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September 2, 2022

***Via Electronic Filing and Hand Delivery***

A. Shonta Dunston
Chief Clerk
NC Utilities Commission
430 North Salisbury Street
Dobbs Building, 5th Floor
Raleigh, NC 27603-5918

*Re: In the Matter of DEP and DEC 2022 Biennial Integrated Resource Plan and Carbon Plan*
*Docket No. E-100 Sub 179*

Dear Ms. Dunston:

Enclosed please find eleven (11), three-hole punched copies of Direct Testimony of William E. Powers for NC WARN and Charlotte Mecklenburg NAACP in the above-referenced docket. The same has also been electronically filed with the NC Utilities Commission this date.

Should you have any questions, please do not hesitate to contact us. Thank you for your assistance with this matter.

Very truly yours,

LEWIS & ROBERTS, PLLC

Matthew D. Quinn

Enclosures
cc: All Parties of Record

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## CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing document upon all counsel of record by email transmission.

This the 2nd day of September, 2022.

*/s/ Matthew D. Quinn*
Matthew D. Quinn

**STATE OF NORTH CAROLINA**
**UTILITIES COMMISSION**
**RALEIGH**

DOCKET NO. E-100, SUB 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

| | | |
|---|---|---|
| In the Matter of: | ) | **DIRECT TESTIMONY OF** |
| Duke Energy Progress, LLC and | ) | **WILLIAM E. POWERS FOR** |
| Duke Energy Carolinas, LLC, 2022 | ) | **NC WARN AND CHARLOTTE** |
| Biennial Integrated Resource Plan | ) | **MECKLENBURG NAACP** |
| and Carbon Plan | ) | |

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is William E. Powers, P.E. My business address is Powers Engineering, 4452 Park Blvd., Suite 209, San Diego, CA 92116.

**Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. My employer is Powers Engineering. I am the founder and principal of the company.

**Q. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.**

A. I am a consulting and environmental engineer with 40 years of experience in the fields of power plant operations and environmental engineering. I have worked on the permitting of numerous combined cycle, peaking gas turbine, micro-turbine, and engine cogeneration plants, and am involved in siting of distributed solar photovoltaic (PV) and battery storage projects. I have been an expert witness is high voltage transmission application proceedings in California, Missouri, and Wisconsin, and have evaluated the impact of rooftop solar and battery storage on electric distribution systems for multiple clients. Furthermore, I have offered reports or testimony in numerous utility resource planning proceedings throughout the country, including in the State of North Carolina.

I began my career converting Navy and Marine Corps shore installation projects from oil firing to domestic waste, including wood waste, municipal solid waste, and coal, in response to concerns over the availability of imported oil following the Arab oil embargo in the 1970's.

I authored "Roadmap to 100 Percent Local Solar Build-Out by 2030 in the City of San Diego" (2020), "(San Francisco) Bay Area Smart Energy 2020" (2012), and "North Carolina Clean Path 2025" (2017), and I have written articles on the strategic cost and reliability advantages of local solar over large-scale, remote, transmission-dependent renewable resources.

I have a B.S. in mechanical engineering from Duke University and an M.P.H. in environmental sciences from UNC – Chapel Hill, and I am a registered professional engineer in California and Missouri.

**Q. HAVE YOU EVER TESTIFIED BEFORE THE N.C. UTILITIES COMMISSION (THE "COMMISSION") OR ANY OTHER REGULATORY BODIES IN ANY PRIOR PROCEEDINGS?**

A. Yes. I testified on behalf of NC WARN in Docket No. E-7, SUB 1214, Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Services in North Carolina, as well as Docket No. E-2, SUB 1219, Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina. Further, I testified on behalf of NC WARN in Docket No. EMP-92, SUB 0, Application of NTE Carolinas II, LLC for a Certificate of Public Convenience and Necessity to Construct a Natural Gas-Fueled Electric Generation Facility in Rockingham County, North Carolina. I have also offered affidavit testimony and reports to this Commission in numerous prior dockets, such as Docket No. E-2, SUB 1089 and Docket No. E-100, SUB 180. Further, I have offered testimony before other utilities commissions across the country, such as the commissions in California, Missouri, and Wisconsin.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my testimony is: 1) to address deficiencies in the proposed Carbon Plan filed in the present docket by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, the "Companies"), and 2) to outline why the Commission should adopt an alternative Carbon Plan similar to that prepared by Synapse Energy Economics on behalf of NCSEA *et al.*

**Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?**

A. The Commission instructed the parties to this proceeding to address specific Carbon Plan topic areas in its Order of July 29, 2022. This testimony will address the following topic areas from among those listed in the Commission's Order:

I. Modeling—Methodology, Assumptions, and Other Modeling Issues
II. Near-Term Procurement and Development Activity
III. Near-Term Development Activity—Small Modular Reactors
IV. Transmission Planning, Proactive Transmission and RZEP
V. EE/DSM Issues / Grid Edge
VI. Reliability

# <u>I. CARBON PLAN MODELING</u>

## *<u>A. Demand Growth Forecast</u>*

**Q. DO YOU AGREE WITH THE COMPANIES' DEMAND GROWTH FORECAST?**

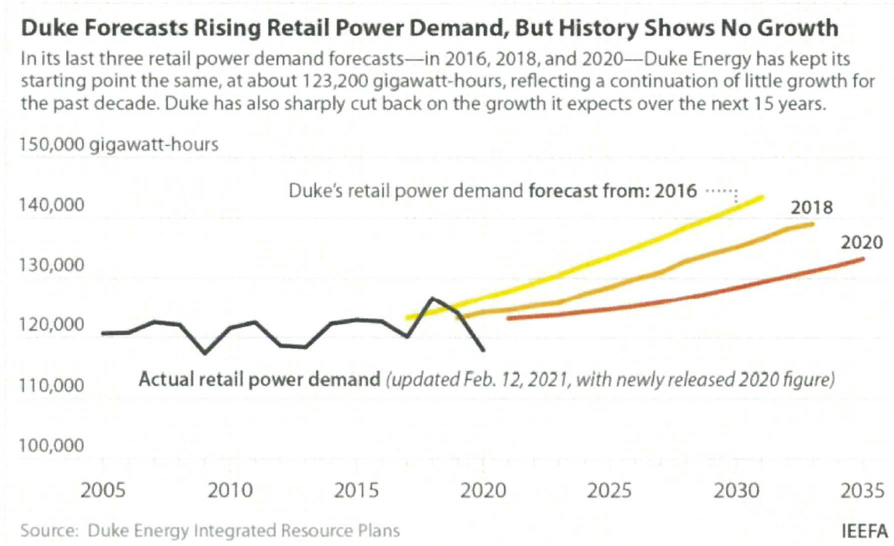
A. In my opinion, the Companies' load growth forecast is flawed and unrealistic. In their "Modeling Panel" direct testimony, the Companies list the four steps they use in developing their demand growth forecasts.[1] These four steps do not include a reality check that would compare the forecast outputs to historic actual annual energy and peak demand trends. As a result, the Companies' proposed Carbon Plan load forecasts show relentless growth, with no mention of the actual load growth trend, with accelerating growth after 2035.[2]

**Q. DO THE ACTUAL LOAD GROWTH RATES EXPERIENCED BY THE COMPANIES SUPPORT THE LOAD GROWTH PROJECTIONS IN THE CARBON PLAN?**

A. No. The Companies have consistently overestimated demand growth in their respective service territories. In Figure 1 below, I provide a chart prepared by Dennis Wamsted, an Energy Analyst with the Institute for Energy Economics and Financial Analysis, which illustrates the Companies' consistent historical overestimation of load growth:

[1] The Companies' Modeling Testimony, p. 115.
[2] The Companies' Carbon Plan, Appendix E, Figure E-17: Load Sensitivity Analysis - Total System Load Comparison [GWh], p. 97.

**Figure 1. Comparison of Duke Energy actual demand growth to forecast demand growth**[3]




**Q. DESCRIBE SOME OF THE FLAWS IN THE COMPANIES' LOAD GROWTH ANALYSIS SPECIFIC TO DEC.**

A. Actual DEC retail sales growth from 2016 through 2021, the most recent five-year period shown in the Carbon Plan, averaged 0.0 percent.[4] Instead, the Companies analyze the period 2012 to 2021 to assert a sales growth rate forecast for DEC of 0.8 percent.[5] 2012 was a relatively low retail sales year, as can be seen in Figure 1 above. Using 2012 as the base year gives the impression of significant demand growth over time, when review of the

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[3] D. Wamsted - Institute for Energy Economics and Financial Analysis, *Key Shortcomings in Duke's North Carolina IRPs: An Issue-by-Issue Analysis: Part 2*, February 2021: [http://ieefa.org/wp-content/uploads/2021/02/Key-Shortcomings-in-Duke-North-Carolina-IRPs_Part-2_February-2021.pdf](http://ieefa.org/wp-content/uploads/2021/02/Key-Shortcomings-in-Duke-North-Carolina-IRPs_Part-2_February-2021.pdf).

[4] The Companies' Carbon Plan, App. F, p. 16. Table F-14: Electricity Sales (GWh) – DEC.

[5] The Companies' Carbon Plan, App. F, p. 15. "Historical Retail Sales growth over the presented period was 0.9% and 0.8% respectively for DEC and DEP."; p. 19. "Projected Retail sales growth is 0.8% and 0.4% for DEC and DEP."

record going back to 2007 shows no growth. The DEC retail sales growth rate forecast used in the proposed Carbon Plan is not supported by actual historical DEC retail demand.

DEC is projecting in its base-case resource forecast that its annual retail sales will increase by 0.7 percent per year and will rise by an estimated 6,974 GWh by 2035.[6] This is equivalent to the output of two new 500 MW CC plants. Two 500 MW CC plants running at capacity factors of 75 percent would generate about this amount of electricity on an annual basis.[7] The justification for this new capacity would be eliminated with an accurate DEC demand forecast.

**Q. DESCRIBE SOME OF THE FLAWS IN THE COMPANIES' LOAD GROWTH ANALYSIS SPECIFIC TO DEP.**

A. The Carbon Plan retail sales data shows that actual DEP retail sales declined from 2016 through 2021, the most recent five-year period, at a rate of -0.7 percent.[8] The Companies analyze the period 2012 to 2021 to assert a sales growth rate forecast for DEP of 0.4 percent.[9] As reflected in Figure 1 above, 2012 was a relatively low retail sales year. Using 2012 as the base year gives the inaccurate impression of demand growth over time. In fact, DEP demand is declining.

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[6] The Companies' Carbon Plan, App. F, p. 20, Table F-16: Forecasted Energy Sales by Class – DEC.
[7] 1,000 MX x 8,760 hr/yr x 0.75 = 6,570,000 MWh/yr.
[8] The Companies' Carbon Plan, App. F, p. 17. Table F-15: Electricity Sales (GWh) – DEP.
[9] The Companies' Carbon Plan, App. F, p. 15. "Historical Retail Sales growth over the presented period was 0.9% and 0.8% respectively for DEC and DEP."; p. 19. "Projected Retail sales growth is 0.8% and 0.4% for DEC and DEP."

Nonetheless, DEP is projecting in its base-case demand growth forecast that its annual retail sales will increase by 0.4 percent per year, rising by an estimated 1,455 GWh by 2035.[10] This projection is simply not supported by the evidence.

**Q. WHAT IS THE SIGNIFICANCE OF THE COMPANIES' OVERSTATED LOAD GROWTH PROJECTION?**

A. The combined 2035 forecast increase in annual retail sales between DEC and DEP above 2023 demand is 8,429 GWh. This is equivalent to the output of about 1,300 MW of CC capacity running at a capacity factor of about 75 percent.[11] This new capacity would not be justifiable with an accurate demand forecast.

The Companies attribute significant load growth, both annual energy and peak load, to the increase over time of electric vehicles ("EVs").[12] Such load growth is not inevitable. Accelerated growth of net energy metering ("NEM") solar would offset increased energy demand due to EV charging. The Companies recognize this scenario in the Carbon Plan, identifying it as the "high NEM sensitivity" case.[13] Minimizing or eliminating the EV charging contribution to peak load could also be

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[10] The Companies' Carbon Plan, App. F, p. 21. Table F-17: Forecasted Energy Sales by Class – DEP.
[11] 1,300 MW x 8,760 hr/yr x 0.75 = 8,541,000 MWh/yr (8,541 GWh/yr)
[12] The Companies' Carbon Plan, App. F, pp. 12-15.
[13] The Companies' Carbon Plan, App. E, p. 17. "Base Net Energy Metering ("NEM") growth reflects currently approved net metering rate designs in the Carolinas as of January 1, 2022. The high NEM sensitivity, which is used in the low load forecast, envisions future program offerings that would drive additional NEM growth in the Carolinas . . ."

achieved by structuring the EV tariff to include very high rates during on-peak hours (for example).

