STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 190

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-110.9 and § 62-110.1(c)	)))))))	**REBUTTAL TESTIMONY OF RICHARD NICHOLAS WINTERMANTEL AND COLE MICHAEL BENSON ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

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I. INTRODUCTION AND OVERVIEW

Q. MR. WINTERMANTEL PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

My name is Richard Nicholas ("Nick") Wintermantel, and my business address is 3000 Riverchase Galleria, Hoover, AL, 35224. I am providing rebuttal testimony on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (and together with DEC, the "Companies"), together with Cole Michael Benson as the "Resource Adequacy Panel" ("Panel").

Q. ARE YOU THE SAME RESOURCE ADEQUACY PANEL THAT FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. IS THE RESOURCE ADEQUACY PANEL INTRODUCING ANY EXHIBITS IN SUPPORT OF THE REBUTTAL TESTIMONY?

A. Yes. We are sponsoring the following exhibits, which are described below.

- **Resource Adequacy Panel Rebuttal Exhibit 1:** SACE, et al.'s[1] Response to Duke DR 4-1.
- **Resource Adequacy Panel Rebuttal Exhibit 2:** Companies' Response to CEBA DR 4-20.
- **Resource Adequacy Panel Rebuttal Exhibit 3:** Companies' Response to CEBA DR 4-13.

[1] "SACE, et al." refers to intervenors Southern Alliance for Clean Energy, Sierra Club, Natural Resources Defense Council, and North Carolina Sustainable Energy Association.

- **Resource Adequacy Panel Rebuttal Exhibit 4:** Provides key figures and tables presented in our testimony in larger, more readable format.

Q. PLEASE EXPLAIN THE PURPOSE OF THE RESOURCE ADEQUACY PANEL'S REBUTTAL TESTIMONY.

A. The purpose of this Panel's rebuttal testimony is to respond to testimony from Public Staff witness Jeff Thomas, SACE, et al. witnesses James Wilson (Wilson Energy Economics), Michael Goggin (Grid Strategies, LLC), Maria Roumpani (ELO Engineering Consulting), Clean Energy Buyers Association ("CEBA") witness Jennifer Chen (World Resources Institute), and NC WARN witness Rao Konidena (Rakon Energy, LLC) regarding the 2023 Resource Adequacy Study prepared for DEC and DEP and Astrapé's recommended reserve margin (included as Attachment I to the Companies' 2023-2024 Carbon Plan and Integrated Resource Plan ("CPIRP" or the "Plan") ("Resource Adequacy Study")).

This Panel's rebuttal testimony also responds to testimony from Attorney General's Office ("AGO") witness Edward Burgess (Morpho Strategies, LLC), SACE, et al. witnesses Goggin and Roumpani, and CEBA witness Chen regarding the 2022 Solar and Storage Effective Load Carrying Capability Study included as Attachment II ("ELCC Study") to the Companies' CPIRP and 2023 Wind ELCC included as Attachment III ("2023 Wind ELCC Study," together with ELCC Study, the "ELCC Studies") to the Companies' CPIRP. Each of these studies was also conducted by Astrapé for the Companies. This Panel's rebuttal testimony is organized by topic beginning with intervenor

comments on the Resource Adequacy Study followed by intervenor comments on the ELCC Studies.

Q. MR. WINTERMANTEL, ON BEHALF OF THE PANEL, PLEASE BRIEFLY SUMMARIZE THE PANEL'S REBUTTAL TESTIMONY.

A. In summary, the Public Staff found the Resource Adequacy Study which recommended a 22% reserve margin to be reasonable and also found the ELCC Study to be reasonable. No party offered a comprehensive analysis to support an alternative planning reserve margin. Several intervenors provided narrow critiques to these studies which are addressed in detail. The Panel stands behind its studies and believes that a 22% planning reserve margin is prudent and reasonable and will allow the Companies to maintain the reliability of the system. The recommended planning reserve margin will provide for continued reliability, particularly in light of the continued evolution of the electric grid with substantial load growth, retirement of dispatchable resources, and growing penetration of variable energy and energy limited resources.

II. RESOURCE ADEQUACY STUDY

Q. PLEASE PROVIDE AN OVERVIEW OF THE RESOURCE ADEQUACY STUDY RESULTS AS DETAILED IN THIS PANEL'S DIRECT TESTIMONY.

A. Astrapé was retained in late 2022 to perform the 2023 Resource Adequacy Study, which determined the minimum reserve margin the Companies should plan for in their respective IRPs. The Resource Adequacy Study determined the reserve margin required to meet the reliability standard of "one day in 10-

years" which equates to a Loss of Load Expectation ("LOLE") of 0.1 days per year. Based on the physical reliability results of the Resource Adequacy Study, Astrapé recommended that the Companies increase their minimum winter planning reserve margin from 17% to 22% for IRP purposes.

Q. PLEASE EXPLAIN WHY THE RESOURCE ADEQUACY STUDY RESULTS ARE REASONABLE.

A. As noted in the Resource Adequacy Study, the increase in reserve margin from 17% to 22% was driven by a reduction in neighbor assistance, the assumption of long-term load forecast error, and generator performance especially during cold periods.[2] As noted by Public Staff witness Thomas, the Companies' 22% reserve margin falls within the 17%[3] to 26% range of reserve margins for Southeast utilities.[4] Astrapé's updated modeling reflects the shifting neighbor resource portfolios resulting from coal retirements and the buildout of renewables and storage on other utilities' systems. This changing resource mix along with the cold weather load response has shifted the resource adequacy risk of the Companies' neighbors to the winter, resulting in less market assistance available to the Companies' during the winter extreme weather periods and increasing the resources the Companies need to carry to maintain a

[2] Resource Adequacy Study at 8.

[3] Santee Cooper initially incorporated a 17% reserve margin it its 2023 IRP. However, the Panel notes that ORS recommended that Santee Cooper increase its reserve margin from 17% to 18%, which was adopted by Santee Cooper during its 2023 IRP proceedings. Order Approving the South Carolina Public Service Authority's 2023 Integrated Resource Plan at 74, Order No. 2024-171, Public Service Commission of South Carolina ("PSCSC") Docket No. 2023-154-E (Mar. 8, 2024).

[4] Public Staff Thomas Direct Testimony at 33.

reliable system.[5] The long-term forecast error and generator performance inputs are also based on updated modeling assumptions. Therefore, the proposed planning reserve margin target is reasonable and necessary to maintain or improve reliability of the grid.

Q. DID ANY OTHER PARTY TO THIS PROCEEDING PERFORM A COMPREHENSIVE RESOURCE ADEQUACY STUDY?

A. No. No other party to this proceeding presented a comprehensive resource adequacy study. As such, while certain parties made narrow recommendations or critiques which are addressed in more detail below, none provided an alternative planning reserve margin for the Commission's consideration in this proceeding. The Companies' Resource Adequacy Study, which is based on prudent and well-established industry best practices and utilizes comprehensive modeling, is reasonable and confirms the need for the recommended 22% planning reserve margin.

A. PUBLIC STAFF POSITIONS

Q. DOES THE PUBLIC STAFF AGREE THAT THE 22% RESERVE MARGIN IS REASONABLE?

A. Yes. Public Staff witness Thomas notes that the overall trend of higher reserve margins has been observed throughout the Southeast, noting specifically that the Tennessee Valley Authority ("TVA") is using a 25% winter reserve margin, Georgia Power is recommending a 26% winter reserve margin, Dominion Energy South Carolina is targeting a 20.1% winter reserve margin, and Santee

[5] Resource Adequacy Study at 9.

Cooper is utilizing a 17% winter reserve margin.[6] The Panel notes that ORS recommended a higher reserve margin of 18% for Santee Cooper, which was adopted by Santee Cooper during its 2023 IRP proceedings.[7] Witness Thomas further noted that it is not unreasonable to assume that a higher reserve margin is necessary given the changes to system dynamics that have occurred since the 2020 Resource Adequacy Study was completed.[8]

Q. DID THE PUBLIC STAFF RAISE ANY CONCERNS ABOUT THE RESERVE MARGIN?

A. Yes. The Public Staff raised one reserve margin-related concern that declining generator reliability across the Companies' existing fleets is driving the need for a higher reserve margin, particularly given that recent winter-weather improvements are not reflected in the data.[9] But it acknowledged that even addressing this concern, the reserve margin would still likely be above 20%.[10]

Q. DO YOU AGREE WITH THIS CONCERN?

A. No. Astrapé typically uses 5 years of historic generator outage data in conducting resource adequacy assessments, as was the case in the Resource Adequacy Study. Using 5 years of generator outage data generally provides a representative sample of unit performance over a long enough timeframe to

[6] Public Staff Thomas Direct Testimony at 33-34.

