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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 175

In the Matter of: Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2021	**INITIAL COMMENTS OF THE SOUTHERN ALLIANCE FOR CLEAN ENERGY**

I. INTRODUCTION

The Southern Alliance for Clean Energy ("SACE") submits these Initial Comments pursuant to the *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing* ("Order Establishing 2021 Biennial Proceeding") issued by the North Carolina Utilities Commission ("Commission") on August 13, 2021. These Initial Comments respond to the Initial Statements filed by Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP") (together "Duke"), and Dominion Energy North Carolina ("DENC" or "Dominion") (collectively, the "Utilities").

SACE retained three consultants to assist with its review of the Utilities' Initial Statements and related work papers. Matt Cox and Kenneth Sercy, of Greenlink Analytics, provided expert review that informed each of the issues discussed below. Brendan Kirby of Consult Kirby provided expert review focusing on the solar integration services charge ("SISC") applied by Duke and the "re-dispatch charge" ("RDC") applied by Dominion, and advised on other issues as well. Mr. Kirby prepared a report on Duke's SISC attached hereto as **Exhibit A** ("Kirby SISC Report") and a report on the RDC attached hereto as **Exhibit B** ("Kirby RDC Report").

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II. PROCEDURAL BACKGROUND

This is the first biennial avoided cost proceeding to take place in an odd-numbered year. In its April 15, 2020 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities (the "Sub 158 Order") at the conclusion of the 2018 avoided cost proceeding (Docket No. E-100, Sub 158), the Commission directed Duke to address certain additional issues ("Sub 158 Additional Issues") in its initial filings in the 2020 biennial proceeding.

On October 30, 2020, in the 2020 proceeding (Docket No. E-100, Sub 167), the Commission granted the Utilities' request to streamline the 2020 avoided cost proceeding, modify the timing of biennial avoided cost proceedings to take place in odd-years starting in 2021, and address the Sub 158 Additional Issues by no later than November 1, 2021, in this 2021 biennial proceeding. The Commission required the Utilities to file a timeline for addressing the Sub 158 Additional Issues, to file updates on their progress on those issues every 45 days, and to work with stakeholders to resolve those issues or otherwise reach consensus on them before its initial filing in the 2021 avoided cost proceeding.

The Utilities held virtual meetings with stakeholders in late August through early October of 2021. Duke also was receptive to additional feedback after the general meetings concluded. SACE appreciates the Utilities' efforts to reach consensus with stakeholders on the Sub 158 Additional Issues before filing and believes that although full consensus was not achieved the discussions were productive. Nevertheless, SACE continues to have some concerns about some of the Sub 158 Additional Issues, as discussed below.

On August 13, 2021 the Commission issued its Order Establishing 2021 Biennial Proceeding.

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On November 1, Duke filed its Joint Initial Statement and Proposed Standard Avoided Cost Rate Tariffs of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC ("Initial Statement").

On November 1, Dominion filed its Initial Statement and Exhibits of Dominion Energy North Carolina ("Initial Statement").

On December 1, SACE petition to intervene and on December 2 the Commission granted SACE's petition.

SACE has reviewed Duke's Initial Statement and Dominion's Initial Statement, and respectfully submits the following Initial Comments.

III. DISCUSSION OF DUKE'S INITIAL STATEMENT

The following discussion identifies concerns with Duke's avoided capacity cost calculations, followed by its avoided energy cost calculations, and proposes solutions. As a result of changes to the grid and to state law, Duke's avoided capacity cost calculations should be based on the assumption that the avoided peaking unit would be an aeroderivative gas turbine, and in the near future, on hydrogen turbines or batteries. Duke's avoided energy cost calculations should be based on a more accurate natural gas commodity price forecast methodology, and a recalculated SISC; the Commission should establish a mechanism to compensate QFs for ancillary services, beginning with a pilot program; and it should reject Duke's proposal to calculate "as-available" rates ex-post at the end of the month but consider revising the ex-ante rate more often.

A. Avoided Capacity Cost Calculations

Recent developments in state law and the ongoing transformation of the electric sector strongly suggest that the Commission should begin to reconsider the appropriateness of the peaker method for avoided cost determinations.

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Duke's Initial Statement illustrates the problem. As discussed below, the combustion turbine ("CT") that Duke has chosen to use as its projected avoided peaking resource is inconsistent with economical future procurement as well as Duke's suggested future procurement. As a result of Session Law 2021-165 (also "House Bill 951" or "H951"), Duke will need to procure large quantities of zero-emitting resources beginning immediately. This will include many gigawatts of solar and wind generation, which as stand-alone facilities have variable and intermittent output. In addition, load is becoming more dynamic as the grid transforms, as a result of phenomena like beneficial electrification. In the very near term, for purposes of selecting the resource used for the peaker method, the flexibility and other operating characteristics of an aeroderivative gas turbine would better match the needs of the changing grid, while also providing the same basic generating capacity services as a CT. Because the up-front capital cost of a CT is lower than aeroderivative gas turbines, Duke's choice to use the former artificially reduces avoided capacity cost.[1]

In the slightly longer term, peaking resources will need to be zero-carbon. According to Duke, it will procure two types of zero-carbon peaking resources: hydrogen-powered combustion turbines and batteries. It appears Duke intends to procure natural gas generation resources with the ability to transition to hydrogen generation resources, and even fully hydrogen-powered combustion turbines will not necessarily be zero-carbon. While SACE opposes further natural gas in Duke's planning portfolio, if Duke is planning such generation then its avoided cost inputs and assumptions should match its plans. The

[1] Even though the up-front cost of an aeroderivative gas turbine are higher than those of a simple CT, the overall cost of a decarbonized system, including one with lots of renewables, may well be lower than proceeding under business as usual.

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same reasoning applies to batteries, although batteries are in fact operationally zero-carbon peaking resources: if they will be the avoided peaking resources then they should be the measure of avoided capacity cost.

