UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of	)	
Practices Leading to Excess Capacity and Waste	)	Docket No. ___________
by Duke Energy Carolinas and Duke Energy Progress	)	

RULE 206 COMPLAINT AND PETITION FOR INVESTIGATION BY NC WARN

PURSUANT TO 18 C.F.R. § 385.206, Rule 206 of the Commission's Rules of Practice and Procedure, now comes the North Carolina Waste Awareness and Reduction Network, Inc. ("NC WARN"), through the undersigned attorney, with a complaint and petition for investigation of the practices of Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") (together "Duke Energy") that lead to excess capacity and waste. As part of this complaint and petition, NC WARN moves that the Commission hold an investigatory hearing in Raleigh, North Carolina, to receive testimony and evidence.

All correspondence may be directed to the undersigned attorney.

SUMMARY OF ARGUMENT.

1. After the merger between Duke Energy and Progress Energy in 2012, the combined Duke Energy provides directly or through municipalities and electric cooperatives more than 95% of the electricity in North Carolina.
2. Duke Energy manipulates the electricity market by constructing costly and unneeded generation facilities, directly leading to generating capacity far above what is reasonable

or necessary to meet demand. This practice leads to customer rates that are unjust and unreasonable.

3. Duke Energy has failed to adequately comply with the Commission Order No. 1000 and related the Commission orders and policies by not effectively connecting its transmission system with neighboring utilities, such as Dominion Power, the Southern Company and the Tennessee Valley Authority ("TVA"), which also have capacity in excess of planned reserve margins.
4. The excess capacity throughout the Southeast region can and should be used among the various utilities to supplement each other's generation requirements, rather than to duplicate the waste of unneeded or underutilized generation.
5. Duke Energy's excess capacity in North Carolina is not an anomaly but is apparent in Duke Energy's other state jurisdictions, especially in Florida.
6. Duke Energy's plan for unrealistic future growth leads to unnecessary, and expensive, generating plants, and as a result, even more excess capacity.
7. NC WARN is requesting an investigation of Duke Energy's practices and the potential benefits of it entering into a regional transmission organization ("RTO").
8. NC WARN is requesting the Commission to force Duke Energy to purchase power from other utilities rather than construct wasteful and redundant power plants.

In further support of the complaint and petition is the following:

A. <u>THE PARTIES</u>.

NC WARN is a not-for-profit corporation under North Carolina law, with approximately 1000 individual members and families across North Carolina, most of whom are customers of

Duke Energy in North Carolina. NC WARN's purpose is to confront the accelerating crisis posed by climate change by challenging Duke Energy practices and at the same time, working for a swift North Carolina transition to energy efficiency and clean power generation. NC WARN partners with other citizen groups and uses sound scientific research to inform and involve the public on important energy issues. Its address is NC WARN, Post Office Box 61051, Durham, North Carolina 27715-1051.

DEC and DEP (formerly Progress Energy) are electric utilities operating generation, transmission and distribution facilities in North and South Carolina service areas. The two utilities have been merged since 2012 and their holding company, Duke Energy, also has service areas in Florida, Ohio, Indiana and Kentucky. See Orders in the Commission Docket No. EC11-60-000: Duke Energy Corp. and Progress Energy, Inc., 136 the Commission ¶ 61,245 (2011) (Merger Order); and Duke Energy Corp. and Progress Energy, Inc., 137 the Commission ¶ 61,210 (2011) (Merger Compliance Order).

B. PRESENTATION OF LEGAL AND FACTUAL ISSUES.

I. DUKE ENERGY'S MANIPULATION OF THE MARKET FAILS TO PROTECT ITS CUSTOMERS.

Duke Energy is a regulated monopoly pursuant to North Carolina law that provides directly or through sales to municipalities and electric cooperatives more than 95% of the electricity in North Carolina. It manipulates the electricity market by constructing costly and unneeded generation facilities leading to generating capacity far above a reasonable reserve margin. This leads to customer rates that are unjust and unreasonable.

Duke Energy has failed to adequately comply with Commission Order No. 1000 and related Commission orders and policies by not effectively connecting its transmission system with neighboring utilities, such as Dominion Power, the Southern Company and the TVA, which also have capacity in excess of planned reserve margins. The excess capacity throughout the Southeast region can and should be used among the various utilities to supplement each other's generation requirements, rather than to duplicate the waste of unneeded or underutilized generation. Duke Energy's excess and redundant capacity in North Carolina is not an anomaly but is apparent in Duke Energy's other state jurisdictions, especially in Florida.

The excess capacity within the Duke Energy territory, as well as in the entire Southeast is demonstrated in the North American Electric Reliability Corporation's ("NERC") "2014 Summer Reliability Assessment."[1] NERC defines reserve margins as "unused generating capacity at the time of peak load as a percentage of expected peak demand," and encourages utilities to plan for adequate reserve margins, especially during peak periods. The attached summary of the study, "NERC's Summer Reliability Assessment highlights regional electricity capacity margins," shows excess capacity throughout the SERC Reliability Corporation. ATTACHMENT A. In the study, SERC-East (the Carolinas) had reserve capacity during peak periods of 24%; SERC-North (primarily TVA), 26%; and SERC Southeast (primarily Georgia and Alabama), 37%. The separate Florida Reliability Coordinating Council had reserve capacity of 29%. The resulting total for Southeast is much greater than the NRC reference margin of 14.8%.

The ongoing failure to reduce excess capacity through transmission and generation planning and cost allocation leads to waste and unreasonable and unjust rates, most of which is caused directly by new plant construction. Duke Energy has received authorization from South

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1 www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014SRA.pdf

Carolina to construct a 750 MW combined cycle generating plant near Anderson, South Carolina. SC PSC Docket No. 2013-392-E. As demonstrated in its annual integrated resource plans ("IRPs") for DEC and DEP, Duke Energy intends to construct 2,234 MW of new nuclear units in 2024 and 2028, and additional 5,048 MW of natural gas plants beginning in 2020. NC Utilities Commission ("NCUC") Docket No. E-100, Sub 141.[2] Recently, a 475-MW merchant natural gas plant was granted a certificate of public convenience and necessity in Duke Energy's North Carolina jurisdiction. NCUC Docket No. EMP-76, Sub 0. Similarly, surrounding utilities have new units planned or currently under construction. Most notably are the new nuclear reactors under construction, Plant Vogtle in Georgia by the Southern Company and the Summer Nuclear Generating Station by South Carolina Electric & Gas and others.

There are no compelling reasons why each utility should continue to construct new generation without looking at mutual purchasing agreements. Duke Energy is only able to implement such wasteful practices in North Carolina because it has a monopoly service area covering almost all of the state. Rather than investigating regional strategies, Duke Energy continues to plan for new generating plants. In its IRPs, Duke Energy is planning on purchasing only .2% of its capacity needs in 2029 (down from the current 3%). ATTACHMENT B. This is directly counter to Commission directives in Order No. 1000 and other orders demonstrating the benefits of regional strategies and utility efforts.

If peak needs were met by interconnecting and sharing power instead of building plants, the customers would save money. Duke Energy and the other Southeast utilities have been summer peaking utilities and most of their planning is for generating capacity to meet summer peak. A review of Duke Energy's projected reserve margins shows excess reserve capacity for

[2] Available at www.ncuc.net "docket portal" "docket search" Docket "E-100, Sub 141," filed on September 14, 2014.

both DEC and DEP. In its IRPs, Duke Energy forecasts 1.5% annual growth for both utilities and, given the additional generating facilities planned for, reserve margins for DEC range from 15% to 22.7% for summer peak (and 19.4% to 25.7% for winter peak), with DEP 15.2% to 21.1% for summer peak (and 22.1 to 31.7% for winter peak).[3] ATTACHMENT C.

Moreover, when the only strategy a utility has is to construct more generating units to meet the summer demand, its new and existing plants may be idle a major part of the year. The result of this practice is the excess reserve capacity during the shoulder months is high, and the off-peak periods even higher. Using average monthly peaks taken from U.S. Energy Information Administration ("EIA") Form-714 for the shoulder months of April, May, October and November, DEC's average reserve capacity during peak is 40.6%, while DEP's is 36% and for several of these shoulder months, more than 50% of the available capacity was not needed.[4]

It should be emphasized that the reserves Duke Energy has determined to be necessary are based on a 1.5% annual growth rate, which flies in the face of flat growth over the last decade and growth projections from other sources. Using a robust, and possibly unattainable, growth rate of 0.5% as a conservative measure, the reserve margins for Duke Energy are far in excess of what is required given the utility's present construction plans. Over the fifteen-year IRP planning horizon under a growth rate of 0.5%, DEC's excess capacity for summer peak ranges from 16.38% to 32.91%, with DEP from 22.88% to 34.96%.

The most recent growth projections by the EIA and the American Council for an Energy-Efficient Economy ("ACEEE") show that electricity sales have stagnated in recent years, and

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[3] Reserve margins calculated reforecasting utilities' projected adjusted peak demand beyond 2015 at a rate of 0.5%, subtracting adjusted peak demand from cumulative capacity incl. demand-side management, divided by generating capacity.

[4] Data from FERC form 714, Part 2, Schedules 2 and 3. Reserve margins calculated subtracting peak demand from total capability, divided by total capability. www.ferc.gov/docs-filing/forms/form-714/overview.asp

consumption has declined in some sectors.[5] During 2013, EIA estimates the average U.S. residential customer used 2.2% less electricity than the average level of consumption between 2008 and 2012. In part due to improvements in appliance and lighting efficiency, “the overall growth trend has been slowing in recent years.” Another recognized source for energy forecasts, the ACEEE projects a zero or potential negative growth future for utilities.[6] According to the ACEEE report, electricity sales fell by 1.9% in 2012 over sales in 2007, and sales in the first ten months of 2013 have fallen even lower. While the economic recession explains the decline in sales in 2008 and 2009, it is much less clear why sales have continued to fall. Both the EIA and the ACEEE suggest long-term trends in energy efficiency have successfully reduced consumption.

NC WARN would also be remiss if it did not add that another viable, and cost-effective, alternative to building new generating plants for summer peak is solar energy. In its updated analysis of the Duke Energy IRPs, NC WARN discussed the declining costs of solar and how it is readily available to meet summer demand.[7] ATTACHMENT D. Purchases from other utilities, with a strong renewable energy component, are major components of a responsible energy future.

Lastly, the problem of unreasonable rates in North Carolina is further compounded by using the load during the summer peak to allocate costs. Recent Duke Energy rate cases have used the summer coincident peak method (also referred to as the 1CP method) to allocate costs so the costs of plants built for peaking reserve are shouldered by residential and small business

[5] EIA, “Short-term Energy Outlook report,” January 7, 2014; available at www.eia.gov/forecasts/steo/report/electricity.cfm

[6] ACEEE, “Why is Electricity Use No Longer Growing?” February 2014. Available at http://aceee.org/files/pdf/white-paper/low-electricity-use.pdf

[7] Report and previous annual updates are available at www.ncwarn.org/responsible-energy-future/

customers who have high peak demand, but do not need the high load during the rest of the year. NCUC Dockets Nos. E-7, Sub 1026 (DEC) and E-2, Sub 1023 (DEP).

II. THE COMMISSION IS AUTHORIZED TO INVESTIGATE AND TAKE OTHER ACTIONS TO PROTECT CUSTOMERS.

Pursuant to section 205 of the Federal Power Act ("FPA"), the purpose of regulatory reform by the Commission is to ensure that rates, terms and conditions of transmission and sales for resale in interstate commerce by public utilities are just, reasonable and not unduly discriminatory or preferential. 16 U.S.C. 824d. Sections 205 and 206 of the FPA allow the Commission to restructure the electricity industry to foster competition and reduce unfair and unreasonable rates. 16 U.S.C. 824d and 824e.

