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April 8, 2022

VIA ELECTRONIC FILING

Ms. A. Shonta Dunston, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Response to Public Staff Data Request No. 1
Docket Nos. E-100, Sub 173 and M-100, Sub 163

Dear Ms. Dunston:

Enclosed for filing in the above-referenced proceeding is the Response of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (the "Companies") to Data Request No. 1 of the Public Staff – North Carolina Utiliites Commission ("Public Staff"). The Public Staff has requested that the Companies file responses so that the Commission will have these responses prior to the technical conference scheduled for April 19, 2022.

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

Sincerely,

Jack E. Jirak

Enclosure

cc: Parties of Record

Duke Energy Carolinas, LLC and Duke Energy Progress, LLC
Docket No. M-100, Sub 163
Public Staff Data Request No. 1
Date Sent: March 25, 2022
Requested Date Due: April 4, 2022, extended to April 8, 2022

Public Staff Technical Contact: Dustin Metz
Phone #: (919) 733-1513
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Public Staff Legal Contact: Lucy Edmondson
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Please file your responses to this data request in the docket so that the Commission may review the responses prior to the Technical Conference.

Please provide responses to this request in an electronic format. If in Excel format, please include all working formulas. In addition, please include (1) the name and title of the individual who has the responsibility for the subject matter addressed therein, and (2) the identity of the person making the response by name, occupation, and job title.

1. Duke's response to Commission question #1, bulleted item 2 states: "In addition, specific incident command and control learnings…". Please respond to the following: 1) describe the command and control environment during an extreme event and how it augments normal day system operators and operations, and 2) describe the "learnings" and the associated plans and time needed to implement them.

Response to part 1: Duke Energy's NERC-certified System Operators are responsible for performing real-time Transmission Operator and/or Balancing Authority functions, which include implementing Real-time actions when necessary to ensure the reliability of the Bulk Electric System ("BES"). The System Operators alleviate operating emergencies or direct timely and appropriate real-time actions to ensure the stable and reliable operation of the BES. This includes performing firm load shedding to prevent or alleviate System Operating Limit or Interconnection Reliability Operating Limit exceedances. Duke Energy's System Operators perform these functions every day, regardless of whether or not the system is faced with an extreme event.

During an extreme event, Duke Energy's System Operators will initiate the Tailgate Team which is responsible for formalizing the communications process regarding adverse system emergency (generation and transmission) situations. Business units that participate in the Tailgate team include, but are not limited to, Generation, Nuclear, Corporate Communications, Customer Delivery, Regulatory Affairs, Fuels and System Optimization, and Wholesale Accounting. The team provides consistent communications regarding system conditions, actions being taken by the ECC, and any anticipated actions, including activating Demand-Side Management Programs and/or implementing other actions to respond to the system emergency. These other actions may include:

- Request additional generation to be brought online
- Voltage Reduction programs to reduce demand-side load
- Request Demand-Side programs administrated by wholesale customers
- Request the purchase of Emergency Power from other Utilities
- Distribution Feeder rotation program activation
- Interruption of Transmission Firm Load

The Tailgate Team will be assembled whenever ECC personnel determine it is appropriate based upon existing or anticipated system conditions. The System Operations Information Coordinator will provide pertinent information to members of the Tailgate Team. It is the responsibility of the members of the Tailgate Team to disseminate information to teammates throughout the Company. Communications regarding system conditions and associated actions will be coordinated from a central location. This communication will be done through members of the Tailgate Team after receiving pertinent information from the System Operations Information Coordinator.

Response to part 2: Duke Energy identified 3 key opportunities for improvement as a result of the multi-disciplined drill referenced in the Companies' response to the Commission's Order and has established the following action items:

- Evaluate ways to strengthen situational awareness of incidents, especially those that impact multiple organizations or jurisdictions. This could involve looking at new technologies to manage the information or developing new processes. Duke Energy is targeting Q4 of 2022 to begin this initiative.
- Expand the multi-organizational exercises to years when Duke Energy is not also participating in GridEx. Duke Energy has been participating in GridEx since it first started in 2011, and Duke Energy conducts annual hurricane and storm drills in the Midwest, Carolinas and Florida. Specific events would dictate what type of scenario would be targeted such as Colonial Pipeline or the Texas grid-instability attack that happened last year. Duke Energy is targeting Q3 of 2022 to begin this initiative.
- Increase employees' awareness of grid status alert levels and what they mean, especially when Duke Energy experiences a red (load management) or purple (load shed) level. The Companies are targeting Q3 of 2022 for this initiative, which will include incorporating this information into the Q3 IST Training.

Response to Public Staff Question #1 provided by: David Mc Ree – Director, Transmission Emergency Preparedness

2. Duke's response to Commission question #1, bulleted items 3, 4, and 5 discusses: 1) gas supply, 2) liquid back up fuel, and 3) nuclear stations.

a. Please explain any evaluations that were conducted regarding Duke's coal fleet and explain any system enhancements that resulted from the evaluations.

Response: Duke Energy reviewed the processes in place for its coal fleet to address cold weather operations. Duke Energy validated that procedures are in place for coal units to prepare the units in advance of cold weather and include checking insulation, heat tracing and equipment layup in advance of predicted low temperatures. We did not identify any specific plant modifications that were needed following this review.

b. When does Duke plan to test combustion turbine operation on liquid fuel each year?

Response: Duke Energy tests its combustion turbine fleet's operation on liquid fuel in accordance with its cold weather internal guidance document, which identifies actions and responsibilities necessary to prepare generation stations for the summer and winter seasons. This document establishes a required quarterly liquid fuel test for our simple cycle combustion turbines ("SCCTs") and a required annual test for our combined cycle combustion turbines ("CCCTs"). The Companies' fleet of SCCTs typically operate on liquid fuel monthly. In compliance with our internal guidance, our fleet of CCCTs will be tested on liquid fuel operations once a year at a minimum. These tests have required significant planning and maintenance as a few of the units have not been required to operate on liquid fuel in several years.

c. Has Duke identified any actual or potential issues related to operating on liquid fuel? If so, has Duke addressed all actual issues?

Response: Infrequent operation on liquid fuel does create some maintenance issues with the fuel oil systems and components. Based on recent testing on liquid fuel, lessons learned have been shared across the fleet to improve unit functionality on liquid fuel. To address issues with components that get plugged with residual oil, Duke has identified necessary parts to stock, such that they can be replaced quickly.

d. How much time does Duke require to address liquid fuel operating issues once identified (i.e., are tests conducted far enough in advance to address issues prior to cold weather)?