The difficulty in identifying the appropriate peaking resource in the wake of Session Law 2021-165 and the ongoing grid transformation indicates the growing challenge that the peaker method has in keeping up with the changing energy landscape. It is no longer safe to assume that a need for capacity would be met with a simple CT. In the near term it could be an aeroderivative gas turbine, a hydrogen turbine, or batteries. At the same time, the massive additions of zero-marginal-cost renewable resources likely will decrease the need for new energy on the system, which will affect the avoided capacity resource; however, in a carbon-constrained planning context, it is unclear whether the peaker method is capable of capturing these effects. The changing nature of system planning and operation under Session Law 2021-165, including flexibility and decarbonization considerations, suggests that it might soon be appropriate for the Commission to reconsider whether the peaker method is the most accurate way to calculate avoided capacity costs.

i. <u>State law requires system flexibility enhancements going forward.</u>

Session Law 2021-165 requires the Commission to take "all reasonable steps to achieve a seventy percent (70%) reduction in emissions of carbon dioxide (CO_2) 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 the year 2050."[2] This carbon-

[2] Session Law 2021-165, Part I, Section 1, https://ncleg.gov/Sessions/2021/Bills/House/PDF/H951v6.pdf.

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reduction mandate will require procuring large amounts of additional zero-carbon resources starting immediately, and will eventually require that future peaking resources are no longer any form of carbon-emitting resource but instead zero-carbon resources such as battery energy storage or demand-side management.

Session Law 2021-165 will require large amounts of additional zero-carbon renewable resources. Duke's 2020 modified integrated resources plan ("IRP") filed in South Carolina contains two portfolios (D and E) that aim to get 70% carbon reduction by 2030,[3] matching the interim North Carolina mandate established by the law.[4] The portfolios indicate that Duke would need approximately 14 gigawatts ("GW") of new solar to achieve at least a 70% carbon reduction by 2035, *even with* other zero-carbon resources forced into the model.[5]

Two other analyses also show that large additions of zero-carbon renewable resources will be required to meet the goals of Session Law 2021-165. SACE commissioned Synapse to prepare a report for the 2020 IRP re-running Duke's modeling using the same model but with more reasonable assumptions,[6] making the report a more accurate forecast than Duke's modified IRPs. The Synapse report indicates that North Carolina will transition from 7.9GW of renewables in 2021 to 40.5GW of renewables in 2035, including approximately 22GW of new solar and many gigawatts of battery energy

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[3] Duke 2020 modified IRP filed in SC, https://dms.psc.sc.gov/Attachments/Matter/81fe90b2-7966-4435-b14a-6a79549bfa33.

[4] Unfortunately, to prepare these portfolios Duke did not perform a full generation expansion optimization to achieve that carbon-reduction goal but instead achieved the reductions by forcing in specified resources (offshore wind in D and small modular nuclear reactors in E), neither of which are likely to be fully available by 2030, artificially increasing the costs.

[5] Duke 2020 modified IRP filed in SC, Table 1-C on p.11 and n.4 to the table, https://dms.psc.sc.gov/Attachments/Matter/81fe90b2-7966-4435-b14a-6a79549bfa33.

[6] Synapse Report filed May 27, 2021 in Docket No. E-100, Sub 165, https://starw1.ncuc net/NCUC/ViewFile.aspx?Id=be90482d-7f8e-4949-babc-c23d33e6d4c5

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storage. Similarly, a report prepared by the consulting firm Brattle Group analyzed pathways to the 70% goal in H951 and showed a need for 9.5GW of new solar by 2030.[7]

With these mandates and considering the pace of interconnection,[8] large-scale procurement of zero-carbon resources to meet the law's carbon-reduction mandate needs to begin immediately. Indeed, Session Law 2021-165 authorizes a substantial solar procurement in 2022 based on "preliminary analysis developed in preparation of the initial Carbon Plan."[9] The procurement will take place in the first half of the year in order to align the procurement with the 2022 Definitive Interconnection System Impact Study ("DISIS") Cluster Study enrollment window, which closes June 29, 2022.[10] According to Duke, there are only four annual DISIS clusters that "could realistically be used to procure solar that could be placed in service by 2030."[11] Rounding the amount of new renewable generation that the above analyses show will be required by 2030 down to 9GW, and applying simple arithmetic, the 2022 procurement alone should be at least 2,250MW.[12]

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[7] Brattle Group Report, https://www.brattle.com/wp-content/uploads/2021/09/A-Pathway-to-Decarbonization-Generation-Cost-and-Emissions-Impact-of-Proposed-NC-Energy-Legislation_Revised-September-2021.pdf (see slide 6).

[8] *See* Exhibit C, Duke Energy Carolinas Carbon Plan Stakeholder Meeting 1: Virtual Meeting – January 25, 2022 at slide 61 (showing projected interconnection ranging from 400MW to 750MW per year in 2026 through 2030, resulting in 9,400MW to 11,000MW online—including existing solar—in 2030); Exhibit D, Solar Interconnection Forecast for Carbon Plan Modeling, Carolinas Carbon Plan Technical Subgroup Stakeholder Meeting (Feb. 18, 2022) (showing projected interconnection ranging from 750MW/yr under "progressive" approach to 1,360MW/yr under "enhanced transmission policy" approach, totaling 10,250MW to 12,300MW by 2030). The bases for these estimates are not clear, but they are very likely insufficient to achieve the carbon-reduction mandate in Session Law 2021-165.

[9] Session Law 2021-165, Part I, Section 2.(c).

[10] Letter from Jack E. Jirak to Ms. A. Shonta Dunston, Jan. 10, 2022, filed in Docket No. E-100, Sub 179, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=ea85d70a-16ab-4bbc-8833-ae3199f49260.

[11] Exhibit E, 2022 Solar Procurement Stakeholder Meeting 1 Presentation at slide 9.