Pursuant to section 202(a) of the FPA, the Commission is mandated to promote and encourage regional strategies for the voluntary interconnection and coordination of transmission facilities by public utilities and non-public utilities for the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy. 16 U.S.C. 824a(a), the Commission's overall mission then is to assist consumers in obtaining reliable, efficient and sustainable energy services at a reasonable cost through appropriate regulatory and market means. Fulfilling this mission involves pursuing two primary goals:

1. Ensure that rates, terms and conditions are just, reasonable and not unduly discriminatory or preferential.
2. Promote the development of safe, reliable and efficient energy infrastructure that serves the public interest.

The prevention of market manipulation is in the public interest, and the Commission has determined that the creation of regional cooperation between utilities operating with transparency is the primary method to do so. Specifically, Section 202a of FPA authorizes the Commission to "divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy." 16 U.S.C. 824a(a); Order No. 2000, p. 131.

In 1999, as part of the federal efforts to restructure the electricity industry, the Commission began encouraging the formation of ISOs and RTOs. The Government Accountability Office ("GAO") issued a report in 2008, "The Commission Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance," recommending that the Commission develop standardized measures or metrics to track the performance of Independent System Operators ("ISOs") and RTO operations and markets.[8] In response, the Commission conducted a stakeholder process to examine ISO/RTO benefits and through its strategic planning process formalized its recommendations and performance metrics.[9]

ISOs first grew out of Orders Nos. 888/889 where the Commission suggested the concept of an ISO as one way for existing tight power pools to satisfy the requirement of providing non-discriminatory access to transmission. Subsequently, in Order No. 2000, the Commission encouraged the voluntary formation of RTOs to administer the transmission grid on a regional basis throughout North America. Order No. 2000 delineated characteristics and functions that an entity must satisfy in order to become a RTO. In Order No. 2000, the Commission encouraged the voluntary formation of RTOs to operate the electric transmission grid and to create organized

[8] www.ferc.gov/industries/electric/indus-act/rto/gao-report.pdf (GAO-08-987; September 2008).

[9] Federal Energy Regulatory Commission, "The Strategic Plan: FY 2009-2014" (rev. March 2013); www.ferc.gov/about/strat-docs/FY-09-14-strat-plan-print.pdf

wholesale electric markets. The development of RTOs and modified market structures was aimed at increasing the efficiency of wholesale electric market operations and increasing non-discriminatory access to the transmission grid. The Commission mandated that RTOs be independent from market participants, fairly exercising operational authority over all transmission facilities under their control.[10]

In its Order No. 1000, the Commission states that its “goal is to promote efficiency in wholesale electricity markets and to ensure that electricity consumers pay the lowest price possible for reliable service.” FERC Docket No. RM99-2-000, December 20, 1999. In order to do this, the Commission’s two-pronged initiatives are competitive markets and regional strategies. RTOs are seen as the key as “appropriate regional transmission institutions could: (1) improve efficiencies in transmission grid management; (2) improve grid reliability; (3) remove remaining opportunities for discriminatory transmission practices; (4) improve market performance; and (5) facilitate lighter handed regulation.” The expressed benefits of an RTO are: (1) increased efficiency of management of the grid; (2) improved market performance; (3); eliminates of opportunities for discriminatory practices; (4) allows for lighter government regulation; and (5) improved grid reliability.

In their comments on Order No. 2000, the vertically integrated utilities in regulated states, such as Duke Energy, disagreed with these benefits, saying that they are taking measures within their own system to make improvements, that government mandates should not come in and interrupt that process, and there is no conclusive data that RTOs provide said benefits. Order No. 2000, p. 73.

The Commission disagreed and concluded that RTOs would have universal benefits including increased efficiency, improved congestion management, more accurate estimates of

[10] *Ibid.*

ATC, better management of parallel path flows, more efficient planning for transmission and generation investments, increased coordination between state regulatory agencies, reduced transaction costs, more successful retail access programs, facilitation of the development of environmentally preferred generation, improved grid reliability, and fewer opportunities for discriminatory transmission practices. Order No. 2000, p. 89. These would lead to efficiencies in the transmission grid and improve market performance, leading to lower prices for customers.

In its initial analysis of the annual benefits of RTO development, the Commission determined there would be savings in the range of $2.4 to $5.1 billion per year, or 1.1% to 2.4% of the costs for the total US power industry. The Commission also found that based on observed costs of RTO or ISO formations, most of the costs are incurred during start up and are not ongoing. As a result, it is highly unlikely that the costs of forming an RTO outweigh the ongoing benefits. Order No. 2000, pp. 94-96. The benefits also continue for decades, and new smart grid and storage technologies will only increase the benefits.

In December 2013, the Entergy Utilities (Arkansas, Mississippi, Texas, Louisiana) completed its integration into the Midcontinent Independent System Operator ("MISO"). Based on a study, partly funded by the Commission, Entergy determined that its consumers will save $1.4 billion over 10 years by joining MISO.[11] As noted above, the costs for joining an RTO are front-loaded, so the net savings will continue and likely increase. This magnitude of likely savings would be available to Duke Energy, especially in the Carolinas, if it entered into an RTO. As addressed in this complaint, additional savings are available to customers when excess capacity is shared and construction of new generating plants is avoided.

In addition, collaborative regional strategies will make compliance with the U.S. Environmental Protection Agency's ("EPA") Clean Power Plan, the Section 111(d) rules, less

[11] www.entergy.com/news_room/newsrelease.aspx?NR_ID=2617

expensive.[12] A recently released study by the RTO PJM shows individual states can reduce the cost of complying with the proposed EPA 111(d) rules by almost 30% through its collaboration option.[13] This savings would be in addition to the direct benefits of transmission and mutual purchases.

Order No. 2000 specifically states that "we conclude that the Commission possesses both general and specific authorities to advance voluntary RTO formation. We also conclude that the Commission possesses the authority to order RTO participation on a case-by-case basis, if necessary, to remedy undue discrimination or anticompetitive effects where supported by the record." Order No. 2000, p. 142.

The most recent order on RTOs is Order No. 1000. The expressed purpose of that order is to reform electric transmission planning and cost allocation for public utility transmission providers. The order builds on the Commission reforms of Order No. 890 and corrects remaining deficiencies with respect to transmission planning processes and cost allocation methods. The order establishes three requirements for transmission planning:

1. Each public utility transmission provider must participate in a regional transmission planning process that satisfies the transmission planning principles of Order No. 890 and produces a regional transmission plan.
2. Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify

[12] www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule

[13] www.pjm.com/~/media/committees-groups/committees/mc/20141117-webinar/20141117-item-03-carbon-rule-analysis-presentation.ashx

transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs.

3. Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs.

The rule further establishes requirements for transmission cost allocation. The order recognizes that incumbent transmission providers may rely on regional transmission facilities to satisfy their reliability needs or service obligations.

Today, RTOs and ISOs serve roughly two-thirds of all electricity customers in the United States by providing transmission service, interconnecting new resources to the transmission grid, and operating organized wholesale electric markets. In recent years, the Commission has issued dozens of orders implementing reforms to the services provided and the markets operated by RTOs and ISOs in an effort to enhance competition and increase efficiency. In its Strategic Plan, the Commission has committed to addressing various issues, including congestion on the transmission grid and interconnection queues to increase efficiency and maintain just and reasonable rates, terms and conditions that are not unduly discriminatory or preferential.

In light of the overcapacity in the Duke Energy service area and in the entire Southeast, regional transmission facilities may significantly reduce costs, and mandatory participation in an RTO may be a necessary remedy for undue discrimination or anticompetitive effects. However, it is apparent from the ongoing excess capacity issues in the Southeast that "voluntary" formation of RTOs has failed. The failure of voluntary RTOs in the region is directly related to the fact that the utilities in the region are monopolies regulated by the public service commissions in their states, or in the case of TVA directly by a governmental agency. By and large, regulated monopoly states are less willing to combine resources across state lines due to the utilities' access to captive ratepayers and influence over state regulators.

Many of the issues in Order 1000 require state public service commission action. For example, some of the issues raised in Order 1000 were investigated by the NCUC in its Docket No. E-100, Sub 123. The resulting report, "Investigation of Federal Requirement to Consider Transmission Ownership by Non-Incumbent Developers," from October 11, 2012, was submitted to the North Carolina Governor and General Assembly and primarily expressed concerns that non-incumbent transmission owners would have the Commission-established return on equity that could be higher than those established by the NCUC for Duke Energy. The issues related to the mutual sharing of excess capacity and requiring healthy interconnections between the utilities were not addressed.

COMPLIANCE WITH RULE 206.

To the extent the argument above does not address the requirements for a Rule 206 complaint, NC WARN offers the following:

A. Description of Alleged Violation and Quantification of Impact or Burden – 18 C.F.R. §§ 385.206(b)(1)-(5).

As described above, the failure of Duke Energy, and other utilities in the Southeast, to enter into RTOs or other mutual purchase arrangements has resulted in and will continue to result in excess capacity. This excess capacity is wasteful and inefficient, and causes reliance on new generating facilities rather than the purchase of power from other utilities. As a result, the rates of Duke Energy's customers will continue to increase significantly as Duke Energy constructs additional generating plants. NC WARN believes this practice is a direct manipulation of the electricity market, and without this manipulation, Duke Energy's customers could save $2 to 5 billion, or more, over the next decade.[14]

B. Other Pending Proceedings – 18 C.F.R. § 385.206(b)(6)

The proceedings pursuant to Order No. 1000 and the related dockets described above do not address the systematic failure of Duke Energy to interconnect and plan with neighboring utilities on transmission and cost allocation issues as they relate to the excess capacity in Duke Energy's jurisdictions. NC WARN is not a party to any of the Commission proceedings although it is an intervening party in NCUC Docket E-100, Sub 141, on the utility IRPs. The issue of Duke Energy's excess capacity over a prudent reserve margin in Duke Energy's 15-year IRP planning horizon may be raised in comments and at hearing in that docket. However, NC WARN's participation in the IRP docket will not lead to a resolution of the issue *sub judice* as the NCUC does not have jurisdiction over transmission planning and interconnections with neighboring utilities in the Southeast or the allocation of costs for the sharing of excess capacity between and among the various utilities.

C. Specific Relief or Remedy Requested – 18 C.F.R. § 385.206(b)(7)

NC WARN requests that the Commission investigate Duke Energy's practices described in this complaint and commission and fund an independent study that closely examines the potential benefits of Duke Energy entering into an RTO in order to purchase capacity as needed rather than to construct wasteful new generating plants. Based on the result of such a study, the Commission should make a determination as to whether Duke Energy should be required to join an RTO. As part of this investigation, NC WARN requests a hearing in Raleigh, NC, to collect evidence and testimony.

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[14] Range is extrapolated from the findings of the Entergy study for participation in MISO and PJM study on compliance with EPA carbon rules.

D. Supporting Documents – 18 C.F.R. § 385.206(b)(8)

In support of its complaint, NC WARN provides the following:

- ATTACHMENT A – NERC, "NERC's Summer Reliability Assessment highlights regional electricity capacity margins."
- ATTACHMENT B – Selected pages from Duke Energy's IRPs (for DEC and DEP) filed in NCUC Docket E-100, Sub 141.
- ATTACHMENT C – Additional pages from Duke Energy's IRPs (for DEC and DEP) filed in NCUC Docket E-100, Sub 141.
- ATTACHMENT D – NC WARN, "A Responsible Energy Future for North Carolina: An Alternative to Duke Energy's 15-Year Plan."
- ATTACHMENT E – Form of Notice.

Other supporting documents cited in the text or in footnotes can be provided upon request.

E. Prior Efforts to Resolve this Dispute – 18 C.F.R. § 385.206(b)(9)

None of the formal or informal dispute resolution procedures have been used. NC WARN does not believe this matter can be adequately resolved between it and Duke Energy, as it requires formal action by the Commission.

F. Form of Notice – 18 C.F.R. § 385.206(b)(10)

A form of notice of this complaint is included herein as Attachment E and also filed separately in Word format.

THEREFORE, NC WARN requests that the Commission fully investigate Duke Energy's practices and if the Commission determines it proper, to require Duke Energy to enter into an

RTO and purchase necessary power from other utilities rather than construct wasteful and redundant generating plants.

