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May 20, 2019

VIA ELECTRONIC FILING

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

RE: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC Reply Comments
Docket No. E-100, Sub 157

Dear Ms. Jarvis:

I enclose Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Reply Comments for filing in connection with the referenced matter.

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

Sincerely,

Lawrence B. Somers

Enclosure

cc: Parties of Record
Robert W. Kaylor, Esquire

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 157

In the Matter of 2018 Integrated Resource Plans And Related 2018 REPS Compliance Plans	)))))	DUKE ENERGY CAROLINAS AND DUKE ENERGY PROGRESS' REPLY COMMENTS

Pursuant to North Carolina Utilities Commission ("the Commission") Rule R8-60(k) and the Commission's February 8, 2019 *Order Granting Second Extension of Time*, Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (and collectively "Duke Energy" or "the Companies"), hereby submit their Reply Comments to the comments filed by the following parties: the Public Staff; the North Carolina Attorney General's Office ("AG's Office"); Environmental Defense Fund ("EDF"); the North Carolina Sustainable Energy Association ("NCSEA"); the joint comments of the Southern Alliance for Clean Energy ("SACE"), the Natural Resources Defense Council ("NRDC") and the Sierra Club (collectively, "SACE et al." or "SACE"); and NC WARN, Inc. ("NC WARN") in this docket.

INTRODUCTION

The Integrated Resource Plan ("IRP") is a "snapshot in time" view of the Companies' proposed mix of diverse resources to reliably meet customers' needs over the fifteen (15) year planning horizon. The IRP process is lengthy and dynamic. The 2018 IRPs were filed on September 5, 2018, and reflect analysis developed by the Companies beginning in early 2018. Now, nearly 18 months after many of the 2018 IRP inputs and assumptions were developed, the Companies have the opportunity to respond to comments filed by various intervenors in March of 2019.

A consistent theme reflected in numerous consumer statements of position filed with the Commission is a call for accelerated retirement of the Companies' remaining coal plants, less reliance on natural gas or other fossil fuels, and greater reliance upon renewable resources, energy storage, demand side management ("DSM") and energy efficiency ("EE"). These same general themes are expressed in the comments filed by many of the intervenors to this docket. The 2018 Duke Energy IRPs reflect a diverse mix of least-cost generation, storage, DSM and EE resources: in 2019, 46% of DEC's capacity is expected to come from carbon-free resources and 39% of DEP's capacity is expected to come from carbon-free resources. Using the assumptions embedded in the 2018 IRPs, 60% of the combined DEC and DEP energy would come from carbon-free resources in 2019. Of the proposed resource additions over the 2018 IRP planning horizon, 46% of the DEC additions and 23% of the DEP additions would come from renewables, storage, DSM and EE.

However, change is constant in the energy industry, and Duke Energy knows that successful companies are those that recognize and adapt to the changing landscape. Accordingly, the Companies share our stakeholders' desire to provide increasingly clean energy for the benefit of our North Carolina and South Carolina customers. A lower carbon future requires a delicate balancing act with no one-size-fits-all solution, as we must continue to provide all of our customers with safe, reliable and affordable energy. In its 2017 Climate Report to Shareholders and its 2018 Sustainability Report, Duke Energy Corporation reiterated our voluntary goal to reduce carbon emissions 40% by 2030, and noted that our long-term strategy is to continue to drive carbon out of our system. The specific potential path forward and timing to a low-carbon energy future, however, will depend on a number of challenging and uncertain factors, including market forces, public policy, technology innovation/commercialization and customer demand. Duke Energy routinely evaluates retirement of its generation assets, but as Duke Energy considers a course specific to the Carolinas, the Companies will evaluate accelerated retirement of their remaining North Carolina coal units, coupled with other necessary supply and demand-side investments to reliably meet customer needs. Because such plans would not only impact the Companies' future generation mix, but would also impact customer rates, any such accelerated coal unit retirement plans would also need to be considered in ratemaking dockets. Duke Energy intends to make appropriate filings with the Commission in future dockets after it has completed its analysis and reached any conclusions.

Commission Rule R8-60 requires all North Carolina electric suppliers to file comprehensive biennial Integrated Resource Plans ("IRPs") with the Commission on September 1 of each evenly-numbered year, with updates to the biennial IRPs on September 1 of each odd-numbered year. The Commission accepted DEC and DEP's 2017 IRP Updates in its April 17, 2018 Order in Docket No. E-100, Sub 147. DEC and DEP filed their biennial 2018 IRPs on September 5, 2018.[1] Pursuant to Commission Rule R8-60(m), on October 23, 2018, DEC and DEP hosted a stakeholder meeting with interested parties to review their 2018 IRPs. On February 4, 2019, the Commission held a public hearing on the 2018 IRPs.

In its March 7, 2019 Comments, the Public Staff generally supports the Companies' 2018 IRPs and Renewable Energy and Energy Efficiency Portfolio Standard ("REPS")

[1] The Companies obtained a verbal extension from Commission Staff to file their 2018 IRPs on September 5, 2018 due to technical issues.

Compliance Plans as reasonable for planning purposes and compliant with Commission rules and requirements. Some specific findings by the Public Staff include:

- The Utilities used accepted econometric and end-use analytical models to forecast their peak and energy needs. (Public Staff Comments at p. 22); DEP's peak load and energy sales forecasts are reasonable for planning purposes, but the Public Staff noted concerns about DEP under-forecasting its winter peaks (*Id*. at pp. 29; 77-81); and DEC's peak load and energy sales forecasts are reasonable for planning purposes (*Id*. at p. 26);
- DEC and DEP should maintain their reserve margins as filed, but continue to present a 16% reserve margin sensitivity analysis in future IRPs (*Id*. at p. 98);
- DEC and DEP forecasted DSM and EE program savings in compliance with Commission Rule R8-60 and previous Commission orders, as well as the presentation of data related to those savings (*Id*. at p. 50);
- DEC and DEP included 150 MW and 140 MW of nameplate battery storage placeholders, respectively, in their IRPs, and the Public Staff encouraged the Companies to continue to enhance their modeling capabilities as described in the Integrated System Operations Planning ("ISOP") sections of the IRPs (*Id*. at pp. 73-77);
- DEC and DEP should be able to meet their REPS obligations during the planning period, with the exception of the swine and poultry waste set-asides, without nearing or exceeding their cost caps, although DEP may

approach the caps in 2020; and DEC and DEP's 2018 REPS Compliance Plans should be approved as filed. (*Id*. at pp. 113-14).

In many respects, the general allegations asserted by certain other intervenors regarding DEC and DEP's 2018 IRPs are very similar to those considered and dismissed by the Commission in recent past IRP proceedings. In essence, some of those allegations are: DEC and DEP's load forecasts and reserve margins may be too high, and DEC and DEP's IRPs should include greater reliance upon DSM and EE programs and measures and renewable energy resources, with less reliance on fossil fuel resources. No party opposed the Companies' 2018 REPS Compliance Plans. The Companies respectfully submit that their 2018 IRPs and REPS Compliance Plans meet all applicable statutory and Commission requirements and should be approved. The following comments reply to specific initial comments of various intervenors.[2]

REPLY TO INTERVENOR COMMENTS

I. Dominion's Analytic Tool

The Public Staff suggests that the Companies adopt fuel diversity analysis similar to the analysis provided by Dominion in their IRP filings. The Companies' high-level understanding of Dominion's approach is the deployment of a long-term stochastic modeling approach. Under such an approach, long-term fuel prices are statistically simulated over hundreds or even thousands of scenarios to examine a distribution of potential outcomes dependent on the mean forecast of various fuels such as coal, natural

[2] DEC and DEP will not respond to all allegations raised in the parties' voluminous initial comments in these reply comments, as many of these allegations have been raised and rejected in previous IRP proceedings. The Companies' lack of reply to a specific comment by another party should not be construed as an acceptance of their argument. Because of some overlapping topics, the Companies have generally organized these reply comments by subject area, rather than by intervenor.

gas and fuel oil. In addition, statistical parameters such as long-term commodity volatility curves and long-term cross commodity correlations would be required in such an approach. While such an approach provides a comprehensive distribution of potential production cost outcomes, it is dependent upon these forward- looking statistical assumptions that are difficult to ascertain and verify. Currently, parties to the IRP have varying opinions on the long-term fuel price forecasts used by the Company. Moving to a long-term statistical approach greatly expands the debate given the dependence on long-term forecasts of fuel volatility, mean reversion parameters and correlation variables. The Companies continue to assert that the use of discrete fuel price sensitivity and scenario analysis provides a more transparent view of fuel diversity benefits. Furthermore, the Companies' discrete sensitivity and scenario approach is consistent with rule R8-60 that outlines variables such as fuel prices should be varied so portfolio results can be viewed under these varying assumptions.

II. Load Forecast

A. General

As noted above, the Public Staff generally found DEC and DEP's 2018 IRP load forecasts to be reasonable for planning purposes and compliant with Commission rules and requirements. On pages 100 to 103 of its Comments, the Public Staff summarized several recommendations to the Commission regarding the 2018 IRPs and future IRP requirements, and the Companies provide their responses to selected Public Staff recommendations and other comments filed by the Public Staff below:

1. That the Companies continue to review their winter peak equations in order to better quantify the response of customers to low temperatures.

The Companies continue to review and improve the load forecast peak model specifications in accordance with the Commission's Order from the 2016 IRP proceeding (Docket No. E-100, Sub 147). Recently, the Companies completed an extensive review of the entire peak load forecasting process, including load definition verification, peak weather methodology, and model specification. The results were summarized in the 2018 IRPs.

The peak forecast model objective is to provide a reasonable forecast of future peak demand under the assumption of <u>normal peak conditions</u>. Note that extreme historical peak demand and weather conditions are captured both in the history used by the peak model, as well as in the weather normalization processes. The Companies caution that any additional attempt to directly or intentionally model extreme peak conditions within the current IRP peak model process would increase the probability of over-forecasting peak demand.

2. That DEC include in its forecasted load the projected impact of Integrated Volt-Var Control ("IVVC") programs.

NCSEA alleged that Duke Energy continues to promote its grid improvement plans, but does not reflect it in its IRPs.[3] NCSEA notes that Duke Energy's grid improvement plans, which would prepare the grid for decentralized, distributed generation over a 10-year period, includes IVVC, a voltage management program, which will allow Duke Energy to manage distribution circuits (to reduce impacts to customers with large motors sensitive to voltage control) and allow the utilization of peak shaving and emergency modes of operation. (NCSEA Comments, pp. 10-13) The original grid improvement plan proposed by the Companies in DEC's last general rate case in Sub 1146 did not contain a

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[3] NCSEA Comments at p. 11.

DEC IVVC program. Based upon stakeholder feedback received through the subsequent grid improvement stakeholder workshops hosted by Duke Energy, the Companies have added a DEC IVVC program and plan to reflect the DEC IVVC program in future IRPs.

3. That DEC and DEP continue to review their load forecasting methodology to ensure that assumptions and inputs remain current and that appropriate models quantifying customers' response to weather, especially abnormally cold winter weather events, are employed.

In response to the Commission's request in 2016, the Companies completed a thorough review of the peak forecasting methodology in 2018, which led to raising the peak forecast significantly. The Companies agree with the Public Staff that the revised methodology provides a reasonable forecast of normal peak demand. The peak forecast process is also continuously adapting to changing weather and demand trends as it receives additional history. This process will result in higher forecasted peaks if extreme winter weather becomes more prevalent. The process will also prevent the models from over-reacting to one or two years where extreme winter weather was an outlying event. An example of this would be comparing the winter of 2017-18, which was a very extreme winter from a demand perspective, to the winter of 2018-19, which was very mild.

Finally, the Companies would caution against attempting to model extreme winter peaking conditions, noting that one of the key drivers of the Companies' 17% reserve margin is to cover such events. Attempting to model customer responsiveness to extreme weather would force the Companies to make broad assumptions about customers' actions during an extreme peak period that could lead to significant over-forecasting of peak demand.

4. That the Companies include in future IRPs and updates a discussion of their use of data from smart meters to inform their load forecasting, cost of service studies, and rate designs.

