STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. M-100, SUB 163

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Investigation Regarding the Ability of North Carolina's Electricity, Natural Gas, and Water/Wastewater Systems to Operate Reliably During Extreme Cold Weather	)	ORDER MAKING FINDINGS AND DIRECTING ACTIONS RELATED TO IMPACT OF WINTER STORM ELLIOTT

BY THE COMMISSION: On January 3, 2023, Duke Energy Progress, LLC (DEP) and Duke Energy Carolinas, LLC (DEC, collectively, Duke) appeared before the Commission to present information on the load shed event that occurred on the DEC and DEP systems on December 24, 2022, due to Winter Storm Elliott.[1]

Subsequent to that presentation, the Public Staff conducted an investigation into the circumstances underlying the event and has engaged DEP and DEC in several rounds of discovery.

On August 7, 2023, the Commission issued an Order Scheduling Technical Conference. On September 26, 2023, the Commission held that technical conference for DEC and DEP to update the Commission with additional data and information since its January presentation and for the Public Staff to present the results of its investigation along with any recommendations resulting from that investigation (Technical Conference).

The purpose of this Order is to present the results of the Commission's assessment of the impact of Winter Storm Elliott on the electric system in North Carolina. Winter Storm Elliott is not the first extreme winter weather event that has impacted North Carolina's electric system, and it certainly will not be the last. As they have done in the past, DEC and DEP must review and revise operations protocols to incorporate lessons learned from each

[1] This docket was initiated on January 26, 2022, when the Commission issued its Order Opening Investigation, Scheduling Technical Conferences, Requiring Responses, and Allowing Comments and Reply Comments to examine reliability and integrity of the jurisdictional utility systems in North Carolina during extreme weather events, in light of the Winter Storm Uri-related outages experienced in Texas in February of 2021. On November 16, 2021, the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) issued the February 2021 Cold Weather Outages in Texas and the South Central United States: FERC, NERC, and Regional Entity Staff Report. The Commission initiated this docket following the issuance of the federal report and on April 19, 2022, held a technical conference focused on the extreme weather preparedness of natural gas and electric utilities in North Carolina.

The Commission's assessment of the impact of Winter Storm Elliott occurs in this docket as it is a continuation of the Commission's review of the ability of the jurisdictional utility systems to operate reliably during extreme cold weather.

event, to ensure that problems or failures experienced during one event do not recur during the next event. Winter Storm Elliott presented new and different challenges — including rapidity of weather change, unusual load behavior, and occurrence over a long weekend including a holiday. DEC and DEP have already begun work on revising operations protocols to incorporate their experience from Winter Storm Elliott. However, to ensure that appropriate actions have been taken to address the deficiencies/failures that occurred during Winter Storm Elliott so that they do not recur, the Commission will direct that DEC and DEP report on such actions to the Commission, as explained below in greater detail.

SOURCES REVIEWED

In issuing this Order, the Commission has reviewed the following sources of information:

(1) All filings made in this docket, including responses to discovery requests from the Public Staff, the January 2023 presentation by DEC and DEP, and the information provided during the Technical Conference;

(2) General Load Reduction and System Restoration Plan (GLRP) of DEC and of DEP;[2]

(3) Inquiry into Bulk-Power System Operations During 2022 Winter Storm Elliott, FERC, NERC, and Regional Entity Staff Report, October 2023 (NERC Report); [3]

(4) Winter Storm Elliott, Event Analysis and Recommendation Report, PJM Interconnection, LLC (PJM), July 17, 2023 (PJM Report);[4]

(5) Gas Electric Harmonization Forum Report, North American Energy Standards Board (NAESB), July 28, 2023 (NAESB Report);[5]

(6) Inspection and Examination Report of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC December 2022 Winter Storm Outages and Blackouts prepared by GDS Associates, Inc. for the Office of Regulatory

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[2] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's General Load Reduction & System Restoration Plans, *Notice of Rulemaking Procedure in the Matter of Load Reduction by Electric Suppliers During Times of Emergencies Caused by Failure or Inadequacies*, No. E-100, Sub 10A (May 12, 2022).

[3] https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022.

[4] https://pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx.

[5] https://www.naesb.org/pdf4/geh_final_report_072823.pdf.

Staff of the South Carolina Public Service Commission, August 25, 2023 (ORS Report);[6] and

(7) After Action Report / Winter Storm Elliott, Tennessee Valley Authority (TVA Report).[7]

WINTER STORM ELLIOTT IN THE DEC AND DEP SERVICE AREAS

On December 21 through December 27, 2022, an arctic cold front, which has since come to be known as Winter Storm Elliott, moved from west to east across most of the nation, bringing rain, snow, ice, and high winds that sent temperatures plummeting at a rapid pace.[8] The front impacted the southeastern United States for several days during this period of time. Many locations in the region recorded daily mean temperatures between 20 and 35 degrees below average.[9] Several long-term stations (i.e., period of record of at least 70 years) recorded their lowest maximum temperature for any December day, including Murphy, North Carolina, which recorded a temperature of 11 degrees on December 24.[10] Grandfather Mountain, North Carolina dropped to -18 degrees on December 24, which tied its 3rd coldest minimum temperature for any December day in a record going back to 1955.[11]

Duke Energy maintains an internal meteorology team that provides both short- and long-term weather forecasts and weather statements specific to DEC and DEP and to

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[6] The Commission notes that Duke expressed the opinion that while the ORS Report is factually "correct" the report omits relevant context and that many of the recommendations emanating from the report "were actions that [Duke was] already performing or planning on doing." Transcript of Technical Conference Held in Raleigh on September 26, 2023, *Investigation Regarding the Ability of North Carolina's Electricity, Natural Gas, and Water/Wastewater Systems to Operate Reliably During Extreme Cold Weather*, No. M-100, Sub 163, at 71 (Oct. 12, 2023) (Tech. Conf. tr.). A letter dated August 29, 2023 addressed to the Chief Clerk/Executive Director of the South Carolina Public Service Commission from Duke Energy indicates that while the "Companies mostly concur with the factual reporting and analysis in the ORS Report, there are complex issues covered in the Report that are not accurately reported or contextualized. The Companies believe these issues must be clarified for the Commission to have a complete and accurate understanding of the events relating to Elliot and the outages it caused." The letter sets forth Duke's points in response to the ORS Report.

The Commission further notes that the Public Staff expressed the general opinion that the ORS Report is "factually accurate" but that additional context could have been provided on certain elements included in the report. *Id.* at 130.

[7] https://www.tva.com/about-tva/reports.

[8] NOAA, National Centers for Environmental Information, National Climate Report, Dec. 2022, available at https://www.ncei.noaa.gov/monitoring-content/sotc/national/2022/dec/monthlysigeventsmap122022.png.

[9] Southeast Regional Climate Center, Monthly Regional Climate Report, Dec. 2022, available at: https://sercc.com/periodic-reports-monthly/?wpv_view_count=3753&wpv-wpcf-reports-monthly-month=12&wpv-wpcf-reports-monthly-year=2022&wpv_filter_submit=Submit.

[10] *Id.*

[11] *Id.*

affiliates in other states.[12] The internal meteorology staff has access to data from a National Oceanic and Atmospheric Administration (NOAA) satellite system, called NOAAPort, which receives a one-way broadcast of NOAA environmental data and information in near-real time. Duke's meteorologists use this data along with data provided by contracted vendors to produce a 15-day forecast of hourly weather parameters (e.g., temperature, dew point) for key locations across the Carolinas. These 15-day forecasts are produced each day and updated, as needed, throughout the day. Forecasts are then blended using a weighted average that is representative of each load base (e.g., DEC and DEP) and integrated into the load forecasting models.[13]

On the morning of Monday, December 19, Duke's internal meteorology team sent an internal email indicating that an expected significant weather system would be moving into the area on December 23.[14] On that same date, an event situational awareness call was scheduled for the morning of Wednesday, December 21, to discuss impacts of the forecasted weather to the Carolinas.[15]

On Tuesday, December 20, the meteorology team provided a weather update projecting significant outages and provided a resource model run detailing estimated generating resource needs.[16]

On Wednesday, December 21, the event situational awareness call was held, during which staff availability, projected storm impact, possibility in change of storm track, and projected storm timeline were discussed.[17] Other operational calls were held on that day to discuss expected weather impacts by distribution zone.[18] Also on Wednesday, December 21, preparatory messaging was sent to medical alert customers and critical healthcare facilities, and a severe weather alert was emailed out to customers.[19] No changes to the resource model run occurred between December 20 and December 21.

On Thursday, December 22, the meteorology team provided an update, and again no changes to the resource model run occurred between December 21 and December 22.[20] An

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[12] Duke Resp. to Public Staff Data Request No. 2 (PSDR2), Winter Storm Elliott (WSE) Item 2-1 (Jan. 25, 2023). As reported by NERC, DEC and DEP use weather forecasting models developed by three external vendors and projects load based on evaluation of their outcomes. DEC and DEP usually pick the highest for extreme cold weather days or looks for a historical day to match. DEP prepares a forecast for DEP East and DEP West (Asheville area). NERC Report at 42 fig.22.

[13] Duke Resp. to PSDR2, WSE Item 2-1 (Jan. 25, 2023).

[14] Duke Resp. to PSDR2, WSE Item 2-6, at attach. Winter Weather Event Timeline (Jan. 27, 2023).

[15] *Id.*

[16] *Id.*

[17] *Id.*

[18] *Id.*

[19] *Id.*

[20] *Id.*

operational call was held on December 22, as well, to discuss anticipated weather-related impacts by distribution zone.

Early Friday, December 23, the meteorology team provided another weather update and wind maps for the event.[21] During a meeting of the meteorology team, the impact of the wind event, customer outages, customer messaging, and expectation of continued weather-related impacts over the next 24 hours were discussed.[22] Similar to previous days, calls were held by operational staff, as well as by planning sections, to discuss weather-related impacts.[23] An email update following one situational awareness call sent on Wednesday December 21, indicated that strong, gusty winds and extreme cold were expected to move through the region early on Friday and anticipated outages to roll through the service area through Friday afternoon.[24] Approximately 100,000 outages were anticipated.[25] As reported to the Commission, wind damage caused power outages for more than 300,000 customers in the Carolinas on December 23.[26] Duke reported to the Commission that by the end of the day on December 23, approximately 36,000 customers were still out of power due to damage associated with the wind event.[27]

Early Friday, December 23, Duke forecasted a DEC system average low temperature of 10 degrees for the morning of Saturday, December 24, and a DEP system average low temperature of 13 degrees for the morning of Saturday, December 24.[28] That forecast was updated in late afternoon on Friday, December 23, to reflect that cold air had not moved into the region as rapidly as the model guidance suggested in the morning and that the DEC system average temperature was 27 degrees while the DEP system average temperature was 32 degrees.[29] The afternoon forecast indicated that with sustained wind speeds at 15 to 20 mph, wind chills were in the single digits across western North Carolina, teens across central North Carolina and 20s across eastern North Carolina. Further, the updated forecast indicated that temperatures were expected to fall during the evening, with a DEC low in the upper single digits to middle teens and a DEP low in the lower to middle teens.[30]

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[21] *Id.*

[22] *Id.*

[23] *Id.*

[24] Duke Resp. to PSDR2, WSE Item 2-7 (Feb. 10, 2023).

[25] *Id.*

[26] Presentation to Commission, *Staff Conference-Transcripts,* No. M-1, Sub 7, at 12 (Jan. 3, 2023) (Presentation to Comm'n tr.).

[27] *Id.* at 40.

[28] Duke Resp. to PSDR2, WSE Item 2-14 (Feb. 3, 2023).

[29] *Id.*

[30] *Id.*

Duke described an "atypical" morning high temperature, afternoon low temperature pattern from December 23 to December 24. Specifically, in DEC, the system average temperature dropped from 41 degrees early in the morning of December 23 to 26 degrees in late afternoon to 16 degrees in late evening and continued to fall overnight, reaching to 8 degrees in the morning of December 24. There was a 10 degree drop in temperature across the evening peak, with sustained wind speeds around 15-20 mph throughout the day, diminishing overnight.[31] In DEP, the system average temperature dropped from 50 degrees in the morning on December 23 to 30 degrees in late afternoon to 21 degrees in the late evening and continued to fall overnight, reaching 12 degrees the morning of December 24. There was a 9 degree drop in temperature across the evening peak, with sustained winds throughout the day.[32]

Duke forecasted temperatures well below normal to persist over the course of December 25, with temperatures moderating over the week.[33]

Other reports related to the impact of Winter Storm Elliott on electric service areas are similar. For example, the Tennessee Valley Authority (TVA) reports that the high winds, heavy rain, and cold temperatures of Winter Storm Elliott arrived in the TVA service territory on December 22 and that the conditions increased energy demand beyond what had been forecasted, resulting in the highest 24-hour electricity demand supplied in TVA history on December 23.[34] TVA's system average temperature was 3 degrees on the morning of Friday, December 23, which it reports as the coldest system average temperature since February 5, 1996.[35] The temperature was 8 degrees for most of Friday night and early Saturday, December 24, and the TVA reports that there have not been back-to-back mornings with system temperature lows in the single digits since February 1996.[36]

In describing the impact of the extreme weather within the RTO-footprint, PJM reported that the "extreme weather not only included bitter cold temperatures that were outside of the data sample used to train the load forecast models (mid-2019 to mid-2022), but also a rapid temperature drop, strong winds, heavy icing and snowfall, all of which occurred unusually early in this winter."[37]

The impact of the storm is similarly described in the NERC Report. Specifically, the report states

> Beginning with forecast colder weather mid-December, and with widespread warnings by December 20, grid operators knew that frigid

[31] Duke Resp. to PSDR2, WSE Item No. 2-15.b (Feb. 3, 2023).

[32] *Id.*

[33] Duke Resp. to PSDR2, WSE Item No. 2-6 (Jan. 27, 2023).

[34] TVA Report at 10.

[35] *Id.* at 8.

[36] *Id.*

[37] PJM Report at 40.

weather was coming. Many issued cold weather preparation notices to their Generation and Transmission Owners and Operators. Temperatures were lower than normal during the Event, although not quite as far off normal lows as during the 2021 event. Winter Storm Elliott's departures from normal minimum lows were largely from 15 to 30 degrees lower than normal, though a small area was even lower. In Winter Storm Uri, departures from normal minimum lows ranged from 40 to 50 degrees lower than normal low temperatures. However, Winter Storm Elliott generally had higher winds than Uri, with gusts up to 60 miles per hour, which increased convective cooling. Rapid temperature drops to subfreezing levels across the eastern half of the U.S. occurred.[38]

ENERGY EMERGENCIES DURING WINTER STORM ELLIOTT

With the extreme weather of December 23-24 came unprecedented electric generation outages, which coincided with winter peak electricity demands. As a result, many Balancing Authorities (BAs) in the Eastern Interconnection declared energy emergencies during these two days.[39]

Duke reported to the Commission that over the preceding week and going into Christmas Eve, it believed sufficient generating resources and supply were available to

[38] NERC Report at 9, 45.

[39] *Id. at 7.* NERC reliability standard EOP-011 establishes a system of Energy Emergency Alerts (EEAs), used to communicate the condition of a BA which is experiencing an energy emergency. To ensure standardization in such communication, NERC has established three levels of EEAs: EEA-0 no energy deficiencies; EEA-1 — all available generating resources in use; EEA-2 — load management procedures in effect; and EEA-3 — firm load interruption imminent or in progress. NERC EOP-011-01 Emergency Operations available at: https://www.nerc.com/pa/ Stand/Reliability%20 Standards/EOP-011-1.pdf.