Response: Duke Energy stations are tested in advance of cold weather. Many of the issues that occur can be fixed within the shift (12 hours). To ensure units are prepared to operate, additional parts are stocked to replace any parts damaged during liquid fuel operations. In addition, Duke Energy has an internal team of operations personnel that meets every-other-month to discuss fleet issues. One of the standing agenda items is to discuss cold/hot weather preparations and lessons learned. This team shares operational experience and best practices so that Duke's fleet is prepared.

Response to Public Staff Question #2 provided by: Mark Gillespie – General Manager, FMS & TGs

3. Duke's response to Commission question #4 states that if the Meteorology team identifies an extreme cold event within a 7 to 14-day horizon, it will incorporate those impacts into future forecasts. In response to question #1, Duke describes its plan to test and operate combustion turbines on liquid fuel prior to cold weather operations.

a. Please define an "extreme cold event". Is there a set temperature threshold, a temperature delta, or a combination of multiple factors?

Response: Duke Energy follows the NERC definition of extreme cold after the 2018 polar vortex. It is 20 to 30 degrees Fahrenheit below average. In the Carolinas a 20 degree below average daily low in January would be around 10 degrees Fahrenheit. Morning minimum forecast lows below 10 degrees Fahrenheit would be considered an "extreme cold event."

Response to Public Staff Question #3.a provided by: Nick Keener – Director, Meteorology

b. Please describe how Duke manages the time gap that may take place between a "cold weather operations" test and extreme cold weather while ensuring the system will be functional when called upon. For example, if cold weather operation testing takes place on December 1st, and an extreme cold weather event occurs on February 1st, a significant amount of time would have passed between the test and the event. What policies and/or procedures does Duke have in place for the time period between the test and the cold weather event?

Response: Duke Energy ensures that its system is prepared for extreme weather through both our periodic testing and ongoing procedures that we have developed over decades of operations. These additional checks complement the tests we run on specific facilities and ensure that the system can perform reliably during a cold weather event. They are summarized as follows:

- Cold weather guidance document: Non-Nuclear generation has a formal fleet-wide guidance document, "Seasonal Preparation Guideline," (FHG-

OPR-NA-GDLN-OP-0005) that identifies actions and responsibilities to prepare generation stations for both summer and winter seasons. Winter preparation activities include checking insulation and heat trace systems. Stations have also created site-specific procedures to document necessary actions unique to their plant.

• Stations have cold weather preparedness procedure/checklists to be used in the Fall: Generation has created a formal guidance document, "Seasonal Preparation Guideline," (FHG-OPR-NA-GDLN-OP-0005) that identifies actions and responsibilities to prepare generation stations for both summer and winter seasons. Winter preparation activities include checking insulation and heat trace systems. Stations have also created site-specific procedures to document necessary actions unique to their plant.

• Stations have standard Preventive Maintenance associated with cold weather preparation entered into their Work Order system.

For the Companies' mission critical nuclear/non-nuclear generating units, the Companies ensure that planned outages occur in the shoulder months (spring and fall) to be prepared for heavy runs to support the peak summer and winter loads.
In addition to the cold-weather preparation activities already in place, the Companies' nuclear/non-nuclear generation fleet is instituting three additional cold-weather prep actions as a result of the following 2021 Texas Event lessons learned:

• Action 1: Ensure a Lessons Learned session is held at end of each peak season, winter/summer.

• Action 2: Ensure fuel oil operation is reliable on units with fuel oil as back-up fuel and prewinter testing frequency is adequate to ensure reliability.

• Action 3: Identify vital off-site power supplies related to power generation and coordinate with Distribution to ensure they are on the critical load list. Consider support systems required for continued station operation, such as: municipal water supplies, gas compressor stations, etc.

NERC Protection & Control ("PRC") standards also support transmission reliability and resiliency. The Companies have robust processes in place to ensure compliance with all PRC standards, including detailed procedures, personnel training, and periodic auditing.

Response to Public Staff Question #3.b provided by: David Mc Ree – Director, Transmission Emergency Preparedness

c. Does Duke test utility assets at the notification of an extreme weather event 7 to 14-days out from the event to ensure system operation, allowing time for any necessary repairs? If not, please describe the current procedure.

Response: Duke Energy does not test utility assets at the time of notification of an extreme weather event. Rather, the Companies perform bi-annual preparedness reviews for operational functions prior to the summer and winter seasons. This review includes coordination between meteorology, operational departments, customer services, and communications and is used to evaluate and assess the necessary actions which should be completed before the summer and winter seasons. These reviews provide coordination with operational functions to ensure departments are prepared for severe weather conditions. The review includes a seasonal weather forecast, load expectations, allows for identification of operational concerns such as assessment of generation availability and weatherization plans, communication protocols between organization and the public, transmission and distribution maintenance, and other operational concerns prior to entering the summer and winter weather seasons. Further facilitating a culture of readiness, the Companies have included “super-peak” case studies of extreme load conditions as part of the integrated seasonal preparedness reviews.

For transmission substations, cold weather mitigation is provided in design specifications for transformers and apparatus; therefore, specific weatherization is not required. Protective relays are installed in environmentally controlled houses, and control house and substation equipment problems generate alarms so the operators monitoring the system can dispatch crews for immediate attention and response. Transmission’s overall maintenance plan requires that visual inspections and operational functions be performed on a defined schedule set forth in the Transmission Maintenance Program Portfolio and Maintenance Interval Schedule. These items are a form of assessment and information gathering.

Transmission manages and assesses operational assets through a diverse approach of inspection and maintenance programs to ensure the integrity of the grid and plan for end-of-life equipment needs. Transmission substation facilities are inspected numerous times throughout the year, depending on their level of remote monitoring in place. Substation visual inspections include looking for early signs of component degradation, overheating, abnormal operating conditions, and vandalism. Weather considerations for these inspections would include verifying cabinet heaters are operational for circuit breakers, transformers, and related equipment with sensitive instrumentation, as well as verifying HVAC systems for buildings/enclosures containing protective relays and battery systems, where installed and applicable. Deficiencies are addressed through the corrective maintenance program in a priority commensurate with the risk presented.

The preventive maintenance program is also in place to proactively test, inspect, and refurbish major transmission components such as circuit breakers, transformers, and protection and control devices before they can mis-operate and introduce vulnerabilities onto the grid, and to ensure their operational readiness.