Respectfully submitted this the 16th day of December 2014.

FOR NC WARN

_____/s/ John D. Runkle ___________
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CERTIFICATE OF SERVICE

I hereby certify that the following persons have been served this COMPLAINT AND PETITION FOR INVESTIGATION BY NORTH CAROLINA WASTE AWARENESS AND REDUCTION NETWORK (FERC) by deposit in the U.S. Mail, postage prepaid, or by email transmission as the contacts for Duke Energy as listed on the Commission's list of Corporate Officials. Courtesy copies have been served on the parties to the NCUC Docket No. E-100, Sub 141, and NCUC counsel.

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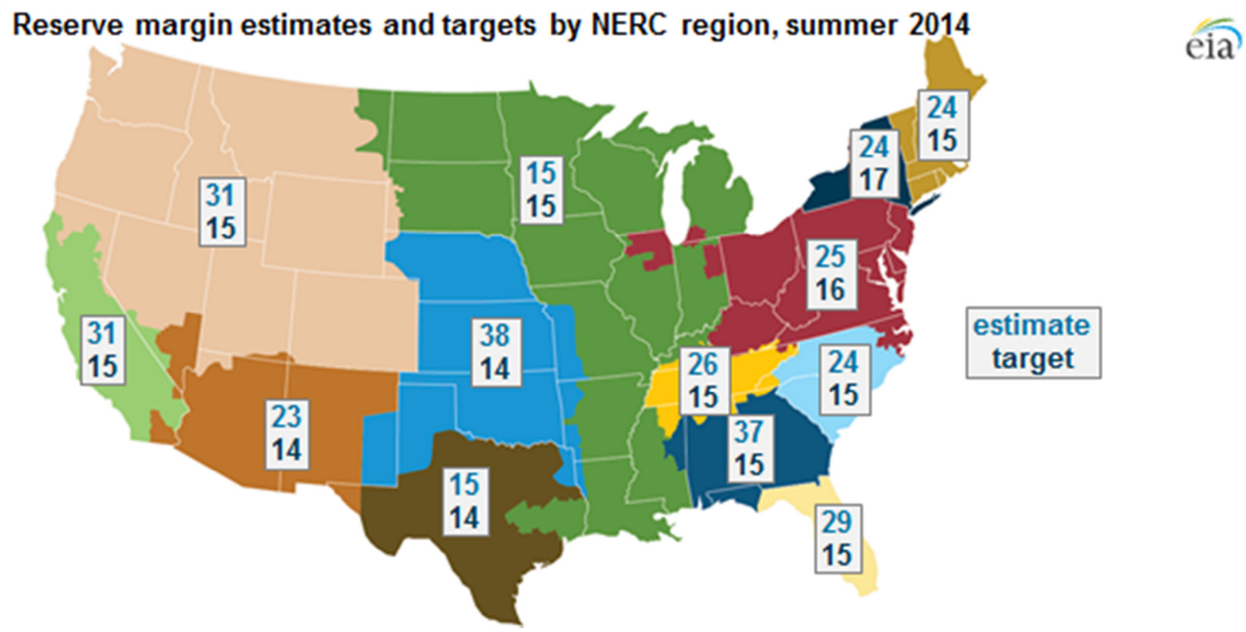
This is the 16th day of December 2014.

_______/s/ John D. Runkle____________________
Attorney at Law

ATTACHMENT A

JUNE 20, 2014

NERC's Summer Reliability Assessment highlights regional electricity capacity margins



Source: North American Electric Reliability Corporation, 2014 Summer Reliability Assessment
Note: Reserve margins are unused generating capacity at the time of peak load as a percentage of expected peak demand.

The North American Electric Reliability Corporation's (NERC) recently released 2014 Summer Reliability Assessment finds all of North America to have enough resources to meet this summer's projected peak electricity demand. Reserve margins, the amount of unused capacity at the time of peak load, expressed as a percentage of expected peak demand, range from just under 15% in Texas to almost 38% in the Southwest Power Pool.

Reserve margins highlight one fundamental requirement of modern electricity systems—always have more capacity available to ensure the reliability of the grid. Due to the lack of large scale, cost effective electricity storage, supply must be able to meet demand at all times. This can be challenging when demand is high or when generators or transmission lines have unexpected outages. Meeting demand can be accomplished through a combination of sufficient generating capacity, a robust transmission system, and demand-side management programs.

Each region has a target reference margin above which summer peak loads should be met reliably in all but the most extreme cases. Reserve margins below the reference margin indicate increased potential for system disruptions during times of high electricity demand. At the other extreme, reserve margins significantly in excess of target levels, although helpful for reliability, may be an indication of underutilized or unused generation capacity.

Areas of interest this summer include the Midcontinent Independent System Operator (MISO), whose anticipated reserve margin of 15.01% is just above the NERC reference margin level of 14.8%. This margin is down significantly from 2013 because of generator retirements and long-term outages as well as the exclusion of nonfirm imports into the system, which had been included in prior assessments, from the calculation this year. This will also be the first summer following the integration of Entergy and its six utility operating companies in December 2013, which are referred to as MISO South. The integration will not only affect MISO operations, but may present challenges to adjacent systems, whose operators have signed an operations reliability coordination agreement with MISO to deal with reliability concerns that may arise regarding power flows between MISO North/Central and MISO South.

In Texas, an anticipated reserve margin of 14.98% is just above the NERC reference margin level of 13.75% and is based on the addition of several new generators in time for the projected system peak in early August. An early summer peak later this month or in July before the new generators come online could require the Electric Reliability Council of Texas (ERCOT) to take emergency actions, ranging from calling a conservation alert to shedding load to help prevent a major blackout.

Managing adequate reserve margins can be challenging for system planners as they deal with a host of short- and long-term considerations for both the supply and demand of electricity.

Supply-side considerations:

- The long-term nature of siting new power plants and transmission lines, with multiyear time horizons, makes capacity changes fairly inflexible in the short term. Planned transmission and generating assets can also be delayed at any time for a number of reasons.

- Changes to the resource mix in much of the country (including the retirements of some large coal and nuclear power plants as well as the addition of a significant number of wind, solar, and natural gas generators) have created challenges for local grid operators.

- Short-term operational issues such as unplanned long-term outages or transmission constraints can also affect reserve margins and system operation.

Demand-side considerations:

- Long-term economic or societal changes can affect electricity demand. In North Dakota, increased oil and gas exploration and production activities have structurally increased electricity demand in the area. Alternatively, demand can decline as a result of decreasing population or increased energy efficiency.

- Demand-side management (DSM), which includes a broad array of programs and application, has matured in recent years and allows grid operators more flexibility in balancing supply and demand.

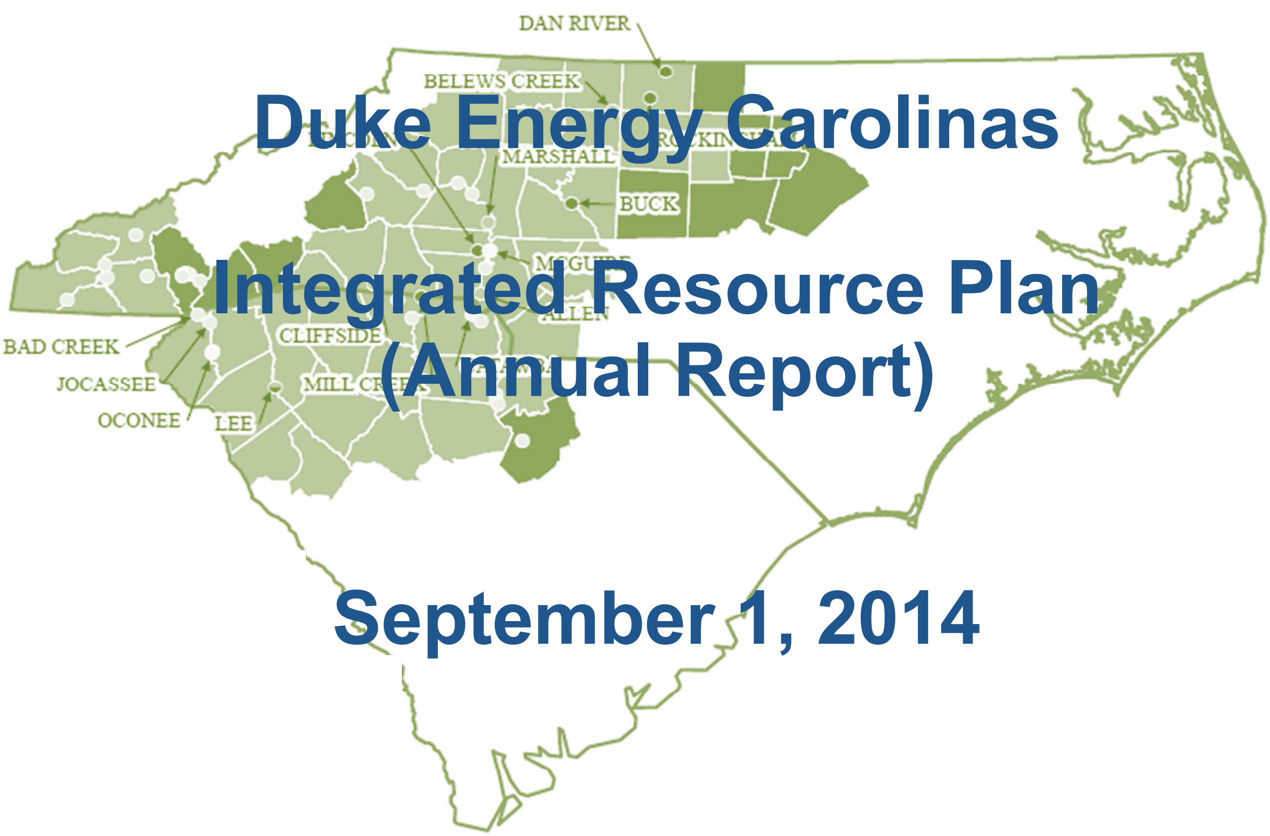
- Short-term events, such as extreme weather, can lead to unanticipated spikes or drops in demand for electricity, which in turn can challenge the balancing of supply and demand.

Principal contributor: Timothy Shear

http://www.eia.gov/todayinenergy/detail.cfm?id=16791

ATTACHMENT B

Duke Energy Carolinas



Integrated Resource Plan (Annual Report)

September 1, 2014

Public

DEC - Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Summer Projections of Load, Capacity, and Reserves tables. All values are MW except where shown as a Percent.

1. Planning is done for the peak demand for the Duke System including Nantahala. Nantahala became a division of Duke Energy Carolinas in 1998.

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

2. A 150 MW firm sale is included in 2014. The sale ends in 2014.

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

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

5. Existing generating capacity reflecting designated additions, planned uprates, retirements and derates as of April, 2014.

   Includes 101 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for NCMPA1 firm capacity sale.

6. Capacity Additions include the conversion of Lee Steam Station unit 3 from coal to natural gas in 2015 (170 MW).

   Lee Combined Cycle is reflected in 2028 (670 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 2014-2020 timeframe and total 18 MW.

   Also included is a 105 MW capacity increase due to nuclear uprates at Catawba, McGuire, and Oconee. Timing of these uprates is shown from 2015-2017.

7. The 370 MW capacity retirement in summer 2015 represents the projected retirement date for Lee Steam Station.

   A planning assumption for coal retirements has been included in the 2014 IRP.

   Allen Steam Station (1127 MW) is assumed to retire in 2028.
   Nuclear Stations are assumed to retire at the end of their current license extension.

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

   No nuclear facilities are assumed to retire in the 15 year study period.

   The Hydro facilities for which Duke has submitted an application to FERC for license renewal are assumed to continue operation through the planning horizon.

   All retirement dates are subject to review on an ongoing basis.

DEC - Assumptions of Load, Capacity, and Reserves Table Cont.

8. Sum of lines 5 through 7.

9. Cumulative Purchase Contracts including purchased capacity from PURPA Qualifying Facilities, an 88 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. Renewables in these line items are not used for NC REPS compliance.