The electric grid in the United States is subject to federally mandated reliability standards developed and enforced by NERC, which is an independent body that has been delegated the authority by the FERC to develop and enforce mandatory standards for the reliable operation and planning of the bulk power system. NERC is divided into six regional entities, and DEC and DEP are members of the SERC Regional Entity, the reliability region comprised of utilities across states in the southeastern United States. Within this regulatory framework, DEC and DEP are responsible for performing a variety of NERC reliability functions, and each must maintain compliance with the mandatory NERC standards. As owners and operators of generation and transmission assets, DEC and DEP are obligated to meet the applicable reliability standards for owning, maintaining, and operating grid assets. In addition, as independent BAs, DEC and DEP must plan for and balance generating resources and supply with customer demand in real time to avoid causing adverse power flow and/or frequency issues that could lead to instability in the bulk power system. Duke's NERC-certified System Operators are responsible for compliance in real-time, ultimately to maintain the safe and reliable operation of the bulk power system.

In general, the contiguous 48 states of the United States involve three main interconnections, which operate largely independently from each other with limited transfers of energy between them: the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas. The Eastern Interconnection encompasses the area east of the Rocky Mountains and a portion of northern Texas and consists of 36 BAs: 31 in the United States and 5 in Canada. All of the BAs in the Eastern Interconnection are electrically tied together during normal system conditions and operate at a synchronized frequency of 60Hz. DEC and DEP are part of the Eastern Interconnection.

In addition to the energy emergency alert system, which emanates from NERC EOP-011, Duke has established its own system of alerts, advisories, and notices, including grid status updates, to ensure that internal stakeholders have clear and sufficient understanding of grid status and associated actions to be considered or taken. The grid status alert system involves the following alerts, of increasing severity: green, yellow, yellow hands off, orange, red, purple, and black. Duke Resp. to PSDR 2, WSE Item No. 2 26 (Feb. 9, 2023).

get through the day on December 24.[40] Beginning December 23, Duke began to see a noticeable and consistent divergence between forecasted load and actual load that continued into the early morning hours of December 24.[41]

DEC

In the early evening of December 23, DEC was projected to have sufficient generating resources and supply to meet demand plus 1,500 megawatts (MW) in operating reserves.[42] Shortly thereafter, divergence between actual load and forecasted load began, but DEC believed it had sufficient resources to meet customer demand, with reserves, on December 24.[43] As of late evening on December 23, DEC was still projecting to be able to meet customer demand with an approximate 900 MW of operating reserves, but actual load (i.e., customer demand) continued to outpace forecasted load.[44] At that point, DEC knew that operating conditions on December 24 across the peak were going to be challenging.[45] On the night of December 23, DEC declared Energy Emergency Alert (EEA) Level-1, as it anticipated that all generating resources would be necessary to meet the December 24 peak.[46] The situation deteriorated from there.

Overnight and into the early morning of December 24, DEC lost generating resources and supply.[47] DEC's Dan River combined cycle facility, while it remained online, was derated by approximately 360 MW.[48] A 100 MW combustion turbine went offline, and though it was brought back online to support operations across the peak, the unit's being offline created operational uncertainty going into the peak.[49] Later in the morning, 400 MW of firm purchased power and 250 MW of non-firm purchased power were curtailed by PJM.[50] A network customer lost much of a 350 MW purchase that it was not able to replace.[51] Thus, leading up to the morning peak on December 24, DEC had lost approximately 1,400 MW of generating resources and supply. DEC had called on

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[40] Presentation to Comm'n tr. at 12.

[41] *Id.* at 20-21.

[42] *Id.* at 19.

[43] *Id.* at 20.

[44] *Id.*

[45] *Id.*

[46] *Id.* at 24; Duke Resp. to PSDR2, WSE Item 2-28 (Jan. 25, 2023).

[47] *See generally,* Duke Resp. to PSDR2, WSE Item No. 2-24 (Jan. 25, 2023).

[48] Presentation to Comm'n tr. at 21; ORS Report at 31.

[49] Presentation to Comm'n tr. at 21.

[50] *Id.* at 21-22; PJM Report at 33, 47; ORS Report at 35-36.

[51] Presentation to Comm'n tr. at 22; Duke Resp. to PSDR2, WSE Item No. 2-26 (Feb. 10, 2023); ORS Report at 37.

demand-side management and demand response resources, which it estimates reduced load by approximately 200 MW.[52]

As conditions deteriorated and load continued to grow, maintaining frequency became a concern for DEC.[53] In the very early morning of December 24, DEC escalated to EEA-2, which meant that DEC was preparing to use all load management tools to meet peak, and, fewer than two hours later, to EEA-3, which meant that load shed was imminent.[54] A load shed event was instituted at 6:14 a.m., and a total of approximately 1,000 MW of load was shed.[55] The December 24 peak load for DEC, 21,768 MW, occurred during the hour ending at 9:00 a.m.[56] As load decreased and a generation plant returned to service, DEC was able to achieve balance between generating resources and demand and ordered the restoration of the circuits that had been shed. By approximately 3:45 p.m. on December 24, all load shed circuits had been restored.[57] Table 1 presents DEC's EEA status from December 23 through December 25.

Table 1. DEC EEA Status December 23-25

Time and Date	**EEA Status**
2025 EPT on 12/23/2022	DEC declared EEA-1
0430 EPT on 12/24/2022	DEC escalated to EEA-2
0610 EPT on 12/24/2022	DEC escalated to EEA-3
1545 EPT on 12/24/2022	DEC declared EEA-1
1100 EPT on 12/25/2022	DEC terminated EEA (EEA-0)

DEP

In the early evening of December 23 and into the early morning of December 24, DEP was projecting to have sufficient generating resources and supply to meet demand plus 1,100 MW in operating reserves.[58] As was the case in DEC, actual load outpaced forecasted load in DEP in the lead up to peak. Recognizing the challenging conditions, DEP declared EEA-1 in the early morning of December 24.[59]

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52 Presentation to Comm'n tr. at 22; Duke Resp.to PSDR2, WSE Item No. 2-23A (Jan. 25, 2023).

53 Presentation to Comm'n tr. at 25.

54 *Id.* at 24; Duke Resp. to PSDR2, WSE Item 2-28 (Jan. 25, 2023).

55 Presentation to Comm'n tr. at 24; NERC Report at 71.

56 Duke Resp. to Comm'r Requests for Follow-Up on WSE Item No. 1-2 (Jan. 18, 2022).

57 Presentation to Comm'n tr. at 24; NERC Report at 71.

58 Presentation to Comm'n tr. at 24; NERC Report at 71-72.

59 Presentation to Comm'n tr. at 27; Duke Resp. to PSDR2, WSE Item 2-28 (Jan. 25, 2023); NERC Report at 71.

Similar to the situation in DEC, during the early morning hours leading up to the peak on December 24, DEP lost generating resources and supply.[60] One unit at the Roxboro coal-fired generating station was derated by approximately 325 MW.[61] One unit at the Mayo coal-fired generating station was derated by approximately 350 MW.[62] 500 MW of firm purchased power was curtailed by PJM.[63] A DEP network customer experienced a significant curtailment of a purchase from PJM during this same time.[64] DEP lost a purchase of 175 MW from an independent power producer.[65] Thus, leading up to the morning peak on December 24, DEP lost more than 1,500 MW of generating resources and supply. Similar to DEC, DEP had called on demand-side management and demand response resources, which it estimates reduced load by approximately 200 MW.[66]

Given the rapidly deteriorating conditions leading up to the peak on the morning of December 24 and the impending imbalance between generating resources and customer demand, DEP escalated to EEA-2 and then quickly to EEA-3. DEP reported to the Commission that, as was the case in DEC, the frequency in DEP was moving below 60 Hz and dropping, which, along with the growing demand, triggered a load shed event in DEP, beginning at 6:25 a.m.[67] The December 24 peak load for DEP, 14,840 MW, occurred during the hour ending at 8:00 a.m.[68] A total of approximately 800 MW of load was shed in DEP, and DEP was able to achieve load and generation balance and continued to maintain frequency stability by 8:00 a.m.[69] By late afternoon on December 24, all load shed circuits had been restored.[70] Operating conditions were again tight on December 25 and December 26. However, by that time DEP was able to find more generating capability from its own generation resources and import purchased power, such that DEP was able to meet customer demand on those days.[71] Table 2 presents DEP's EEA status from December 24 and December 25.

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[60] *See generally*, Duke Resp. to PSDR2, WSE Item No. 2-24 (Jan. 25, 2023).

[61] Presentation to Comm'n tr. at 26.

[62] *Id.*

[63] *Id.* at 27; PJM Report at 33, 47; ORS Report at 35-36.

[64] Presentation to Comm'n tr. at 26.

[65] *Id.*

[66] *Id.* at 22; Duke Resp. to PSDR2, WSE Item No. 2-23A (Jan. 25, 2023).

[67] Presentation to Comm'n tr. at 27.

[68] Duke Resp. to Comm'r Requests for Follow-Up on WSE Item No. 1-2 (Jan. 18, 2022).

[69] Presentation to Comm'n tr. at 24; NERC Report at 71.

[70] Presentation to Comm'n tr. at 28.

[71] *Id.* at 18-19; ORS Report at 16.

Table 2. DEP EEA Status December 24-25[72]

Time and Date	EEA Status
0537 EPT on 12/24/2022	DEP declared EEA level 1
0606 EPT on 12/24/2022	DEP escalated to EEA level 2
0618 EPT on 12/24/2022	DEP escalated to EEA level 3
1620 EPT on 12/24/2022	DEP declared EEA level 1
1715 EPT on 12/24/2022	DEP escalated to EEA level 2
0504 EPT on 12/25/2022	DEP declared EEA level 1
0900 EPT on 12/25/2022	DEP terminated EEA (EEA level 0)

The figure below, provided by Duke to the Commission, depicts a consolidated timeline of events from the evening of December 23 through the load shed events on December 24.

Other BAs in the Eastern Interconnection

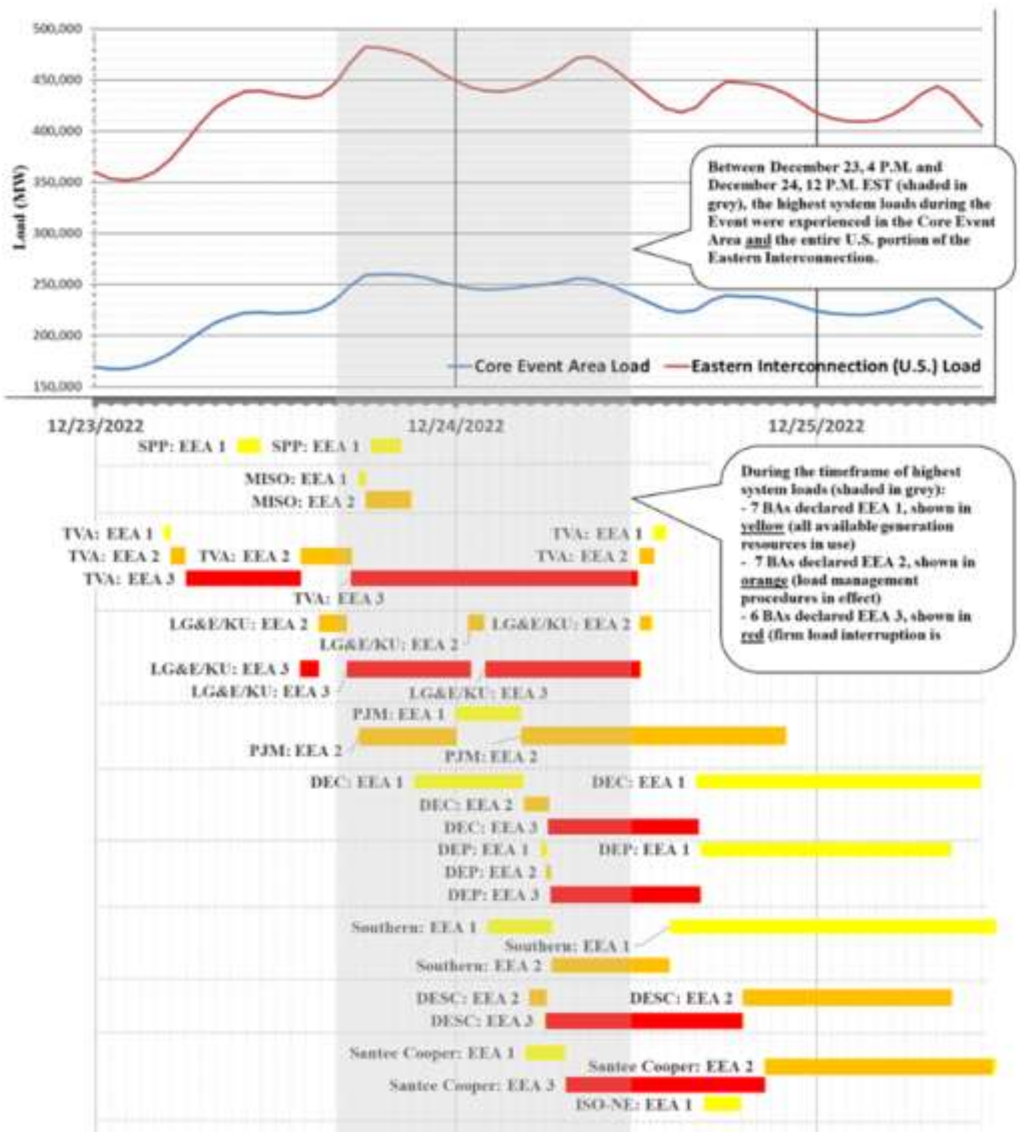
As reported by NERC, almost all of the BAs in the Eastern Interconnection were adversely affected by the storm, including SPP, MISO, Southern Company, TVA, LGE-KU, SC PSA, DESC, DEC, DEP, PJM, NYISO, and NE-ISO.[73] In addition, by the end of December 24, almost all of the impacted BAs were forced to implement EEA procedures. These BAs encountered the same circumstances as DEC and DEP — rapidly increasing customer demand due to the cold weather and high levels of unplanned generation outages and derates. NERC reported that customer demand increased dramatically from the morning

[72] Duke Resp. to PSDR2, WSE Item 2-28 (Jan. 25, 2023).

[73] NERC Report at 7.

of December 22 to the evening of December 23 and noted BAs had little energy to share with other BAs experiencing emergencies.[74] Figure 39 from the NERC Report, below, depicts the energy emergency timelines experienced by the impacted BAs, including DEC and DEP.

Figure 39: Core Event Area and Eastern Interconnection (U.S.) System Loads and Event Area Energy Emergencies Timeline – December 23 12:00 a.m. to December 25, 12:00 p.m.



[74] *Id.* at 57-58.

