survey report for the proposed Piedmont-Duke Metering and Regulating Station, Lincoln County, North Carolina (Haynes)	No sites recorded (NC Bib No 3500)
ER 97-7310	1996	Archaeological Sample Survey, NC 16, North of Lucia to NC 150 Gaston, Lincoln, and Catawba Counties, North Carolina, T.I.P. number R-2206 (Sanborn)	49 sites recorded (NC Bib No 3954)
ER 06-1538	2006	Archaeological reconnaissance survey of Clark Tract (517 acres), Lincoln County, North Carolina (Edwards)	Total 9 sites recorded (NC Bib No 5748)
ER 06-0770	2006	Archaeological survey of proposed improvements to the East Lincoln County wastewater treatment and collection system, Lincoln County, North Carolina (Southerlin)	Total of 3 sites recorded, all not eligible (NC Bib No 5825)
CH 15-0842	2015	N/A (None)	Cleared by SHPO; no survey required

Through these various surveys as well as independent investigations, a total of 48 archaeological sites have been recorded within the study area. One of these sites was determined eligible; Site 31LN78 was mitigated and does not need consideration for planning purposes. Two sites (31LN65 and 31LN202) are categorized as “unassessed” and as they have no formal determination of eligibility should be considered potentially eligible for planning purposes. None of these unassessed sites are located within the proposed project tract. The remaining 45 sites are noted on their respective site forms as not eligible for the NRHP. Of note there are four sites within or partially within the project area (see Figure 1). Each of these sites has been determined not eligible for the NRHP. Table 2 itemizes the known archaeological sites in the study area.

Table 2. Archaeological sites (n= 48) within the Lincoln County CT Addition Study Area.

SiteNo	Type	Report Reference	NRHP Status	Notes
31LN65	Historic	None (Student, 1987)	Unassessed	No associated survey area; old cotton mill; overlaps with historic resource LN0529
31LN78	Historic/Prehistoric	Gardner et al. 1990	Eligible/ Mitigated	Determined eligible and mitigated through Data Recovery
31LN79	Historic/Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity/low density
31LN80	Historic/Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity

31LN81	Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity
31LN82	Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; limited research potential
31LN83	Historic/Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; limited research potential
31LN84	Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity
31LN85	Historic/Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; limited research potential
31LN86	Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; limited research potential
31LN87	Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; limited research potential
31LN88	Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; limited research potential
31LN89	Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity
31LN90	Historic	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity/low density
31LN91	Historic/Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity
31LN92	Historic/Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity/low density
31LN93	Historic/Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; research potential achieved through survey and testing; site (c1912 Morrison House) subsequently demolished
31LN94	Historic/Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity
31LN95	Historic/Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity/low density
31LN96	Historic/Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity
31LN97	Historic/Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity/low density
31LN98	Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity/low density
31LN99	Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity/low density
31LN100	Historic/Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity/low density
31LN101	Historic/Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity/low density
31LN102	Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity/low density
31LN103	Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity/low density

31LN104	Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity/low density
31LN105	Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity/low density
31LN106	Historic/Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity/low density
31LN107	Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity/low density
31LN108	Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity/low density
31LN109	Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity/low density
31LN110	Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity/low density
31LN111	Prehistoric	Gardner et al. 1990	Not Eligible	Duke Energy/Lowesville Tract; poor integrity/low density
31LN160	Prehistoric	Abbott and Sanborn 1996	Not Eligible	Limited potential; erosion/integrity
31LN181	Prehistoric	None Given 1998	Not Eligible	Wilkinson Site/Amateur Recording
31LN196	Historic/Prehistoric	Edwards 2006	Not Eligible	Limited potential; property now under development
31LN197	Historic/Prehistoric	Edwards 2006	Not Eligible	Limited potential/low density; property now under development
31LN198	Historic/Prehistoric	Edwards 2006	Not Eligible	Limited potential; property now under development
31LN199	Historic/Prehistoric	Edwards 2006	Not Eligible	Limited potential; property now under development
31LN200	Historic/Prehistoric	Edwards 2006	Not Eligible	Low density/limited potential; property now under development
31LN201	Historic	Edwards 2006	Not Eligible	Low density/limited potential; property now under development
31LN202	Historic	Edwards 2006	Unassessed	Recommended for testing
31LN203	Historic	Edwards 2006	Not Eligible	Low density/limited potential; property now under development
31LN204	Historic	Edwards 2006	Not Eligible	Low density/limited potential; property now under development
31LN206	Prehistoric	Southerlin 2006	Not Eligible	No potential
31LN207	Historic	Southerlin 2006	Not Eligible	No potential

Historic Architecture

The literature review was also designed to determine if any historic architectural properties have been recorded within the study area. This research included a review of all previously recorded resources on file through the HPO Web, the North Carolina State Historic Preservation Office (SHPO) repository of recorded architectural property data. This data includes National Register of Historic Places (NRHP) listed properties, resources recorded during Section 106 investigations, determinations of eligibility (DOEs), properties placed on the SHPO's Study List for further research, and resources recorded through surveys for counties and municipalities.