All transmission class circuits are inspected twice annually through the aerial patrol program, which consists of trained observers looking for significant threats to transmission conductors and structures from either vegetation, aging, external damage including lightning and wind, or collateral damage including public interference. Wood pole transmission circuits are inspected from ground walking patrols every four to six years depending on the geographical conditions. Inspections are to identify groundline rot and other structural deficiencies, but also provide an opportunity to inspect insulators and hardware. Transmission towers are also inspected on a periodic basis to identify structural deficiencies and other defects requiring repair/replacement.

Response to Public Staff Question #3.c provided by: David Mc Ree – Director, Transmission Emergency Preparedness

d. Please explain the process of notifying and planning fuel oil resupply. Would this resupply occur when an extreme cold weather notification is within 7 to 14-days as identified by the Meteorology team?

Response: The process to evaluate oil resupply begins with a combination of monitoring weather forecasts and an internal 7-day fuel forecast.

- Internal weather updates are provided daily giving an early forecast to potential cold weather.
- Portfolio Management produces and posts a 7-day forecast which includes forecasted fuel oil burns.
- The Fuel Oil trader uses the forecast data to produce a 7-day Fuel Oil inventory projection which incorporates current fuel oil inventories held at the plants, 7-day forecasted burns at the applicable sites and any scheduled replenishment deliveries. The report is sent via e-mail communication to Fuels & Systems Optimization ("FSO") management, Regulated & Renewable Energy ("RRE") management, portfolio management and the Energy Control Center/Security Operation Center ("ECC/SOC") as well as natural gas and power traders.

As part of the normal extreme cold weather planning process, daily tailgate meetings between the fuels group and ECC may be scheduled where system conditions are reviewed including fuel supply, prices, inventories, volumes, power markets and other economic and reliability discussions that would result in impacts to fuel decisions and resupply planning. Oil burn inventory impacts would be monitored for the need for purchasing and scheduling fuel oil deliveries. Deliveries to plant sites would be coordinated by the fuel oil trader, oil suppliers and plant operational personnel to enable delivery and replenishment as needed.

Response to Public Staff Question #3.d provided by: Jim McClay – Managing Director, Natural Gas Trading

i. [sic] Please provide examples of Duke's fuel oil re-supply for operations during a cold weather event such as the one in January 2018 and describe the required logistics.

Response: Examples of fuel oil re-supply for operations during a cold weather event are bulleted below.

a. During the month of January 2018 Duke Energy resupplied 45.5M gallons of fuel oil that were delivered to generating sites in the Carolinas.
    - Duke used a combination of delivered supply agreements and offsite storage to source the fuel oil.
    - 6,000 truckloads during the month were delivered to resupply that volume which is on average roughly 200 truckloads per day.

b. The logistical factors to be taken into account include but are not limited to:
    - road conditions
    - distance from the terminal to the plant
    - unloading hours – many plants had to go to 24-hour coverage
    - unloading bays at the plants – many plants can unload multiple trucks at the same time
    - ramp in of trucking resources

Response to Public Staff Question #3.i[sic] provided by: Jim McClay – Managing Director, Natural Gas Trading

4. Please provide a detailed description of the third-party load forecasting models to forecast loads for extreme weather events. This response should include a detailed description of the weather variables used in the third-party models.

Response: Duke Energy uses the same external third-party vendor load forecast models to forecast load for weather normal days and extreme weather events. The third-party models are advanced computer neural networks and regression-based time series models that utilize proprietary algorithms to analyze and forecast load. The third-party models use historical hourly loads and hourly weather forecast variables for temperature, dew point, cloud cover and wind speed provided by the Duke Energy meteorologists.

Response to Public Staff Question #4 provided by: Rupert Bruce – Lead Portfolio Management Analyst

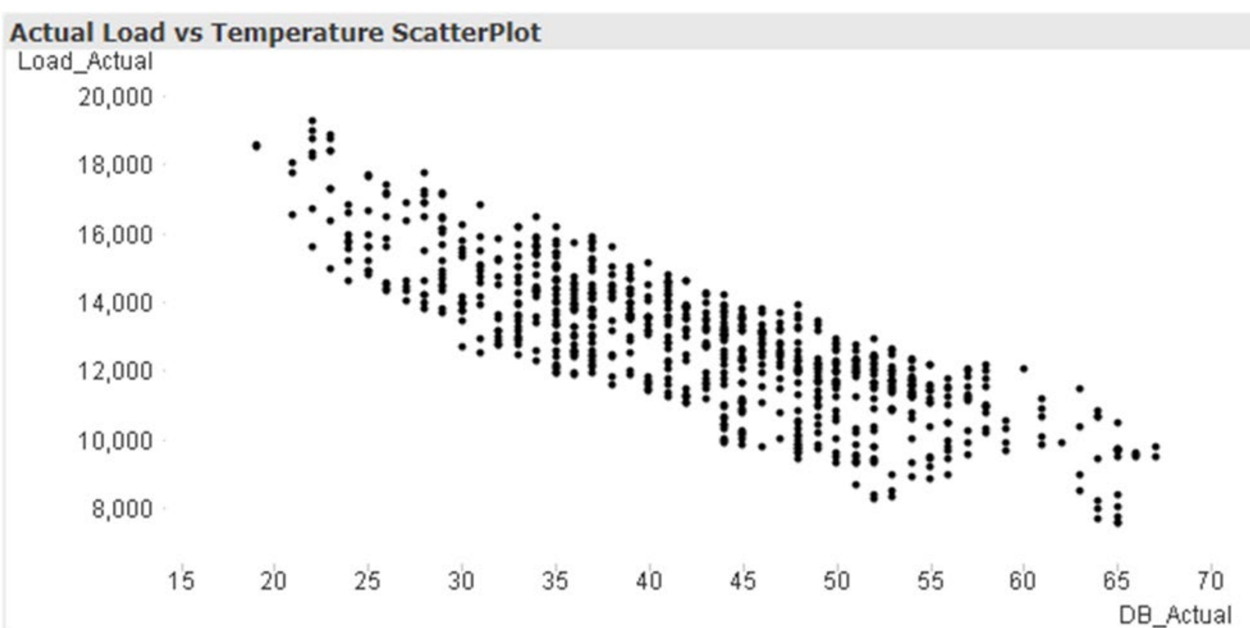
5. Please provide a detailed description of the load forecasting models that are based on historical loads during similar cold weather events.

