STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

BEFORE THE UTILITIES COMMISSION

IN THE MATTER OF:	)
Duke Energy Progress, LLC, and Duke	)
Energy Carolinas, LLC, 2022 Biennial	)
Integrated Resource Plans and Carbon	)
Plan	)

COMMENTS AND ISSUES OF THE

CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION

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The passage of House Bill 951 (HB951) presents an historic opportunity for North Carolina to modernize its electric power system, dramatically reduce carbon emissions, and protect North Carolina ratepayers from cost uncertainty and rising fuel prices.

Under HB951, the North Carolina Utilities Commission (Commission) has been charged with the task of adopting a Carbon Plan that dramatically reduces carbon emissions from the Duke Energy generation fleet at least cost while preserving system reliability. While the Carbon Plan filed by Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP) (collectively "Duke Energy") is a big step in the right direction, it does not satisfy the requirements of HB951. Simply stated, the Carbon Plan does not take all reasonable seps toward achieving the carbon reduction mandates of HB951 and fails to reduce carbon emissions at the least cost. It leaves opportunities on the table to protect ratepayers and prepare North Carolina for the changes required by HB951 – opportunities the Commission should seize.

EXECUTIVE SUMMARY

The Carolinas Clean Energy Business Association (CCEBA) makes the following comments and recommendations, detailed in the sections below:

- **HB951 requires the Commission to take all reasonable steps to reach 70% reduction of CO_2 from 2005 levels by 2030, by the least cost method which maintains or improves the stability and reliability of the grid. Duke Energy's four portfolios do not achieve those required results, and three of them seek extensions of time that have not yet been proven necessary.**

- **CCEBA agrees with Duke Energy that the Commission should adopt a Near-Term Execution Plan to begin work on those elements that would be consistent with all potential 2030 Carbon Plans portfolios have in common.**

- **Duke Energy's constraint on solar procurements in the first three to four years of the Carbon Plan is unwarranted, skews the Near-Term Execution Plan, and increases the cost of the Carbon Plan for ratepayers. Due to the negative impact on ratepayers, the Commission should forcefully question and push back on the premises behind Duke Energy's proposed solar cap.**

- **CCEBA recommends comprehensive transmission planning reform and urges the Commission to direct Duke Energy to take steps to reform the NCTPC process in order to advance the stated policy of HB951 and the Carbon Plan through long-term, proactive and holistic transmission planning that will allow for the least-cost, timely integration of new low carbon resources.**

- **In the meantime, CCEBA supports the "Red Zone" transmission upgrades set forth in Appendix P to the Carbon Plan as critical steps to allow the required volumes of solar to move forward at least-cost by 2030.**

- **Duke Energy's Carbon Plan places unjustified faith in the development of Advanced Nuclear and green hydrogen technologies, skewing its cost estimates in favor of Advanced Nuclear and new gas generation and against solar, storage, and wind.**

- **CCEBA recommends a Near-Term Execution Plan that lifts the cap on solar, mandates a procurement of both stand-alone storage and Solar+Storage, and encourages the development of offshore wind resources in North Carolina.**

- **CCEBA recommends beginning an immediate stakeholder process to develop a Solar+Storage PPA that adequately compensates developers, incentivizes the addition of storage to solar projects, and allows Duke Energy to dispatch the storage associated with Solar+Storage, as required by HB951. CCEBA believes that all solar procured through HB951 after 2022 should be paired with energy storage, and recommends the Commission direct Duke Energy to model the dispatch of energy storage, including storage associated with Solar+Storage.**

- **CCEBA supports Duke Energy's recommendation to "shrink the challenge" through adoption of energy efficiency and grid edge programs, but urges the Commission to use reasonable assumptions about the achievable volume of savings.**

- **CCEBA supports Duke Energy's proposal to consolidate system operations across DEP and DEC, including Balancing Authorities, Transmission Operators, Transmission Service Providers, and Transmission Planners as during the near term of the Carbon Plan (2022-2024).**

INTRODUCTION

CCEBA is a non-profit organization formed under the laws of North Carolina. CCEBA is organized for the purpose of promoting and advocating public policy positions supportive of renewable power generation in North and South Carolina. CCEBA is a 501(c)(6) organization representing businesses in the clean energy sector, including a range of clean energy project developers, manufacturing, engineering, construction, professional and financial services, and non-energy businesses wishing to purchase clean energy. With over 60 members, including most of the utility-scale solar developers in North and South Carolina, onshore and offshore wind developers, battery storage developers and other energy businesses, CCEBA monitors and participates in energy policymaking in both Carolinas.

CCEBA's discussion of the Carbon Plan submitted by Duke Energy is not intended as a comprehensive analysis of the modeling inputs and data used to produce the Carbon Plan, which is the province of experts in modeling and economics, many of whom have been engaged by other Intervenors. CCEBA will review their findings and engage in discussions and any necessary evidentiary proceedings as the Carbon Plan docket proceeds.

Rather, this document is intended as a high-level review of the Carbon Plan with more intensive comment on several specific areas that are highly relevant to CCEBA and its members. First, CCEBA analyzes the legal requirements of HB951 pertaining to the development of a Carbon Plan and discuss whether the proposed Carbon Plan meets those requirements. Second, we address those parts of the Carbon Plan with which CCEBA agrees. Third, we address specific ways in which the Carbon Plan can and must be improved. Fourth, we recommend elements of the Near-Term Action Plan that should be adopted. Fifth, we respond to each of the requests for relief set forth in Duke Energy's Petition. And finally, we list issues for evidentiary hearing.

DISCUSSION

I. Background

As Duke Energy notes in the first chapter of the Carbon Plan, in the last twenty years North Carolina has begun a "transition away from continued reliance on emissions-intensive resources."[1] Duke Energy states that collectively, DEP and DEC have "retired approximately 4,400 MW of aging, inefficient coal-fired generation… in the last decade,

[1] Carbon Plan, Ch. 1, p. 2.

the Companies' solar resources have grown to approximately 4,350 MW of installed solar in the Carolinas."[2]

North Carolina's solar industry has played a key role in this transition. Since the passage of Senate Bill 3 in 2007, which established the REPS standards, North Carolina has seen the installation of over 7,900 MW of solar energy facilities,[3] ranking fourth in the nation, and the solar industry has invested over $10 billion in North Carolina.[4] North Carolina's solar industry presently employs over 8,000 North Carolinians.[5]

Through projects developed under the Public Utility Regulatory Policies Act (PURPA) and more recently through the Competitive Procurement of Renewable Energy (CPRE) under North Carolina House Bill 589 (HB589), the utility-scale solar industry has been on a strong path year over year to reducing costs, increasing efficiency, and delivering carbon-free, locally sourced power. CCEBA and other renewable energy advocates have worked at every stage to encourage both Duke Energy and the state to accelerate this progress and maximize the long-term benefits of clean energy for North Carolina ratepayers.

II. Discussion of HB951

Building on this progress, the North Carolina General Assembly enacted and Governor Cooper signed Session Law 2021-165, referred to as HB951. It requires a fundamental shift in the way North Carolina generates electricity, and mandates that

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[2] *Id.*
[3] SEIA State Solar Spotlight 2022 – North Carolina, available at http://www.seia.org/states (Attached as **Exhibit A**). This number includes facilities other than those in Duke Energy territory.
[4] *Id.*
[5] US Energy & Employment Report 2021, available at https://www.energy.gov/sites/default/files/2021-07/USEER%202021%20State%20Reports.pdf, p. 234 of 359. (North Carolina pages attached as **Exhibit B**).

these changes occur quickly. Several of its provisions speak directly to the requirements of a Carbon Plan to be adopted by the Commission.

A. Carbon Dioxide Reduction Goals and Timelines

The centerpiece of the Act is a *requirement* that the Commission "take all reasonable steps to achieve a seventy percent (70%) reduction in emissions of carbon dioxide (CO2) emitted in the State from electric generating facilities owned or operated by electric public utilities from 2005 levels by the year 2030 and carbon neutrality by 2050."[6]

In order to accomplish the 70% reduction, HB951 tasks the Commission to:

> Develop a plan, no later than December 31, 2022, with the electric public utilities, including stakeholder input, for the utilities to achieve the authorized reduction goals, which may, at a minimum, consider power generation, transmission and distribution, grid modernization, storage, energy efficiency measures, demand-side management, and the latest technological breakthroughs to achieve the least cost path consistent with this section to achieve compliance with the authorized carbon reduction goals (the "Carbon Plan").[7]

The Act provides narrow exceptions to the 2030 date. First, the Commission retains the sole discretion to:

> determine optimal timing and generation and resource-mix to achieve the least cost path to compliance with the authorized carbon reduction goals, including discretion in achieving the authorized carbon reduction goals by the dates specified in order to allow for implementation of solutions that would have a more significant and material impact on carbon reduction. provided, however, the Commission shall not exceed the dates specified to achieve the authorized carbon reduction goals by more than two years, [8]

The only justifications allowed under HB951 for an extension of the 70% reduction by 2030 mandate for more than two years are: (i) "in the event the Commission

[6] HB951, Part I, Sec.1.
[7] HB951, Part I, Sec. 1(1).
[8] HB951, Part I, Sec. 1(4).

authorizes construction of a nuclear facility or wind energy facility that would require additional time for completion due to technical, legal, logistical, or other factors beyond the control of the electric public utility" or (ii) "in the event necessary to maintain the adequacy and reliability of the existing grid."[9]

CCEBA submits that "authorizes construction of a nuclear or wind energy facility" must mean more than merely including nuclear or wind facilities as potential resources in a Carbon Plan.[10] There are many steps between that inclusion and the authorization of construction of a given facility. Indeed, the North Carolina General Statutes set out a clear process for authorizing the construction of electric generating facilities through the Certificate of Public Convenience and Necessity (CPCN) process.[11] Understanding that, if the Commission, in complying with an adopted Carbon Plan, authorizes the construction of such a facility through the issuance of a CPCN, and "technical, legal, logistical, or other factors beyond the control of the electric public utility" delay that construction, then the Commission may extend the compliance deadline to accommodate those uncontrollable delays. HB951 does *not* authorize the Commission to allow for a delay of more than two years solely because the utility wishes to include nuclear or wind resources in the Carbon Plan.[12]

Thus, the adopted Carbon Plan *must* achieve the 70% reduction by 2030 *unless* one of the following three specific findings is made: (1) the Commission decides to exercise its authority to extend the deadline by no more than two years to achieve the

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[9] *Id.*
[10] It should be noted that the two non-Duke Energy-related leaseholders in Federal waters off North Carolina have yet to indicate that they would require any additional time past 2030 to complete their projects to serve Duke Energy customers.
[11] *See* N.C. Gen. Stat. §62-110.1.
[12] Other offshore leaseholders could very well contend that their projects could be complete by 2030. Duke Energy does not provide proof otherwise.

optimal generation and resource mix to achieve 70% reduction by least cost means, or (2) by longer if the authorized construction of nuclear and wind facilities is delayed *due to factors beyond the control of the public utility* or (3) where a delay is *necessary* to maintain the adequacy and reliability of the grid.

B. Requirements for Least Cost and Reliability

HB951 requires that the Carbon Plan pursue the "least cost path" to achieving the above reductions, and that in developing the Carbon Plan, the Commission "[c]omply with current law and practice with respect to the least cost planning for generation, pursuant to G.S. 62-2(a)(3a), in achieving the authorized carbon reduction goals and determining generation and resource mix for the future."[13]

N.C. Gen. Stat. § 62-2(a)(3a) establishes as public policy of the State of North Carolina:

> (3a) To assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, *to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable*, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills;

At the same time, HB951 also requires that the Commission "[e]nsure any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid."[14]

[13] HB951, Part I, Sec. 1(2).
[14] HB951, Part I, Sec. 1(3).