We also considered any locally significant properties that may not be formally listed with the state. Lincoln County has a Historic Preservation Commission charged with overseeing local historic properties; no additional resources to those previously known (see Table 3) were identified. Similarly, we reviewed a listing maintained by the Lincoln County Historical Society; no additional resources to those listed in the SHPO records were identified. Finally, prior to the windshield survey, we also reviewed historic maps and aerials to obtain locations of potential historic properties and guide our field effort.

There are 7 previously recorded architectural resources in the study area. Two of the resources are listed on the NRHP (LN003 "Ingleside" [1972] and LN0528 "Mount Welcome" [1991]). Of note, the original 1972 NRHP listing for LN003 "Ingleside" included five acres; a subsequent DOE by the NCSHPO in 1991 expanded its eligible boundary (shown on Figure 1 and in our GIS dataset). An additional 3 properties (LN0527, LN0540, and LN0573) are considered eligible for the NRHP due to previous DOEs or their placement on the NCSHPO Study List. Two other properties (LN0529 and LN0585) are previously surveyed properties; LN0529 is the extant ruins of a cotton mill that overlaps with archaeological site 31LN65 and is considered potentially eligible. Property LN0585 is purportedly a 2-story brick house near Leeper's Creek in the southwestern periphery of the study area. It could not be relocated during the windshield survey. Table 3 below provides a summary of the architectural resources.

Table 3. Previously Recorded Architectural Resources (n=7) in the Study Area.

Property ID	Status	Property Name	Description/Notes	Windshield Survey/ NRHP Rec
LN0527	Study List (1986)	John R. Asbury House	Ca 1900 Two story I-House; weatherboard; balcony; extended shed porch w square columns	Extant/Eligible
LN0573	Study List (2008)/ Determination of Eligibility (1979)	Mariposa Road Bridge	1912 pin-connected Pratt thru truss (DOT 540022); historic bridge inventory; now county-owned	Extant/Eligible
LN0003	National Register (1972)	Ingleside	1817 2-story Federal brick house; Eligible under Criteria A and C	Extant/Listed
LN0540	Determination of Eligibility (1993)	Kincaid Family House	1907 2-story side gable frame Colonial Revival house w/ 3 hip roof dormers above 1-story hip roof front porch; Eligible under Criteria C	Extant/Eligible
LN0528	National Register (1991)	Mount Welcome (John Franklin Reinhardt House)	1885 2-story frame house	Extant/Listed

LN0529	Survey	(former) Mariposa Cotton Mill	Brick wall ruins on north side of creek (overlaps with Archaeo Site 31LN65)	Extant/potentially eligible for architecture and archaeology
LN0585	Survey	House (Approximate site)	2-story hip roof brick house w/ wraparound porch & 2 interior chimneys	Could not locate from public view or through aerial map review; possibly demolished

Windshield Survey for Historic Architecture

On December 7 and 8, 2016, the project historian conducted a windshield reconnaissance of the Lincoln County CT Addition study area. As outlined in National Register Bulletin #24, a windshield reconnaissance-level survey is useful in ascertaining “a general picture of the distribution of different types and styles [of architectural resources], and of the character of different neighborhoods” (Parker 1985:35-36). Windshield surveys are also useful for making preliminary assessments of eligibility based on the architectural integrity of properties, but not in ascertaining the historical associations a property might possess.

The reconnaissance consisted of a vehicular inspection of architectural resources visible from all publicly accessible roads within the study area. When a comparison of current and historic topographic or aerial maps indicated properties located along private roads or abandoned and existing field roads, we supplemented our work through a review through aerial photography or online tax records if possible. In general, late fall vegetation enabled good visibility to most properties, although some private properties distanced from roadways were not visible. The purpose of our windshield reconnaissance was to:

1. Evaluate all previously recorded architectural resources (if any);
2. Locate/assess architectural resources not previously recorded and that appear to meet the minimum fifty year age requirement for the NRHP, and
3. Identify potentially eligible NRHP properties and mark in the GIS data set.