[7] Order Approving the South Carolina Public Service Authority's 2023 Integrated Resource Plan at 74, Order No. 2024-171, PSCSC Docket No. 2023-154-E (Mar. 8, 2024).

[8] Public Staff Thomas Direct Testimony at 34.

[9] Public Staff Thomas Direct Testimony at 34. CEBA witness Chen makes similar arguments regarding use of historical outage rates. CEBA Chen Direct Testimony at 13, 27.

[10] Public Staff Thomas Direct Testimony at 34.

capture periods of declining generator performance as well as periods of improved generator performance following reliability upgrades. To the extent that more recent winter weatherization has been implemented, the impacts of these modifications may not be known at this time but would be captured in future resource adequacy studies. Even though this Panel disagrees with the concern, witness Thomas acknowledged that even if the impact of these updated outages were removed, the Companies would still increase their reserve margins to over 20%.[11] It is also Astrapé's understanding that the CPIRP plans to develop resources over the 2027-2031 timeframe to meet the 22% reserve margin. Thus, new resource adequacy studies will likely be conducted prior to the Companies reaching the 22% reserve margin, allowing for time to check and adjust as new data is gathered and assessed.

B. RESPONSE TO INTERVENORS

Q. DO YOU AGREE WITH SACE, ET AL. WITNESS WILSON THAT THE COMPANIES OVERSTATED WINTER LOAD RESPONSE TO EXTREME COLD TEMPERATURES? [12]

A. No. Astrapé used the same regression approach it has used in jurisdictions across the country to capture load response at extreme temperatures. In addition, as directed by the PSCSC,[13] Astrapé considered other methods including incorporating the number of cold days preceding the extreme cold day as well

[11] Public Staff Thomas Direct Testimony at 34.

[12] SACE et al. Wilson Direct Testimony at 10.

[13] Order Requiring Modification to Integrated Resource Plans at 86 (Ordering Paragraph No. 5), Order No. 2021-447, PSCSC Docket Nos. 2019-224-E and Docket No. 2019-225-E (June 28, 2021).

as investigating if the cold weather load response to temperature has increased over time.[14] The additional methods considered did not indicate a strong relationship between these factors and cold weather load response and therefore, Astrapé maintained the same approach used in the 2020 study.

Q. DID YOU COMPARE YOUR COLD WEATHER REGRESSION ANALYSIS TO THE ANALYSIS PRESENTED BY SACE, ET AL.?[15]

A. Yes. Witness Wilson argues against Astrapé's inclusion of higher temperature points and shows a regression for DEC only including points under 12 degrees and a regression for DEP-East[16] under 18 degrees. Figures 1 and 2 below show a comparison of 3 regressions: the ones utilized by Astrapé to perform the load modeling for the study (blue), the ones proposed by witness Wilson (orange), and then finally ones that include data points one degree higher than the break points proposed by witness Wilson (black). As the figures show, simply by including one additional temperature point, the MW/degree relationship proposed by witness Wilson significantly increases from 108 MW/degree to 265 MW/degree in DEC and 196 MW/degree to 263 MW/degree in DEP-East respectively. This additional temperature point shifts the load response to values that are very similar to the Astrapé approach, as shown in the figures. In response to Duke DR 4-1 asking for the technical basis used to determine the appropriate cutoff temperature for the regressions, Witness Wilson stated that

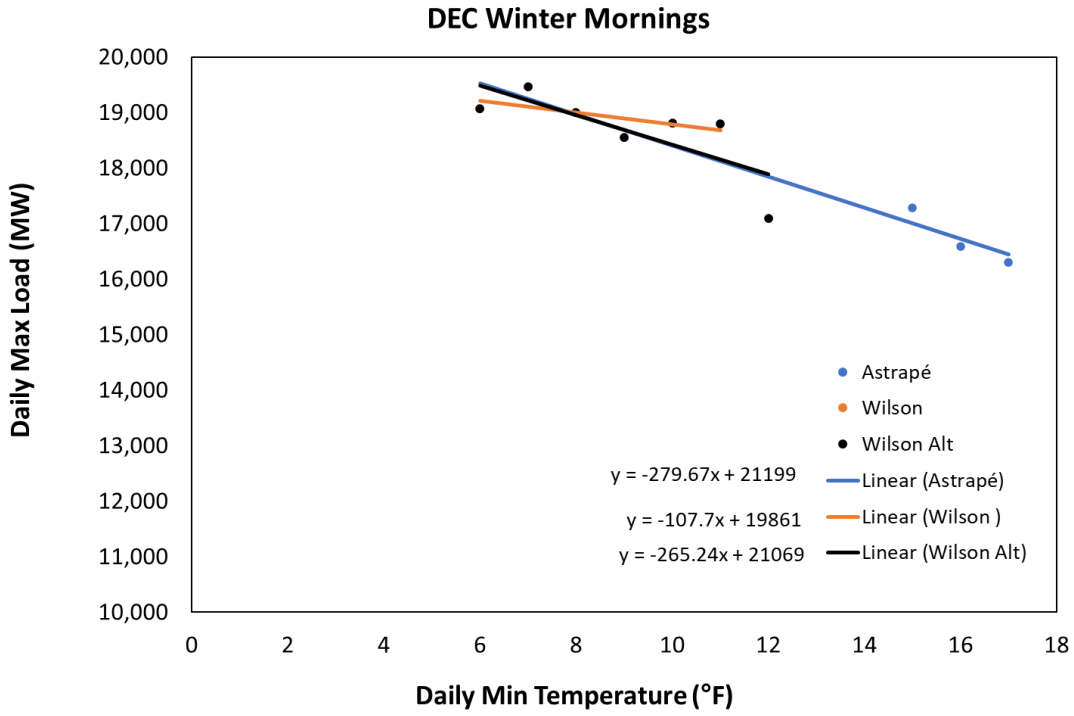
[14] Resource Adequacy Study, Appendix A, at 57-58.

[15] SACE et al. Wilson Direct Testimony Exhibit JFW-2 at 44-45.

[16] Represents the CPLE Balancing Authority Area.

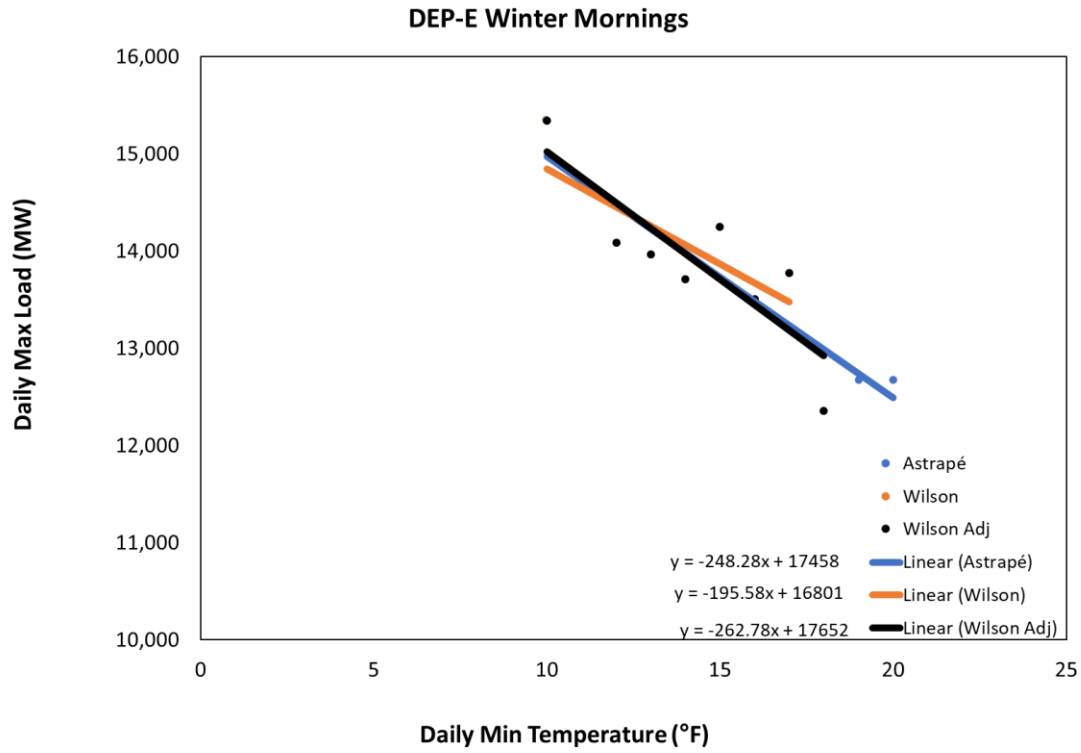
"for regression purposes a larger sample is generally preferred; but once there is a discontinuity (meaning, the next observation does not appear to align with the colder ones), I stop adding observations."[17] Given the limited number of data points for these regressions, it is expected that the inclusion/exclusion of various data points can lead to different MW/degree relationships. However, Astrapé believes that the final MW/degree relationships used in the study are robust as demonstrated below in Figures 1 and 2 and if the regressions proposed by Witness Wilson were used, the cold weather load response would be understated.