Therefore, while the 70% required reduction in CO2 must take place at least cost and without hampering grid reliability, it nevertheless *must* be accomplished. One can conceive of HB951 as adding a third leg to a stool. Whereas before HB951, IRP planning and resource development was required to be done at least cost and sustaining reliability, while considering for planning purposes additional concerns such as procurement of renewable energy and retirement of coal generation, HB951 elevates reduction of CO2 emissions to an equal footing with the prior concerns. In short, the Commission and Duke Energy cannot choose not to comply with the 70% reduction in order to reduce costs. Compliance *must* be achieved in the least cost manner that maintains reliability.

The goal of the Carbon Plan process therefore must be to maintain and improve upon the reliability of the electrical system in North Carolina, reduce carbon dioxide emissions *and* protect ratepayers. As discussed below, these goals can be achieved through continued procurement of renewable generation with no fuel costs and limited-to-no technology risk, large-scale adoption of multiple types of short and long-term storage, and, very importantly, improved transmission planning.

C. Duke's Carbon Plan Does Not Comply with HB951

While HB951 is clear that the Commission must approve a plan that achieves 70% reduction over 2005 levels of carbon by 2030, except in limited circumstances, the Carbon Plan proposed by Duke Energy fails to achieve this goal. As explained by Duke Energy, "[t]he Plan explores the risks and benefits of two pathways for achieving the interim 70% reduction target, with both pathways resulting in carbon neutrality of the systems by 2050. . . . one pathway achieves the 70% target by 2030 and the second pathway achieves the 70% target by 2034 through reliance on offshore wind and/or nuclear SMR generation technologies as is contemplated by HB951." Within the second pathway, Portfolio 2, relying on a deployment of 1.6GW of Offshore Wind, would achieve 70% reduction by 2032, while the other two portfolios, each involving reliance on deployment of SMRs, purport to achieve it by 2034.[15]

Of the four portfolios proposed by Duke Energy in its Carbon Plan, only one would achieve 70% reduction by 2030, and this portfolio is severely flawed by Duke Energy's adoption of an arbitrary and unjustified low cap on solar additions, which inflates the cost of the portfolio and reduces its chance of success. And while HB951 allows the Commission up to two years of flexibility in achieving this reduction to "allow for implementation of solutions that would have a more significant and material impact on carbon reduction," Duke Energy fails to explain why it needs extra time for compliance in its additional portfolios or how these options would satisfy the least cost requirement.[16]

Thus, Duke Energy does not show that additional time is necessary in order "to allow for implementation of solutions that would have a more significant and material impact on carbon reduction." Duke Energy's attempts to extend the compliance with the 70% reduction requirement by more than two years is not consistent with HB951's authorization of such a delay *only* where an authorized construction is delayed by factors beyond Duke Energy's control. Duke Energy's Carbon Plan also does not establish that any of these three portfolios would meet the requirements of HB951 to achieve the CO2 reduction by "the least cost path" or that reliance on these technologies – particularly SMRs – would be "reasonable" or even feasible by 2034. HB951 requires such a finding.

[15] Carbon Plan, Exec. Summ., at 10.
[16] Simply delaying action to defer costs is not consistent with the intent of HB951 or existing least cost principles.

III. Positive Attributes of the Carbon Plan

Despite its flaws, there are many aspects of the Carbon Plan proposed by Duke Energy that CCEBA can and does support. This list is not meant to be exhaustive, but merely a representation of the elements of the Carbon Plan that lend themselves to further development after input from all stakeholders.

First, CCEBA appreciates the obvious hard work that went into the assembly of the Carbon Plan itself. While CCEBA leaves to other intervenors the modeling and analysis of the data produced by Duke Energy, the document itself is a serious and detailed effort at presenting Duke Energy's vision of how it can achieve its objectives. CCEBA has reservations about some of the choices Duke Energy asks the Commission to make, but the Carbon Plan is a rational and thoughtful place from which to begin the discussions. That effort should not be overlooked.

Second, CCEBA agrees with Duke Energy on the concept of a Near-Term Execution Plan, under which the Commission approves those initial steps necessary to begin the progress toward achieving the 2030 mandate, regardless of generation portfolio, rather than deciding on a long-term plan immediately. CCEBA agrees that, properly selected, those near-term actions can be achieved and longer-term decisions reconsidered in the first bi-annual update to the Carbon Plan in 2024. While CCEBA does not recommend the adoption of Duke Energy's particular recommendations for near-term actions, the concept itself is reasonable.

Third, Duke Energy also discusses in its Carbon Plan the concept of "shrinking the challenge." CCEBA agrees that a broad spectrum of load reduction efforts through Energy Efficiency and Grid Edge programs. CCEBA supports this concept and the efforts outlined in the Carbon Plan as well as those likely to be proposed by other Intervenors.

CCEBA however cautions the Commission against overly optimistic assumptions of the results of these efforts, which could lead to an artificially low forecast for the need for clean and renewable generation.

Fourth, and crucially, CCEBA supports Duke Energy's proposal in Appendix R of the Carbon Plan to consolidate system operations across DEP and DEC, including Balancing Authorities, Transmission Operators, Transmission Service Providers, and Transmission Planners as during the near term of the Carbon Plan (2022-2024).[17] In particular, this reform will ameliorate the obvious problem of much of the renewable resources to be added under the Carbon Plan being added to the DEP territory, including offshore wind off the North Carolina coast. Without this consolidation, those resources located in the DEP territory will likely produce more energy than needed by the load on the DEP system. Moreover, the DEC system is, at least in the short term, likely to have more long-term storage options with the presence of the Bad Creek and Jocassee pumped hydro storage facilities. As a result, generators in the DEP territory could face curtailment at a greater rate than resources located in DEC. Moreover, the cost of integrating resources predominately located in the DEP territory would be reflected on the bills of DEP ratepayers but not DEC ratepayers.[18] Unifying the NERC functions and transmission planning functions of the two companies would reduce these risks and result in a more equitable system, both for generators and customers.

Fifth, CCEBA supports the "Red Zone" transmission upgrades discussed in Appendix P of the Carbon Plan as necessary to the maximization of Near-Term

[17] Carbon Plan, Appx R, at 1-2.
[18] *See* Carbon Plan, Chapter 3, Figure 3-12, showing average monthly and compound annual growth rate of DEP customer bills is greater than DEC customer bills in all portfolios.

renewables capacity, particularly in the DEP area. In prior years, Duke Energy has contended that transmission constraints limit the interconnection of projects in areas identified as the Red Zone. Quantified by Duke Energy in its Carbon Plan, "in the recent DEP Transitional Cluster Study, 35 out of 43 resources requesting interconnection, representing 1,4454.9 MW, showed some level of dependency on what are known as the Fresian projects (now withdrawn queue number Q380) network upgrades."[19] Additional areas of constraint identified in the Transitional Cluster Study process and in various generator interconnection studies are also in need of upgrades.[20] While CCEBA believes that more fundamental transmission process reform is required, as discussed below, the organization supports the inclusion of the identified Red Zone upgrades in Table P-3 of the Carbon Plan as an important part of any Near-Term Execution Plan.

IV. CCEBA Critique and Recommendations

A. Reject The Solar Cap - Imposing Initial Interconnection Restrictions On the Encompass Modeling Unfairly Skews All Portfolios Against Increased Solar

CCEBA strongly objects to the "cap" in new solar during the first few years of all of Duke Energy's proposed portfolios. These caps will harm North Carolina ratepayers by forcing the procurement of higher cost and higher risk technologies, where modeling would otherwise have selected solar as a least-cost resource. Duke Energy proposes two potential interconnection scenarios – high and low – both of which limit interconnection in 2027 to 750MW and in 2028 to 1,050MW. The procurements of these levels are then

[19] Carbon Plan, Appx. P, at 12.

[20] Over half of the potential projects in the July 2022 DISIS are in areas determined by Duke Energy to be congested Red Zones. *See* DEP: https://www.oasis.oati.com/cpl/ and DEC: https://www.oasis.oati.com/duk/

built into the Near-Term Execution Plan proposed by Duke Energy as its preferred initial actions to pursue the Carbon Plan. Table I-2 in the Carbon Plan details these scenarios:

Table I-2: Maximum Solar (MW) Allowed to Connect Annually (by Jan. 1 of year shown)

Beginning of Year	2027	2028	2029	2030+
70% by 2034 with Wind or Nuclear	750	1,050	1,350	1,350
70% by 2030	750	1,050	1,800	1,800

In discussing its Execution Plan, Duke Energy makes clear that it is the first, lower solar procurement approach that it intends to pursue: "Subject to further guidance from the Commission, the Companies are targeting 1,000 MW to be procured in the 2023 solar procurement and 1,350 MW to be procured in a potential 2024 solar procurement (totalling 3,100 MW in the near term including the 750 from 2022 SP Program)."[21]

Although Duke Energy fails to provide a clear justification, let alone convincing evidence, for its arbitrary solar constraints, it states that "[b]ased partially on the historic maximum of nine solar transmission interconnections in a year and an assumption of an average solar facility size of 80 MW, the Companies targeted 750MW to be connected in 2026."[22] Duke Energy then goes on to state that "the average annual new solar capacity added to the grid since 2015 is approximately 520MW. In fact, the annual interconnection capacity only exceeded 700MW in two years (2015 and 2017)."[23] When asked in discovery to provide underlying data supporting the limitations in Table I-2, Duke Energy responded that it did not have "specific underlying calculations for the annual selection constraints" because the limitations were based on unspecified "engineering judgement and transmission planning experience."[24]

[21] Carbon Plan, Ch. 4, Execution Plan, at 17-18.
[22] *Id.*
[23] *Id.* at 7.
[24] Duke Energy Response to NCSEA and SACE DR 3-30. (Attached as **Exhibit C**).

Duke Energy, however, has been able to mount large interconnection efforts in past years in response to state public policy. As noted in Appendix I of the Carbon Plan, in prior years "the State incented a truly unparalleled amount of 5 MW and smaller utility-scale solar generation," such that "the Companies' nation-leading solar historic interconnection success is even more remarkable given that such outcomes required interconnection of *hundreds* of distribution-connected utility-scale projects."[25] The interconnection of far lower numbers of higher-capacity projects under the Carbon Plan should therefore be possible. In other words, if hundreds of 5MW projects can be connected in a short timeframe, a much lower number of 80MW projects should not be the insurmountable challenge claimed by Duke Energy.

By not at least modeling an unconstrained solar interconnection in the first few years of the Carbon Plan, Duke Energy has prevented a true comparison of cost and capability. Without a baseline that shows what the model would have generated without these caps, it is difficult if not impossible for the Commission to determine whether the proposed portfolios are reasonable or achieve "optimal timing and generation and resource-mix to achieve the least cost path to compliance" as required by HB951.

If, after developing a less constrained model, the Commission were to be convinced by material evidence that it is necessary to delay 70% compliance until 2032 or assume a gradual increase in interconnections over the first few years due to established, proven interconnection constraints and concerns about the stability of the grid, then the Commission retains the discretion to take those steps. But currently, Duke Energy has not presented that evidence.

[25] Carbon Plan, Appx. I, at 6 (emphasis added).