10. New nuclear 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 that year.

    Addition of 1,117 MW Lee Nuclear Unit additions in 2024 and 2026.

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

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

    Addition of 866 MW of combined cycle capacity in 2020.

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 that year.

    Addition of 792 MW of combustion turbine capacity in 2028.

13. Cumulative solar, biomass, hydro and wind resources to meet NC REPS compliance

    Also includes compliance resources for South Carolina (discussions in Chapter 5).

14. Sum of lines 8 through 13.

15. Cumulative Demand Response programs including load control and DSDR.

16. Sum of lines 14 and 15.

17. The difference between lines 4 and 16.

18. Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand
    Minimum target planning reserve margin is 14.5%.

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

Table 8-D DEC Base Case

Duke Energy Carolinas Resource Plan [1] Base Case						
Year	**Resource**			**MW**		
2015	Lee 3 NG Conversion	Nuclear Uprates	Hydro Units Return to Service [2]	170	60	2
2016	-			-		
2017	Nuclear Uprates			45		
2018	Lee CC [3]			670		
2019	Hydro Units Return to Service [4]			10		
2020	New CC		Hydro Units Return to Service [4]	866		6
2021	-			-		
2022	-			-		
2023	-			-		
2024	New Nuclear			1117		
2025	-			-		
2026	New Nuclear			1117		
2027	-			-		
2028	New CT			792		
2029	-			-		

Notes: (1) Table includes both designated and undesignated capacity additions

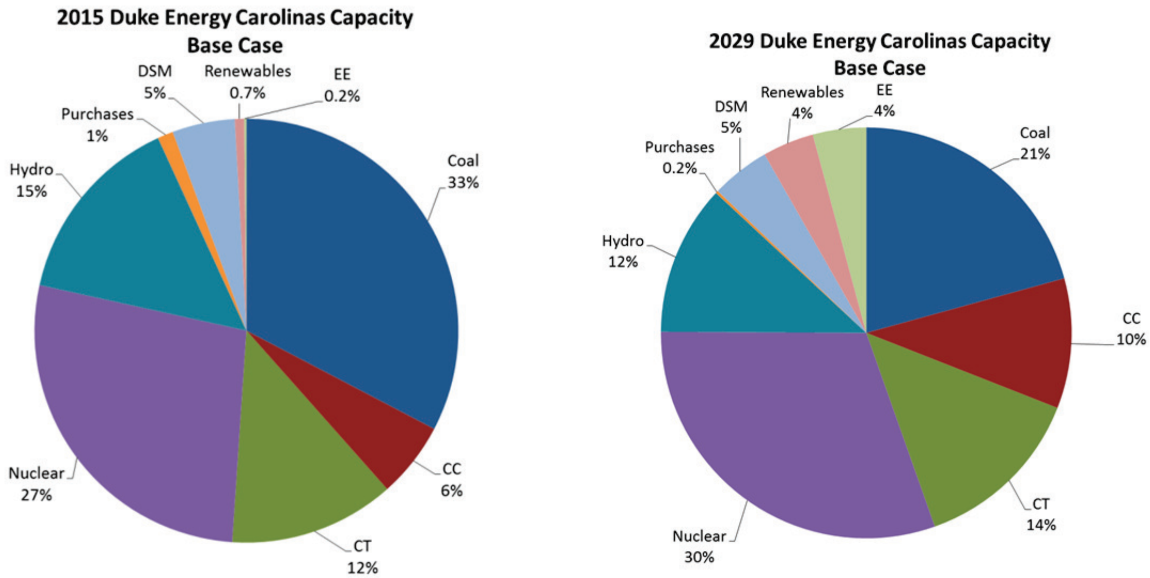
(2) Bryson City and Mission hydro units return to service

(3) Lee CC capacity is net of NCEMC ownership of 100 MW

(4) Rocky Creek Units currently offline for refurbishment; these are expected return to service dates

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 2029, 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.

Chart 8-B Duke Energy Carolinas Capacity by Fuel Type – Base Case [1]



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 2014 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.

[1] In 2021, the REPS compliance plan of 12.5% is comprised of approximately 25% Energy Efficiency, 25% purchases of out-of-state RECs, 5-10% from RECs not associated with electrical energy (including animal waste resources), and the balance from purchases of renewable energy.

Table 8-D below represents the annual non-renewable incremental additions reflected in the combined DEC and DEP Base Cases as compared to the Joint Planning Case. The plan contains the undesignated additions for DEC and DEP over the planning horizon.

Table 8-E DEC and DEP Joint Planning Case

Duke Energy Carolinas and Duke Energy Progress Combined Base Cases [1]		
Year	**Resource**	**MW**
2015	-	-
2016	-	-
2017	-	-
2018	-	-
2019	-	-
2020	New CC New CC	866 866
2021	New CT	792
2022	New CC	866
2023	-	-
2024	New Nuclear	1117
2025	-	-
2026	New Nuclear	1117
2027	New CC	866
2028	New CT	792
2029	New CT	396

Notes: (1) Table only includes undesignated capacity additions

Delays CC 1 year

Delays Need for CT & Reduces Total CT Need

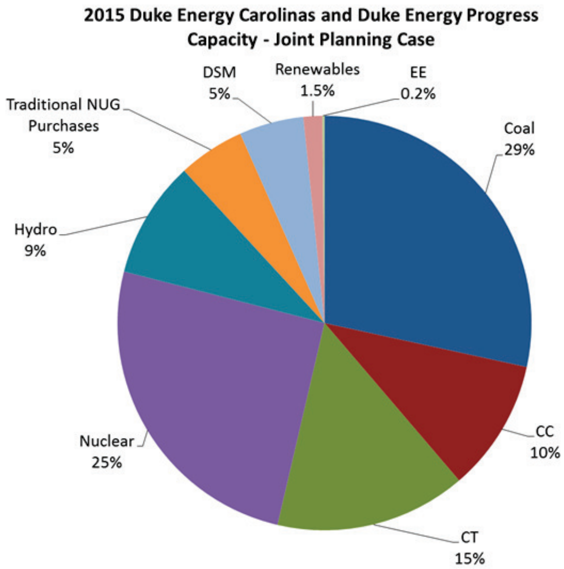
Delays CC 1 year

Duke Energy Carolinas and Duke Energy Progress Joint Planning Case		
Year	**Resource**	**MW**
2015	-	-
2016	-	-
2017	-	-
2018	-	-
2019	-	-
2020	New CC	866
2021	New CC	866
2022	New CC	866
2023	-	-
2024	New Nuclear	659 / 458
2025	-	-
2026	New Nuclear	659 / 458
2027	-	-
2028	New CC New CT	866 1188
2029	New CT	396

The following charts illustrate both the current and forecasted capacity and energy by fuel type for the DEC and DEP systems, as projected by the Joint Planning Case. In this Joint Planning Case, the Companies continue to rely upon nuclear and CT resources, but the reliance on natural gas CC resources increases due to favorable natural gas prices and the reliance on coal resources decrease. The Companies' renewable energy and EE impacts continue to grow over time, as also reflected in the Base Cases for both Companies.

Under a carbon constrained future, the collective output from nuclear generation is projected to remain at approximately half of all energy requirements for DEC and DEP collectively assuming the addition of the Lee Nuclear Station. Conversely, the output of coal-fired facilities is expected to be reduced by more than half while natural gas generation more than doubles in output over the planning horizon. Renewable and EE resources grow significantly from today's levels making meaningful contributions to the energy needs of the Carolinas. However, these resources do have limitations in their aggregate energy contributions due to physical limitations associated with intermittency, as well as economic limitations in light of expiring tax subsidies.

Chart 8-C **CAPACITY CHARTS**
(DEC and DEP Joint Planning Case)



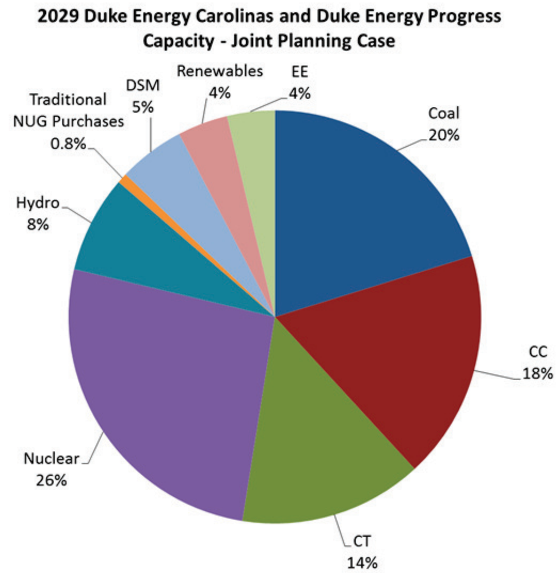
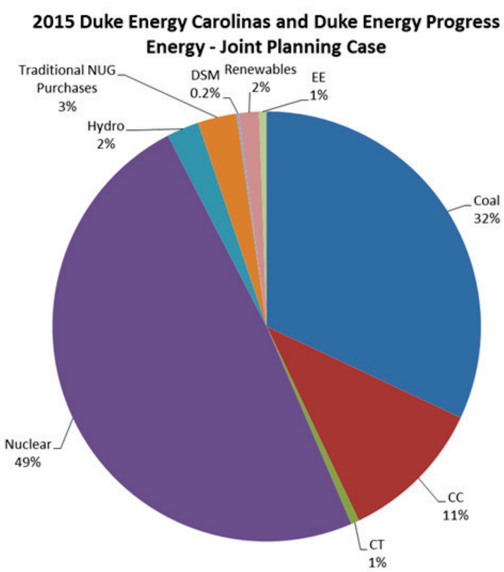
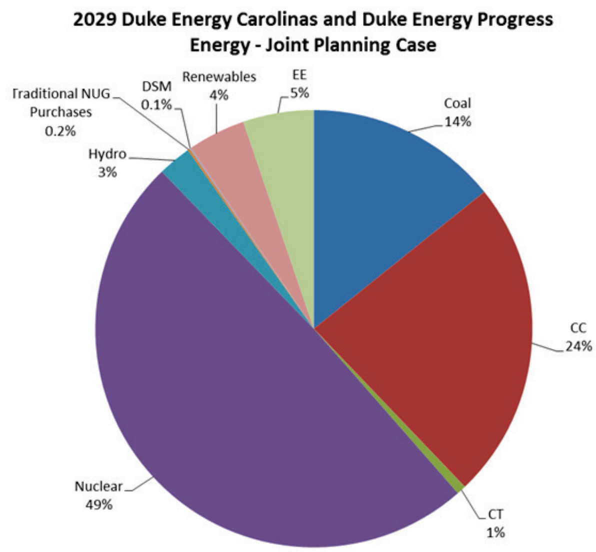


Chart 8-D **ENERGY CHARTS**
(DEC and DEP Joint Planning Case)