The last fifteen years of data on the Companies' annual retail sales (*see* Figure 1 above) and winter peak demand trends[14] provide no basis for projecting any annual energy demand or peak load growth going forward. Much of the CT and nuclear build-out proposed by the Companies in the 2035 to 2050 timeframe is designed to meet load growth that is highly unlikely to materialize.

**Q. THE COMPANIES ALLUDE TO GROWTH IN EV ADOPTION AND ELECTRIFICATION AS POTENTIAL DRIVERS OF FUTURE LOAD GROWTH. DO YOU AGREE?[15]**

A. Not necessarily. Many of the Companies' customers are already all-electric.[16] As they install more efficient electrical devices over time, customer electric demand may decline. The August 2022 Inflation Reduction Act directs major funding at incentives for high efficiency electrical appliances.[17] EV owners often pair rooftop solar with EV

[14] The Companies' Carbon Plan, App. F, pp. 18-19 (System Peaks).
[15] The Companies' Modeling Testimony, pp. 15 & 55.
[16] The Companies' Response to the Public Staff's Data Request No. 1-2 in NCUC Docket No. E-100 SUB 180 (*see* Tab 4 ("DEC Unit Costs"), lines 11-13). This spreadsheet cannot be filed as an exhibit because it must be provided in native Excel format. This Excel spreadsheet will be provided to any party or Commission staff upon request.
[17] Kiplinger Tax Letter, *Save More on Green Home Improvements Under the Inflation Reduction Act*, August 19, 2022: https://www.kiplinger.com/taxes/605069/inflation-reduction-act-tax-credits-energy-efficient-home-improvements.

ownership.[18] If this pattern continues, much of the electric load increase imposed by EVs will be supplied behind-the-meter and will not result in load growth for the Companies. In short, substantial additional study would be required before any conclusion could be reliably made that growth in EV adoption will materially drive future load growth. At this moment, the Companies' conclusion is purely speculative.

**Q. WHAT LOAD GROWTH FORECAST DO YOU RECOMMEND THE COMPANIES USE IN THE CARBON PLAN?**

A. The Companies should assume recent actual annual energy and peak demand rates are the best indicator of future trends. The Companies have a substantial degree of control over future growth rates. For example, a favorable NEM tariff will lead to a higher percentage of EV owners also having rooftop solar, to address the EV load and any additional home loads due to electrification.

**Q. DID OTHER PARTIES ADOPT A SIMILAR PERSPECTIVE?**

A. Yes. The City of Asheville/Buncombe County cautioned that the Commission should not simply assume that higher EV adoption rates and building electrification will necessarily result in an increase in grid power demand. The City of Asheville/Buncombe County stated, "Load forecasts should be adjusted to proactively and accurately account for the impact of demand side management DSM programs and technological advances that

[18] Solar Builder, *Electric vehicles will drive solar installations — and these key home upgrades*, March 14, 2022: https://solarbuildermag.com/featured/electric-vehicles-will-drive-solar-installations-and-these-key-home-upgrades/.

reduce load as well as increased load that may result from transportation and building electrification."[19]

### *B. Modeling Inputs and Assumptions Regarding Reliability*

**Q. DO YOU HAVE CRITICISMS REGARDING THE COMPANIES' MODELING INPUTS AND ASSUMPTIONS ON THE ISSUE OF RELIABILITY?**

A. Yes, I have several criticisms regarding the Companies' modeling inputs and assumptions on the reliability issue. In fact, the Companies' modeling errors related to the reliability issue directly led the Companies to propose an unnecessary and prolonged reliance upon coal-fired generation.

Because these reliability issues involve the Companies' modeling, I will address these issues under the present "Modeling" topic. Subsequently, I will address other reliability issues under a separate "Reliability" topic appearing separately below.

**Q. DO YOU AGREE WITH THE COMPANIES THAT A 17% WINTER PLANNING RESERVE MARGIN CREATES SIGNIFICANT RISK OF OVER-RELIANCE ON NON-FIRM MARKET PURCHASES?**

A. No. In the last two winters the Companies have left many thousands of MW of coal capacity and combustion turbine ("CT") capacity idle at the winter peak, and dispatched no DSM resources, and imported relatively little non-firm power from neighboring balancing authorities. In their prefiled direct

[19] City of Asheville/Buncombe County Comments, p. 3.

testimony, the Companies present the high-capacity factors of their coal units during a week-long January 2018 cold snap to imply this one week is representative of the critical role the coal units play during winter peak load events generally.[20] The Companies also assert that their CTs play this same vital role.[21]

Actual operating data for the Companies' coal and CT fleets during the winter of 2020/2021 and 2021/2022 tell a different story. There is a large excess of coal capacity and CT capacity that goes unused, with little reliance on non-firm imports (excluding inter-Companies transactions) from neighboring balancing authorities. Below, Table 1 summarizes the circumstances of the highest winter peak hour in 2020/2021 and the highest winter peak hour in 2021/2022 for the Companies. Table 2 (below) summarizes the quantity of coal unit capacity, CT capacity, and DSM that was not utilized to meet the winter peak hours summarized in Table 1. Also below, Table 3 lists the relatively small amount of non-firm imports relied on by the Companies to meet the winter peak demand for the winter peak hours summarized in Table 1.

[20] The Companies' Reliability Testimony, Table 1: Coal Generation Capacity Factors for January 2-8, 2018, p. 68.
[21] The Companies' Transmission Testimony, pp. 73-74.

**Table 1. Summary of Conditions During the Companies' Highest Coincident Winter Peak Hours, Winter 2020/2021 and Winter 2021/2022**

| Date, hour | Demand, MW | Winter peak hour demand ranking | DSM dispatched, MW |
|---|---|---|---|
| February 4, 2021, hour ending 8 am: | | | |
| DEC | 15,583 | 1st highest, 2020/2021 | 0 |
| DEP | 11,815 | 2nd highest, 2020/2021 | 0 |
| January 27, 2022, hour ending 8 am: | | | |
| DEC | 16,282 | 1st highest, 2021/2022 | 0 |
| DEP | 12,746 | 6th highest, 2021/2022 | 0 |

DEP 1st highest actual winter peak demand hour in winter 2020/2021 was 11,984 MW on January 29, 2021 in the hour ending at 8 am. DEP 1st highest actual winter peak demand hour in winter 2021/2022 was 13,148 MW on January 23, 2022 in the hour ending at 8 am. *See* Companies' Response to the Public Staff's Data Request Nos. 4-1, 4-2 & 26-2.

**Table 2. Coal, CT, and DSM Capacity Not Used During Companies' Highest Coincident Winter Peak Hours, Winter 2020/2021 and Winter 2021/2022**

| Date, hour | Coal used/ idle, MW | CT used/ idle, MW | DSM used/ idle, MW | Coal, CT, DSM idle, MW |
|---|---|---|---|---|
| Total Companies' coal winter capacity = 9,294 MW; CT capacity = 6,147 MW. | | | | |
| Feb. 4, 2021, 8 am | 5,773/3,521 | 2,711/3,436 | 0/700 | 7,657 |
| Jan. 27, 2022, 8 am | 6,187/3,107 | 2,699/3,448 | 0/700 | 7,255 |

Note: Total Companies' coal winter capacity = 9,294 MW; CT winter capacity = 6,147 MW. See 2022 Carbon Plan, Appendix D, Table D-1 (p. 2) and Table D-2 (p. 5). Companies' DSM capacity = 700 MW. See 2022 Carbon Plan, Appendix G, Table G-12 (p. 27).

**Q: THE COMPANIES STATE THAT THEY RELY ON NON-FIRM IMPORTS TO OFFSET 6.5 PERCENT OF THE 23.5 PERCENT RESERVE MARGIN WHICH THEY WOULD NEED TO OPERATE DURING "ISLAND" MODE TO REDUCE THE RESERVE**

**MARGIN TO 17 PERCENT.[22,23] DID THAT HAPPEN AT THE WINTER PEAKS IN 2020/2021 AND 2021/2022?**

A. No. The Companies relied on substantially less non-firm imports (excluding inter-Companies exchanges) at the 2020/2021 and 2021/2022 winter peaks. Slightly more than 1,000 MW of non-firm imports were relied on by the Companies to meet the 2020/2021 and 2021/2022 coincident winter peaks, as shown in Table 3 below.

**Table 3. Non-Firm Imports Relied On By Companies' During Highest Winter Peak Hours, Winter 2020/2021 and Winter 2021/2022**

| Date, hour | DEC total imports, MW | DEC imports w/o imports from DEP, MW | DEP total imports, MW | DEP imports w/o imports from DEC, MW | Companies coincident peak demand, MW | Non-Companies imports, % of coincident peak demand |
|---|---|---|---|---|---|---|
| 02/4/21, 8 am | 1,433 | 1,031 | 0 | 0 | 27,398 | 3.8 |
| 1/27/22, 8 am | 1,636 | 1,151 | 0 | 0 | 29,028 | 4.0 |

Source of imports data: Duke Energy DR response NC WARN DR 3-3.

**Q. WHAT WOULD THE QUANTITY OF NON-FIRM IMPORTS HAVE BEEN IF THE COMPANIES HAD REACHED THE "6.5 PERCENT OF TOTAL RESERVE MARGIN" TARGET FOR NON-FIRM IMPORTS?**

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22 The Companies' Modeling Testimony, p. 108.

23 *See* the Companies' 2020 IRPs filed in NCUC Docket No. E-100 SUB 165. DEC's 2020 IRP, p. 72: "The Base Case reflects a 6.5% decrease in reserve margin compared to the Island Case (from 22.5% to 16.0%). Thus, approximately 29% (6.5/22.5 = 29%) of the Company's reserve margin requirement is being satisfied by relying on the non-firm capacity market." DEP's 2020 IRP, p. 74: "The Base Case reflects a 6.25% decrease in reserve margin compared to the Island Case (from 25.5% to 19.25%). Thus, approximately one quarter (6.25/25.5 = 25%) of the Company's reserve margin requirement is being satisfied by relying on the non-firm capacity market."

A. Using the actual winter peaks as the point of reference, the amount of non-firm imports relied on to meet the 2020/2021 coincident winter peak, if they equaled 6.5 percent of the reserve margin, would have been 2,199 MW.[24] The amount of non-firm imports relied on to meet the 2021/2022 coincident winter peak, if they equaled 6.5 percent of the reserve margin, would have been 2,330 MW.[25]

**Q. IS THIS QUANTITY OF NON-FIRM IMPORTS USED TO MEET THE WINTER PEAK CONSISTENT WITH THE COMPANIES' CALCULATIONS?**

A. Yes. The Companies' witness Farver states "Reiterating what the Companies communicated to the Commission in the 2020 IRP Technical Conference, the Companies' Resource Adequacy study accounts for nearly 2,000 MW of non-firm assistance from neighboring systems during peak demand periods."[26]

**Q. SO THE COMPANIES WERE SHORT, RELATIVE TO THEIR NON-FIRM IMPORTS TARGET, BY ABOUT 1,000 MW AT THE 2020/2021 AND 2021/2022 WINTER PEAKS?**

A. Yes. 1,031 MW of non-firm imports were utilized by the Companies to meet the 2020/2021 winter peak, not 2,199 MW. 1,151 MW of non-firm imports were utilized to meet the 2021/2022 winter peak, not 2,330 MW. In each case, the Companies collectively underutilized non-firm imports. Had the

[24] (27,398 MW x 1.235) x 0.065 = 2,199 MW.
[25] (29,028 MW x 1.235) x 0.065 = 2,330 MW.
[26] The Companies' Transmission Testimony, p. 61.

non-firm imports target been met, the Companies could have idled more than 1,000 MW of additional Companies-owned generation that would have been substituted with non-firm imports. For example, more than 1,000 MW of the Companies' coal capacity that was online to meet the winter peak could have been idled.

**Q. DID THE FAILURE TO REACH THE NON-FIRM IMPORTS TARGET COMPROMISE THE COMPANIES' RESERVE MARGIN DURING THE COMPANIES' 2020/2021 AND 2021/2022 WINTER PEAKS?**

A. No. Below, Table 4 summarizes the Companies' dispatched and unused coal, CT, and DSM capacity at the 2020/2021 and 2021/2022 winter peaks. Over 7,000 MW of this capacity was not utilized to meet the 2020/2021 and 2021/2022 winter peaks.

**Table 4. Coal, CT, and DSM Capacity Not Used During Companies' Highest Winter Peak Hours, Winter 2020/2021 and Winter 2021/2022**

| Date, hour | Coal used/ idle, MW | CT used/ idle, MW | DSM used/ idle, MW | Coal, CT, DSM idle, MW |
|---|---|---|---|---|
| Feb. 4, 2021, 8 am | 5,773/3,521 | 2,711/3,436 | 0/700 | 7,657 |
| Jan. 27, 2022, 8 am | 6,187/3,107 | 2,699/3,448 | 0/700 | 7,255 |

Table 5 (below) summarizes the actual equivalent planning reserve margins at the 2020/2021 and 2021/2022 coincident winter peaks, considering only 1) actual non-firm imports and 2) unused coal, CT, and DSM capacity to calculate the reserve margin.[27] Table 5 clearly demonstrates that the Companies' actual reserve margins during the 2020/2021 and 2021/2022 winter peaks were ample.