It is worth noting that Duke Energy's constrained approach is not consistent with plans adopted by other utilities around the country, which forecast larger, and in some cases far larger, volumes of interconnection during the same timeframe. The table below describes some of those predicted volumes, and provides links to the documents referenced:

Resource Plan/RFP	Summary	Source
NextEra Real Zero Resource Plan	Plans 86 GW of solar additions to FPL by 2045, an average of 4 GW/yr. Realistically, given ramp-up period, this will likely require 4.5-5.0 GW/yr average additions starting 2025-2026. (see page 14 of blueprint)	https://www.nexteraenergy.com/content/dam/nee/us/en/pdf/NextEraEnergyZeroCarbonBlueprint.pdf
Entergy 2022 Resource Plan	Entergy announced in June 2022 that it is now forecasting up to 17 GW of renewable additions by 2031 (see pg 31 of recent investor presentation). Assuming this capacity don't start coming online substantially until 2026, this will require adding up to ~3.4 GW/yr on average.	https://entergycorporation.gcs-web.com/static-files/2a90a616-8405-4f74-b76b-97b579dd0f18
TVA 2022 RFP	TVA procuring 5 GW of CO2-free resources, planned for commercial operation by 2029. Assuming 4.5 GW of this is placed in service from 2026-	https://www.tva.com/newsroom/press-releases/tva-issues-one-of-the-nation-s-largest-requests-for-carbon-free-energy

	2029, this entails 1.13 GW/yr of resource additions.	
Dominion Energy VA Resource Plan	VA Clean Economy Act (VCEA) calls on DOM to procure 21.3 GW of renewables by 2035; assuming those resources are online by 2039, and assuming the first resources come online in 2025, this translates to ~1.5 GW/yr avg. installation rate.	https://lis.virginia.gov/cgi-bin/legp604.exe?201+sum+HB1526
CPUC 2022 Resource Plan	Plans for 25.5 GW of renewables and 15 GW of storage/DR to be added by 2032. Assuming this capacity don't start coming online substantially until 2026, it will require adding ~4.3 GW/yr of renewables on average.	https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-approves-long-term-plans-to-meet-electricity-reliability-and-climate-goals
NY Climate Leadership and Community Protection Act	To reach CLCPA's 70% renewable electricity by 2030 target, the state will need to procure up to 2 GW/yr of	https://cleanenergynews.ihsmarkit.com/research-analysis/new-york-state-approves-first-expedited-power-project.html

	renewables (4,500 GWh/yr)	
Entergy 2022 RFPs	Seeking 3 GW of renewable capacity (1.5 GW Louisiana, 1.0 GW Arkansas, 500 MW Mississippi)	https://pv-magazine-usa.com/2022/07/06/entergy-seeks-to-grow-renewables-up-to-2500-over-next-decade/
PS Oklahoma Q4 2021 RFP	Seeking 4.15 GW of renewable capacity (2.8 GW wind, 1.35 GW solar)	https://www.prnewswire.com/news-releases/pso-issues-requests-for-proposals-for-purchase-of-wind-and-solar-generation-resources-301426753.html
Dominion Virginia 2022 RFP	Seeking 1.2 GW of solar and onshore wind	https://news.dominionenergy.com/renewable-development-projects
Duke Energy Indiana 2022 RFP	Seeking 1.1 GW of renewable capacity	https://www.renewablesnow.com/news/duke-energy-targets-expansion-plans-11-gw-renewables-rfp-773761/
Indiana Michigan Power 2022 RFP	Seeking 1.3 GW of renewables	https://www.prnewswire.com/news-releases/im-seeks-detailed-proposals-for-1-300-mw-of-solar-wind-energy-301503013.html
Georgia Power Q4 2021 RFP	Seeking 1 GW of renewables	https://www.prnewswire.com/news-releases/georgia-power-continues-renewable-energy-expansion-by-seeking-1-000-mw-of-new-generation-301418902.html
Arizona Public Service 2022 RFP 2021 RFP	Seeking 800 MW of renewables	https://www.solarpowerworldonline.com/2022/05/arizona-public-service-is-seeking-proposals-for-solar-storage-projects/

Table 1

Moreover, Duke's more constrained pace of interconnections runs counter to the Federal Energy Regulatory Commission's (FERC) policy as expressed in the , 2022 Notice of Proposed Rulemaking ("Transmission NOPR").[26] Noting that many of the nation's transmission providers, including Duke Energy, had exceeded interconnection study deadlines for more than 25% of any study type for two consecutive quarters,[27] the Transmission NOPR proposes to eliminate the "reasonable efforts" standard and to impose financial penalties on transmission providers who do not meet study deadlines.[28] FERC found in the Transmission NOPR that "timely provision of interconnection service is critical to maintaining just and reasonable rates."[29] These and other reforms in the NOPR are aimed at one thing: accelerating the pace of transmission and interconnection of new resources throughout the United States.

Duke Energy's arguments for why it should restrict additions of new solar thus are not consistent with other utilities or Federal policy, and it has simply not justified these restrictions in the first four years of the Carbon Plan. The Commission should require an unconstrained model run and consider material evidence to determine what level of procurement will best comply with the requirements of HB951. Artificially limiting solar, as Duke Energy proposes, could cause significant harm to North Carolina ratepayers by forcing the procurement of higher-cost resources.

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[26] Building for the Future Through Electrical Regional Transmission Planning and Cost Allocation and Generator Interconnection, 179 FERC ¶ 61,028 (Docket No. RM21-17-000) (Issued April 12, 2022) (to be codified at 18 CFR Pt. 35) ("Transmission NOPR") (can be found at https://www.ferc.gov/media/rm21-17-000).
[27] *Id.*, para. 165.
[28] *Id.*at paras. 168, 169.
[29] *Id.* at para. 167.

B. <u>The Duke Energy Portfolios Are Too Reliant on Unproven Technology Which May Not Achieve Commercial Viability</u>

A review of the Carbon Plan portfolios advanced by Duke Energy shows that the company intends to rely in the long term to a significant degree on advanced nuclear technology such as Small Modular Reactors (SMR) and the eventual replacement of natural gas with green hydrogen. Duke Energy also includes onshore and offshore wind production in technologies it calls "new to the Carolinas."[30] However, as discussed below, wind is a mature technology, especially when compared to SMRs and green hydrogen, and should be considered separately. Dependence on SMRs and green hydrogen brings with it substantial risk and uncertainty. Constraining shorter term options such as solar, storage, and wind power based on an assumption that these riskier technologies will be available in later years is dangerous. If the technologies do not develop as hoped, the opportunity to achieve carbon reduction earlier and at a lower cost to ratepayers is lost. If, on the other hand, these technologies develop, then they may still be part of the ultimate solution in the long-term, and future ratepayers will benefit.

1. Advanced Nuclear Reactors, While Promising, Are Risky and Do Not Warrant Restricting Existing Renewables and Storage

The first risky bet that Duke Energy places in its Carbon Plan is on advanced nuclear and small modular reactors (SMRs). "To further the energy transition and meet the CO2 emissions reduction target, Duke Energy is planning to move forward with the development of advanced nuclear in the Carolinas."[31] Duke Energy acknowledges in Appendix L of the Carbon Plan that there are only "four new advanced nuclear plants

[30] Carbon Plan, Exec. Summ., at 3; Appx. E., at 33-37.
[31] Carbon Plan, Appx. L, at 10.

scheduled to be built and in commercial operation by the end of this decade: two SMRs and two advanced reactors."[32] Nevertheless, Duke Energy proscribes a Near-Term and Long-Term execution plan that would aim to have an advanced reactor in service in North Carolina by 2032.[33]

This optimistic view of the possibilities of SMRs and advanced reactors is not shared by many experts. A recent article in opposition to the adoption of SMRs in the Bulletin of the Atomic Scientists argues such a technology would have difficulty competing on a cost basis with more established methods of generation, such as solar and both onshore and offshore wind:

> For small modular reactors to consistently achieve the same costs as the present large reactors would be a monumental task. And at that point, small modular reactors would still be an economic failure, given the high costs of large reactors. The Wall Street firm, Lazard, estimates the average cost of utility-scale solar and wind power is approximately $40 per megawatthour; the corresponding average figure for large nuclear plants is about $160, four times as high, and the upper end of the range is as much as $198 (Lazard 2020).[34]

A more optimistic view can be found in The Breakthrough Institute's July 6, 2022, analysis. That report describes advanced nuclear as having great potential to play a significant role in advancing the clean energy transition, but notes the investment required:

> Inclusion of advanced nuclear designs among the available technology options for a clean energy transition leads to large-scale advanced reactor deployment as part of a least-cost pathway to a clean electricity future. However, the degree to which the United States can successfully develop an advanced nuclear energy sector over the next 15 years will crucially

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[32] *Id.* at 9.
[33] *Id.* at 10.
[34] Arjun Makhijani & M. V. Ramana (2021) "Can small modular reactors help mitigate climate change?", Bulletin of the Atomic Scientists, p. 208, 77:4, 207-214, DOI:10.1080/00963402.2021.1941600 (Available at: https://doi.org/10.1080/00963402.2021.1941600) (Attached as **Exhibit D**).

> depend upon mobilizing sufficient capital investment and public policy support starting immediately from the present day.[35]

The Breakthrough Report recommends substantial federal and state participation in incentivizing and capitalizing advanced nuclear technology, including Federal loan guarantees, conducting Environmental impact pre-qualification and feasibility studies, regulatory licensing modernization and fee reform, technology-neutral clean energy tax credits, inclusion of nuclear energy in state clean energy portfolio standards, and support for export of advanced nuclear projects.[36] In its Carbon Plan, Duke Energy acknowledges that these technologies are not yet economically viable, stresses the importance of "aggressive" Federal Government investment to bring them to market, and notes that Duke Energy itself has participated in that development.[37] Such Federal support will need to continue and increase for there to be any hope of economically viable advanced nuclear.

In addition to the technology and cost risks of advanced nuclear and SMRs, the technologies bear significant operational risks as well. Foremost among these is the production and treatment of nuclear waste, which remains a significant issue with advanced nuclear and may, in some cases, be worse than that which has bedeviled traditional nuclear power plants.

One recent assessment of the impact of three different types of SMRs "on the management and disposal of nuclear waste relative to that generated by larger commercial reactors of traditional design" found that "relative to a gigawatt-scale

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[35] Dr. Adam Stein, Jonah Messinger, Dr. Seaver Wang, Juzel Lloyd, Jameson McBride, & Rani Franovich (2022) "Advancing Nuclear Energy – Evaluating Deployment, Investment, and Impact in America's Clean Energy Future", The Breakthrough Institute, at 21 (available at https://thebreakthrough.org/articles/advancing-nuclear-energy-report) ("the Breakthrough Report") (Attached as **Exhibit E**).
[36] Breakthrough Report at 6.
[37] Carbon Plan, Appx. L., at 66-7.

[Pressurized Water Reactor], these reactors will increase the energy-equivalent volumes of [Spent Nuclear Fuel] (SNF), long-lived Low and Intermediate Level Waste (LILW), and short-lived LILW by factors of up to 5.5, 30, and 35, respectively."[38] The study went on to conclude that "SMR waste streams will bear significant (radio-)chemical differences from those of existing reactors. Molten salt– and sodium-cooled SMRs will use highly corrosive and pyrophoric fuels and coolants that, following irradiation, will become highly radioactive. Relatively high concentrations of ^{239}Pu and ^{235}U in low–burnup SMR SNF will render recriticality a significant risk for these chemically unstable waste streams."[39] The study concluded that, though it only analyzed three types of proposed reactors, "these findings are driven by the basic physical reality that, relative to a larger reactor with a similar design and fuel cycle, neutron leakage will be enhanced in the SMR core. Therefore, most SMR designs entail a significant net disadvantage for nuclear waste disposal activities."[40]

CCEBA does not contend that there is no role for advanced nuclear energy to play in the transition away from carbon-intensive generation such as coal and natural gas. CCEBA therefore does not oppose the elements of Duke Energy's Near-Term Execution plan relating research and investigation of advanced nuclear. However, especially in light of the concerns and risks discussed above, it is essential that that execution plan be sufficient to support Carbon Plan portfolios that do not rely on new nuclear to achieve the 70% decarbonization mandate of HB951.