Figure 1: DEC Winter Morning Load Regression Comparison



[17] Resource Adequacy Panel Rebuttal Exhibit 1.

Figure 2: DEP-East Winter Morning Load Regression Comparison



Witness Wilson also argues against using the regressions to extrapolate load behavior at lower temperatures because "for the lowest temperatures, the relationship between temperature and load is much weaker."[18] He continues this argument by saying "[u]nder the very rare extreme cold conditions, some schools, offices, and other commercial, government, and industrial facilities may open late, remain closed, or operate at reduced levels, reducing loads during the early morning peak on such days."[19] However, Winter Storm Elliot and its significant load response occurred on Saturday, December 24th, a day when schools, offices, and government facilities were likely closed, negating

[18] SACE, et al. Wilson Direct Testimony Exhibit JFW-2 at 42.

[19] *Id.*

witness Wilson's claim that extreme cold conditions may have a correlating reduction in load. In addition, DEP peaked on a Sunday during the cold weather event experienced in early 2018[20] when most schools, offices, and government facilities were likely closed. Outside of already established DR programs, it would also not be prudent for the Companies to plan with the assumption that schools and businesses would stay closed or reduce their operations in response to extreme cold weather.

Q. DID THE RESOURCE ADEQUACY STUDY OVERSTATE THE LIKELY FREQUENCY OF EXTREME COLD TEMPERATURES BY USING HISTORICAL TEMPERATURE DATA BACK TO 1980, WEIGHTED EQUALLY?

A. No. Astrapé does not believe it is prudent to remove extreme weather years when modeling the potential risk that the Companies might face in the future. The weather patterns seen in 1985 can happen again and Astrapé assigned it a 1 in 43 probability of occurrence. There is no evidence that suggests customers will not see a weather year such as 1985 in a future year and this event is exactly the type of event that should be captured in a resource adequacy analysis. While witness Wilson points out that the annual minimum temperatures on average are increasing, this does not correlate to the frequency of these events. EPRI published a report in January of 2021 on "Exploring the Impacts of Extreme Events, Natural Gas Fuel and Other Contingencies on Resource Adequacy" which noted that "[c]old events are less cold on average but are increasing in

[20] DEP's recorded peak for the early 2018 cold weather event occurred on Sunday, January 7.

frequency" and that it is "seeing a weaker winter jet stream that 'allows' cold air from polar Canada to dip down into the northern half of the U.S. with greater frequency (e.g., creating cut-off lows, sometimes referred to as the Polar Vortex)."[21] The Polar Vortex contributed to the extreme weather seen during Winter Storm Elliot[22] as well as the cold weather event experienced in 2018.

Q. CAN RELIABILITY FOR THE COMPANIES BE IMPROVED IF TRANSMISSION TIES ARE EXPANDED TO NEIGHBORING GRID OPERATORS, AS SUGGESTED BY WITNESS GOGGIN?[23]

A. Generally, no. In the studies conducted for the Companies and across the Southeast, Astrapé has seen that transmission capability is not the constraint during extreme cold periods. DEC and DEP are modeled with significant transmission import capability and the constraint during extreme winter periods is the capacity available in surrounding regions. It is important to understand that these cold periods such as Winter Storm Elliott impact the entire region resulting in widespread capacity shortages. Thus, it is the capacity shortage and not a shortage in available transmission capacity that impacts reliability. Planning to a 22% reserve margin is the appropriate solution which appropriately takes into account the assistance provided by neighboring regions.

[21] Exploring the Impacts of Extreme Events, Natural Gas Fuel and Other Contingencies on Resource Adequacy, *available at* https://www.epri.com/research/products/000000003002019300.

[22] A portion of the Polar Vortex that became separated from the main circulation contributed to the extreme weather seen during Winter Storm Elliot.

[23] SACE, et al. Goggin Direct Testimony at 57.

Q. PLEASE RESPOND TO CEBA WITNESS CHEN'S CLAIM[24] THAT THE COMPANIES PROVIDED NO CLEAR CONCEPTUAL EXPLANATION FOR WHY THE UPDATED ECONOMIC LOAD FORECAST ERROR DISTRIBUTIONS REPRESENT NEAR SYMMETRICAL PROBABILITIES FOR OVER AND UNDER FORECASTING IN THE 2023 RESOURCE ADEQUACY STUDY WITH A SLIGHT SKEW TOWARDS UNDER-FORECASTING LOAD GROWTH IN THE FUTURE AND THAT THE COMPANIES PROVIDED NO EXPLANATION ABOUT HOW THE NEW METHODOLOGY WILL PRODUCE BETTER FORECAST ERROR DISTRIBUTIONS.

A. As with all aspects of the studies Astrapé performs on behalf of the Companies, the Companies and Astrapé have a continuous improvement mindset where the methods, models, and assumptions that go into the studies are consistently evaluated for potential improvement. As stated in the attached response to CEBA DR 4-20,[25] the Companies elected to change the methodology that develops the long-term economic load forecast uncertainty for the Resource Adequacy Study. The Companies' baseline load forecast utilizes macroeconomic data from Moody's Analytics as one of the core inputs for the projection of long-term growth. The Resource Adequacy Study also utilizes a long-term load forecast uncertainty to recognize the fact that in the delivery

[24] CEBA Chen Direct Testimony at 26.

[25] Resource Adequacy Panel Rebuttal Exhibit 2.

year, the long-term load forecast could have under or over forecasted the expected load. It is a natural fit to use the same economic forecast data, from the same vendor, for alignment purposes, in both the long-term load forecast and in the resource adequacy study's long-term economic load forecast uncertainty input.

Q. PLEASE RESPOND TO CEBA WITNESS CHEN'S CRITICISM[26] THAT THE COMPANIES SHOULD HAVE BEEN ABLE TO WITHSTAND A 1 IN 10 LOLE EVENT WITH A 24% RESERVE MARGIN DURING WINTER STORM ELLIOT.

A. Witness Chen seems to mischaracterize physical reliability and planning to the one day in 10-year standard (LOLE of 0.1). At its core, physical reliability is risk planning, mitigation, and acceptance: The Commission is setting a level of acceptable risk when it sets the Companies' planning reserve margin. Currently, the most common metric used to measure physical reliability risk is the LOLE metric with the industry level of acceptable risk being one day of load shed every ten years or an LOLE of 0.1 days per year.

A system planned to a 0.1 LOLE physical reliability level will on average experience one day of load shed every ten years. Planning to the 22% reserve margin recommended in the Resource Adequacy Study does not guarantee the Companies will not shed load. Rather, it would ensure that given the assumptions made in the Study, the Companies could expect on average to experience one day of load shed every ten years.

[26] CEBA Chen Direct Testimony at 7.

What that specific day with load shed looks like cannot be known precisely but typically includes extreme weather, poor unit performance, and neighboring regions also experiencing extreme weather and therefore tight capacity conditions. There is no specific "1 in 10 LOLE event" that the Companies' plan for. Figure C-5 of Appendix C to the CPIRP[27] shows the spectrum of the 494 observed load shed events in the model run with a 22% winter planning reserve margin. Any of those load shed events could be the event that occurs. To have an expectation of no load shed events which seems to be what witness Chen is suggesting would require the Companies to have a reserve margin much greater than 22%.

Q. DO YOU AGREE WITH CEBA WITNESS CHEN[28] THAT THE BASE CASE, WHICH IS THE BASIS FOR THE RESERVE MARGIN INCREASE, HAS LIMITED RESOURCE SHARING ACROSS DEC, DEP, AND THEIR NEIGHBORS?

A. No. The study topology of the Base Case, as shown in Figure 1 of Attachment I to the CPIRP,[29] models the Companies with nine surrounding regions including Associated Electric Cooperative, Louisville Gas and Electric, TVA, Southern Company, PJM West[30] & PJM South,[31] Yadkin, PowerSouth Energy

[27] CPIRP Appendix C at 71.

[28] CEBA Chen Direct Testimony at 24.

[29] CPIRP Attachment I at 14.