**Table 5. Calculated Actual Winter Peak Equivalent Planning Reserve Margins ("PRMs") for DEC and DEP in the Winters of 2020/2021 and 2021/2022**

| Winter peak year | Coincident winter peak, MW | Unused coal, CT, and DSM, MW | Reserve margin at actual peak, % |
|---|---|---|---|
| 2020/2021 | 27,398 | 7,657 | 27.9 |
| 2021/2022 | 29,028 | 7,255 | 25.0 |

**Q. ARE THE COMPANIES' ACTUAL 2020/2021 AND 2021/2022 COINCIDENT WINTER PEAK LOADS SHOWN IN TABLE 5 REPRESENTATIVE OF "TYPICAL YEAR" COINCIDENT WINTER PEAK LOADS FOR THE COMPANIES?**

A. Yes, especially the 29,028 MW coincident winter peak in the winter of 2021/2022. The last 10-year average, 5-year average, and 2-year average winter peak actual demand for DEC and DEP are shown in Table 6. These are non-coincident actual winter peak values for each utility.[28] The 2021/2022 DEC actual winter peak demand of 16,282 MW falls between the most recent 5-year and 2-year DEC averages, while the 2020/2021 DEC actual winter peak demand of 15,583 MW was incrementally below the most recent 2-year average of 15,933 MW.

[27] The Companies' idle combined-cycle, nuclear, hydro, or pumped storage capacity during the 2020/2021 and 2021/2022 winter peak hours are unknown by NC WARN *et al.*

[28] Coincident peak values are generally lower, as the Companies rarely experience individual peaks in the same hour.

**Table 6. 10-Year, 5-Year, And 2-Year Average Noncoincident Actual DEC and DEP Winter Peak Demand**[29]

| Utility | 10-year average | 5-year average | 2-year average |
|---|---|---|---|
| DEC | 17.048 | 16,791 | 15,933 |
| DEP | 13,779 | 13,388 | 12,566 |

The 2021/2022 DEP actual winter peak demand of 13,148 MW falls between the most recent 5-year and 2-year DEP averages, while the 2020/2021 DEP actual winter peak demand of 11,894 MW was incrementally below the most recent 2-year average of 12,566 MW.

The planning reserve margin ("PRM") used by the Companies is supposed to be based on the 1-in-2 year peak forecast,[30] or "average year" forecast, and that peak forecast is supposed to be based on actual historic data. The 2021/2022 DEC and DEP actual winter peak loads of 16,282 MW and 13,148 MW, respectively, are representative of actual 1-in-2 year coincident winter peak loads. The 2020/2021 DEC and DEP actual winter peak loads of 15,583 MW and 11,894 MW, respectively, are incrementally below the actual 1-in-2 year winter peak loads.

For the 2020/2021 coincident winter peak, the Companies could have met their 17 percent PRM target with 3,000 MW less reserve

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[29] For actual winter peaks in years 2013-2021, see the Companies' Carbon Plan, App. F, p. 18, Tables F-8 and F-9 ("Actual"). For 2022, see Table 1 to the present testimony (above),
[30] North American Electric Reliability Corporation (NERC), *M-1 Reserve Margin*: https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx (accessed on August 28, 2022): "Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand in planning horizon . . . Generally, the projected demand is based on a 50/50 forecast."

capacity.[31] If the Companies had met the peak demand non-firm imports target, adding about 1,000 MW to their supply, the 17 percent PRM target could have been met with 4,000 MW less reserve capacity.

That reduction in reserve capacity need could be the permanent closure of 4,000 MW of coal capacity. There was 5,773 MW of the Companies' coal capacity online at the 2020/2021 winter peak. The Companies could have maintained the 17 percent target PRM with the target non-firm imports level and 1,773 MW of coal capacity. The Companies can generate up to 2,618 MW of output from the dual-fuel coal units firing natural gas only.[32] The Companies could have readily met a 1,773 MW demand with their dual-fuel coal units on natural gas only.

For the 2021/2022 coincident winter peak, the Companies could have met their 17 percent PRM target with 2,300 MW less reserve capacity.[33] If the Companies had met the peak demand non-firm imports target, adding more than 1,000 MW to its supply, the 17 percent PRM target could have been met with 3,300 MW less reserve capacity.

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[31] (27,398 MW + 7,657 MW) – (27,398 MW x 1.17) = 2,999.3 MW.

[32] The Companies' Carbon Plan, App. E, Table E-46, p. E-47. "Cliffside 5 and Marshall 1 and 2 are capable of co-firing on natural gas at 40% capacity. However, these units are only able to do so when the other units at these sites are not fully utilizing their natural gas capability." Total dual-fuel coal unit simultaneous output on natural gas: Belews Creek 1: 1,110 x 0.50 = 555 MW; Belews Creek 2: 1,110 x 0.50 = 555 MW; Cliffside 6: 849 MW x 1.00 = 849 MW; Marshall 3 = 658 MW x 0.50 = 329 MW; Marshall 4 = 660 MW x 0.50 = 330 MW. Total simultaneous natural gas-only output from dual-fuel coal units = 2,618 MW. Total non-simultaneous dual-fuel unit natural gas capacity is 3,150 MW (The Companies' Carbon Plan, Introduction, p. 2).

[33] (29,028 MW + 7,255 MW) – (29,028 MW x 1.17) = 2,300.2 MW.

In the case of the 2021/2022 winter peak, that reduction in reserve capacity need could be the permanent closure of 3,300 MW of coal capacity. There was 6,187 MW of the Companies' coal capacity online at the 2021/2022 winter peak. The Companies could have maintained the 17 percent target PRM with the target non-firm imports level and 2,887 MW of coal capacity.[34] As noted, the Companies can generate up to 2,618 MW of output from the dual-fuel coal units firing natural gas only. The Companies could largely meet a 2,887 MW demand with their dual-fuel coal units firing natural gas only.

**Q. ARE THE COAL-ONLY UNITS IN THE COMPANIES' COAL PLANT INVENTORY EXPENSIVE TO OPERATE AND POTENTIALLY UNRELIABLE?**

A. Yes. DEP has two coal-only plants, Mayo (one unit, 713 MW) and Roxboro (four units, 2,462 MW).[35] Mayo is nearly 40 years old and very costly to operate at \$90/MWh.[36] Roxboro has a production cost of \$54/MWh.[37] The average age of the Roxboro units is 50 years.[38] Roxboro is a prime example, due to the age of the coal units there, of the Companies' statement in their proposed Carbon Plan that "The Companies' remaining coal facilities are nearing the end of their technical and economic life and becoming riskier to

[34] 6,187 MW -3,300 MW = 2,887 MW.
[35] The Companies' Carbon Plan, App. D, p. 2, Table D-1.
[36] DEP's 2020 FERC Form 1, April 15, 2021, p. 403. Mayo, line 35, expenses per net KWh = \$0.0897 (\$89.70/MWh).
[37] Ibid, p. 402.1 (Roxboro, \$0.0538/kWh).
[38] Ibid.

operate; thus, retirement is increasingly inevitable."[39] All DEC coal units, except for Allen Units 1 and 5 which are projected to be retired in early 2024,[40] are dual-fuel and can operate at partial load or full load on natural gas.

**Q. BASED ON HOW THE COMPANIES MET THE 2020/2021 AND 2021/2022 ACTUAL COINCIDENT WINTER PEAKS, CAN THE COMPANIES MEET WINTER PEAK DEMAND WITHOUT FIRING COAL?**

A. Yes. The Companies have sufficient excess capacity in their supply portfolios, and sufficient underutilized non-firm imports supply, to immediately eliminate coal-only units from their portfolios. The remaining dual-fuel coal units have a combined simultaneous output capacity on natural gas of 2,618 MW. This is a sufficient capacity contribution to assure the Companies can meet the "typical year" winter peak demand with a 17 percent reserve margin.

**Q: THE COMPANIES EXPRESS DOUBT ABOUT THE AVAILABILITY OF NON-FIRM IMPORTS IN THE FUTURE. DO THE WINTER RESERVE MARGINS IN NEIGHBORING BALANCING AUTHORITIES CITED IN THE COMPANIES' DIRECT TESTIMONY SUPPORT THIS CLAIM?**

[39] The Companies' Carbon Plan, Introduction, p. 4.

[40] Ibid, App. E, p. 45. "Additionally, the remaining Allen units, units 1 and 5, were modeled to be retired by the beginning of 2024, consistent with transmission project under construction in DEC to enable the retirement of these units."

A. No. The Companies go to considerable lengths to document the more conservative winter planning reserve margins being applied by neighboring balancing authorities to make the case that the Companies' winter 17 percent PRM is reasonable.[41] All neighboring balancing authorities listed by the Companies, with the exception of Virginia Electric Power Company, have winter PRMs of 20 percent or greater. The Companies have provided no evidence that neighboring balancing authorities will be less able in the future to provide non-firm imports than they are now.

*C. Modeling Assumptions Regarding Capital Costs*

**Q. HAVE THE COMPANIES MADE CRITICAL ERRORS IN THEIR CAPITAL COST ASSUMPTIONS FOR CTs AND CCs?**

A. Yes. The lack of any publicly-available CT and CC \$/kilowatt ("\$/kW") capital cost information in the Carbon Plan is a major flaw from the standpoint of assessing the validity of the portfolios without signing a non-disclosure agreement ("NDA").

In the Companies' earlier iteration of a climate action plan, the 2020 Climate Report, the Companies publicly identified capital cost assumptions of \$650/kW for CCs and \$550/kW for CTs.[42] The inclusion of specific capital cost estimates for the CTs and CCs allowed other parties to

[41] The Companies' Modeling Testimony, Table 7, p. 107.
[42] The Companies' 2020 Climate Report, p. 24: Combustion Turbines – \$550/kilowatt (kW) (represents multi-unit site); Combined Cycle – \$650/kW (represents 2x1 advanced class).

corroborate the accuracy of those estimates through comparisons to recent CC and CT projects built by the Companies.

The Companies have actual recent experience building both CC and CT projects. The capital costs of these CC and CT projects are known. These are the CC and CT capital costs that should be used in the Carbon Plan modeling and not hypothetical, generic values which are revealed only to parties willing to sign an NDA.

The actual capital cost of the 560 MW Asheville combined cycle plant, which came online in 2020, was $817 million.[43] This is equivalent to a unit CC cost of about $1,460/kW,[44] over double the Companies' assumed CC cost of $650/kW in the 2020 Climate Report. The same National Renewable Energy Laboratory ("NREL") database that the Companies reference as the basis for their solar and battery storage costs in their proposed Carbon Plan identifies a generic mid-range capital cost for CC plants of $1,044/kW in 2021, declining only slightly to $977/kW in 2035.[45] Presumably the Companies did not use this same NREL 2021 Annual Technology Baseline ("ATB") moderate scenario data for the CC capital

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[43] Duke Energy News Center, *Duke Energy Progress customers receiving 560 megawatts of cleaner energy from new natural gas power plant in North Carolina*, July 22, 2020: https://news.duke-energy.com/releases/duke-energy-progress-customers-receiving-560-megawatts-of-cleaner-energy-from-new-natural-gas-power-plant-in-north-carolina.

[44] $817,000,000 ÷ 560,000 kW = $1,459/kW.

[45] NREL, Electricity Annual Technology Baseline (ATB) 2021, "Fossil Energy Technologies" tab, Natural Gas FE CT Ave CF, webpage accessed July 2, 2022. https://atb.nrel.gov/electricity/2021/fossil_energy_technologies.

cost, as they did for solar and battery storage, because the value was inconveniently high.

The capital cost of the 402 MW Lincoln CT, the most recent example of a CT built and owned by the Companies, is not public information and was filed with the Commission under seal.[46] For this reason, I assume the CC cost multiplier of the Asheville CC plant, which is more than double the generic CC cost assumption used by the Companies in the 2020 Climate Report, also applies to new CTs. This is equivalent to a unit CT cost of approximately $1,250/kW,[47] compared to the Companies' assumed CT cost of $550/kW in the 2020 Climate Report. Also, the NREL ATB database referenced by the Companies identifies a generic mid-range capital cost for CTs of $919/kW in 2021, declining to $823/kW in 2035.[48]

The Companies rely on the NREL ATB database for capital cost values for some generation sources, but opt to develop distinct proprietary values for the CCs and CTs in the Carbon Plan. This choice by the Companies implies that they found the NREL ATB CC and CT capital costs to be too high to support the CC and CT capacity the Companies desired in the Carbon Plan portfolios.

[46] *See* NCUC Docket No. E-7 SUB 1134.