[38] LM Krall, AM Macfarlane, and RC Ewing, "Nuclear Waste from Small Modular Reactors" Proceedings of the National Academy of Sciences (2022), Vol. 119, No. 23, at 10 (available at https://www.pnas.org/doi/pdf/10.1073/pnas.2111833119) (Attached as **Exhibit F**).
[39] *Id.*
[40] *Id.*

2. Green Hydrogen Also Has Risks Which Do Not Warrant Increased Investment in Natural Gas Resources Instead of Existing Renewables and Storage

Duke Energy's Carbon Plan modeling "includes 3.600-3,900 MW of economic gas resources (along with 4,000-6,000 MW of economically included energy storage) to enable retirement of 8,400 MW of coal generation and integrate 12,700-17,200 MW of renewables subject to interim CO2 reduction targets consistent with HB951." (Carbon Plan, Appx. M at 6.) Much of this additional natural gas generation is proposed to be developed during the Near-Term Execution plan. Table 3 of the Executive Summary calls for two new Combustion Turbines totaling 800 MW by 2027-2028 and one new Combined Cycle plant at 1,200 MW by 2027-2028, as well as a potential second 1,200 MW CC to be submitted in 2024 and operational by 2030.[41]

While the need for this amount of new natural gas generation is a function of the model, which will be subject to significant critique by other Intervenors, there is no doubt that Duke Energy seeks a substantial investment in natural gas generation to provide flexibility in responding to load while integrating renewable generation onto the system and retiring uneconomic coal assets.

The problem is that gas infrastructure is likely to be uneconomic before the end of the planning period under HB951. These assets would normally have a 40-year engineering lifetime, but with climate risk and the 2050 net-zero mandate of HB951 gas plants will face an operational lifetime far shorter than that. A recent report from the Energy Transition Institute evaluated the planned natural gas investment in Duke Energy's 2020 IRP which was, admittedly, much larger than that anticipated by the

[41] Carbon Plan, Exec. Summ., Table 3-3.

Carbon Plan portfolios. The report found that the proposed 6.1 – 9.1 GW of new natural gas generation in that IRP would present a risk to ratepayers of over $4.8 billion in stranded asset costs over the lifetime of the assets.[42] The investments set out in the Carbon Plan are lower, but no less subject to the risk of becoming stranded assets.

Duke Energy, however, notes that the new units "will be designed for high flexibility (ramping, turndown, cycling ability) needed with a high renewables presence and also with a future hydrogen transition in mind. Hydrogen blending with natural gas and eventually 100% hydrogen use will lower any future CT/CC's carbon footprint over time."[43] By using hydrogen, Duke Energy hopes to extend the useful economic life of its gas assets and thereby avoid both emissions and the stranded asset problem. However, even Duke Energy notes that this is a long-term play, and that the hydrogen market is not sufficiently mature to forecast supply, particularly of the green hydrogen which would be required to prevent upstream emissions from cancelling out the benefit of burning hydrogen.[44]

Duke Energy proposes hydrogen blending with natural gas to fire its natural gas fleet: "Hydrogen blending is represented with a starting point of approximately 3% in 2035 and ramps up in several steps to approximately 15% in the early 2040s and holding steady thereafter"[45] The Carbon Plan then would build new peakers with 100% hydrogen

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[42] T. Fitch, "Carbon Stranding: Climate Risk and Stranded Assets in Duke's Integrated Resource Plan" January 2021, at 48. (Available at: https://energytransitions.org/report%3A-carbon-stranding) (Attached as **Exhibit G**).
[43] Carbon Plan, Appx. M, at 7.
[44] Carbon Plan, Appx. O, at 3.
[45] Carbon Plan, Appx. O. at 3.

capability after 2040[46] after which "hydrogen supply and use is expected to significantly grow and become an important component of achieving carbon neutrality by 2050."[47]

However, burning hydrogen is not without risks to equipment and the environment, and these challenges need to be overcome before hydrogen can be considered a viable clean energy option. In addition to damage to burners, injectors, and other infrastructure caused by the differing combustion qualities of hydrogen, burning hydrogen leads to significant increases in emissions of Nitrogen Oxide, a controlled pollutant.[48] One proposed 30% hydrogen project in Utah shows significant problems with controlling these emissions. "According to a report issued by the project's own developer, Mitsubishi, this mixture of hydrogen and natural gas '*will produce NOx and CO2 emissions equivalent to those from modern natural gas plants*.'"[49] The future of green hydrogen as a generation source is therefore quite risky.

3. *The Carbon Plan Should Not Bet on Long-Term Possibility to the Exclusion of Current Proven Technologies*

CCEBA does not discourage the exploration of all possible methods of reducing CO2 emissions to comply with the mandate of HB951. However, the Carbon Plan should not limit current application of proven technology on the hope that a technological *deus ex machina* will resolve the remainder of the problem after 2030. Both SMRs and the integration of green hydrogen into gas-fired generation facilities are promising but unproven technologies which bring with them substantial potential cost and risk. Solar

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[46] *Id.*
[47] *Id.*
[48] Lew Milford, et al., *Hydrogen Hype in the Air*, CLEAN ENERGY GROUP BLOG (December 14, 2020) https://www.cleanegroup.org/hydrogen-hype-in-the-air/#_ednref22 *See also,* ETN Global, *Hydrogen Gas Turbines: The Path Towards a Zero-Carbon Future*, European Turbine Network, (January 2020) https://etn.global/wp-content/uploads/2020/02/ETN-Hydrogen-Gas-Turbines-report.pdf.
[49] Milford (citing Mitsubishi Heavy Industries Group, *Renewable Energy Storage: Combining Existing Dry Low NOx Combustion Technology with Proven Hydrogen Storage and Production Approaches* 2020. https://www.changeinpower.com/wp-content/uploads/2020/03/MHPS-ACES-Proven-Technology.pdf).

and wind, along with battery storage, are available and scalable now and in the near future. Limiting early investment in proven clean and less expensive technologies such as solar and wind while relying on technology to rapidly improve and costs to rapidly fall in advanced nuclear to make up the gap between 2035 and 2050 is a strategy that risks failure and missed opportunity. On the other hand, continuing to aggressively develop mature technologies while exploring and preparing the way for additional ones to be developed is more defensible. CCEBA recommends the latter approach.

If the Commission allows reliance on SMRs and green hydrogen combustion technologies in planning the 2030 or 2035 portfolios, and Duke Energy is allowed to incur costs in the near term to pursue them, there should be equal efforts to explore technological solutions in the areas of faster integration of solar, long-term storage (such as compressed CO_2 and flow batteries), and transmission technologies such as advanced conductors that have equal or greater promise. The Commission should exercise healthy skepticism where the Carbon Plan relies on future technological advancement and should impose enforceable benchmarks and require regular updates from Duke Energy to control against runaway investment and cost. The cause of reducing CO_2 emissions and modernizing North Carolina's electric power system will not be served by repeating the bad bets made by the utility industry in such cases as the VC Sumner Nuclear Plant in South Carolina and the Vogtle Nuclear Plant in Georgia.

C. Transmission Planning Improvements Are Required for the Carbon Plan to Be a Success

CCEBA wholly supports the implementation of the Red Zone improvement transmission projects listed in Appendix P of the Carbon Plan (RZ Improvements), along with near-term transmission investments necessary to allow for the development of offshore wind resources. However, merely authorizing immediately necessary projects will not be sufficient to ensure the success of the overall Carbon Plan. In addition to those projects, the Commission should restructure the manner in which transmission improvements are considered in North Carolina. This restructuring is critical to ensuring the Carbon Plan requirements are met on time, in a least cost manner.

North Carolina, through the North Carolina Transmission Planning Cooperative, has historically relied on an incremental approach to determining what transmission and distribution improvement are necessary. Interconnection and cluster studies identify transmission and distribution needs to accommodate proposed generation. This incremental process was appropriate in the past, but as distributed generation has become a larger part of the generation fleet, has been at least partly responsible for significant delays in the completion of cluster studies, unaddressed transmission backlogs, and conditions like that faced in the areas of North Carolina identified as "Red Zones" by Duke Energy. As the Transmission NOPR makes clear, FERC expects planning entities to undertake more regional and proactive transmission planning to help resolve these backlogs and delays.

The Commission should require Duke Energy to undertake proactive resource planning effort that combines the generation planning set forth in the Carbon Plan with proactive transmission planning of the grid. While this approach will not identify all necessary upgrades to accommodate all new resources seeking interconnection, the selection of cost-effective system upgrades will provide a "road-map" for future development consistent with the Commission's policy choices and reduce the number of upgrades requested by specific interconnection requests.

Duke Energy has previously responded to inquiries about transmission upgrades and planning by saying that transmission was the province of the NCTPC, and not the Commission. This is a technically correct, but incomplete answer. CCEBA submits that rather than each agency conducting its own processes, with only occasional interface through Duke Energy, the process should be iterative and parallel, so that the resource decisions made by the Commission inform the efforts of Duke Energy and the NCTPC on a constant basis. Rather than a slower annual process, the NCTPC should be receiving instruction from the Commission based upon the resources and regional transmission needs required to implement the Carbon Plan and undertaking repeated long-term planning efforts to map out the most cost-effective solution for interconnection and transmission needs over the succeeding 10-20 years.

Through such efforts, the Commission can reduce total system costs and risks by incorporating realistic projections of the anticipated generation mix, policy mandates, load levels, and load profiles over the anticipated lifetime of a transmission investment, thus avoiding the risk of "buying" a new transmission asset only to need to improve it in only a few years. Further, such processes help the planners account for the full range of transmission project benefits – not just to the individual project or projects that request interconnection – but to the entire system, enabling investments to be cost-effective. A third benefit of proactive system planning is to allow scenario-based planning that addresses uncertainties and high-stress grid conditions across a number of potential conditions, including extreme events, so that selected transmission projects add to the resiliency and capacity of the grid.

Other regions have implemented similar reforms to their transmission planning process and can serve as models for the Commission, including SPP, CAISO, MISO, and NYISO.[50] Their programs and experience can inform the approach the Commission chooses to take.

CCEBA therefore urges the Commission to require proactive planning to guide development, keep costs manageable, and allow stakeholder participation in grid planning to a greater extent than the current system of reacting to individual projects. Should Duke Energy determine that the terms of its current Open Access Transmission Tariff do not allow such efforts, the Commission should require Duke Energy to seek the necessary amendments and FERC approval.

D. The Commission Should Select A Larger Amount of Standalone and Solar+Storage For Procurement in the Near Term.

1. *Storage Provides Substantial Benefit to the Grid and Improves the Performance of Renewable Generation.*

Storage, whether standalone or paired with solar (Solar+Storage), offers numerous benefits to the grid. In the 2018 Energy Storage Options for North Carolina report prepared by the North Carolina State Energy Storage Team for the Energy Policy Council and the Joint Legislative Commission on Energy Policy[51], the study authors identified numerous roles that in front of the meter storage could play in the specific context of North Carolina's energy grid. Those roles include: voltage support and control, reliability enhancement, capacity deferral and peak shaving, reducing the need for transmission investments by boosting capacity and reducing overloading, transmission

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[50] *See* Report of Brattle Group filed by the Clean Power Suppliers Association with their comments in this docket.

[51] NC State Energy Storage Team, *Energy Storage Options for North Carolina*, (December 2018) [hereinafter NC State Storage Report] https://energy.ncsu.edu/storage/wp-content/uploads/sites/2/2019/02/NC-Storage-Study-FINAL.pdf (Attached as **Exhibit H**).

congestion relief, peak capacity deferral, bulk energy "time shifting", frequency regulation, spinning and non-spinning reserves, black start capacity, flexible ramping, and synthetic inertia to provide fast responses in a system where the share of variable renewables is high.[52]

To different extents, these benefits can be provided either by stand-alone (and thus under HB951 utility-owned) storage or by hybrid systems in which the storage component is combined with PV solar (or other variable renewable resources.) With stand-alone storage, the basic operating mode is to charge when load is low and to discharge when load is high. In market-based systems, that demand would result in higher or lower energy prices and the opportunity to operate as arbitrage. The battery is operated on a daily (or diurnal) cycle, completing a roundtrip full charge and discharge within 24 hours. Additional operating modes may be applied as a response to certain system conditions to reduce curtailment or to provide other ancillary services to the system.