[12] Procurement to meet the 2030 carbon-reduction goal cannot be back-loaded into the later years between now and 2030 or it will not be possible to interconnect the projects in time. As the slides from the first Carbon Plan stakeholder meeting showed, between now and 2030 Duke Energy anticipates being able to interconnect a maximum of 750MW per year, absent proactive transmission planning. Exhibit C, Duke Energy Carolinas Carbon Plan Stakeholder Meeting 1: Virtual Meeting –January 25, 2022 at slide 61 (showing projected interconnection ranging from 400MW to 750MW per year in 2026 through 2030, resulting in 9,400MW to 11,000MW online—including existing solar—in 2030); Exhibit D, Solar

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The substantial additions of renewable resources in these analyses further underscore existing indications of the value of system flexibility on the Duke grid, greatly strengthening the likelihood that Duke's future procurement of peakers will target highly flexible technologies.

ii. An aeroderivative gas turbine is the appropriate avoided capacity resource in the near term.

An aeroderivative turbine will be the most economical highly flexible CT technology at present, making it a more appropriate resource to use to calculate avoided capacity costs in this proceeding than a simple CT that cannot offer the same flexibility and operational efficiencies. None of this is to say that Duke should construct additional fossil gas-fired generating resources—even if aeroderivative gas turbines—nor that SACE would support such a move. The peaker method is a hypothetical exercise that measures the capacity value of a QF based on the assumption that the capacity provided by the QF allows the utility to avoid building a least-cost peaking unit that it otherwise would have built. Whether Duke needs additional peaking capacity and what the peaking resource should be, when that need is identified, are separate questions appropriately addressed through the IRP, certificate of public convenience and necessity, and Carbon Plan processes.

Interconnection Forecast for Carbon Plan Modeling, Carolinas Carbon Plan Technical Subgroup Stakeholder Meeting (Feb. 18, 2022) (showing projected interconnection ranging from 750MW/yr under "progressive" approach to 1,360MW/yr under "enhanced transmission policy" approach, totaling 10,250MW to 12,300MW by 2030). SACE supports exploring proactive, transparent, and cooperative transmission planning and would look forward to working with Duke Energy on the subject. Furthermore, from a climate-change perspective, it is cumulative emissions more than annual emissions that heat the planet. Reducing emissions early and maintaining the reductions over time results in lower cumulative emissions and is more valuable to mitigating climate change. Accordingly, if anything, Duke Energy should front-load procurement of zero-emission resources, and doing so is consistent with the purpose of HB951.

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An aeroderivative gas turbine essentially is a modified aviation turbine of the kind used to propel a jumbo jet.[13] According the EIA's current Cost & Performance Estimates for New Utility-Scale Electric Power Generating Technologies,

> Aeroderivative CTs differ from industrial frame CTs in that aeroderivative CTs have been adapted from an existing aircraft engine design for stationary power generation applications. Consequently, compared to industrial frame CTs of the same MW output, aeroderivative CTs are lighter weight, have a smaller size [physical] footprint, and have more advanced materials of construction. Additionally, aeroderivative CTs in general operate at higher pressure ratios, have faster start-up times and ramp rates, and higher efficiencies compared to industrial frame CTs.[14]

These characteristics, particularly faster start-up times and ramp rates, and higher efficiencies will be increasingly valuable when Duke is responding to more intermittent resources in the near-term, before widespread battery deployment.

SACE recognizes that Duke Energy's proposed avoided capacity rates are calculated [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Nevertheless, on balance the evidence indicates that the appropriate avoided peaking resource is an aeroderivative gas turbine rather than a CT. First, aeroderivative gas

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[13] John Ingham & Monamee Adhikari, General Electric Co, Aeroderivative Gas Turbines at 3 (2019), https://www.ge.com/content/dam/gepower-microsites/global/en_US/documents/avr/GEA34130%20AeroderivativeGT_Whitepaper_R5.pdf.

[14] EIA at 5-2, https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.

[15] See Response to NC Public Staff Data Request 3-3.

[16] *E.g.*, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 15 (Aug. 13, 2021), Docket NO. E-100, Sub 167, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=b36b2878-827f-492c-b227-1ac82e878408.

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turbines are a commercially mature technology with substantial deployment in the power sector, and with growing use by Southeastern utilities with increasing solar penetration. Duke found aeroderivative gas turbines commercially available, technically feasible, and relatively low cost as far back as 2003.[17] And nearly a decade ago there was already a "trend toward aeroderivative turbines" with 112 coming online after 2008 in the United States compared to just 26 other-class CTs.[18] Now, aeroderivatives are the leading CT technology recently deployed in PJM, and another highly flexible generation technology, reciprocating engines, has proliferated in Texas alongside growing wind penetration.[19] In the Southeast in particular, Dominion Energy South Carolina (DESC) has proposed and received approval from the SC Public Service Commission to construct aeroderivative units in 2023 and 2024.[20] DESC also proposed and received approval in its most recent avoided cost application to assume aeroderivative CTs as the avoided resource for avoided capacity rate calculations.[21] Further, TVA has proposed adding more than 500 MWs of aeroderivative units by 2024.[22]

Second, although Duke's preexisting IRPs are no longer accurate guides to future generation procurement after the passage of Session Law 2021-165, even those IRPs

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[17] Progress Energy Carolinas Resource Plan at 8 (2003), https://starw1 ncuc net/NCUC/ViewFile.aspx?Id=7692f1b1-1c03-422f-aa62-7fd129aec7fb.

[18] *See* Samuel A. Newell, et al., Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM at 8 (2014), https://starw1.ncuc net/NCUC/ViewFile.aspx?Id=3592a0df-a228-45f4-919e-27fb4dee8349.