[47] Adjusted combustion turbine unit cost: ($1,460/kW ÷ $650/kW) x $550/kW = $1,235/kW.

[48] NREL, Electricity Annual Technology Baseline (ATB) 2021, "Fossil Energy Technologies" tab, Natural Gas FE CT Ave CF, webpage accessed July 2, 2022. https://atb.nrel.gov/electricity/2021/fossil_energy_technologies.

**Q. WHAT CAPITAL COST ASSUMPTIONS SHOULD THE COMPANIES USE FOR THE CTs AND CCs IN THEIR PROPOSED CARBON PLAN PORTFOLIOS?**

A. The Commission should direct the Companies to use the final capital cost of the Lincoln 402 MW CT and the Asheville 560 MW CC as the base case 2022 capital cost assumptions for CTs and CCs in the Carbon Plan portfolio modeling.

**Q. DO COMPETING UTILITIES IDENTIFY SOLAR PLUS STORAGE ("SPS") AS SUPERIOR TO OTHER GENERATION OPTIONS FOR COST REASONS, INCLUDING GAS-FIRED GENERATION?**

A. Yes. Other investor-owned utilities operating in the markets of the Companies' sister operating companies view solar plus battery storage as a superior alternative to CTs for cost reasons alone. For instance, NextEra Energy, parent company of Florida Power & Light ("FPL"),[49] states that "batteries are now more economic than gas-fired peakers (CTs), even at today's natural gas prices."[50] FPL is the largest investor-owned utility in Florida.[51] NextEra Energy also forecasts the production cost of solar plus battery storage is less than the production cost of an existing CT.[52]

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[49] Companies owned by NextEra Energy: https://www.nexteraenergy.com/company/subsidiaries.html.
[50] GreenTech Media, *NextEra looks to spend $1B on energy storage in 2021*, April 22, 2020.
[51] EIA, *Florida Electricity Profile 2020* (*see* Table 3, "Top five retailers of electricity, with end use sectors"): https://www.eia.gov/electricity/state/florida/.
[52] NextEra Energy, Investor Conference 2022, PowerPoint, June 14, 2022, p. 26: https://www.investor.nexteraenergy.com/~/media/Files/N/NEE-IR/news-and-

FPL is far larger than Duke Energy Florida, with 114,000 GWh of retail sales in 2020 compared to 39,000 GWh for Duke Energy Florida.[53] By way of comparison, the combined DEC and DEP retail sales in North Carolina were 92,000 GWh in 2020.[54]

NextEra Energy included its forecast of late 2020s production costs for selected generation technologies in its June 2022 Investor Conference 2022 presentation.[55] These production costs are summarized in Table 7 below.

**Table 7. NextEra Energy Late 2020s Production Costs For Selected Generation Technologies**

| Generation technology | Production cost, $/MWh |
|---|---|
| Solar with 4-hour battery storage* | 30 - 37 |
| Existing natural gas-fired | 35 - 47 |
| Existing nuclear | 34 - 49 |
| Existing coal-fired | 43 - 74 |
| New natural gas CC | 56 - 69 |

*) Assumes a 4-hour battery to achieve roughly equivalent reliability during peak hours for comparison with dispatchable generation sources.

The relative cost relationships shown in Table 7 hold true for the Companies' units as well. For example, the CT power plant with the lowest

events/events-and-presentations/2022/06-14-2022/June%202022%20Investor%20Presentation_Website_vF.pdf.

[53] EIA, *Florida Electricity Profile 2020* (*see* Table 3, "Top five retailers of electricity, with end use sectors"): https://www.eia.gov/electricity/state/florida/. 2020 FPL retail sales = 113,663,998 MWh; 2020 Duke Energy Florida retail sales = 39,230,213 MWh.

[54] EIA, *North Carolina Electricity Profile 2020* (*see* Table 3: "Top five retailers of electricity, with end use sectors"): https://www.eia.gov/electricity/state/northcarolina/. 2020 DEC retail sales = 55,703,047 MWh; 2020 DEP retail sales = 36,297,536 MWh. Total 2020 DEC + DEP = 92,000,583 MWh.

[55] NextEra Energy, Investor Conference 2022, PowerPoint, June 14, 2022, p. 26: https://www.investor.nexteraenergy.com/~/media/Files/N/NEE-IR/news-and-events/events-and-presentations/2022/06-14-2022/June%202022%20Investor%20Presentation_Website_vF.pdf.

production cost among the Companies' CTs is the 978 MW Rockingham plant, with a production cost of $42 per MWh in 2019.[56] This contrasts with the production cost of DEP's coal-only Roxboro and Mayo plants, which range from $54/MWh to $90/MWh.[57] There are CTs in the Companies' fleet that operate at lower cost than DEP's remaining coal units and are a lower-cost power production option to those coal-only units.

*D. Counter Carbon Plan*

**Q. DID OTHER INTERVENORS TO THE PRESENT DOCKET PROPOSE CARBON PLANS WHICH ARE PREFERABLE TO THE COMPANIES' PROPOSED CARBON PLAN?**

A. Yes. For instance, the portfolio prepared by Synapse Energy Economics ("Synapse") for NCSEA *et al.* is far superior to the Carbon Plan proposed by the Companies, and I would support adoption of the Synapse proposal. However, the portfolio developed by Synapse does not include any details on the nature of the utility-scale solar development included in the scope of the portfolio. The Commission should also direct that the utility-scale solar component of the Synapse portfolio prioritize the Distributed Generation SPS described in NC WARN *et al.*'s July 15, 2022 comments filed with the Commission in this proceeding. The Distributed Generation SPS prioritizes solar projects less than 5 MW installed at the distribution grid level in or

[56] DEC's 2019 FERC Form 1, April 14, 2020, p. 403.3 (Rockingham), line 35, $0.043/kWh ($42/MWh).
[57] DEP's 2020 FERC Form 1, April 15, 2021, p. 402.1 (Roxboro, $0.0538/kWh) and p. 403 (Mayo, $0.0897/kWh).

near demand centers (Charlotte, Raleigh-Durham, Greensboro/Winston-Salem), to avoid the delay and cost of the major transmission build-out that would be necessary if much of the new solar capacity is located in the rural transmission "red zones" preferred by the Companies.

## II. NEAR-TERM PROCUREMENT ACTIVITY

### *A. Errors in the Companies' Analysis of Solar Paired with Storage*

**Q. DID THE COMPANIES MAKE ERRORS RELATED TO THEIR ANALYSIS OF THE LIKELY PERFORMANCE OF SOLAR PAIRED WITH STORAGE ("SPS")?**

A. Yes. The Companies include a minimal amount of battery storage in the Carbon Plan in the near term, in part due to "outcome driven" assumptions by the Companies. As discussed in more detail below, the Companies committed the following errors: (a) the Companies undersized the battery storage component of SPS, and (b) the Companies failed to assume for modeling purposes that the storage component of SPS can be charged from either the associated solar array or the grid. These errors constitute serious flaws in the Companies' proposed Carbon Plan portfolios. As a result, the Carbon Plan target of 350 MW of cumulative operational battery storage by the end of 2027 is very limited in light of the actual U.S. battery storage deployment rate of 3,500 MW per year in 2021.[58,59]

**Q. DO THE COMPANIES CURRENTLY LAG BEHIND THEIR PEERS IN IMPLEMENTING BATTERY STORAGE?**

A. Yes. The Companies' claim in their 2020 IRPs that the electric utility industry has little meaningful experience with batteries is unsupported.[60] However, utility-scale battery storage has been deployed at scale in the U.S. since 2016.[61] Yet in their proposed Carbon Plan, the Companies imply that utility-scale battery storage is still transitioning to full commercial status, and therefore, the Companies propose to add only 350 MW of new battery storage by 2027.[62] The Companies' said assumption is unwarranted.

A specific concern expressed by the Companies in their 2020 Climate Report is the ability of the battery storage industry to manufacture the 15,000 MW of additional four-, six- and eight-hour battery storage by 2030 that the Companies say they would need to avoid adding new gas-fired capacity.[63] The Companies have only 13 MW of operational battery storage

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[58] The Companies' Carbon Plan, Appendix E, p. 26. ". . . the Carbon Plan assumes the deployment of approximately 350 MW of nameplate capacity (approximately 110 MW in DEC and 240 MW in DEP) with various storage capacity durations through 2027."

[59] Wood Mackenzie, *US battery storage deployment doubles in a single year*, March 24, 2022: https://www.woodmac.com/news/opinion/us-battery-storage-deployment-doubles-in-a-single-year/.

[60] NCUC E-100 SUB 165, DEC's 2020 IRP, p. 23. "The lack of meaningful industry experience with battery storage resources at this scale presents significant operational considerations that would need to be resolved prior to deployment at such a large scale."

[61] Renewable Energy World, *A Brief History of Utility-Scale Energy Storage*, September 19, 2017: https://www.renewableenergyworld.com/storage/a-brief-history-of-utility-scale-energy-storage/#gref.

[62] The Companies' Carbon Plan, App. E, p. 26.

[63] The Companies' 2020 Climate Report, p. 2.

as of May 2022.[64] In contrast, leading balancing authorities have thousands of MW of battery storage online.

The Companies' concern about the ability of SPS to completely displace new gas capacity is misplaced. The Companies are far behind their peers in adopting battery storage. The California Independent System Operator ("CAISO"), which includes three major investor-owned utilities, had about 2,500 MW of operational 4-hour battery storage at the end of 2021 and anticipates having 12,000 MW of battery storage by 2025.[65,66] The California Public Utilities Commission has ordered procurement of 1,000 MW of 8-hour battery storage to complement the 4-hour battery storage fleet.[67] CAISO has an all-time summer peak load of about 50,000 MW, compared to the Companies' combined summer peak record of 34,079 MW.[68,69]

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[64] The Companies' Carbon Plan, App. K, p. 2, Table K-1: Energy Storage Systems Located in the Carolinas.

[65] CAISO, *Another side of the battery story*, December 8, 2021: http://www.caiso.com/about/Pages/Blog/Posts/Another-side-of-the-battery-storage-story.aspx.

[66] CAISO, *Storage: An intersection between reliability today and climate goals of tomorrow*, September 14, 2021: http://www.caiso.com/about/Pages/Blog/Posts/Storage-An-intersection-between-reliability-today-and-climate-goals-of-tomorrow.aspx.

[67] Ibid. "As penetration of storage grows, managing the system will require that storage resources be of longer duration or that significantly more four-hour resources are built. In fact, the California Public Utilities Commission has already ordered the procurement of 1,000 MW of 8-hour (long duration) storage."

[68] CAISO, *California ISO Peak Load History 1998 through 2021*: https://www.caiso.com/documents/californiaisopeakloadhistory.pdf. All-time peak = 50,270 MW (2006).

[69] By way of comparison, the Companies' combined summer peak record is 34,079 MW. *See* Duke Energy News Center, *Duke Energy Carolinas Customers Set Summertime Record for Electricity Use*, June 15, 2022: https://news.duke-energy.com/releases/duke-energy-carolinas-customers-set-summertime-record-for-electricity-use-6873667.

Grid battery storage capacity is rapidly expanding in the U.S., as shown in Figure 2 below. Battery storage deployments are expected to reach 7,500 MW per year in 2025, of which about 80 percent is grid battery storage. Below, Figure 3 shows that battery storage deployments in 2021 met the 2021 projection in Figure 2 on the pathway to 7,500 MW per year of overall battery storage additions in 2025. The Companies' battery storage installation target through 2027 is 350 MW, about 1 percent of the projected US installed capacity through 2025 shown in Figure 2.[70]

A 2030 target of 15,000 MW of new battery storage would not require a leap in battery production capability. Other utilities are approaching this target much more quickly than 2030. As noted, California investor-owned utilities are projected to have 12,000 MW of grid-tied battery storage online by 2025. The Companies are unlikely to encounter battery storage supply issues if they opt to pursue deployment of 15,000 MW of battery storage by 2030 to avoid the addition of new CC and CT capacity.

[70] The cumulative US installed battery storage capacity through 2025 shown in Figure 2 is approx. 30,000 MW.

