BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 147

In the Matter of:	**)**	**NCSEA'S**
2016 Biennial Integrated Resource Plans	**)**	**[PUBLIC]**
and Related 2016 REPS Compliance Plans	**)**	**COMMENTS**

NCSEA'S COMMENTS

Pursuant to the North Carolina Utilities Commission ("Commission") Rule R8-60(k) and the Commission's January 20, 2017 *Order Granting Extension of Time to File Comments and Setting Final Date for Discovery Requests*, the North Carolina Sustainable Energy Association ("NCSEA") submits the following comments on the 2016 integrated resource plans ("IRPs") submitted by Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, Inc. ("DEP") (collectively, "Duke"), and Dominion North Carolina Power ("DNCP").

INTRODUCTION

NCSEA's comments are arranged as follows: First, the comments address Duke's significant reliance on "forward prices," rather than a fundamental forecast, in fuel forecasting for their IRPs, and by extension their avoided cost calculations. Second, the comments address how energy storage is addressed in the IRPs. Finally, the comments address the differences between DEP's two service territories.

NCSEA requests (1) that the Commission address or determine whether such significant reliance on "forward prices" in fuel forecasting is appropriate in the context of the avoided cost proceeding, (2) that the Commission direct the utilities to quantify and incorporate all value streams provided by energy storage in future IRPs and (3) that the

Commission direct DEP to provide separate analyses for their DEP-East and DEP-West service territories in future IRP filings.

I. <u>DUKE'S FUEL FORECASTING METHODOLOGY</u>

In past proceedings, the Commission has addressed the interdependence of the utilities' long-term fuel forecasts and generation expansion plans and has discussed that fuel forecasts drive the utilities' generation planning and generation build decisions. *See*, *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, pp. 24-27, Docket No. E-100, Sub 140 (Dec. 17, 2015) (hereinafter "*2014 Order*"). In its *2014 Order* the Commission recognized the following with respect to forecasting fuel prices:

> The Commission acknowledges that forecasting natural gas and coal prices over the next fifteen years is challenging and that forward market prices may provide a better snapshot of prices over the near and short-term future. However, forward market prices do not reflect the same level of analysis and consideration given to the development of long-term forecasts, as performed by firms whose expertise is in long-term forecasting. The Commission finds that the increased reliance on forward prices for natural gas by the Utilities in their 2014 IRPs, and on coal prices by DEC and DEP, adequately captures some of these changing market conditions at this time. This determination also reflects the important relationship that exists between the biennial avoided cost proceeding and the IRP, and helps to maintain internal consistency between these proceedings. As such, the Commission agrees with the Public Staff that DEC, DEP, and DNCP should recalculate their avoided energy rates using natural gas and coal price forecasts that are constructed in a consistent manner with those utilized in their 2014 IRPs.

2014 Order, p. 27. Thus, the Commission has previously noted the shortcomings of forward market prices relative to the long-term forecasts, which are prepared by firms whose expertise is in long-term forecasting. Thus, while the Commission has never directed the utilities to construct their respective fuel forecasts using a specific number of years of forward market prices and a specific number of years of fundamental, long-term forecasts, the Commission has cautioned of the risks associated with the forward prices.

Additionally, the Commission has previously directed Duke and DNCP as follows:

> That to the extent the Utilities wish to adjust the way in which they utilize forward prices and long-term forecasts in future IRP and avoided cost proceedings, those changes shall first be proposed and approved as part of the biennial IRP proceeding before being incorporated in avoided cost calculations.

2014 Order, Ordering Paragraph 9.

In its 2016 IRP, Duke's fuel forecasts rely on forward prices during an initial 10-year period, followed by a 4-year transition period, followed by fundamental long-term forecasted pricing during the remaining years. *See*, *DEC and DEP Response to NCSEA Data Request No. 1-13*, Docket No. E-100, Sub 148. In contrast, DNCP's fuel forecasts rely on forward prices during an initial 18-month period, followed by an 18-month transition period, followed by fundamental long-term forecasted pricing during the remaining years. *See*, *DNCP Response to Public Staff Data Request No. 2-4*, Docket No. E-100, Sub 147.

NCSEA has previously stated and supported its position on the construction of fuel forecasts using a blend of forward prices from futures markets and fundamentals-based forecasts in future years through the Affidavit of Ben Johnson, Ph. D., filed in Docket No. E-100, Sub 140, on August 7, 2015 ("Johnson Affidavit").

Fundamental forecasts are an appropriate source of fuel cost data since they represent an estimate of the price that will be paid by the utility for specific types of fuel purchased at specific dates in the future. In contrast, forward prices from the futures markets are not predictions or estimates of what prices will occur in the future. Rather, forward prices tend to systematically understate the true cost of acquiring fuel at future dates. The prices observed in the futures markets are generally not for the fuel itself, but for contracts that represent a carefully structured, highly standardized bundle of legal rights and obligations. Utilities do not typically purchase fuel in futures markets in order to receive physical delivery of the fuel at future dates. But, if they were to do so, they would incur substantial additional carrying costs for fuel purchased in this manner, over and above the "forward price" paid for the futures contract itself. These carrying costs include interest on their investment and the cost of equity capital during the entire time from the date when they purchase the futures contract until they date when they receive physical delivery of the fuel, months or years later. Accordingly, futures prices tend to systematically understate the actual cost of acquiring fuel for future delivery, and the magnitude of this understatement becomes more serious the longer the time period over which future prices are being used. *See generally*, Johnson Affidavit, ¶¶ 12-28.

Thus, it is NCSEA's position that fundamentals-based forecasts in future years are more representative of a utility's avoided cost and that it is not appropriate to rely on ten years of "forward prices" in estimating future avoided cost. The extent to which forward prices are appropriately relied upon, rather than the fundamental long-term forecasts, is particularly significant in the context of the biennial avoided cost proceeding, which is currently pending before the Commission in Docket No. E-100, Sub 148. Accordingly, NCSEA asks that the Commission address or determine whether such significant reliance on "forward prices" is appropriate in the context of the avoided cost proceeding. The appropriate reliance on fundamental forecast and futures prices, and the appropriate time periods over which these data sources should be used, are issues that are best resolved in the context of the avoided cost proceeding.