In consideration of the foregoing, the Commission makes the following

FINDINGS

Preparation and Readiness

a. Load Forecasting

Duke utilizes multiple third-party load forecasting models to plan for extreme weather event scenarios. These load forecasting models utilize both Duke's internal meteorology BA-specific weather forecasts as well as National Weather Service forecasts for its BAs that produce separate load models for those respective weather forecasts. Additionally, Duke's load forecasting/unit commitment analysts utilize automated tools that generate forecasts based on historical loads during similar weather conditions for up to seven years in the past.[75]

From December 19, through the early evening of December 23, Duke's load forecasting indicated that Duke would have sufficient generating resources and supply to meet load (i.e., customer demand) with a reserve margin.[76] The Public Staff confirmed that as of December 22, even with the W.S. Lee unit outage and the Robinson nuclear outage, Duke was projecting to be able to meet customer demand with adequate reserves and noted that this "shows the dynamics of how quickly things transpired between [December] 22 through [December] 25."[77]

However, beginning on December 23, Duke began to experience a noticeable and consistent divergence between forecasted load and actual load that continued into the early morning hours of December 24.[78]

Duke reported to the Commission that, for its December 24 load forecast, the day-ahead load forecast error was in the 6-10% range.[79] At the January 3 briefing to Commissioners, Duke reported that the difference was close to 10% for DEC and 5-6% for DEP.[80] In follow-up to the January 3 briefing, Duke reported to the Commission a specific

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[75] Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Response to NCUC's January 26, 2022 Order Requiring Responses to Commission Questions, *Petition for Investigation Regarding the Reliability and Integrity of the Electric Grid in North Carolina and Investigation Regarding the Ability of North Carolina's Electricity, Natural Gas, and Water/Wastewater Systems to Operate Reliably During Extreme Cold Weather*, Nos. M-100, Sub 163, E-100, Sub 173, at Response to Question 4 (Feb. 23, 2022).

[76] Presentation to Comm'n tr. at 16.

[77] Tech. Conf. tr. at 122.

[78] Presentation to Comm'n tr. at 20-21; Duke Resp. to PSDR2, WSE Item No. 2-17 (Jan. 25, 2022).

[79] Tech. Conf. tr. at 54. Duke reported to the Commission that a typical load forecast error is in or around 3% and that operating reserve calculations factor in load forecast error. Presentation to Comm'n tr. at 65, 82.

Load forecasts appear to be developed at least 6 days in advance, as Duke reports that load forecasts are archived only to a 6-day ahead horizon, not the 7-day ahead horizon requested by the Public Staff. Duke Resp. to PSDR2, WSE Item 2-17, January 25, 2023. Duke asserted that the forecast error increases farther out in time from the date of the load being forecast. Tech. Conf. tr. at 54.

[80] Presentation to Comm'n tr. at 65.

Mean Absolute Percent Error (MAPE) for the DEC load forecast deviation from actual load on December 24 of 90.9% and 95.7% for DEP.[81] Additionally, Duke reported that the error between the actual peak load on December 24 and the day-ahead forecast was 2,200 MW (21,768 MW-19,458 MW) for DEC and 927 MW (14,840 MW-13,913 MW) for DEP, which represent 10.2% and 6.2% of the actual peak load the two BAs, respectively, experienced. The NERC Report depicts the impacted BA's four-, three-, two-, and day-ahead peak load forecasts versus actual peak load in terms of percent difference for December 24 and indicates that the DEC difference was greater than the DEP difference.[82]

Figure 19: BAs' Four-, Three-, Two-, and Day-Ahead Peak Load Forecasts vs. Actual[128] Peak Loads (Percent Difference) For December 23, 2022

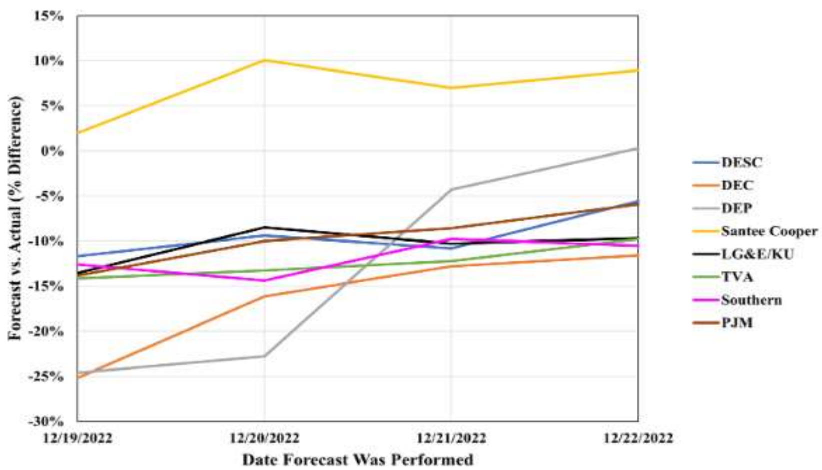
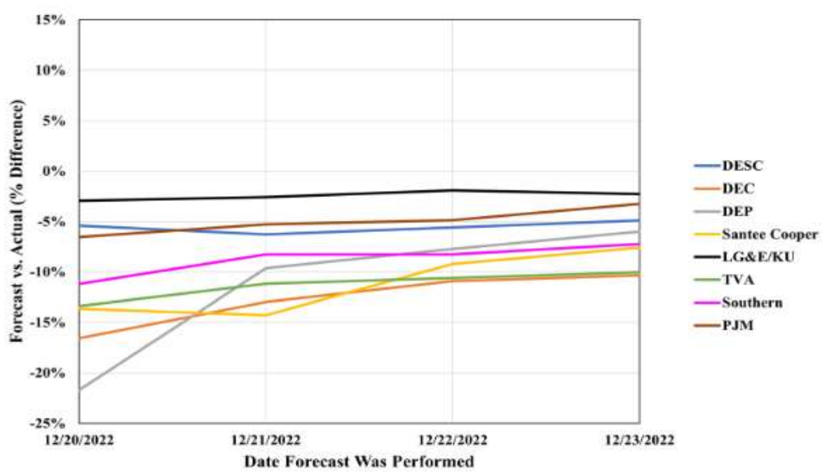


Figure 20: BAs' Four-, Three-, Two-, and Day-Ahead Peak Load Forecasts vs. Actual Peak Loads (Percent Difference) For December 24, 2022



128 For Figures 19, 20, and 21, for BAs that implemented load management measures during their respective peak load timeframes, actual peak loads used for calculations are based on BAs' estimated peak loads without load management.

[81] Duke Resp. to Comm'r Requests for Follow-Up on WSE Item No. 1-2 (Jan. 18, 2022).

[82] NERC Report at 41 fig.20.

Duke reported to the Commission that load forecasting involves the use of a regression model, which bases its ability to forecast accurately on forecasted weather conditions and on known history or historical events, including how load behaves on a weekday, or a weekend, or a holiday, or different months of the year.[83]

In explaining, in part, the load forecasting error, Duke reported to the Commission that a "combination of issues" impacted the load forecasting, including the "coldest temperatures in a December since the 1980s."[84] Duke also reported to the Commission on January 3 that "[n]ot only were the temperatures much lower than typical in our region, they dropped at a very fast rate. It got much colder, much faster than what we normally see here in the Carolinas."[85] In addition, Duke reported to the Commission that the BAs experienced an "atypical" morning high temperature, afternoon low temperature pattern from December 23 to December 24.[86] Duke acknowledged that its weather forecast generated on December 23 for December 24 was approximately two degrees off for DEC and approximately one degree off in DEP and that there was no cloud cover and there were very high winds associated with a wind chill impact.[87]

The ORS Report notes that the lack of a similar weather event so early in the winter hindered Duke Energy's forecasting models.[88]

The PJM Report also notes that atypical weather conditions impacted load forecasting, indicating that "[t]he weather not only included bitter cold temperatures that were outside of the data sample used to train the load forecast models (mid-2019 to mid-2022), but also a rapid temperature drop, strong winds, heavy icing and snowfall, all of which occurred unusually early in the winter."[89] PJM reported that while it uses "a sophisticated set of load forecasting tools and processes, [PJM] believe[s] the Dec[ember] 23 and 24 load forecasts highlight a case where two simultaneous conditions, a holiday and extreme weather with very limited analogous history, occurred together to produce atypically large forecast errors."[90] PJM explained that the load forecast is determined by an algorithm that considers expected weather conditions, day of the week and holidays, and that its model had not been exposed to the conditions that occurred on December 23, with the confluence of unprecedented cold temperature drops, the holiday and the weekend.[91]

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[83] Presentation to Comm'n tr. at 64-65.

[84] *Id.* at 17.

[85] *Id.* at 12.

[86] Duke Resp. to PSDR2, WSE Item No. 2-15.b (Feb. 3, 2023).

[87] Presentation to Comm'n tr. at 65.

[88] ORS Report at 17.

[89] PJM Report at 40.

[90] *Id.* at 41.

[91] *Id* at 40.

Duke also explained that the forecasting error was impacted by unexpected load behavior. Specifically, Duke reported to the Commission that “the load behavior at these temperatures, wind speeds and all these other conditions was — the higher load, likely from electric heating, other things that were just not, had not been seen by this model quite as clearly in the past.”[92]

In discussing the peak load forecasts of the impacted BAs, the NERC Report notes that both TVA and Southern Company commented that winter peak load conditions do not exhibit a saturation point like summer peak air-conditioning-driven loads do, because electric heating (auxiliary backup heating for heat pumps, electric strip heating and electric space heaters) increases winter peak load in a non-linear manner as temperatures decrease.[93] The NERC Report also cites to a data point from its 2021 report related to Winter Storm Uri that heating demand due to electric auxiliary heating increases from two to four times once temperatures drop below 14 degrees.[94, 95]

While the load forecasting errors of DEC and DEP were atypically large, they were in alignment with other impacted BAs. As a specific example, PJM reported a load forecast error of approximately 9% on December 23 and 24.[96] In addition, TVA reported that its load forecasting tools did not accurately predict the load or the potential risks

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[92] Presentation to Comm’n tr. at 65.

[93] NERC Report at 31.

[94] *Id.* at n.104. In response to the extreme cold weather that occurred in and around Texas in February 2021, during which significant outages and load shed occurred, the FERC and NERC conducted an investigation, culminating in the release of a final report. *See* The February 2021 Cold Weather Outages in Texas and the South Central United States, FERC, NERC, and Regional Entity Staff Report, November 2021, available at: https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

[95] The Commission notes that the PJM Report indicates that the

> relationship between load and temperature can change with time, as behind-the-meter solar, data centers, and new types of appliances are connected to the system. PJM monitors these changes, continually evaluates load patterns to assess impacts, and retrains and enhances the models, as needed. Staff analyzed electric heating statistics from the Energy Information Administration and determined that there does not appear to be a significant transition to electric heating in the PJM footprint that would have caused under-forecasting of winter load.

PJM Report at 15. However, the Commission also notes that the report indicates that the load valley (i.e., the low point of demand) on December 24 was significantly greater than was forecast and was higher than any other peak, or high point of demand, for that date over the previous decade. *Id.* at 39 fig.19.

While the Commission recognizes that PJM did not attribute the load valley phenomenon to home heating, and in fact indicates that home heating did not cause under-forecasting of load, the Commission is concerned that increased home heating electrification throughout the PJM footprint and into the northeastern United States, to the extent that this occurs, could amplify stress in the Eastern Interconnection during times of extreme, or perhaps even just cold, winter weather.

[96] *Id.* at 40.

experienced during Winter Storm Elliott.[97] And, as indicated in the NERC Report at although the impacted BAs projected higher electricity demands, most of the BAs significantly underestimated the peak loads in advance of December 23 and 24, the most extreme cold weather days of the storm.[98]

b. Winterization of Generating Stations

NERC reliability standard EOP-011-2 obligates DEC and DEP to have cold weather preparedness plans in place.[99] On January 3, Duke reported to the Commission that the cold weather preparedness plan focuses on three areas: inspection of freeze protection equipment; maintenance of freeze protection equipment; and training of personnel on inspection and maintenance of the equipment.[100] Duke reported that while EOP-011-2 did not take effect until April 2023, DEC and DEP were required to complete certain obligations in the fourth quarter of 2022. Duke reported that DEC and DEP had timely satisfied those obligations.[101]

Consistent with its obligations under EOP-011-2, DEC and DEP undertook comprehensive winter preparedness efforts at all generation sites.[102] Duke reported that the Regulated and Renewable Energy (RRE) organization within Duke Energy, which is responsible for the non-nuclear generation fleet, developed "Seasonal Preparation Guidelines" in 2017 to formally document the expectations for generation stations and that each station has a corresponding winter preparation plan that is consistent with these guidelines.[103] Duke explained that the preventative maintenance and seasonal local procedures are based on historical data and lessons learned and are implemented annually prior to winter operations.[104] Duke confirmed also that the RRE has implemented EOP-011-2 for each generating station.[105] Similarly, Duke has adopted policies and procedures for the nuclear generation fleet to ensure winter readiness.[106] Duke reported that winter readiness activities for the nuclear fleet were expected to be completed by November 1, 2023.[107]

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[97] TVA Report at 18, 24.

[98] NERC Report at 41.

[99] NERC Standard EOP-011-2.

[100] Presentation to Comm'n tr. at 78.

[101] *Id.*

[102] Duke Resp. to PSDR2, WSE Item No. 2-1 (Jan. 25, 2023); Duke Resp. to PSDR2, WSE Item No. 2-2 (Jan. 30, 2023); Duke Resp. to PSDR2, WSE Item No. 2-13 (Feb. 9, 2023).

[103] Duke Resp. to PSDR2, WSE Item No. 2-1 (Jan. 25, 2023).

[104] *Id.*

[105] *Id.*

[106] *Id.*

[107] *Id.*

In addition, Duke reported that Duke Energy holds an annual Winter Preparedness Webinar at which various business units present information detailing the preparations that have been taken to prepare for the winter season and to address any that have been identified as potential challenges to the completion of winter season preparations.[108] For the last three seasons, the webinar has been held on the following dates: December 15, 2020; October 25, 2021; and November 2, 2022.[109]

Duke also reported to the Commission on specific actions taken from December 19 through December 25, 2022, to prepare for the winter weather. This information included discussion of the daily weather forecasts and updates, internal communications regarding fuel supply and availability, and other pertinent information related to Duke's decision-making during this time period.[110]

Duke reported that generator freezing issues impacting performance on December 23 and 24 were substantially lessened as compared with performance during the 2014 Polar Vortex,[111] due in part to Duke's winterization efforts.[112]

The Public Staff did not take specific issue with Duke's general winter preparedness or with the level of preparation at any generating site. In fact, the Public Staff noted that Duke's winter weather program is a tool that has been in place and will continue to be refined and noted that Duke had taken action in response to lessons learned from extreme cold weather episodes in 2014 and 2015, which may have mitigated additional load shed during Winter Storm Elliott.[113] In responding to a question from the Commission regarding lessons to be learned from Winter Storm Elliott for the future, the Public Staff explained that even minor inadequacies in winterization efforts could have major consequences and gave the example of an inch-wide gap in insulation, difficult to see because the gap was beneath a control box, that contributed to a plant derate.[114]

However, the Public Staff did express concern regarding "degrading plant performance" and the reduction of staffing and in operating and maintenance expenditures and suggested that the Commission may need to provide more oversight of Duke's annual operations and system maintenance.[115] The Public Staff noted that the electric system is in a state of transition, as certain aspects of the generation fleet are

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[108] Duke Resp. to PSDR2, WSE Item No. 2-3 (Jan. 27, 2023).

[109] *Id.*

[110] Duke Resp. to PSDR2, WSE Item No. 2-6 (Jan. 30, 2023); CONFIDENTIAL Duke Resp. to PSDR2, WSE Item No. 2-13 (Feb. 3, 2023).

[111] In January 2014, portions of the United States, including North Carolina, experienced a weather condition known as a polar vortex, where extreme cold weather conditions occurred in lower latitudes than normal, resulting in an extended period of temperatures 20 to 30° F below average.

[112] Duke Resp. to PSDR2, WSE Item No. 2-15 (Feb. 3, 2023).

[113] Tech. Conf. tr. at 128, 130-32.

[114] *Id.* at 131.