**Figure 2. U.S. battery storage additions to reach 7,500 MW annually in 2025**[71]

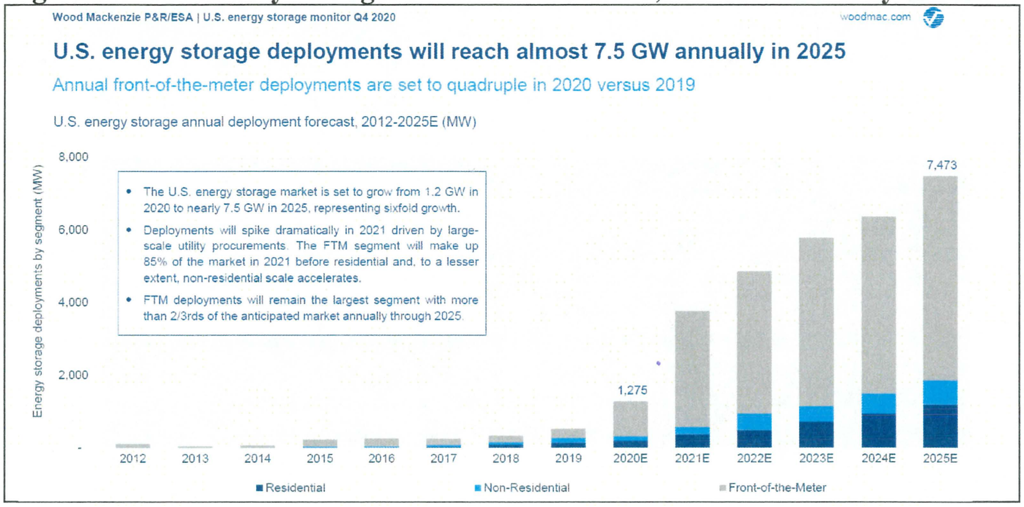
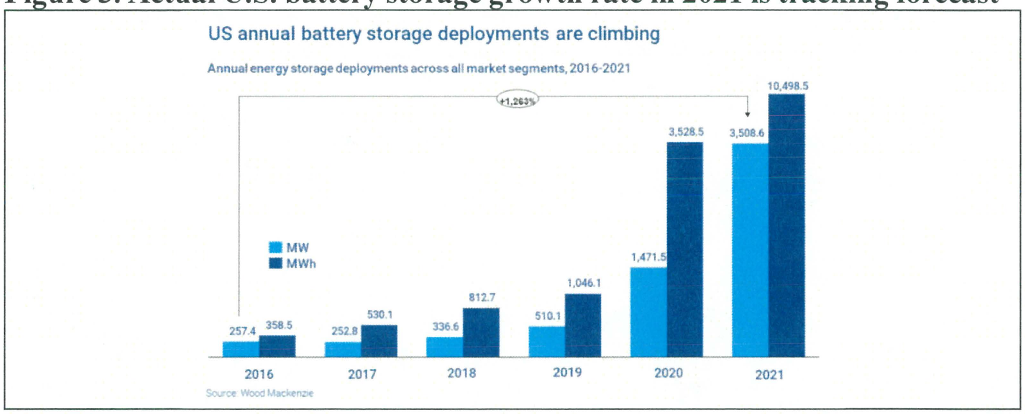



**Figure 3. Actual U.S. battery storage growth rate in 2021 is tracking forecast**[72]




In light of the above context, it is important to note that the lack of sufficient battery storage in the portfolios is a primary reason that the Companies fill the gap with new CC and CT capacity.

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[71] Bloomberg Green, *This Is the Dawning of the Age of the Battery*, December 17, 2020: https://www.bloomberg.com/news/articles/2020-12-17/this-is-the-dawning-of-the-age-of-the-battery.

[72] Wood Mackenzie, *US battery storage deployment doubles in a single year*, March 24, 2022: https://www.woodmac.com/news/opinion/us-battery-storage-deployment-doubles-in-a-single-year/. "Overall, 2021 was a record year for grid-scale battery storage deployments with 2.9 GW/9.2 GWh in total, despite over 2 GW being pushed into 2022 and 2023."

**Q. DID THE COMPANIES MAKE ANY DEFINITIONAL ERRORS WHICH HAD THE EFFECT OF REDUCING THE COMPANIES' PROPOSED RELIANCE UPON SPS?**

A. Yes. The Companies used a misleading definition of solar plus 4-hour battery storage in the Carbon Plan. The generally accepted industry definition of the number of hours of battery storage relative to the nameplate capacity of the solar array is the number of hours of storage at the capacity rating of that solar array. In other words, if the solar array is rated at 75 MW, then four hours of battery storage is 75 MW x 4 hours = 300 megawatt-hours (MWh).

The Companies do not use this definition. The base case SPS system modeled by the Companies is a 75 MW solar array coupled to 20 MW of battery storage with four hours of storage at 20 MW.[73] This results in the equivalent of about one hour of storage at 75 MW, not four hours of storage at the capacity rating of the solar array. The Companies have added an additional SPS configuration at the request of Public Staff, 75 MW solar with 40 MW/160 MWh storage (50% 4-hour storage).[74] However, this additional configuration, while an improvement on the two SPS configurations in the Carbon Plan, is one-half the storage necessary for the SPS to achieve equivalency to a CT.

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[73] The Companies' Carbon Plan, App. K, p. 7. "For SPS in the Carbon Plan, the Companies originally intended to only model a 4-hour battery that was sized at 25% of the solar facility, but based on this feedback, the Companies included a 2-hour storage option that was paired with solar, sized at 50% of the solar capacity."
[74] The Companies' Modeling Testimony, p. 151.

**Q. DID THE COMPANIES ACKNOWLEDGE IN THEIR DIRECT TESTIMONY THEIR ERROR IN FAILING TO MODEL THE SPS BATTERIES AS CAPABLE OF BEING RECHARGED WITH GRID POWER TO MAXIMIZE THE RELIABILITY OF THE BATTERIES TO MEET THE WINTER PEAK?**

A. Yes. In their prefiled direct testimony, the Companies state: "The Companies acknowledge that hybrid SPS assets are being designed with bidirectional inverters to enable charging the storage asset with both DC solar energy and grid energy."[75] However, the Companies go on to say that the Encompass model is not yet equipped to model this reality, and will not be until later this year.[76]

**Q. IS THIS A CREDIBLE BASIS FOR NOT ACCORDING THE SPS BATTERIES THE HIGH LEVEL OF RELIABILITY THEY ACTUALLY WILL HAVE AT THE WINTER PEAK?**

A. No. The portfolio modeling performed by the Companies must reflect that the SPS batteries can be charged with grid power to assure battery reliability at the winter peak.

**Q. DESPITE THE COMPANIES' ACKNOWLEDGMENT, ISN'T THE COMPANIES' TESTIMONY STILL FULL OF CLAIMS THAT THE SPS BATTERY STORAGE IS OF LIMITED USEFULNESS TO MEET THE WINTER PEAK BECAUSE THE SPS BATTERIES**

[75] The Companies' Modeling Testimony, p. 154.
[76] Ibid.

**MAY NOT GET FULLY CHARGED BY SOLAR UNDER INCLEMENT WINTER PEAK CONDITIONS?**

A. Yes. Again and again, despite the Companies' acknowledgment that the SPS batteries can charge from the grid if collocated solar power is not available, the testimony contains a drumbeat of assertions to the contrary.

**Q. CAN YOU PROVIDE A FEW EXAMPLES?**

A. Yes. Examples from the Companies' Modeling testimony and Reliability testimony are provided in Table 8 below.

**Table 8. Statements in Companies' Testimony Asserting Limited SPS Battery Reliability**

| Modeling Testimony, page | Companies' Statement |
|---|---|
| 137 | In short, energy limited batteries that need to be charged do not allow for the avoidance of the transmission project to enable these coal retirements. |
| 153 | It is likely that if the SPS asset with a larger storage component can only charge from solar there will be times that the storage component will not be fully charged at the time of peak demand and therefore its contribution to meeting peak demand will be diminished. |
| 154 | The SPS system was not allowed to be charged from the grid. The only source of charging for the SPS system was the full DC solar energy output of the solar resource that the storage asset was coupled with. |
| Reliability Testimony, page | |
| 69 | However, if the SPS system experienced just one-two cloudy days earlier in that week, there would not be enough energy to charge the batteries to make it through the remainder of the week to supply the equivalent amount of energy as was produced from the Roxboro Plant |
| 70 | If the Companies are dependent on renewable energy resources to serve customer demand and to charge battery storage (on cold, snowy, cloudy winter days), energy adequacy becomes a big operational concern. |

| | |
|---|---|
| 70 | On the low capacity factor days, Duke Energy would not receive enough energy from solar to refill the pumped storage basins, let alone charge four-hour batteries. |
| 73 | . . . additional gas generation capacity is a necessary complement to renewables and storage to provide dispatchable capacity and ensure energy adequacy during winter months when solar output is not well correlated to the Companies' early morning peak load shapes . . . |
| 74 | Not only is solar not well correlated to the Companies' winter load shape, as mentioned previously, winter is the time where solar capacity factors can vary drastically as shown in Figure 10. This day-to-day change would make it difficult, if not impossible, to reliably depend on significant solar energy to store for peaking capacity needed to ensure reliability during an extended cold weather period. |

**Q. HOW SHOULD THE COMMISSION MOVE FORWARD IN SELECTING A PREFERRED CARBON PLAN PORTFOLIO IF THE COMPANIES' MODELED PORTFOLIOS CONTAIN SUCH SERIOUS FLAWS?**

A. The Commission should reject the portfolios advanced by the Companies and select instead an alternative advanced by another party to the proceeding.

**Q. WHAT ALTERNATIVE PORTFOLIO WOULD YOU RECOMMEND THE COMMISSION ADOPT?**

A. As described more fully above, the Synapse portfolio should be adopted with additional specificity on the development of the SPS component of the portfolio. The solar component of the Synapse portfolio should prioritize utility-scale solar less than 5 MW interconnected at the distribution grid level and located in or near major North Carolina demand centers.

**Q. WHAT IS THE SOURCE OF THE "SMALLER SCALE UTILITY SPS INTERCONNECTED AT THE DISTRIBUTION LEVEL CLOSE TO LOAD" ALTERNATIVE THAT YOU PROPOSE?**

A. This approach was proposed in NC WARN *et al.*'s July 15, 2022 comments to the Commission in this proceeding as the "Distributed Generation Counter Proposal."

**Q. PLEASE PROVIDE MORE DETAIL ON THE SPS ASPECTS OF NC WARN *ET AL.*'S SAID PROPOSAL.**

A. Wholesale urban SPS installations would be built on commercial and industrial rooftops, parking lots, available urban parcels with 1 MW+ solar potential, and brownfield sites. Battery storage, with a minimum of 4 hours of storage at the capacity of the paired solar array, would be collocated with all new solar to assure the dispatchability of the solar resource and provide maximum resilience.

The solar potential in North Carolina on commercial rooftops, commercial parking lots, undeveloped large urban parcels, and brownfield (contaminated land) sites is about 67,000 MW (105,000 GWh per year).[77] This is two-and-a-half times the 25,000 MW of new solar capacity that would be needed – by itself with no additional renewable resources – to meet the 2050 carbon-free target in the Carbon Plan.[78] Of the 105,000 MW

[77] B. Powers – Powers Engineering, *North Carolina Clean Path 2025*, August 2017, p. 57: https://www.ncwarn.org/wp-content/uploads/NC-CLEAN-PATH-2025-FINAL-8-9-17.pdf.

[78] 1 MWac of installed fixed solar capacity in NC produces about 1,500 MWh per year of solar energy. There is approximately 8,000 MW of existing solar capacity in North

total, about 18,600 MW (~30,000 GWh per year) is rooftop and commercial parking lot PV potential. Open parcels with at least 1 MW solar capacity potential and without restrictive uses in urbanized areas of North Carolina can provide up to 43,000 MW (68,000 GWh per year) of solar capacity. There is also approximately 5,000 MW (8,000 GWh per year) of additional PV that could be developed on contaminated land, known as brownfield sites, in North Carolina. The quantity and distribution of these solar resources are shown in Table 9 below.

**Table 9. Estimate of North Carolina Local Solar and Brownfield PV Potential**

| Unit | Residential rooftop | Commercial/ industrial rooftop | Commercial parking lot | Undeveloped urban > 1 MW parcels | Brown-fields | Total |
|---|---|---|---|---|---|---|
| MW | 19,400 | 9,300 | 9,300 | 43,000 | 5,000 | 86,000 |
| GWh/yr | 30,600 | 14,700 | 14,700 | 68,000 | 8,000 | 136,000 |

**Q. DO THE COMPANIES ACKNOWLEDGE THE POTENTIAL TO BUILD SOLAR PROJECTS OUTSIDE OF THE "RED ZONE" AS A WAY TO ACCELERATE SOLAR/SPS DEPLOYMENTS?**

A. Yes. The Companies state: "Also, in order to connect the amount of solar intervenors such as CPSA or CCEBA suggest should be modeled, developers would need to locate solar outside of transmission constrained

Carolina, producing about 12,000,000 MWh per year. Therefore, sufficient new solar capacity to generate 38,000,000 MWh per year must be added. 38,000,000 MWh/yr ÷ 1,500 MWh/MW = ~25,000 MW.

areas that may be more costly than locations that could be connected once RZEP are completed."[79]

### *B. The Companies' Proposed Conversion from Natural Gas to "Green Hydrogen"*

**Q. DO YOU HAVE CONCERNS ABOUT THE COMPANIES' PROPOSED CONVERSION OF NATURAL GAS TO "GREEN HYDROGEN"?**

A. Yes. The Companies' proposal is highly speculative and not supported by the evidence.

**Q. PLEASE DESCRIBE YOUR CONCERNS REGARDING THE SOURCES CITED BY THE COMPANIES IN FAVOR OF THIS PROPOSED TRANSMISSION TO GREEN HYDROGEN.[80]**

A. For example, the Companies relied on a 19-page green hydrogen ($H_2$) promotional brochure prepared by the Department of Energy's ("DOE") Office of Energy Efficiency and Renewable Energy ("EERE"). That said promotional brochure contains exceptionally low aspirational cost projections for green $H_2$ production, as support for the future viability of gas turbines operating on 100 percent green $H_2$. The Companies' extensive reliance upon this short promotional brochure for such a significant planning issue is unrealistic.