II. <u>Storage in the Integrated Resource Plans</u>

It is undisputed that the generation profile of solar generation does not inherently align with either a summer peak or a winter peak. Duke has noted "that intermittent solar QFs provide[s] little support during the morning peak and no support during the late afternoon peak. Yet, in the mid-day, QFs delivered must-take energy in excess of system needs, and created load following and unit cycling reliability challenges." *Comments of Duke Energy Corporation to the Federal Energy Regulatory Commission's Technical Conference Concerning Implementation Issues Under the Public Utility Regulatory Policies Act of 1978 ("PURPA")*, pp. 2-3, Federal Energy Regulatory Commission Docket No. AD16-16-000 (June 7, 2016) (hereinafter "*Duke's PURPA Technical Conference Comments*"). DEP's IRP notes that "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." *Duke Energy Progress, LLC 2016 Integrated Resource Plan Revision*, p. 24, Docket No. E-100, Sub 147 (Sept. 30, 2016) (hereinafter "*DEP's 2016 IRP*"). DEP is "currently experiencing operationally excess energy due to the unplanned and unconstrained level of solar capacity and ongoing development" and DEC "will experience operationally excess energy in the future if unplanned and unconstrained solar development continues." *DEC Response to NCSEA Data Request No. 2-4*, Docket No. E-100, Sub 147 (attached as **Exhibit A**). DEP has observed "at least 20 instances of operationally excess energy occurrences due to operationally excess solar capacity interconnected with the DEP system." *Id.* When these events have occurred, DEP has "cycle[d] down base load units required for evening demand that are not intended for cycling or dump the excess energy contingent on the availability of non-firm transmission and a purchasing counterparty." *Duke's PURPA Technical Conference Comments*, pp. 2-3 (emphasis in original). *See also*, Exhibit A ("The DEP BA managed through these operationally excess energy instances by moving the excess energy into another sink BA, using then available non-firm transmission, at a lower rate than the avoided cost rate.").

DEP first began experiencing these events "at approximately 844 MWs of installed solar capacity." Exhibit A. Of note, DEP has approximately 1,710 MW of installed solar capacity in 2017, *DEP's 2016 IRP, p. 21*. At the time that it filed its IRP, DEP noted that roughly 450 MW of third-party solar was under construction in its service territory and that over 3,000 MW of solar was in its interconnection queue, *DEP's 2016 IRP*, p. 22, and as of December 31, 2016, DEP had 631 MW of solar under construction in its service territory, with an additional 2,276 MW of open solar projects in its interconnection queue. *Duke Energy Progress, LLC Quarterly Interconnection Queue Performance Report and Quarterly Interconnection Queue Status Report*, Docket No. E-100, Sub 101A (Jan. 31, 2017). DEP's Base Case expects to add an additional 1,155 MW of solar to its grid by 2031. *DEP's 2016 IRP*, p. 23.[1] Under the high renewables case, DEP could add as much as 3,293 MW of solar. *DEP's 2016 IRP*, p. 28. Similarly, DEC predicts that it "will experience operationally excess energy in the future if unplanned and unconstrained solar development continues." Exhibit A. DEC will have a total of 735 MW of installed solar

[1] Given that DEP's interconnection queue report states that 631 MW of solar is currently under construction in its service territory, under DEP's base case only 484 MW of new solar projects will be developed in its service territory between now and 2031.

capacity in its territory in 2017. *Duke Energy Carolinas, LLC 2016 Integrated Resource Plan Revision*, p. 20, Docket No. E-100, Sub 147 (Sept. 30, 2016) (hereinafter "*DEC's 2016 IRP*"). At the time that it filed its IRP, DEC noted that roughly 140 MW of third-party solar was under construction in its service territory and that over 900 MW of solar was in its interconnection queue, *DEC's 2016 IRP*, pp. 21-22, and as of December 31, 2016, DEC had 34 MW of solar under construction in its service territory and an additional 845 MW of open solar projects in its interconnection queue. *Duke Energy Carolinas, LLC Quarterly Interconnection Queue Performance Report and Quarterly Interconnection Queue Status Report*, Docket No. E-100, Sub 101A (Jan. 31, 2017).

Looking into the future, Duke predicts that "By 2020, . . . QFs injecting must-take levels of energy significantly in excess of system needs, will force the utility either to cut deep into nuclear operations or purchase and pay for excess energy injected into the system and somehow attempt to move it off the system subject to the availability of <u>non-firm</u> transmission." *Duke's PURPA Technical Conference Comments*, p. 3. When the "levels of must-take, non-dispatchable QF energy being injected into the system [are] greater than intra-day minimum load requirements, the utility will have to either: (i) cycle off base load and nuclear units on an intra-day basis to balance loads, even though those units are needed to meet evening demand and are not intended to be cycled, or (ii) find ways to dump the excess energy, contingent on non-firm transmission availability and a willing buyer – both presenting material reliability challenges." *Id.*, p. 6.

Despite Duke's prediction that in future years solar generation will "cut deep into nuclear operations" and necessitate "cycl[ing] off base load and nuclear units on an intra-day basis to balance loads, even though those units are needed to meet evening demand

and are not intended to be cycled," under the Joint Planning Case, DEC and DEP's IRPs project shared DEP-DEC ownership of the W.S. Lee Nuclear Facility in 2026, and DEC's base case calls for that 2.2 GW of new nuclear generation to be completed in 2028. *DEP's 2016 IRP*, p. 8; *DEC's 2016 IRP*, p. 43. Construction of additional nuclear generation will only serve to exacerbate the situation, and the current IRP process undervalues the benefits that energy storage can provide both as a generation resource as well as to other aspects of the grid.