Embedded storage is combined with other resources such as solar, wind or other non-base load power plants. In a slightly modified form of arbitrage, the storage uses some of the generated power to charge during times when load is relatively low, and discharges the stored energy during times of higher demand, typically at peak load. Diurnal storage operation is tightly aligned with solar PV availability and less so with wind generation. In systems with a lot of solar generation, typical operating challenges relate to the sudden drop-off of supply in the late afternoon and early evening period,

[52] *Id.* at 11-13; the NC State Storage Report provides substantial detail and engineering analysis of all of these uses on pages 51 through 136. *See also,* Jennie Jorgenson, et al., *Grid Operational Impacts of Widespread Storage Deployment,* at p. 30 (2022). Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-80688. https://www.nrel.gov/docs/fy22osti/80688.pdf (Attached as **Exhibit I**).

which can force additional fast-start thermal generation to come online, and to the lack of supply from solar for night-peaking systems. Solar+Storage addresses both issues by allowing time-shifting of the solar generation to reduce the drop-off rate and to deliver more power for the nighttime peak.

Implementation of storage with increased implementation of solar also can bring financial benefits and may help control costs to ratepayers. As discussed in a recent NREL study:

> Increased levels of renewable energy may increase the need for frequency control services to manage increased variability and uncertainty in the power system. Increased levels of [renewable] penetration can also change the shape of the net load, or the load minus the [renewable] generation, influencing [Battery Electric Storage System (BESS)] projects that provide load following, arbitrage, peaking capacity, or similar services.
>
> Models of the California system have shown a strong relationship between solar PV deployment and BESS' ability to replace conventional peaking capacity, also known as the BESS capacity credit (Denholm and Margolis 2018). As the shape of the load curve affects the ability of storage to provide peaking capacity, resources such as PV that cause load peaks to be shorter will enable shorter duration batteries, which are less expensive, to displace conventional peaking capacity.[53]

It is therefore clear that storage, when combined with solar, enhances the value of the solar generation and can provide substantial operational and cost-saving benefits to the grid and end users. Duke Energy recognizes this potential value, but unfortunately its forecasted storage resources in its various portfolios are confusing, as discussed below.

2. The Carbon Plan's Storage Projections Are Confusing and Inconsistent

[53] Thomas Bowen, et al., *Grid-Scale Battery Storage Frequently Asked Questions*, GREENING THE GRID, at 6 (2019). Golden, CO: NREL. NREL/TP-6A20-7442. (Attached as **Exhibit J**) (citing Paul Denholm and Robert Margolis, *The Potential for Energy Storage to Provide Peaking Capacity in California under Increased Penetration of Solar Photovoltaics* (March 2018). Golden, CO: NREL NREL/TP-6A20-70905. https://www.nrel.gov/docs/fy18osti/70905.pdf).

The amount of new energy storage forecast in the Carbon Plan portfolios is inconsistent. In Chapter 3, Duke Energy sets out Table 3-3, showing that each of the portfolios set forth in the Carbon Plan anticipates differing amounts of incremental additions of storage through 2030 and 2035. Portfolio 1 calls for 2,067 MW of storage by 2030 and 5,671 by 2035[54] inclusive of "4-hour and 6-hour battery energy storage, battery energy storage at solar-plus-storage sites, and pumped storage hydro." (*Id.* at n. 4.) Portfolios 2-4 call for substantially less. (*See* Carbon Plan, Table 3-3.) However, in Appendix K (Energy Storage), Duke Energy states "Delivering on the HB951 70% interim target will require development of approximately 2,500 MW to 3,700 MW of storage, inclusive of 4-hr and 6-hr grid tied battery energy storage, battery energy storage at solar-plus storage sites, and pumped storage hydro, as discussed further in Chapter 3 (Portfolios)." (Carbon Plan, Appx. K at 8.)

These numbers are generally lower than those proposed in the analogous portfolios set forth in Duke Energy's 2020 IRP. For instance, in the 70% High Wind Portfolio in the IRP, Duke Energy forecasted needing 4,400 MW of incremental storage by 2035 in the combined system. In the Base Case with Carbon Policy – which would only achieve 62% reduction by 2035 – Duke Energy would add 2,200 MW of incremental storage by that date.[55] While the inputs, assumptions and methodologies of the IRP are not the same as those used in the Carbon Plan, and CCEBA is not suggesting they are an apples-to-apples comparison, the comparative volume is a useful point of

[55] 2020 Duke Energy Carolinas, LLC Integrated Resource Plan, at p. 16, Docket No. E-100, Sub 165, September 1, 2020.

analysis, calling into question whether the much lower 2,067 MW forecast in Portfolio 1 of the Carbon Plan would be sufficient to help achieve 70% reduction by 2030.

In another forecast of storage additions, the near-term (2022-2024) actions set forth in the Execution Plan (Chapter 4), Duke Energy proposes to "finalize procurement strategy and initiate procurement activities relative to procurement strategy for 1,600 MW of battery energy storage (1,000 MW stand-alone storage, 600 MW storage paired with solar)."[56] This same 1,600 MW (1,000 MW standalone plus 600 MW Solar+Storage) figure is described in the Executive Summary as a proposed resource selection "In-Service through 2029."[57]

It is thus unclear exactly how much storage Duke Energy intends to add and when.

3. *The Carbon Plan's Storage Forecasts Do Not Adequately Address the Differing Characteristics of Standalone and Solar+Storage*

Table K-2 from Appendix K below summarizes the Solar+Storage and the standalone storage options the model was able to choose from to meet the targets of the Carbon Plan.

Table K-2: Energy Storage Options in the Carbon Plan Modeling

Stand-alone Storage	Solar paired with Storage
50 MW / 200 MWh	75 MW solar + 20 MW / 80 MWh battery
50 MW / 300 MWh	75 MW solar + 40 MW / 80 MWh battery
50 MW / 400 MWh	

However, the Carbon Plan does not adequately describe the different performance and cost characteristics applied to standalone storage vs. Solar+Storage, which makes it impossible to understand if the mix of standalone storage vs. Solar+Storage is reasonable.

[56] Carbon Plan, Ch. 4, at 23.
[57] Carbon Plan, Exec. Summ., at 23.

In fact, on page 33 of Appendix E, when describing standalone batteries vs Solar+Storage, Duke Energy states that "standalone storage resources can charge from and dispatch to the grid, whereas storage paired with solar is assumed in the Carbon Plan to be DC-tied, and thus, only able to charge from the solar facility." (Carbon Plan, Appx. E at 33.) However, in response to discovery requests, Duke Energy concedes that DC-tied Solar+Storage can charge from the grid, with the ELCC values of the solar and storage being 100 percent additive.

To be clear, as acknowledged by Duke in response to discovery,[58] DC-coupled Solar+Storage utilizing bi-directional inverters *can* grid charge, and thus any charging constraint applied by the model should be lifted. This difference is important because the ability to grid-charge should increase the ELCC of a Solar+Storage resource, with the ELCC values of the solar and storage being 100% additive, thereby rendering it more competitive against other technologies in a model without these constraints.

For Solar+Storage resources, Duke Energy must further distinguish between whether a Solar+Storage facility is a co-located resource or a hybrid resource. For a co-located resource, the solar and storage share a point of interconnection but operate independently. Alternatively, for a Solar+Storage hybrid, the solar and storage share a point of interconnection, are physically coupled, and share a control system, such that the asset operates as a single resource. This distinction has modeling implications that need to be considered.

[58] *See* Duke Response to Attorney General's Office DR 3-4 (acknowledging that "the ELCCs of standalone solar and standalone storage were assumed to be additive for [Solar+Storage]," indicating that the storage element of a Solar+Storage project would be grid-chargeable) (Attached as **Exhibit K**).

Finally, Duke Energy should explain why AC-coupled Solar+Storage was excluded as a possible Solar+Storage configuration. AC and DC-coupled Solar+Storage systems have relative advantages and disadvantages based on their respective system architectures. In the case of AC-coupled Solar+Storage, there is no shared inverter at the POI and thus no shared interconnection limit, unless a shared interconnection limit is requested in a shared interconnection request. Unless otherwise limited, the interconnection capacity for AC-coupled Solar+Storage is the sum of the AC nameplate of the solar facility plus the AC nameplate of the energy storage. Thus, the solar and storage portions of an AC-coupled Solar+Storage asset could both be dispatched at max capacity simultaneously, unlike a DC-coupled Solar+Storage. On the other hand, DC-coupled Solar+Storage has a relatively higher round-trip efficiency at the point of measurement and can take advantage of DC-clipping that boosts specific production over the course of the year. However, in the case of DC-coupled Solar+Storage the maximum facility output would be limited to the shared interconnection limit of the PV nameplate requested, unless otherwise noted.

It is unclear whether an AC-coupled Solar+Storage would have additional ELCC value over a DC-coupled Solar+Storage, but this issue is worth further study and analysis, and Duke Energy should share that analysis with stakeholders and the Commission so that ELCC values are properly applied to DC-coupled vs AC-coupled Solar+Storage resources.

Tables E-61 through E-68 of Appendix E show the final annual resource additions and coal retirements for the four portfolios, and the tables break out the amount of energy storage that comes online categorized as either standalone energy storage or storage from

Solar+Storage. More clarity is needed on how the models chose between standalone storage vs. Solar+Storage, why the model could only choose stand-alone storage in years 2025 and beyond, and how the amounts per year were determined.[59]

Duke Energy should analyze and report on the trade-offs in value and costs between Solar+Storage and standalone energy storage to optimally address system needs and guide developer choices. Consider the analysis of hybrid/co-located assets vs. standalone energy storage assets in wholesale markets conducted by Berkeley Labs.[60] The report shows that coupling generators with storage can have benefits and drawbacks. Berkeley quantified the "coupling benefit," which included: tax credits, construction cost savings, cost savings from shared equipment and interconnection and permitting costs, capturing otherwise clipped energy, facilitating intraday energy shifting, and generally more dispatch flexibility.[61] They also quantified the "coupling penalty" of such projects vs. standalone energy storage that is sited optimally instead of being restricted by the location of the generator.[62]

Batteries sited independently can provide additional value to the local grid, such as congestion relief and volatility mitigation. The coupling penalty averaged $2.3/MWh across the seven organized wholesale markets. The coupling penalty can grow to $14/MWh if batteries are charged solely from the solar generator, if the interconnection capacity is limited to the solar generator's size, and if storage dispatch is operated with

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[59] In addition, these tables contain reference to both Solar+Storage (SPS) and "battery paired with solar" without defining the latter term anywhere in the Carbon Plan. Clarification is required to understand whether battery paired with solar is modeled differently from Solar+Storage.
[60]Will Gorman, et al., *Are Coupled Renewable-Battery Power Plants More Valuable Than Independently Sited Installations?* (May 2021). Berkeley, CA: Lawrence Berkeley National Laboratory. https://eta-publications.lbl.gov/sites/default/files/2021.04.09_geospatial_for_ae_pre-print.pdf (Attached as **Exhibit L**) (Summary report available at: https://emp.lbl.gov/news/berkeley-lab-releases-top-10-research).
[61] *Id.*at Section 4-1.
[62] *Id.*at Section 4-2.

perfect foresight. These potential penalties are generalized for a variety of market structures nationwide and most would actually not be applicable on Duke Energy's system. However, the cost *savings* of coupling Solar+Storage are ubiquitous and highlight the potential portfolio value of coupling. Duke Energy should provide a similar analysis for understanding the potential drawbacks and additional values of stand-alone energy storage versus Solar+Storage in North Carolina to determine the optimal amount of standalone storage vs Solar+Storage for each portfolio. Duke Energy should also outline in its analysis the effect of ay limitations on how the energy storage is charged on the value of storage.