[115] *Id.* at 126.

reaching near end of life, and that certain of the older generating plants were not designed to be operated in the current state they are today.[116] The Public Staff also noted that the reduction in staffing for the generating stations may be a cost-saving measure that has gone too far in overburdening the remaining staff with too many responsibilities.[117]

In response to the concern pointed out by the Public Staff, Duke noted that certain generating plants called on during Winter Storm Elliott are not being operated in the way they were designed. Specifically plants designed to be operated as baseload generation are now being cycled up and down, which has created operational complexities.[118] Duke also noted for the Commission that with respect to staffing, Duke worked to have staff in the right place at the right time during the event but also that Duke was "trying to make good decisions that are good for the plant, and also good for the customer" in terms of rates paid by the customer.[119]

c. Generator Outages and Derated Output

Generator outages and derates impacted DEC's and DEP's ability to serve its customers during December 24. An outage is a complete reduction in a generator's output while a derate is a partial reduction in a generator's power output. Two types of generator outages/derates are relevant in this context: planned and forced. Planned generator outages/derates are typically scheduled months or even years in advance, in order to perform necessary maintenance, or in the case of nuclear power plants, refueling.[120] Planned outages/derates are typically performed in the "shoulder months" of the year,[121] to avoid creating a generating capacity shortfall when the electric system may need generation. Forced generator outages/derates are not scheduled or anticipated and can result from any number of issues including weather impact, mechanical failures, or fuel supply issues.

The NERC Report notes that all of the impacted BAs went into Winter Storm Elliott with some measure of generation unavailable, but during the afternoon and evening of December 22 unplanned generator outages began to rapidly escalate.[122] Further, NERC reported that more than 371,000 MW of generation was lost to forced outages, derates and failures to start during the entirety of the storm — a period stretching from December 21 to December 26.[123]

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[116] *Id.*

[117] *Id.* at 135.

[118] *Id.* at 138-39.

[119] *Id.* at 139-40.

[120] NERC Report at 43.

[121] Tech. Conf. tr. at 113.

[122] NERC Report at 45.

[123] *Id.*

i. Generator Outages and Derates Prior to Winter Storm Elliott

DEC and DEP experienced a number of generator outages, both planned and forced, before Winter Storm Elliott. Specifically, Duke reported the following planned outages/derates and forced outages/derates for DEC as of December 23, 2022, none of which was related to weather:[124]

DEC

Generator	Type	2022 Winter Capacity (MW)	Derate (MW)	Planned or Forced
Allen 1	Steam	167	167	Planned
Allen 5	Steam	259	259	Planned
Belews Creek 1	Steam	1110	125	Forced
Cliffside 5	Steam	546	71	Forced
Marshall 1	Steam	380	380	Forced
Marshall 2	Steam	380	380	Forced
WS Lee	Combined Cycle	809	809	Forced
Mountain Island 1	Hydro	14	14	Planned
Ninety-Nine Islands 4	Hydro	3.4	3.4	Planned
Oxford 2	Hydro	20	20	Forced
Rhodhiss 3	Hydro	12.4	12.4	Planned
Bad Creek 3	Hydro	340	340	Planned
Bear Creek 1	Hydro	9.5	9.5	Planned

Prior to Winter Storm Elliott, Allen 1 and Allen 2 were in extended planned reserve (EPR).[125] Duke reported that per its EPR procedure, there is a 5-day call-back requirement to put the Allen units in service. On December 22, Duke considered bringing the Allen units out of EPR. In general, a normal startup for the two units would be around 36 hours to get both online. As a result, Duke estimated that the units could be placed back online on December 26 or early December 27. However, by that time, temperatures were forecast to be increasing, and Duke reported that the units would not be needed.[126] So, no action was taken at that time to bring the units back into service. Duke also reported to the Commission that once the decision was made not to bring Allen out of

[124] Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Presentation and Generating Unit Status Summary Document, *Petition for Investigation Regarding the Reliability and Integrity of the Electric Grid in North Carolina and Investigation Regarding the Ability of North Carolina's Electricity, Natural Gas, and Water/Wastewater Systems to Operate Reliably During Extreme Cold Weather*, Nos. M-100, Sub 163, E-100, Sub 173 (Jan. 4, 2023); Duke Resp. to PSDR2, WSE Item No. 2-22 (Feb. 3, 2023).

[125] Duke Resp. to PSDR2, WSE Item No. 2-13 (Feb. 3, 2023).

[126] *Id.*; Tech. Conf. tr. at 116-17.

EPR, staffing resources were lost to travel due to the holiday.[127] Duke reported that once it became aware of a change in the need as a result of weather and load dynamics it had to recall staffing resources. At that point, Duke had to decide between attempting to bring the Allen units online as quickly as possible or repairing and returning the Marshall units to service.[128]

The total derate for DEC (i.e., generating capacity not available) going into Winter Storm Elliott was 2590.3 MW.

DEP

Generator	Type	2022 Winter Capacity (MW)	Derate (MW)	Planned or Forced
Robinson	Nuclear	759	759	Planned
Mayo 1	Steam	713	113	Forced
Roxboro 3	Steam	698	73	Planned
Roxboro 4	Steam	711	211	Forced
Smith Energy Complex 2	Simple Cycle CT	192	47	Forced
Wayne County	Simple Cycle CT	195	40	Forced
Walters	Hydro	36	36	Planned

Thus, the total derate for DEP (i.e., generating capacity not available) going into Winter Storm Elliott was 1,279 MW.

ii. Generator Outages and Derates Due to Winter Storm Elliott

The NERC Report indicates that from December 21 through December 26, within the BAs in the Eastern Interconnection most impacted by the storm, more than 371,000 MW of generation were lost to forced outages, derates and failures to start.[129] The NERC Report attributes roughly one third of those outages to the freezing weather.[130] In addition, the NERC Report indicates that: (1) TVA experienced 6,000 MW of unplanned outages before instituting load shed on December 23; (2) over the 24-hour period from the morning of December 23 to the morning of December 24, PJM sustained nearly 33,000 MW of unplanned outages; (3) Southern Company experienced 1,390 MW of unplanned outages from midnight to December 24, 6:00 a.m.; and (4) Santee Cooper experienced 500 MW of unplanned generator outages beginning early on December 24.[131]

[127] *Id.* at 117.

[128] *Id.*

[129] NERC Report at 45.

[130] *Id.* at 18.

[131] *Id.* at 47-48.

The NERC Report emphasizes that freezing issues were one of the primary causes of unplanned generator outages during Winter Storm Elliott and that 75% of the generator failures caused by the weather occurred at temperatures above the generator's documented operating temperatures.[132]

DEC and DEP experienced a number of generator outages during Winter Storm Elliott. Specifically, Duke reported the following additional generator outages/derates as of the beginning of the rolling outages on December 24, 2022, many of which were related to weather:[133]

DEC

Generator	Type	2022 Winter Capacity (MW)	Derate (MW)	Planned or Forced	Related to Weather	Detail for Weather-Related
Dan River	Combined Cycle	718	359	Forced	Yes	Forced offline[134] due to frozen LP drum level transmitters and delayed in returning to service because of gas turbine compressor bleed valve fault. Heat trace for the LP drum level transmitter energized and all insulation was observed to be intact. Wind exposure overcame the measures in place.
Buck	Combined Cycle	718	178	Forced	Yes	Derated due to low pressure on the Transco interstate pipeline. Available during peak hour but not during entirety of load shed event.
Mountain Island 2	Hydro	14	14	Forced	Yes	Cold air entering building created condition under which unit would not start.
Tennessee Creek	Hydro	11.5	11.5	Forced	No	
Clemson	CHP	14	14	Forced	Yes	Gas turbine tripped due to low pressure delivered from the Fort Hill Natural Gas Authority.

[132] *Id.* at 18-19.

[133] Duke Resp. to PSDR2, WSE Item No. 2-24 (Jan. 25, 2023); Duke Resp. to PSDR2, WSE Item No. 2-22 (Feb. 3, 2023).

[134] Just before midnight on December 23.

DEP[135]

Generator	Type	2022 Winter Capacity (MW)	Derate (MW)	Planned or Forced	Related to Weather	Detail for Weather-Related
Mayo 1	Steam Station	713	350	Forced	Yes	Boiler tripped due to frozen component lines. Cold weather overcame intact and energized heat trace and insulation. Frozen gypsum impacted production.
Roxboro 3	Steam Station	698	398	Forced	Yes	Boiler components tripped due to frozen sensing lines and frozen switches. Cold weather overcame intact and energized heat trace and insulation.
Smith Power Block 4	Combined Cycle	570	273	Forced	Yes	Forced offline due to frozen transmitter and sensing lines. Heat trace for the sensing lines was found energized and heating, however, a 1-inch gap in the line's insulation/lagging was discovered which allowed the line to freeze.
Blewett 1	Simple Cycle CT	17	17	Forced	No	
Blewett 2	Simple Cycle CT	17	17	Forced	No	
Blewett 4	Simple Cycle CT	17	17	Forced	No	

Thus, significant forced outages occurred going into the load shed events on December 24, and this generating capacity was unavailable to DEC and DEP to meet the morning peaks.

Mostly consistent with Duke's report to the Commission, the NERC Report notes:

> In the DEC and DEP footprints, unplanned generation outages and derates began at about 11:30 p.m. on December 23, and by December 24 at 8 a.m.,

[135] Duke reported that Roxboro 1 and 2 experienced problems subsequent to the morning peak on December 24 as a result of cold weather impact and were derated through the evening peak. These units were available at full capacity through the morning peak. Duke Resp. to PSDR2, WSE Item No. 2-22 (Feb. 3, 2023).

DEC and DEP had lost about 2,000 MW; outages continued into the early afternoon of December 24.[136]

II. Natural Gas and Electric Coordination

The NERC Report indicates that virtually all of the impacted BAs saw generators lost or derated due to "Natural Gas Fuel Issues," which the report defines to include:

> the combined effects of decreased natural gas production; cold weather impacts and mechanical problems at production, gathering, processing and pipeline facilities resulting in gas quality issues and low pipeline pressure; supply and transportation interruptions; curtailments and failure to comply with contractual obligations. Additionally, it includes shippers' inability to procure natural gas due to tight supply, prohibitive, scarcity-induced market prices, or mismatches between the timing of the natural gas and energy markets.[137]

The NERC Report notes that the issue was most acute in PJM but that "SPP, TVA, LG&E/KU and VACAR-South RC all reported gaining awareness on December 23 or 24 that generating units were struggling to find adequate natural gas supply or that pipelines were struggling or unable to maintain adequate pressure at certain locations."[138]

The Transco pipeline, owned by the Transcontinental Gas Pipe Line Company, LLC (an affiliate of the Williams Company), is the primary interstate pipeline in North Carolina with which Piedmont Natural Gas (Piedmont) and Public Service Company of North Carolina (PSNC) directly interconnect.[139] Transco delivers natural gas through a 10,000-mile interstate transmission pipeline system extending from Texas to New York and transports approximately 15% of the nation's natural gas.[140] Duke contracts with Transco for interstate transportation. In terms of intrastate transportation, both Piedmont and PSNC provide service to DEC and DEP for their power generating stations in North Carolina.

Duke reported that although it was notified of a pressure issue on the Transco Pipeline on December 24, the pressure drop occurred after the peak and did not affect the impacted gas fired generator's ability to serve during the peak. However, the generator was derated after the peak during some of the load shed event. Duke also

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[136] NERC Report at 48.

[137] *Id.* at 49 n.134.

[138] *Id.* at 49.

[139] North Carolina has historically been heavily dependent on one interstate pipeline, Transco, for its natural gas requirements. While two other interstate pipelines provide limited volumes into North Carolina at its borders with other states, Transco is the only pipeline that crosses North Carolina, generally along the I-85 corridor.

[140] Williams Company, Operations, Transco available at https://www.williams.com/pipeline/transco/.

reported that two units experienced gas pressure issues, resulting in derates, on December 25.

Piedmont reported pressures below recent historical average beginning on or around early morning on December 24 at: (1) the Lincoln Transco meter; (2) the Spencer Buck Transco meter; (3) Cannon Bottom Transco #2 meter; (4) Kernersville Transco meter; (5) the Transco Iredell Station inlet; (6) the Greenville Transco OPP inlet; (7) the HF Lee Combined Cycle Station inlet; (8) the Duke Dan River inlet; and (9) the Sutton Combined Cycle Station inlet.[141]

Piedmont reported that its "redelivers" or "transports" gas to the following Duke plants located within Piedmont's North Carolina service territory: Sutton, Smith Energy Center, HF Lee, Wayne County, Lincoln, Buck, Belews Creek, Marshall, Dan River, and Rockingham. Piedmont reported that during the period December 23 through December 29, Piedmont had no operational issues that impaired or impeded Piedmont's ability to provide gas service to Piedmont's power generation customers. Piedmont reported that communications between Duke Energy and Piedmont during this time were control room to control room regarding supplier pressures at Dan River, Buck, and Rockingham and that such communications were the result of Duke's desired gas pressures from Transco for power generation not being met by Transco.[142]

Like Piedmont, PSNC reported experiencing "lower than historical operating pressures from Transco's mainline."[143] In a recent proceeding before the Commission, PSNC witness Rose Jackson testified that

> temperatures fell on the night of December 23rd, pressures at [PSNC's] Dan River Takeoff from Transco dropped well below the historical operating pressure that the Company uses to model deliveries of gas on that part of the system. As a result, the Company was unable to deliver quantities of peaking supply and off-system storage as originally planned.[144]

PSNC explained that the takeoff of gas from the Transco pipeline was most impacted at Dan River "because that's where the null point or where the volumes that are flowing from the Gulf to the North and the North to the South. That null point was fluctuating right there around Dan River."[145]

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141 Piedmont Resp. to PSDR2, WSE Item No. 2-13 (Feb. 20, 2023).

142 Piedmont Resp.to PSDR2, WSE Item No. 2-16 (Feb. 20, 2023).

143 PSNC Resp. to PSDR2, WSE Item No. 2-14d-e (Mar. 27, 2023).

144 Transcript of Hearing Held in Raleigh, North Carolina on Tuesday, August 8, 2023, *Application of Public Service Company of North Carolina, Inc. for Annual Review of Gas Costs*, No. G-5, Sub 661, at 23 (Aug. 28, 2023).

145 *Id.* at 53.

In the context of communications with Transco during the storm, PSNC testified to the Commission:

> One of the things that [Transco has] stated is that they communicated with the various parties prior to Winter Storm Elliott. That did not occur in the southern region. They have told us since that they have a coordination meeting in the northern region where they have all the different shippers that include LDCs, power generation plants; they also include interconnecting pipelines in that meeting to discuss and to prepare for a weather event such as Winter Storm Elliott. That did not occur in the southern region.[146]

Additionally, in describing dynamics on Transco during the storm, PSNC testified that Transco

> [was] noticing that supply was not coming in on the receipt side of their system. So that was pulling down their line pack on their system. But then, when prices posted for that day, typically prices do post in the morning time period, the — we had — we contacted 17 suppliers before we could find any amount of gas to purchase, and the price of that gas was so high, so much higher than what the OFO and the — I'm sorry, the Operational Flow Order penalty on Transco's system was, then you started seeing shippers that were overtaking Transco's system.
>
> So what happened is you had supply not coming in on the receipt side and gas going out on the delivery side that was not scheduled or accounted for, so the line pack just dropped tremendously on Transco's system. And because we sit at the null point, that's why Dan River was so greatly affected with the pressure drop.[147]

PSNC explained more succinctly to the Commission that during Winter Storm Elliott, many shippers made an economic decision to continue to take off the pipeline even though the supply that they had contracted for did not show up, specifically testifying:

> There were other shippers on Transco's system, not PSNC, that decided to take more gas than what they had contracted for. So they didn't have sufficient capacity to deliver but they continued to use gas, therefore, having a short, imbalance position.[148]

[146] *Id.* at 51.