[19] PJM Reference Unit Presentation on behalf of P3 Group of PJM generation owners, at 7 and 10. https://www.pjm.com/-/media/committees-groups/committees/mic/20180706-special/20180706-item-02-reference-unit-issues-to-consider-post-meeting.ashx

[20] SC PSC Docket No. 2021-93-E. Request: https://dms.psc.sc.gov/Attachments/Matter/c74f4a04-659e-45b1-8d8a-edffbe0fe203 PSC Order: https://dms.psc.sc.gov/Attachments/Matter/33b20473-bcdb-4370-8e61-8509ef30ea53

[21] SC PSC Order: https://dms.psc.sc.gov/Attachments/Matter/44693d87-4d63-4dda-9457-7506979c64e2 and LEI report referenced therein, discussing aero-CT assumptions at 29-33: https://dms.psc.sc.gov/Attachments/Matter/01e1b361-89e9-4f39-8c1c-be0b3a6206d6

[22] See https://www.tva.com/environment/environmental-stewardship/environmental-reviews/nepa-detail/johnsonville-aeroderivative-combustion-turbine-project

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indicate a need for peaking resources with advanced flexibility capabilities such as those provided by aeroderivative gas turbines. In its 2018 IRP, DEC concluded that F-frame CTs would be the most economical peaking resource—"unless there is a special application that requires the fast start capability of the aero-derivative CTs or reciprocating engines."[23] And Duke agrees "that H-class or other more advanced aeroderivative CTs could be a future way for the Companies to manage the intermittent output of must-take solar generators."[24] Dominion has also considered aeroderivative gas turbines in recent years because their faster start-up and ramping capability makes them more flexible and useful for balancing the grid as more intermittent renewable resources are added.[25]

Similarly, Duke's 2020 IRP indicated that new peaking resources will need to be more flexible than they have been in the past, and Duke has even modified the "generic" plant's base designs accordingly:

> As more intermittent generation becomes associated with Duke's system there is a greater need for generation that has rapid load shifting and ancillary support capabilities. This generation would need to be dispatchable, possess desirable capacity, and ramp at a desired rate. Some of the technologies that have 'technically' screened in possess these qualities or may do so in the near future. Effort is being made to value the characteristics of flexibility and quantify that value to the system. As a result of the flexible generation need, some features of 'generic' plant's base designs have been modified to reflect the change in cost and performance to accomplish a more desired plant characteristic to diminish the impact of the intermittent generation additions.[26]

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[23] Duke Energy Carolinas, LLC 2018 Integrated Resource Plan and 2018 REPS Compliance Plan at 186, Docket No. E-100, Sub 157, https://starw1.ncuc net/NCUC/ViewFile.aspx?Id=aa9862b5-5e31-4b3f-bb26-c8a12c85c658.

[24] Reply Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC at 18 (Mar. 5, 2021), Docket No. E-100, Sub 167, https://starw1.ncuc net/NCUC/ViewFile.aspx?Id=2c0e9f74-a595-40c9-9ffb-f2a611ab655e.

[25] Direct Testimony of Bruce E. Petrie on behalf of Dominion North Carolina Power at 13, 17-18 (Feb. 21, 2017), Docket No. E-100, Sub 148, https://starw1.ncuc net/NCUC/ViewFile.aspx?Id=5445875e-200d-4013-af3c-803186fe9e3a.

[26] DEC 2020 IRP at 323.

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In its 2021 IRP update, Duke again made the case for advanced and more-flexible gas turbines:

> The Company continues to evaluate advanced combined cycle ("CC") and combustion turbine ("CT") technologies with the capability of burning natural gas and hydrogen as viable options to accelerate an energy transition toward a lower carbon footprint with the ultimate goal of being net zero carbon emitting by 2050. Improving efficiency and reliability of CC and CT units makes these resources more economically attractive, as well as effective resources for enabling significant carbon reductions through accelerated economic coal retirements and providing the flexibility needed to incorporate significant levels of incremental intermittent renewable generation onto the system.[27]

Further, Duke continues to develop an advanced combustion turbine unit at the Lincoln CT Plant.[28] While Duke does not designate aeroderivative technology as part of its preferred plan in its most recent IRP, it also does not appear to have materially evaluated the relative merits of CT versus aeroderivative technology options. Thus, the absence of aeroderivative units from Duke's current IRP is not dispositive on this point.

The capital and fixed O&M costs to construct an aeroderivative gas turbine are markedly higher than for a CT. Table 1 shows overnight capital cost and fixed O&M assumptions for a representative industrial F-frame CT and an aeroderivative gas turbine, from the EIA's Annual Energy Outlook.[29] Additionally, [BEGIN CONFIDENTIAL]

[redacted]

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[27] DEC 2021 Update to 2020 Short-Term Action Plan, NC REPS and CPRE Plan at 10-11 (Sept. 1, 2021), Docket No. E-100, Sub 165, https://starw1 ncuc.net/NCUC/ViewFile.aspx?Id=3eaf4cc8-2bbd-4a18-8edd-2f2d5c0b79dd; DEP 2021 Update to 2020 Short-Term Action Plan, NC REPS and CPRE Plan at 11 (Sept. 1, 2021), Docket No. E-100, Sub 165, https://starw1.ncuc net/NCUC/ViewFile.aspx?Id=6ebf0ec3-be46-4f57-a0f5-c3d520d2dec3.

[28] DEC 2021 Update at 11.

[29] EIA, https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

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[redacted] [END CONFIDENTIAL]

Table 1: Comparison of capital and FOM costs for CT technologies

	Overnight cost (2020 $/kW) - Carolinas	FOM (2020 $/kW-yr)
F-frame	649	7.04
Aeroderivative	1,071	16.38
% Difference	65%	133%

The Commission should not allow Duke to base its avoided capacity cost calculation on an outdated peaking resource. The Commission should require Duke to recalculate its avoided capacity costs using an aeroderivative gas turbine as the avoided peaking resource, or at a minimum the Commission should require Duke to explain how continued construction of CTs for peaking capacity would be consistent with changing system needs, the requirements of Session Law 2021-165, and the forthcoming Carbon Plan.

iii. <u>Hydrogen-capable turbines and associated infrastructure upgrade costs should be used to calculate avoided capacity costs in the near future.</u>

The carbon-reduction mandate and the additional batteries forecast in the analyses above indicates that very soon the avoided future peaker will not be fossil fuel-burning at all. Duke is planning for this already. Duke anticipates that, going forward under the Carbon Plan, future peaking resources will be either battery storage or hydrogen-powered

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combustion turbines.[30] Similarly, in its most recent earnings update Duke Energy forecast spending $4 billion on "hydrogen-enabled natural gas generation" in the coming five years.[31] Accordingly, these zero-carbon peaking resources would most accurately represent the capacity cost avoided by a QF in the near future.