The study area is located in southeastern Lincoln County near the community of Lowesville. It encompasses approximately 6,969 acres bisected by NC 1412 (Mariposa Road), NC 1383 (Ingleside Farm Road), Old NC 16, and Old Plank Road. Other primary roads include NC 73, the new NC 16 bypass, and June Dellinger Road. Historic aerials show this area was balanced between large agricultural tracts and other wooded areas. Lowesville has always been a crossroads with no dedicated residential or commercial district. It represents a non-cohesive collection of early to mid-twentieth century residential housing with limited commercial examples. Historically, a smaller community also existed near the intersection of Mariposa Road and Leeper’s Creek, where once stood an old cotton mill (aerials show it stood as late as the 1960s) founded by Joseph G. Morrison at the turn of the twentieth century. We reviewed these locations for potential historic districts, but no cohesive collection of architecture was identified. There are three historical church congregations in the study area, two on Old Plank Road and another on Old NC 16, but none of the churches are recommended as eligible. No cemeteries were visible from the public roadways except for those directly associated with the three existing churches.

Of note, we identified four historical markers during the windshield survey. Of these, two are associated with previously recorded standing structures (“Ingleside” and “Mount Welcome”, discussed below). The other two markers, both on Old Plank Road, reference the now-demolished “Cottage Home” which once stood on present-day Duke Energy property. Cottage Home was the home of Reverend Robert H. Morrison, and the location of Thomas “Stonewall” Jackson’s marriage to Mary Anna Morrison. According to one of the markers, the house burned in 1911. A subsequent brick structure was constructed later; that building was documented in 1990 prior to demolition (Gardner et al. 1990).

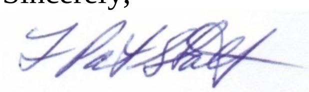
The study area contains a moderate number of resources that are at least 50 years of age, but the vast majority have been modified by non-historic materials and/or incompatible alterations. The older building stock is largely represented by early to mid-twentieth-century framed houses of varying types as well as mid-twentieth-century ranch houses. Many of the ranch houses retain much of their architectural integrity; however, none appear to exhibit expressive ranch features beyond their basic linear form. The existing built environment within the study area is more broadly characterized by mid- and late twentieth-century housing, particularly modular housing. The most recent housing trends are modern (post-2000), such as new development under construction north of the Duke Energy CT plant. During the windshield reconnaissance, we identified no additional resources within the study area that retain sufficient architectural integrity to be considered eligible for inclusion in the NRHP. The best and most significant architectural examples have been captured by previous surveys.

As noted, there are 7 previously recorded architectural properties within the study area. We re-located six of these during the windshield reconnaissance. The two NRHP listed properties (LN003 “Ingleside” and LN0528 “Mount Welcome”) remain intact. Three additional DOE and Study List properties (LN0527, LN0540, and LN0573) are extant, retain integrity, and should be considered are considered eligible. Two other properties (LN0529 and LN0585) are previously surveyed properties; LN0529 is the extant ruins of a cotton mill that overlaps with archaeological site 31LN65 and is considered potentially eligible. Property LN0585 (recorded by Brown, 1985) is purportedly a 2-story brick house near Leeper’s Creek in the southwestern periphery of the study area. It could not be relocated during the windshield survey or during an aerial map review. It may be demolished or is potentially misplotted in the state GIS. Table 3 provides information on each of these resources.

Where possible, architectural properties identified as listed, eligible, or potentially eligible for the NRHP should be avoided and visual effects considered during project planning. In addition, we observed numerous other properties that appear to be 50 years old (thus, meeting the minimal standard for NRHP eligibility consideration) distributed throughout the study area; these are properties that would be recorded by an architectural historian to satisfy National Historic Preservation Act (NHPA) Section 106, if that regulatory compliance is required. Due to alterations or modifications, these properties appear to have lost their architectural integrity and may not meet the criteria of eligibility for listing on the NRHP under Criterion C. However, these properties might possess historical significance that could only be determined through more detailed archival research. We did not attempt to plot each of these resources in our GIS dataset. Further, there are four sites within the proposed project area. While the project area has been systematically surveyed for archaeological sites (Gardner et al. 1990) and it is unlikely that additional sites exist, should Section 106 compliance be required, we recommend consultation with the NCSHPO confirming that no additional surveys are warranted prior to the project moving forward.