Duke has identified two avenues to addressing issues of excessive generation during certain periods of the day. The first option identified by Duke is to have greater operational control over solar generation. *See*, *DEP's 2016 IRP*, p. 24. *See also*, *DEC Response to PS9-4*; *DEP Response to PS8-4* (attached as **Exhibit B**) ("The impacts of increasing penetration of must-take solar may need to be considered in future plans when recommending the types of resources needed to meet the winter reserve margin requirements (high ramp rate, operational flexibility, etc.). Conversely, to the extent future solar additions have automatic generation control technology, this issue would not be as severe."). Duke has also identified the possibility of new technologies that can help address the issue. *See*, *DEP's 2016 IRP*, p. 24 ("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."). Notably, however, Duke does not identify energy storage as an avenue for addressing this potential issue.

A. RENEWABLES PLUS STORAGE

According to the National Association of Regulatory Utility Commissioners' ("NARUC") Staff Subcommittee on Rate Design:

> Energy storage can be used as a resource to add stability, control, and reliability to the electric grid. Historically, storage technologies have not been widely used because they have not been cost competitive with cheaper sources of power such as fossil fuels. However, given the recent decline in costs and technological improvements in storage, storage has become an option that is able to compete with many other resources. With the growing use of intermittent technologies such as wind and solar energy, energy storage technologies can provide needed power during periods of low generation from intermittent resources that will assist in keeping the electric grid stable and possibly prevent curtailment of resources in spring and fall months when electricity consumption is not affected by summer air-conditioning or winter heating loads.

NARUC Manual on Distributed Energy Resources Rate Design and Compensation, NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS, p. 47 (Nov. 2016).

"There are targeted locations where electricity storage can be cost-effective and should be pursued. These include placement at strategic points where storage provides supplemental generation capacity during some hours, and a place to 'park' surplus generation from high renewable penetration or nuclear generation at times when it is not needed for current demand." Jim Lazar, *Teaching the "Duck" to Fly*, Second Edition, REGULATORY ASSISTANCE PROJECT, p. 34 (Feb. 2016). There are areas in DEP and DEC territory that would be described as a "targeted location." "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." *DEP's 2016 IRP*, p. 24. Since DEP and DEC are experiencing excessive solar energy, storage would be ideal for the surplus generation.

In NCSEA's initial comments in the 2014 IRP docket, NCSEA criticized DEC and DEP for failing to model energy storage, noting:

> First, the utilities recognize that energy storage can assist with the integration of intermittent distributed energy resources to the grid. Second, the utilities recognize that energy storage installed at substations can provide load shifting, thereby reducing strain on generation resources. Finally, the utilities have performed technical screenings and initial analyses, but have not modeled energy storage for their IRPs.
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> . . .
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> NCSEA requests the Commission direct the utilities to use the best available model to consider energy storage during the IRP process. Because of the current lack of models that best integrate energy storage, at this time the directive would mean that the utilities use their current best practices and existing models. When more appropriate models become available, they should be used by the utilities for future IRPs.

NCSEA's Initial Comments, pp. 11-14, Docket E-100, Sub 141 (March 2, 2015).

In their reply comments, DEC and DEP stated:

> As the costs of this technology decline and impacts of energy storage on the grid come into clearer focus in the coming years, it may be a beneficial addition to the Companies' IRPs, but until then, it would not be prudent to include these systems. The Companies continue to monitor advanced energy storage technologies and evaluate potential uses in the Carolinas. However, at this time these technologies are neither economical, nor viable on a macro level for use in the IRP. The Companies will include Li-ion battery storage technology in the economic supply-side screening process as part of the 2015 IRP.

DEC and DEP's Reply Comments, pp. 18-19, Docket E-100, Sub 141 (April 20, 2015). In its *Order Approving Integrated Resource Plans and REPS Compliance Plans*, the Commission agreed with DEC, DEP, and DNCP's assessment of energy storage technologies stating, "[t]hese technologies are not economical or viable at this time for mandatory inclusion in the utilities' IRPs. Further, as models do not currently exist for a proper evaluation of energy storage, the Commission does not see a benefit in simply asking the IOUs to take their best shot at a modeling approach at this time." *Order Approving Integrated Resource Plans and REPS Compliance Plans*, p. 48, Docket E-100, Sub 141 (June 26, 2015).

Now in their 2016 IRPs, both DEP and DEC note that:

> 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).

DEC's 2016 IRP, p. 139; *DEP's 2016 IRP*, p. 139.

Furthermore, DEC and DEP acknowledge that "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." *DEC's 2016 IRP*, p. 24; *DEP's 2016 IRP*, p. 25. DEP highlights its commitment to install 5 MW of storage in the DEP-West region, and states that the project "will be a great learning experience for the Company on how to effectively deploy more battery storage in the future to facilitate safe, reliable, and cost effective integration of renewable resources with the rest of the generation, transmission, and distribution systems." *DEP's 2016 IRP*, p. 25.

While NCSEA commends the companies for including some analysis of energy storage in their 2016 IRPs, we believe they are still failing to recognize the full value of energy storage to the companies and to their customers. To begin with, the 2 MW / 8 MWh lithium ion battery storage system is the only type energy storage to be included in the companies' economic screening curve analysis model. *See*, *DEC's 2016 IRP*, pp. 140-141; *DEP's 2016 IRP*, pp. 137-138. While NCSEA believes this is a positive addition to the companies' economic screening analysis, it is disappointing that this relatively small and distribution-based application of energy storage was the only technology considered in this economic screening. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. *See*, *DEC-DEP Response to SACE Data Request No. 1-1*, Docket No. E-100, Sub 147 (attached as **Exhibit C**). This narrow consideration of energy storage technology and the failure to recognize the grid benefits of storage in the economic screening analysis resulted in all energy storage technologies being excluded from the quantitative analysis component of the IRPs as potential supply-side resource options to meet future capacity needs. *See*, *DEC's 2016 IRP*, p. 63; *DEP's 2016 IRP*, p. 63. Rule R8-60(c)(2) directs the utilities to develop and keep current an integrated resource plan which incorporates, at a minimum, the following:

> [a] comprehensive analysis of all resource options (supply-and demand-side) considered by the utility for satisfaction of native load requirements and other system obligations over the planning period, including those resources chosen by the utility to provide reliable electric utility service at least cost over the planning period.