[79] The Companies' Modeling Testimony, p. 168.
[80] Ibid, p. 179.

**Q. DO THE COMPANIES SIMPLY ASSUME A CONVERSION TO 100 PERCENT GREEN HYDROGEN WILL HAPPEN BY 2050, DESPITE THE UNCERTAINTIES?**

A. Yes. The Companies propose a tremendous build-out of CC and CT capacity on the presumption that all gas-fired generation will convert to 100 percent $H_2$ fuel by 2050, while at the same time acknowledging that the conversion to $H_2$ may not happen. The Companies, while acknowledging "significant uncertainties" in the future supply of $H_2$, simply assume that $H_2$ will be available at scale in 2050 to operate all CCs and CTs on 100 percent $H_2$. On that basis, the Companies propose to add 800 MW to 2,400 MW of CCs and 6,400 MW to 10,900 MW of CTs to achieve carbon neutrality by 2050.[81]

The Carbon Plan asserts that all CTs and CCs will burn 100 percent $H_2$ by 2050, if uncertainties around $H_2$ supply are resolved by then. There is no assessment of what happens with the CTs and CCs if those uncertainties are not resolved by 2050. The issue of stranded costs associated with new gas-fired generation, and who will be responsible for those stranded costs, is not addressed by the Companies in the Carbon Plan or testimony supporting the Carbon Plan.

There also is no accounting in the Carbon Plan for the potentially high capital cost of converting a CC or CT power plant designed to burn

[81] The Companies' Carbon Plan, Chapter 1, p. 31.

natural gas to burn 100 percent $H_2$. The Companies simply assume that green $H_2$ will be "readily accessible" in 2050.[82] All elements of the Companies' existing CC and CT power plants that will operate beyond 2050 will likely require major modification to enable use of 100 percent $H_2$ fuel.[83,84] These elements include: fuel piping component materials, pipe sizes, sensors and safety systems, and gas turbine components exposed to $H_2$ combustion exhaust gases.[85] There is no indication that the Companies have considered the additional cost of converting the CC and CT power plants to burn 100 percent $H_2$, or the potentially high fuel cost of green $H_2$ that will be required.

**Q. DO GAS TURBINE MANUFACTURERS ANTICIPATE A WHOLESALE CONVERSION OF GAS TURBINES TO 100 PERCENT GREEN HYDROGEN BY 2050?**

A. No. Gas turbine manufacturers envision gas turbines firing 100 percent $H_2$ as operating infrequently, and then only in regions with high power costs.

[82] Ibid, p. 31.

[83] The Companies' Carbon Plan, App. E, p. 23. "A limited number of natural gas resources currently on the system are expected to continue operating in 2050 and beyond. These include the WS Lee CC, the Asheville CCs, Sutton CTs 4 and 5, and Lincoln CT 17. For these combustion units that are planned to remain on the system in 2050, the Carbon Plan assumes these units are converted to hydrogen-fired units near the end of the planning horizon. In the Carbon Plan modeling, these units operate exclusively on hydrogen to comply with the 2050 carbon neutrality target."

[84] Siemens, *Hydrogen power with Siemens gas turbines*, 2020, p. 16: https://www.infrastructureasia. org/-/media/Articles-for-ASIA-Panel/Siemens-Energy---Hydrogen-Power-with-Siemens-Gas-Turbines.pdf?la=en&hash=1B91FADA342293EFB56CDBE312083FE1B64DA111.

[85] Ibid.

For instance, Siemens, a major European gas turbine manufacturer and the provider of the Companies' 402 MW Lincoln 17 CT, states:[86]

> As significantly, today, running electrolysis to produce 50 MW for one hour at a CCGT running at 50% efficiency could require 175 MW of renewable power and 3,400 kilograms (more than 14,000 gallons) of hydrogen, he said. "So, the affordability part of the equation could be an issue," which is why hydrogen power could prove more economical as short-term (three or four hours a day) renewable support in places such as Europe, he added.

Even this niche for gas turbines burning 100 percent $H_2$ is undercut by the gas turbine industry's recognition that battery storage is already the preferred technology to fill this shorter-duration power supply role:

> Asked how the technology will compete against advancements in battery storage, Browning (Mitsubishi Hitachi Power Systems) said, "We think lithium-ion batteries will probably be the right choice if you want to store electricity for shorter periods of time." The economics of hydrogen "are going to work no matter how long you store it," he noted.

Utility-scale solar plus lithium-ion battery storage is already a more cost-effective alternative to a CT burning natural gas according to the power industry itself.[87] Utility-scale long-duration lithium-ion battery storage systems are being installed now. There will be no obvious power generation "gap" for gas turbines firing $H_2$ blends or 100 percent $H_2$, operating only a few hours a day, to fill in the future.

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[86] Power Magazine, *High-Volume Hydrogen Gas Turbines Take Shape*, September 2019: https://www.powermag.com/high-volume-hydrogen-gas-turbines-take-shape/.

[87] GreenTech Media, *NextEra looks to spend $1B on energy storage in 2021*, April 22, 2020: https://www.greentechmedia.com/articles/read/nextera-energy-to-spend-1b-on-energy-storage-projects-in-2021.

*C. The Companies' Natural Gas Price Projections*

**Q. DO YOU HAVE CONCERNS ABOUT THE COMPANIES' NATURAL GAS PRICE PROJECTIONS?**

A. Yes. As described below, the Companies' natural gas price projections fail to adequately recognize the volatility in the natural gas market and are unrealistically optimistic.

**Q. DID THE COMPANIES MAKE ANY ATTEMPT TO CROSS-CHECK OR ADJUST THEIR LOW AND CONSISTENT NATURAL GAS PRICE FORECAST WITH VOLATILE NATURAL GAS PRICES OF THE LAST 10-15 YEARS?**

A. No. The Companies' testimony on this issue suffers the same weakness as their demand forecast testimony. There was no look-back to assess how accurate the natural gas price forecasts have been relative to the actual natural gas prices.

**Q. HAS HIGH VOLATILITY BEEN A DEFINING FEATURE OF ACTUAL NATURAL GAS PRICES OVER THE LAST 15-20 YEARS?**

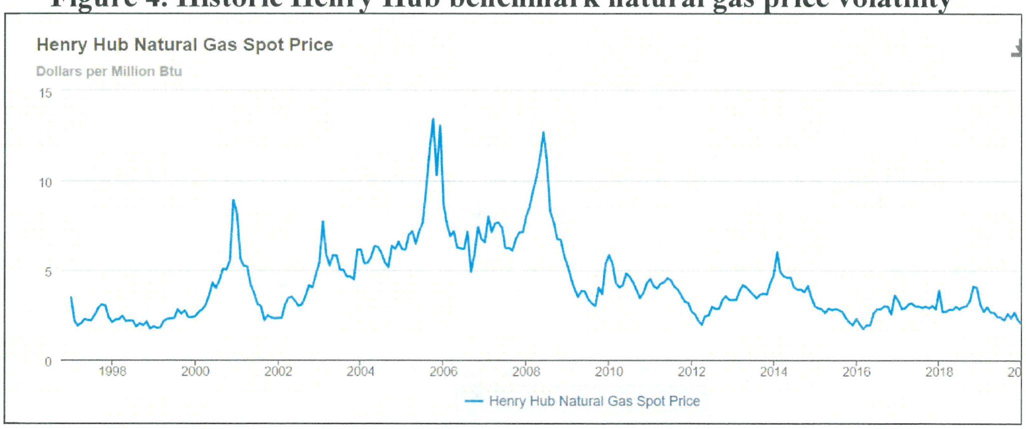
A. Yes. The Carbon Plan acknowledges significant natural gas price risk, though only in the context of potentially insufficient firm natural gas pipeline capacity to supply the proposed new gas-fired capacity. The

Companies address this risk in a sensitivity analysis by displacing CC capacity with battery storage and CTs.[88]

**Q. HOW VOLATILE HAVE NATURAL GAS PRICES BEEN OVER THE LAST 15-20 YEARS?**

A. Actual natural gas prices have been quite volatile. Natural gas price volatility has been an inherent feature of the natural gas market, as shown in Figure 4 below. Natural gas prices have been especially volatile in 2022, with the May 2022 Henry Hub price over $8 per million Btu. Western Europe has become a high-demand, priority delivery point for U.S. natural gas in the form of LNG as a result of the Ukraine war, driving increases in U.S. natural gas prices. Yet the Companies' proposed Carbon Plan assumes a low base price for natural gas, under $4/MMBtu through 2032 rising to $5/MMBtu in 2040, as shown in Figure 5 below.

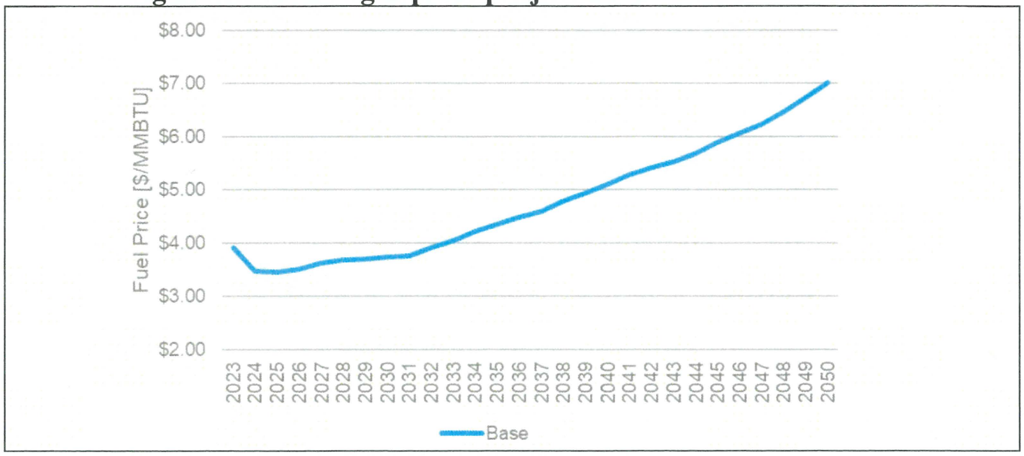
**Figure 4. Historic Henry Hub benchmark natural gas price volatility**[89]




[88] Methane is not mentioned in the Companies' proposed Carbon Plan. Methane is a much stronger greenhouse gas than $CO_2$. However, there is no mention in the proposed Carbon Plan of upstream methane emissions from the production of natural gas and the impact of those methane emissions on climate.

[89] EIA, Natural Gas, https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm (accessed July 3, 2022).

**Figure 5. Natural gas price projection in the Carbon Plan**[90]




**Q. DOES SOLAR POWER EXHIBIT PRICE VOLATILITY OVER TIME?**

A. No. There is no price volatility over time in the price (free) or availability of solar power.

## III. NEAR-TERM DEVELOPMENT ACTIVITY— SMALL MODULAR REACTORS

**Q. DO YOU HAVE CONCERNS ABOUT THE COMPANIES' PROPOSED RELIANCE UPON SMALL MODULAR REACTORS?**

A. Yes. Small modular reactors ("SMRs") are an unproven option without any history of success in the power industry, and in addition, SMRs are not economically viable.

**Q. PLEASE DESCRIBE HOW THE COMPANIES HAVE FAILED TO PROVE THAT SMRs ARE ECONOMICALLY VIABLE IN PRACTICE?**

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[90] The Companies' Carbon Plan, App. E, p. 40, Figure E-6: Base Henry Hub Natural Gas Price Forecast [$/MMBtu].

A. The Companies include SMRs in all four Carbon Plan portfolios, despite the present lack of a commercially viable SMR. Bringing reliable and cost-effective SMRs into the marketplace remains highly speculative and high-risk, in spite of numerous SMR developers putting in years of effort. The challenges include unproven and challenging designs, cost viability and economies-of-scale, lack of full regulatory or investor approval, radioactive waste, safety and security, and competition from cheaper, safer alternatives. Any combination of these uncertainties remaining unresolved would make construction of SMRs unlikely.