4. *Duke Energy Appears to be Double-Counting on Depth of Discharge Requirements, Contrary to Industry and Utility Practice*

On page 7 of Appendix K (Energy Storage) of the Carbon Plan, Duke Energy states:

> **Depth of Discharge**: The cost of the battery storage assets in the Carbon Plan assumes that the asset is designed to include a 90% depth of discharge ("DoD") constraint. This means that if a battery is designed with 100 megawatt-hours ("MWh") of usable energy, the total energy of the battery would be 111.1 MWh. The depth of discharge constraint is included to reflect requirements of the original equipment manufacturer to maintain the warranty on most batteries.

However, original equipment manufacturers and energy storage integrators already factor in this depth of discharge constraint when pricing and procuring assets for developers and purchasers. For example, NREL's Cost Projections for Battery Storage: 2021 Update utilizes BloombergNEF cost projections for "usable" kWh of battery storage, which "means that round trip efficiency and depth of discharge are accounted for in the price of the battery pack in dollars per kWh."[63] This is the source that Duke Energy cites in "Figure 2-4: Key Base Assumptions" for modeled capital costs for "Storage."[64] Thus, Duke's constraint is inaccurate and results in energy storage resources being less competitive against other resource types, and Duke should not be assuming that pricing mark-up in its modeling. This constraint should be adjusted to reflect industry practice, wherein costs and capacity are factored in by third-party developers as they bid projects into procurements. Further, a competitive procurement process for build-own-transfer standalone storage facilities would demonstrate industry practice and pricing and provide lower cost storage projects to ratepayers.

5. CCEBA Recommends the Commission Order the Procurement of Both Standalone and Solar+Storage in the Near-Term

Considering the synergies available through the combination of solar and storage, CCEBA proposes that the Commission order that all solar procurements after the completion of the 2022 Procurement be of Solar+Storage resources, provided that an acceptable rate design for such facilities that adequately incentivizes the inclusion of storage can be developed. Further modeling should be directed to determine the optimum ratio of storage capacity to solar generating capacity. CCEBA also notes that the existing fleet of utility-scale solar projects on the DEP and DEC system has potential to provide meaningful on-peak capacity and flexibility to the system via the addition of battery storage to those facilities, as discussed in testimony to the Commission in E-100, SUB 158.

[63] Wesley Cole, et al. *Cost Projections for Utility-Scale Battery Storage: 2021 Update*, at p. 4. (2021). Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-79236. https://www.nrel.gov/docs/fy21osti/79236.pdf (Attached as **Exhibit M**).

[64] Carbon Plan, Chapter 2, Methodology and Key Assumptions, at p. 17, Figure 2-4.

The Commission should further direct Duke Energy to procure all stand-alone storage resources, through competitive procurements that allow participation by build-own-transfer bidders, to ensure that all such procurement occurs at least cost and that the above-mentioned Depth of Discharge constraint be modified to reflect industry practice and facilitate the selection of standalone storage in future modeling. Finally, the Build Own Transfer procurement process should be constructed to comply with LGIP 10.11.1 or NCIP 4.4.10.1 readiness requirements, such that the designation of a volume of standalone storage in the Carbon Plan is sufficient to comply with the requirement that "the Generating Facility has been selected by a Resource Planning Entity in a Resource Plan." Otherwise, Duke Energy-developed projects would have a competitive advantage against third party development as the only projects in a position to meet that non-monetary readiness requirement.

6. Prior to Storage Procurement, Contract Structures Must Be Developed to Adequately Capture the Economic Value of Storage, Particularly When Paired with Solar

The Carbon Plan recognizes that solar and storage paired together can increase the flexibility and energy output of solar.[65] Throughout the Carbon Plan, Duke Energy expresses the intention of increasing its procurement not only of solar, but of Solar+Storage. CCEBA supports this expansion.

The development of PPAs that adequately and appropriately compensate sellers of energy from Solar+Storage projects must be addressed to maximize the opportunity for Solar+Storage procurement. Current PPAs proposed by Duke Energy and approved by

[65] Carbon Plan, Ch. 2, at 18.

the Commission do not do so, with the consequence that Solar+Storage is underrepresented in recent competitive procurements of renewable energy.

Tranche 2 of the CPRE process under HB 589, which took place in 2021, clearly illustrated this problem. In that solicitation, despite reported efforts throughout the Stakeholder Process to encourage the submittal of storage-related bids, the Independent Administrator (IA) reported that it only received three proposals in DEC that contained storage (out of 34) and 1 in DEP (out of six) and none of those made the list of finalists because they weren't competitive.[66]

The structure of the PPA used in Tranches 2 and 3 of CPRE included a rate and bidding structure that tracked the avoided cost rate structure, minus the bid decrement. This structure failed to recognize the value of storage and restricted its use such that the benefits that adding storage to a project provides were undercompensated. As a result, it was very difficult to propose projects with energy storage as an economical alternative.

Under the CPRE approach, there were essentially two ways for an IPP to profit from the addition of storage: First, the seller could time-shift some of the facility's output to the grid to higher-rate periods. Second, the seller could use the storage to "smooth" its output to avoid application of the Solar Integration Service Charge. The drawback of this second approach is that it requires the facility to keep the battery charged during all generating hours to mitigate volatility. Doing so limits the amount of charge available for time-shifting. As a result, the extra revenue over the life of the PPA is not sufficient to cover the costs of adding the storage to the project.

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[66] Independent Administrator's *Conclusion of Tranche 2 Step 2 Evaluation and Selection of Proposal* ("Step 2 Report"), at pp.1-2, Docket No. E-7, Sub 1156, filed February 9, 2021 (Attached as **Exhibit N**).

The 2022 Procurement PPA recently approved by the Commission is not based on the avoided cost rate structure. However, by agreement of Duke Energy and all stakeholders, no storage was included in that procurement, precisely because all parties realized there was insufficient time to develop a pricing structure which would properly compensate storage for the benefits it provides and encourage bidders.

There are, nevertheless, available models for crafting a Solar+Storage PPA structure to allow more value to be derived from using the storage component as a capacity resource, such as paying a consistent tolling payment for capacity in addition to payment for energy delivered. Further possibilities include flexible payment structures and performance incentives for additional uses (e.g. operating reserves, primary frequency response, etc) paired with utility dispatch/control of the battery storage system (within its warranty parameters) for optimized benefit to Duke's system.

A salient example of such contract structure can be found in the TVA 2022 RFP for Carbon Free Resources,[67] which contains the following pertinent provisions:

> …Flexibility in charging/discharging periods will be necessary due to uncertainty in demand profiles and will be directed by TVA subject to the terms of the PPA. [p. 13]
>
> …The BESS shall be available to supply reactive power (up to 32.9 percent of BESS MW rating) and primary frequency response (with a maximum 5 percent droop and ±0.036 Hz deadband) at all times, including when not charging or discharging. [p.13]
>
> Proposals interconnected to the TVA transmission system may contain storage which may be charged by the renewable resource or directly from TVA's grid subject to the limitations set forth in the PPA. For projects

[67] TVA Request for Proposals for Carbon-Free Energy Resources ("2022 Carbon -Free RFP"). Issued July 12, 2022. (Located at: https://tva-azr-eastus-cdn-ep-tvawcm-prd.azureedge.net/cdn-tvawcma/docs/default-source/information/2022-carbon-free-rfpd536f164-d4ea-449e-9b2a-8ad646404463.pdf?sfvrsn=85f6c1f4_3) (Attached as **Exhibit O**).

receiving ITC and per the terms of the PPA, TVA will compensate Respondent for recaptured ITC in the event of excess grid charging.. [pp. 12-13].

If proposing a coupled storage or stand-alone offer, the capacity firm pricing shall be provided as a Year 1 $/kW-mo price that escalates at 2% annually through the term of the PPA and is paid according to the monthly weighting factors in Exhibit B of the RFP. The Storage technology must be AC-Coupled and have grid charging capability. [p 38]

This example highlights the value of energy storage to TVA's system and the material system benefits beyond energy time shifting – not limited to primary frequency response, operating reserves, and reactive power support – that are enabled by the flexibility of a tolling contract structure.

As an example of the kind of flawed provision of recent Duke Energy PPAs that could use improvement, CCEBA directs the Commission's attention to Exhibit 9-3 (page 68) of the approved CPRE Tranche 2 PPA. There, Duke Energy defined State of Charge as follows:

State of Charge			Percentage of the Allowable Depth of Discharge currently charged within the storage device. Example: A nameplate rated 10 MWh storage device is currently allowed to store energy up to 80% of its nameplate rating and down to 20% of its nameplate rating. The storage device currently has 4 MWhs stored in the device. The Allowable Depth of Discharge is 10 MWh *80% - 10 MWH * 20% = 6 MWh The State of Charge = 4 MWh / 6 MWh = 66.66%

CCEBA argues that there is no need for Duke to artificially limit the range of the energy storage by adjusting the nameplate capacity. Most integrators size the Battery Energy Storage System (BESS) so that the AC nameplate capacity and power outputs reflect the true capability of the BESS, with 0% to 100% range for the depth of discharge.

The calculation Duke Energy applies above limits a BESS unnecessarily, and the effect is to make it 40% more expensive than the BESS would otherwise be. In general, the PPA needs to allow for the BESS to capture the most value for the capacity and power made available to Duke Energy to allow for revenue and cost certainty for the contracted period. Such structures would encourage bidding and participation.

CCEBA requests that the Commission direct Duke Energy to work with stakeholders on appropriate Solar+Storage PPA structures to be used in the 2023 procurement and thereafter.

E. <u>The Carbon Plan Likely Overstates the Potential for Onshore Wind Development (Exclusive of Imports)</u>

The Carbon Plan notes several difficulties onshore wind faces as a resource in North Carolina, including siting limitations, the NC Ridge Law and community resistance.[68] In addition the legislatively-enacted moratorium from 2016-2018 effectively quashed the development of onshore wind in North Carolina, resulting in only one 208MW onshore wind farm (Amazon Wind Farm US East) operating in North Carolina in PJM territory, and one 189 MW farm (Timbermill Wind Farm - also in PJM territory) in the process of permitting.[69] As the voice of renewable energy developers in the Carolinas, including developers of onshore wind projects, CCEBA is unaware of any current onshore projects under development in the state other than the 189 MW Timbermill Wind Farm in PJM's territory . CCEBA thus has serious doubts about whether onshore will be available at the volumes predicted by Duke Energy for inclusion in a portfolio that achieves 70% reduction by 2030. Moreover, the recently completed

[68] Carbon Plan, Appx J, at 10-13.
[69] *Id.*at 10.

DISIS cluster summary published this week shows *no* onshore wind projects in the queue.[70]

Nevertheless, all four Carbon Plan portfolios proposed by Duke Energy include 600MW of onshore wind by 2030 and 1200MW by 2035. The Carbon Plan is largely silent as to where those resources will be sited or how they will be procured.[71] While CCEBA is not suggesting at this time that onshore wind additions should be taken off the table, the high degree of uncertainty about the near-term availability of this resource given the requirements of HB951 and current lack of projects in development further weighs against being too optimistic about near-term onshore wind volumes and in favor of eliminating arbitrary constraints on solar additions.

F. CCEBA Recommends that the Commission Encourage Offshore Wind Development in the Near-Term Execution Plan

The Carbon Plan notes that offshore wind is "a mature, scalable, and increasingly cost-effective zero-carbon resource,"[72] but calls for only 800MW of offshore wind by 2030 in P1 with no additional development by 2035. In P2, the Carbon Plan calls for 800MW by 2030 and 1600 MW by 2035. There is no offshore development at all in P3, and only 800MW by 2035 in P4.