By this provision, a truly comprehensive analysis of energy storage should include and value energy storage's ability to satisfy native load requirements <u>and</u> satisfy other system obligations over the planning period.

As detailed in a recent report, "A crucial component of the value of storage is its ability to support multiple applications—and thus value streams—at the same time." American Council on Renewable Energy & ScottMadden, Inc., *Beyond Renewable Integration: The Energy Storage Value Proposition*, p. 20 (November 2016) ("Storage Value Report"). These benefits include:

- Integration of renewables, especially given the intensity and variability of generation;
- Peak load shaving;
- Emergency response and resilience;
- Grid stability; and
- Energy cost reduction such as avoided transmission and distribution costs.

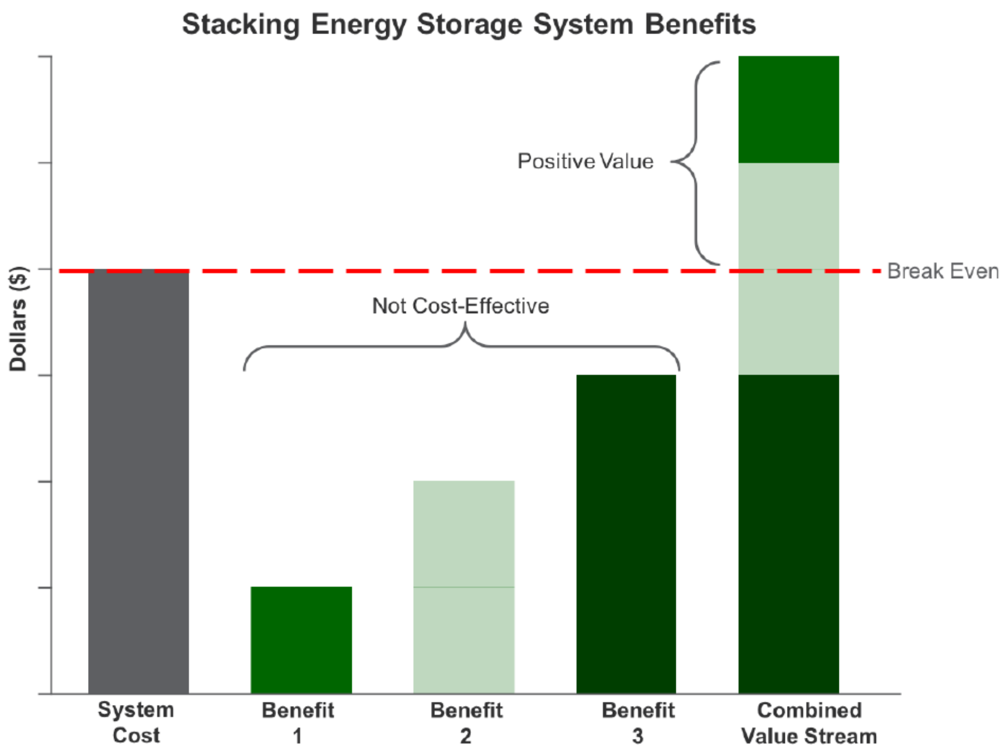
Id., pp. 8-11.

DEC and DEP's IRPs only analyze the generational value of energy storage and do not quantify the value of these additional benefits. As detailed in **Figure 1**, failing to value the full "stack" of energy storage benefits can (and in the case of the 2016 IRPs, it did) inadvertently exclude energy storage from the IRP and therefore all of its potential benefits to utilities and their customers.

While NCSEA has been primarily referring to battery storage in these comments, it should be noted that DEC did not evaluate new pumped storage units or retrofitting existing hydroelectric units to operate in a pumped storage capacity. *DEC Response to*

PSDR 7-8 (attached as **Exhibit D**). In addition, DEC notes that it did not analyze in its IRP process how it uses its existing pumped hydroelectric storage facilities. *DEC Response to Public Staff Data Request No. 11-5*, Docket No. E-100, Sub 147 (attached as **Exhibit E**).

Figure 1[2]



B. <u>OTHER BENEFITS OF ENERGY STORAGE</u>

If energy storage costs continue to decline at their anticipated rates of 12%-15% annually, *Storage Value Report*, p. 32, utilities will be doing themselves and their customers a disservice if they continue to undervalue energy storage in their IRPs and therefore their future generation portfolio and grid services. Inasmuch as DEC and DEP are beginning to model the benefits that energy storage provides, NCSEA requests that they ensure that the other benefits provided by energy storage are included in their IRP. In

[2] Storage Value Report, p. 20.

the alternative, NCSEA requests that DEC and DEP identify how the IRP process prevents the full value of storage from being evaluated. NCSEA is encouraged that, "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." *DEC's 2016 IRP*, p. 140; *DEP's 2016 IRP*, p. 137. The companies further noted that, "[a]dditional regional engineering analysis will continue in 2017 and beyond . . . As yet, we have not seen our first analysis results to predict the beginning of our deployment plans." *DEC Response to NCSEA Data Request No. 2-14*, Docket No. E-100, Sub 147 (attached as **Exhibit F**).

In light of the fact that the utilities are already working on battery storage predictions and deployment plans, NCSEA asks that the Commission direct the utilities to quantify and incorporate the full value stream that energy storage technologies provide in future IRPs and IRP updates. In addition, the Commission should direct the utilities to identify the regulatory barriers or their interpretation of Rule R8-60 that currently prevents them from incorporating the full value of energy storage in their IRPs in a filing before the Commission.