The Companies agree that smart meter data has the potential to be very informative from a load forecasting perspective. In addition, the Commission has initiated a rulemaking on certain data access issues in Docket No. E-100, Sub 161, which is pending and may help inform the load forecasting review. The Companies also note, however, that the Commission has existing Smart Grid Technology Plan dockets, which provide the Commission and parties with extensive information about smart meters and how DEC and DEP are utilizing this technology and data issues, so the Companies do not believe that additional formal reporting should be required in the IRPs. Nonetheless, the Companies will update the Public Staff on their progress in incorporating smart meter data into the load forecasting process.

B. Reply to SACE et al. Load Forecasting Comments

SACE et al. consultant, James F. Wilson of Wilson Energy Economics generally found DEC and DEP's 2018 IRP load forecasts to be reasonable for planning purposes and compliant with Commission rules and requirements. On pages 21 to 23 of his Evaluation of Load Forecasts, Mr. Wilson summarized several recommendations to the Commission regarding the 2018 load forecasts, to which the Companies are providing their responses to selected recommendations below:

1. The Companies should research the drivers of the very high loads that have occurred in each service territory under very cold weather.

The Companies agree with the Public Staff's assessment in their 2018 IRP comments on this issue: That primary drivers of high peak demand during extreme temperatures are the predominance of electric heat pumps, and the lack of availability of natural gas as a heating source. These factors are more significant in DEP than in DEC territory, which is indicative by how much more sensitive the DEP region is to extreme winter weather. The Companies will continue to share information on this topic with the Public Staff and other intervenors as more information becomes available.

2. **The Companies should develop a more sophisticated model of how extreme winter weather affects their loads, drawing upon the experience gained over the past five years. The focus should be on accurately modeling not just the usual (that is, long-term typical) peak-producing weather, but also more extreme conditions, which have occurred in recent years and can cause loads well above the usual annual peaks. Detailed analysis might show, for example, that an average of temperatures over an extended period leading up to the morning peak hour (perhaps 12 preceding hours) better predicts the peak than the single hourly or daily average temperature, and that other conditions, such as wind speeds and cloud cover, also have predictive value. A similar model for extreme summer weather could also be developed.**

It is the Companies' understanding that the peak forecast should provide a reasonable forecast of system demand, under the assumption of peak normal weather. The model does account for any historical extreme weather and peak conditions within the past 7 years for model specification, and the past 30 years for the development of peak weather normal conditions. The Companies disagree with the suggestion to modify the current peak model to capture extreme conditions, as this would conflict with the NCUC's Order from the 2016 IRP proceeding, Docket No. E-100, Sub 147. More specifically, such a modification would increase the standard errors of the peak model coefficients, resulting in a peak forecast that will not satisfy the NCUC's mandate of a peak forecast that predicts probable growth. Note that although both jurisdictions have seen several extreme winters recently, these few data points are clearly outliers. Structuring the peak model to model historical outliers would result in peak forecasts that may drastically over-or under-forecast peaks, even under normal circumstances. Finally, the Companies do not share Mr. Wilson's perception regarding the lack of sophistication of the peak models. The Companies continuously evaluate the peak model specifications to improve peak forecast accuracy, in accordance with the Commission's Order from the 2016 IRP proceeding, Docket No. E-100, Sub 147.

3. The Companies should provide more comprehensive documentation of their peak load forecasting methodology. The Companies should consider enhancing their approach to make use of a broader set of high load data (not just monthly peaks), and an enhanced relationship between weather conditions and load as described above. The Companies should also consider providing sensitivity analysis of the peak forecasts to key drivers and assumptions, to demonstrate whether the forecasts are likely to be stable over time, or instead may change substantially due to new data.

The Companies are committed to transparency regarding all aspects of the load forecast methodology. The Companies cannot endorse Mr. Wilson's recommendations suggested above, which would conflict with producing a reasonable peak forecast, as mandated by N.C. Gen. Stat. § 62-110.1(c). Finally, the Companies question how Mr. Wilson defines "stability over time." The Companies' peak models use actual monthly peaks and the average daily weather on the day of peak as inputs. In recent years, some of these historical data points reflect extreme or mild peak conditions. While Mr. Wilson may perceive these extreme historical data points as instability, the Companies view each historical data point as vital information that will provide guidance in identifying vital information that leads to improving load forecast accuracy.

4. The Companies should develop a more effective method for estimating historical weather-normalized peak loads. Weather-normalized values are very useful for understanding load trends, and the Companies' new approach appears to have shortcomings (the approach used in the 2016 IRPs accounted for weather variation more completely). The more

sophisticated model of how weather affects loads, recommended above, should contribute to a more accurate weather-normalization methodology.

The Companies agree with Mr. Wilson about the importance of the peak weather-normalization process in understanding peak history and evaluating peak forecasts. The Companies also agree that our methodology is "imperfect," as are all our processes (and those of every load forecaster who attempts to predict the future), due to the dynamic nature of load forecasting. However, the Companies disagree with Mr. Wilson's following assertions regarding our weather-normalization process:

- Mr. Wilson's comments inaccurately describe the Companies' weather-normalization process via simplification, compared to the summary description provided in the 2018 IRPs.
- Mr. Wilson asserts that the Companies recognize that the weather normalization process is "imperfect" and does not fully remove the impact of actual weather. The Companies agree that the methodology is imperfect, primarily due to the natural chaotic behavior of weather. Specifically, the more extreme (normal) peak conditions are, the less (more) likely the peak normalization process will be to capture weather impacts accurately.
- Mr. Wilson refers to the previous weather-normalization process (2016 IRP) as being superior to the current methodology. Mr. Wilson mistakenly describes our process as focusing solely on the peak day. Part of our revised peak weather normalization process implicitly includes a "build-up" effect from the previous day(s) of the peak. This enhancement has proven to be more effective in generating peak weather normal than the previous methodology, which focused solely on the

coldest day, which may or may not have aligned with the day of peak. It is important to note that Mr. Wilson's comments appear to be directed more at extreme peak events, which are outliers in history, versus the normal peak demand history that typically occurs.

- The Companies dispute Mr. Wilson's assertions that the weather-normalization process does not produce a clear historical trend. Tables C-5 and C-6 of the 2018 IRPs provide annual historical trends of DEC and DEP actual and weather normal peak trends. In comparison, Mr. Wilson's charts (JFW-5 to JFW-8) provide an "alternate" view of this data by narrowing the magnitude of the Y-Axis, which gives the perception of nonlinearity. Finally, Mr. Wilson asserts that the Companies' peak weather normal history should be a steady linear trend. In his comments, he assumes that the underlying drivers of the peak weather-normalization history were relatively stable. However, from 2011 to 2018, both DEC and DEP saw various economic, weather, industrial, and jurisdictional load definitions disruptions that impacted the weather normalization process.

5. With respect to wholesale loads, the Companies should provide historical aggregate wholesale firm commitments. Weather-normalized historical peaks should be estimated for the wholesale customer loads separately (and such estimates should exclude quantities associated with any short-term wholesale transactions that may have been in place at the time of the peak). The Companies should further evaluate wholesale customers' contribution to system peak loads, which affect required reserve margins and capacity needs.

The Companies currently incorporate an energy and demand forecast methodology like the retail energy and peak forecasts, with the following exceptions:

- All forecasts are econometric models; and

- The Companies do not forecast North Carolina Electric Membership Corporation ("NCEMC") and North Carolina Eastern Municipal Power Agency ("NCEMPA") contracts per agreement, and incorporate those forecasts into the system forecast as given.

III. Natural Gas Prices

A. The Companies disagree with Public Staff's recommendation to revise the natural gas fuel price forecast used in developing the generation expansion plans to use no more than five years of forward market data before transitioning to the fundamental forecast.

As the Public Staff references in their comments, the duration that the Companies use market-based natural gas prices prior to transitioning to fundamental natural gas forecasts has been the subject of extensive testimony and discussion before the Commission, most recently in the initial comments filed by parties in the 2018 avoided cost proceeding in Docket No. E-100, Sub 158. The Public Staff references the "same arguments and perspectives it raised on pages 21-28 of its February 12, 2019, initial comments in Docket No. E-100, Sub 158"[4] where they argued that the Companies should use five years of market data before switching to the fundamental forecast.

The Companies similarly incorporate by reference their Reply Comments, filed on March 27, 2019 in Docket No. E-100, Sub 158 on pages 10-19, as evidence for continuing to rely on 10 years of forward market data in the Companies' filed IRPs. Specifically, the Commission directed the Companies to maintain consistency between the fuel forecasts presented in their IRPs and those used in their avoided cost filings and that "to the extent the Utilities wish to propose changes in the way they utilize forward prices and long-term

[4] Public Staff IRP Comments at p. 71.

forecasts…these changes should be made in the Utilities' biennial [IRPs], and the same approach should be used in their biennial avoided cost filings for that same year."[5] Generally, the Companies make the following arguments as part of a broader discussion of natural gas prices in the referenced reply comments:

- The Companies' customers are facing a $4.5 billion long-term financial obligation and $2 billion overpayment risk as a consequence of an unprecedented number of Qualifying Facilities ("QFs") obligating the Companies to purchase their output, coupled with the use of lagging and inaccurate fundamental forecasts to calculate avoided cost rates.
- As demonstrated by the continued, regular purchase of 10 years of forward market natural gas, the market for purchasing 10 years of forward market natural gas is liquid.
- In these regular purchases of 10 years of forward market natural gas, the Companies obtained multiple price quotes, each with similar prices, evidencing that there are multiple sellers in the current 10-year natural gas market, and there is a lack of price volatility in the 10-year forward natural gas market.
- The Companies are not alone in North Carolina in their ability to purchase 10-year forward natural gas, as another market participant in North Carolina (name filed under seal in Docket No. E-100, Sub 158) purchased significant quantities of 10-year forward natural gas.

[5] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities,* at 27, Docket No. E-100, Sub 140 (Dec. 17, 2015).

The Companies uphold that using 10 years of forward market natural gas prices in their IRPs is appropriate for evaluating future generation needs and allows for an appropriate head-to-head comparison of long-term purchase power obligations from QFs required under PURPA.

B. Contrary to the AG's Office suggestion, the Companies already consider the impacts and future costs from natural gas price volatility in their filed IRPs.

On page 10 of its comments, the AG's Office asserts as a concern that, "Duke's reliance on natural gas raises a risk that ratepayers will face unanticipated, unmodeled costs from natural gas price volatility." This concern, however, is precisely why the Companies consider a range of future fuel price scenarios, including high and low natural gas prices, in the development of their IRPs. As described in Chapter 13 of the 2018 DEP IRP and Chapter 12 of the 2018 DEC IRP, and in greater detail in Appendix A of both IRPs, the Companies consider natural gas prices that are both significantly lower and significantly higher than base assumptions in both the short and long-term. The impacts of these sensitivities on each of the seven portfolios are detailed in the above referenced sections in the IRP. The AG'S Office suggestion that Duke does not "thoroughly evaluate…potential future costs from natural gas price volatility" is inconsistent with the analysis that is actually filed in the Companies' IRPs. It should be noted the AG's Office does not mention the risk of falling gas prices that has contributed to the current projection of a $2.5B customer overpayment for solar QF generation that was based on natural gas price forecasts significantly above the current market prices for natural gas.

IV. Rate Impacts Included in IRP

In Docket E-100, Sub 147, the Public Staff previously recommended that DEC and DEP "file a residential rate analysis of the proposed expansion plans, along with a comprehensive risk analysis that addresses similar key risk factors employed by DNCP" in future IRPs. The Commission did not rule on the issue of including a residential rate analysis of the proposed expansion plans in its June 27, 2017 *Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans* in Docket No. E-100, Sub 147 ("2016 IRP Order").

However, in the 2016 IRP Order, the Commission stated that "The Commission recognizes that risk analyses, such as that utilized by DNCP, may better inform the Integrated Resource Planning process. However, the Commission is without sufficient evidence of the value derived from such risk analyses to require DEP and DEC to utilize similar analytical tools in the development of their IRPs."[6] As such, the Companies will continue to perform sensitivity analyses on multiple variables in future IRPs. These sensitivities are intended to determine the impacts to portfolios when variables are stressed. Therefore, the sensitivities are utilized to help mitigate risks of the selected portfolio to the customer.