As with an aeroderivative gas turbine, future avoided capacity costs defined by these resources are likely to be higher than those defined by a CT. Taking hydrogen-powered turbines first, only turbines powered by 100% "green" hydrogen would truly be zero-carbon. The hydrogen industry has adopted a color-coding system to differentiate hydrogen produced by different methods. Two factors affect the carbon dioxide associated with hydrogen production: the feedstock used for the hydrogen and the source of the energy used to produce or capture it. "Green" hydrogen is produced using water as a feedstock, meaning oxygen is its byproduct, and using zero-carbon clean electricity to power the electrolysis process.[32] The cost of green hydrogen is falling,[33] but it likely will not be the most economical method of decarbonizing the power sector, in contrast with sectors with fewer zero-carbon alternatives, for many years to come.[34] Further, existing natural gas

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[30] Exhibit C, Duke Energy Carolinas Carbon Plan Stakeholder Meeting 1: Virtual Meeting – January 25, 2022 at slide 63. The merits of aeroderivative gas turbines relative to CTs, discussed above, suggest that any hydrogen-burning turbines potentially should be aeroderivatives as well.

[31] Lynn Good & Steve Young, Duke Energy, Earnings Review and Business Update at 11 (Feb. 10, 2022), https://desitecoreprod-cd.azureedge net/_/media/pdfs/our-company/investors/news-and-events/2021/4qresults/q4-2021-earnings-presentation-reg-g.pdf?la=en&rev=83cf9ace2f3942709f8ea075f9bd3e88.

[32] *Id.*

[33] *See* Nima Simon, et al., *Examining the current and future economics of hydrogen energy*, ICF (Aug. 13, 2021), https://www.icf.com/insights/energy/economics-hydrogen-energy (including projected cost decline from approximately $3/kg in 2020 to approximately $1/kg in 2050, less if produced solely using otherwise-curtailed renewable energy); '*Green' Hydrogen to Outcompete 'Blue' Everywhere by 2030*, BNEF (May 5, 2021), https://about.bnef.com/blog/green-hydrogen-to-outcompete-blue-everywhere-by-2030/.

[34] Hydrogen Council, Path to hydrogen competitiveness: A cost perspective at 16 (2020), https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf (showing cost curve for hydrogen across sectors); *id*. at 58 (estimating that hydrogen costing approximately $3/kg produces electricity at approximately $140/MWh).

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infrastructure cannot handle pure hydrogen without modifications and operating changes.[35] And combusted hydrogen is corrosive to standard turbine blades.[36] While potentially worthwhile, the necessary upgrades will add to the cost of zero-carbon hydrogen peakers.[37]

Batteries are increasingly being used as peaking resources,[38] and this trend will continue in the coming decades.[39] Costs are declining rapidly.[40] Already, hybrid solar-plus-storage can displace fossil fuel-burning peaking generation,[41] and even "mid-merit" fossil gas generators as well.[42] Batteries, whether paired with solar generation or not, may represent a viable peaking resource in the very near term. Recognizing that battery capacity

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[35] Nima Simon, et al., *Examining the current and future economics of hydrogen energy*, ICF (Aug. 13, 2021), https://www.icf.com/insights/energy/economics-hydrogen-energy ("natural gas transmissions lines have the technical capability of accommodating up to 50% hydrogen; distribution lines can accommodate up to 20%").

[36] Robert Schulte and Fredric Fletcher, *Green hydrogen & electrolysis load factor: The elephant in the room*, Power Eng'g (July 27, 2021), https://www.power-eng.com/emissions/green-hydrogen-electrolysis-load-factor-the-elephant-in-the-room/.

[37] Despite indications that Duke views hydrogen-powered turbines as zero-carbon resources, it is possible that Duke is not planning to procure turbines capable of running entirely on hydrogen, nor of procuring solely "green" hydrogen to power them. For example, Duke might be planning to procure conventional fossil gas-burning combustion turbines and simply power them with small percentages of gray or blue hydrogen mixed with fossil gas at levels low enough not to damage pipelines or turbines. Such a plan would not be consistent with the carbon-reduction mandate in Session Law 2021-165 or the requirements of the climate emergency. Further, because any new conventional fossil gas-burning generation would not be capable of running 100% hydrogen without costly modifications, at a minimum the cost of those modifications and any additional transportation costs would need to be included in the avoided capacity cost.

[38] *See* Cheryl Katz, *In Boost for Renewables, Grid-Scale Battery Storage Is on the Rise*, Yale Environment 360 (Dec. 15, 2020), https://e360.yale.edu/features/in-boost-for-renewables-grid-scale-battery-storage-is-on-the-rise.

[39] *See* Jennie Jorgenson, et al., Storage Futures Study: Grid Operational Impacts of Widespread Storage Deployment at 13 (2022), https://www.nrel.gov/docs/fy22osti/80688.pdf.

[40] *Annual Technology Baseline: Utility-Scale Battery Storage*, NREL, https://atb.nrel.gov/electricity/2021/utility-scale_battery_storage (last visited Feb. 22, 2022); Wesley Cole and A. Will Frazier, NREL, Cost Projections for Utility-Scale Battery Storage: 2020 Update, https://www.nrel.gov/docs/fy20osti/75385.pdf.