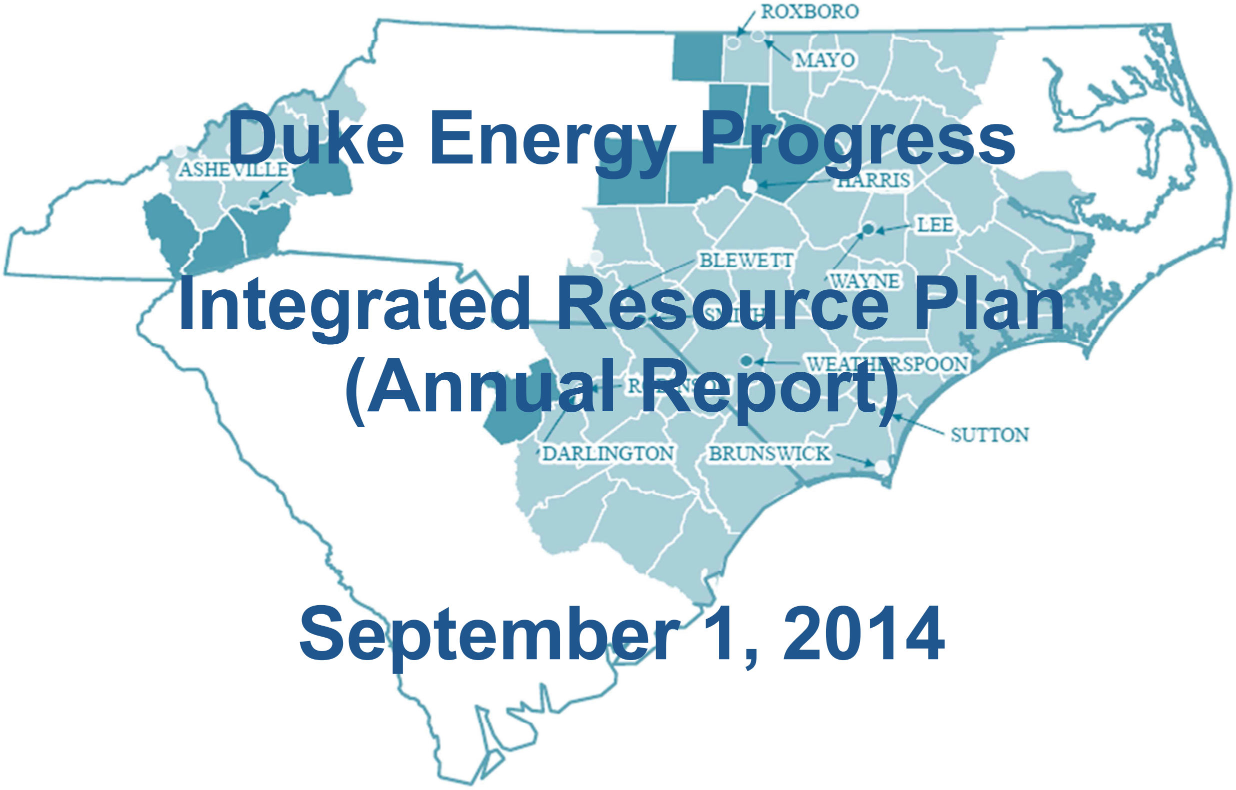




Duke Energy Progress

Integrated Resource Plan (Annual Report)

September 1, 2014



Public

DEP - Assumptions of Load, Capacity, and Reserves Table

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

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

2. Firm sale of 150 MW through 2024.

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

4. Peak load adjusted for FERC mitigation sale, firm sales, and cumulative energy efficiency .

5. Existing generating capacity reflecting designated additions, planned uprates, retirements and derates as of April, 2014.

   Includes total unit capacity of jointly owned units.

6. Capacity Additions include:

   Planned nuclear uprates totalling 38 MW in the 2014-2017 timeframe.

   Planned combined cycle uprates totalling 137 MW in 2018.

   Expected replacement of Sutton CT units 1, 2A and 2B with an 84 MW combustion turbine in 2017.

7. Planned Retirements include:
   Sutton CT Units 1, 2A and 2B in 2017 (61 MW)
   Darlington CT Units 1-11 by 2020 (553 MW)
   Blewett CT Units 1-4 and Weatherspoon CT units 1-4 in 2027 (180 MW)

8. Sum of lines 5 through 7.

9. Cumulative Purchase Contracts have several components:

   Purchased capacity from PURPA Qualifying Facilities, Anson and Hamlet CT tolling,

   Butler Warner purchase, Southern CC purchase, and Broad River CT purchase.

   Additional line items are shown under the total line item to show the amounts of renewable and traditional resource purchases. Renewables in these line items are not used for NC REPS compliance.

DEP - Assumptions of Load, Capacity, and Reserves Table Cont.

10. New nuclear 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 that year.

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

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

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

    Addition of 866 MW of combined cycle capacity in 2020, 2022 and 2027.

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 that year.

    Addition of 126 MW of combustion turbine capacity in 2019.

    Addition of 792 MW of combustion turbine capacity in 2021.

    Addition of 396 MW of combustion turbine capacity in 2029.

13. Cumulative solar, biomass, hydro and wind resources to meet NC REPS compliance.

    Also include compliance resources for South Carolina (discussed in Chapter 5).

14. Sum of lines 8 through 13.

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

16. Sum of lines 14 and 15.

17. The difference between lines 4 and 16.

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

    Minimum target planning reserve margin is 14.5%.

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

Table 8-D DEP Base Case

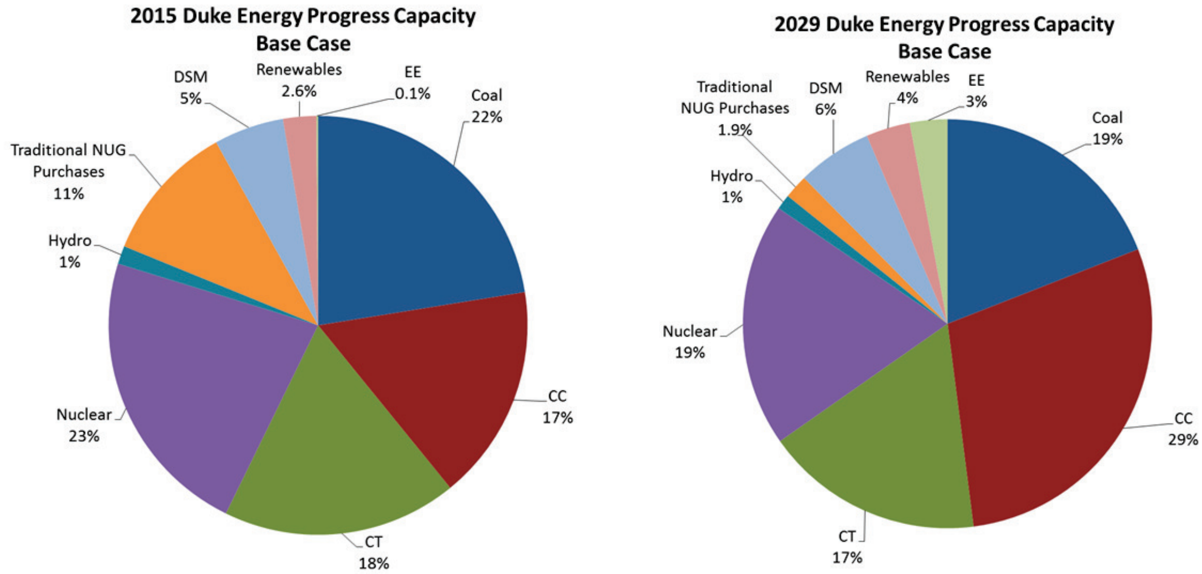
Duke Energy Progress Resource Plan (1)
Base Case

Year	Resource		MW	
2015	Nuclear Uprates		20	
2016	-		-	
2017	Sutton Replacement CTs	Nuclear Uprates	84	14
2018	CC Uprates		137	
2019	Fast Start CT		126	
2020	New CC		866	
2021	New CT		792	
2022	New CC		866	
2023	-		-	
2024	-		-	
2025	-		-	
2026	-		-	
2027	New CC		866	
2028	-		-	
2029	New CT		396	

Notes: (1) Table includes both designated and undesignated capacity additions

The following charts illustrate both the current and forecasted capacity by fuel type for the DEP system, as projected by the Base Case. As demonstrated in Chart 8-B, the capacity mix for the DEP system changes with the passage of time. In 2029, the Base Case projects that DEP will have a smaller reliance on coal, nuclear and purchases and a higher reliance on gas-fired resources, renewable resources and EE as compared to the current state.

Chart 8-B Duke Energy Progress Capacity by Fuel Type – Base Case [1]



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 2014 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-D below represents the annual non-renewable incremental additions reflected in the combined DEC and DEP Base Cases as compared to the Joint Planning Case. The plan contains the undesignated additions for DEC and DEP over the planning horizon.

[1] In 2021, the REPS compliance plan of 12.5% is comprised of approximately 25% Energy Efficiency, 25% purchases of out-of-state RECs, 5-10% from RECs not associated with electrical energy (including animal waste resources), and the balance from purchases of renewable energy.

Table 8-D Joint Planning Case

Duke Energy Carolinas and Duke Energy Progress Combined Base Cases [1]				
Year	Resource		MW	
2015	-		-	
2016	-		-	
2017	-		-	
2018	-		-	
2019	-		-	
2020	New CC	New CC	866	866
2021	New CT		792	
2022	New CC		866	
2023	-		-	
2024	New Nuclear		1117	
2025	-		-	
2026	New Nuclear		1117	
2027	New CC		866	
2028	New CT		792	
2029	New CT		396	

Notes: (1) Table only includes undesignated capacity additions

Delays CC 1 year

Delays Need for CT & Reduces Total CT Need

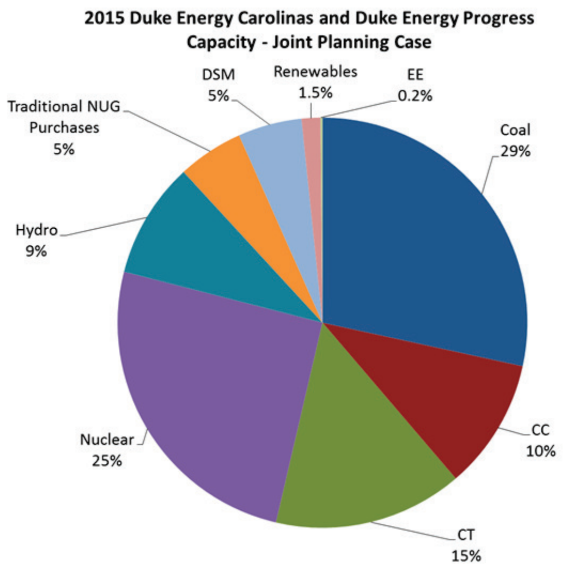
Delays CC 1 year

Duke Energy Carolinas and Duke Energy Progress Joint Planning Case				
Year	Resource		MW	
2015	-		-	
2016	-		-	
2017	-		-	
2018	-		-	
2019	-		-	
2020	New CC		866	
2021	New CC		866	
2022	New CC		866	
2023	-		-	
2024	New Nuclear		659 / 458	
2025	-		-	
2026	New Nuclear		659 / 458	
2027	-		-	
2028	New CC	New CT	866	1188
2029	New CT		396	

The following charts illustrate both the current and forecasted capacity and energy by fuel type for the DEP and DEC systems, as projected by the Joint Planning Case. In this Joint Planning Case, the Companies continue to rely upon nuclear and CT resources, but the reliance on natural gas CC resources increases due to favorable natural gas prices and reliance on coal resources decrease. The Companies' renewable energy and EE impacts continue to grow over time, as reflected in the Base Cases for both Companies.

Under a carbon constrained future, the collective output from nuclear generation is projected to remain at approximately half of all energy requirements for DEC and DEP collectively assuming the addition of the Lee Nuclear Station. Conversely, the output of coal-fired facilities is expected to be reduced by more than half while natural gas generation more than doubles in output over the planning horizon. Renewable and EE resources grow significantly from today's levels making meaningful contributions to the energy needs of the Carolinas. However, these resources do have limitations in their aggregate energy contributions due to physical limitations associated with intermittency, as well as economic limitations in light of expiring tax subsidies.