V. Capacity Value of Solar and Storage

On page 85 of its Comments, the Public Staff states its concern that "there is a disconnect between how Duke plans to meet its peak system load and how it values the capacity contribution of solar resources." A remedy is proposed by the Public Staff to

[6] *Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans,* Docket No. E-100, Sub 147 (June 27, 2017) at 61.

calculate the Capacity Value of Solar utilizing a Coincident Peak methodology which would address the perceived disconnect between Peak Load Hours and High Risk Hours.

Although Duke Energy does not yet have access to the models used by the Public Staff in determining the Coincident Peak methodology,[7] the Companies are trying to ascertain why the Public Staff's proposed capacity values in Table 11 remain static despite the fact that possibly over 10,000 MW of solar capacity could be installed in the Carolinas over the next 15 years. In Tables S5 and S6 of the Capacity Value of Solar ("CVS") study completed by Astrape Consulting, each additional tranche of solar capacity provides diminishing marginal capacity value to the system.

Astrape calculated its results in the CVS study by modeling thousands of iterations in its proprietary Strategic Energy Risk Valuation Model ("SERVM") using 36 different weather years developed from a National Renewable Energy Laboratory ("NREL") dataset dating back to 1980. Both the seasonal and hourly pattern changes were captured across different solar penetration levels. As solar increases across the system resulting in optimal performance on sunny days, system Loss of Load Expectation ("LOLE") shifts to the winter; firm load shed events no longer occur during solar hours and become more prominent during hours of little to no daylight. The Companies cannot ascertain from Figure 7, Table 10, or Table 11 in the Public Staff's comments that any research into the shift in LOLE has been performed, which therefore does not support fixed winter/summer capacity values that do not adapt to the level of solar installed on the DEC and DEP systems. The Companies would like to continue the ongoing dialogue with the Public Staff on this and other proposed calculations.

[7] The Companies did not send a timely data request to the Public Staff to gain this information, but the Public Staff has graciously agreed to provide the information requested by the Companies in a late data request.

As further support for the Companies' probabilistic approach to valuing solar capacity, the Companies refer the Commission to the direct testimony of Brian Horii[8] on behalf of the South Carolina Office of Regulatory Staff in PSCSC Docket No. 2019-2-E. On page 8 and beginning on line 17 of his testimony, Mr. Horii's states as follows:

> E3 has been at the forefront of evaluating the impact of renewable resources on utility planning and operations. Through our work it is clear that resources such as wind and solar generation must be evaluated using probabilistic methods that evaluate all hours of a given period, not just a single peak hour. Moreover, the importance of probabilistic models is generally recognized across the industry, as noted by the North American Electric Reliability Corporation's ("NERC") *Probabilistic Adequacy and Measures Technical Reference Report (April, 2018): There is a recognized need to support probability-based resource adequacy assessment resulting from the changing resource mix with significant increases in variable and energy-limited resources (intermittent in nature), changes in net demand profiles resulting in the shifting of the hour of the peak demand, and other factors can have an effect on resource adequacy. (NERC, p.6)*

In his testimony, Mr. Horii disputes the appropriateness of using a coincident peak hour approach to valuing the capacity contribution of solar generation and notes that such an approach fails to recognize the capacity value provided not just by output at the time of the peak hour but also by the output during the myriad of other peak hours for which there is a non-zero risk of the utility being unable to meet all customer demand.[9] Mr. Horii further referenced the detailed hourly solar capacity value studies performed by Astrape Consulting for DEC and DEP to infer a capacity value contribution for incremental solar for another utility's system.[10]

[8] Mr. Horii is a Senior Partner with Energy and Environmental Economics, Inc. ("E3") and was retained by the South Carolina Office of Regulatory Staff ("ORS") to assist in the analysis of South Carolina Electric & Gas Company's avoided cost calculations, and review the Value of Distributed Energy Resource ("DER") methodology, in SC Docket No. 2019-2-E.

[9] Brian Horii Direct Testimony in PSCSC Docket No. 2019-2-E, at 8.
[10] Brian Horii Direct Testimony in PSCSC Docket No. 2019-2-E, at 10-11.

A. The Companies disagree with the AG's Office assessment that the Companies may be undervaluing the peak load contribution of solar technologies.

The AG's Office disputes the Companies' assertion that additional solar resources beyond those shown in the 2018 IRPs have limited value because additional solar capacity only provides negligible contribution to meeting peak load needs (AG's Office IRP Comments, pp. 3-4). The AG's Office cites a "study performed by the National Renewable Energy Lab [NREL] in California, where solar resources have a higher penetration rate" as the basis for the argument that solar resources may have more capacity value than that attributed by the Companies. *Id*. While North Carolina is #2 in the U.S. in installed solar behind only California, the AG's Office argument is flawed for two reasons: (1) California has significantly higher solar irradiance than North Carolina, and (2) California's electricity demand profile is significantly different than North Carolina's electricity demand profile simply based on the range of temperatures seen in California versus North Carolina, as well as different sources of heating and cooling in the two jurisdictions. The Companies point out that consumers in North Carolina and South Carolina have significantly higher energy needs due to much greater electrical heating and cooling demand than California. Simply put, regional differences in solar output as well as customer usage profiles make such a comparison meaningless. The AG's Office's use of a study that is based on California electricity demand and solar conditions to criticize Duke Energy for not placing enough value on solar in North Carolina - - when North Carolina is second to only California in installed solar capacity - - is disappointing.

B. The Companies acknowledge that inclusion of additional storage and solar plus storage resources in the IRPs may be warranted, as suggested by the AG's Office; however, Duke Energy is committed to studying

the true value of energy storage on the DEP and DEC systems before arbitrarily assigning value in the IRPs.

For the first time, the Companies included battery storage as a resource in the 2018 IRPs. In total, DEC and DEP included nearly 300 MW (nameplate) of lithium-ion battery storage as capacity resource placeholders which were assumed to provide 80% of their nameplate capacity towards meeting the Companies' winter peak capacity needs per the Electric Power Research Institute ("EPRI") study cited in the 2018 IRPs. Additionally, the Companies acknowledge in the IRPs that "Battery storage costs are expected to continue to decline, which may make this resource a viable option for grid support services, including frequency regulation, solar smoothing during periods with high incidences of intermittency, as well as, the potential to provide overall energy and capacity value."[11] Furthermore, despite the AG's Office assertion that Duke Energy "does not thoroughly evaluate [the downward trend of storage technology costs],"[12] to the contrary, the Companies' IRPs assume that battery storage costs drop by nearly 40% by year 2025 in the IRP Base Case.[13] Additionally, the Companies' IRPs include an aggressive capital cost sensitivity that would further the decline in battery storage costs to 60% by 2025. Finally, the Companies include a sensitivity of replacing a future undesignated CT with a grid-tied battery storage option in both the DEC and DEP IRPs.[14]

Even though the Companies acknowledged the potential benefits of storage, included steep cost declines for battery storage technologies, evaluated a sensitivity of

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[11] DEC IRP p. 33; DEP IRP p. 33.
[12] AG's Office IRP Comments, p.5.
[13] DEC IRP p. 101; DEP IRP p. 102.
[14] Portfolio #7 (CT Centric / High Renewables with Battery Storage) is assessed in variety of CO_2, fuel price, and capital cost scenarios.

replacing a future CT with battery technology, and went as far as to include upwards of 300 MWs of battery storage as capacity assets in the DEC and DEP IRPs, the AG's Office argues the Companies did not go far enough by not evaluating multiple storage plus solar technologies. There is the potential for battery storage technologies to provide value to the DEP and DEC systems, but pairing storage with solar to allow "the storage component to benefit from federal investment tax credits"[15] as suggested by the AG's Office may not always be in the best interest of the Companies' customers. Because North Carolina's peak conditions occur in both summer afternoon and winter mornings and afternoon, and can be at least several hours in duration, there may be limitations to the capacity value of batteries, particularly batteries charged solely from solar resources. Furthermore, on May 10, 2019, the NCUC issued its *Order Granting Certificate of Public Convenience and Necessity with Conditions* for the DEP Hot Springs Microgrid Project, which is a combination 3 MW (DC) solar and 4 MW lithium-based battery energy storage system. The Commission held that although it is not clear that the Hot Springs Microgrid is the most cost-effective way to address reliability and service quality issues at Hot Springs, the overall public convenience and necessity would be served by granting the CPCN for the solar generation components of the microgrid because the system benefits of the microgrid are difficult to quantify and DEP will gain valuable experience by operating the Hot Springs Microgrid as a pilot project. The Commission further stated that it supports "cost-effective development of solar and battery storage by DEP . . . and encourages DEP to continue to pursue such projects on behalf of its customers." Hot Springs Order at p. 17.

[15] AG's Office IRP Comments, p. 4.

Duke Energy is committed to further studying the capacity value of incremental battery storage (both grid-tied storage and solar plus storage systems) in the Carolinas at increasing penetration levels. Like the Capacity Value of Solar study, the Companies completed in 2018, a similar study is required to study the capacity value of storage. A study of this type is both time and data intensive; however, the Companies expect to include the results of a capacity value of storage study as early as the Companies' 2020 biennial IRP filings.

C. NREL Study

NCSEA alleged that the fact that Duke Energy is studying how the grid can accommodate renewable energy penetration of 50% of peak demand somehow "undermines the credibility of their own IRPs, and calls into question how Duke has modeled clean energy resources."[16] NCSEA further alleged that their Synapse study shows that Duke Energy has "unfairly marginalized clean energy resources." *Id.* NCSEA also cited the Virginia State Corporation Commission's rejection of Dominion's IRP because of failure to adequately model clean energy resources. (p. 14)

Duke Energy plans to study a number of scenarios. The entire study including Phase II will take as much as two years and possibly longer to complete, which would not be timely for the current IRPs. When Duke Energy's General Manager, Distributed Energy Technologies Renewable Integration & Operations, Ken Jennings, recently spoke at the University of North Carolina at Chapel Hill, he acknowledged that Duke Energy will be examining a number of scenarios but did not state that the system would definitely be able

[16] NCSEA comments at p. 14.

to accommodate that much intermittent solar. He also mentioned that the study would be similar to the TECO Study which states that:

> Must-Take solar becomes infeasible once solar penetration exceeds 14% of annual energy supply due to unavoidable oversupply during low demand periods, necessitating a shift to the Curtailable mode of solar operations. As the penetration continues to grow, the operating reserves needed to accommodate solar uncertainty become a significant cost driver, leading to more conservative thermal plant operations and increasingly large amounts of solar curtailment.

The TECO Study further states:

> The energy value on the TECO system of additional solar energy in Curtailable operating mode decays rapidly above about 14% solar energy penetration. The energy value (or, equivalently, the production cost savings) is calculated as the change in annual production costs as solar penetration increases, excluding the capital cost of additional solar resources. Solar provides very little marginal energy value at penetration levels above 19%. In the extreme – above 23% solar energy production potential – solar has a negative marginal energy value.

At that time, Duke Energy did not know exactly what the scenarios would be. Currently, Duke Energy projects for Phase I a penetration level as high as 35% solar as a component of energy rather than summer peak demand, which is about 28,000 MW of solar and actually closer to 70% of summer peak demand. Absent results from both the Phase 1 and Phase II versions of the study, it would be imprudent to make assumptions about the utility's ability to manage such levels of intermittent solar, and if the results of the NREL study are similar to the results of the TECO study, such levels of intermittent solar may actually require more thermal generation than is currently called for in the IRPs.

VI. Statement of Need Section in IRP

The Companies determine each utility's future (avoidable) generation need based on the difference between customer demand, net of energy efficiency, and the sum of the utility's existing resources and projected resources, to meet a required annual planning reserve margin (currently 17% for both DEC and DEP). When this difference causes the annual planning reserve margin to fall below 17%, a new resource is required in order to reliably meet customer needs. DEC's and DEP's IRP models select the most economic resources to meet customers' needs in the first year that a new capacity resource is required to maintain the planning reserve margin.