III. INTEGRATED RESOURCE PLANNING IN DEP-WEST

The characteristics of DEP's two service territories, DEP-East and DEP-West, differ drastically. Based upon (1) the original purpose of integrated resource planning, (2) differing forecasts for the two service territories, (3) the geographic separation of the two service territories, and (4) DEP's commitment to the DEP-West service territory as a part of the Western Carolinas Modernization Project, NCSEA believes that DEP-West and

DEP-East should not be, and cannot properly be, analyzed as a single system in the IRP process. Accordingly, NCSEA requests that the Commission require DEP to complete separate analyses for DEP-East and DEP-West in future IRPs and IRP updates.

A. The Original Purpose of Integrated Resource Planning

In 1988, the Commission adopted a new set of rules requiring utilities to perform least cost integrated resource planning (IRP).[3] *See generally*, *Order Adopting Rules*, Docket No. E-100, Sub 54 (Dec. 8, 1988). The original purpose of the least-cost IRP process was "to ensure that each regulated electric utility operating in North Carolina [was] developing reliable projections of the long range demands for electricity in *its service area* and a combination of reliable resource options for meeting the anticipated demands in a cost effective manner." Rule R8-56(a) (emphasis added) (repealed by *Order Preliminarily Adopting Revised Rules*, Docket No. E-100, Sub 78A (March 26, 1998)). While the least-cost IRP process since been replaced, the Commission originally intended the IRP process to ensure that the long range electricity demands were met within the specified service areas.

In addition to the original purpose of least-cost IRPs, "[t]he rules specif[ied] . . . that alternative resource options must be studied and compared in such depth that a

[3] Prior to 1987, integrated resource planning focused on supply-side planning. *See*, *State ex. rel. Utilities Commission v. N.C. Electric Membership Corp.*, pp. 2-3, 105 N.C. App. 136 (Jan. 21, 1992) ("The parties are in general agreement that prior to 1987, the Commission's and the utilities' general practice was to focus strictly on 'supply-side' considerations in analyzing the long- range needs for electricity in North Carolina. Supply-side considerations relate to <u>increasing the supply</u> of power available to a given utility, either by building new electricity generating units or by purchasing power from other utilities. In June 1987, however, the General Assembly enacted legislation amending N.C. Gen. Stat. 62-2 (The Public Utilities Act's 'Declaration of Policy') by adding a new subsection (3a).") (emphasis in original).

balanced, realistic evaluation of the options can be made." *Order Adopting Rules*, pp. 1-2, Docket No. E-100, Sub 54 (Dec. 8, 1988). Without analyzing, studying, and comparing the unique and individual options available for DEP-West and DEP-East independently, a balanced, realistic, evaluation cannot be completed. Additionally, "[t]he primary thrust of the least cost integrated resource planning strategy under consideration was to integrate both demand-side and supply-side energy planning into a comprehensive program that will weigh the costs and benefits of the available resource options and provide the basis for a balanced evaluation of those options." *Order Adopting Least Cost Integrated Resource Plans*, p. 4, Docket No. E-100, Sub 58 (May 17, 1990). As discussed further below, given DEP's unique commitments to their DEP-West service territory as a part of the Western Carolinas Modernization Project, DEP cannot adequately examine demand-side energy planning for DEP-West when it is combined with DEP-East for a single analysis.

B. FORECASTING

The IRP process requires "a comprehensive analysis of all resource options (supply-and demand-side) considered by the utility for satisfaction of native load requirements and other system obligations . . . ." However, there are differing forecasts for DEP-West and DEP-East that are not accounted for in DEP's single IRP. In fact, DEP acknowledges the differing load forecasts in the two service territories, noting that "events in the East are not always coincident in the West . . . ."

The Commission's rules require that the forecasts filed by DEP are to "include descriptions of the methods, models, and assumptions used by the utility to prepare its peak load (MW) and energy sales (MWh) forecasts and the variable used in the models." Rule R8-60(i)(1). However, the characteristics of the peak loads differ in DEP-East and DEP-

West. As shown in **Table 1** and **Table 2**, DEP expects that DEP-East will fluctuate between a summer peak and a winter peak for several years, while DEP-West is already a winter peaking system. As is shown in **Table 3**, when the two service territories are analyzed in a single IRP, the resulting analysis shows that the combined service territories are already a winter peaking system, which masks the fact that DEP-East is not expected to remain a winter peaking system until after 2023.

Table 1. DEP-East Load Capacity Requirements[4]

SUMMER					WINTER				
Demand Year	Base Retail	Net Before EE	Reductions EE	Net Load	Demand Year	Base Retail	Net Before EE	Reductions EE	Net Load
2016	12,150	12,150	(20)	12,130	2016	11,984	11,984	(2)	11,982
2017	12,324	12,324	(54)	12,269	2017	12,310	12,310	(29)	12,281
2018	12,454	12,454	(87)	12,367	2018	12,443	12,443	(55)	12,388
2019	12,626	12,626	(119)	12,507	2019	12,618	12,618	(80)	12,539
2020	12,701	12,701	(148)	12,553	2020	12,729	12,729	(103)	12,626
2021	12,835	12,835	(174)	12,661	2021	12,735	12,735	(132)	12,603
2022	13,008	13,008	(201)	12,807	2022	12,930	12,930	(153)	12,776
2023	13,227	13,227	(229)	12,998	2023	13,331	13,331	(177)	13,154
2024	13,403	13,403	(254)	13,148	2024	13,526	13,526	(197)	13,330
2025	13,580	13,580	(281)	13,299	2025	13,719	13,719	(217)	13,502
2026	13,737	13,737	(306)	13,431	2026	13,709	13,709	(233)	13,476
2027	13,912	13,912	(328)	13,583	2027	13,894	13,894	(250)	13,643
2028	14,143	14,143	(343)	13,800	2028	14,095	14,095	(261)	13,834
2029	14,316	14,316	(349)	13,967	2029	14,513	14,513	(271)	14,242
2030	14,489	14,489	(349)	14,141	2030	14,712	14,712	(270)	14,442
2031	14,676	14,676	(350)	14,326	2031	14,914	14,914	(272)	14,642
2032	14,807	14,807	(344)	14,464	2032	14,880	14,880	(268)	14,612
2033	14,974	14,974	(348)	14,626	2033	15,061	15,061	(267)	14,794
2034	15,179	15,179	(338)	14,842	2034	15,502	15,502	(262)	15,241
2035	15,360	15,360	(320)	15,040	2035	15,690	15,690	(240)	15,450
2036	15,559	15,559	(303)	15,257	2036	15,910	15,910	(226)	15,684
2037	15,733	15,733	(290)	15,442	2037	15,862	15,862	(218)	15,644
2038	15,891	15,891	(262)	15,629	2038	16,390	16,390	(201)	16,189
2039	16,137	16,137	(252)	15,885	2039	16,489	16,489	(187)	16,302
2040	16,475	16,475	(235)	16,240	2040	16,691	16,691	(174)	16,517
2041	16,586	16,586	(217)	16,369	2041	17,064	17,064	(168)	16,896