Chart 8-C CAPACITY CHARTS (DEC and DEP Joint Planning Case)



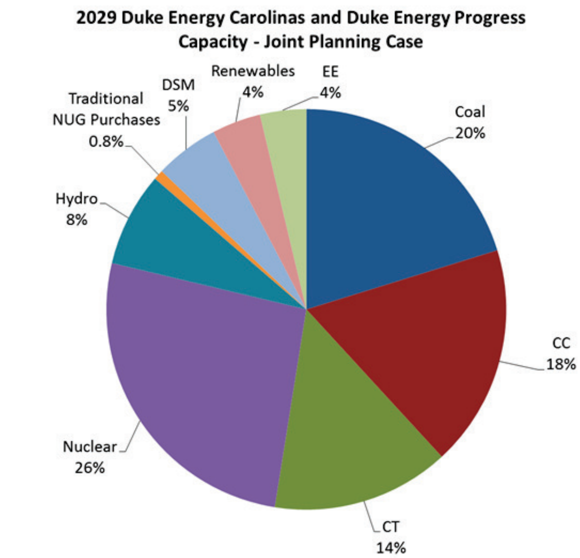
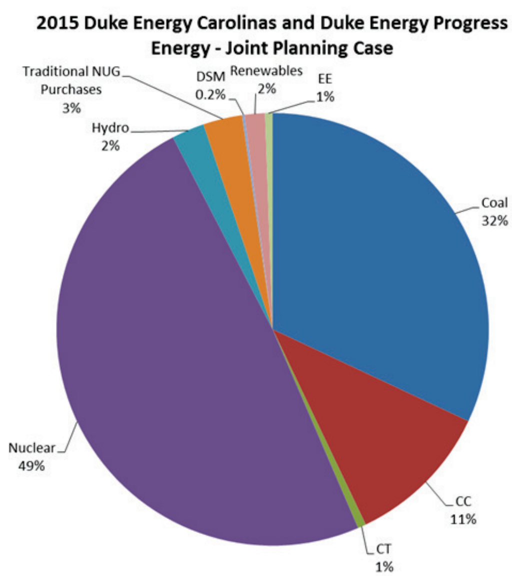
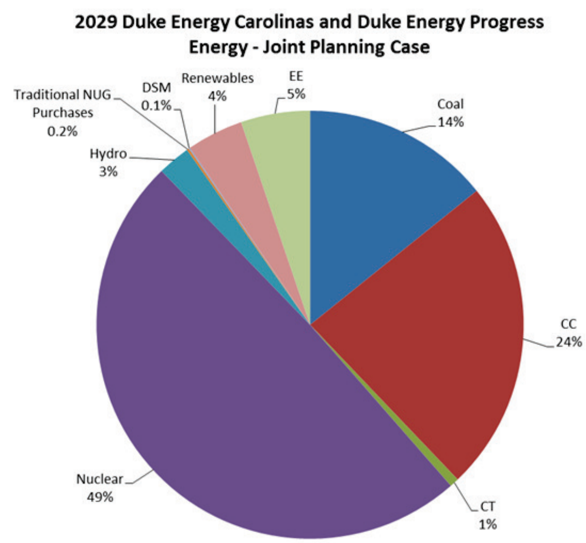


Chart 8-D ENERGY CHARTS (DEC and DEP Joint Planning Case)





The following charts group the energy based upon the emission impacts of the resources in the DEC and DEP Joint Planning Case. The Zero Emission category includes nuclear, hydro, renewables, EE and DSM resources. The Natural Gas category includes clean burning gas CCs and CTs. It must be noted that the remaining coal facilities are controlled with state-of-the-art environmental emission control technologies.

ATTACHMENT C

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

Summer Projections of Load, Capacity, and Reserves for Duke Energy Carolinas 2014 Annual Plan

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Load Forecast															
1 Duke System Peak	18,635	19,033	19,407	19,792	20,219	20,563	20,815	21,146	21,492	21,896	22,232	22,597	22,987	23,425	23,748
2 Firm Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(101)	(164)	(230)	(297)	(366)	(440)	(524)	(617)	(715)	(811)	(912)	(1,002)	(1,081)	(1,149)	(1,211)
4 Adjusted Duke System Peak	**18,533**	**18,869**	**19,177**	**19,495**	**19,853**	**20,123**	**20,291**	**20,529**	**20,777**	**21,085**	**21,320**	**21,595**	**21,906**	**22,276**	**22,537**
Existing and Designated Resources															
5 Generating Capacity	20,449	20,311	20,311	20,356	21,026	21,036	21,042	21,042	21,042	21,042	21,042	21,042	21,042	21,042	19,915
6 Designated Additions / Uprates	232	0	45	670	10	6	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	(370)	0	0	0	0	0	0	0	0	0	0	0	0	(1,127)	0
8 Cumulative Generating Capacity	**20,311**	**20,311**	**20,356**	**21,026**	**21,036**	**21,042**	**21,042**	**21,042**	**21,042**	**21,042**	**21,042**	**21,042**	**21,042**	**19,915**	**19,915**
Purchase Contracts															
9 Cumulative Purchase Contracts	**243**	**237**	**233**	**230**	**189**	**186**	**100**	**81**	**79**	**79**	**79**	**79**	**78**	**56**	**5**
Non-Compliance Renewable Purchases	73	68	64	60	58	58	58	58	56	55	55	55	55	43	5
Non-Renewables Purchases	169	169	169	169	131	128	42	24	24	24	24	24	24	14	0
Undesignated Future Resources															
10 Nuclear	0	0	0	0	0	0	0	0	0	1,117	0	1,117	0	0	0
11 Combined Cycle	0	0	0	0	0	866	0	0	0	0	0	0	0	0	0
12 Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0	0	792	0
Renewables															
13 Cumulative Renewables Capacity	274	316	324	321	414	533	626	710	799	882	953	1,018	1,071	1,111	1,112
14 Cumulative Production Capacity	**20,828**	**20,864**	**20,912**	**21,576**	**21,639**	**22,626**	**22,633**	**22,698**	**22,786**	**23,986**	**24,057**	**25,238**	**25,291**	**24,974**	**24,924**
Demand Side Management (DSM)															
15 Cumulative DSM Capacity	**1,072**	**1,095**	**1,142**	**1,180**	**1,213**	**1,264**	**1,264**	**1,264**	**1,264**	**1,264**	**1,264**	**1,264**	**1,264**	**1,264**	**1,264**
16 Cumulative Capacity w/ DSM	**21,900**	**21,959**	**22,054**	**22,756**	**22,852**	**23,891**	**23,898**	**23,963**	**24,051**	**25,250**	**25,321**	**26,503**	**26,556**	**26,238**	**26,188**
Reserves w/ DSM															
17 Generating Reserves	3,367	3,090	2,877	3,261	2,999	3,768	3,606	3,434	3,273	4,165	4,001	4,908	4,650	3,962	3,651
18 % Reserve Margin	**18.17%**	**16.38%**	**15.00%**	**16.73%**	**15.11%**	**18.73%**	**17.77%**	**16.73%**	**15.76%**	**19.75%**	**18.77%**	**22.73%**	**21.23%**	**17.79%**	**16.20%**

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

Winter Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2014 Annual Plan

	15/16	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
Load Forecast														
1 Duke System Peak	17,784	18,175	18,556	18,934	19,246	19,485	19,771	20,092	20,478	20,829	21,180	21,520	21,933	22,243
2 Firm Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(100)	(145)	(192)	(262)	(317)	(379)	(449)	(523)	(595)	(671)	(740)	(799)	(850)	(896)
4 Adjusted Duke System Peak	**17,684**	**18,029**	**18,364**	**18,672**	**18,929**	**19,105**	**19,322**	**19,570**	**19,883**	**20,158**	**20,440**	**20,721**	**21,083**	**21,346**
Existing and Designated Resources														
5 Generating Capacity	21,227	21,087	21,132	21,877	21,812	21,822	21,828	21,828	21,828	21,828	21,828	21,828	21,828	21,828
6 Designated Additions / Uprates	232	45	745	0	10	6	0	0	0	0	0	0	0	0
7 Retirements / Derates	(372)	0	0	(65)	0	0	0	0	0	0	0	0	0	(1,161)
8 Cumulative Generating Capacity	**21,087**	**21,132**	**21,877**	**21,812**	**21,822**	**21,828**	**21,828**	**21,828**	**21,828**	**21,828**	**21,828**	**21,828**	**21,828**	**20,667**
Purchase Contracts														
9 Cumulative Purchase Contracts	**205**	**199**	**198**	**195**	**155**	**152**	**60**	**41**	**39**	**39**	**39**	**39**	**39**	**18**
Non-Compliance Renewable Purchases	29	24	22	19	18	18	18	18	16	15	15	15	15	5
Non-Renewables Purchases	175	175	175	175	137	134	42	24	24	24	24	24	24	14
Undesignated Future Resources														
10 Nuclear	0	0	0	0	0	0	0	0	0	1,117	0	1,117	0	0
11 Combined Cycle	0	0	0	0	0	907	0	0	0	0	0	0	0	0
12 Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0	0	872
Renewables														
13 Cumulative Renewables Capacity	121	132	130	117	160	262	297	328	366	401	424	444	458	475
14 Cumulative Production Capacity	**21,413**	**21,463**	**22,205**	**22,123**	**22,136**	**23,148**	**23,091**	**23,103**	**23,139**	**24,292**	**24,314**	**25,452**	**25,465**	**25,172**
Demand Side Management (DSM)														
15 Cumulative DSM Capacity	**570**	**577**	**588**	**594**	**597**	**601**	**601**	**601**	**601**	**601**	**601**	**601**	**601**	**601**
16 Cumulative Capacity w/ DSM	**21,983**	**22,040**	**22,792**	**22,718**	**22,733**	**23,748**	**23,692**	**23,704**	**23,740**	**24,892**	**24,915**	**26,053**	**26,066**	**25,773**
Reserves w/ DSM														
17 Generating Reserves	4,299	4,010	4,428	4,046	3,804	4,643	4,369	4,134	3,857	4,734	4,475	5,331	4,983	4,427
18 % Reserve Margin	**24.3%**	**22.2%**	**24.1%**	**21.7%**	**20.1%**	**24.3%**	**22.6%**	**21.1%**	**19.4%**	**23.5%**	**21.9%**	**25.7%**	**23.6%**	**20.7%**

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

Summer Projections of Load, Capacity, and Reserves
for Duke Energy Progress 2014 Annual Plan

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Load Forecast															
1 Duke System Peak	12,983	13,198	13,406	13,626	13,856	14,075	14,303	14,539	14,786	15,041	15,284	15,517	15,793	16,046	16,298
2 Firm Sale	150	150	150	150	150	150	150	150	150	150	0	0	0	0	0
3 Cumulative New EE Programs	(60)	(101)	(139)	(173)	(210)	(252)	(297)	(342)	(386)	(428)	(467)	(499)	(527)	(549)	(571)
4 Adjusted Duke System Peak	**13,074**	**13,247**	**13,417**	**13,603**	**13,796**	**13,974**	**14,157**	**14,347**	**14,550**	**14,763**	**14,817**	**15,018**	**15,266**	**15,496**	**15,726**
Existing and Designated Resources															
5 Generating Capacity	12,779	12,799	12,799	12,836	12,973	12,973	12,567	12,567	12,567	12,567	12,567	12,567	12,567	12,387	12,387
6 Designated Additions / Uprates	20	0	98	137	0	0	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	0	0	(61)	0	0	(406)	0	0	0	0	0	0	(180)	0	0
8 Cumulative Generating Capacity	**12,799**	**12,799**	**12,836**	**12,973**	**12,973**	**12,567**	**12,567**	**12,567**	**12,567**	**12,567**	**12,567**	**12,567**	**12,387**	**12,387**	**12,387**
Purchase Contracts															
9 Cumulative Purchase Contracts	**1,865**	**1,876**	**1,875**	**1,655**	**1,487**	**1,342**	**772**	**441**	**441**	**441**	**441**	**441**	**439**	**406**	**373**
Non-Compliance Renewable Purchases	173	185	184	183	183	183	93	91	91	91	91	91	89	56	23
Non-Renewables Purchases	1,692	1,692	1,692	1,472	1,304	1,159	679	350	350	350	350	350	350	350	350
Undesignated Future Resources															
10 Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Combined Cycle	0	0	0	0	0	866	0	866	0	0	0	0	866	0	0
12 Combustion Turbine				0	126	0	792	0	0	0	0	0	0	0	396
Renewables															
13 Cumulative Renewables Capacity	276	319	337	315	368	426	408	441	473	496	529	554	577	590	579
14 Cumulative Production Capacity	**14,940**	**14,994**	**15,048**	**14,943**	**14,954**	**15,326**	**15,531**	**16,099**	**16,131**	**16,154**	**16,187**	**16,212**	**16,919**	**16,900**	**17,251**
Demand Side Management (DSM)															
15 Cumulative DSM Capacity	**885**	**925**	**966**	**1,002**	**1,036**	**1,046**	**1,053**	**1,060**	**1,066**	**1,073**	**1,079**	**1,086**	**1,092**	**1,098**	**1,098**
16 Cumulative Capacity w/ DSM	**15,826**	**15,920**	**16,014**	**15,945**	**15,990**	**16,372**	**16,584**	**17,159**	**17,197**	**17,227**	**17,266**	**17,298**	**18,011**	**17,998**	**18,350**
Reserves w/ DSM															
17 Generating Reserves	2,752	2,672	2,598	2,342	2,194	2,399	2,427	2,812	2,647	2,463	2,449	2,279	2,745	2,502	2,623
18 % Reserve Margin	**21.1%**	**20.2%**	**19.4%**	**17.2%**	**15.9%**	**17.2%**	**17.1%**	**19.6%**	**18.2%**	**16.7%**	**16.5%**	**15.2%**	**18.0%**	**16.1%**	**16.7%**