[30] PJM West is defined as the following PJM Zones: American Electric Power, East Kentucky Power Cooperative, ComEd, Duke Energy Ohio, Duke Energy Kentucky, Allegheny Power Systems, Dayton Power and Light Company and Ohio Valley Electric Corporation.

[31] PJM South is defined as the PJM DOM Zone.

Cooperative, Dominion Energy South Carolina (formally known as South Carolina Electric & Gas), and Santee Cooper. Astrapé recognizes that DEC and DEP are part of the larger Eastern Interconnection and models the majority of all Southeast Energy Exchange Market ("SEEM") members.[32] The study included comprehensive modeling of the other areas' loads and resources ensuring weather diversity and generator outage diversity are captured.

Further, as noted in the Resource Adequacy Study, DEC and DEP intend to merge and as a result the Combined Case is the recommended Base Case scenario. In the modeling for the Resource Adequacy Study, this combined utility includes joint unit commitment, dispatch, and ancillary services, and consolidates the balancing authorities and removes associated transmission constraints between existing BAs.[33]

For all of these reasons, it is clear that the Resource Adequacy Study provides a comprehensive look at the Companies' interconnected system and captures the reserve margin benefits of those interconnections.

Q. DO YOU AGREE WITH CEBA WITNESS CHEN[34] THAT THE BASE CASE SHOULD TAKE INTO ACCOUNT EXCESS CAPACITY IN SURROUNDING REGIONS?

A. No. The purpose of modeling resources and load for neighboring entities is to capture inherent weather diversity and generator outage diversity that the

[32] Due to the limited transmission capability from the Florida peninsula to Southern Company, Florida entities were excluded from the modeling.

[33] Resource Adequacy Study at 6, n.8.

[34] CEBA Chen Direct Testimony at 26.

Companies have with their neighbors. In order to accurately capture this, Astrapé modeled all the neighbors assuming they also planned to the one day in 10-year standard (0.1 LOLE) which is the most common industry resource adequacy standard. Witness Chen is suggesting that the Companies should expect surrounding regions to build excess capacity to allow the Companies to lean on their neighbors and build less capacity reserves. This is not a prudent modeling methodology and puts the Companies' customers at substantial risk. The Companies have no control over what neighboring entities such as Southern Company, TVA, or PJM may build in the future. The Companies can only control their resource plans and it would be imprudent to assume a neighboring entity such as Southern Company is going to carry, for example purposes, 5% more reserves for the long term in order for the Companies to meet its LOLE target at a lower reserve margin. Further, if all entities planned this way by assuming neighboring regions had excess capacity, then all entities would have target reserve margins that are too low. It is a more reasonable assumption to assume that neighboring entities will be at the one day in 10-year LOLE standard which allows the Companies to take advantage of weather and generator outage diversity it has with its interconnected neighbors.

Lastly, the Panel does not expect surrounding regions to have excess capacity in extreme winter weather periods. The 2023/2024 NERC Winter Reliability Assessment shows that many of the entities surrounding the Companies have elevated risk meaning during extreme weather conditions there could be insufficient operating reserves (see Figure 3 below). Given this

information and the recent 2022 Winter Storm Elliott event, the Panel would not advise modeling neighbors with excess capacity in order to reduce the Companies' reserve margin.

Figure 3: NERC 2023-2024 Winter Reliability Assessment

Winter Reliability Risk Area Summary[35]

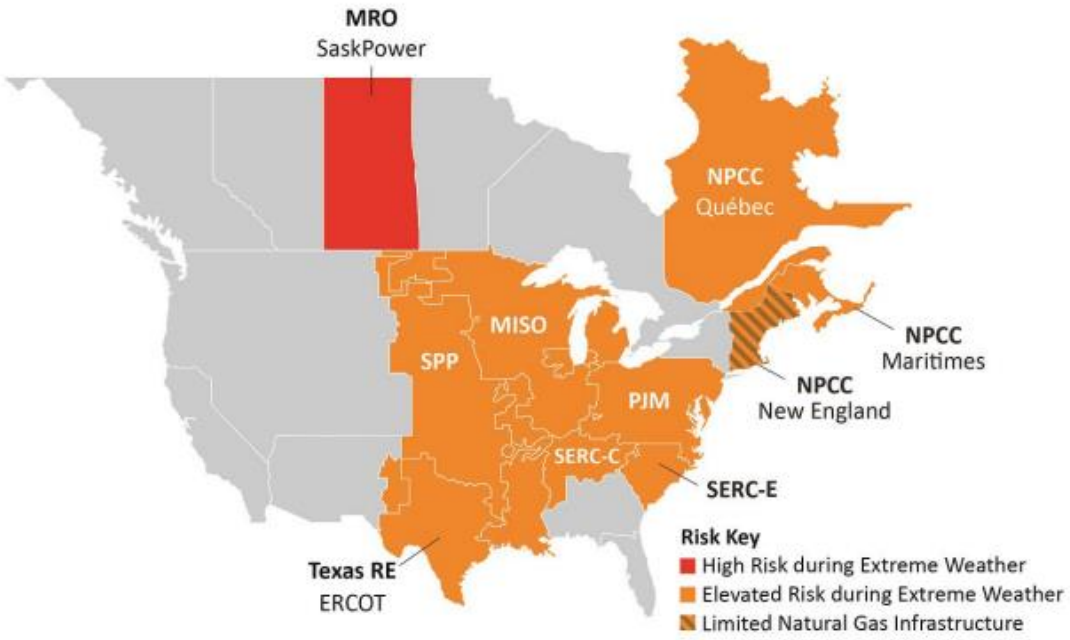


Figure 1: Winter Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

Q. **DO YOU AGREE WITH CEBA WITNESS CHEN[36] THAT THE 1-IN-10 LOLE CRITERION TENDS TO ESTABLISH RESERVE MARGINS HIGHER THAN THE ECONOMICALLY OPTIMAL RESERVE**

[35] NERC 2023-2024 Winter Reliability Assessment, November 2023, slide 5, *available at* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

[36] CEBA Chen Direct Testimony at 8.

MARGIN AND THAT ONE WAY TO AVOID THIS IS TO ESTIMATE THE COST OF INCREASING RESOURCE ADEQUACY REQUIREMENTS THROUGH THE COST OF NEW ENTRY ("CONE")?

A. As previously discussed, the most common industry resource adequacy standard is the one day in 10-year LOLE standard, which equates to an LOLE of 0.1 days per year While the Panel agrees that an economic approach can be utilized to understand an economic optimal reserve margin, that does not mean system physical reliability on behalf of customers should be ignored.

In her description of economic reserve margin analysis, witness Chen mischaracterizes the benefits of new capacity as only avoiding loss of load as shown in Figure 1 of her testimony. Adding a new resource at the CONE provides more economic benefits than simply reducing loss of load. Our studies have shown that the benefits of production cost savings, and avoidance of expensive market purchases as a result of scarcity pricing add substantial benefit on top of the reduction in loss of load. Astrapé has analyzed economics in the past and even for the Companies in the 2020 Resource Adequacy Study. Those results showed that depending on the confidence level the analysis assumes on system energy costs, the reserve margin required to meet the one day in 10-year LOLE standard can actually be fairly close to the economic reserve margin. It is rational to view the data this way because CONE, which represents the fixed cost of the resource, is more known with a small band of uncertainty while system energy costs are much more volatile because they can

be extremely high in years with reliability events. In order to attempt to put CONE and the system energy costs on a similar basis in regard to uncertainty, higher confidence level ranges can be considered for system energy costs. In the 2020 study, DEC saw that using the 85th percentile[37] resulted in a reserve margin slightly higher than the reserve margin required to meet the one day in 10-year LOLE standard. Even in the FERC report that witness Chen cites, which was authored by Astrapé and the Brattle Group and based on a hypothetical system, the risk mitigation benefit of increased reserve margins is discussed: Specifically how incorporating the 85th percentile or higher on system reliability costs can show the economic optimal reserve margin near the reserve margin required to meet the one day in 10-year LOLE standard.[38]

In conclusion, the economic analysis serves as another data point but does not substitute for ensuring reliability for customers during a time when the industry is experiencing a rapid transition.

Q. HOW DO YOU RESPOND TO SACE, ET AL. WITNESS ROUMPANI'S CLAIM[39] THAT THE STATIC APPROACH TAKEN IN THE RESOURCE ADEQUACY STUDY CAN RESULT IN AN INFLATED RESERVE MARGIN FOR THE YEARS THAT THE COAL UNITS HAVE RETIRED, AND AN OVERBUILD OF THE SYSTEM?