[147] *Id.* at 53-54.

[148] *Id.* at 69.

The NERC Report corroborates this testimony, indicating that

> as the storm progressed, supply shortfalls continued and customers' demand increased to a level where some customers began taking more gas than what they supplied and/or confirmed through nominations, which contributed to low pipeline pressures.[149]

In the context of fulfilling its obligations during Winter Storm Elliott, PSNC reported that it redelivered (i.e., transported), during the period December 23 through December 29, all gas it received on its system for Duke Energy's power generating units.[150]

PJM is served by a number of interstate pipelines, including Transco. PJM reported that "nearly all of the natural gas consumed by generation in PJM originates in the Marcellus and Utica shale in the Appalachian region" and that "[h]istorically, loss of supply due to gas production well freeze-offs during cold snaps [in this region] has not been as severe as compared to gas basins in the south central and southwestern United States."[151] PJM reported that, going in to the storm, the anticipated loss of natural gas production due to weather was 2 to 3 Bcf (billion cubic feet) per day in the Appalachian region but that actual loss was closer to 10 Bcf, which significantly challenged the ability for natural gas-fired power generating resources to procure fuel.[152]

PJM reported that outages on gas generating units were primarily attributed to physical plant issues (freezing and plant equipment issues), but gas generators also experienced a significant level of gas supply issues. The gas supply-related outages accounted for just over 11,000 MW (approximately 13% of total gas generation capacity) at the peak hour on December 24.[153]

PJM reported that

> [t]he storm and the rapid onset of cold temperatures heavily impacted natural gas production, particularly in the Marcellus and Utica basins, which are the predominant source of the natural gas procured by gas generation in the PJM footprint. This led to significant loss of gas supply for all downstream gas consumers, particularly larger, more efficient gas-fired power generation units that require nominated supplies flowing at uniform and higher pipeline pressures to operate.[154]

[149] NERC Report at 182.

[150] PSNC Resp. to PSDR2, WSE Item No. 2-19 (Mar. 27, 2023).

[151] PJM Report at 22, 62.

[152] *Id.*

[153] *Id.* at 50.

[154] *Id.* at 62.

PJM also reported that

> [e]xacerbating the lack of gas supply was the fact that Elliott occurred over a long holiday weekend, which tends to have lower gas supply liquidity. Many gas buyers, especially LDCs and other customers with more predictable gas usage levels, purchase their gas supplies on Friday for the Saturday, Sunday and Monday gas days. Gas generators in many cases need to buy their gas supply each day of the weekend period based on their awarded or anticipated dispatch. With the majority of gas traded on Friday, the market for gas commodity can become less liquid, resulting in increased supply scarcity and potentially higher intraday gas prices.[155]

With respect to the coordination between electric utilities and their natural gas transporters and suppliers, Commission Rule R8-41(c) obligates each electric public utility to include, in its annual filing required by R8-41(b) related to load-reducing plans and emergency procedures, a verified statement by an officer stating that: (1) the utility had identified all the gas-electric dependencies and inter-dependencies that could threaten electric operations or customer service during extreme cold weather or other emergencies; (2) the electric utility had discussed those dependencies and inter-dependencies with the appropriate gas utility(ies) and pipeline(s); (3) the electric utility had, in cooperation with the gas utility(ies) and/or pipeline(s), established a plan for managing the dependencies and inter-dependencies during extreme cold weather events and other emergencies; and (4) the electric utility had within the last 12 months demonstrated its ability to start its black start generators from a cold shutdown state during cold weather. DEC and DEP had filed the verified statement required by Rule R8-41(c) on May 12, 2022.[156]

III. Load Management

a. General Load Reduction and System Restoration Plans

Commission Rule R8-41 obligates DEC and DEP to file with the Commission emergency load reduction plans and emergency procedures and to update those plans and procedures on an annual basis. Prior to Winter Storm Elliott, DEC and DEP had filed their respective General Load Reduction and System Restoration Plans (GLRP) on May 12, 2022.[157]

While both the DEC GLRP and the DEP GLRP address the procedures that the utility is to employ in the event that load reduction or system restoration is necessary,

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155 *Id.* at 62-63.

156 Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, General Load Reduction and System Restoration Plans, *Notice of Rulemaking Procedure in the Matter of Load Reduction by Electric Suppliers During Times of Emergencies Caused by Failure or Inadequacies,* No. E-100, Sub 10A, at 32-36 (May 12, 2022).

157 *Id.* at 3-31.

each is organized differently. The DEC GLRP describes manual actions that the utility may implement to manage load. The DEP GLRP is organized around DEP's grid status level system and identifies actions that may be taken at each grid status level. Duke reported that the differences in the plans caused some confusion for system operators.[158] However, Duke reported that DEC and DEP are working to align their plans.[159]

The DEC GLRP indicates that in addition to the automatic underfrequency load shedding program accomplished through relays installed on the transmission system, DEC may take any of the following manual actions in any order to reduce load: (1) request generators to maximize capability and availability; (2) request relief from environmental or technical specification constraints; (3) reduce internal load on the system; (4) institute load management through demand side programs; (5) appeal to large customers and governmental agencies; (6) make general request for voluntary load reduction; (7) manually reduce voltage on distribution circuits; (8) interrupt distribution circuits; (9) institute emergency relief plans on the bulk transmission system; and (10) request wholesale customers to implement demand response programs and adjust distributed energy resources (DERs) to reduce effective net demand. As reported by DEC, in advance of the load shed event, DEC took several of these actions, including: (1) instituted load management through demand side programs; (2) requested a wholesale customer, to implement demand response programs; (3) interrupted distribution circuits; and (4) reduced internal load on the system.

The DEP GLRP does not mandate any specific action in any specific order. As reported by DEP, in advance of the load shed event, DEP took several actions to manage load, including: (1) instituted a voltage reduction; (2) reduced internal load on the system; (3) requested a wholesale customer to implement demand response programs; (4) instituted load management through demand side programs; and (5) interrupted distribution circuits.[160]

b. Demand-Side Management and Calls for Conservation

With respect to demand side management specifically, Duke reported that, prior to having to shed load, it called on demand response on the morning of December 24, which Duke approximates created 200 megawatts of load reduction in each BA.[161] Duke reported that there were no demand response programs expected to be online or

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[158] Tech. Conf. tr. at 25-26.

[159] *Id.* at 138.

[160] When DEP operators were having problems with the load shed tool, DEP interrupted two transmission lines to get the final 111 MW of load reduction that its system needed to recover. Presentation to Comm'n tr. at 107.

[161] Presentation to Comm'n tr. at 70; CONFIDENTIAL Duke Resp. to PSDR2, WSE Item Nos. 2-19, 2-26 (Feb. 10, 2023). The ORS Report suggests that Duke achieved an estimated 723 MW of reduction in load, with an estimated 47 MW of non-performance, between 4:00 a.m. and 6:30 a.m. on December 24. ORS Report at 44.

available, but failed to respond when called; however Duke also reported that certain programs underperformed.[162]

The Public Staff did not take issue at the Technical Conference with the performance of the demand side management programs that were called on during the storm.

Duke reported that it issued a news release, early in the morning of December 24, calling for conservation from customers.[163] Duke also reported that later, on the evening or the afternoon of December 24, following the load shed events, it issued a call for conservation message to all the channels asking for assistance on Christmas morning and then issued another message on the afternoon of December 25, asking for assistance on the morning of December 26.[164]

The Public Staff recommended an enhancement of communications protocols and expressed the concern that protocols for calls for conservation should be implemented or improved.[165]

c. Wholesale Customer Capabilities

With respect to wholesale customer capabilities, DEC and DEP called on wholesale customers for assistance in managing load in advance of the load shed events. Specifically, on December 24, DEC and DEP requested NCEMC to implement its demand response program.[166]

d. Rotating Load Shed

To address imbalance between load and generating resources and to ensure frequency stability, DEC and DEP shed load early in the morning on December 24. The load shed events on December 24 were the first load shed events in Duke's history.[167] For DEC and DEP, the decisions to initiate rotating load shed were made by NERC-certified system operators employed by the companies.[168] Duke reported that between 6:10 and 6:25 a.m., operators requested an initial load shed of 400 MW for DEC and 600 MW for DEP.[169] Between 7:00 and 7:10 a.m., operators requested a second load

[162] Duke Resp. to PSDR2, WSE Item No. 2-23 (Jan. 25, 2023).

[163] Presentation and Generating Unit Status Summary Document (Jan. 3, 2023).

[164] Presentation to Comm'n tr. at 135.

[165] Tech. Conf. tr. at 127, 133-34.

[166] CONFIDENTIAL Duke Resp. to PSDR2, WSE Item No. 2-19 (Feb. 10, 2023).

[167] Presentation to Comm'n tr. at 12-13.

[168] Duke Resp. to PSDR2, WSE Item No. 2-26 (Feb. 10, 2023).

[169] DEC/DEP Presentation from Sept. 26, 2023 Tech Conf. at 24 (Dec. 21, 2023).

shed of 600 MW for DEC and 200 MW for DEP.[170] At 7:35 a.m., the tool ceased to respond and a manual action to interrupt two transmission lines in DEP was necessary.[171]

DEP and DEC utilized a rotating load shed (RLS) tool to effect the load shed requested.[172] Duke reported that the RLS tool automatically sheds a user-defined number of megawatts using a prioritized list of circuits and then maintains that amount of load shed by automatically de-energizing additional circuits and restoring those that had previously been de-energized.[173] Circuits are intended to be de-energized for no more than 15 to 30 minutes at any one time.[174]

On December 24, the tool did not perform as expected.[175] In DEC, the RLS tool successfully de-energized 350 circuits, which equated to approximately 1000 megawatts of load shed, but malfunctioned in the process of restoring circuits, causing circuits to be de-energized much longer than anticipated.[176] This delay caused cold load pickup issues, which necessitated manual restoration by the utility, further increasing the time to restoration for those customers.[177] In DEP, the tool successfully de-energized 110 circuits, which resulted in approximately 600 megawatts of load shed; however, the tool was overwhelmed by the number of circuits being addressed and ceased to function, requiring subsequent manual action to shed additional load.[178]

Duke reported that the RLS tool had been tested in a simulated environment, changing curtailment amounts, but that the tool had not been tested at the loads that were shed during the event.[179]

The Public Staff confirmed that the RLS tool did not work as planned and that the failure of the tool exacerbated outage time for customers.[180]

Other BAs in the Eastern Interconnection were forced to shed load primarily as a result of unplanned generator outages and curtailment of energy imports from neighboring BAs while load remained historically high. Specifically, the TVA declared

[170] *Id.*

[171] *Id.*

[172] Duke Resp. to PSDR2, WSE Item No. 2-26 (Feb. 10, 2023).

[173] Tech. Conf. tr. at 40.

[174] *Id.*

[175] *Id.* at 41.

[176] *Id.*

[177] *Id.* at 42.

[178] *Id.*

[179] Duke Resp. to PSDR2, WSE Item No. 2-26 (Feb. 10, 2023).

[180] Tech. Conf. tr. at 122.

EEA-3 and shed approximately 1,500 MW in mid-morning of December 23.[181] Later, during the early morning of December 24, TVA was forced to shed a total of 3,200 MW of load.[182] During the early evening of December 23, LG&E/KU was forced to shed 300 MW of load.[183]

The Southern BA did not shed load, but early morning on December 24 instituted a voltage reduction to reduce load, declared EEA-2, and then later received an emergency import of 1,000 MW from Florida Power and Light, which dramatically improved conditions in the BA.[184]

PJM did not shed load during Winter Storm Elliott but was faced with an unprecedented amount of unplanned generation outages during Winter Storm Elliott — reaching approximately 47,000 MW on the morning of December 24. At that point, PJM was at an increased risk of load shed approaching the morning peak on that date. PJM reported that if another large unit were lost or imports from NYISO into PJM were cut, PJM would have considered initiating a voltage reduction action and, if necessary, issuance of an EEA-3 and a manual load dump.[185]

e. Complications With Restoring Service

Duke reported that the significant wind event on December 23 that resulted in system damage complicated system management later on during the cold weather event.[186] Duke reported that at the end of the day on December 23, approximately 36,000 customers were still out of power due to damage associated with the wind event.[187] Duke reported wind event restoration had to be managed in sync with the load shed restoration activities in order to maintain system stability and safety.[188] Specifically, Duke reported to the Commission that

> when [Duke] went into the load shed event, some of the circuits that were impacted by the load shed were also circuits that had customers out associated with the wind event. Because [Duke] had to move to manual operation, the operators had to go in and make sure that they identified those circuits that were out of service associated with the wind event before they began restoration from the load shed to ensure that we did not

[181] NERC Report at 64.

[182] *Id.* at 71.

[183] *Id.* at 65.

[184] *Id.* at 72.

[185] PJM Report at 63.

[186] Duke Resp. to PSDR2, WSE Item No. 2-16 (Jan. 27, 2023).

[187] Presentation to the Comm'n tr. at 40.

[188] The line workers and field personnel deserve special recognition and commendation for their part in the restoration effort. These men and women spent long hours performing dangerous tasks under difficult weather conditions in order to restore power to hundreds of thousands of North Carolinians.

> re-energize any damaged circuits that had damage to them that could jeopardize the safety of the public, [Duke's] customers, or [Duke's] employees as they were continuing to do restoration.[189]

The failures of the RLS tool also complicated restoration of service. Duke reported that manual restorations are slower than automated restoration using the tool, and thus outage times were increased.[190] Additionally, Duke reported that circuits being out longer than anticipated "introduced cold load pickup issues" that exacerbated delay in restoring service.[191]

The Public Staff did not take issue with Duke's explanation that damage from the wind event made more complicated the load shed restoration activities. The Public Staff reported to the Commission that "storm restoration activities may have contributed to larger than expected load increases, given the phenomenon of cold weather pickup. However, tradition — traditional reserve margins should have accounted for this level of very — variation and system load estimates."[192]

IV. Imports

a. Export Capabilities of Neighboring BAs on December 23-24

As previously discussed, almost all of the Eastern Interconnection was adversely affected by the storm: SPP, MISO, Southern Company, TVA, LGE-KU, SC PSA, DESC, DEC, DEP, PJM, NYISO, and NE-ISO.[193]

TVA experienced rapid generating unit outages and declared EEA-1, EEA-2 and then EEA-3 early on December 23. TVA secured emergency power from Duke, Southern Company, PJM, and MISO, but this solution was short-lived, and ultimately TVA was forced to shed load on December 23 and December 24.[194]

In the late afternoon of December 23, system conditions deteriorated in PJM. PJM issued an EEA-2 in the early evening, and as load ramped down, the EEA-2 was cancelled late in the evening of December 23. PJM issued an EEA-1 in the early hours of December 24 and then EEA-2 in the late afternoon of December 24. In the late hours of

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189 Presentation to the Commission tr. at 40.

190 Duke Resp. to PSDR2, WSE Item No. 2-26 (Feb. 10, 2023).

191 Tech. Conf. tr. at 41-42.

192 *Id.* at 122.

193 NERC Report at 7.

194 *Id.* at 10-11.