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

Winter Projections of Load, Capacity, and Reserves
for Duke Energy Progress 2014 Annual Plan

	14/15	15/16	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
Load Forecast															
1 Duke System Peak	12,468	12,729	12,849	13,051	13,287	13,481	13,765	13,980	14,135	14,303	14,493	14,693	14,935	15,158	15,285
2 Firm Sale	150	150	150	150	150	150	150	150	150	150	0	0	0	0	0
3 Cumulative New EE Programs	(39)	(70)	(98)	(123)	(162)	(194)	(229)	(263)	(297)	(330)	(360)	(385)	(407)	(424)	(441)
4 Adjusted Duke System Peak	**12,579**	**12,809**	**12,901**	**13,079**	**13,275**	**13,437**	**13,687**	**13,867**	**13,987**	**14,124**	**14,133**	**14,308**	**14,528**	**14,734**	**14,844**
Existing and Designated Resources															
5 Generating Capacity	14,057	13,866	13,886	13,900	13,908	14,045	14,045	13,513	13,513	13,513	13,513	13,513	13,513	13,513	13,281
6 Designated Additions / Uprates	4	20	14	84	137	0	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	(195)	0	0	(76)	0	0	(532)	0	0	0	0	0	0	(232)	0
8 Cumulative Generating Capacity	**13,866**	**13,886**	**13,900**	**13,908**	**14,045**	**14,045**	**13,513**	**13,513**	**13,513**	**13,513**	**13,513**	**13,513**	**13,513**	**13,281**	**13,281**
Purchase Contracts															
9 Cumulative Purchase Contracts	**1,954**	**1,945**	**1,957**	**1,956**	**1,695**	**1,527**	**1,382**	**791**	**409**	**409**	**409**	**409**	**409**	**408**	**399**
Non-Compliance Renewable Purchas	124	115	127	126	125	125	125	35	34	34	34	34	34	33	24
Non-Renewables Purchases	1,830	1,830	1,830	1,830	1,570	1,402	1,257	756	375	375	375	375	375	375	375
Undesignated Future Resources															
10 Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Combined Cycle	0	0	0	0	0	0	907	0	907	0	0	0	0	907	0
12 Combustion Turbine	0	0	0	0	147	0	0	872	0	0	0	0	0	0	0
Renewables															
13 **Cumulative Renewables Capacity**	176	165	190	199	168	204	274	240	256	272	278	294	302	310	314
14 Cumulative Production Capacity	**15,996**	**15,996**	**16,046**	**16,063**	**16,055**	**15,923**	**16,223**	**16,470**	**17,011**	**17,026**	**17,033**	**17,049**	**17,057**	**17,739**	**17,733**
Demand Side Management (DSM)															
15 Cumulative DSM Capacity	**573**	**575**	**586**	**602**	**616**	**629**	**642**	**649**	**657**	**664**	**671**	**679**	**686**	**692**	**698**
16 Cumulative Capacity w/ DSM	**16,569**	**16,571**	**16,633**	**16,665**	**16,672**	**16,552**	**16,865**	**17,120**	**17,668**	**17,690**	**17,704**	**17,727**	**17,743**	**18,431**	**18,432**
Reserves w/ DSM															
17 Generating Reserves	3,990	3,762	3,732	3,586	3,397	3,115	3,179	3,253	3,681	3,566	3,571	3,419	3,214	3,697	3,588
18 % Reserve Margin	**31.7%**	**29.4%**	**28.9%**	**27.4%**	**25.6%**	**23.2%**	**23.2%**	**23.5%**	**26.3%**	**25.2%**	**25.3%**	**23.9%**	**22.1%**	**25.1%**	**24.2%**

ATTACHMENT D

A Responsible Energy Future for North Carolina: An Alternative to Duke Energy's 15-Year Plan

Duke Energy's proposal for the next 15 years (filed Oct. 2014): fracking gas and new nuclear power plants, more emissions, coal ash and rate hikes. We propose competition that will lead to cleaner, cheaper energy. The people of North Carolina should be able to choose our path forward. Duke Energy ignores the rapidly falling cost of solar, North Carolina's potential for wind energy, energy efficiency and emerging storage options for clean electricity. Duke is working to stop the explosion in financing options that can lower costs and make clean power more widely available.

Each year Duke Energy must file a 15-year plan for meeting electricity demand in North Carolina – where it has monopoly control. In reviewing these Integrated Resource Plans, or IRPs, the NC Utilities Commission is legally required to ensure that utilities adopt the "least cost mix" of generation and energy-saving measures that is achievable in order to avoid undue costs for customers.

In fact, the NC Supreme Court has specified that the purpose of the IRPs is to prevent the costly overbuilding of new power plants.

Due to a 2012 merger, Duke Energy now operates two utilities that straddle the Carolinas. Together, Duke Energy Carolinas and Duke Energy Progress generate more than 95% of the electricity consumed in North Carolina. As a regulated monopoly, Duke Energy is guaranteed a large profit for its shareholders for providing the power.

In its 2014 IRP, Duke Energy relies heavily on coal-fired power far into the future, increased burning of fracking gas, and construction of high-risk nuclear plants – with negligible amounts of clean, affordable renewable energy and energy saving programs. Duke proposes to increase all renewable energy by only a miniscule 1% from its 2013 plan – from 3% to 4% – by 2029. In an age of escalating climate change, Duke Energy's approach is reckless and weak.

It is clear that Duke Energy plans to keep raising captive customers' rates by building power plants that are not needed, while attempting to lock out competition.

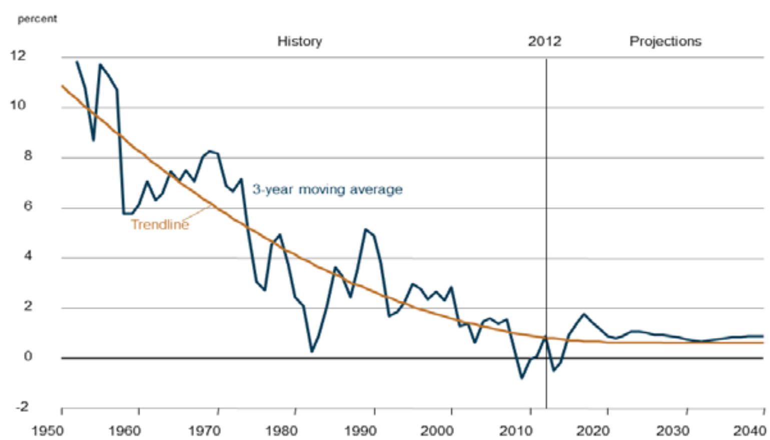
A $25 BILLION FICTION

Duke Energy bases its "build more plants, raise rates" plan on a forecast of high growth in customers' use of electricity – about 1.4% each year – even though usage across the electric industry has been steady for more than a decade. Jim Rogers – Duke Energy's CEO until 2013, who remains the industry's leading spokesman – says growth will be "flat to declining," and that new power plants won't be built at all. The U.S. Energy Information Administration (EIA) agrees that growth will be flat for the foreseeable future.

The projected growth in electricity usage is critical to determining the need for new power plants. The difference between a 1.4% increase and flat growth over the 15-year period is equal to $25 – 30 billion worth of new power plants – if customers are forced to go this route.[1]

The chart below shows the dramatic slow-down in the growth of electricity demand.[2]

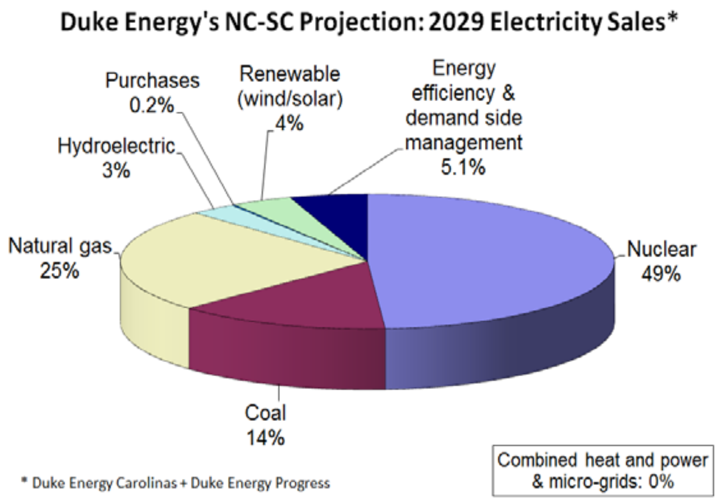
Figure MT-29. U.S. electricity demand growth in the Reference case, 1950-2040

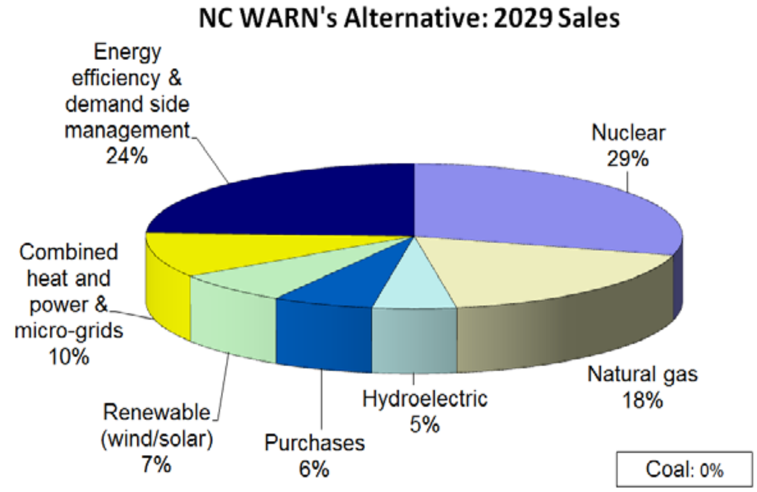


A SAFER, CHEAPER PATH

In response to Duke Energy's 2012 IRP, NC WARN created an alternative *Responsible Energy Future*. The analysis showed that, even using Duke Energy's exaggerated growth projections, all coal plants in the Carolinas can be phased out and no natural gas and nuclear plants need to be constructed. (See the report and NC WARN's comments on both the 2012 and 2013 IRPs at ncwarn.org.)

In our early 2014 update, NC WARN adjusted our proposal to reflect the flat demand with a greater adoption of renewable energy, energy efficiency and combined heat and power. This would allow all coal plants and most of the natural gas plants to be closed down.