[37] Duke Energy Carolinas, Integrated Resource Plan, Attachment III at 53 (Figure 13), Docket No. E-100, Sub 165 (Sept. 1, 2020).

[38] Resource Adequacy Requirements: Reliability and Economic Implications, The Brattle Group and Astrapé Consulting, September 2013, Section III.A.4, *available at* https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf.

[39] SACE et al. Roumpani Direct Testimony at 38.

A. As an initial matter, it is not practical to conduct a resource adequacy study and develop individual planning reserve margins to cover every possible scenario and combination of resources for all years in a planning period. Astrapé recommends that new resource adequacy studies typically be conducted every two to three years or when key input assumptions have changed that may impact the study results. The Resource Adequacy Study modeled study year 2027 to develop a planning reserve margin target for the planning period.[40] The SERVM simulation results are broadly applicable to future years assuming that resource mixes and market structures do not change in a manner that shifts the reliability risk to a different season or different time of day. The Panel agrees with witness Roumpani's point that changing resource mixes can result in changes in the planning reserve margin. However, future studies will allow for time to check and adjust for a changing resource portfolio. As explained on pages 38-39 of the IRP and Modeling Panel's Direct Testimony, the Companies included a reliability verification step in the planning process to ensure that the final portfolio maintains or improves reliability.

Q. DO YOU AGREE WITH WITNESS CHEN[41] THAT INCLUDING PLANNED OUTAGES DURING LOSS-OF-LOAD EVENTS IN THE MODELING CAN OVERESTIMATE UNAVOIDABLE OUTAGES AND UNDERESTIMATE CAPACITY AVAILABILITY DURING CERTAIN TIMES?

[40] The year 2027 was chosen because it is four years into the future (at the time of the study) which is indicative of the amount of time needed to permit and construct a new generating facility.

[41] CEBA Chen Direct Testimony at 13.

A. No. As stated in the attached response to CEBA DR 4-13,[42] almost all of the loss of load events occur during days with no planned maintenance. Astrapé confirmed with a SERVM run that if planned maintenance was removed from the few days where planned maintenance was scheduled and there was loss of load, the resulting LOLE metric would not materially change. Further, the planning reserve margin to achieve 0.1 LOLE would also not materially change.

Q. DO YOU AGREE WITH NC WARN WITNESS KONIDENA'S STATEMENT[43] THAT NERC'S 2023-2024 WINTER REFERENCE RESERVE MARGIN LEVEL FOR SERC-EAST IS 15%?

A. I am not familiar with a NERC term "Reference Reserve Margin Level", but I am familiar with NERC's Reference Margin Level ("RML") term and agree that NERC has assigned 15% for the SERC region.[44]

Q. WHAT IS NERC'S REFERENCE MARGIN LEVEL?

A. In NERC's resource adequacy assessments, it includes an RML for each assessment area. NERC notes that the assumptions and naming convention of this metric vary by assessment area, and an assessment area may determine an RML using both deterministic and probabilistic (e.g., based on a 0.1 LOLE) approaches. In some assessment areas, an RML is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the RML is a requirement. However, it is important to note that if an RML is not

[42] Resource Adequacy Panel Rebuttal Exhibit 3.

[43] NC WARN Konidena Direct Testimony at 8-9.

[44] DEC and DEP are members of the SERC region and members of the SERC-East subregion.

provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.[45] Since SERC does not provide an RML to NERC, NERC assigns a 15% RML to SERC in its resource adequacy assessments. RML is not established by NERC "for an area to meet the one day in 10-year LOLE standard", as suggested by witness Konidena.[46]

Q. DOES NERC RECOMMEND THAT THE COMPANIES PLAN TO A 15% REFERENCE MARGIN LEVEL?

A. No. To be clear, NERC has not conducted any study for the Companies' systems that suggests a 15% winter reserve margin is sufficient to maintain reliable electric service. Blindly using this reference would be irresponsible, as every region of the country is different with different resource adequacy challenges. Further, as discussed by witness Thomas, surrounding regions all have winter reserve margin requirements of greater than 15%.[47]

Q. DO YOU AGREE WITH WITNESS KONIDENA'S CLAIM ON PAGE 9 OF HIS DIRECT TESTIMONY THAT "A REFERENCE MARGIN LEVEL IS ESTABLISHED FOR AN AREA TO MEET THE 1 DAY IN 10-YEAR RELIABILITY STANDARD?"

A. No, not for all assessment areas. As I noted earlier, some assessment areas may establish an RML based on the 0.1 LOLE standard. However, for assessment areas that do not establish an RML, NERC assigns 15% for predominately

[45] NERC 2023-2024 Winter Reliability Assessment, November 2023, slide 34, *available at* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

[46] NC WARN Konidena Direct Testimony at 9.

[47] Public Staff Thomas Direct Testimony at 33-34.

thermal systems. SERC does not establish an RML and thus NERC assigns a 15% RML to SERC. The 15% RML that NERC assigns to SERC is not based on the one day in 10-year LOLE standard. NERC clearly states that the planning reserve margin is the primary metric used to measure resource adequacy and is defined as the difference in resources and net internal demand then divided by net internal demand and shown as a percentage.[48]

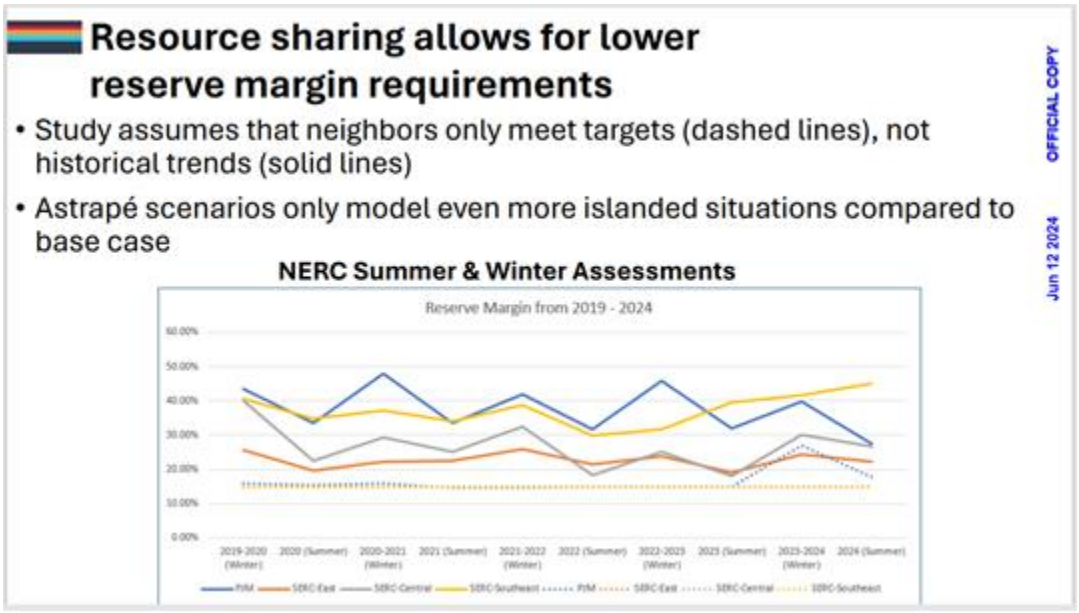
Q. WHAT IS ASTRAPÉ'S RECOMMENDED WINTER PLANNING RESERVE MARGIN?

A. The results of the Resource Adequacy Study indicate that a 22% winter planning reserve margin is needed to meet reliability and maintain a 0.1 LOLE.

Q. AT THE JUNE 17, 2024 TECHNICAL CONFERENCE, WITNESS CHEN DISCUSSED HISTORICAL RESERVE MARGINS IN THE FOLLOWING FIGURE 4, WHICH WAS NOT INCLUDED IN HER DIRECT TESTIMONY. PLEASE DESCRIBE WHAT THE CHART SHOWS AND ANY CONCERNS THAT YOU HAVE WITH THIS CHART.

[48] NERC 2023-2024 Winter Reliability Assessment, November 2023, slide 34, *available at* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

Figure 4: CEBA's Technical Conference Presentation Materials, Slide 9



A. The chart is inaccurate and misleading and was not included in witness Chen's Direct Testimony but was used to illustrate the erroneous claim that historical reserve margins are much greater than target reserve margins required to meet the one day in 10-year standard or (LOLE of 0.1). The slide suggests that the dotted lines are planning reserve margin targets for surrounding neighbors to meet the one day in 10-year LOLE standard. The dotted lines seem to fall at about a 15% reserve margin which aligns with NERC's RML that it assigns to SERC as a reference level of reserves, as explained above in response to NC WARN witness Konidena's claims. Regardless, SERC does not have a 15% target reserve margin and a 15% reserve margin is significantly lower than neighboring reserve margin requirements. As Public Staff Witness Thomas points out, Southern Company, which makes up the majority of SERC Southeast, requires a 26% winter reserve margin and TVA, which makes up the

majority of SERC Central, requires a 25% winter reserve margin.[49] If those are plotted correctly on the curve, the target reserve margins (dashed lines) would be approximately 10% higher than what witness Chen shows on her slide. As stated previously, the Companies can only control their own resource plans and it would be imprudent to assume a neighboring entity would carry more reserves for the long term in order for the Companies to meet its LOLE target at a lower reserve margin.