[41] *See* Bloomberg NEF, How PV-Plus-Storage Will Compete With Gas Generation in the U.S. (2020), https://assets.bbhub.io/professional/sites/24/BloombergNEF-How-PV-Plus-Storage-Will-Compete-With-Gas-Generation-in-the-U.S.-Nov-2020.pdf (finding solar-plus-storage a "zero-emissions threat to gas"); Xi Lu, et al., *Combined solar power and storage as cost-competitive and grid-compatible supply for China's future carbon-neutral electricity system*, Proc. of the Nat'l Academy of Sci. of the U.S. of Am. (Oct. 19, 2021), https://www.pnas.org/content/118/42/e2103471118.

[42] *See* Colleen Leuken, *Beyond Peaker Replacement: Solar+Storage Finds a New Job*, Fluence (Apr. 18, 2019), https://blog fluenceenergy.com/fluence-energy-storage-solar-storage-mid-merit-utility-scale-asset.

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tends to range from two to eight hours—although long-duration storage also is increasingly viable—the contribution to meeting capacity needs will be slightly different from the traditional simple CT used for avoided capacity cost analysis. However, in a future in which simple fossil-gas CTs will not be procured while batteries will be procured to meet peaking needs, batteries could form part of the appropriate measures of avoided capacity cost.

Accordingly, although SACE does not recommend using the cost of hydrogen-powered turbines or batteries to calculate avoided capacity costs in this proceeding, doing so might be appropriate in a future proceeding.

B. Avoided Energy Cost Calculations

SACE has four main concerns with Duke's avoided energy cost calculations. First, they should be based on a more standard natural gas commodity price forecast methodology, relying on forward contract prices for far less time than Duke's anomalous methodology does. Second, Duke should recalculate the SISC after correcting flaws identified in the Kirby SISC Report. Third, the Commission should establish a mechanism to compensate QFs for ancillary services, beginning with a pilot program. Finally, and the Commission should reject Duke's proposal to calculate "as-available" rates ex-post at the end of the month.

i. Duke's natural gas commodity price forecast methodology should be revised.

As Duke points out in its Initial Statement, the appropriate methodology to accurately forecast commodity prices has been a contested issue in biennial avoided cost proceedings since 2014, when Duke began relying on ten years of forward contract natural

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gas marketplace data before switching to market fundamental forecasts.[43] It is appropriate to revise this methodology in light of the passage of Session Law 2021-165 and the inaccuracy of forward market prices in recent times.

The issue was litigated in the 2016 biennial avoided cost proceeding after Duke switched from using five years of forward contract natural gas price data to ten years,[44] and the Commission determined that it was appropriate to "adopt a method relying on market data for eight years and fundamental forecasts thereafter."[45] In the 2018 biennial avoided cost proceeding the Commission determined that the parties "produced substantial, competent, and material evidence and well-articulated arguments" but the evidence did not definitively support changing the methodology.[46]

In the streamlined 2020 biennial avoided cost proceeding, Duke applied the methodology established by the Commission but also argued in its Initial Statement that it should be allowed to use the same methodology in the avoided cost proceeding as it does in its IRPs, relying on ten years of forward natural gas market price data before transitioning to commodity price estimates derived from fundamental forecasts.[47] SACE, in joint comments with the Carolinas Clean Energy Business Alliance ("CCEBA"), and the North Carolina Sustainable Energy Association ("NCSEA") responded to Duke's argument by pointing out that the use of even eight years of forward market prices raises

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[43] Duke Initial Statement 25.

[44] *See* Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 75 (Oct. 11, 2017), Docket No. E-100, Sub 148, https://starw1 ncuc.net/NCUC/ViewFile.aspx?Id=9b202168-0968-4338-9c64-70b5366ab109.

[45] *Id.* at 77.

[46] Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 59 (Apr. 15, 2020), Docket No. E-100, Sub 158, https://starw1 ncuc.net/NCUC/ViewFile.aspx?Id=eff66bdb-e96f-417f-a526-e88dc8d3a6d9.

[47] Joint Initial Statement and Proposed Standard Avoided Cost Rate Tariffs Of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC at 19-20 (Nov. 2, 2020), Docket No. E-100, Sub 167, https://starw1.ncuc net/NCUC/ViewFile.aspx?Id=db8926e9-cdf2-48b0-bc7b-bf597e73ff92.

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concerns about the transparency, practical applicability, and liquidity of the price data, and that a transition period between the forward-only forecast and the fundamental forecast would allow for a smoother transition between forecast methodologies.[48] SACE, CCEBA, and NCSEA supported their argument with an expert report prepared by Crossborder Energy's Tom Beach.[49] In its Reply, Duke opposed SACE, CCEBA, and NCSEA's critique but stated that it "may support a different position on natural gas commodity price forecasting methodologies in future proceedings."[50] The Commission determined that the streamlined nature of the proceeding did not allow for thorough consideration of the issue and authorized Duke to continue using the eight-year-forward-contract methodology that the Commission adopted in the 2016 proceeding.[51]

It is appropriate for the Commission to revise this methodology in this proceeding. In its Initial Statement, Duke states that it continued to use the eight-year-forward-contract methodology that the Commission adopted in the 2016 proceeding in an "effort to reduce the number of potential contested issues for the Commission's determination, and that it achieved a consensus with the Public staff on continuing to use that methodology.[52] SACE is very mindful of the limits of the resources available to the Commission and wishes to minimize contested issues whenever possible, particularly given the significant and time-

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[48] Joint Initial Comments of the Southern Alliance for Clean Energy, North Carolina Clean Energy Business Alliance, and the North Carolina Sustainable Energy Association at 15 (Jan. 25, 2021), Docket No. E-100, Sub 167, https://starw1.ncuc net/NCUC/ViewFile.aspx?Id=d56dd368-5078-4f16-a48b-8d4ec55a46e6.

[49] *Id.*, Ex. A.

[50] Reply Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC at 9, (Mar. 5, 2021), Docket No. E-100, Sub 167, https://starw1 ncuc.net/NCUC/ViewFile.aspx?Id=2c0e9f74-a595-40c9-9ffb-f2a611ab655e.