[70] *See* OASIS filings for DEP: https://www.oasis.oati.com/cpl/ and DEC: https://www.oasis.oati.com/duk/ under "Generator Interconnection Info/Cluster Queue."
[71] Although Duke indicates that assumed DEC onshore wind resources would be in the form of imports, it doesn't provide detail on how these imports will be procured or how Duke will overcome the technical challenges to imports it described in its presentation to the Commission in last year's IRP Technical Conference. *See* Docket No. E-100, Sub 165; Transcript of Technical Conference Held via Videoconference on October 6, 2021, Volume 4 (Attached as **Exhibit P**). In particular, note the testimony of Witness Nick Wintermantel, pp. 13-21 (discussing uncertain nature of imports from neighboring systems in poor weather) and the discussion of the Grid/Transmission Panel of witnesses Sammy Roberts, Glen Snider and Mark Byrd, pp. 72-74 (discussing costs and infrastructure needed to bring wind power from Oklahoma and the Midwest).
[72] Carbon Plan, Appx. J., at 1.

As noted above, while Offshore Wind may be "new to the Carolinas," unlike advanced nuclear or hydrogen, it is a mature resource and not a hypothetical one, with known technology risks and projected cost declines that are well-supported by global wind energy experience. Last year alone, 21.1 GW of offshore wind capacity was connected to the grid worldwide, according to the Global Wind Energy Council.[73] American Clean Power reports that American states have established nearly 45GW of offshore wind procurement targets to date, with 10.3GW in 12 projects being developed to come online by 2026.[74]

In Appendix E, Quantitative Analysis, Duke Energy states that its Offshore Wind Modeling Assumptions provide that offshore wind is only available to the DEP territory and only in 800MW build increments.[75] "Due to uncertainty with future development of offshore wind, and availability of offshore wind lease areas, the Companies assume a limited amount of offshore wind is available starting in 2030 with additional offshore wind capacity available beginning in the early 2040s."[76]

However, Governor Cooper's Executive Order 218 "Advancing North Carolinas Economic and Clean Energy Future" ("EO 218") issued on June 19, 2021, commits the State to developing 2.8 GW of offshore wind by 2030.[77] These figures are not inconsistent with North Carolina's potential offshore wind resources. The Federal Government estimated 1.485GW of potential wind resource in the Kitty Hawk Lease

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[73] Rebecca Williams, et al., *GWEC Global Offshore Wind Report 2022,* at p. 7 (June 29, 2022). Brussels, Belgium: Global Wind Energy Council. https://gwec.net/gwecs-global-offshore-wind-report/.
[74] *Offshore Wind Power Facts*; American Clean Power https://cleanpower.org/facts/offshore-wind/ (accessed July 15, 2022).
[75] Carbon Plan, Appx. E, at 37.
[76] *Id.*
[77] EO 218 (Attached as **Exhibit Q**).

Area and 2.25GW in the Carolina Long Bay (Wilmington) Lease Area.[78] A recent study of a hypothetical 2030 2.8GW development offshore of North Carolina determined that at a 30-year cost premium of $9.45 Billion, the project would return $13.23 Billion in economic and transmission benefits to North Carolina during the same period, for a net benefit of approximately $3.78 Billion.[79]

Moreover, offshore wind and solar are complementary technologies. With a high capacity factor of between 40 and 50 %, offshore wind in the Carolinas could play a significant role in meeting peak load in the winter and reducing variability in a similar manner to that traditionally seen in coal and gas resources.[80] The figure below from the Southeastern Wind Coalition's report show how a hypothetical mix of solar, onshore wind and offshore wind results in more on peak generation in both winter and summer seasons, as well as fewer fluctuations.[81]

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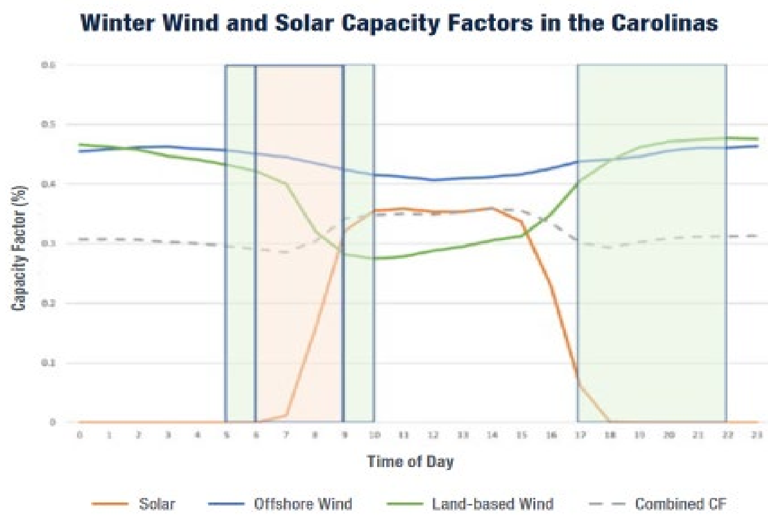
[78] Walter Musial, *et al.*, *Offshore Wind Market Report*: *2021 Edition,* at p. 17 (August 2021). National Renewable Energy Laboratory DOE/GO-102021-5614. https://www.energy.gov/sites/default/files/2021-08/Offshore%20Wind%20Market%20Report%202021%20Edition_Final.pdf.
[79] Jaime Simmons, *et al.*, *North Carolina Offshore Wind Cost-Benefit Analysis*, at p. 12 (January 2022). Southeastern Wind Coalition and E2. (Attached as **Exhibit R**).
[80] Simmons, at 16-17.
[81] *Id.*

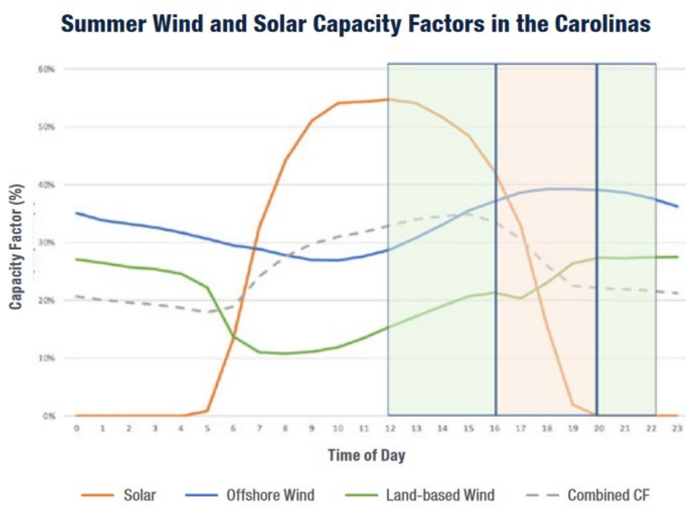
FIGURE 5 // Seasonal wind and solar complementarity in the Carolinas (winter/summer)[74]

Avoided Cost Peak Periods

PREMIUM
Winter: 6–9 am; Summer: 4–8 pm

ON PEAK
Winter: 5–6 am, 9–10 am & 5–10 pm; Summer: 12–4 pm & 8–10 pm





CCEBA notes that there is significant potential for development of offshore wind in each of the leasehold areas off the North Carolina coast. As written in the Carbon Plan, the Kitty Hawk Lease Area, awarded to Avangrid Renewables, LLC in 2017, is further along in the permitting process than those lease areas in the Carolina Long Bay awarded to Duke Energy Renewables Wind, LLC and TotalEnergies Renewables USA, LLC in May 2022. Several key steps have occurred in the Kitty Hawk Lease Area that have not had the opportunity to be pursued in the Carolina Long Bay. Avangrid submitted a Site Assessment Plan (SAP) to BOEM in September 2019, which was approved in April 2020. The SAP describes activities that will be conducted to assess the lease area for offshore wind development, including installation of two floating light and detection ranging buoys, as well as a metocean/current buoy. Avangrid then submitted a Construction and Operations Plan (COP) in November 2020. This COP describes the full scope of the proposed Kitty Hawk North Wind Project and triggers a number of permitting steps, including the initiation of a formal Environmental Impact Statement (EIS) under NEPA. On July 30, 2021, BOEM published a Notice of Intent (NOI) to Prepare an EIS, and the impact assessment is now underway. Currently, BOEM estimates the EIS and all the other permitting steps will be completed by December 2023. At that point, the project would be able to officially start construction.[82] Avangrid estimates that the Kitty Hawk Lease Area contains at least 2,500 MW[83] of potential for offshore wind development.

[82] A full permitting timetable for Kitty Hawk North is available here: https://www.permits.performance.gov/permitting-project/kitty-hawk-north-wind-project and Kitty Hawk South here: https://www.permits.performance.gov/permitting-project/kitty-hawk-south-offshore-wind-project.
[83] *See* information compiled at http://www.kittyhawkoffshore.com (accessed July 15, 2022). This amount could rise depending on the type and size of turbines used.

Appendix J of the Carbon Plan focuses primarily on the Carolina Long Bay lease sites off Bald Head Island, but each of the above permitting steps must also be accomplished for any projects in those areas. Taking an offshore wind project from lease area award to operation is undoubtedly a lengthy, comprehensive process.

Regardless of which offshore wind projects are included in generation portfolios or in what year they will ultimately come on line, the integration of offshore wind into North Carolina's generation fleet will necessitate the construction of significant additional transmission capacity in the DEP territory.[84] These improvements should not only benefit offshore wind, but other renewables projects in the region, and should be undertaken with the proactive and holistic approach recommended by CCEBA in Section IV-C above. Commencing the early-stage work necessary to bring offshore wind generation to the state will likely lead to earlier availability of offshore wind as a resource and greater capacity for the integration of other renewable resources.

While HB951 mandates that the Commission achieve the 70% reduction by 2030 by the least cost path, it also requires the Commission to "[e]nsure any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid."[85] CCEBA submits that while in the near term, offshore wind generation is likely to be more expensive on a per MWh basis than PV solar, the combination of solar and wind, just as the combination of solar and storage, is likely to produce benefits to the grid and the reliability of electric power in North Carolina. Resource diversity produces benefits in

[84] This necessity speaks in support of Duke Energy's expressed intention to combine the balancing authority areas of DEP and DEC as set forth in Appendix R of the Carbon Plan. Significant additional transmission resources in the DEP territory can bring on resources that benefit both territories, and aid compliance with the requirements of HB951, which benefits all North Carolinians. The cost of those investments should be evenly distributed as well.
[85] HB951, Part I, Sec. 1(3).

terms of capacity and reliability that may not be reflected in initial costs. Moreover, the costs in offshore wind are expected to decline within the planning horizon of the Carbon Plan.

Finally, Duke Energy has a significant amount of onshore wind in the Carbon Plan, rising to 1,200MW by 2035 across all portfolios, and as previously noted, CCEBA has concerns that these volumes may be too optimistic. As a result, it is critical that the Near-Term Execution Plan increase Solar+Storage procurement and include the development activities needed to accelerate deployment of offshore wind.

V. NEAR-TERM EXECUTION PLAN RECOMMENDATIONS

CCEBA supports a near-term execution plan that would support multiple potential pathways to achieving the 70% decarbonization mandate, including portfolios that increase solar and Solar+Storage procurement by 2030 or 2032 without Duke Energy's arbitrary and unjustified solar interconnection caps. With a more reasonable rate of annual solar additions, CCEBA believes that the least-cost 2030 compliance portfolio may well include 800 MW of off-shore wind, as shown in Duke Energy's P1 portfolio. But in any case, the Near-Term Execution Plan should also include all necessary preparations to add a least 1,600 MW of off-shore wind at the earliest opportunity because of the importance of offshore wind to the longer-term compliance plan, the contribution that wind can make to reliability and grid stability, and long-term cost savings that can be realized from jump-starting offshore wind development in the state.

Because it is consistent with these pathways, CCEBA supports a Near-Term (three-year) Execution plan that includes procurement of the first three years of solar[86]

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[86] Each year's procurement should be a reasonable share of the total procurement ultimately required in the final 70% reduction portfolio.