Response: The load forecasting models described in question 4 utilize Duke Energy's historical hourly loads and weather attributes including past cold weather events. Once the load forecast models are finished processing, Duke Energy's unit commitment portfolio manager reviews the load forecasts and trends for each day and develops the system unit commitment plan. Additionally, the unit commitment portfolio manager will retrieve and review the history of similar days for comparison and discuss that information with meteorology and the Energy Control Center. Once the reviews are complete, the forecast will be published and used for the system unit commitment resource plan which typically occurs twice daily but on extreme days may occur more often.

Response to Public Staff Question #5 provided by: Rupert Bruce – Lead Portfolio Management Analyst

6. Please provide detailed support for the temperature load response curve, the variables and equation used to determine the curve, and the impacts to system planning and operation.

Response: The figure below shows DEC's temperature/load response curve for January 2019 using actual load and temperature. When forecasting the load for a future date, the weather forecast provides temperature, dew point, cloud cover and wind speed. The models also use calendar effects such as time of the day, day of the week, and holiday vs. non-holiday. As outlined in question 4, Duke Energy utilizes third-party vendors that have proprietary algorithms that are not provided to Duke Energy, and therefore, cannot be described here. Duke Energy provides hourly load, temperature, humidity, cloud cover and wind speed as inputs to the third-party load forecasting models, and the unit commitment portfolio manager uses the various forecasts for the development of the hourly load forecast used for system planning.



Response to Public Staff Question #6 provided by: Rupert Bruce – Lead Portfolio Management Analyst

7. In response to Commission question #4, Duke discussed models that simulated loads using temperatures reaching 10 degrees below the lowest recorded temperature over the last 30 years.

a. Normalizing for load growth, what DEP peak load did the model predict for hour ending 8:00 am on Thursday, January 7, 2014 when the system average temperature was approximately 11 degrees and available operating reserves were less than 1%? In addition, did the model runs assume any load curtailments?

Response: The current load model predicted DEP's peak load for hour ending 8 am Tuesday January 7, 2014 of 14,721 MW. The load model does not assume any curtailments. Any curtailments would be based on real-time system conditions and needs and managed by transmission operations.

b. Normalizing for load growth, what DEC peak load did the model predict for hour ending 8:00 am on Thursday, January 7,2014 when the system average temperature was approximately 12.0 degrees and available operating reserves were less than 1%? In addition, did the model runs assume any load curtailments?

Response: The current load model predicted DEC's peak load for hour ending 8 am Tuesday January 7, 2014 of 21,577 MW. The load model does not assume any curtailments. Any curtailments would be based on real-time system conditions and needs and managed by transmission operations.

Response to Public Staff Question #7 provided by: Rupert Bruce – Lead Portfolio Management Analyst

8. In regard to question #7, please answer the same questions for the 2015 and 2018 winter peak demands for both Companies.

Response: The Companies have interpreted this question as a reference to "Commission question #7". In response to Commission question #7, please find below the generating units that were unable to operate due to the cold weather or weather-related fuel constraints and the actions taken for 2015 and 2018 winter peak demands.

2015 Winter Peak

The following outages occurred during the winter peak due to weather conditions:

DEP Smith Energy Complex Unit 4-S – **Description of event:** U8 drum levels high due to freeze issues. **Remediation:** Drum Level Transmitters moved to the top of the heat recovery steam generator inside new temperature-controlled boxes with heat trace upgrades.

DEP Smith Energy Complex Units 4-8 – **Description of event:** U8 hot reheat header pressure freeze causing ST4 trip and unable to recover. **Remediation:** Wind breaks installed around transmitter boxes with heat trace/insulation upgrade.

DEP Smith Energy Complex Units 4-7 – **Description of event:** Manually tripped due to low LP drum low, low hotwell due to PB4 freeze. **Remediation:** Upgrade of heat trace and insulation.

DEP H.F. Lee CC1A – **Description of event:** High continuous purge manifold pressure trip due to ice plug in vent line. **Remediation:** The manifold purge line was warmed and purged. The unit was returned to service. The purge vent lines were later modified on the LCC CTs to mitigate this freezing issue.

Note: there were no events in DEC units during the 2015 winter peak due to weather conditions.

2018 Winter Peak

The following outages occurred during the winter peak due to weather conditions:

DEP Wayne CT12 – **Description of event:** Atomizing air lines frozen. **Remediation:** The AA compressor filter sensing lines were warmed and purged. The unit was returned to service.

DEP Weatherspoon CT2 – **Description of event:** PS4 signal line frozen. **Remediation:** Installed blow down piping and valves to the PS4 sensing lines where they enter the auxiliary equipment rooms on all four units. This allows purging of moisture out of the sensing lines during freezing weather to eliminate the issue.

DEP Sutton 4-S – **Description of event:** HP feedwater flow transmitters froze causing high drum level trip. **Remediation:** Found broken 120vac feeder circuit to heat trace from power panel. Replaced wiring and repaired conduit to prevent re-occurrence.

Note: there were no events in DEC units during the 2018 winter peak due to weather conditions.

Response to Public Staff Question #8 provided by: Trudy Morris – Generation & Regulatory Strategy Director

9. Duke responded to Commission question #4: "Additionally, Duke Energy's Load Forecasting/Unit Commitment Analysts utilize automated tools that can generate forecasts based on historical loads during similar weather conditions for up to seven (7) years in the past. In addition, Duke Energy ran tests after the 2021 Texas Event to simulate how load models would fare in case of temperatures 10 degrees below the lowest recorded temperature over the last 30 years and both DEC and DEP BA load models indicated that such temperatures would not compromise the reliability of the system."

a. In Duke's analysis, what was the lowest recorded temperature over the last 30 years?