[4] *DEC-DEP Response to SACE Data Request No. 1-7*, Docket No. E-100, Sub 147.

Table 2. DEP-West Load Capacity Requirements[5]

SUMMER

Demand Year	Base Retail	Net Before EE	Reductions EE	Net Load
2016	900	900	(1)	898
2017	913	913	(5)	908
2018	925	925	(7)	918
2019	939	939	(10)	929
2020	955	955	(12)	943
2021	966	966	(13)	953
2022	977	977	(15)	962
2023	995	995	(20)	975
2024	1,011	1,011	(22)	989
2025	1,030	1,030	(25)	1,005
2026	1,044	1,044	(24)	1,021
2027	1,059	1,059	(26)	1,034
2028	1,080	1,080	(30)	1,050
2029	1,096	1,096	(31)	1,065
2030	1,114	1,114	(31)	1,083
2031	1,132	1,132	(32)	1,100
2032	1,143	1,143	(28)	1,115
2033	1,160	1,160	(28)	1,132
2034	1,180	1,180	(32)	1,149
2035	1,197	1,197	(30)	1,167
2036	1,213	1,213	(27)	1,186
2037	1,223	1,223	(24)	1,199
2038	1,236	1,236	(21)	1,215
2039	1,252	1,252	(22)	1,229
2040	1,265	1,265	(21)	1,244
2041	1,283	1,283	(20)	1,262

WINTER

Demand Year	Base Retail	Net Before EE	Reductions EE	Net Load
2016	1,140	1,140	(0)	1,140
2017	1,159	1,159	(3)	1,156
2018	1,178	1,178	(6)	1,172
2019	1,199	1,199	(9)	1,189
2020	1,219	1,219	(12)	1,207
2021	1,239	1,239	(15)	1,223
2022	1,260	1,260	(18)	1,242
2023	1,281	1,281	(21)	1,260
2024	1,302	1,302	(23)	1,279
2025	1,325	1,325	(26)	1,299
2026	1,347	1,347	(28)	1,319
2027	1,367	1,367	(30)	1,338
2028	1,387	1,387	(31)	1,356
2029	1,409	1,409	(33)	1,377
2030	1,428	1,428	(33)	1,396
2031	1,451	1,451	(33)	1,418
2032	1,471	1,471	(32)	1,439
2033	1,494	1,494	(32)	1,462
2034	1,516	1,516	(32)	1,485
2035	1,536	1,536	(29)	1,507
2036	1,557	1,557	(28)	1,529
2037	1,579	1,579	(26)	1,553
2038	1,599	1,599	(24)	1,576
2039	1,618	1,618	(20)	1,597
2040	1,648	1,648	(27)	1,621
2041	1,666	1,666	(20)	1,645

[5] *Id.*

Table 3. Combined Load Capacity Requirements of DEP-East and DEP-West[6]

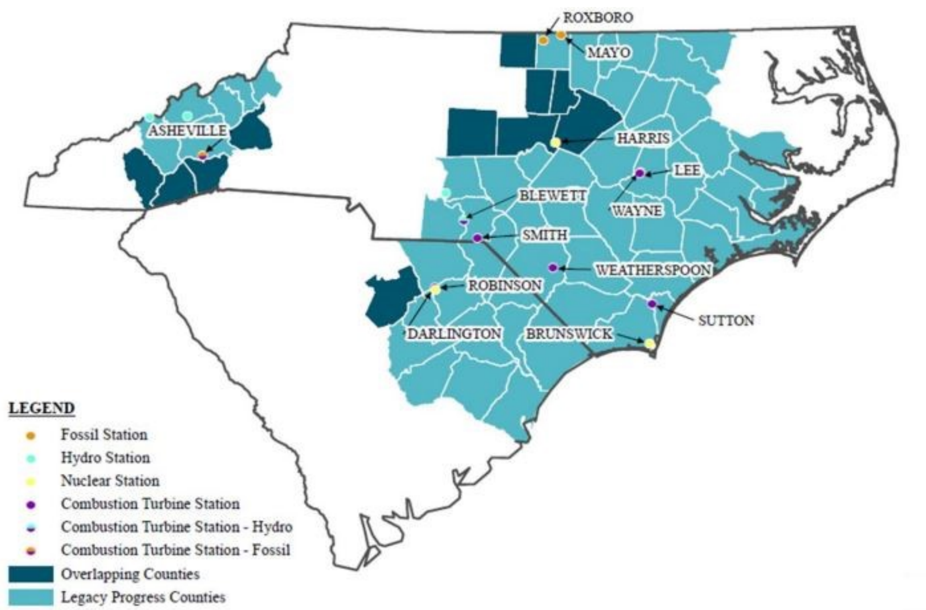
YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2017	13,127	13,158	65,000
2018	13,234	13,277	65,414
2019	13,385	13,442	65,952
2020	13,444	13,542	65,869
2021	13,599	13,728	66,442
2022	13,753	13,918	67,137
2023	13,919	14,107	67,873
2024	14,083	14,300	68,751
2025	14,249	14,488	69,413
2026	14,435	14,689	70,184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

C. Geographic Separation

In addition to differing load forecasts, the DEP-East and DEP-West are two distinct balancing authority areas that have different, independent generating facilities and lack sufficient transmission capacity to allow them to operate as a single entity. As shown in **Figure 2**, the two service territories are geographically isolated and, as set forth below, there are several reasons why the geographic separation of the two service territories should dictate that they be planned differently.