III. RESULTS OF ELCC STUDIES

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANIES' ELCC STUDIES.

A. Astrapé performed the 2022 Solar and Storage ELCC Study and the 2023 Wind ELCC Study on behalf of the Companies for use in developing the CPIRP. In the 2022 Solar and Storage ELCC Study, large penetrations of solar and large penetrations of storage were analyzed and the synergistic benefits between the two technologies were captured. Also, various durations of storage were analyzed. The results of that analysis showed that marginal winter solar ELCCs were generally less than 5% due to solar not being available during extreme morning peaks and that initial tranches of storage showed high ELCC (near 100%) but decline at differing rates depending on penetration and duration of storage. Similarly, the 2023 Wind ELCC Study results were varied with solar penetration to capture any wind and solar synergistic benefits. The results showed that onshore marginal winter wind ELCC values ranged in the 20-45%

[49] Public Staff Thomas Direct Testimony at 33.

range depending on penetration across the Companies and 60-75% for offshore marginal winter wind ELCC values. The marginal ELCCs from these studies were used in the Companies' expansion planning model.

Q. DID THE PUBLIC STAFF FIND ASTRAPÉ'S ELCC STUDIES TO BE REASONABLE?

A. Yes, the Public Staff found the Companies' ELCC Studies to be reasonable.[50]

A. RESPONSE TO INTERVENORS

Q. DO YOU AGREE WITH AGO WITNESS BURGESS'S CONTENTION[51] THAT THE COMPANIES HAVE INFLATED THE RELIABILITY CONTRIBUTIONS OF GAS RESOURCES SINCE DUKE DOES NOT HAVE FIRM FUEL SUPPLY FOR A LARGE SHARE OF ITS GAS FLEET?

A. No. The reliability of gas resources was not inflated. As described more fully in the Natural Gas Firm Transportation and Fuel Supply Panel's rebuttal testimony, all of the Companies' existing and planned gas resources have either access to interstate firm gas transportation or delivered gas supply with onsite backup fuel supply.

Q. HOW DO YOU RESPOND TO SACE, ET AL. WITNESS ROUMPANI'S CLAIM THAT THE CAPACITY CONTRIBUTION OF NATURAL GAS

[50] Public Staff Thomas Direct at 39-40.

[51] AGO Burgess Direct Testimony at 61.

RESOURCES IS OVERESTIMATED IN THE COMPANIES' MODELING?[52]

A. The approach utilized by Astrapé and the Companies fully recognizes that new gas resources do not provide 100% ELCC due to forced outages. To adjust for this, as discussed in this panel's direct testimony, solar, storage, and wind resources are not compared against a perfect load but rather a load that reflected a 4% outage rate in order to evaluate renewables on a level playing field with a gas resource. The 4% outage rate represents the high end of new thermal resources such as new combined cycle or combustion turbine resources. By performing the study this way, solar, wind, and storage resources only have reduced ELCCs due to their intermittent profiles in case of solar and wind and energy limitations in the case of storage. As discussed in more detail in the Natural Gas Firm Transportation and Fuel Supply Panel's rebuttal testimony, new gas resources will have firm gas transportation and onsite back-up fuel supply. In addition, new gas resources will be winterized to address the lowest temperatures seen on record.[53] For these reasons the marginal ELCC of a new gas resource will be equal to 1 – Equivalent Forced Outage Rate ("EFOR") and the upward adjustment made to the storage, solar, and wind ELCCs put the resources on an equal playing field.

[52] SACE, et al. Roumpani Direct Testimony at 67.

[53] Commission Rule R8-61 (Certificate of Public Convenience and Necessity) requires "a verified statement as to whether the facility will be capable of operating during the lowest temperature that has been recorded in the area."

Q. HOW DO YOU RESPOND TO INTERVENORS THAT CONTEND DUKE ENERGY HAS NOT REDUCED THE ACCREDITED CAPACITY VALUE OF GAS GENERATORS TO ACCOUNT FOR THE RELIABILITY RISKS OF CORRELATED GAS GENERATOR OUTAGES, LIKE THOSE EXPERIENCED DURING WINTER STORM ELLIOTT AND OTHER RECENT COLD SNAPS?[54]

A. As previously stated, new gas resources will have firm fuel supply[55] and be winterized to satisfy Commission Rule R8-61(b)(4)(iv). As discussed above, the ELCCs of solar, wind, and storage were conducted to compare against a new gas resource that was assumed to have a 4% forced outage rate to ensure an equal playing field. Said another way, the ELCC value for a given resource is a comparison to a new gas unit with a 4% forced outage rate which implies that a unit that has 4% forced outage rate would still get a 100% ELCC. Of note, there is still uncertainty in the long-term forced outage rates for new resources such as utility scale battery energy storage systems ("BESS") which should continue to be evaluated as that technology matures within the industry. Astrapé did recognize that older thermal resources have shown some level of correlated outages and those are included in the resource adequacy study. Correlated outages for existing units were based on the 5 years (2018-2022) of historical outage rate data used in the study.

[54] SACE, et al. Goggin Direct Testimony at 65; SACE, et al. Roumpani Direct Testimony at 63-64; CEBA Chen Direct Testimony at 11.

[55] Reference the Natural Gas Firm Transportation and Fuel Supply Panel's rebuttal testimony for details regarding fuel supply security of the Companies' generation fleet.

Q. SACE, ET AL. WITNESSES ROUMPANI[56] AND GOGGIN[57] REFERENCE A 2022 ASTRAPÉ REPORT WHICH SHOWS THAT CORRELATED OUTAGES CAN SIGNIFICANTLY REDUCE RELIABILITY CONTRIBUTIONS OF THERMAL RESOURCES. PLEASE PROVIDE SOME GENERAL CONTEXT TO THE ASTRAPÉ REPORT AND ITS FINDINGS, AND ITS RELEVANCE IN THIS PROCEEDING.

A. The report cited is an analysis of historical data and the ELCC represents an average ELCC of the fleet versus the marginal ELCC of a new resource. While the average ELCC of the thermal fleet was not calculated for the Companies, the correlated cold weather outages as discussed in the Resource Adequacy Study[58] were modeled in the study which would yield an ELCC of less than 1-EFOR for the thermal fleet. Provided fuel plans and winterization plans for new gas resources, a new gas resource's marginal ELCC would only decrease from 100% due to expected forced outage rates (1- EFOR) which is why solar, wind, and storage were only compared against a resource with a 4% outage rate.

IV. CONCLUSION

Q. DOES THIS CONCLUDE THE PANEL'S REBUTTAL TESTIMONY?

A. Yes.

[56] SACE, et al. Roumpani Direct Testimony at 64.

[57] SACE, et al. Goggin Direct Testimony at 68.

[58] Resource Adequacy Study, Section III.G at 33.

SACE, et al.

Request:

Pages 44 and 45 of witness Wilson's direct testimony shows two regression equations. Please provide the rationale for determining the threshold of temperatures under 12 degrees for DEC and the threshold under 18 degrees for DEP-E.

Response:

The goal is to understand the incremental impact of additional temperature drop at the most extreme temperatures. Accordingly, I begin with the coldest observations and work backward. As long as additional, warmer observations are reasonably aligned with the coldest, I add observations, because for regression purposes a larger sample is generally preferred; but once there is a discontinuity (meaning, the next observation does not appear to align with the colder ones), I stop adding observations.

For my Figure 13 using temperatures under 12 degrees for DEC, the next observation fell far from the coldest six observations and their trend line. Similarly for my Figure 14 using temperatures under 18 degrees for DEP-E, the next observation fell far from the coldest seven observations and their trend line.

Response provided by: James Wilson

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DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Why did the 2020 economic load forecast error distribution model weigh over- forecasting more than under-forecasting load? Does this distribution pertain to long-term forecast and not short-term forecasts? Why did you choose a more symmetrical distribution this time for the 2023 study? Is the long-term load forecast now more under forecasted and, if so, by how much? In other words, is the more symmetrical distribution essentially based on an assumption that DEC/DEP equally over- and under-forecasts load in the long term?