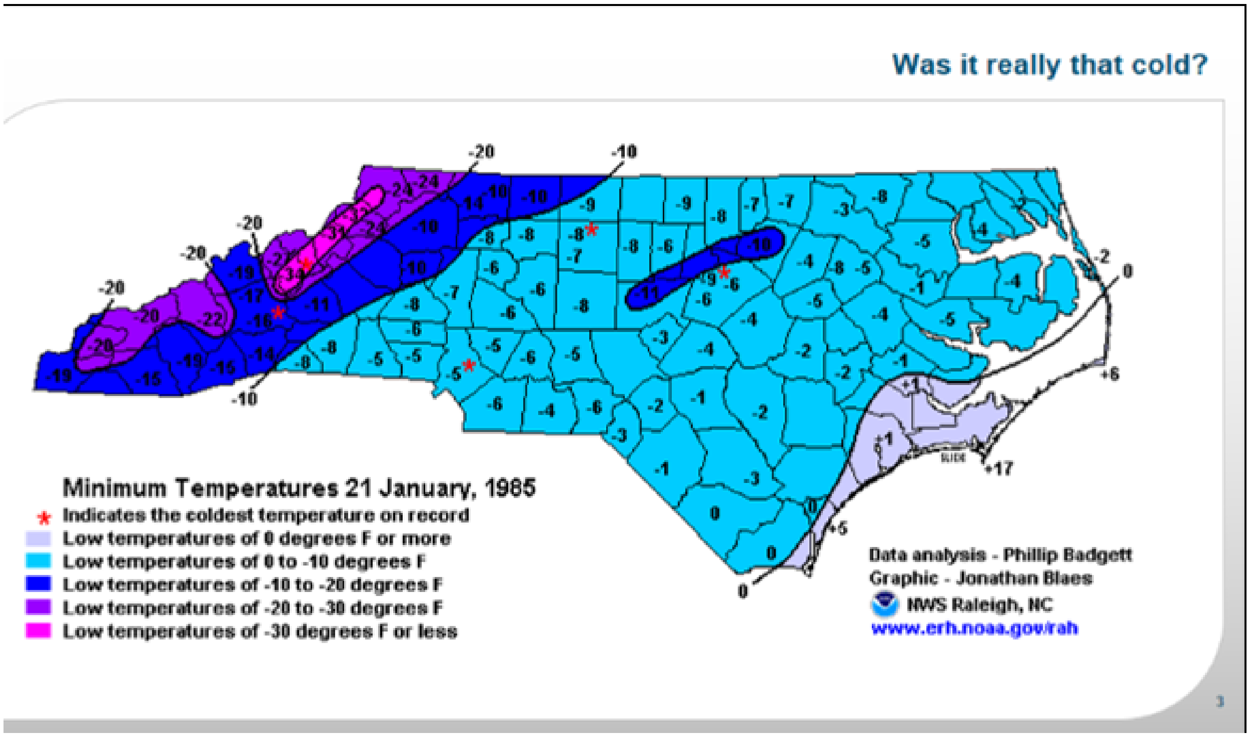
Response: In Duke's analysis, the lowest recorded temperature over the last 37 years in North Carolina history was -16 degrees Fahrenheit in Asheville. Duke's review also noted historically low temperatures of -5 degrees Fahrenheit in Charlotte and -9 degrees Fahrenheit in Raleigh. Please see the chart below.

b. Over what duration did Duke assess the low temperature condition?

Response: Duke Energy's analysis included a review of the hourly system average temperatures from January 2-8, 2018. Duke Energy also reviewed the actual temperatures for January 20-26, 1985.

c. What criteria did Duke use to determine that such temperatures would not compromise reliability of the system?

Response: Duke Energy used its load forecast models and the data from 2018 and 1985 mentioned to forecast hourly loads if such temperatures occurred during the 2021 winter. An additional analysis was done where Duke Energy shifted the January 2 through January 8, 2018 hourly system average temperatures lowered by 10 degrees Fahrenheit so that the coldest morning occurred on a weekday and forecasted the hourly load. The load forecasts from these different scenarios show that combined Carolinas load peaked around 43 GW. The load forecast was reasonable, and thus load forecast error would not compromise reliability of the system.



Response to Public Staff Question # 9 provided by: Sammy Roberts – GM, Transmission Planning and Operations Strategy

10. In follow up to Commission question #5, did Duke use a 24-hour period to assess the Peak Day forecast accuracies?

<u>**Response**</u>: Yes. Duke utilized the 24-hour MAPE weighted by the actual load for each hour.

a. What were the forecasted and actual Peak Day temperatures and loads?

Response: Please see the table below.

	Load Actual (MW)	**1-Day Forecast (MW)**	**3-Day Forecast (MW)**	**Temp Actual (°F)**	**1-Day Temp Forecast (°F)**	**3-Day Temp Forecast (°F)**
2019 Winter Peak Hour	32,955	32,617	32,013	21	20	21
202 Winter Peak Hour	30,642	30,796	30,674	25	24	23
2021 Winter Peak Hour	30,053	29,917	30,617	24.5	25	23

Response to Public Staff Question #10 provided by: Rupert Bruce – Lead Portfolio Management Analyst

11. Duke's response to Commission question #8 states that 13,100 MW of natural gas fired capacity has some dual fuel capability and could run on coal or oil. In the following paragraph, Duke states it has approximately the equivalent of 80 full load burn ("FLB") hours of fuel inventory. Do the equivalent 80 FLB hours apply to the entire 13,100 MW that have dual fuel capability or to a subset of MW, e.g., just Combustion Turbines?

Response: The approximate 80 FLB only applies to dual fuel units of both DEC and DEP combined.

a. Please provide, individually, DEC's and DEP's amount of MWs of dual fuel capable generation, specific units, and the approximate FLB hours per utility and unit.

Response: Of the approximate 13,100 MW of natural gas units, approximately 10,900 MW's have both gas and oil capability, and approximately 2,224 MW's are natural gas capable only.
See DEC_DEP_M100_Sub163_March2022_Attachment A for DEC and DEP detail of MW of dual fuel capable generation, specific units and approximate FLB hours.

Response to Public Staff Question # 11 provided by: Jim McClay – Managing Director, Natural Gas Trading

12. In regard to Commission question #8, how many gallons of fuel oil were used/delivered during the 2018 cold weather event in late December through early January?

Response: 40.7M gallons were burned between December 28, 2017 and January 31, 2018. Of the total, 34.5M gallons were burned between December 28, 2017 and January 8, 2018.

a. Please provide, individually, DEC's and DEP's total gallons equivalent FLB per utility and unit.

Response: Please see attached file "M-100 Sub 163, E-100 Sub 173_PSDR1-12a Attachment.xlsx."

Response to Public Staff Question #12 provided by: Jim McClay – Managing Director, Natural Gas Trading

13. In regard to Commission question #9, Duke reported load profiles of DEC and DEP combined. Please provide the same load profile analysis in Figure 1 for DEC and DEP individually and the amount of resource contribution for the load (i.e., nuclear, CT, CC, coal, solar) for each utility.

Response: Figures 1R1DEC and 1R1DEP reflect the load profile analysis for DEC and DEP Individually.