December 24, PJM backed out of EEA-2; PJM did not return to EEA-0 until late in the evening of December 24.[195]

Southern Company declared EEA-1 in the very early morning hours of December 24 and later in the morning declared EEA-2. Southern obtained emergency energy from Florida Power and Light, which assisted Southern in meeting its all-time December record peak load early on December 24 and enabled it to provide emergency energy to DESC.[196]

Thus, none of the neighboring BAs had energy to export when the DEC and DEP BAs were most in need on December 24.

b. Curtailed Imports to DEC and DEP

As its operating reserve level began to drop, Duke made several purchases out of PJM late in the day on December 23 in an effort to improve resource adequacy.[197] In the early morning of December 24, a firm purchase of 400 MW from PJM began to flow into DEC but was later curtailed during DEC's peak hour, and a non-firm purchase of 250 MW from PJM was curtailed to zero before it was scheduled to begin flowing at 5:30 a.m. [198]

Also, like DEC, DEP made a firm purchase of 500 MW from PJM that began flowing into DEP in the early morning of December 24 but was curtailed beginning at 5:45 a.m.[199] An additional firm purchase was significantly curtailed to one of DEP's network customers in the morning of December 24.[200]

With respect to the curtailment of firm purchases, Duke reported to the Commission that it was the first time Duke has had a firm purchase curtailed.[201] Duke also reported that, with respect to exports and imports, it has "always been the understanding that the seller's customers are more important than the buyer's customers."[202]

The Public Staff noted for the Commission that one of the lessons to be learned from this event is that historical assumptions related to firm imports must be reassessed.

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[195] PJM Report at 29-34; NERC Report at 11.

[196] *Id.*

[197] Presentation to the Comm'n tr. at 52-53.

[198] Duke Resp. to PSDR2, WSE Item No. 2-6 (Jan. 27, 2023).

[199] *Id.*

[200] Duke Resp. to PSDR2, WSE Item No. 2-6 (Jan. 27, 2023); Presentation to Comm'n tr. at 26, 54-55.

[201] Tech. Conf. tr. at 91.

[202] *Id.* at 94.

Specifically, the Public Staff noted that "[f]irm is not dependable during a system emergency" while neighboring BAs are also experiencing energy emergencies.[203]

V. Network Customers

Duke defines "network customers" as those customers that have a relationship with Duke through its open access transmission tariff (OATT).[204] With respect to Duke's network customers, certain such customers purchase electricity at wholesale from Duke while others purchase from independent power producers.

Duke reported that a network customer's power supplier tripped offline in DEC during the early morning hours of December 24 before the peak and that no practical mechanism was in place for DEC to reduce impacted wholesale load in the timeframes necessary.[205] Duke reported that DEC served that load with energy that could have gone to DEC's other customers, including retail customers.[206]

Duke reported that a firm purchase from PJM by one of DEP's network customers was significantly curtailed on the morning of December 24.[207]

The Public Staff asserted that network customers that purchase power from merchant power plants became Duke's load, as their power suppliers were offline during critical periods of time when Duke's system was in need.[208]

Specifically in the context of DEP, the Public Staff testified in DEP's most recent fuel rider proceeding as to an "increase in energy imbalance net revenues compared to typical months" during Winter Storm Elliott. The Public Staff explained that

> [e]nergy imbalance charges are charges that a transmission service provider, in this case DEP, collects when power flows at the delivery point do not match the scheduled flows. If a third party causes more than its scheduled power flows, the third party will be assessed a monetary penalty. If a third party causes less, the third party will have a monetary credit. These over- and under-deliveries are accumulated over each hour of the month,

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[203] *Id.* at 123.

[204] *Id.* at 27.

[205] Duke Resp. to PSDR2, WSE Item No. 2-26 (Feb. 10, 2023); Presentation to Comm'n tr. at 22.

[206] Tech. Conf. tr. at 49.

[207] Duke Resp. to PSDR2, WSE Item No. 2-6 (Jan. 27, 2023); Presentation to Comm'n tr. at 26, 54.

[208] Tech. Conf. tr. at 124.

> and a final amount is determined monthly and billed or credited to the third party.[209]

The Public Staff also testified that the

> OATT requires that transmission network customers self-curtail or schedule replacement generation resources when directed to do so by the Transmission Service Provider (in this case, DEP) to balance the Balancing Authority Area load. During the Winter Storm Elliott load shed event, a certain transmission network customer did not respond to DEP's direction to do so; and therefore, was supplied uninterrupted service by DEP during the load shed event, which drove the increase in energy imbalance net revenues for the month of December 2022.[210]

The ORS Report also addressed this issue and concluded that Duke's provision of service to network customers that lost power supply during the morning peak on December 24 contributed to Duke's resource inadequacy.[211]

VI. Communications

a. Internal

The information reported by Duke in response to the Public Staff's investigation reveals a complicated web of internal communications — involving the meteorology team, system planners, operators, unit commitment personnel, field personnel, and fuel procurement personnel, among others — leading up to and during Winter Storm Elliott and the periods of energy emergencies in DEC and DEP.

The Commission notes that the GLRPs for DEC and for DEP specify various communications that are to occur when the utility must implement an emergency plan. The DEC GLRP does not establish clear, unambiguous communication responsibilities; rather, the plan describes, in general terms, communications that must occur in the context of the utility's decision to implement an emergency plan to manage load. The DEP GLRP includes a section directly addressing communications — specifically establishing protocols to be used when a decision is made to place in effect a "grid status level" — but the plan references a "Communications Chart" which was not included with the plan filed in the docket.

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[209] Joint Testimony of Evan D. Lawrence and Dustin R. Metz, Public Staff – North Carolina Utilities Commission, *Application of Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-133.2 and Commission Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities*, No. E-2, Sub 1321, at 15 n.2 (Sept. 1, 2023).

[210] Id. at 16 n.3. Duke did not rebut this testimony of the Public Staff.

[211] ORS Report at 38.

Subsequent to Winter Storm Elliott, DEC and DEP filed the May 2023 updates to their respective GLRPs.[212] The filing indicates that DEC and DEP are "implementing a number of actions based on lessons learned from the general load reduction event which occurred on December 24, 2022 as a result of Winter Storm Elliott."[213] Among those actions are improvements to internal communications with the goals of ensuring participation by necessary personnel in risk assessment meetings and support more descriptive conservation messaging to better inform network customers on actions they can take to reduce load.[214] The 2023 DEP GLRP filed with the Commission includes the Communications Chart and clearly identifies individuals with communications responsibilities. The 2023 DEC GLRP does not include this information.

At the Technical Conference, Duke reported to the Commission on its need to become "more nimble in communicating grid risks both internal Duke and to our external stakeholders."[215] Also at the Technical Conference, Duke reported to the Commission on its efforts to align the DEC GLRP and the DEP GLRP to a common format, in the interest of ameliorating any confusion that the differences in the plans may have caused.[216]

b. External

On December 21, Duke sent preparatory messaging to medical alert customers and critical healthcare facilities, and a severe weather alert was emailed out to customers.[217]

Duke reported to the Commission that the events occurring on December 23 through the morning of December 24 evolved quickly, with little time for communications for appeals for conservation ahead of peak hours.[218] DEC issued a public appeal for conservation, through a general press release, in the very early morning hours of December 24, ahead of the peak.[219]

Duke did not initiate communications with customers in advance of the load shed events. Duke reported to the Commission that it actually entered the communication plan

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[212] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's General Load Reduction and System Restoration Plans, *Notice of Rulemaking Procedure in the Matter of Load Reduction by Electric Suppliers During Times of Emergencies Caused by Failure or Inadequacies*, No. E-100, Sub 10A (May 12, 2022).

[213] *Id.*

[214] *Id.*

[215] Tech. Conf. tr. at 28.

[216] *Id.* at 26.

[217] Duke Resp. to PSDR2, WSE Item 2-6, at attach. Winter Weather Event Timeline (Jan. 27, 2023).

[218] Duke Resp. to PSDR2, WSE Item 2-15 (Feb 3, 2023).

[219] Electric Emergency Incident and Disturbance Report, U.S. Department of Energy Form DOE-417, December 25, 2022, Schedule 2-Narrative Description (filed in response to questions from Commissioners at the Jan. 3, 2023 Presentation to Commission), No. M-100, Sub 163 (Jan. 9, 2023).

after the load shed had started.[220] Duke reported that immediately following the initiation of load reductions, it initiated communications to customers and stakeholders using mass communication channels, including social media, traditional media, website, and mobile application updates.[221] Duke emphasized the need to use expedient means of communication as the situation unfolded rapidly on December 24.[222]

Duke reported to the Commission:

> In quick succession, [it] added an alert banner to our customer outage map; [] posted messages on Facebook and Twitter; [] distributed news releases; [] had a team of communicators that were conducting media interviews to answer questions; []updated our Interactive Voice Response system, the IVR system; and [] placed alert banners up on our main website and mobile site.[223]

Immediately following the initiation of the load shed events, Duke relied on mass communications to customers, in the interest of getting the message out quickly.[224] Duke reported that its initial messages to customers communicated that outages would last 15-20 minutes, which ended up being incorrect for many of the customers who experienced outages, and that the restoration times were adjusted as additional information was learned about the RLS tool failures and the need for manual restoration.[225]

Duke reported to the Commission that on the evening of December 24 it initiated communications requesting that customers conserve energy on the mornings of December 25 and 26 and that there was a good response from customers to those messages as they assisted Duke in managing load on those days.[226]

Based on the results of its investigation, the Public Staff indicated the need for enhancement of customer communications protocols.[227] Specifically, the Public Staff suggested the need for more transparency in communications leading up to the event

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[220] Presentation to Comm'n tr. at 43.

[221] *Id.*

[222] *Id.*

[223] *Id.* at 43-44.

[224] *Id.* at 43.

[225] *Id.* at 44-45.

[226] *Id.* at 45.

[227] Tech. Conf. tr. at 133-34.

and earlier calls for conservation.[228] The Public Staff also suggested using additional social media platforms to communicate with customers.[229]

DIRECTIVES

In mid-2023, subsequent to Winter Storm Elliott, FERC Commissioners were called on to address both the Energy and Natural Resources Committee of the United States Senate as well as the Committee on Energy and Commerce, Subcommittee on Energy, Climate, and Grid Security of the United States House of Representatives. To both bodies, on the topic of the reliable operation of the bulk power system, the FERC Chairman remarked that "[w]e face unprecedented challenges to the reliability of our nation's electric system . . . extreme weather of all kinds is threatening power to customers across the country."[230] The situation with respect to the electric system in North Carolina is no different. The NERC's annual Winter Reliability Assessment evaluates the resource and transmission adequacy needed to meet projected peak demand for the upcoming season across the various regions, including the SERC Region. The report notes that a severe cold weather event extending to the South could lead to energy emergencies as operators face likely sharp increases in generator forced outages and electricity demand and that in these areas, forecasted peak demand has risen while resources have changed little since 2022 when Winter Storm Elliott caused energy emergencies across the Region.[231] The report also notes that while SERC has adequate resources for normal winter conditions, the region's generators are vulnerable to derates and outages in extreme conditions.[232] Further, specifically with respect to SERC-East, which is comprised of North Carolina and South Carolina, the report notes that

> [e]xpected resources meet operating reserve requirements under normal peak-demand scenarios. A severe cold weather event extending to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

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[228] *Id.* at 133.

[229] *Id.* at 133-34.

[230] Testimony of Chairman Willie Phillips, Federal Energy Regulatory Commission, Committee on Energy and Natural Resources, United States Senate, May 4, 2023, available at: https://www.energy.senate.gov/services/files/B7FE1551-6BA0-4DB7-A5A5-19755800D83E; Testimony of Chairman Willie Phillips, Federal Energy Regulatory Commission, Committee on Energy and Commerce, Subcommittee on Energy, Climate, and Grid Security, United States House of Representatives, June 13, 2023, available at: https://www.ferc.gov/media/testimony-chairman-willie-phillips-oversight-ferc-adhering-mission-affordable-and-reliable.

[231] 2023-2024 Winter Reliability Assessment, November 2023, available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf, 6.

[232] *Id.* at 6.

Load shedding is unlikely but may be needed under wide-area cold weather events.[233]

In light of the Commission's findings related to Winter Storm Elliott as well as the continuing risk to reliability identified in the most recent Winter Reliability Assessment, the Commission directs Duke to take the actions described below in detail. The NERC Report includes a number of recommendations that are informed by its investigation into the performance of the electric grid during Winter Storm Elliott. While the Commission expects Duke to review and implement all applicable recommendations included in the NERC Report, in the interest of regulatory efficiency the Commission has not attempted to duplicate any of the directives included in the NERC Report. However, several of the Commissions directives build upon NERC's recommendations, taking into account facts and circumstances that are specific to North Carolina.

I. Preparation and Readiness

a. Load Forecasting

At the Technical Conference, Duke reported to the Commission on work undertaken since Winter Storm Elliott to improve forecasting. Duke reported that 12 action areas were identified and that work had already begun or been completed on most of those areas. Specifically with respect to load forecasting enhancements, Duke reported that immediately following Winter Storm Elliott, forecast models were updated to reflect loads observed over that period of time, which should improve the models' ability to predict load with greater accuracy, and those loads were validated with vendors.[234]

Duke also reported that it had undertaken analysis on how back-up heat, or heat strips associated with heat pumps, performed during Winter Storm Elliott, in order to learn how the home heating loads performed at different temperatures so that these data could be incorporated into the models.[235]

In addition, Duke reported that it had begun investigating "bottom-up forecasting" that involves the use of customer load data from AMI to inform the forecasting models. Duke explained that bottom-up forecasting could be used to forecast load with much greater granularity across the BAs, such as down to the substation or feeder level.[236]

Duke reported also that it had analyzed how risk or uncertainty is identified in a forecast, specifically how risk or uncertainty was communicated internally to raise awareness and drive preparation.[237] Duke concluded that its planning process involved

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[233] *Id.* at 22.

[234] Tech. Conf. tr. at 11.

[235] *Id.* at 12.

[236] *Id.* at 13.

[237] *Id.* at 16.

the necessary actions but that those actions were not sufficiently formalized. Duke reported that it has begun to formalize actions and procedures with the establishment of the grid risk assessment process, which is intended to add rigor to internal discussions and communications regarding forecast uncertainty on the load-side or supply-side.[238]

The Commission recognizes that load forecasting during extreme cold is but one component of ensuring sufficient supply to meet demand. However, it is the critical first component. Duke must take action to ensure that its load forecasting capabilities are responsive to dynamics on the electric system, no matter how quickly those dynamics emerge and change. Duke's load forecasting capabilities are all the more important given the load growth North Carolina has and is poised to experience, as well as the aging and impending retirement of certain of Duke's generating resources.

To this end, and consistent with Recommendation 9 of the NERC Report and particularly in light of NERC's most recent Winter Reliability Assessment, Duke is directed to review its short-term load forecasting capabilities by analyzing the drivers of extreme cold weather load.

Duke is directed to file a detailed, written explanation of its analysis of home heating load, both what it discovered regarding load dynamics during Winter Storm Elliott and as well as the potential scale of home heating load as growth continues in the Carolinas. The explanation should also address whether home heating load contributed to abnormal load valleys. To the extent that there are other drivers of extreme cold weather load that merit analysis to ensure improved load forecasting, Duke is directed to analyze such drivers and include an explanation of the analysis in its report to the Commission.

b. Outages – Planned

Duke reported to the Commission that it has evaluated "outage optimization," specifically "making more energy available, more of the time." Duke reported that it is assessing when planned outage season should begin and when outage season should end.[239]

The Commission recognizes the tension between ensuring that sufficient resources are available and ensuring that those resources have been adequately maintained so that they perform as expected. Historically, Duke has been able to take advantage of "shoulder seasons" when demand is low to perform necessary maintenance. The timing of Winter Storm Elliott in December is one example of how expectations regarding shoulder seasons must be reconsidered. Duke reported to the Commission that it intends not to conduct planned outages in December, which the Commission recognizes as a necessary first step.[240] As weather continues to challenge

[238] *Id.* at 16-17.

[239] *Id.* at 35.