Response:

The 2020 and 2023 economic load forecast error ("LFE") distributions differ due to their use of different underlying sources of economic uncertainty. The 2020 distribution is based on a backward-looking methodology using historical forecast errors in the 4-year Congressional Budget Office GDP projections.

The Companies updated the 2023 economic LFE distribution to use a forward-looking approach using the same macroeconomic data source that is used for the baseline load forecast. As discussed in Appendix D – Electric Load Forecast, the Companies utilize Moody's Analytics' baseline forecast as one of the core inputs for the projection of long-term load growth. The 2023 Resource Adequacy Study used a new approach to estimating the macroeconomic forecast error relative to this central projection that takes advantage of additional higher and lower macroeconomic forecast scenarios that are assigned explicit probabilities by Moody's.

The Moody's baseline forecast is the median outcome from a series of macroeconomic simulations and thus higher or lower economic growth scenarios are simulated as being equally probable. However, the magnitude of the forecast error in these scenarios is not necessarily identical and thus the resulting multipliers are not symmetrical. Any symmetry or asymmetry in the resulting economic LFE distribution is a result of the Moody's forecasting process and will vary as the forecast of economic conditions change.

Both the 2020 and 2023 distributions of economic load forecast error are specifically intended to capture the effects of potential long-term deviations in the macroeconomic environment on load growth from the baseline forecast and do not reflect the distribution of potential short-term (e.g., operational) load forecast errors.

Responder: Patrick O'Connor, Lead Quantitative Analyst

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DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

In the modeling, the historical outage data includes planned outages. Could some of these planned outages be scheduled for when the capacity is not needed, particularly as short-term load forecasts are improved? If so, does including these planned outages in historical outage data overestimate outages and underestimate capacity availability during certain times? In other words, does SERVM include the grid operator's ability to schedule planned outages around events? How large of an impact is that on the resulting recommended reserve margin?

Response:

Forced outage data is based on historical data. The planned maintenance percentage rates are based on planned data and not historical data. SERVM schedules planned outages based on the average daily peak net loads. SERVM optimizes the planned maintenance to be scheduled during off peak days. This results in no planned maintenance scheduled in the vast majority of loss of load events for DEC and DEP.