Figure 1R1DEC

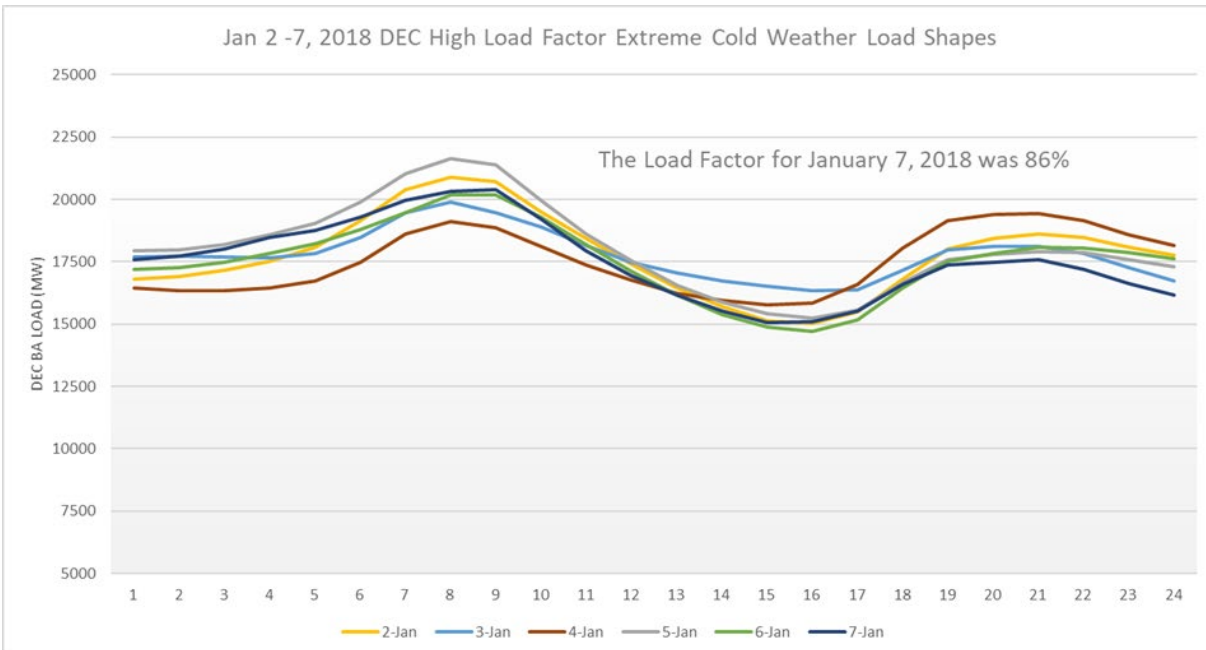
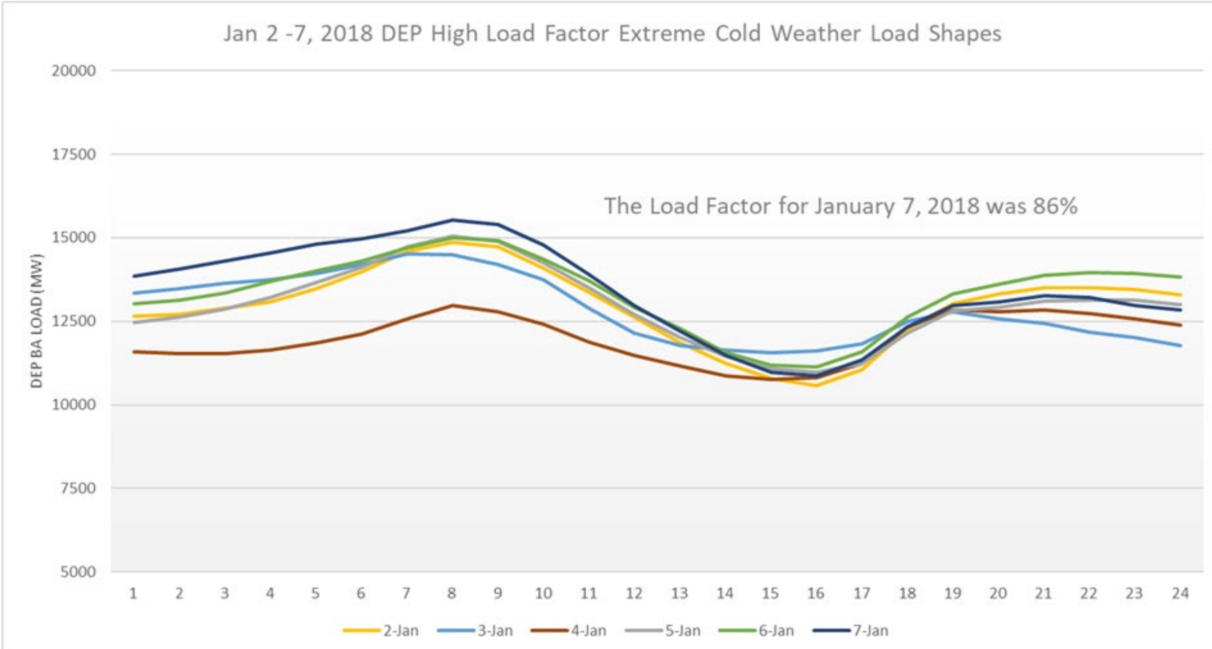


Figure 1R1DEP



Please see attached the Excel spreadsheets showing the amount of resource contribution for the load (i.e., nuclear, CT, CC, coal, solar) for each utility for January 2-7, 2018: "M-100 Sub 163, E-100 Sub 173_PSDR1-13_DEC Attachment.xlsx" and "M-100 Sub 163, E-100 Sub 173_PSDR1-13_DEP Attachment.xlsx".

Response to Public Staff Question #13 provided by: Sammy Roberts – GM, Transmission Planning and Operations Strategy

14. In regard to Commission question #9 and Duke's response in Figures 3 & 4, please explain how Duke's coal dual fuel optionality (DFO) was reported in the table and graph. If the coal/gas DFO plants were included in Figure 3, please re-graph the same results with an updated Figure 4.