**Q. ARE THERE ANY PROMINENT EXAMPLES WHICH ILLUSTRATE YOUR POINT THAT SMRs ARE BOTH IMPRACTICAL AND NOT ECONOMICALLY VIABLE?**

A. Yes. This situation is reminiscent of the decade-plus effort by Duke Energy and other United States utilities to design, license and construct the Westinghouse AP1000 reactor as part of the last "nuclear renaissance" beginning in 2005.[91] The effort ended in cancellation of all but one of the more than a dozen twin-reactor AP1000 projects that reached some stage of planning, licensing or construction. Billions of dollars in stranded costs were passed along to ratepayers, primarily across the Southeast. Duke Energy cancelled the last of its three failed projects in 2017.

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[91] The Guardian, *Reviving nuclear power debates is a distraction. We need to use less energy*, November 7, 2013: https://www.theguardian.com/commentisfree/2013/nov/08/reviving-nuclear-power-debates-is-a-distraction-we-need-to-use-less-energy.

The manufacturer Westinghouse and utilities such as Duke Energy had claimed that the "Advanced Passive (AP) 1000" reactor would avoid the large cost overruns and mid-stream cancellations of the first generation of US nuclear power plant construction projects. That promise was largely based on plans for off-site construction of various modules that could then be pieced together at each proposed site. The AP1000 plan was not successful. In fact, the sole US AP1000 project still underway, Plant Vogtle Units 3 and 4 in Georgia, is years behind schedule with a cost of over $30 billion.[92] The same promise of off-site, modular construction used with the AP1000 is central to the promotion of SMRs.

NuScale, considered the leading US developer of SMR technology, is years behind schedule. Cost estimates for its SMR are speculative, as no units have yet been built or operated.[93]

NuScale reached agreement with Utah Associated Municipal Power Systems (UAMPS) in 2017 to build twelve 50 MW modules that would come online in 2024.[94] Later, the plan changed to six 77 MW modules

[92] GPB News, *Georgia nuclear plant's cost now forecast to top $30 billion*, May 9, 2022: https://www.gpb.org/news/2022/05/09/georgia-nuclear-plants-cost-now-forecast-top-30-billion.

[93] IFEEA, *NuScale's Small Modular Reactor - Risks of Rising Costs, Likely Delays, and Increasing Competition Cast Doubt on Long-Running Development Effort*, February 2022, pp. 6-9: https://ieefa.org/wp-content/uploads/2022/02/NuScales-Small-Modular-Reactor_February-2022.pdf.

[94] Utility Dive, *NuScale makes public debut but requires 'a lot of financing' to launch small nuclear reactor in 2029*, June 1, 2022: https://www.utilitydive.com/news/nuscale-makes-public-debut-but-requires-a-lot-of-financing-to-launch-smal/624568/.

projected to come online in 2029.[95] The currently projected NuScale production cost could be more than twice the cost of utility-scale solar and wind power generation.[96]

Investor reaction to NuScale's progress has been mixed. Despite going public in May 2022, NuScale still "needs substantial financing to stay afloat for the next several years" until its UAMPS project comes online.[97,98] Officials say current cash projections would carry the company until 2024. NuScale's problematic financial state would indicate a 2029 operational date for its SMR is highly problematic.

**Q. DO YOU HAVE OTHER CONCERNS ABOUT SMRs?**

A. Yes. Radioactive waste is also a weakness of SMRs. A May 2022 research study found that, if ever built, SMRs will produce far more, not less, radioactive waste per MW generated than the typical US nuclear reactor.[99] SMRs would add to the intractable challenge the US has faced throughout the nuclear power era: namely, how to safely manage spent fuel and other waste streams for generations to come.

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[95] Utility Dive, *Newly public small modular reactor developer NuScale reports increased losses, big cash infusion*, June 8, 2022: https://www.utilitydive.com/news/newly-public-small-modular-reactor-developer-nuscale-reports-increased-loss/625102/.

[96] IEEFA, *supra* n.93.

[97] Utility Dive, *supra* n.94.

[98] Utility Dive, *supra* n.95.

[99] Stanford News, *Stanford-led research finds small modular reactors will exacerbate challenges of highly radioactive nuclear waste*, May 30, 2022: https://news.stanford.edu/2022/05/30/small-modular-reactors-produce-high-levels-nuclear-waste/.

**Q. WHAT IS YOUR RECOMMENDATION REGARDING THE AUTHORIZATION OF DEVELOPMENT FUNDING FOR SMRs?**

A. It would be imprudent for the Commission to authorize any development funding for SMRs.

## IV. TRANSMISSION PLANNING, PROACTIVE TRANSMISSION AND RZEP[100]

**Q. THE COMPANIES CLAIM THAT BUILDING LARGE-SCALE SOLAR IN THE "RED ZONE" WOULD BE THE LEAST-COST SOLAR ENERGY ALTERNATIVE. DO YOU AGREE?**

A. No. The Public Staff expressed concern, regarding the Companies' 2022 Solar Procurement Proposal, that the uncertain cost of transmission upgrades necessary to interconnect large volumes of (utility-scale) solar may not result in least-cost compliance with HB 951's carbon reduction goals.[101] These transmission upgrade costs reflect project developer preference to locate these projects in transmission-limited rural areas where land costs are low.[102] The Companies' testimony implies this is sufficient reason, solar developer preference, for the proposed extremely extensive Red Zone Expansion Plan

[100] Red Zone Transmission Expansion Plan ("RZEP").
[101] NCUC, 2022 Solar Procurement Proposal, Docket No. E-2, Sub 1297 & Docket No. E-7, Sub 1268, Initial Comments of the Public Staff, March 28, 2022, p. 4.
[102] Ibid, p. 7: "Stakeholders from the solar industry have emphasized the need to site solar capacity in DEP's southeastern service territory due to available land and lower land costs to solar developers. However, DEP's southeastern territory has significant transmission congestion because of the large amount of solar generation currently located in this area. The large quantities of new solar capacity in the interconnection queue in that area are already resulting in larger transmission upgrade costs compared to DEC. If solar capacity and the necessary transmission upgrades are built in DEP's territory to meet DEC's carbon reduction goals, current cost allocation methodologies could cause the costs to be largely recovered from DEP customers."

("RZEP"),[103] However, it is the ratepayer, not the solar developers, that will pay for the backbone transmission system upgrades necessary to develop the Red Zones.

Reliance on wholesale rooftop and parking lot SPS in the Carbon Plan would largely eliminate transmission upgrades that would otherwise be necessary to interconnect utility-scale solar proposed in areas of the state with inadequate transmission capacity.

**Q. ARE THERE FAR LESS TRANSMISSION COST IMPACTS WITH SMALLER (< 5 MW) ARRAYS CONNECTED AT THE DISTRIBUTION LEVEL?**

A. Yes. The Companies' proposed Carbon Plan is correct in pointing out that the historic pattern in the Carolinas of building smaller 5 MW utility-scale solar arrays, interconnected at the distribution level, has allowed the incorporation of over 4,000 MW of solar capacity with little utility upgrade expense. The Companies state:[104]

> Of the 4,350 MW of solar connected today, over 95% of installed solar projects are smaller, distribution-tied projects
> . . .
>
> One of the key barriers to adding resources, particularly solar, to the system is increasing transmission network upgrades required to interconnect new

[103] The Companies' Transmission Testimony, p. 36. "The bid window for 2022 Solar Procurement recently closed on July 22, 2022. Of the more than 5,000 MW of proposals received, over 70% of the MW are located in known red-zone areas. These known congested areas have been shared with market participants ahead of the 2022 Solar Procurement, and all three CPRE RFPs, and yet this information does not seem to drive project development to non-congested areas in any significant way."
[104] The Companies' Carbon Plan, App. I, p. 1.

resources. The one justification used by the Companies for shifting to large, transmission-dependent utility-scale solar arrays is the improved efficiency of the solar production. The Companies note that the existing, distribution grid-connected projects have efficiencies in the range of 23 percent, while the larger proposed arrays would use bifacial panels and single-axis tracking to improve efficiency to 28 percent.[105]

There is no acknowledgement in the Companies' proposed Carbon Plan that smaller projects can also use bifacial panels and single-axis tracking in the future, negating the implied advantage of larger, transmission-connected solar projects. There is also no comment on the fact that the higher cost of bifacial solar panels largely offsets the increased solar production.[106] Finally, solar project economies-of-scale are not addressed in the Carbon Plan. A distribution grid-connected 5 MW solar array with bifacial solar panels and single-axis tracking in the same location would have the same 28 percent efficiency as the Companies assert for the 75 MW solar arrays modeled in the Carbon Plan. The major cost advantage of interconnection at the distribution level is the avoidance of substantial transmission upgrade costs.

The economies-of-scale are largely realized for solar projects at relatively small size. Figure 6 (below) was developed by NREL and is a

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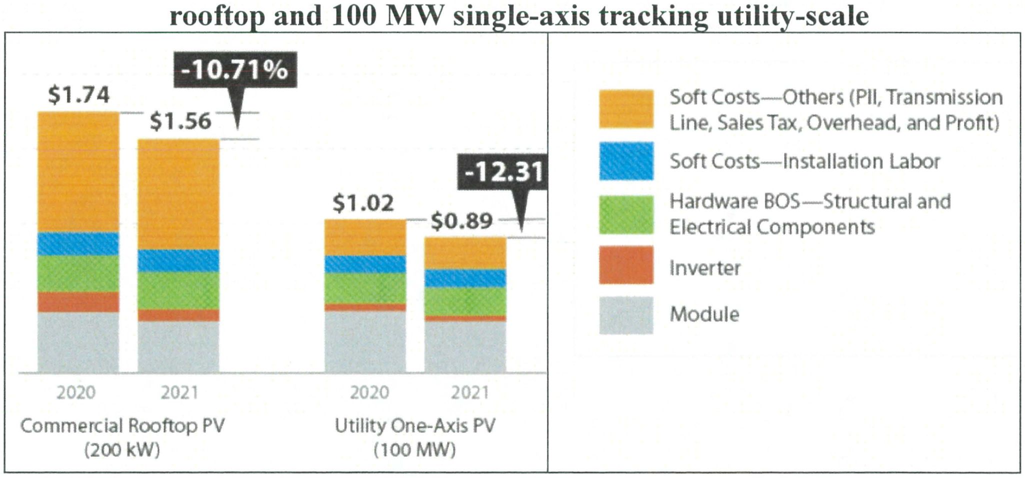
[105] Ibid, p. 2.

[106] Reuters, *U.S. Solar tariffs bolster growing dominance of bifacial panels*, March 16, 2022: https://www.reutersevents.com/renewables/solar-pv/us-solar-tariffs-bolster-growing-dominance-bifacial-panels.

comparison of the cost elements of a 200 kW commercial rooftop solar array and a 100 MW single-axis tracking solar array.[107] There is essentially no difference in the \$/watt cost of the hardware and installation labor between the two projects. The cost difference is in the level of effort (soft costs – orange) required by solar installation firms to secure individual commercial rooftop projects compared to a single 100 MW utility-scale project. However, the Companies have the capability to aggregate hundreds of rooftops and substantially reduce the soft costs associated with wholesale urban projects.

**Figure 6. NREL comparison of solar cost elements, 200 kW commercial rooftop and 100 MW single-axis tracking utility-scale**




**Q. IS THERE SUFFICIENT DISTRIBUTION LEVEL WHOLESALE SOLAR POTENTIAL IN OR NEAR DEMAND CENTERS TO PRIORITIZE THIS SOLAR RESOURCE?**

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[107] NREL, *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2021*, November 4, 2021: https://www.nrel.gov/news/program/2021/new-reports-from-nrel-document-continuing-pv-and-pv-plus-storage-cost-declines.html.

A. Yes. The Companies have tremendous, and largely untapped, commercial/industrial building wholesale rooftop and parking lot solar potential and urban undeveloped land potential available for the development of wholesale SPS projects. North Carolina has a solar rooftop and parking lot solar potential of 38,000 MW.[108] The state has an undeveloped urban land wholesale SPS potential of 43,000 MW.[109] There is ample solar potential to meet the Carbon Plan reduction targets with projects that tie into the local distribution grid and predominantly serve local demand.

There are no transmission constraints to the wholesale urban SPS installation rate. The Companies have imposed a 750 MW per year solar expansion restriction due to transmission constraints.[110] The Companies project they can increase the solar interconnection pace to 1,800 MW per year by 2030 in Portfolio 1.[111] Prioritizing wholesale urban SPS would eliminate transmission constraints on the solar build-out toward carbon-free power.

One U.S. investor-owned utility has built a large-scale aggregated warehouse rooftop project selling wholesale power over the distribution grid. In March 2008, Southern California Edison ("SCE") proposed to build 250 MW of solar on warehouse rooftops in urban Southern California. The

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[108] B. Powers – Powers Engineering, *NC Clean Path 2025*, Table 25, p. 57: https://www.ncwarn.org/wp-content/uploads/NC-CLEAN-PATH-2025-FINAL-8-9-17.pdf.
[109] Ibid.
[110] The Companies' Carbon Plan, Chp. 2, p. 19. Table 2-10: Maximum Solar [MW] Allowed to Connect Annually.
[111] Ibid, p. 17.

project involved aggregating a large number of 1 MW to 2 MW rooftop projects. The California Public Utilities Commission ultimately approved a larger 500 MW SCE warehouse rooftop solar project in June 2009, stating:[112]

> Unlike other generation resources, these (large-scale rooftop solar) projects can get built quickly and without the need for expensive new transmission lines. And since they are built on existing structures, these projects are extremely benign from an environmental standpoint, with neither land use, water, or air emission impacts.