In its filed comments, the Public Staff stated that, "the assumptions made regarding qualified facility (QF) capacity; the treatment of QF contracts that expire within the planning period, planned utility uprates, energy efficiency programs, load assumptions, generation unit retirement assumptions, and avoidable and unavoidable planned generation units, all directly impact the first year of capacity need, which is used to calculate avoided capacity payments in the Avoided Cost proceeding. It is clear from the initial comments in Docket No. E-100, Sub 158 (2018 Avoided Cost), that these assumptions have not been clearly specified by each of the Utilities."[17] The Public Staff goes on to recommend that "the Utilities, in their IRP Update to be filed in 2019 and all future IRPs and updates, include a new Utility Statement of Need section." Utilities could then reference this in biennial avoided cost proceedings, establishing clearly the first year of capacity need for the calculation of avoided capacity payments."[18] The Public Staff believes that, at a minimum, the proposed Statement of Need section should include the following:

1. The year in which the Utility would fall below its planning reserve margin without commitment(s) to procure additional resources.

[17] Public Staff Comments, p. 90 Paragraph 1.
[18] Public Staff Comments, p. 90 Paragraph 2.

2. Whether QF contracts expiring within the Avoided Cost term are renewed / replaced in kind, or excluded.
3. Whether Utility uprates are solely installed for additional capacity and if they could be considered avoidable.
4. Whether new EE measures are included in the determination of capacity need.
5. The quantity of MW needed in the first year, and a discussion of whether avoided capacity payments will be made to QF contracts executed in excess of that capacity.
6. The year in which the Utility's first avoidable capacity need becomes unavoidable.
7. Whether it is appropriate to create a separate "Avoided Cost Portfolio" in the IRP's portfolio analysis section, which might present a more objective determination of capacity need that could ensure QFs providing capacity are not treated as captive.

The Companies agree with Public Staff's recommendation and will include a Statement of Need section to more clearly identify the undesignated capacity needs for each utility in DEC's and DEP's 2019 IRP Updates and in future biennial IRP filings.

VII. QF Contract Expiration in the IRP

In its Initial Comments, NCSEA takes exception with the method used by Duke Energy in the treatment of QF contract expirations in the IRPs. NCSEA states that, "despite the fact the PPAs with QFs will eventually expire, Duke assumes that the PPAs will 'be either renewed or replaced in kind.' However, there is no guarantee, or requirement, that a

QF will continue to provide the utility with capacity past the end of its initial PPA, even if the QF has remaining operational life." [19] This statement was made in reference to a data request response provided by the Companies to the Public Staff in this docket.[20]

This data request response refers specifically to solar QFs, as existing QFs of any other technology are assumed to retire at the end of the contract term. Solar capacity, however, will continue to grow in the future, increasing the Companies' planned solar capacity. As such, the capacity of existing solar QFs will either be procured by the renewal of existing contracts or replaced with other solar PPAs. Whether the capacity is from an existing QF or another QF does not matter in the context of the IRP, only that the capacity comes from a solar resource.

NCSEA goes on to allege that "Duke assumes for planning purposes that a QF's PPA will be renewed despite the fact that it has made numerous efforts in other proceedings to make it more difficult for a QF to renew a PPA,"[21] going on to cite Docket No. E-100, Sub 101 and Docket No. E-100, Sub 158, as examples. Both dockets cited by NCSEA have to do with the upgrade of QF equipment, which is in no way impactful to the 2018 IRPs.

NCSEA continues its argument by stating that "other wholesale PPAs are removed from DEC and DEP's respective generation stacks when they expire and create capacity needs. However, Duke treats PPAs with QFs differently in its planning process."[22] It is true that DEC and DEP have consistently assumed across multiple planning cycles that all wholesale purchase contract capacity is removed in the year after a wholesale contract

[19] NCSEA's IRP Comments, p. 25, Paragraph 1.
[20] Duke Energy Carolinas, LLC's Response to Public Staff Data Request No. 6-4 and Duke Energy Progress, LLC's Response to Public Staff Data Request No. 4-12, included in NCSEA's Comments as Attachment 2.
[21] NCSEA's IRP Comments, p. 25, Paragraph 2.
[22] *Ibid*. p. 26, Paragraph 1.

expires and that QFs are not presumptively assumed to establish a new Purchase Power Agreement ("PPA") to deliver capacity and energy to the Companies over a new fixed term in the future. If, however, the QFs have already executed a contract extension or renewal with the Companies, the specific contract capacity will be included past the original contract expiration year to the new year of expiration of the extended/new contract. Thus, the existing QF contracts may either be renewed, or replaced with other new solar facilities so that in total the aggregate solar penetration reaches levels projected in the IRP. The IRP is agnostic as to which choice is made but rather focuses on an expected level of solar penetration. Furthermore, the IRPs present scenarios with both higher and lower levels of solar penetration that are also agnostic to the decision of renewal versus replacement with new solar facilities. It must be noted that this is consistent with the approach for all contracted generation. For example, at the time DEP's 2018 IRP was filed, several natural gas PPAs were expiring. The IRP did not explicitly assume these contracts were renewed but rather put in a generic undesignated PPA that was deemed avoidable by QFs for the purpose of establishing avoided cost rates. Therefore, NCSEA's argument that the Companies are treating existing QF contracts differently and unfairly in the IRPs is untrue.

Based upon the foregoing circumstances, the Companies continue to find their IRP planning approach of assuming a capacity reduction after expiring QF contracts reasonable and consistent with the objectives of their IRPs to determine the long-range generation needs to reliably serve their customers' energy needs in North Carolina. Thus, DEC and DEP are justified in removing from their respective IRPs the third-party wholesale contract capacity (both QF and non-QF) in the year when the contract expires.

The Companies have taken a reasonable and consistent approach to recognizing expiring wholesale purchase contracts, including QF contracts, in their 2018 IRPs. The Companies' IRPs actually assume that, upon expiration of any third-party wholesale purchase contract (both QF and non-QF), the Companies recognize a reduction in capacity by the amount of the capacity provided in the expiring wholesale purchase contract in the year following contract expiration. This approach to capacity planning is not new. Since the Duke Energy/Progress Energy merger, the Companies' 2012, 2014, 2016, and 2018 biennial IRPs have all consistently assumed the expiration of wholesale purchase PPAs, including QF PPAs, that result in a need for replacement capacity to be procured through each utility's resource planning process to meet the targeted reserve margin during a given year. Thus, the expiration of each PPA has the potential to impact the timing of the Companies' first capacity need, particularly when viewed in aggregate with other contract expirations or retirements. Fundamentally, it is prudent resource planning not to rely upon assumed future third-party owned capacity in years where no contract or other legally-enforceable commitment guaranteeing delivery exists.

VIII. Climate Change

A. The Companies agree with the AG's Office that incorporating environmental considerations into resource planning is critical even if specific standards are not yet defined in environmental regulations, which is why the Company models the potential costs of future CO_2 legislation as part of their comprehensive scenario analysis described in the IRP.

As described in Chapter 13 of the DEP IRP and Chapter 12 of the DEC IRP, and in more granular detail in Appendix A of both IRPs, the Companies analyzed the potential costs associated with multiple government-imposed limitations on greenhouse gas emissions. These CO_2 sensitivities are placeholders for future legislations, and the IRPs reflect the costs associated with the implementation of those potential regulations. Any benefits to the Companies' customers associated with those potential regulations are largely driven by state and federal rules and standards that are also evolving and will influence how technologies are deployed. To be clear, the IRP does not set policy, but it responds to regulations and can provide a view of the impacts of potential regulations, as the Companies have shown with potential greenhouse gas emission regulations.

B. The Companies support lowering carbon emissions, and the IRPs are consistent with Duke Energy's Sustainability Report. Furthermore, the DEC and DEP systems are projected to exceed Executive Order No. 80 which set a goal of reducing statewide greenhouse gas emissions to 40% below 2005 levels by 2025.

The Companies have been aggressive with their pace of retiring coal plants (having retired more than half of their Carolinas coal plants over the last decade), adding renewables to the resource mix, increasing EE/DSM offerings to their customers, and operating a reliable nuclear fleet that provides half of our customers' energy demand with zero CO_2 emissions. These actions, along with operating efficient natural gas generation with low cost fuel, will allow the DEC and DEP systems to meet and exceed the goals of Executive Order No. 80, signed in the Fall of 2018, as well as the Companies' own sustainability targets, all while meeting the Commission's Rule R8-60 requirement to "provide reliable electric utility service at least cost over the planning period."[23] Duke Energy is participating in the Executive Order No. 80 stakeholder meetings and, although the State's specific plans to implement the executive order are currently unknown, with the

[23] NCUC R8-60 – Integrated Resource Plans and Filings.

final report not expected until October 2019, the Companies will address any additional requirements in future IRPs once any additional requirements are known.

IX. Demand-Side Management and Energy Efficiency

The Companies disagree with the statement made by SACE et al., at pages 12-13 of their IRP Comments, that the Companies' projections of DSM/EE peak savings in the later years of the IRP are "inconsistent with its declared commitment to continue to grow the amount of DSM/EE resources to meet customer demand." Specifically for the DSM projections, the amounts of DSM included in the IRP forecast are based on the Companies' past experience with customer acceptance of these programs and the expectation that the amount of DSM capacity savings will reach a steady-state level beyond the first few years of the IRP forecast is consistent with this experience. As explained in detail in the response to comments of NCSEA in the 2018 Avoided Cost proceeding, Docket No. E-100, Sub 158, the Companies believe that the forecast of DSM program savings are reasonable and accurately reflect a continued effort to add new customers; however, the forecast recognizes customer response to these programs has been limited, despite targeted and ongoing efforts to increase participation.[24] Therefore, the Companies' forecast of additional increases in DSM peak savings for the next few years followed by a period of steady-state peak savings is reasonable and prudent and accurately reflects the amount of "customer demand" for these programs.

Also, regarding the impact of EE programs on peak demand, the Companies disagree with the intervenors' conclusion that Utility Energy Efficiency ("UEE") program disinvestment occurs in the outer years of the IRP forecast. Incremental annual UEE

[24] See Duke Energy Reply Comments, NCUC Docket No. E-100, Sub 158 (Mar. 27, 2019) at pp. 63-66.

savings projection levels are similar throughout the entire forecast period as shown in the tables in Appendix D of the IRPs. However, as shown in the LCR tables in the IRPs (Tables 12-E and 12-F), the outer year UEE projections are being offset by UEE programs initiated 8 to 10 years prior that have reached the end of their useful life. Once UEE savings reach this stage, they no longer contribute to future UEE cumulative savings and are therefore removed from the cumulative savings amounts. Failure to remove these savings from the cumulative amounts would result in over-stating, or "double-counting" the impact of the Companies' UEE programs on sales. Accordingly, the Companies' approach to DSM/EE in the 2018 IRPs is appropriate.

X. Alternative Filed Resource Plans

A. The Synapse Report filed by NCSEA is the product of a special interest group that appears to make assumptions in their model with a predetermined outcome in mind. The Synapse Report would not conform to the regulated utilities' requirement to provide *reliable* electric utility service at least cost over the planning period and should be dismissed.

The Synapse report filed by NCSEA as Attachment 1 to its comments claims to detail "a realistic clean energy future that provides both the energy and capacity to meet the needs of Duke's customers, while effectively meeting future reliability requirement as traditional generating resources are retired"[25]; however, the report's cost savings are based on multiple assumptions that, if implemented, would cripple the reliability of the DEC and DEP systems.

[25] NCSEA Comments (E-100 Sub 157).pdf, p. 5- 6

First, the Synapse report, which purports to gain an immediate cost savings of 28% through "removal of [coal generation] must-run designations"[26] does not consider "transmission implications that may or may not be associated with must-run designations."[27] The must-run designations that Synapse removes are not required at all energy demand levels on the DEP and DEC systems, and the Companies are not seeking "to find a use for the costly must-run coal generation"[28] as Synapse suggests. In fact, in Synapse' attempt to match the DEC and DEP IRP base cases (with must-run designations included), "one-third of the coal generation shown in 2019 is exported to neighboring utility service territories rather than being used to meet Duke Energy's own load requirements."[29] The Companies do not model sales to neighboring utilities unless those are firm sales with co-owners that are part of nuclear generation contracts or the new Lee CC, and the Companies generally do not sell energy to external markets unless there are economic incentives for consumers to do so. Generally, must-run requirements increase as system energy demand levels increase or other generating units near the must-run units are not available. This level of detail was not considered relevant to Synapse as they relied on Horizons Energy's National Database for their EnCompass model[30] which greatly oversimplifies must-run requirements on the DEC and DEP systems. Must-run requirements are in place to maintain stability on the transmission system by providing voltage support or other services. Without these must-run requirements, the transmission

[26] North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan, Prepared for the North Carolina Sustainable Energy Association by Synapse Energy Economics, Inc. p. 6
[27] NCSEA Response to Duke Data Request No. 1, Item No. 1-3 part c.
[28] North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan, Prepared for the North Carolina Sustainable Energy Association by Synapse Energy Economics, Inc. p. 6.
[29] North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan, Prepared for the North Carolina Sustainable Energy Association by Synapse Energy Economics, Inc. p. 5.
[30] NCSEA Response to Duke Data Request No. 1, Item No. 1-3 part b.

system would be in jeopardy of not being able to serve load, which is a risk that Synapse and NCSEA have ignored.