There are also a few game-changers coming into play. The cost of solar is down dramatically, and investment in solar and clean energy is exploding in parts of the U.S. that allow solar to compete. Despite this quickly-changing market, Duke Energy plans to build even more natural gas plants and plans to build a 550-mile, $4.5 billion fracked gas pipeline from West Virginia to North Carolina.[3]

Many studies have shown that fracked gas (natural gas) is just as bad as coal – and maybe worse – in creating greenhouse gas emissions.[4]

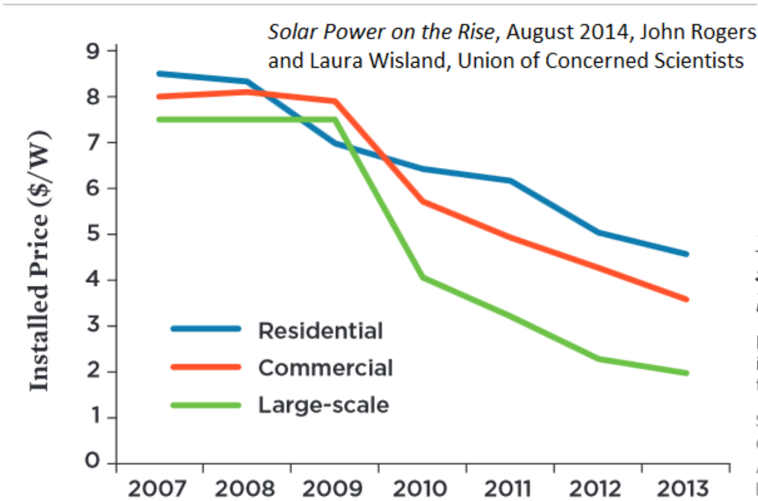
We don't need more fracked gas in North Carolina. We need more clean energy. When all the costs of dirty energy are taken into account, clean energy is economically superior.[5]

THE COST OF SOLAR IS DOWN DRAMATICALLY

The cost of solar continues to fall. The 5-year decrease in the "levelized" cost of solar PV – key because it reflects the total cost of power over the solar installation's lifetime – is 78%.[6] A recent analysis by research firms, including U.S. national labs, shows the clear decline in the cost of solar PV.

In October 2014 Deutschebank reported that solar had reached grid parity (cost-competitive with traditional power plants) in 10 states, and would reach grid parity in 36 of 50 U.S. states by 2016.[7]

FIGURE 3. The Falling Price of Solar PV by U.S. Sector, 2007–2013



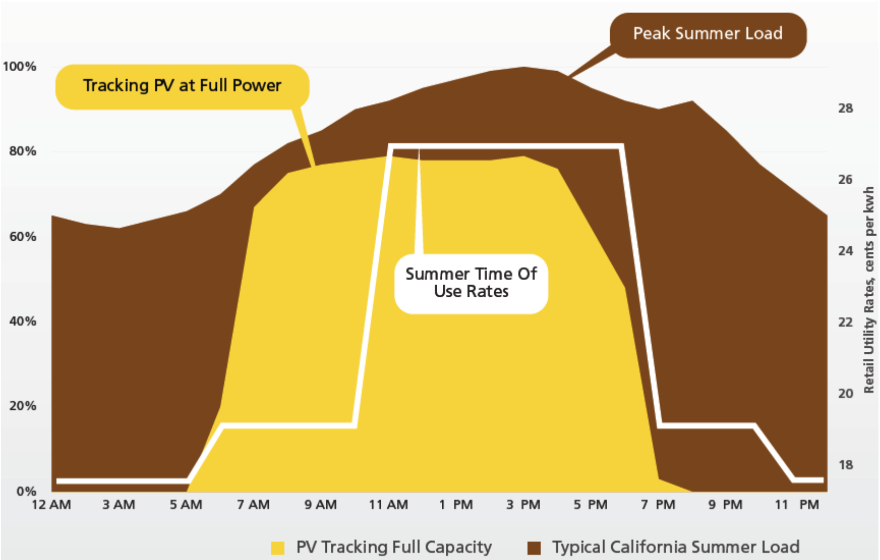
Prices for PV systems in the United States have dropped by 50 percent or more in recent years, with the sharpest declines for large-scale projects.

NOTE: In Figures 3 and 5, "Commercial" includes all small-scale non-residential installations. "Large-scale" cost data for 2007–2009 include systems larger than 100 kilowatts.

SOURCES: GTM RESEARCH AND SEIA 2014A; GTM RESEARCH AND SEIA 2013; GTM RESEARCH AND SEIA 2012; BARBOSE ET AL. 2011; BARBOSE, DARGHOUTH AND WISER 2010; GTM RESEARCH AND SEIA 2010; WISER, BARBOSE, AND PETERMAN 2009; WISER ET AL. 2009.

Solar has additional value since it adds electricity to the grid at costly peak power times, saving Duke Energy and its customers the expense of having to build new power plants to meet peak demand.[8]

A September 2014 analysis shows utility-scale solar is cost-competitive with coal and natural gas.[9]



Solar Meets Critical Peak Power Demand

Graph from Stephen Lacey, "This Looks Like a Job for Solar PV," thinkprogress.org, July 25, 2011.

Data sources: For summer peak load shape – California Independent System Operator (CAL-ISO); For time of use rates – Pacific Gas and Electric Company (PG&E); For PV Tracking Output – Solaria Corporation.

INVESTMENT IN CLEAN ENERGY IS EXPLODING

According to the International Energy Agency (IEA), solar could be the dominant source of electricity in the world by 2050.[10] Investment in clean energy in North Carolina and the U.S. has been exploding.

Global investment in clean energy was $254 billion in 2013, while the U.S. invested $48.4 billion.[11]

An estimated $2.6 billion was invested in clean energy projects in North Carolina between 2007 and 2013, supported by state funds of $135.2 million. Private investment was twenty times that of state incentives.[12]

Despite the enormous potential of solar in North Carolina, Duke Energy is working overtime to kill policies that make clean energy easier, cheaper for customers and more widespread.

In the 2014 Avoided Cost docket currently before the NC Utilities Commission, NC's large-scale solar industry is at risk from Duke Energy's proposal to significantly reduce the amount paid for solar and to further stall the already burdensome approval process for independent solar projects.[13]

The effort to reduce the amount paid for solar is taking place in many different states as many utilities, including Duke Energy, seek to kill the growth of clean solar power.[14]

NC WARN's UPDATED 2015 RESPONSIBLE ENERGY FUTURE

Our updated *Responsible Energy Future* calls for North Carolina to achieve the following by 2029:

- 7% renewable energy, 24% energy efficiency, and 10% combined heat and power, as a percentage of total electricity sales;
- phase out all coal-fired power plants;
- no new natural gas or nuclear plants; and
- close the dirtiest natural gas and most dangerous nuclear units.

A transition to cleaner energy will benefit our economy and our health. Eliminating coal from North Carolina's energy mix and reducing the use of natural gas keeps the $1.7 billion for out-of-state coal in our state's economy, while drastically reducing the climate-harming pollution pumped into the atmosphere and coal ash stored next to our rivers and groundwater. Ramping up clean energy sources promotes economic development; a 2013 census estimates the clean energy industry employs 18,404 workers in the state and brings in $3.6 billion in revenue.[15]

It is clear that a balanced mix of distributed power (putting electricity where it is needed) and energy efficiency is the most reliable, cost effective and readily available path over the next 15 years.

DISRUPTIVE CHALLENGES FOR UTILITIES; MORE CLEAN ENERGY FINANCING OPTIONS

Meanwhile, there are many "disruptive challenges" in the electric utilities business, such as the growing opposition to carbon-producing power, the demise of the nuclear renaissance, rapid advances in utility-scale batteries and the emergence of solar energy as a cost-effective option. Some have pronounced these rapidly changing market conditions the "corporate death spiral," a process already severely harming the largest European utilities. Duke Energy's plans suggest its executives are ignoring these industry-wide changes, and we cannot allow them to drag North Carolina's economy down.

A transition by Duke Energy toward a business model that embraces new advances in the industry such as distributed energy and energy efficiency, instead of one that relies on massive, unneeded centralized power plants, could be a national, if not international, game-changer to reduce the drastic impacts of climate change.

If the Utilities Commission approves Duke Energy's 2014 IRP as proposed, it approves a status quo that will strangle North Carolina's solar and clean energy industries and continue polluting our air and water. There is much at stake for North Carolina, and for each one of us; the status quo is no longer acceptable.

State law requires the Utilities Commission to consider NC WARN's *Responsible Energy Future* plan. The bottom line is that our approach can provide an estimated *annual* savings for NC electricity customers of more than $2 billion.[16] It is a responsible energy future, one that promotes a good economy and jobs, and will provide us all with a healthier place to live while implementing solutions to climate change.

November 2014

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[1] The most recent estimate of the cost of a single nuclear unit is in the $13 – 15 billion range, including escalation, financing costs, initial fuel, contingencies and reserves. www.bellbend.com

[2] http://www.eia.gov/forecasts/aeo/MT_electric.cfm

[3] http://www.chathamstartribune.com/news/article_52a705bc-32b8-11e4-8f80-0019bb2963f4.html

[4] http://www.eeb.cornell.edu/howarth/publications/Howarth_2014_ESE_methane_emissions.pdf

[5] http://thinkprogress.org/climate/2011/02/16/207534/life-cycle-study-coal-harvard-epstein-health/

[6] http://www.solarserver.com/solar-magazine/solar-news/current/2014/kw39/lazard-lcoe-analysis-costs-of-pv-continue-to-drop-solar-power-is-increasingly-cost-competitive-with-traditional-energy-sources.html

[7] http://www.resilience.org/stories/2014-11-04/investment-in-solar-stocks-crushed-big-oil *Investment in Solar Stocks Crushed Big Oil,* by Deborah Lawrence, 11/5/14.

[8] http://thinkprogress.org/climate/2011/07/25/278369/this-looks-like-a-job-for-solar-pv-heat-wave-causes-record-breaking-electricity-demand/

[9] http://www.scottmadden.com/insight/807/renewables-becoming-cost-competitive-other-challenges-remain.html

[10] http://uk.reuters.com/article/2014/09/29/us-solar-iea-electricity-idUKKCN0HO11K20140929*Solar could dominate electricity by 2050: IEA,* Reuters, 9/29/14

[11] Investments in clean energy in 2013 were lower than 2012, due to falling solar costs and policy uncertainty. http://about.bnef.com/press-releases/clean-energy-investment-falls-for-second-year/

[12] http://c.ymcdn.com/sites/www.energync.org/resource/resmgr/Resources_Page/NCSEA_econimpact2014.pdf, ES-1.

[13] www.ncwarn.org/dukehatessolar See satirical 30 second video

[14] http://www.greentechmedia.com/articles/read/Duke-Buying-500M-of-North-Carolina-Solar-to-Mixed-Reviews

[15] North Carolina Sustainable Energy Association, *Economic Impact Analysis of Clean Energy Development in North Carolina-2014 Update,* pages ES-1 and ES-2: http://c.ymcdn.com/sites/www.energync.org/resource/resmgr/Resources_Page/NCSEA_econimpact2014.pdf

[16] http://www.ncwarn.org/wp-content/uploads/Sum-Update-FINAL-4-18-14-Resp-En-Future-2014.pdf

ATTACHMENT E

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of	)	
Practices Leading to Excess Capacity and Waste	)	Docket No. ___________
by Duke Energy Carolinas and Duke Energy Progress	)	

NOTICE OF COMPLAINT AND PETITION FOR INVESTIGATION

Take notice that on [to be determined], the North Carolina Waste Awareness and Reduction Network, Inc. ("NC WARN") filed a formal complaint against Duke Energy, pursuant to Section 206 of the Federal Power Act, 16 U.S.C. § 824e and Rule 206 of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice and Procedure, 18 C.F.R. §385.206. The complaint and petition for investigation requests that the Commission fully investigate Duke Energy's practices as and if the Commission determines it proper, to require Duke Energy to enter into an RTO and purchase necessary power from other utilities rather than construct wasteful and redundant generating plants. As part of the complaint, NC WARN alleges Duke Energy manipulates the market so that is can construct new generating plants that are not needed and not warranted given the overcapacity in the Southeast region.

NC WARN certifies that copies of the complaint were served on the contacts for Duke Energy as listed on the Commission's list of Corporate Officials. Any person desiring to intervene in or protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.211, 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and five copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426. This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any of the Commission Online service, please email the Commission OnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: [to be determined].

Kimberly D. Bose
Secretary