[240] *Id.*

system operations with extreme temperatures, unfamiliar weather patterns, or widespread, long duration events that impact multiple BAs, Duke must become more flexible and strategic in its approach to outages. In addition, at the Technical Conference, Duke reported to the Commission that it was evaluating ways to better coordinate and better lead the execution of outages.[241] The Commission interprets this to mean that there is room to improve outage protocols to ensure minimum outage duration. To this end, the Commission directs Duke to file a report that provides planned outage protocols and identifies any revisions to protocols that have been made since Winter Storm Elliott.

c. Outages – Forced Due to Weather

At the Technical Conference, Duke updated the Commission on efforts undertaken since the storm to correct for weather-related problems experienced during the storm. Duke reported that, in the hours leading up to the load shed event, DEC and DEP lost approximately 1,300 MW of generating capacity at four generating stations due to two causes: (1) problems with heat trace measures; and (2) problems with piping insulation. With respect to heat trace, Duke identified areas where heat trace was either missing or not functioning to its full capacity. With respect to piping insulation, Duke found gaps in insulation, areas where insulation had pulled apart, and areas where repairs had been done to the plant and the insulation had not been installed completely.[242] Duke determined that in spite of having performed "walk downs" at generating stations to inspect winterization measures, failures occurred in inaccessible areas. Duke reported that it would modify its inspection process going forward to correct for this.[243] Duke also indicated that all issues that it identified post Winter Storm Elliott would be repaired by cold weather season.[244]

The Commission recognizes that, across the Eastern Interconnection during Winter Storm Elliott, the weather caused significant generator outages and derates. The Commission also recognizes the Public Staff's acknowledgement that lessons learned from extreme cold weather events in 2014 and 2015 were in place and most likely prevented the recurrence of similar issues that occurred in 2014 and 2015.

However, protecting the generating fleet from the impacts of weather is mostly within Duke's control, and the Commission expects Duke to institute all reasonable measures to ensure that its units are available to serve customers when they are most needed.

Duke is required to implement NERC Standard EOP-011-2, the currently effective standard that requires generator owners to have cold weather preparedness plans, which include inspection and maintenance of freeze protection measures. Duke reported to the

[241] *Id.* at 36.

[242] *Id.* at 33-34.

[243] *Id.* at 34.

[244] *Id.*

Commission that it was in compliance with many of the requirements of the standard in advance of the deadline.[245]

Duke also reported to the Commission that it is on track to comply with NERC Standard EOP-012-2, which was developed in response to Winter Storm Uri, by the October 1, 2024 implementation date and has already begun to implement the majority of its requirements. Duke explained that NERC Standard EOP-012-2 requires generators to update their cold weather preparedness plans to include the Extreme Cold Weather Temperature (ECWT) and Generator Cold Weather Critical Components (GCWCC) and document freeze protection measures for those components. In addition, generator owners must provide unit-specific cold weather plan training on an annual basis. Duke reported that it has completed all the items required by EOP-012-2, except the action to include GCWCCs in cold weather preparedness plans. Duke reported that all existing generating stations meet the protection requirements to operate at or below the ECWT and no upgrades are required.[246]

Given that the NERC standards related to extreme weather involve extensive reporting obligations, the Commission directs DEC and DEP to engage in concurrent reporting by filing simultaneously at the Commission the reports required by the NERC standards.

The Commission further instructs Duke to inform the Commission of any additional areas beyond those contemplated by the NERC standards that Winter Storm Elliott revealed must be addressed to improve chances of unit availability. Duke has already reported to the Commission that it has assigned a seasonal readiness coordinator to each generating station who will be accountable for the readiness of that station.[247] To the extent that Winter Storm Elliott revealed other vulnerabilities, such as wind impacts or precipitation impacts, the Commission directs Duke to identify and implement reasonable measures to address such vulnerabilities. To this end, the Commission directs Duke to file a report that identifies, by generating station: (1) the seasonal readiness coordinator; (2) repairs, replacements or additions to winterization measures made following Winter Storm Elliott, if any; (3) winterization measures taken beyond that which would be required by the NERC standards; and (4) measures implemented to ensure that all aspects of the station, those accessible and those not "accessible" have been evaluated and addressed, if necessary and that inspections, going forward, will cover all aspects of the station.

[245] Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Response to Commission Questions, No. M-100, Sub 163 (Feb. 23, 2022).

[246] Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Responses to Commissioner Data Requests from September 26, 2023 Winter Storm Elliott Technical Conference, No. M-100, Sub 163 (Oct. 13, 2023).

[247] Tech. Conf. tr. at 36.

d. Generating Plant Transition

In both DEC's and DEP's most recent general rate cases, the Public Staff noted concerns regarding "degrading" performance at certain of Duke's generation plants, as well as concerns regarding reductions in staffing and in spending to maintain those plants.[248] In reporting to the Commission on its investigation into Duke's performance during Winter Storm Elliott, the Public Staff noted that the fact that the electric system is in a state of transition, as certain aspects of generation fleet are reaching near end of life, must be taken into account and that these older plants were not designed to be operated in the current state they are currently operated.[249]

Duke agreed with the Public Staff's point that certain of its plants are not operated in the way they were designed to operate, specifically that certain of them were designed as baseload plants but are now being cycled.[250] Duke also noted that the concern regarding staffing was fair and that the companies expend effort to have sufficient staff in the right locations at the right time.[251] Duke pointed out, though, that in terms of allocating resources among generating units, the companies are trying to make decisions that are good for the companies and for the customers.[252]

The Commission recognizes that the initial decision on Allen was made prior to the extreme weather's arrival in North Carolina and that as the weather changed, the resource needs changed. The Commission is also aware that when the decision was made at that time to leave Allen in EPR, certain staff were released to travel for the holiday and then Duke was left in the difficult position of having to allocate the remaining resources to Marshall, which had been out of service due to a mechanical issue. The bottom line is, however, that during the extreme weather, when the system was in emergency need of energy, Allen was not available to meet that need, despite being maintained and kept in service for that very purpose.

The Commission notes that the Allen units were in EPR status going in to Winter Storm Elliott and that as Duke reported:

> Allen's a bit of a unique case because its capacity factor is so low, it's down in the single digits, that it's got a small contingent of resources. And it also relies on resources from another unit.[253]

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[248] *Id.* at 125-26, 135-36.

[249] *Id.* at 126.

[250] *Id.* at 138-39.

[251] *Id.* at 139.

[252] *Id.* at 140.

[253] *Id.* at 117.

The Commission notes that the Allen units are soon to retire.[254] However, the possibility exists that other aged generating resources may trend in the direction of Allen — resources with low capacity factors that are maintained only to run on a very limited basis, presumably when the system is in need.

The Commission is concerned that Duke's protocols for units like Allen are not sufficiently robust to ensure that units like Allen are available when the system most needs those units. To ensure that units maintained to run on a limited basis for reliability purposes are available when most needed, the Commission directs Duke to report to the Commission the following information: (1) protocols for maintaining generating resources with very low capacity factors, to ensure that such units are available when they are needed; (2) protocols for staffing generating resources that are operational on a very limited basis; (3) protocols for determining when such units should be committed/dispatched; and (4) protocols for actually returning such units to service once the commitment/dispatch decision has been made. Duke's report should identify where lessons learned from Winter Storm Elliott have been incorporated into these protocols.

II. Gas and Electric Coordination

DEC and DEP relied on significant natural gas-fired generating resources to get through the peak hours, as well as the load shed event, on December 24.

DEC's fleet includes the following natural gas-fired combined cycle (CC) generators: (1) Buck, 718 MW; (2) Dan River, 718 MW; and (3) WS Lee, 809 MW. The WS Lee CC was out of service prior to and during Winter Storm Elliott.

DEP's fleet includes the following natural gas-fired combined cycle generators: (1) Asheville PB1, 280 MW; (2) Asheville PB2, 280 MW; (3) HF Lee, 1,054 MW (winter); (4) Smith Energy PB4, 570 MW; (5) Smith Energy PB5, 680 MW; and (6) Sutton, 719 MW.

In addition, DEC's fleet includes approximately 3,264 MW (winter) of simple cycle combustion turbine (CT) units. DEP's fleet includes approximately 2,898 MW (winter) of simple cycle combustion turbine units.

As reported to the Commission by Duke, only four of the natural gas-fired generators experienced issues on December 24 that impacted their availability during peak or the load shed event. Dan River and Smith Energy PB4 experienced freezing issues that led to derates. The remaining two generators, Clemson CHP, and the Buck CC, were derated as a result of insufficient natural gas pressure off Transco. Buck and Dan River were again derated on December 25, as a result of low pressure.

[254] Verified Petition for Approval of 2023-2024 Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, *Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2023 Biennial Carbon Plan and Integrated Resource Plans*, No. E-100, Sub 190, at tbl.B-1 (Aug. 17, 2023).

NERC reported that, on December 24, PJM had 186 generating units that failed to start, and that one-third of those units were natural gas-fired CTs and CC units that reported to PJM that they did not have fuel or were fuel-limited.[255] Not clear is whether these units did not have fuel or were fuel-limited as a result of low pressures or supplier force majeure. Also not clear, is whether any of these units did not attempt to source/nominate natural gas on December 24 because they did not receive a day-ahead commitment from PJM. The Commission is concerned that any changes made by PJM to its capacity market or its energy market in response to gas-electric dynamics could exacerbate pressure issues in North Carolina, especially as the null point on Transco remains in and around North Carolina.

The Duke natural gas-fired fleet played a critical role in providing service during the storm, and the fleet will continue to play a critical role for customers in North Carolina. However, dynamics on the interstate pipeline system during extreme winter weather jeopardize the role that these generators must play. In light of the circumstances experienced during Winter Storm Elliott, the Commission has concerns regarding the capability of the interstate pipeline system to deliver natural gas reliably — in quantities and at pressures contracted for — during periods of stress, such as extreme weather events. Indeed, both Piedmont and PSNC reported to the Commission that pressures experienced at certain receipt points on Transco dropped well below historical range beginning on December 23. Both the Buck CC and the Dan River CC experienced derates as a result of low gas pressure on December 25. Duke, Piedmont and PSNC reported no issues, with one minor exception, with their ability to nominate the necessary gas volumes; rather the issues reported involve their not receiving natural gas supply at the necessary pressures.

Additionally, of great concern to the Commission is that during the event, natural gas shippers were making the economic decision to take natural gas off the pipeline, out of balance with their obligations, which no doubt exacerbated problems being experienced in North Carolina.

The Commission concludes, while Duke, Piedmont and PSNC managed the challenging dynamics on the interstate pipeline during the storm, there is work to be done to ensure that all are prepared to manage and mitigate these dynamics when they recur, or perhaps, become more complicated during the next extreme cold weather event. Therefore, the Commission directs Duke to re-visit certain of the issues covered by the Commission's natural gas electric coordination statement set forth in Rule R8-41 and the Commission will initiate a new docket to examine gas-electric coordination. Specifically, Duke is directed to (1) identify all the gas-electric dependencies and inter-dependencies that could threaten electric operations or customer service during extreme cold weather or other emergencies; (2) discuss those dependencies and inter-dependencies with the appropriate gas utilities and pipelines; and (3) establish a plan for managing the dependencies and inter-dependencies during extreme cold weather events and other emergencies with the appropriate gas utilities. Additionally, the Commission directs Duke

[255] NERC Report at 50.

to, in consultation with Piedmont and PSNC, discuss and develop a proposal for joint planning process in which the three utilities can engage to prepare for and respond to natural gas transportation vulnerabilities in North Carolina during extreme cold weather events.[256] The proposal should identify any approvals from the Commission that might be necessary for the companies to engage in joint planning.

Finally, the Commission views dual-fuel optionality as one approach to mitigating natural gas transportation related challenges that arise during extreme cold weather. Duke reported that of the 55 simple cycle CT units in the combined DEP/DEC fleet, 32 of those units operated on fuel oil[257] and 20 operated on natural gas during Winter Storm Elliott. As previously reported to the Commission, certain of the CCs in the DEC/DEP fleet are dual-fuel capable.[258] Based on its review of the information presented, it appears to the Commission that none of the CCs switched to fuel oil during the storm. The Commission directs Duke to report to the Commission on: (1) whether any CCs in the DEC/DEP fleet were switched to fuel oil during the event; (2) the current protocols for switching a CC from natural gas to fuel oil; (3) the dates on which any of the dual-fuel CCs in the DEC/DEP fleet have been switched; and (4) whether and the extent to which Duke has investigated expanding dual-fuel capability to any other CCs in the DEC/DEP fleet.

III. Load Management

a. GLRP

The GLRP, required by Commission Rule R8-41, is intended to guide the actions of DEC and DEP in order to maintain the stability of the electric system and ensure continuity of service during periods of several capacity shortages.

At the Technical Conference, Duke reported to the Commission that the lack of structural consistency between DEC's and DEP's GLRPs, which may have caused some internal confusion.[259] Duke reported that it has begun the work to convert the plan to a common format and will have the updated plan ready to file by the May 2024 filing deadline.[260]

The potential that there was insufficient familiarity, on the part of certain stakeholders, with the GLRPs and the potential that the GLRPs, particularly DEC's, lacked robust communications protocols, is of concern to the Commission. System

[256] This directive is intended to be consistent with and build on Recommendation 13 from the NAESB Report. As Duke, PSNC and Piedmont consider a joint planning proposal, the companies should consider whether and how other recommendations from the NAESB Report could be adapted to the effort.

[257] The Commission notes that neither Duke nor the Public Staff reported any issues with fuel-switching during the weather event. The Commission recognizes and commends the effort of Duke personnel to prepare for and execute this operational feat at a critical time under critical conditions.

[258] Duke Resp. to PSDR1, WSE Item No. 1-12a (Apr. 8, 2022).

[259] Tech. Conf. tr. at 26-27.

[260] *Id.* at 27.

emergencies can occur rapidly, as was the case with Winter Storm Elliott, and require quick and well-coordinated action in order to protect DEC's and DEP's systems, as well as the Eastern Interconnection.

To this end, the Commission directs Duke to file a detailed written explanation of the training protocols for relevant internal stakeholders on the GLRP.

b. ***Coordination* with Wholesale Customers**

In addition, the Commission recognizes that coordination with wholesale customers is a critical component of load management. Duke reported to the Commission on actions taken with certain wholesale customers to manage load during the emergency. The Commission again emphasizes that wholesale customers must play a role in managing load on the system, particularly during times of stress. Duke is directed to update the Commission on work undertaken to increase utilization of wholesale customer capabilities, particularly winter capabilities, going forward.

c. ***RLS Tool***

With respect to rotating load shed, at the Technical Conference, Duke reported that on December 24, neither the RLS tool nor DEC/DEP personnel performed as expected.[261] Duke described a number of steps taken to address the issues experienced with the tool, including software-related fixes and on-going contact with the vendor of the tool.[262] Duke also described how its testing of the tool has changed since Winter Storm Elliott, including increasing the number of scenarios tested and increasing the scale and duration of load shed.[263] In addition, Duke has improved the environment in which it runs the tests, moving from a fully simulated environment to an environment that mirrors the production environment.[264] Finally, Duke reported to the Commission that training, which incorporates lessons learned during Winter Storm Elliott, is on-going with personnel in both the Energy Control Center and the Distribution Control Center on the automated process, using the RLS tool, and on the manual process.[265]

While the Public Staff noted the failures of the RLS tool, the Public Staff did not take specific issue with the tool or Duke's use of the tool or make any recommendations specific to the tool at the Technical Conference.

The Commission recognizes that emergency circumstances might arise that will require Duke's taking action to stabilize its BAs or to protect the integrity of the Eastern Interconnection. Both fortunately and unfortunately, December 24 was the first time in

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[261] *Id.* at 40-41.