Another source of cost savings in the Synapse report is the reduction of the required minimum reserve margins in DEC and DEP from 17% to 15% based on the NERC 2018 Long Term Reliability Assessment.[31] As noted in footnote 4 on page 53 of the NERC report, SERC members perform individual reliability assessments, and SERC does not provide reference margin levels for its subregions. Further, page 151 of the NERC report states that NERC applies a 15% margin for predominately thermal systems if a reference margin is not provided by a given assessment area. In short, the SERC and NERC reports cited by NCSEA as a basis for a lower reserve margin do not reflect the level of solar penetration that exists in the Carolinas or the need for a winter reserve margin target as determined by the Companies' resource adequacy studies. The minimum reserve margin requirement in DEC and DEP has been a point of extensive comment since the 17% reserve margin was introduced in the 2016 IRP Reports. The minimum reserve margin requirement is based on comprehensive resource adequacy studies that the Companies conducted with Astrape Consulting in 2016. Although some of the intervening parties apparently still chose to stubbornly debate the findings of the study, the NCUC found the 17% reserve margin requirement reasonable for planning purposes, with the requirement that the Companies and the Public Staff file a joint report summarizing their review after filing the 2017 IRP Update.[32] Synapse took it upon themselves to ignore the 17% requirement that was developed through a study that was focused on the issues facing the

[31] NCSEA Response to Duke Data Request No. 1, Item No. 1-2 part b.
[32] *Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans,* Docket No. E-100, Sub 147.

DEC and DEP systems, and instead used the NERC study that did not consider the level of solar penetration facing the Carolinas, which was a major driver of the increased reserve margin requirement. Again, Synapse and NCSEA are relying on a reduction in system reliability to drive the results of their biased resource report.

The third source of cost savings that is inconsistent with maintaining a reliable energy system in the Carolinas is Synapse's reliance on energy imports into the Carolinas. The Synapse "Clean Energy scenario" relies on 14% energy imports from neighboring utilities to meet demand by 2033.[33] This reliance on neighboring utilities to meet the Carolinas' energy and capacity needs is inconsistent with the reality that there is not enough firm transmission available to reliably import this level of energy, and the Synapse study makes no mention of the costs required to obtain firm transmission into the region. NCSEA and Synapse are either ignorant of the realities of transmission constraints into DEC and DEP, or they have intentionally ignored them.

It is not clear that increasing energy imports from neighboring utilities, as NCSEA proposes to do, would result in fewer CO_2 emissions for the Carolinas. In fact, relying on other states' generation, including those states that may still rely mainly on coal generation, would be contrary to the spirit of Executive Order No. 80's goal to reduce CO_2 emissions in the state to 40% of 2005 emission levels by 2025. As stated above, the Companies' plan already exceeds Executive Order No. 80's directive by using resources located in the Carolinas.

Perhaps the comment that most clearly shows the lack of understanding by NCSEA and Synapse as to what constitutes a reliable system is their following statement:

[33] North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan, Prepared for the North Carolina Sustainable Energy Association by Synapse Energy Economics, Inc. p. 5.

> The Clean Energy Scenario maintains the required 15 percent reserve margin and EnCompass projects no loss-of-load hours and sees zero hours with unserved energy, proving that the retirement of fossil fuels and build-out of renewables leads to no new system reliability issues.[34]

One does not simply use the Companies' weather normalized peak demand forecast, along with an hourly load shape from the EnCompass National Database as Synapse did, and claim no reliability concerns when the model converges without unserved energy hours. That is equivalent to someone guaranteeing that because they did not run out of gas when they drove from Chapel Hill to Raleigh at 7:00 a.m. on a Sunday morning with their low fuel light on, then they could successfully complete that drive at any time with little gas in the tank. How would they fair at 5:00 pm on a Friday in rush hour? When asked to explain their understanding of why the Companies carry a reserve margin, NCSEA's consultant, Ric O'Connell responded:

> NCSEA understands the reserve margin used in the IRP is a "planning reserve margin" which is defined by NERC as: *Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand in [the] planning horizon*.

That definition may be accurate for the NERC study, but the Companies carry a reserve margin to be able to meet unexpected demand due to extreme temperatures, economic load forecast uncertainty, and unexpected outages of its operating units. The reserve margin that the Companies require is there not just to meet expected demand, but to be able to reliably serve customers under extreme and unexpected circumstances.

In summary, any party can claim that their plan is lower cost than the Companies' plans, but to achieve those costs savings in the manner that NCSEA and Synapse did, while still claiming to meet the reliability standards that the NCUC, the Companies, and their

[34] NCSEA Comments, p.8.

customers demand, is unrealistic and lacks regulatory rigor. Duke Energy, as the regulated utility in North Carolina, has the sole obligation to meet its customers' energy needs at all times throughout the year, and the Companies are steadfast in their belief that the DEC and DEP IRPs achieve that standard by doing so at the lowest reasonable cost while meeting and exceeding environmental regulations at the state and federal levels. Simply put, other parties to this docket do not have the obligation to serve, nor do they have an obligation to maintain a reliable electric system. Their use of overly simplistic modeling approaches to reach a predetermined ideological outcome would not be compliant with reliability standards and as such should be rejected.

XI. SACE et al.'s consultant Applied Economics Clinic's ("AEC") Report, "Review of Duke Energy's North Carolina Coal Fleet in the 2018 Integrated Resource Plans" includes misleading and false accusations regarding the Companies' business practices.

The assertion of the Applied Economics Clinic in Attachment 2 of the SACE et al. comments that "the Companies have hard-wired the useful lives for their existing coal units, preventing a fair comparison of the economics of these units relative to replacement resources"[35] is misleading. The retirement dates for existing coal units are projections for planning purposes in the IRPs, and are based on retirement dates in depreciation studies approved in the most recent general rate cases by the Commission (and the Public Service Commission of South Carolina "PSCSC").

Additionally, AEC's assertion that "…the Companies make major decisions about their resources behind closed doors"[36] is disingenuous.[37] Multiple analyses are performed

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[35] *Review of Duke Energy's North Carolina Coal Fleet in the 2018 Integrated Resource Plans*, p. 18, Part A.
[36] *Id*.
[37] By this logic, SACE et al.'s comments and AEC's report were also prepared "behind closed doors" as the Companies did not see them until they were filed with the Commission.

regarding the retirement options of the Companies' coal units, as confirmed in data requests received and cited by AEC in the SACE et al. Attachment 2. The results of those analyses are utilized and represented in the next filed IRP. Furthermore, the Companies' IRPs and depreciation studies are open to scrutiny in the public and transparent dockets this Commission oversees with the intervention and active participation of parties like SACE et al.

While SACE at al. and AEC attempt to discredit the Companies and their commitment to meet our customers' energy needs at the lowest reasonable costs, the full picture is not considered. The Companies are regulated by this Commission and the PSCSC and are under an obligation to provide reliable, and affordable service to their customers. The special interest group intervenors, on the other hand, may freely utilize whatever data sources and reports that support their intended purpose, while ignoring the realities of the obligation of serving customers. Statements made by the intervenors criticizing the Companies' analysis techniques, assumptions, and generally, any decision that does not meet their agenda are presented as fact in their comments, without regard for realistic actualities. In reality, the statements and assertions aimed at discrediting the Companies are incorrect. Notwithstanding Duke Energy's criticism of SACE et al.'s tactics, as noted above, the Companies will continue to evaluate potential accelerated retirement of their remaining North Carolina coal units and advise the Commission in future dockets.

XII. NRDC's commissioned ICF analysis is unable to be reviewed and should be considered inconsequential.

SACE et al.'s comments state that NRDC commissioned the energy consultant, ICF, to perform analyses to develop its own "optimum" resource plan based upon inputs developed by NRDC. ICF utilized their Integrated Planning Model ("IPM") to develop what they call an "economically optimized" case and an "IRP" case, which is intended to replicate the No Carbon Base Case presented by the Companies in its filed IRP.

In a data request to SACE et al., [38] the Companies requested a copy of the report developed by ICF in the study, to which SACE et al. responded that, "ICF did not develop a report. All written materials were developed by NRDC, based on data outputs provided by ICF using their IPM model with all assumptions and policy scenarios provided by NRDC."[39] In the data request response, NRDC provided a file including the inputs developed by them. There is no discussion or detailed information about the calculation and algorithm details of the models. Additionally, how the input data was actually utilized in the model is unclear. In the same response, NRDC provided a single page of outputs for each case developed by the ICM model.[40] While two cases were provided, an "economically optimized" case was not one of them. SACE et al.'s data request response provides outputs for a "reference case" (also titled as "BAU No CCS") and an "IRP case." It is unclear if the "reference case" and the "economically optimized" case are the same case. As such, it is impossible for the Companies to adequately review and comment on the outputs at this time.

Even so, NRDC presents ICF's "economically optimized" case as a least cost option as compared to the "IRP" scenario that was created. There are several issues in question from the Companies' point of view. First, in the ICM results presented as Attachment 1 of NRDC's Comments, in the description of the "economically optimized"

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[38] *Southern Alliance for Clean Energy, Natural Resources Defense Council and the Sierra Club Responses to Second Data Request of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC,* NCUC Docket No. E-100, Sub 157 dated April 29, 2019.
[39] *Id*. Response to DEC/DEP Data Request No. 2-1.
[40] *Id.* Response to DEC/DEP Data Request No. 2-2 including Input and Output Excel Files.

case, it is stated that, "the model was allowed to endogenously retire and add generating resources to determine a least-cost pathway for the state given existing federal and state regulations."[41] Once again, in the absence of information regarding the calculation methodology and rigor of the ICM study, it is not clear how the model does this, what units are retired or when they are retired.

Additionally, NRDC states in Attachment 1 that "the only additional natural gas capacity added is from units already under construction" in the "economically optimized" case.[42] However, the capital costs and fuel prices utilized by ICF for new natural gas units are based on publicly-available generic data that is proven to be higher than in-house new-build costs developed for Company-specific locations and that consider economies of scale/scope that make these resources economic options. The costs utilized to make this statement are inordinately high and likely give any natural gas resources an unfair disadvantage.

NRDC claims, also, that "this 'optimized' case only represents a possible future in which decisions are made by an infallible market operator, instead of a reality where regulators may have to base their decisions on imperfect or incomplete information, and utilities are driven by incentives that do not always align with their customers' interests."[43] First, there is no such thing as an "infallible market operator," which discredits the "optimized" case as being unrealistic. Second, the inference that utilities make decisions based on "incentives" that do not "align with customers' interests" is, outrageous.

[41] *Economically Optimized Independent Power Sector Modeling Shows Multiple Benefits when Compared to Duke's IRP*, p. 2, bullet one.
[42] Ibid. p. 1, bullet three.
[43] *Economically Optimized Independent Power Sector Modeling Shows Multiple Benefits when Compared to Duke's IRP*, p. 5, paragraph two.

Additionally, the SACE et al. inference that the information utilized by the Companies is incomplete is absolutely false. The Companies' resource plans are based on best-available information that takes months to gather, vet, and include properly in modeling and analysis utilized to develop the resource plans.