[51] Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 23-24 (Aug. 13, 2021), Docket No. E-100, Sub 167, https://starw1 ncuc.net/NCUC/ViewFile.aspx?Id=b36b2878-827f-492c-b227-1ac82e878408.

[52] Duke Initial Statement at 25-26.

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sensitive work required to implement Session Law 2021-165. However, unlike the 2020 biennial avoided cost proceeding, this is not a streamlined proceeding and the Commission should not authorize a methodology that will foreseeably produce inaccurate results. In addition, because this issue has been litigated in prior proceedings it could be resolved without undue burden.

SACE submits that the eight-year-forward-contract methodology inherently produces inaccurate results for reasons discussed in the 2016, 2018, and 2020 proceedings, particularly in the Cross-border Energy report filed in the 2020 proceeding. Two recent developments indicate that the methodology is ripe for revision now.

First, the Carbon Plan will replace Duke's 2022 biennial IRP[53] and for the Carbon Plan Duke has proposed to replace the ten-year-forward-contract methodology used in its prior IRPs with "5 years of market gas w/ 3 year blend to fundamentals."[54] This change is consistent with the Public Staff's longstanding position in avoided cost dockets that Duke should use no more than five years of forward contract prices,[55] although the new methodology still uses forward contract prices for much longer than the two to three years that SACE believes is appropriate.[56] It is also more consistent with the South Carolina

[53] Order Requiring Filing of Carbon Plan and Establishing Procedural Deadlines at 3 (Nov. 19, 2021), Docket No. E-100, Sub 179, https://starw1 ncuc.net/NCUC/ViewFile.aspx?Id=12e88c31-1ed2-4581-85ab-2d396c780c1f.

[54] Ex. C, Duke Energy Carolinas Carbon Plan Stakeholder Meeting 1: Virtual Meeting –January 25, 2022 at slides 66.

[55] *E.g.*, Public Staff Initial Comments at 29-24, E-100 Sub 140, https://starw1 ncuc net/NCUC/ViewFile.aspx?Id=5af8d4f6-d717-4abe-bdf1-3c5f395cf139; Public Staff Hinton testimony at 33-34, E-100 Sub 148, https://starw1 ncuc.net/NCUC/ViewFile.aspx?Id=afe638f4-97b1-454e-b8f2-828df097de5f; Public Staff Proposed Order at 85, E-100 Sub 148, https://starw1 ncuc net/NCUC/ViewFile.aspx?Id=ed5aea4c-13b9-4d12-8854-51bae4f096e4; Public Staff Initial Statement at 21-28, E-100 Sub 158, https://starw1.ncuc net/NCUC/ViewFile.aspx?Id=14bc24da-25a7-4f86-af4c-14c299ef2fcc.

[56] A Duke representative has testified in South Carolina that the use of three years of forward contract pricing, followed by a shift to fundamental forecasts, is a more standard approach to projecting gas prices in the utility industry. Order Requiring Modification to Integrated Resource Plans, Docket No. 2019-

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Public Service Commission's conclusion that the ten-year-forward-contract methodology used in Duke's prior IRPs "is flawed and results in generation mixes which do not represent the most reasonable and prudent means of meeting Duke's energy and capacity needs" because it "commits Duke to large-scale buildouts of natural gas generation assets, at the expense of renewables and storage, endangering Duke's internal commitment to net-zero generation by 2035."[57] The South Carolina Public Service Commission directed Duke to "remodel its portfolios using natural gas pricing forecasts that rely on market prices for eighteen months before transitioning over eighteen months to the average of at least two fundamentals-based forecasts."[58] Similarly, SACE, CCEBA, and NCSEA recommended in the 2020 proceeding to blend forward market prices and fundamentals during a transition period in order to smooth the transition.[59]

Furthermore, for its market fundamentals forecast Duke plans to "[u]se an average of EIA, EVA, IHS and Wood MacKenzie" in an effort to decrease volatility from year to year.[60] This is consistent with the recommendation by SACE, CCEBA, and NCSEA in the 2020 proceeding to average fundamental forecasts, and as those parties noted in that proceeding, doing so will provide additional transparency and a check on the private forecasts.

224-E and Docket No. 2019-225-E — Order No. 2021-447 at 62 (June 28, 2021), https://dms.psc.sc.gov/Attachments/Order/28c909bb-889f-4095-b364-1ab8359ee799

[57] Order Requiring Modification to Integrated Resource Plans, Docket No. 2019-224-E and Docket No. 2019-225-E — Order No. 2021-447 at 17 (June 28, 2021), https://dms.psc.sc.gov/Attachments/Order/28c909bb-889f-4095-b364-1ab8359ee799.

[58] *Id.* at 64.

[59] This effect is plainly visible in the chart on slide 66 of the presentation made at the first Carbon Plan stakeholder meeting. Ex. C, Duke Energy Carolinas Carbon Plan Stakeholder Meeting 1: Virtual Meeting –January 25, 2022 at slides 66.

[60] Ex. C, Duke Energy Carolinas Carbon Plan Stakeholder Meeting 1: Virtual Meeting –January 25, 2022 at slides 66.

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SACE recognizes that EVA, IHS, and Wood MacKenzie are all private forecasts, which in general are opaque in their methodology and basis, in contrast to the public nature of the EIA modeling platform, which is extensively documented and vastly more transparent.[61] EIA's AEO also remains a highly regarded set of energy, economic, and environmental projections. In this proceeding, Duke has relied on IHS alone for its fundamental forecast, and as a consequence, even making use of data requests Intervenors only have access to IHS forecasts, in addition to the public EIA forecasts. This suggests an approach for this proceeding of blending IHS and EIA for purposes of the fundamental forecast, since in this proceeding only these forecasts pass the most basic transparency test of parties being able to review the forecast datapoints themselves. In sum, for this proceeding, SACE recommends averaging the Spring 2021 IHS and EIA 2021 Reference Case for purposes of the fundamental forecast.