[262] *Id.* at 43.

[263] *Id.* at 44.

[264] *Id.*

[265] *Id.* at 31-32.

Duke's history that load had to be shed for this purpose. While the failures of the RLS tool exacerbated the outage time experienced by many customers, the Commission recognizes that Duke has taken action to identify the root cause of the failures and to mitigate against recurrence of such failures, such that if and to the extent that rotating outages are necessary at any point in the future, the outage to customers will be of very limited duration — no longer than the 15-30 minute window the RLS tool is capable of achieving.

The Commission directs Duke to file a report outlining the actions taken by Duke to address the failures of the RLS tool experienced during Winter Storm Elliott, how much load shed Duke believes is feasible from the RLS tool for DEC and DEP respectively based on the experience with Winter Storm Elliot, and any protocols Duke has developed for manual restoration of circuits in the event the RLS tool fails during a subsequent cold weather event.

IV. Energy Imports

The Commission notes that Duke made firm and non-firm purchases of power for import on December 23 in order to increase operating reserves when they were forecasted to be below target. However, the Commission notes that, by that point in time, all neighboring BAs were also experiencing energy emergencies. While the Commission is particularly concerned about the curtailment of firm purchases from neighboring BAs, it is not surprising to the Commission that those imports were curtailed to levels below the purchase or curtailed entirely.

The Commission acknowledges Duke's report that the curtailment of firm purchases during Winter Storm Elliott was the first time, to Duke's knowledge, that a firm purchase had been curtailed. However, the Commission also acknowledges Duke's comment that historically, the seller's customers are more important than the buyer's customers.

In light of Duke's experience with imports during the peak hours on December 24, the Commission directs Duke to revisit its assumptions regarding reliance on imports during forecasted extreme weather events. Specifically, given the events of Winter Storm Elliott, the Commission is of the impression that it will be unreasonable, going forward, for Duke to plan around or assume that it will have the ability to import during extreme cold weather events.[266] The Commission directs Duke to report to the Commission on the risk of curtailment of both firm and non-firm, and especially firm, purchases from neighboring BAs during future extreme cold weather events and how its policies or practices related to energy imports during extreme winter weather have changed since Winter Storm Elliott.

[266] NERC Report at 150.

V. Network Customers

During the Technical Conference, Duke identified interface with its network customers as an area for improvement.[267] The Commission concurs. It is unacceptable that a network customer's inability to provide for its own energy requirements during an emergency contributed to Duke's inability to serve those customers to whom Duke is obligated to provide service. Duke must take every step to ensure that this type of situation does not recur, even at times when system dynamics change rapidly, as they did during Winter Storm Elliott.

Duke reported to the Commission that it must have contact information for network customers, more specifically for an individual that is "operationally responsive." Duke reported that it was working with its network customers, which are of varying degrees of sophistication, to ensure an appropriate contact for Duke so that when Duke gives an instruction or an update on grid status, the network customer can take that and make adjustments and help the situation.[268] The lack of contact information for network customers is concerning to the Commission and, to the extent not already remedied, must be remedied immediately.

Also at the Technical Conference, Duke reported to the Commission that it was working to develop a process, using existing technology, through which Duke will communicate to network customers any change in grid status.[269] In response to a question from the Commission during the Technical Conference regarding curtailing transmission service to network customers to avoid situations like those which occurred during Winter Storm Elliott, Duke responded that it is focusing on

> [b]ecom[ing] more nimble and agile in communication with those [network] customers. All of them. And work with them to let them know, okay, we're in this grid status. We're approaching an EEA-1, EEA-2, EEA-3. If you recall, EEA-3 is we're on the verge of load shed. And in the — in the — the direction to them — the operating instruction to a network customer will be stay in balance because they've got their own obligations. It's a balancing authority. We're looking at the balancing authority load. We really — as a balancing authority, we don't recognize the different customers. We're looking at the overall balance of the footprint. And so our instruction to them would be balance your load with generation resources.[270]

The Commission directs Duke to file a report identifying: (1) each network customer in DEC and in DEP; (2) the wholesale power supplier for each network customer; (3) the primary point of contact, who has operational authority, at the network

[267] Tech. Conf. tr. at 27.

[268] *Id.* at 52.

[269] *Id.* at 27.

[270] *Id.* at 49-50.

customer for Duke; (4) the primary point of contact at Duke for each network customer; (5) a general description of the network customer's performance during Winter Storm Elliott; and (6) the communications protocols and process that have been developed for interfacing with network customers during emergency conditions to ensure the coordination of load management efforts between Duke and the network customer.

On August 29, 2023, Duke provided to the Chief Clerk of the South Carolina Public Service Commission a written response to the ORS Report[271] that included the following statement:

> Duke Energy will continue to review policies and procedures to improve coordination with network and wholesale customers. However, Duke Energy cannot "ensure" that network and wholesale customers address supply issues. Duke Energy can and does assess a penalty if those supply issues are not addressed pursuant to the Federal Energy Regulatory Commission approved Open Access Transmission Tariff (Table ES-2 item 11).

The Commission recognizes that Duke cannot control whether and the extent to which a network customer provides for its own power supply and accepts Duke's assertion that it does not have the "tactical ability" to shed load for its network customers.[272] However, Duke is in a position to assess whether the network customer has complied with its obligations under the OATT. To this end, the Commission directs Duke to file a detailed, written explanation of: (1) a network customer's general obligations under the OATT in emergency situations, with reference to specific provisions of the OATT; (2) Duke's process for assessing whether a network customer is in compliance with these provisions of the OATT; (3) Duke's process for communicating with network customers regarding compliance with the OATT; (4) the process established by Duke for assessing any penalty to network customers as allowed by the OATT and the circumstances under which such penalty would be assessed; and (5) the process (including all communications protocols) established by Duke, in response to experience during Winter Storm Elliott, for curtailing transmission service to network customers during emergencies.

VI. Communications

a. Internal

Duke reported to the Commission on efforts to update the GLRPs for DEC and DEP as well as to reconfigure the "tailgate process" into the "grid risk assessment

[271] Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Responses to Commissioner Data Requests from September 26, 2023 Winter Storm Elliott Technical Conference, *Investigation Regarding the Ability of North Carolina's Electricity, Natural Gas, and Water/Wastewater Systems to Operate Reliably During Extreme Cold Weather*, No. M-100, Sub 163 (Oct. 13, 2023).

[272] Tech. Conf. tr. at 53.

process."[273] Each of these efforts involves changes to or clarifications of internal communications protocols during emergencies. Of highest priority to the Commission is that protocols for internal communications during periods of system emergency be clear, unambiguous, known to the relevant personnel and conducive to being implemented quickly. The Commission expects the internal communications protocols to be included with the revised GLRPs filed with the Commission pursuant to this Order. In addition, the Commission directs Duke to file the internal communications protocols, or a detailed explanation thereof, associated with the grid risk assessment team.

b. External

The Commission recognizes that the events of December 23 and December 24 leading up to the load shed events evolved quickly. However, communications with customers during this time were not satisfactory, and Duke acknowledged that information shared with customers did not meet their expectations as to accuracy.[274] In particular, Duke's failure to issue an appeal for conservation prior to December 24 is of concern to the Commission. Even though Duke may not have known that it would not have adequate resources to serve load until the morning of December 24, conditions were sufficiently tight that a call to customers on December 23 may have eased the increasing load headed into the peak on December 24 and mitigated the extent of the load shed necessary. Customers should be given the opportunity to provide assistance during emergencies, and they, in fact, did provide some assistance later on December 25 and December 26, as Duke reported.[275] In addition, Duke's failure to notify customers in advance of the load shed events is not acceptable, and the failure to provide accurate restoration times — albeit complicated by the failures of the RLS tool — further exacerbated the stress and frustration of customers.

At the Technical Conference, Duke reported to the Commission on actions that have been undertaken to improve communications with customers during events like Winter Storm Elliott. Specifically, Duke reported that it has updated its automated messaging platform to reflect messages that are specific to the type of event being experienced, which would replace the typical outage alerts that go out to customers.[276] Duke reported that 90 percent of customers for whom Duke has either a mobile phone number or e-mail address are enrolled in the automated messaging program.[277]

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[273] Duke also referenced a "grid threat assessment" team during the Technical Conference. The Commission interprets the "grid risk assessment" and "grid threat assessment" to be the same thing.

[274] Presentation to the Comm'n tr. at 14.

[275] *Id.* at 15.

[276] Tech. Conf. tr. at 46.

[277] *Id.* at 47.

In addition, Duke reported efforts to align external communications with the GLRP, specifically how to communicate to customers as it moves through the EEA levels and how to ensure appropriate communications to news media and on social media.[278]

The Commission expects Duke to make every effort to communicate with customers regarding emergency situations, as communications can be integral to ensuring public safety and well-being. The Commission recognizes that Duke communicated with customers during the event. However, Duke must reach customers in advance of emergency conditions. Duke must issue appeals for customer conservation, even conservatively early in the context of an anticipated emergency situation, and Duke must communicate with customers in advance of load shed. The Commission expects that Duke's automated messaging tools should be capable of communicating with customers rapidly; however, to the extent that the load shed must happen more quickly than automated messaging can be deployed, Duke must issue general notices of outages to customers across a variety of media, including traditional and social.

While Duke provided updates to the Commission on its external communications efforts during the January 3 presentation and later at the Technical Conference, the Commission directs Duke to file a detailed explanation of customer communications protocols to be deployed during emergencies, which reflect the changes made since Winter Storm Elliott.

CONCLUSION

Having reviewed the extensive information related to Winter Storm Elliott reported to the Commission and otherwise accessible to the Commission, the Commission concurs with the Public Staff that the load shed event of December 24 was the result of a confluence of the factors discussed in detail in this Order. The Commission's review has identified deficiencies and vulnerabilities made apparent by Duke's performance during Winter Storm Elliott and notes the continuing risk to reliability of winter weather that has been identified by NERC. The reporting obligations established in this Order are intended to: (1) confirm that Duke has taken action to address problems that were identified or arose during Winter Storm Elliott; (2) ensure that the GLRPs filed annually by Duke reflect lessons learned or experienced gained, if any, from the previous winter; and (3) establish a Winter Reliability Assessment report pursuant to which, going forward, Duke will report to the Commission each fall on actions taken to assess and address winter reliability risks.

[278] *Id.* at 138.

IT IS, THEREFORE, ORDERED as follows:

1. That the Commission shall initiate a new docket for the purpose of receiving reports from Duke directed in this Order related to winter reliability (Winter Reliability Assessment Docket);

2. That the Commission shall initiate a new docket for the purpose of receiving reports directed in this Order related to the coordination between gas and electric utilities (Gas-Electric Coordination Docket);

3. That within 60 days after the issuance of this order Duke shall file with the Commission in the Winter Reliability Assessment Docket the following:

a. A detailed, written explanation of its analysis of home heating load, both what it discovered regarding load dynamics during Winter Storm Elliott and the scope and scale of home heating load as growth continues in the Carolinas. The explanation should address whether home heating load contributed to abnormal load valleys;

b. A report that provides planned outage protocols and identifies any revisions to protocols that have been made since Winter Storm Elliott;

c. A report that identifies, by generating station: (1) the seasonal readiness coordinator; (2) repairs, replacements or additions to winterization measures made following Winter Storm Elliott, if any; (3) winterization measures taken beyond that which would be required by the NERC standards; and (4) measures implemented to ensure that all aspects of the station, those accessible and those not "accessible" have been evaluated and addressed, if necessary and that inspections, going forward, will cover all aspects of the station;

d. A report identifying: (1) whether any CCs in the DEC/DEP fleet were switched to fuel oil during the event; (2) the current protocols for switching a CC from natural gas to fuel oil; (3) the dates on which any of the dual-fuel CCs in the DEC/DEP fleet have been switched; and (4) whether and the extent to which Duke has investigated expanding dual-fuel capability to any other CCs in the DEC/DEP fleet;

e. A written explanation of the training protocols for relevant internal stakeholders on the GLRPs;

f. A report outlining the actions taken by Duke to address the failures of the RLS tool experienced during Winter Storm Elliott, how much load shed Duke believes is feasible from the RLS tool for DEC and DEP respectively based on the experience with Winter Storm Elliot, and any protocols Duke has developed for manual restoration of circuits in the event the RLS tool fails in another cold weather event;

g. A report identifying the risk of curtailment of firm and non-firm purchases from neighboring BAs and how Duke's policies and practices related to energy imports during extreme winter weather have changed since Winter Storm Elliott;

h. A report identifying: (1) each network customer in DEC and in DEP; (2) the wholesale power supplier for each network customer; (3) the primary point of contact, who has operational authority, at the network customer for Duke; (4) the primary point of contact at Duke for each network customer; (5) a general description of the network customer's performance during Winter Storm Elliott; and (6) the communications protocols and process that have been developed for interfacing with network customers during emergency conditions to ensure the coordination of load management efforts between Duke and the network customer;

i. A detailed, written explanation of: (1) a network customer's general obligations under the OATT in emergency situations, with reference to specific provisions of the OATT; (2) Duke's process for assessing whether a network customer is in compliance with these provisions of the OATT; (3) Duke's process for communicating with network customers regarding compliance with the OATT; (4) the process established by Duke for assessing any penalty to network customers as allowed by the OATT and the circumstances under which such penalty would be assessed; and (5) the process (including all communications protocols) established by Duke, in response to experience during Winter Storm Elliott, for curtailing transmission service to network customers during emergencies;

j. The internal communications protocols, or a detailed explanation thereof, associated with the grid risk assessment team; and

k. A detailed explanation of customer communications protocols to be deployed during emergencies, which reflect the changes made since Winter Storm Elliott;

4. That within 90 days of the issuance of this order, Duke shall file in the Gas Electric Coordination Docket the following:

a. A report that (1) identifies all the gas-electric dependencies and inter-dependencies that could threaten electric operations or customer service during extreme cold weather or other emergencies; (2) discusses those dependencies and inter-dependencies with the appropriate gas utility(ies) and pipeline(s); and (3) establishes a plan for managing the dependencies and inter-dependencies during extreme cold weather events and other emergencies with the appropriate gas utilities;

b. A proposal for joint planning process in which Piedmont, PSNC and Duke can engage to prepare for and respond to natural gas transportation vulnerabilities in North Carolina during extreme cold weather events;

5. That Duke shall file with the Commission in a sub-docket of the Winter Reliability Assessment Docket, all reports filed by DEC and DEP with NERC/FERC required by the extreme weather reliability standards;

6. That starting in November 2024, and thereafter annually, Duke shall file in the Winter Reliability Assessment Docket its Winter Reliability Assessment, confirming for the Commission the steps taken to ensure readiness and preparation, as well as identifying any potential vulnerabilities, for the coming winter season; and

7. That starting in May 2025, and thereafter annually, when Duke files the GLRPs, Duke shall file a report in the Winter Reliability Assessment Docket outlining any issues that impacted the ability of the utility to serve load in the previous winter. If relevant, the report may include a summary of the following:

a. Issues identified in NERC reports;

b. Reports from seasonal readiness coordinator for each generating station;

c. Issues related to training internal stakeholders on GLRPs;

d. Issues related to coordination with wholesale customers;

e. Issues related to the performance of the RLS tool, or successor program;

f. Issues related to energy imports;

g. Issues related to coordination of load management with network customers; and

h. Issues related to internal and external communications.

ISSUED BY ORDER OF THE COMMISSION.

This the 22nd day of December, 2023.

NORTH CAROLINA UTILITIES COMMISSION

A. Shonta Dunston

A. Shonta Dunston, Chief Clerk