Responder: Tom J. Davis, Principal Planning Analyst

Figure 1: DEC Winter Morning Load Regression Comparison

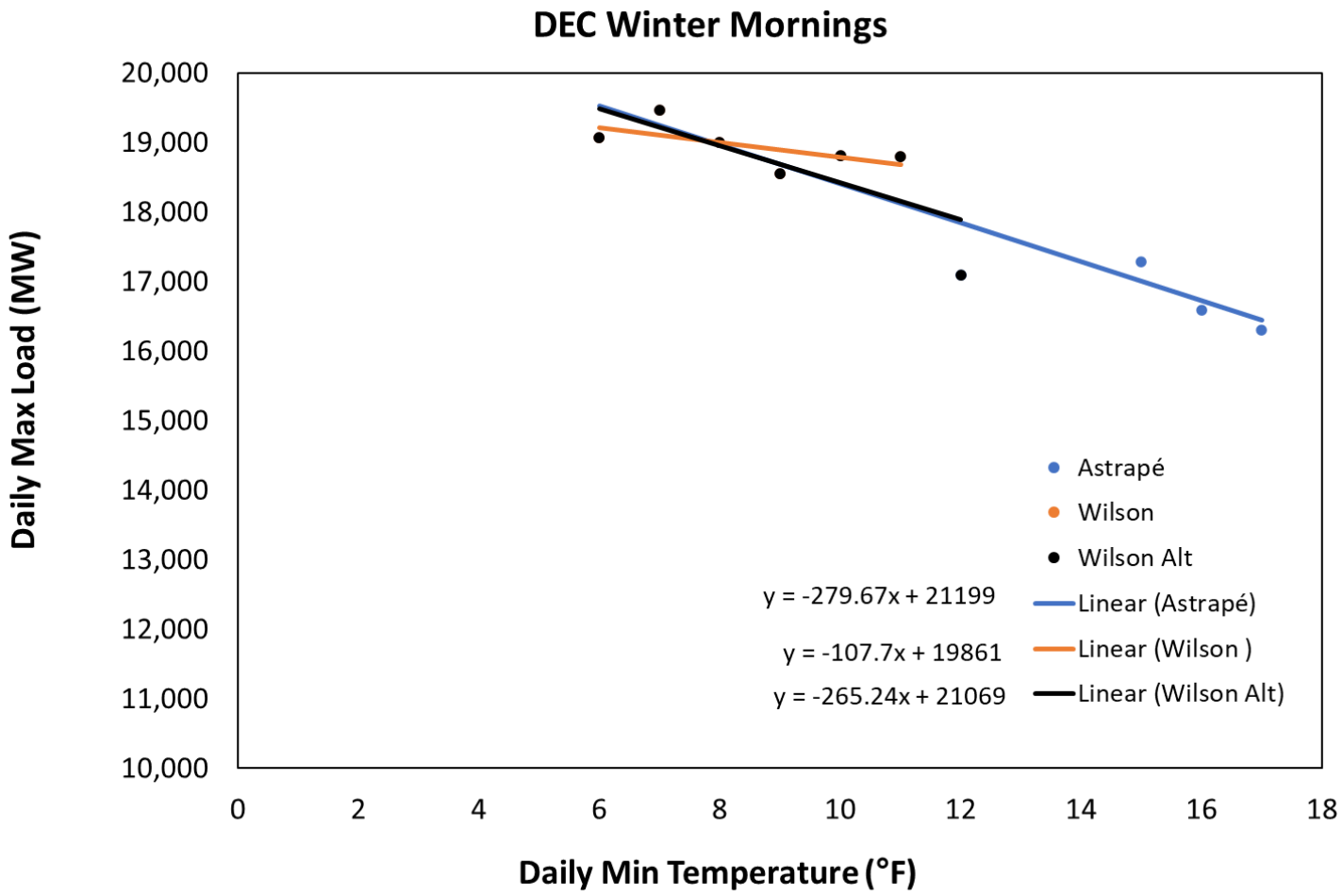


Figure 2: DEP-East Winter Morning Load Regression Comparison

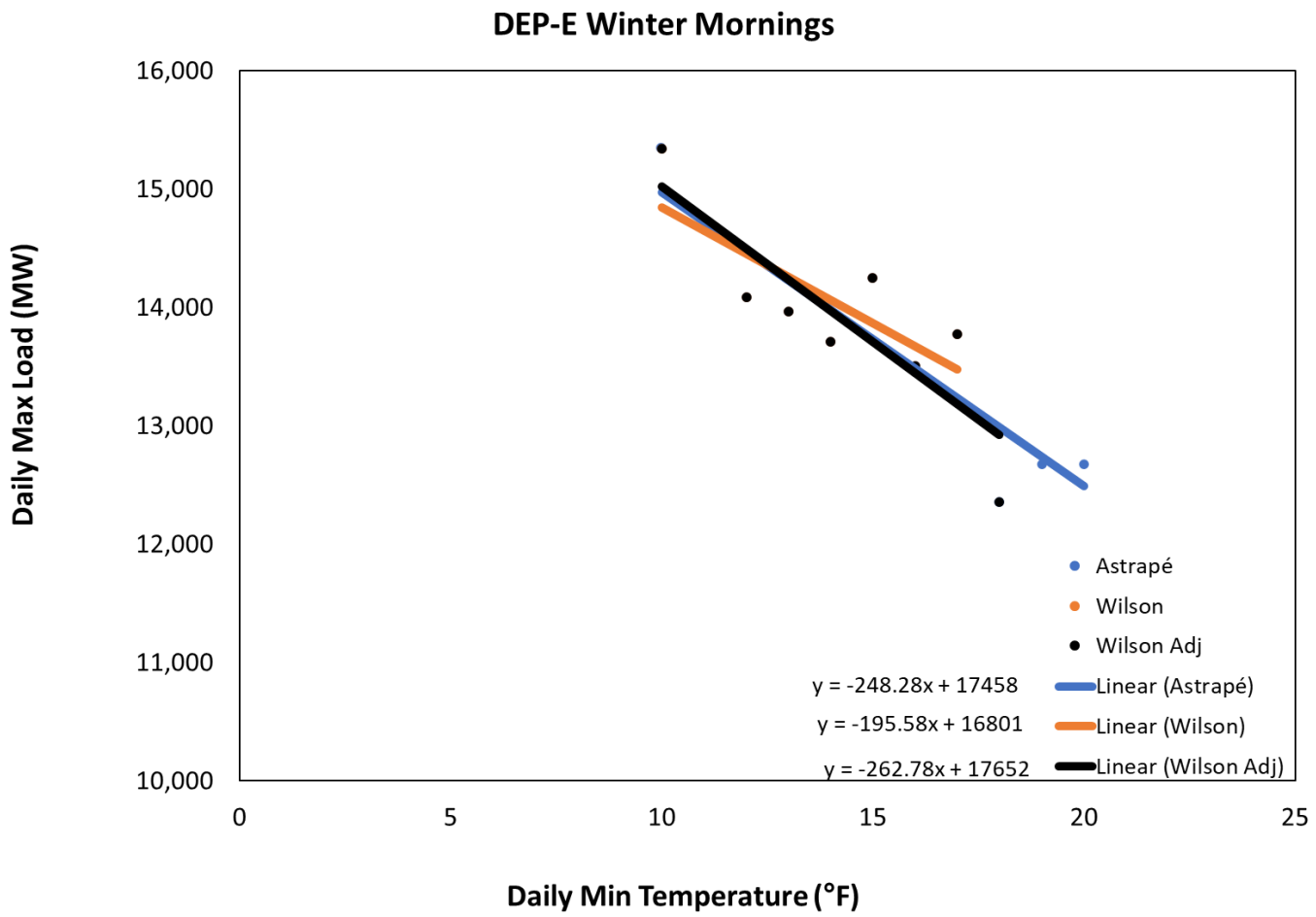


Figure 3: NERC 2023-2024 Winter Reliability Assessment

Winter Reliability Risk Area Summary[1]

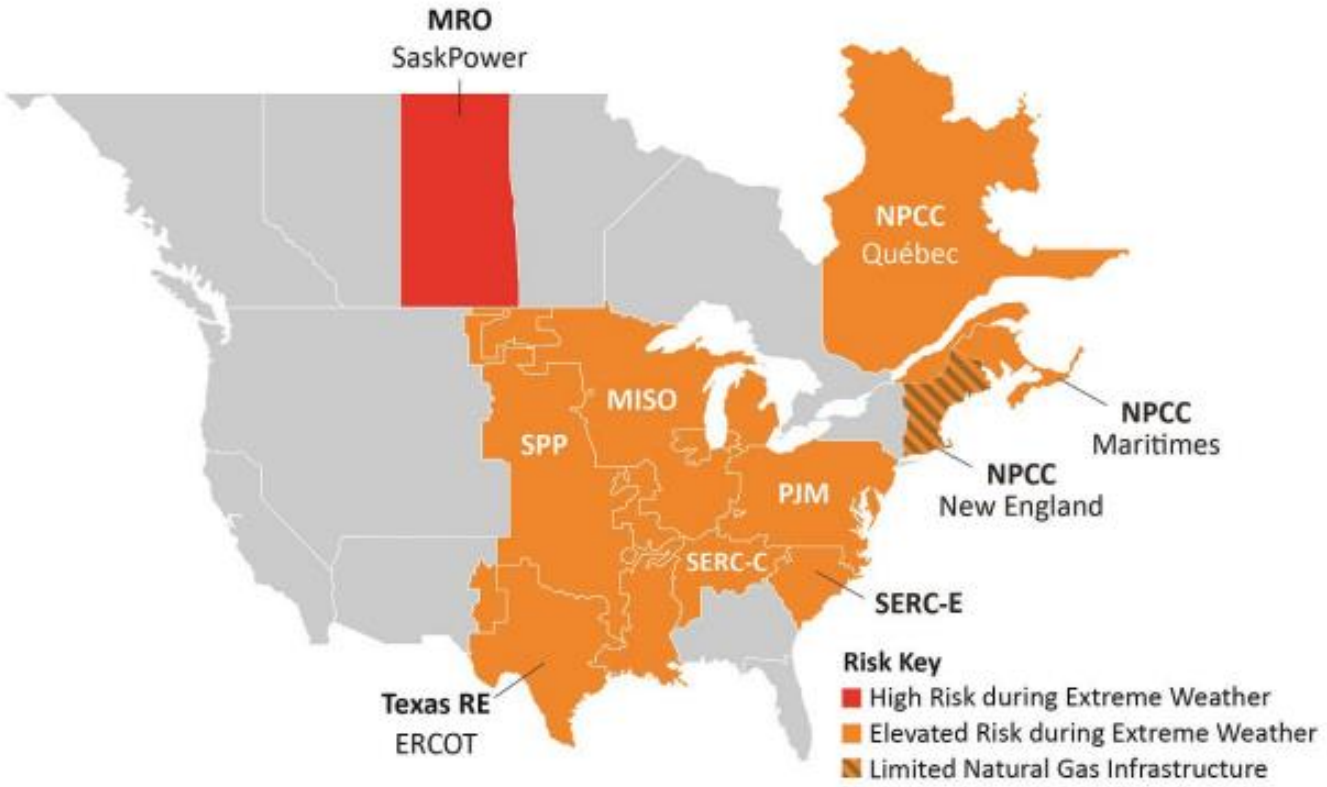


Figure 1: Winter Reliability Risk Area Summary

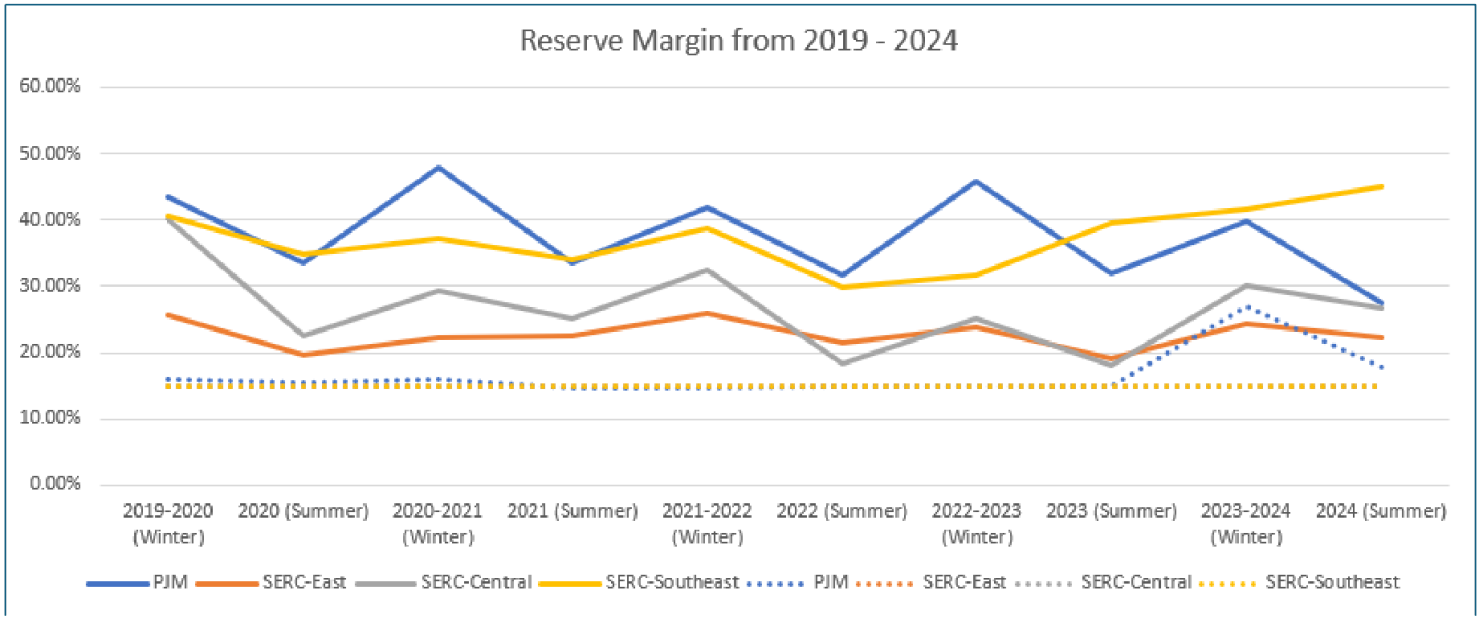
Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

Figure 4: CEBA's Technical Conference Presentation Materials, Slide 9

Resource sharing allows for lower reserve margin requirements

- Study assumes that neighbors only meet targets (dashed lines), not historical trends (solid lines)
- Astrapé scenarios only model even more islanded situations compared to base case

NERC Summer & Winter Assessments



[1] NERC 2023-2024 Winter Reliability Assessment, November 2023, slide 5, *available at* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.