[6] *DEP IRP*, p. 18.

Figure 2[7]



As defined by the North American Electric Reliability Corporation ("NERC"), a balancing authority is "[t]he responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time." *Petition of the North American Electric Reliability Council and North American Electric Reliability Corporation for Approval of Proposed Reliability Standards*, Glossary of Terms Used in Reliability Standards, p. 2, FERC Docket No. RM06-16-000 (Nov. 15, 2006). The balancing authority areas are "[t]he collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area." *Id.* DEP-East and DEP-West are two distinct balancing areas. *See*, *Duke Energy Progress, LLC's Revised Exhibits to Western Carolinas Modernization Project Application*, Revised Exhibit 1B Attachment A, p. 1, Docket No. E-2, Sub 1089 (Feb. 1,

[7] *DEP's 2016 IRP*, p. 14.

2016) ("As a [Balancing Authority], Duke Energy Progress has the responsibility to conduct operational planning to ensure resource adequacy for meeting projected demand, including reserve requirements for its two (2) BA Areas, CPLE and CPLW.").

Further support for the argument that DEP-East and DEP-West should be planned separately comes from the fact that there is insufficient transmission capacity to enable the two to be operated as a single system. In 2016, the North Carolina Transmission Planning Collaborative examined the transmission implications of DEP's Western Carolinas Modernization Project. *See generally, Report on the NCTPC 2016-2026 Collaborative Transmission Plan* (Jan. 13, 2017). As noted by DEP in 2015, there is less than 400 MW of transmission capacity connecting DEP-East to DEP-West. *See*, *Order Granting Application In Part*, *With Conditions, and Denying Application in Part*, Docket No. E-2, Sub 1089, n. 7 (March 28, 2016) ("In its application, DEP asserts that there is a maximum Total Transmission Import Capability of 750 MW into the DEP-Western Region. Of this total, 198 MW must be held in reserve as Transmission Reliability Margin in the event of the loss of the largest single unit in the BAA, currently Asheville Unit 1. DEP also has 164 MW of import commitments. DEP uses the remaining 388 MW of import capability into its West BAA to transfer firm capacity and energy from its East BAA into its West BAA. The West BAA has 865 MW of internal generation and a realized peak load of nearly 1,200 MW."). The NCTPC's 2016 plan identified the need for an additional 436 MW of transmission capacity for DEP-West. *Report on the NCTPC 2016-2026 Collaborative Transmission Plan*, p. 2.

D. DEP's Commitment to the Western Carolinas Modernization Project

DEP has made extensive commitments to the DEP-West territory to implement energy efficiency in an effort to prevent the need for a natural gas peaker plant in coming years. "A partnership between Duke Energy Progress, Buncombe County, and the City of Asheville has been formed to develop innovative energy solutions to meet the area's growing energy needs and avoid the construction of the contingent combustion turbine." *DEP's 2016 IRP*, p. 54. This commitment to DEP-West differs from any commitments that have been made to DEP-East. Additionally, the project is solely benefiting DEP-West. "The Western Carolinas Modernization Project is an energy innovation project for the Asheville area in the western region of DEP. The goal of this project is to partner with the local community and elected leaders to help transition western NC to a cleaner, smarter, and more reliable energy future." *Id.*, p. 7. However, this commitment cannot be fully realized without analyzing the impacts of innovative pilot programs that are, or will be, unique to the DEP-West service territory. By analyzing both service territories in a single IRP, DEP did not conduct sufficient analysis to determine whether the collaborative approach to averting the need for a peaker plant can be successful.

Conclusion

As set forth in these comments, NCSEA requests the following actions be made by the Commission. First, NCSEA requests that the Commission address or determine whether significant reliance on "forward prices" in fuel forecasting is appropriate in the context of the avoided cost proceeding. Second, NCSEA requests that the Commission direct the utilities to quantity and incorporate all value streams provided by energy storage in future IRPs, or in the alternative, direct the utilities to identify the regulatory barriers or their interpretation of Rule R8-60 that currently prevents them from incorporating the full value of energy storage in their IRPs. Finally, due to the extensive and drastic differences between DEP-West and DEP-East, NCSEA requests that the Commission direct DEP to provide separate analyses for their DEP-East and DEP-West service territories in future IRP filings.

Respectfully submitted, this the 17th day of February, 2017.

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CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing Comments by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

This the 17th day of February, 2017.

/s/ Peter H. Ledford
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Exhibit A

DUKE ENERGY CAROLINAS, LLC

Request:

Please provide a detailed description and specific examples of the impacts mentioned on page 23 of the DEC IRP, including, "excess energy challenges during the middle of the day during mild conditions when overall system demand is low." The response should identify the types of impacts, frequency of occurrence, what other generating facilities were operating during these occurrences, reliability concerns, and how the Company is responding to these impacts.