__Response__: Figures 3 and 4 are reflective of a future hypothetical combined Carolinas BA high renewable portfolio meant to show that, with no new gas and Cliffside 6 converted to all gas, there are periods with this portfolio when dispatched against the 2018 customer demand where all of the customer demand cannot be served due to the limitations of wind 2.4 GW, solar 14 GW, solar plus storage 1 GW, and 4-hour battery storage 5 GW given the weather that occurred during the January 2, 2018 – January 8, 2018 period. 9.9 GW of coal has been retired in this portfolio, and 683 MW of coal has been converted to gas. If it is considered that 1110 MW of Belews Creek coal-fired generation is converted to 100% gas and current non-Duke generation purchases are preserved (2083 MW of primarily gas-fired generation in NC) in lieu of a 1500 MW off-system purchase, this revised high renewable portfolio results in a small amount of unserved energy, 176 MW, on January 3 when dispatched against the extreme cold weather high demand period of January 2-8, 2018 as shown in Figures 3R1 and 4R1 below. This amount of unserved energy could be covered by short-term capacity and/or non-firm energy purchases.

Figure 3R1

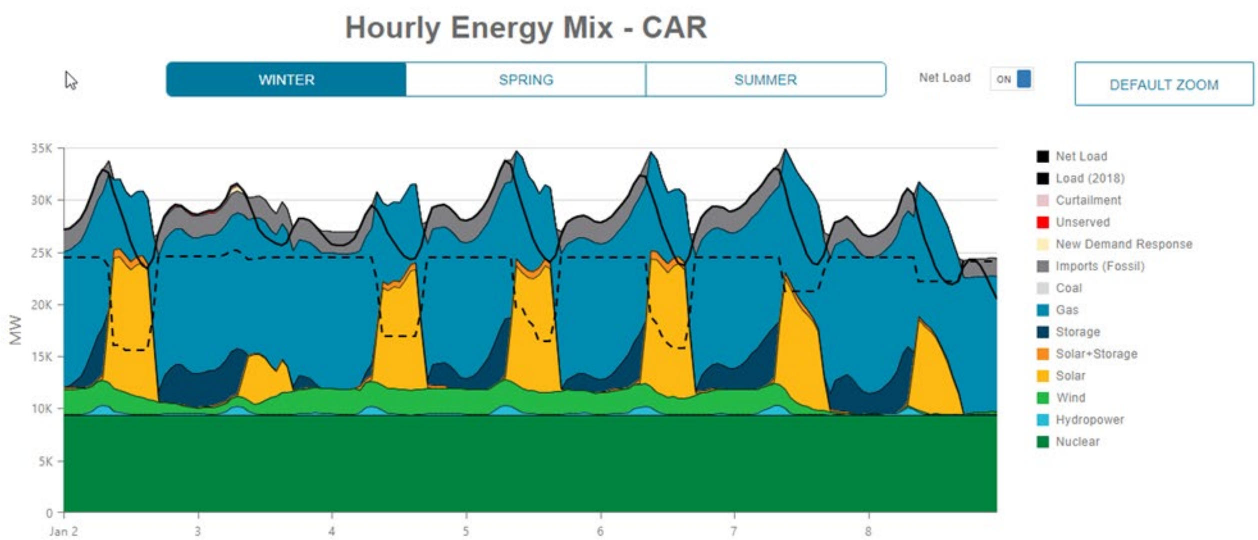


Figure 4R1

CAR | DEC | DEP

Update | Reset

Resource	Existing MW	Proposed MW	Change
Nuclear	9,348	9,348	0
Advanced Nuclear	0	0	0
Solar	2,691	14,000	11,309
Solar+Storage	0	1,000	1,000
Onshore Wind (OK)	0	0	0
Offshore Wind (CAR)	0	2,400	2,400
Battery Storage (4 hour)	0	5,000	5,000
Combined Cycle	4,850	4,850	0
Combustion Turbine	6,369	8,162	1,793
Coal	10,583	0	(10,583)
Imports (Fossil)	0	2,083	2,083
Exports	0	0	0
Demand Response	938	2,400	1,462
Hydropower	1,409	1,409	0
Pumped Storage	2,140	2,140	0
Total Megawatts	38,328	52,792	14,464

a. Also, please provide an updated Figure 3 & 4 for each respective Balancing Area.

Response: Figures 3 and 4 and Figures 3R1 and 4R1 reflect a consolidated Carolinas System Operations state which DEC and DEP are projected to be in prior to implementing a high renewables portfolio such as in this example.

Response to Public Staff Question #14 provided by: Sammy Roberts – GM, Transmission Planning and Operations Strategy

15. Explain the value of fuel diversity in the current generation fleet and how the diversity helps system planning and operations during the time of extreme peak demands.

Response: Our generation fleet is powered by several generation resources including nuclear, hydro, coal, gas, solar, and fuel oil. We also have executed purchased power agreements with third parties. During periods of extreme peak system conditions, the Companies will utilize our diverse generation fleet and purchased power agreements to economically and reliably serve our customers. Having fuel diversity during periods of extreme peak demands provides value in planning and operations by increasing the overall capabilities of the generation fleet, reducing the exposure to one fuel, mitigating the costs risk of single fuel price volatility, and reducing the risk of curtailment of a particular fuel.

Fuel diversity provides the company the ability to optimize at the lowest cost generation resource while maintaining system reliability. For example, nuclear generation provides reliable around-the-clock baseload energy with a fuel source that is not affected by freezing, transportation issues, or short-term price volatility. Natural gas combined cycle and coal generation also provide baseload energy around the clock. Additionally, dual fuel combustion turbines can utilize fuel oil as a primary or back-up fuel to natural gas to generate electricity at various sites during extreme cold weather events to manage overall fuel and system needs. In addition, the Companies' fuel procurement strategy includes procuring fuel in advance to ensure sufficient supply and maintaining on-site inventories of coal and fuel oil. The Companies actively monitor the power market on a 24-hour basis for opportunities to make purchases that support system load when economic or needed for reliability.

Response to Public Staff Question # 15 provided by: Joseph McCallister – Managing Director, System Optimization

16. In regard to Commission question #10, please explain how Duke coordinates with natural gas providers (i.e., Transco, Piedmont, PSNC, etc.) in the event of a load shedding event and the potential need to lower existing generation to match load. The Public Staff is concerned that large changes in natural gas usage would impact other customers connected to the gas infrastructure. Please describe any real time mitigation measures and communication channels that exist.

Response: In general, a load shedding event occurs when there is not enough generation online to support load. However, if the Companies needed to lower generation to match load (e.g., if too much load was shed and generation needed to drop to balance the system), Duke Energy's units on automatic generation control would be the first generators taken offline to match the load. Duke Energy would then reduce generation from other sources, such as hydro or small gas units next. Therefore, the Companies would attempt to minimize impacts to the natural gas system by focusing on reducing generation from other sources first. Additionally, during these events, our Large Account Managers and Fuel Supply group would be in contact with our Natural Gas vendors to keep them informed of the situation.