The CEO of SCE at the time, John Bryson, was an advocate for the warehouse rooftop solar project, explaining how it benefitted the SCE grid:[113]

> "These new solar stations, which we will be installing at a rate of one megawatt a week, will provide a new source of clean energy, directly in the fast-growing regions where we need it most," said Bryson.

Multi-year delays in solar deployments, huge transmission build-out expenditures, and increasing community resistance to large-scale solar development in rural areas can be avoided by prioritizing smaller-scale utility solar projects on the distribution grid in and near demand centers.

**Q. DO THE COMPANIES ACKNOWLEDGE COMMUNITY RESISTANCE TO LARGE-SCALE SOLAR DEVELOPMENT IN THE RED ZONES?**

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[112] CPUC press release, *CPUC Approves Edison Solar Roof Program* (June 18, 2009): https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/NEWS_RELEASE/102580.PDF.

[113] Edison International News Release, *Southern California Edison Launches Nation's Largest Solar Panel Installation*, March 27, 2008: https://newsroom.edison.com/releases/southern-california-edison-launches-nations-largest-solar-panel-installation.

A. Yes. The Companies acknowledge growing rural community resistance to solar projects, referencing other parties in stating "In ten years, 1,800 MW/year of solar would cover approximately 225 square miles of land . . . "[Local opposition to development] is increasingly one of the top barriers . . ."[114]

**Q. DOES THE CARBON PLAN CONSIDER ANY ALTERNATIVE SOLAR DEVELOPMENT OPTIONS TO AVOID THE TRANSMISSION CONGESTION, TRANSMISSION COST, AND COMMUNITY RESISTANCE IN RED ZONES?**

A. No. This failure constitutes an error in the Companies' proposed Carbon Plan.

## V. EE/DSM ISSUES / GRID EDGE

**Q. IS THE COMPANIES' STATED COMMITMENT IN THE CARBON PLAN TO PRIORITIZE "SHRINKING THE CHALLENGE" REFLECTED IN THE PROJECTED ROOFTOP SOLAR (NEM) INSTALLATION RATE?**

A. No. In their proposed Carbon Plan, the Companies claim to use a three-pronged approach, focusing first on "grid edge" strategies, including NEM solar, to reduce energy requirements and load profiles. The Carbon Plan underscores that:[115] Grid edge programs are identified as the first priority in the Carbon Plan. Grid edge programs include energy efficiency (EE),

[114] The Companies' Modeling Testimony, pp. 166-167.
[115] The Companies' Carbon Plan, Executive Summary, p. 9.

demand-side management (DSM), customer self-generation (NEM solar), voltage management and other distributed energy resources (DER).[116] The Carbon Plan forecasts 15 percent growth rate for NEM solar through 2030.[117] However, the Companies have proposed modifications to the NEM tariff that will reduce the economic benefit of NEM by 30 percent or more to address an alleged (by the Companies) cost shift from NEM residential customers to non-NEM residential customers.[118]

The Companies' growth projection for NEM has substantially declined between the 2020 DEC and DEP IRPs and the Carbon Plan. There were 169 MW of NEM solar online in the Companies' territories in North Carolina at the end of 2021.[119] The Companies projected in the 2020 IRPs that 745 MW would be online in North Carolina by 2035.[120] This is a NEM solar increase in North Carolina of 576 MW between the end of 2021 and 2035.

The Companies' proposed Carbon Plan projects a NEM addition rate of 26.5 MW per year in North Carolina,[121] the equivalent of an

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[116] The Companies' Carbon Plan, App. G, p. 1.
[117] The Companies' Carbon Plan, Chp. 2, p. 12.
[118] NCUC Docket No. E-100 SUB 180, Joint Initial Comments of NC WARN *et al.*, March 29, 2022.
[119] The Companies' total NEM solar capacity at the end of 2021, per EIA (https://www.eia.gov/electricity/data/eia861m/#netmeter): DEC NC = 90.6 MW; DEP NC = 78.5 MW. Total NEM solar = 169.1 MW.
[120] NCUC Docket No. E-100 SUB 165, DEC's 2020 IRP, p. 230, Table C-4.
[121] The Companies' total NEM solar capacity at the end of 2021, per EIA (https://www.eia.gov/electricity/data/eia861m/#netmeter): DEC NC = 90.6 MW; DEC SC = 92.3 MW; DEP NC = 78.5 MW; DEP SC = 19.8 MW. NC NEM solar = 169.1 MW; Total NEM solar = 281.2 MW. The Companies' Carbon Plan, App. G, p. 18, Table G-7: current NEM production = 493,343 MWh/yr. Table G-8: new NEM production by 2030 = 697,707 MWh/yr. Therefore, total new NEM by 2030 (in MW) = 281.2 MW x (697,707

additional 371 MW by 2035.[122] The Carbon Plan reduces the role of NEM solar dramatically, relative to the 2020 IRP forecasts, despite identifying NEM solar as a first priority in reducing carbon emissions. The NEM solar additions forecast in the 2020 IRPs were made in the context of the Companies modifying the NEM tariff to reduce bill savings.[123] That process is underway in the Commission's Docket No. E-100 SUB 180. No new rationale is put forth in the Companies' proposed Carbon Plan to justify the substantial decline in new NEM solar capacity in North Carolina between the Companies' 2020 IRP(s) forecast and the Carbon Plan forecast.

**Q. DOES THE CARBON PLAN NEM INSTALLATION RATE ANTICIPATE THE TEN-YEAR EXTENSION OF THE SOLAR TAX CREDIT IN THE AUGUST 2022 INFLATION REDUCTION ACT (IRA)?**

A. No. The White House projects that North Carolina will add an additional 170,000 rooftop systems,[124] and South Carolina will add an additional 220,000 rooftop systems,[125] as a result of the 10-year extension of the solar

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MWh/yr ÷ 493,343 MWh/yr) = 397.7 MW. New NC NEM by 2030 = (169.1 MW/281.2 MW) x 397.7 MW = 239 MW. Annual NC NEM additions, 2022-2030 (9 years) = 239 MW/9 years = 26.5 MW per year.

[122] The Companies' Carbon Plan NEM forecast is through 2030. The Carbon Plan forecast is extrapolated to 2035 to calculate expected additional NC NEM solar capacity in 2035. 26.5 MW per year x 14 years (2022-2035) = 371 MW.

[123] NCUC Docket No. E-100 SUB 165, DEC's 2020 IRP, p. 228: "For this IRP, DEC assumes that NEM tariffs will evolve to more closely align with the cost to serve rooftop solar customers, such that bill savings would gradually decrease over time."

[124] North Carolina: https://www.whitehouse.gov/wp-content/uploads/2022/08/North-Carolina.pdf.

[125] South Carolina: https://www.whitehouse.gov/wp-content/uploads/2022/08/South-Carolina.pdf.

tax credit in the IRA. These rooftop solar additions have not been factored into the Companies' NEM solar forecasts or their load growth projections.

## VI. RELIABILITY

**Q. DO THE COMPANIES MISSTATE THE CAUSES OF THE CAISO BLACKOUTS IN AUGUST 2020 TO SUPPORT A POSITION THAT OVER-RELIANCE ON IMPORTS CAN COMPROMISE RELIABILITY?**

A. Yes. In the Companies' prefiled direct testimony, Mr. Holeman states that ". . . over-reliance on imports was a causal factor for the (August 2020 CAISO blackout) events."[126] I was an expert witness in the California Public Utilities Commission proceeding that examined the causes for the August 14-15, 2020 blackouts, and my testimony in the proceeding is attached hereto as **Exhibit 1**.[127] Over-reliance on imports was not a significant factor in the CAISO August 14-15, 2020 blackouts. Market mismanagement by the CAISO was the overwhelmingly primary cause, which allowed the exporting of 3,500 MW of California generation to neighboring states when that supply was needed in California. The second and substantially less significant cause was the high forced outage rate of

[126] The Companies' Reliability Testimony, p. 79.
[127] **Exhibit 1**, California Public Utilities Commission, Rulemaking R.20-11-003 (Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021), Prepared Opening Testimony of Bill Powers, P.E., On Behalf of the Protect Our Communities Foundation, January 11, 2021.

aging coastal steam boiler units that remain operational specifically to provide capacity during summer heat waves.

**Q. IS MR. HOLEMAN CORRECT WHEN HE ASSERTS ALL IMPORTS INTO THE CAISO BALANCING AUTHORITY ARE FIRM IMPORTS?**

A. No. The Root Cause Analysis that Mr. Holeman references states that "The imports category includes both non-resource-specific resources as well as resource-specific imports like those from Hoover Dam and Palo Verde Nuclear Generating Station."[128] CAISO imports consist of a mix of firm and non-firm imports.

**Q. DOES MR. HOLEMAN ACKNOWLEDGE THE CAISO BLACKOUTS' PRIMARY CAUSE, SUPPLY MISMANAGEMENT BY CAISO, IN HIS TESTIMONY?**

A. No. He notes that "The 2020 California firm load shed event . . . multiple factors including . . . and (CAISO) market functions that compounded the existing supply challenges."[129] The "market functions" issue was the cause of the blackouts. According to CAISO, a computer programming error allowed exports from California to be allowed when the supply was needed in California to meet demand.[130] 3,500 MW was being exported from

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[128] CAISO *et al.*, *Root Cause Analysis (RCA) – Mid-August 2020 Extreme Heat Wave*, January 13, 2021, p. 48: http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.
[129] The Companies' Reliability Testimony, pp. 38-39.
[130] CAISO *et al.*, *Root Cause Analysis (RCA) – Mid-August 2020 Extreme Heat Wave*, January 13, 2021, p. 5: http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

California at the time the rolling blackouts were initiated on both days.[131] To put this in perspective, 3,500 MW is approximately the entire capacity of the Companies' combined cycle fleet added in the last ten years.[132] This was not a simple "market function" executed by the CAISO – it was a major CAISO error that resulted in two avoidable rolling blackouts at a time when supply was adequate to meet demand but some of that in-state supply was erroneously exported out-of-state.

**Q. WAS THE SAME ENTITY RESPONSIBLE FOR THE AUGUST 2020 BLACKOUTS, CAISO, ALSO THE LEAD INVESTIGATOR ON THE ROOT CAUSE ANALYSIS OF THE BLACKOUTS?**

A. Yes. There was no neutral, independent investigation of the root causes of the blackouts. The bias toward deflecting responsibility for the blackouts to the weather is reflected in the title of CAISO's root cause analysis – "Root Cause Analysis – Mid-August 2020 Extreme Heat Wave." It was hot in California in August 2020. However, the peak load on August 14, 2020 was approximately the forecast 1-in-2 peak summer load. The rolling blackout was initiated after the peak had been reached and demand was in decline. The loads were substantially lower on August 15, 2020. Again the rolling blackouts were initiated after the peak load had occurred and the load was in decline.[133]

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[131] Ibid, Figure B.36: Total Day-Ahead Scheduled Exports by Category, p. 122.
[132] The Companies' Modeling Testimony, p. 158, n.131. "Generation added last 10 years = . . . 3,860 MW CCs (Dan River, WS Lee, Asheville, Lee, Sutton CCs) . . ."
[133] *See* **Exhibit 1** hereto, California Public Utilities Commission, Rulemaking R.20-11-003 (Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure

**Q. WHY IS IT IMPORTANT THAT THE RELIABILITY OF IMPORTS WAS NOT A FACTOR IN THE CAISO AUGUST 2020 BLACKOUTS?**

A. It is important to avoid over-procurement by the Companies based on the erroneous concept that non-firm imports are not reliable. Mr. Holeman correctly points-out that about 20 percent of the supply utilized by California utilities in the CAISO control area is imported power.[134] This contrasts with the 4 percent imported power contribution to the Companies' supply to meet the actual winter peaks in the winters of 2020/2021 and 2021/2022. He then incorrectly asserts that "This has presented problems when increasing temperatures across the broader region divert non-dedicated resources."[135] The demand when CAISO initiated the first blackout was at a typical 1-in-2 summer peak level. The second blackout was initiated the following day at an actual demand well below the 1-in-2 summer peak level. What matters is the magnitude of the load that must be met. "Increasing temperatures" had nothing to do with CAISO's failure to meet the demand on those two August 2020 days.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

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Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021), Prepared Opening Testimony of Bill Powers, P.E., On Behalf of the Protect Our Communities Foundation, January 11, 2021, p. 2.

[134] The Companies' Reliability Testimony, p. 78.

[135] Ibid.