Response:

As discussed below, operationally excess energy on a utility's Balancing Authority (BA) causes a variety of operational and reliability compliance challenges and risks. In particular, in the Carolinas, due to the high levels of unconstrained solar injections into DEC's and DEP's systems, each independent DEC and DEP BA is either: (a) in the case of DEP currently experiencing operationally excess energy due to the unplanned and unconstrained level of solar capacity and ongoing development or (b) in the case of DEC will experience operationally excess energy in the future if unplanned and unconstrained solar development continues. These reliability and operational challenges and risks are caused on a BA at high solar generation deployment levels because solar facilities inject variable and intermittent quantities of energy only during mid-morning to mid-afternoon hours (i.e. approximately 10 am to 3 pm). With respect to the reliability challenges and BA resources needed to provide reliable load following service, please refer to Section III of DEC's and DEP's Joint Initial Statement and Exhibits filed in Docket No. E-100, Sub 148 on November 15, 2016 (the, "Sub 148 filing").

In particular, with respect to DEP, as noted in the Sub 148 filing, DEP has started to experience operationally excess energy events at approximately 844 MWs of installed solar capacity. DEP has experienced at least 20 instances of operationally excess energy occurrences due to operationally excess solar capacity interconnected with the DEP system. As further discussed below, at the time these excess energy events occurred the DEP BA had online and operating at appropriate reliability levels those generating resources that comprised the load following resources for the selected Security Constrained Configuration (defined below), as well as resources necessary to provide reliability regulation support and ancillary services. The DEP BA managed through these operationally excess energy instances by moving the excess energy into another sink

BA, using then available non-firm transmission, at a lower rate than the avoided cost rate. As the Sub 148 filing notes, PURPA solar generators totaling more than 3,700 MWs are either under construction or requesting to interconnect and sell their output to DEP, projecting that solar capacity will continue to grow in DEP over the next few years – increasing to over 1,700 MW of installed solar capacity by the end of 2017 and to approximately 2,200 MWs of installed PURPA solar capacity in 2018. Therefore, the instances of and severity of the instances of these operationally excess energy events are going to increase, making it more challenging for DEP as the BA to comply with mandatory NERC/SERC reliability regulations and increasing risks associated with physically maintaining reliability on the system.

DEP, as the BA must select a set of load following resources that will meet the peak system requirements for the upcoming day and next few days, and that can also be reduced to levels below the mid-day system load, referred to as the "Security Constrained Configuration." DEP also selects a Security Constrained Configuration that can accommodate PURPA injections into the BA; however, the Security Constrained Configuration can only be reduced to certain levels while reliably maintaining regulation, frequency, ramping, and upcoming peak demands (the "Lowest Reliability Operating Level" or "LROL") – or else the BA will not be able to meet those mandatory reliability requirements. Solar facilities are continuing to inject energy into the BA even after the Security Constrained Configuration has reduced its generation output to the LROL – demonstrating that the DEP system in particular has more solar operating capacity (and therefore energy) than the BA system can reliably accommodate.

For reliability, the system must limit the levels of unconstrained PURPA solar generation being injected into the system by way of emergency curtailments and install additional resources to meet regulation and ramping needs; or the system must begin to partially or seasonally decommit its base load resources and replace these resources with flexible generation that will operate before solar facilities begin and after the solar ceases delivery, i.e., from approximately 3 pm in the afternoon to 10 am the next day.

Exhibit B

DUKE ENERGY CAROLINAS

Request:

Please discuss how increased solar generation (including the associated increase in generation ramping requirements) and the new NERC Balancing Control Performance Standards influence the higher reserve margin recommended in the 2016 Study. Please quantify the impact of each of these on the higher reserve margin.

Response:

The increase in ramping requirements of solar generation did not impact the 2016 Resource Adequacy Study. The study was simulated on an hourly basis and did not take into account loss of load or renewable generation curtailment due to insufficient system ramping capability. Since load was shed to protect the minimum regulation requirement in the study, any additional load following required due to solar penetration did not impact this study. If the amount of operating reserves protected by firm load shed were to increase due additional solar generation, then the reserve margin would need to increase. The impacts of increasing penetration of must-take solar may need to be considered in future plans when recommending the types of resources needed to meet the winter reserve margin requirements (high ramp rate, operational flexibility, etc.). Conversely, to the extent future solar additions have automatic generation control technology, this issue would not be as severe.

DUKE ENERGY PROGRESS

Request:

Please discuss how increased solar generation (including the associated increase in generation ramping requirements) and the new NERC Balancing Control Performance Standards influence the higher reserve margin recommended in the 2016 Study. Please quantify the impact of each of these on the higher reserve margin.

Response:

Reference response to PSDR DEC 9-4.

Exhibit C

[CONFIDENTIAL]

Exhibit D

NC Public Staff
Docket No. E-100, Sub 147
NC Public Staff Data Request No. 7
2016 IRP
Item No. 7-8

DUKE ENERGY CAROLINAS

Request:

Has the Company evaluated new pumped storage units or retrofitting of existing hydroelectric units to operate in a pumped storage capacity? If so, please provide a description of the construction costs, timelines for development, and other relevant factors impacting this decision.

Response:

At present, the company has no plans to construct new pumped storage units, nor retrofit traditional hydroelectric plants into pumped storage units.

Exhibit E

DUKE ENERGY CAROLINAS

Request:

Has non-utility owned renewable generation caused the Company to modify its operations of its pumped storage hydroelectric facilities? If so, please provide a narrative on the changes in operation of the pumped storage facilities, including changes in scheduling of recharge or discharge of power.

Response:

The 2016 IRP did not evaluate this issue. This assessment would require running two production cost runs, one with non-utility owned solar and another without non-utility owned solar to then analyze the effect on pump storage operations. No such analysis was conducted in the IRP scenarios.

Exhibit F

DUKE ENERGY CAROLINAS, LLC

Request:

Please provide copies of the battery storage prediction models and deployment plans mentioned on page 140 of the IRP.

Response:

The Energy Storage team is working to determine short term (5 years) and long term (15 years) battery storage predictions and deployment plans. Neither of these is completed at this time and will not be completed for months to come. We have engineering studies underway to help us understand the opportunities in a few regions. Additional regional engineering analysis will continue in 2017 and beyond. The more analysis we complete the more complete the predictions and deployment plans will become. As yet, we have not seen our first analysis results to predict the beginning of our deployment plans.