Response to Public Staff Question #16 provided by: Chalmers Hinton, General Manager, DCC Operations

17. In regard to Commission question #11, please explain the circuit designation for customer groups within Duke's system.

Response: There are three priority groups within our Distribution circuits. They are designated as such:

Priority 1: General residential customers, small and medium commercial and industrial customers. The largest number of customers are assigned to this priority
Priority 2: Large industrial and wholesale customers served from distribution
Priority 3: Customers that are deemed extremely critical to public health and security

Response to Public Staff Question #17 provided by: Chalmers Hinton, General Manager, DCC Operations

18. In regard to Commission questions # 15 and #16, please explain, list, and graph the amount of DEC's and DEP's TRM and VACAR contribution from each utility for the following cold weather events for 1) actual contribution and 2) theoretical contribution:

a. 2014 Polar Vortex Event

b. 2015 Polar Vortex Event

c. 2018 Cold weather event

d. February 17, 2021

Response: The MW mentioned below are TRM contributions and because of the simplicity of the responses in each scenario below a graph was not warranted.

a) 2014 Polar Vortex Event – DEC allocated 497 MW and DEP allocated 377 MW. During this period, DEC supplied 1410 MW to members on January 7, 2014. DEP received 200 MW of VACS RSG from PJM during the peak hours.
b) 2015 Polar Vortex Event – DEC allocated 496 MW and DEP allocated 385 MW. During this period, no VACAR Reserve amount was requested by members from either DEC or DEP during the peak hours.
c) 2018 Cold weather event – DEC allocated 519 MW and DEP allocated 395 MW. During this period, no VACAR Reserve amount was requested by members from either DEC or DEP during the peak hours.
d) February 17, 2021 – DEC allocated 533 MW and DEP allocated 407 MW. During this period, no VACAR Reserve amount was requested by members from either DEC or DEP during the peak hours.

Response to Public Staff Question #18 provided by: David Mc Ree – Director, Transmission Emergency Preparedness

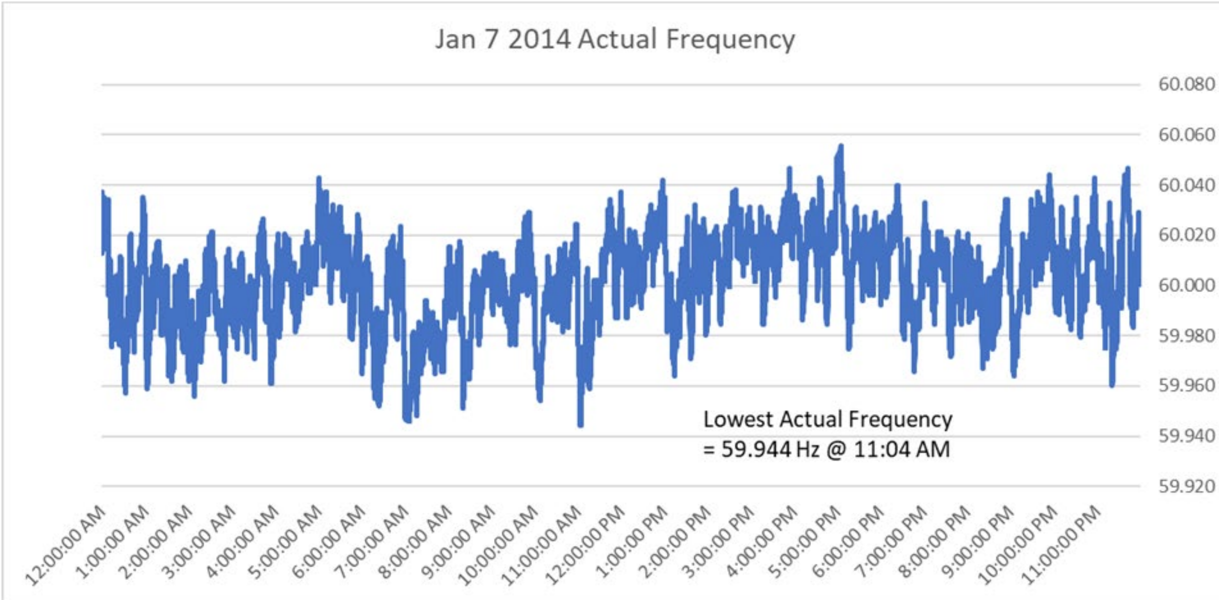
19. With regard to the VACAR reserve sharing agreement, transmission loading, and system operation during an extreme cold weather event, please explain if DEC and DEP must hold a specific reserve or headroom on the transmission tie lines between VACAR reserve sharing members in the event reserves are called upon.

Response: Yes, specific reserve amounts are included in the calculation of the Transmission Reserve Margin ("TRM") for the transfer between VACAR Reserve sharing members.

Response to Public Staff Question #19 provided by: David Mc Ree – Director, Transmission Emergency Preparedness

20. In regard to Commission question #18, please describe any potential under/over frequency events during the 2014 and 2015 polar vortex events, with and without DSM activations (if possible), and with and without non-firm power purchases made in response to high load and/or generation loses.

Response: DEC and DEP's data retention does not allow for retrieval of frequency data in the Historical Data Recorder or OSI PI for these years. However, Duke Energy was able to recover an Excel file from data retrieved in 2014 for the January 7, 2014 Polar Vortex event. This data is provided in a chart and reflects the lowest frequency recorded for the January 7, 2014 day as 59.944 Hz, well above any automatic load shed action level such as the first level of underfrequency load shed ("UFLS") at 59.3 Hz. The attached report, "M-100 Sub 163, E-100 Sub 173_PSDR1-20 Attachment.pdf," filed with NERC reflects the actions taken by DEP on January 7, 2014 to maintain reliable operations of the DEP system. The DEC system did not need to take this level of actions for ensuring balancing of resources and demand. DEC and DEP system operators are trained to take actions necessary to balance resources and demand to prevent jeopardizing Eastern Interconnection system frequency.



Response to Public Staff Question #20 provided by: Sammy Roberts – GM, Transmission Planning and Operations Strategy

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Response to Public Staff Data Request No. 1, in Docket Nos. E-100, Sub 173 and M-100, Sub 163, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to parties of record.

This the 8th day of April, 2022.

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