Finally, NRDC claims that renewable generation (primarily solar) replaces any existing coal or future natural gas resources by stating, "renewable energy generation more than makes up for the generation reductions…"[44] It is impossible for intermittent solar to replace baseload resources required to reliably meet the Companies' customer demand, particularly during peak times when solar is only available to a small degree. The ICM model outputs provided in SACE et al.'s data request response mentioned above do not provide any discernable information about the operational reliability assumptions and load shapes of the solar generation or the impacts of even higher levels of intermittent solar to the Companies' generating system. As determined by the Capacity Value of Solar study presented in the Companies' filed IRPs,[45] solar resources provide very little capacity value at the time of winter peak demand and capacity values decrease as the penetration of solar increases. Thus, infinitely high amounts of solar cannot be added to a generating system and still maintain the integrity and reliability of the system and meet required NERC reliability standards.

Once again, SACE et al. fail to consider the real world in which the Companies operate. DEC and DEP are regulated utilities that have real obligations to its customers. It is the Companies' highest commitment to serve their customers in the most reliable,

[44] Ibid. p. 1, bullet 4.
[45] *DEC 2018 IRP* Chapter 9 and *DEP 2018IRP* Chapter 9.

dependable, environmentally-friendly and economical manner possible. There are real-world consequences to the theoretical exercises SACE et al. continue to present as fact. The misleading and incomplete information presented by the intervenors consistently supports their own agenda but is developed without full consideration of the best interest of all customers.

XIII. ISOP and IDP Rulemaking

In their comments, EDF and NCSEA asked the Commission to initiate a rulemaking proceeding to adopt procedures related to ISOP and Integrated Distribution Planning ("IDP"), respectively. The Companies do not oppose a rulemaking, but recommend that the Commission allow interested parties to participate in a pre-rulemaking stakeholder process to facilitate common understanding of ISOP and IDP issues, and attempt to reach consensus on as many areas as possible to make the formal rulemaking process more collaborative and efficient. The Companies have discussed this stakeholder proposal informally with the Public Staff, and believe that such a process could be beneficial to the Commission and interested stakeholders.

XIV. Resource Adequacy

The Companies used a 17% minimum winter reserve margin target in development of their 2018 IRPs, consistent with results from the 2016 resource adequacy studies. Since completion of the 2016 studies, the Companies have worked extensively with the Public Staff and other intervenors to explain study results and methodology and respond to discovery in efforts to address intervenor questions and concerns.

As an initial matter, the Companies note that they have complied with all Commission orders regarding the 2016 resource adequacy studies. The NCUC's 2016 IRP

Order in Docket No. E-100, Sub 147 concluded that the reserve margins included in the DEP and DEC 2016 IRPs are reasonable for planning purposes. However, the Commission also directed DEP and DEC to work with the Public Staff to address outstanding concerns raised by the Public Staff and SACE consultant Wilson. The Commission further directed the Companies and the Public Staff to file a Joint Report summarizing their review and conclusions within 150 days of the filing of Duke's 2017 IRP updates. The Joint Report was filed on April 2, 2018 and noted that although the discussions between the Public Staff and the Companies were helpful, the parties did not reach agreement regarding the methodology used to incorporate economic load forecast uncertainty. Ultimately, the Public Staff recommended that DEC and DEP utilize a 16% reserve margin in their IRPs, and Duke recommended a minimum 17% winter reserve margin in their IRPs. The NCUC's April 16, 2018 *Order Accepting Filing of 2017 Update Reports and Accepting 2017 REPS Compliance Plans* in Docket No. E-100, Sub 147, accepted the parties' Joint Report and concluded that DEC and DEP may continue to utilize the minimum 17% winter reserve margin for planning purposes in their 2018 IRPs. In addition, the Commission ordered DEC and DEP to further address the economic load forecast uncertainty issue in their 2018 IRPs. The Commission also required the Companies to present a sensitivity analysis in their 2018 IRPs that illustrates the impact of a 16% winter reserve margin, including the specific risk impact (LOLE) of using a 16% minimum reserve margin versus a 17% minimum reserve margin. The Companies complied with the Commission orders in developing their 2018 IRPs.

Economic Load Forecast Uncertainty

In this docket, the Pubic Staff continues to support a 16% reserve margin target based on their PS-S2 scenario proposed in Sub 147 which reflects the removal of short duration cold weather-related outages primarily experienced during the winter of 2014, and also incorporates different economic load forecast uncertainty assumptions as compared to assumptions used in the 2016 studies. As a result of these differences, the PS-S2 scenario results in a reserve margin target of 16%, though the Companies continue to support a reserve margin target of 17%.

The Companies have previously demonstrated that removal of the cold weather outages, as requested by the Public Staff, is insignificant to the 2016 Resource Adequacy study results and impacts the average reserve margin by less than 0.1%. As documented extensively in the Joint Report and the Companies' 2018 IRPs, the Companies believe that the Public Staff's load forecast uncertainty assumptions overstate the probability that actual load will be at or below the Companies' forecast levels. The Companies are not comfortable with the over forecast bias that is assumed in the Public Staff's load forecast error assumptions, which reflect a probability of over forecasting load approximately 48% of the time and under forecasting load approximately 17% of the time.

Instead, the Companies believe that because the load forecast represents a 50/50 forecast, the load forecast uncertainty should reflect possible loads that are equally likely to fall either above or below the forecast. That is, 50% of the time load growth is expected to be higher than projected, and 50% of the time it is expected to be lower than projected. This load forecast uncertainty distribution more reasonably captures expected fluctuations in load growth as compared to the PS-S2 scenario, which reflects an over-forecast of load the majority of the time.

Further, as demonstrated in the Companies' 2018 IRPs, assuming perfect knowledge of its 50/50 weather normal forecast, the Public Staff's recommended 16% reserve margin is only 0.28% greater than the reserve margin needed with perfect forecasting knowledge. The Companies believe that there is meaningful load growth uncertainty over a two to four-year period and that reserves of greater than 0.28% of load are required to manage that risk.

Given the disagreement in methodology and assumptions for incorporating load uncertainty in the resource adequacy studies, it is notable that the Public Staff expressed concerns in their IRP comments regarding DEP's projected annual peak demand growth rate reflecting a significant departure as compared to higher growth of actual winter peaks.[46] Through discovery[47] the Companies asked the Public Staff to reconcile that concern with their position regarding the economic load forecast uncertainty included in the resource adequacy studies which reflects a significantly greater probability of over-forecasting load growth compared to under-forecasting load growth. The Public Staff explained that their concerns about the forecasting accuracy of DEP's winter peak demands relate to the inability of the forecasting process to adequately capture how customers' use of energy changes in response to extreme weather events. The Public Staff further noted that this issue is unrelated to the economic load uncertainty referred to in the Public Staff's

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[46] Reference page 78 of Public Staff's Comments which states: "The Public Staff is also concerned with the predicted annual growth rate of DEP's winter peaks of 0.7%, reflecting a significant departure from the historical growth of its actual winter peaks that have grown at a 3.0% CAGR from 2013 through 2018, while the weather-normalized peaks have grown at 2.1%."
[47] Public Staff response to DEC/DEP data request No. 1-1.

scenario PS-S2. The Companies appreciate and recognize this difference but also note that this issue further illustrates the uncertainty in the non-weather-related load forecast, and the Companies believe that the uncertainty included in the resource adequacy studies is not unreasonable.

Multi-Year Economic Load Forecast Uncertainty

SACE et al. consultant Wilson suggests that including multi-year economic load forecast uncertainty in the resource adequacy studies is not appropriate and suggests that many short lead-time actions could and very likely would be taken if load grows faster than expected.[48] Mr. Wilson suggests that if the rate of load growth raised concerns about resource adequacy, utilities would have time adjust their plans and take actions such as accelerating the development of new resources, increasing demand response or energy efficiency programs, delaying a planned retirement, adjusting firm purchases or allowing wholesale contracts to expire. While these are all worthy ideas and actions that the Companies would likely consider in the event of a significant increase in the load forecast due to economic or other uncertainty, such alternatives are not always sufficiently available or practical to satisfy a resource deficit. In particular, large quantities of demand response and energy efficiency programs are typically not achievable within a short timeframe.

The 2018 DEP IRP saw a 600 MW increase in winter peak demand from the 2017 IRP Update, which contributed to an approximate 2,000 MW near-term need for capacity and energy resources in DEP. As a result of that increase, and as identified in the IRP, DEP conducted a capacity and energy market solicitation that sought to extend existing purchase power contracts and identify new capacity proposals from similar operationally

[48] SACE et al. Comments, Attachment 4, at 15.

capable existing generation facilities or systems with firm transmission deliverability into DEP. While the response to the market solicitation was robust, the capacity need in DEP is significant, and additional steps may be needed to ensure that DEP can continue to meet its 17% minimum reserve margin requirement. However, options, including deferring unit retirements, are limited. Additionally, due to the influx of solar in the Carolinas, which has limited contribution to meeting winter peak capacity needs, the transmission interconnection queue is operating with a significant delay, which makes building new generation that requires transmission interconnection studies, very challenging to execute in an expedited manner. As the timing required to site new generation increases, and older generating units are asked to operate longer to meet capacity requirements, the need to include multi-year economic load forecast uncertainty in the resource adequacy studies only increases. The reality of these circumstances suggests that including only one year of load forecast uncertainty, as suggested by Mr. Wilson, to establish a long-term reliability planning target is inadequate.

Relationship between Winter Load and Cold Temperatures

SACE et al. consultant Wilson echoes many of the same arguments he presented in the 2016 IRP Proceeding concerning the Companies' 2016 Resource Adequacy studies. In particular, he again argues against the methodology used to capture the relationship between winter load and cold temperatures.[49] As previously noted, the Companies have complied with all Commission orders regarding the 2016 Resource Adequacy studies, including working with the Public Staff to address Mr. Wilson's concerns.

[49] SACE et al. Comments, Attachment 4, at 6-13.

Mr. Wilson notes that including "more rather than less historical weather data is preferred" but also suggests that the 15-year period from 1982-1996 should be excluded because it results in flawed regressions and overstates winter resource adequacy risk.[50] This is also apparent from his statement "…the 2016 RA Studies results are very sensitive to the choice of 20 or 30 historical weather years…"[51] The Companies note that the purpose of a reserve margin is to cover uncertainties such as extreme load and generator outages and it would be irresponsible to ignore the potential for these extreme cold weather events when assessing resource adequacy. Thus, excluding 15 years of the 36-year weather history used in the study just because it reflects colder temperatures compared to other historical years is irresponsible. These are precisely the periods that the reserve margin is designed to cover. In fact, as noted in the Joint Report, NCUC Rule R8-61 (CPCN) requires utilities to provide "a verified statement as to whether the facility will be capable of operating during the lowest temperature that has been recorded in the area…"[52] The implication is that this Commission is concerned and expects utilities to provide reliable service to customers even during extreme weather events.

Pursuant to the Commission's June 27, 2017 Order accepting the Companies' 2016 IRPs, the Public Staff and the Companies reviewed the cold weather load modeling in the 2016 studies and performed a sensitivity analysis that reduced the regression equations significantly for temperatures below the levels seen in recent years.[53] This sensitivity analysis showed a relatively small decrease in reserve margin (0.3%) given that the sensitivity reduced the cold weather impact by half of that assumed in the base case. The

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[50] SACE et al. Comments, Attachment 4, at 12.
[51] SACE et al. Comment, Attachment 4, at 25.
[52] Joint Report filed in Docket No. E-100, Sub 147, April 2, 2018, at slide 10.
[53] Joint Report filed in Docket No. E-100, Sub 147, April 2, 2018, at slide 20.

reason that the impact is not larger is because the sensitivity only impacts 7 occurrences in the 36-year weather history. As stated by the Public Staff in the Joint Report, after having further discussions with the Companies, the Public Staff was satisfied that the approach taken in the 2016 studies by the Companies is reasonable.[54]

The Companies further note that the 2016 resource adequacy studies reflected a maximum summer peak that was 7.5% above the expected summer peak for both DEC and DEP. In comparison, the 2018 PJM Reserve Requirement Study reflects a maximum summer peak that is 24% higher than the expected summer peak.[55] For winter, the 2016 study for DEC reflected a maximum winter peak that was 18.3% greater than the expected winter peak while the DEP study reflected a winter peak that was 21.5% greater than the expected winter peak. In comparison, the 2018 PJM study reflected a maximum winter peak that was 21% higher than the expected winter peak. Thus, the variability in load due to temperature extremes that was modeled in the 2016 resource adequacy studies for DEC and DEP were at or below the peak load variability included in the 2018 PJM study.