(together with an optimal amount of paired storage) necessary to reach a remodeled 70% reduction of CO2 by 2030 or 2032 and the next stages of development of offshore wind resources. Such steps should include, at a minimum, transmission planning sufficient to accept a sizable injection of off-shore wind by 2030 and later increments; a request for information ("RFI") process held confidentially to allow the Commission to assess potential off-shore wind proposals with detailed information from the three leaseholders about their projects that could serve Duke's customers, including the size of potential projects, projected costs, prospective transmission upgrades, developer qualifications, expected benefits for projects that could be completed by 2030, and other relevant data; and a stakeholder group established to determine the best steps forward for developing off-shore wind by 2030. These steps are important regardless of the 70% carbon reduction path, because near-term investment in offshore wind development is essential to lowering the cost of that resource and achieving the HB951 mandates at least cost.

VI. RESPONSE TO DUKE ENERGY'S REQUESTS FOR RELIEF

Duke Energy makes eight specific requests for relief in its Petition. CCEBA's responses to each of these requests are set forth below.

(1) Affirm that the Companies' Carbon Plan modeling is reasonable for planning purposes and presents a reasonable plan for achieving HB951's authorized CO2 emissions reductions targets in a manner consistent with HB951's requirements and prudent utility planning;

CCEBA objects to this request. The Duke Energy Carbon Plan, while a significant document that represents an improvement over Duke Energy's prior RFPs, should be amended to address the concerns of CCEBA and other Intervenors. In the interest of limiting disputes regarding Duke's modeling and limiting issues for decision by the Commission, CCEBA has only taken issue with limited elements of Duke's modeling inputs and assumptions – most notably its arbitrary and unjustified cap on solar additions. However, CCEBA's discussion above of specific issues does not mean that it agrees with all other elements of the Duke Energy Carbon Plan.

(2) Approve the near-term supply-side development and procurement activities identified above in Table 3, including by:

(a) Deeming the following resources as being selected in this initial Carbon Plan for purposes of HB951, Section 1.(2), in all cases subject to the obligation to obtain a CPCN (where applicable) and to keep the Commission apprised of material changes in assumed pricing or schedule:

- **(i) 3,100 MW of solar generation (including 750 MW requested to be procured through the 2022 Solar Procurement Program), of which a substantial portion is assumed to include paired storage;**
- **(ii) 1,600 MW of battery storage (1,000 MW stand-alone storage, 600 MW storage paired with solar);**
- **(iii) 600 MW of onshore wind;**
- **(iv) 800 MW of CTs; and**
- **(v) 1,200 MW of CC**

CCEBA objects to this relief. As set forth above, while CCEBA agrees with the concept of a near term supply-side development and procurement plan, the plan proposed by Duke Energy is hampered by the solar cap, the identified errors in the treatment of standalone storage and Solar+Storage, and the uncertainty as to the source of the 600MW of onshore wind requested by Duke Energy. CCEBA believes that these unacceptable provisions of the Carbon Plan result in unnecessary limitations on renewable resources in the short term and an overemphasis on new natural gas. CCEBA urges the adoption of a Near-Term Execution Plan that addresses CCEBA and other Intervenor concerns and that is consistent with additional portfolios that should be included in the Carbon Plan. CCEBA also notes that whether and how much new natural gas generation should be included in the Near-Term Execution Plan should be determined after revised portfolios have been developed and it has been confirmed that such additions are indeed "no regrets."

(b) Approving the Companies' plans to pursue initial development activities to support the future availability of offshore wind, SMRs and new pumped storage hydro at Bad Creek to ensure that these resources are available options for the Companies' customers on the timelines identified the portfolios if selected in future Carbon Plan updates;

CCEBA does not object in principle to this request and agrees that it would be prudent for the Commission to authorize initial efforts to develop these resources. As stated above, however, CCEBA does not agree that SMRs should be in the same category as offshore wind or pumped hydro storage, both of which are established technologies successfully deployed at scale worldwide. CCEBA encourages the Commission to establish development benchmarks and reporting requirements for the development of SMRs and Advanced Nuclear, and to closely monitor progress to avoid substantial expenditures on projects that may not ever see operation.

(c) Making the following additional determinations with respect to the project development activities summarized in Table 3:

(i) Engaging in initial project development activities for these resources is a reasonable and prudent step in executing the Carbon Plan to enable potential selection of these generating facilities in the future;

(ii) To the extent not already authorized under applicable accounting rules, that the Companies are authorized to defer associated project development costs for recovery in a future rate case (including a return on the unamortized balance at the applicable Companies then authorized, net-of-tax, weighted average cost of capital), subject to the Commission's review of the reasonableness and prudence of specific costs incurred in such future proceeding; and

(iii) That in the event the long lead time resources are ultimately determined not to be necessary to achieve the energy transition and the CO2 emission reduction targets of HB951, such project development costs will be recoverable through base rates over a period of time to be determined by the Commission at the appropriate time;

CCEBA agrees with these principles in concept, subject to a revised and more Near-Term Execution Plan being developed and approved based on a more appropriate suite of potential compliance portfolios.

(3) Approve the Companies' proposed actions with respect to existing supply-side resources, including through expanding flexibility of the existing gas fleet and continued disciplined pursuit of SLRs for the Companies' existing nuclear fleet;

CCEBA does not oppose this request, including Duke Energy's pursuit of SLRs through the existing regulatory process to extend the life of its existing nuclear fleet. To the extent that this request refers to the development of "green hydrogen" infrastructure to allow conversion of natural gas generators to hydrogen, CCEBA encourages the Commission to regard these expenditures with the same careful skepticism as should be applied to SMRs. Duke Energy's reliance on green hydrogen as the panacea to the stranded asset problem which awaits any substantial investment in natural gas generation must be supported by actual progress in the development of a fuel supply chain and proof of the technical and financial feasibility of green hydrogen generation. Such expenditures should, as with SMRs, be subject to careful oversight, benchmarking of progress, and regular reports to the Commission and stakeholder input.

(4) Approve the Companies' plans to advance Grid Edge and Customer Programs and to update the underlying determination of the utility system benefits in the Companies' approved EE/DSM Cost Recovery Mechanism;

CCEBA supports this request and will be participating actively in the proposal and development of new customer programs in companion dockets to produce programs which meet customer demands for delivery of clean, renewable power.

(5) Acknowledge that HB951 establishes new public policy goals requiring new generation and other resources that will necessarily inform the Companies' transmission system planning processes as outlined in the Open Access Transmission Tariff and direct the Companies to continue to study future transmission needs to reliably implement the Carbon Plan through the NCTPC and other appropriate forums;

CCEBA supports this request. As noted above, CCEBA agrees with Duke Energy that the Carbon Plan should inform the transmission system planning process as stated public policy. CCEBA urges the Commission to require Duke Energy to engage in proactive and iterative planning through the NCTPC that enables the substantial investments in renewable generation that are required to meet the requirements of HB951. CCEBA further urges the Commission to determine whether Duke Energy should be required to seek amendment of the OATT if necessary to accommodate this needed change in the state's approach to transmission planning.

(6) Approve the Companies' methodologies outlined in Appendix A (Carbon Baseline and Accounting) for tracking compliance with HB951's CO2 emissions reductions targets and confirm the Commissions' accounting requirements for emissions from new out-of-state resources selected by the Commission (if any) as described above;

CCEBA defers to other intervenors that may have more expertise on this topic, but strongly agrees with Duke that CO2 emission from new out-of-state generation sources that are procured pursuant to the Carbon Plan should be treated as in-state emissions. To do otherwise would totally undermine the purpose and intent of HB951 and reduce this entire expensive and time-consuming process to nothing more than rearranging the deck chairs on the Titanic.

(7) Affirm that the first biennial Carbon Plan update proceeding should be held in 2024 and that the Companies' next biennial IRPs will be held in abeyance to 2024 to align with the Carbon Plan update, as further discussed in Chapter 4 (Execution Plan);

CCEBA supports this approach.

(8) Direct the Companies and Public Staff to develop and propose for comment by January 31, 2023, revisions to the Commission's IRP Rule R8-60 and related rules for certificating new generating facilities to support execution of the Carbon Plan.

CCEBA supports this approach, so long as full opportunity is given for stakeholder and intervenor participation, comment, and feedback.

VII. ISSUES FOR EVIDENTIARY HEARING

Pursuant to the Commission's April; 1, 2022 Order Establishing Additional Procedures and Requiring Issues Report, CCEBA recommends the following as logical issues for an evidentiary hearing:

1. **Duke Energy's solar interconnection capacity during the Near-Term Execution Plan time-frame** – The Commission can receive and consider material evidence as to the amount of new solar or other renewable resources that can be interconnected in the near term. Duke Energy's assumptions are currently unsupported and inconsistent with both their past interconnection capacity and the scale of planned renewables adoption by other utilities similar to Duke Energy. In light of FERC's clear instruction to speed up the pace of interconnection, Duke

Energy should be required to prove the need for any caps on the selection of solar or Solar+Storage. In addition, CCEBA is strongly of the view that the annual solar procurements during the three years of the Near-Term Execution Plan should not be strictly limited by uncertain, conservative assumptions about Duke's ability to interconnect solar resources in the calendar year that is four years after the procurement year. Rather than giving up in advance, the annual procurement volumes should preserve the possibility of a more ambitious rate of interconnection. Larger annual procurement volumes also acknowledge the fact that there is not a precise correlation between the year of procurement and the year of interconnection and ensure that there will not be shortfalls in projected interconnections. Larger procurement volumes also provide additional information to guide the transmission planning process and allow for sharing of system upgrade costs. Thus, the Commission could avoid the need for an evidentiary hearing on Duke's interconnection capabilities by accepting the position of CCEBA and other intervenors that higher annual procurement volumes are in the public interest even if there is some uncertainty about the rate at which Duke Energy can complete interconnections.

2. **The Nature of Needed Transmission Process Improvements** – CCEBA believes that the Commission would be well-served to hear evidence or expert testimony on the types of improvements that can and should be made to the transmission planning process to allow for faster and more efficient improvements.

3. **Needed Transmission Improvements for the Near-Term Execution Plan** – The Commission should hear testimony concerning the necessity of the Transmission Improvements in Appendix P of the Carbon Plan as well as any other projects that could be included in a Near-Term Execution Plan in order to promote the adoption and integration of new carbon-free generation at least cost.
4. **Proper modeling input / structure and final selection of portfolios for inclusion in the Carbon Plan** – CCEBA anticipates that the Commission will be receiving multiple modeling runs from several Intervenors. It would be prudent to allow Duke Energy and Intervenors to produce expert testimony supporting the assumptions, inputs and outputs of such models and subject those witnesses to questioning by other parties and the Commission itself. In addition, while CCEBA agrees with Duke Energy that the Carbon Plan should include multiple portfolios and that a preferred portfolio should not be selected until 2024, CCEBA believes that all four of Duke's proposed portfolios are inappropriate and that the Commission selection of a suite of portfolios for inclusion in the Carbon Plan will benefit from expert testimony. However, CCEBA believes that the scope of the evidentiary hearing on this question can be significantly narrowed and does not require litigation regarding the majority of modeling inputs or methodology.

VIII. CONCLUSION

In conclusion, based on the arguments and information presented herein CCEBA requests that the Commission reject the four portfolios proposed in Duke Energy's Carbon Plan. In their place, CCEBA urges the Commission to require the adoption of a

Carbon Plan that sets out a Near-Term Action Plan and potential portfolios to achieve the mandates of HB951 in a way consistent with the above comments.

Respectfully submitted, this 15th day of July, 2022.

CAROLINAS CLEAN ENERGY
BUSINESS ASSOCIATION

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CERTIFICATE OF SERVICE

Undersigned counsel for the Carolinas Clean Energy Business Association hereby certifies that on this date he has served the foregoing Comments and Issues of Carolinas Clean Energy Business Association on the parties of record to this docket by electronic means and/or by depositing copies in the United Sates mail, postage prepaid.

This 15th day of July, 2022.

__/s/ John D. Burns___
John D. Burns