The attached Resources Map (Figure 1) details the findings from both the literature review and windshield reconnaissance. The projection used to develop the map and shapefiles was NAD 1927 UTM Zone 17. Should you have any questions about the GIS data or property recommendations, please do not hesitate to send me an email (patriciastallings@brockington.org) or call 678-638-4126.

Sincerely,



F. Patricia Stallings
Senior Historian

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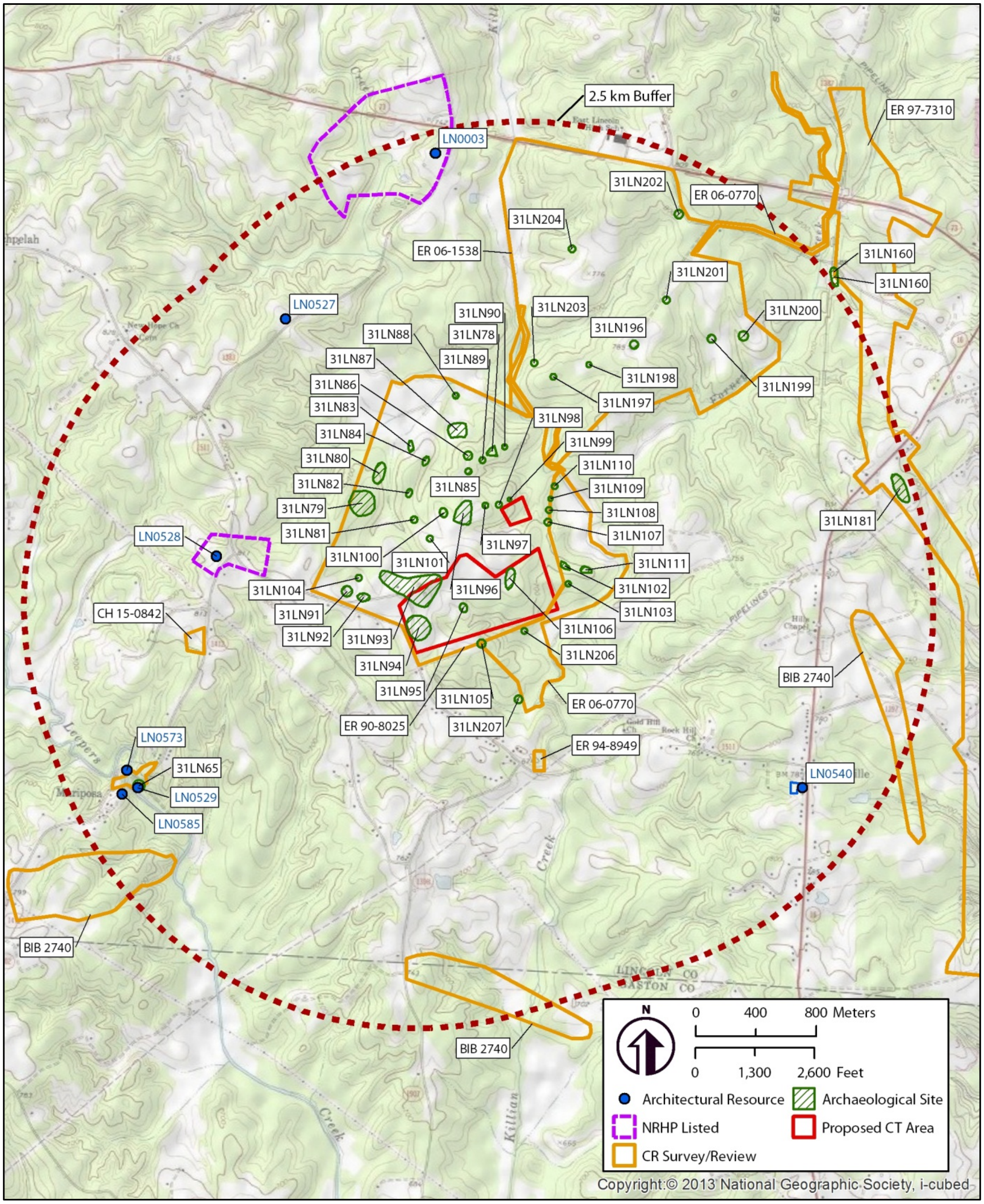

Figure 1. Lincoln County CT Addition Study Area, Resources Map (see GIS data for additional detail).