The Companies and Astrape recognize that appropriately capturing the relationship between extreme cold weather and load are key drivers of the resource adequacy study results. Although there is limited data at extreme cold temperatures, the Companies and Astrape believe that the modeling included in the 2016 studies was reasonable. For the reasons cited herein, the Companies believe that Mr. Wilson's comments on this topic are not persuasive.

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[54] Joint Report filed in Docket No. E-100, Sub 147, April 2, 2018, at 2.

[55] 2018 PJM Reserve Requirement Study: https://www.pjm.com/-/media/planning/res-adeq/2018-pjm-reserve-requirement-study.ashx?la=en

Operating Reserve Assumptions

Mr. Wilson initiated a new unfounded claim in SACE's comments by claiming that the 2016 Resource Adequacy studies exaggerate winter risk through the operating reserve assumptions. Mr. Wilson's claim that over 1,000 MW for DEC, and about 750 MW for DEP, of operating reserves are held back in the SERVM model resulting in firm load curtailments is grossly inaccurate.[56] In fact, SERVM allows operating reserves to drop to the regulation requirement which was 216 MW in DEC and 134 MW in DEP for the resource adequacy and solar capacity value studies. It is interesting to note that the Companies responded in detail to this exact question in response to DEC-DEP SACE DR 2-19 in Sub 147, yet Mr. Wilson still makes these unsubstantiated claims regarding the operating reserves policy used in the studies. Mr. Wilson's arguments have no basis in fact and should be rejected.

Demand Response Assumptions

SACE et al. consultant Wilson concludes that the Companies' demand response winter assumptions should be "brought up to the summer level."[57] Although the Companies agree that winter demand response programs are a reasonable tool for reducing winter peak demand and winter LOLE, when available, the levels of reduction proposed by Mr. Wilson are extremely optimistic and not reasonably achievable in the near term, if at all. As an example, the residential DEP EnergyWise Home program currently offers winter measures (Hot Water Heaters & Heat Pump Heat Strips) in its Western region in and around Asheville. These measures have been in place for 10 years and have been marketed aggressively with direct mail, email, outbound calling, and door-to-door

[56] SACE et al. Comments, Attachment 4, at 20.
[57] SACE et al. Comments, Attachment 4, at pp. 19-20.

canvassing. Over that 10-year period, the program has achieved 15 MW for a residential customer base of approximately150,000. Assuming the same level of achievable potential in the rest of DEP and DEC, a more reasonable estimate of residential winter DSM would be 150 MW in each jurisdiction in 10 years, which would only be true if those measures remained cost-effective into the future.

Moreover, actual program experience from DEP EnergyWise Home has shown that winter residential program potential is actually more difficult to achieve than summer potential for several reasons. First, not all residential customers have electric resistance hot water heaters or heat pumps with electric resistance strip heat. Instead, almost all have compressorized cooling in the form of straight air conditioning or heat pumps. Second, residential winter measure installations require appointments to enter the customer's home that are often rescheduled and more costly than a summer air conditioning installation, which does not require an in-home installation.

The Companies also note their plans to implement new winter DSM programs as proposed in the 2018 IRPs, and continue to work toward implementation of those programs. However, the extreme amounts of winter demand response programs anticipated to be cost-effective and reasonably achievable as cited by Mr. Wilson cannot prudently be included in the IRP forecast. Mr. Wilson attempts to support his claim by stating that the most recent Market Potential Study for DEC and DEP identified additional winter demand response technical and economic potential up to 2,300 MW;[58] however, the amount of potential that is reasonably achievable must be based on the Companies' experience with DSM program adoption and, in the Companies' experience, adoption of

[58] SACE et al. Comments, Attachment 4, at 20.

high levels of DSM programs has been challenging despite significant effort by the Companies. Therefore, Mr. Wilson's claim that winter demand response can be magically brought up to the summer level to reduce winter resource adequacy risk should be rejected.

Load net of Solar Resources

Mr. Wilson makes the following assertion on page 22 of Attachment 4 to SACE's Comments:

> A more balanced seasonal weighting is also suggested by the simple fact that the vast majority of high load hours are in summer on both systems. According to DEC's load forecast, 83% of the highest load hours (top 1%) are in summer; for DEP's load forecast, 74% of the top 1% load hours are in summer.

As Mr. Wilson points out, the Companies do experience significant summer loads; however, summer peaks occur in late afternoon hours when solar has significantly greater energy contributions as compared to dark winter mornings where very little – if any -- solar is available at the time of peak. Thus, the summer peak loads net of solar output are reduced relative to winter peak loads net of solar. This load net of solar has a significant impact on summer versus winter LOLE values and represents the net load that the remainder of the Companies' resources must satisfy. However, when asked whether Mr. Wilson's analysis of seasonal weighting reflected consideration of load net of solar resources, SACE et al. responded, "…that comment referred to load, not load net of any particular resources."[59] Further, when asked to provide a detailed explanation of why Mr. Wilson believes it is appropriate to exclude the impact of solar generation when evaluating seasonal loss of load risk, SACE et al. responded, "Not applicable."

The Companies appreciate constructive feedback regarding their planning processes and studies. However, misleading (winter load and temperature relationship),

[59] SACE et al. response to Duke Data Request 4-5.

unachievable (demand response potential) and false (operating reserves policy) claims regarding the 2016 resource adequacy studies largely do not add value and are counter-productive. The Companies also note that their review of Mr. Wilson's comments was also limited by insufficient information and late responses to the Companies' data requests (SACE et al.'s responses to DEC/DEP Data Requests Nos. 4-2 and 4-5).

Resource Adequacy Summary Comments

As stated in the 150 Day Joint Report and 2018 IRPs, the Companies believe that a holistic review and consideration of resource adequacy study inputs and assumptions is appropriate when judging the reasonableness of the study results. While some parties may believe that certain study inputs and assumptions may have overstated the required reserve margin (i.e., resulting in a reserve margin that is too high), the Companies believe that certain assumptions in the 2016 studies, including outage rate modeling and market assistance assumptions, may have been aggressive and understated the required reserve margin (resulted in a reserve margin that is too low). The Companies agree with Mr. Wilson's comment that resource adequacy and reserve margin requirements can change over time. This is precisely why the Companies conduct periodic resource adequacy assessments in order to capture significant changes in inputs and assumptions that may impact study results. The Companies plan to work with the Public Staff to refresh inputs and assumptions and complete new resource adequacy studies in support of their 2020 IRPs. The Companies believe it is prudent to maintain a minimum 17% winter reserve margin to provide adequate reliability and satisfy the target of less than 1 firm load shed event every 10 years. The Companies recommend use of a 17% winter reserve margin until such time as a new study is completed.

XV. NC WARN Comments

In its comments and attached report, NC WARN has, yet again, argued that the Commission should adopt an energy plan for North Carolina that is unrealistic and would jeopardize the reliable and affordable energy system that this Commission has consistently required from Duke Energy in fulfilling the Commission's mission under the Public Utilities Act. Although NC WARN objected to 8 of the 13 data requests DEC and DEP sent to it seeking analytical and factual support for statements made in its filed IRP comments and report, the information NC WARN did provide in its responses reveals that its comments and report are not supported by competent analysis or facts.[60] For example, in DEC and DEP Data Request 1-4, the Companies asked NC WARN to:

> Please provide all documents and analyses including inputs, assumptions, calculations, results, models, spreadsheets with working formulas, or other data or information supporting your position that sufficient and cost-effective battery storage can be online by 2025 to displace thousands of megawatts of natural gas generation.

In response, NC WARN simply referred the Companies to the reports filed by NC WARN in connection with its 2017 and 2018 IRP comments. In other words, NC WARN asserted that the underlying analysis supporting its comments was simply its own comments. Likewise, in DEC and DEP Data Request 1-7, the Companies asked NC WARN:

> On page 9 of your initial comments, you state that, "In his report, Mr. Powers establishes that DEC and DEP can achieve one-hundred (100) percent fossil-free energy by 2030, getting halfway there by 2025." Please identify and produce all documents and analyses including inputs, assumptions, calculations, results, models, spreadsheets with working formulas, or other data or information upon which you and/or Mr. Powers rely upon in support of this statement.

[60] NC WARN's Responses to First Data Request of Duke Energy Progress LLC and Duke Energy Carolinas LLC are attached hereto as DEC/DEP Exhibit 1.

In response, NC WARN simply stated, "This statement is explained in detail, with applicable citations, in Mr. Powers' *N.C. Clean Path 2025 Report* and the *Update: N.C. Clean Path 2025*." This lack of quantitative analysis and circular reasoning is found throughout NC WARN's data request responses. See DEC/DEP Exhibit 1. Although NC WARN's simplistic and hyperbolic conclusions may advance its own interests, its arguments should not, and cannot, be credibly relied upon by the Commission or anyone who truly values a reliable and affordable supply of energy for the State of North Carolina.

XVI. Requests for an Evidentiary Hearing.

Some intervenors, as well as many of the consumer statements of interest filed with the Commission, have asked for an evidentiary hearing. The Companies respectfully assert that an evidentiary hearing is not necessary, because the Commission has a voluminous record before it, including studies and reports from various technical witnesses, which is adequate to review and rule on the adequacy of the Duke Energy 2018 IRPs.[61] Furthermore, as discussed at the outset of these reply comments, the IRPs are a "snapshot in time," and the 2019 IRP Updates are due to be filed on September 3, 2019[62] - - approximately three and a half months from now. The Companies therefore respectfully assert that an evidentiary hearing at this point of the proceeding would leave little, if any, time to complete the record on the 2018 IRPs prior to the filing of the 2019 IRP Updates and would therefore be of limited value, especially when all intervenors have had the opportunity to make legal, factual, and technical arguments to the Commission in their filed comments. Finally, some comments - - particularly those contained in some consumer

[61] The Companies also incorporate by reference their November 15, 2018 Response in Opposition to NC WARN Motion for Evidentiary Hearing filed in this docket.
[62] September 1, 2019 is a Sunday, and September 2, 2019 is the Labor Day holiday.

statements - - appear to reflect an incorrect assumption that Commission acceptance of an IRP constitutes the Companies' request for, or Commission approval of, specific generation resources contained therein. As the Commission noted in its June 26, 2015 *Order Approving Integrated Resource Plans and REPS Compliance Plans*, in Docket No. E-100, Sub 141, at page 11:

> General Statute 62-110.1(c), in pertinent part, requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity." In *State ex rel. Utils. Comm'n v. North Carolina Electric Membership Corporation*, 105 N.C. App 136, 141, 412 S.E.2d 166, 170 (1992), the Court of Appeals discussed the nature and scope of the Commission's IRP proceedings. The Court affirmed the Commission's conclusion that
>
> [t]he Duke and CP&L plans were "reasonable for the purposes of [the] proceeding" before it. That is to say, the plans submitted by Duke and CP&L were reasonable for the purpose of "analy[zing]…the long-range needs for expansion of facilities for the generation of electricity in North Carolina…" See N.C. Gen. Stat. § 62-110.1(c).
>
> The Court further explained that the IRP proceeding is akin to a legislative hearing in which the Commission gathers facts and opinions that will assist the Commission and the utilities to make informed decisions on specific projects at a later time. On the other hand, it is not an appropriate proceeding for the Commission to use in issuing "directives which fundamentally alter a given utility's operations." With regard to the Commission's authority to issue specific directives, the Court cited the availability of the Commission's certificate of public convenience and necessity (CPCN) proceedings and complaint proceedings. Id., at 144, 412 S.E.2d at 173.

As such, by statute, decisions on the need, cost and timing of a specific generation resource would only be made after a CPCN application was filed and considered by the Commission in a public and transparent CPCN proceeding conducted pursuant to N.C. Gen. Stat. §§62-110.1 and 62-82. Accordingly, Duke Energy respectfully asserts that the requests for an evidentiary hearing on the 2018 IRPs should be denied.

CONCLUSION

In conclusion, the Companies submit that their 2018 Integrated Resource Plans and Renewable Energy and Energy Efficiency Portfolio Standards Compliance Plans meet the requirements of all applicable statutes, Commission Rules, and Commission orders and should be approved. Furthermore, DEC and DEP assert that there is no compelling reason to hold an evidentiary hearing when all parties have had adequate opportunity to present their comments and alternatives before the Commission, and the requests for same should be denied.

Respectfully submitted, this the 20th day of May, 2019.

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 157

In the Matter of	)	
	)	NC WARN'S RESPONSES
2018 Biennial Integrated Resources Plans and	)	TO FIRST DATA
Related 2018 REPS Compliance Plans	)	REQUESTS OF DUKE
	)	ENERGY PROGRESS LLC
	)	AND DUKE ENERGY
	)	CAROLINAS LLC

NOW COMES NC WARN, by and through undersigned counsel, and hereby submits these Responses to the First Data Requests of Duke Energy Progress LLC ("DEP") and Duke Energy Carolinas LLC ("DEC"):

RESPONSES TO FIRST DATA REQUESTS

1-1. Page 2 of your initial comments states the following:

"As a result, installed battery capacity in the U.S. is projected to increase from about 400 MW per year in 2018 to about 4,000 MW per year in 2023."

Please identify and provide any documents which detail the amount of installed battery capacity that would have to be available in North Carolina to enable DEC and DEP to replace nearly one-half of their coal and gas generation by 2025 and the cost of the battery capacity as well as the cost to ratepayers to retire the coal and gas generation.

Response: NC WARN objects to the request for "any documents," which is overly broad and unduly burdensome. Without waiving this objection, NC WARN provides the following response:

NC WARN filed Initial Comments in the 2017 Integrated Resource Plans proceeding, Docket No. E-100, Sub 147. Attachment B to NC WARN's Initial Comments in the 2017 Integrated Resource Plans docket was the *North Carolina Clean Path 2025* report by Bill Powers (the "*N.C. Clean Path 2025* report"). See pages 34-35 of the *N.C. Clean Path 2025* report for details on the amount of battery storage necessary to displace nearly one-half of North Carolina's coal and gas electricity production by 2025. See pages 42-56 of the *N.C. Clean Path 2025* report for details on the assumed cost of battery capacity. The *N.C. Clean Path 2025* report assumes solar and battery systems are third-party owned and most of the capacity added by 2025 is net-metered residential and commercial capacity offsetting retail rates.

1-2. Pages 2 through 5 of your initial comments refer to the Sierra Club's *100% Commitments in Cities, Counties & States* by listing certain cities that have or expect to be powered by up to 100 % renewable electricity:

With regard to the statements on p. 3 at paragraph 4.g that "As of 2015, Aspen, Colorado was powered by one-hundred (100) percent renewable electricity" and paragraph 4.h that "As of 2014, Burlington, Vermont was powered by one-hundred (100) percent renewable energy" and paragraph 4.i on page 4 that "As of 2018, Georgetown, Texas was powered by one-hundred (100) percent renewable energy," and paragraph 4.j that "As of 2013, Greensburg, Kansas was powered by one-hundred (100) percent renewable energy," please state whether any or all of the above-listed cities are connected to an electric grid that serves electric customers beyond the city limits of the listed cities. Please state whether any of the listed cities used coal or gas-fired generation to backstand times when intermittent solar, wind or hydro was not available to provide renewable energy to the residents of the listed cities and also state whether any of the listed cities had or have battery storage equal to 100 % of the electric energy consumed by the respective cities.

Did the city of Georgetown, Texas have to renegotiate its wind and solar contracts after costs came in at more than $23.1 million over budget for the years 2016-17, and did the city contract for more solar and wind capacity than needed to supply electric power to its customers?

Response: NC WARN objects to the present Data Request as overly broad and unduly burdensome. Moreover, the information responsive to the present Data Request is publically available and as easily accessible by Duke Energy Carolina LLC ("DEC") and Duke Energy Progress LLC ("DEP") as by NC WARN.

1-3. Page 9 of your initial comments in paragraph 18.b states:

"Expand DEC and DEP's inadequate community solar program;"

Please (i) define "inadequate" and (ii) all documents and analyses including inputs, assumptions, calculations, results, models, spreadsheets with working formulas, or other data or information upon which you rely upon in support of this statement.

(iii) Is NC WARN aware that the community solar program contained in HB 589 was developed by stakeholders, including many environmental and renewable energy advocates, and enacted by the North Carolina General Assembly ("NCGA"). (iv) Are you asserting that the NCGA enacted "inadequate community solar programs" in HB 589?

Response: As an attachment to its Initial Comments in the present docket, NC WARN filed a report by Mr. Powers entitled *Update: N.C. Clean Path 2025*.

Both the *N.C. Clean Path 2025* report and the *Update: N.C. Clean Path 2025* establish that DEC and DEP are lagging behind nationwide trends with respect to solar power, including community solar, and battery storage. These two reports explain the basis for NC WARN's above-quoted statement in paragraph 18.b of its Initial Comments.

1-4. Page 9 of your initial comments in paragraph 18 d states:

"Redirect reliance upon gas turbine generation to reliance upon battery storage, especially solar combined with battery storage."

Please provide all documents and analyses including inputs, assumptions, calculations, results, models, spreadsheets with working formulas, or other data or information supporting your position that sufficient and cost-effective battery storage can be online by 2025 to displace thousands of megawatts of natural gas generation.

<u>Response</u>: NC WARN objects to the request for "all documents," which is overly broad and unduly burdensome. Without waiving this objection, NC WARN provides the following response: Please see NC WARN's response to Data Request No. 1-1 above.

1-5. On page 10 at paragraph 21 you state that DEC and DEP have failed to "keep pace with their peers on the implementation of renewables…"

Please provide (i) a list of any states that you allege have more interconnected solar capacity and more solar projects than DEC and DEP in North Carolina; (ii) a list any "peers" which you allege DEC and DEP have failed to keep pace with on the implementation of renewables; and (iii) identify and produce all documents upon which you rely for such statements and in providing your response to this data request.

<u>Response</u>: Detailed responsive information was provided in NC WARN's Initial Comments in this docket, as well as the *N.C. Clean Path 2025* report and the *Update: N.C. Clean Path 2025*. By way of further response, DEC and DEP project in their respective IRPs that eight (8) percent of their electricity production will be from renewable energy by 2033. This compares to fifty (50) percent in California by 2030, and one-hundred (100) percent in California by 2045. Hawaii and New Mexico also have one-hundred (100) percent renewable energy mandates. Other states have similar legislation in process.

1-6. On pages 10 and 11 at paragraph 21 of your initial comments you state:

"The IRP process should be placed in the hands of the Commission and allow the state/public to decide their energy future."

Are you aware that pursuant to the Commission's September 27, 2018 *Order Scheduling Public Hearings on 2018 IRP Reports and Related 2018 REPS Compliance Plans* that N.C.G.S. § 62-2(a)(3a) vests the Commission with the duty to regulate public utilities and their expansion in relation to long-term energy conservation and management policies and that N.C.G.S. § 62-110.1(c) requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs" for electricity in North Carolina? That being the law that is currently in place, upon what basis do you contend the IRP process should be placed in the hands of the Commission?

Response: NC WARN objects because this Data Request calls for a legal conclusion, violates the work product doctrine, and is otherwise objectionable.

1-7. On page 9 of your initial comments, you state that, "In his report, Mr. Powers establishes that DEC and DEP can achieve one-hundred (100) percent fossil-free energy by 2030, getting halfway there by 2025." Please identify and produce all documents and analyses including inputs, assumptions, calculations, results, models, spreadsheets with working formulas, or other data or information upon which you and/or Mr. Powers rely upon in support of this statement.

Response: This statement is explained in detail, with applicable citations, in Mr. Powers' *N.C. Clean Path 2025* report and the *Update: N.C. Clean Path 2025*.

1-8. Has NC WARN or Mr. Powers or anyone on their behalf prepared a cost estimate and customer rate impact analysis for the "NC Clean Path 2025" plan authored by Mr. Powers and attached to your initial comments? If so, please identify and produce any such cost estimate and customer rate impact, including all documents and analyses including inputs, assumptions, calculations, results, models, spreadsheets with working formulas, or other data or information which support any such cost estimate and customer rate impact.

Response: The *N.C. Clean Path 2025* report demonstrates that the electricity cost from net-metered N.C. commercial and residential solar, and solar with batteries, is at or below the retail cost of residential and commercial grid power in N.C. in 2017. Battery costs have declined on average twenty (20) percent per year since 2010, and new battery technologies entering the market, like zinc-air batteries (proven reliable by Duke Energy at the Mt. Signal cell tower), as documented in *Update: N.C. Clean Path 2025*, could accelerate this cost decline trend. The net-metered solar and battery cost benefit will increase further as solar and battery costs continue to decline. NC WARN also asserts that net-metered solar and batteries are a net economic benefit for bundled customers who do not have solar or batteries, as documented in pages 55-56 of the *N.C. Clean Path 2025* report.

1-9. On page 10 of your initial comments, you state, "in light of the practical goal of North Carolina becoming one-hundred (100) percent fossil fuel-free by 2030, DEC and DEP's IRP reports are grossly out of step with the needs of North

Carolina's customers." Please (i) define "practical" and (ii) identify and produce all documents and analyses including inputs, assumptions, calculations, results, models, spreadsheets with working formulas, or other data or information upon which you rely upon in support of this statement.

<u>Response</u>: NC WARN objects to the request to "identify and produce all documents," which is overly broad and unduly burdensome. Without waiving this objection, NC WARN provides the following response: Please see NC WARN's response to Data Request No. 1-5 above.

1-10. On page 4 of the "NC Clean Path 2025" plan, Mr. Powers states, "There are no technical or economic reasons that North Carolina cannot retire all coal- and gas-fired power generation even more rapidly than was projected in 2017's *North Carolina Clean Path* 2025." Please identify and produce all documents and analyses including inputs, assumptions, calculations, results, models, spreadsheets with working formulas, or other data or information which support this statement.

<u>Response</u>: NC WARN objects to the request to "identify and produce all documents," which is overly broad and unduly burdensome. Without waiving this objection, NC WARN provides the following response: This is among the principal conclusions of the *Update: N.C. Clean Path 2025*, and that said report contain a detailed analysis, with citations, in support of this conclusion.

1-11. Please identify (i) which coal and gas-fired power plants you and Mr. Powers allege that DEC and DEP can or should retire by 2025 to reach your halfway goal of 100% fossil free energy by 2030 and (ii) please identify and produce all documents and analyses including inputs, assumptions, calculations, results, models, spreadsheets with working formulas, or other data or information which support this statement.

<u>Response</u>: NC WARN objects to the request to "identify and produce all documents and analyses," which is overly broad and unduly burdensome. Without waiving this objection, NC WARN provides the following response: All remaining operational DEC and DEP coal plants would be retired by 2025. The gas plants will continue to serve load and will transition to a purely back-up role by 2030. The analysis supporting these conclusions, including citations, is found in the *N.C. Clean Path 2025* report and the *Update: N.C. Clean Path 2025*.

1-12. On page 4 of the "NC Clean Path 2025" plan, Mr. Powers states, "Solar power combined with battery storage is now beating new natural gas-fired power plants on cost-effectiveness and reliability." Please provide (i) the costs for solar power combined with battery storage and the costs for new natural gas-fired power plants upon which you rely to make this statement; and (ii) please identify and produce all documents and analyses including inputs, assumptions, calculations, results, models, spreadsheets with working formulas, or other data or information which support this statement.

Response: NC WARN objects to the request to "identify and produce all documents and analyses," which is overly broad and unduly burdensome. Without waiving this objection, NC WARN provides the following response: Responsive information is found on pages 46-48 of the *N.C. Clean Path 2025* report, and throughout the *Update: N.C. Clean Path 2025*.

1-13. Does NC WARN support DEC and DEP's continued operation and reliance upon nuclear generating stations as part of NC WARN's "NC Clean Path 2025" plan?

Response: This Data Request is addressed and answered, with supporting citations, on pages 4, 6 and 31 of the *N.C. Clean Path 2025* report.

This the 25th day of March, 2019.

*/s/ Kristen L. Wills*_____________________
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CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing document upon counsel for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC by email transmission.

This the 25th day of March, 2019.

*/s/ Kristen L. Wills*______________________
Kristen L. Wills

OFFICIAL COPY

May 20 2019

`CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Reply Comments, in Docket No. E-100, Sub 157, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to the following parties of record:

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This is the 20th day of May, 2019.

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