Second, the dramatic increase in natural gas prices over the past year shows the potential inaccuracy of forward market prices even as little as one year out. For example, even in January 2021, less than one year before natural gas prices would rise to more than $5/mmbtu, the forward market was pricing natural gas at below $3/mmbtu on average for 2021 and 2022, and at around $2.50/mmbtu for 2023.[62] In fact, gas spot prices averaged nearly $4/mmbtu in 2021 and are currently expected to average between $3.50 and $4/mmbtu during 2022 and 2023.[63] In other words, mere months before a major and persistent increase in gas prices, the forward market was expecting a business as usual

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[61] See https://www.eia.gov/outlooks/aeo/nems/documentation/ . For example, the NEMS documentation includes hundreds of pages of publicly available, detailed description of natural gas markets alone.

[62] S&P Global Market Intelligence. 2022. Natural Gas Forwards and Futures. https://www.spglobal.com/marketintelligence/en/. Accessed January 13, 2022.

[63] EIA. Short-term Energy Outlook January 2022 at 16.

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outlook for years to come. And while fundamental forecasts such as the EIA's Annual Energy Outlook did not perfectly predict the upswing either, the January 2021 AEO projections were much closer to the prices that were ultimately seen in the market. Beyond recent forward market dynamics, the expansion of liquified natural gas export terminals is exposing U.S. gas markets to global markets,[64] which is likely to raise volatility in US markets just as other globally traded commodity fuels are subject to high volatility.[65] This will impact forward markets more than it impacts fundamentals forecasts, further underscoring the prudence of maintaining a shorter period of usage for forwards data within natural gas forecasts.

At a minimum, it is clear that the natural gas forwards market in recent months failed to price in one or more fundamental supply and/or demand factors. This urges caution in relying on the forwards market for any amount of time within current forecasting efforts.

Accordingly, the Commission should require Duke to recalculate its avoided energy costs using a more accurate natural gas commodity price methodology. SACE recommends adopting the basic methodology applied by Dominion, "using 18 months of forward market prices, 18 months of blended prices," before switching fully to fundamental forecasts,[66] averaging the Spring 2021 IHS and EIA 2021 Reference Case as discussed

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[64] US Energy Information Administration, Short-Term Energy Outlook February 2022 at 3 and 15.

[65] *See What Drives Crude Oil Prices?*, U.S. Energy Info. Admin., https://www.eia.gov/finance/markets/crudeoil/spot_prices.php (last visited Feb. 23, 2022); Kevin Dobbs, Industrial, LNG Demand to Drive Natural Gas Consumption Through 2022, Natural Gas Intelligence (Feb. 15, 2022), https://www naturalgasintel.com/industrial-lng-demand-to-drive-natural-gas-consumption-through-2022/ (noting increasing post-pandemic European and Chinese demand and potential for further European demand resulting from Russian aggression in Ukraine); S&P Global Platts, *GASTECH 2021: LNG spot price volatility key focus for market players* (Sept. 23, 2021), https://www.spglobal.com/platts/en/market-insights/latest-news/lng/092321-gastech-2021-lng-spot-price-volatility-key-focus-for-market-players.

[66] Dominion Initial Statement 7.

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above. This is essentially identical to the methodology recently required by the South Carolina Public Service Commission in its IRP, except the that South Carolina Commission explicitly required using at least two fundamental forecasts.[67]

ii. The updated Solar Integration Service Charge is flawed.

SACE greatly appreciates the Commission's decision to require an independent technical review of the 2018 Astrapé Study that formed the basis of the SISC deducted from the avoided energy cost rate paid to variable solar QFs.[68] SACE believes that the process was productive, as evidenced by the technical review committee's ("TRC") decision to discuss SACE's concerns in its report and incorporate some of them.[69] As a result of the TRC's input, the 2021 Astrapé Study is greatly improved relative to the 2018 Astrapé Study. SACE recommends building on the success of this approach and requiring third-party independent technical review, informed by stakeholder input, of Duke's analyses in the avoided cost and other proceedings in the future.

However, as detailed in the Kirby SISC Report attached as **Exhibit A**, the 2021 Astrapé Study does contain three main flaws that inflate the value of the SISC and therefore artificially depressed avoided energy cost paid to solar QFs. First, the 2021 Astrapé Study assumed that solar load-following reserves are required during multiple hours during which there is no solar generation, before sunrise and after sunset. The effect plainly is to overcharge solar QFs for reserves.

[67] *Id.* at 64.

[68] Order Establishing Standard Rates and Contract Terms For Qualifying Facilities at 95 (April 15, 2020), Docket No. E-100, Sub 158, https://starw1 ncuc.net/NCUC/ViewFile.aspx?Id=eff66bdb-e96f-417f-a526-e88dc8d3a6d9.

[69] Brattle TRC report at III-14 to III-16.

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Second, the "combined case," which approximates the Joint Dispatch Agreement ("JDA") under which DEC and DEP are currently operating, as recommended by the TRC, failed to account for the reduction in solar load-following reserves that are required under JDA operations. Including the "combined case" is one of the biggest improvements in the 2021 Astrapé Study and as expected it showed that it is cheaper to supply load-following reserves when the system is operated pursuant to the JDA, because the system has more resources available to draw from, which makes it more likely that cheaper resources can be used. However, operating the system pursuant to the JDA also reduces not just the per-unit *cost* of solar reserves but also the *amount* of load-following reserves necessary because the JDA *nets* the DEC and DEP systems' dispatch needs to meet real-time balancing requirements. If one of the Duke entities requires reducing generation to balance load while the other requires increasing generation, under the JDA Duke will combine those needs and the system as a whole will only increase or decrease generation by the *net* amount needed. The 2021 Astrapé Study applied load-following reserve requirements determined in the *island* case to the JDA case. This does not reflect how the JDA actually meets DEC and DEP real-time balancing requirements, overstating load-following reserve requirements and therefore artificially increasing the SISC.

Finally, the 2021 Astrapé Study applied an unnecessarily stringent five-minute "flexibility violation" metric that is inappropriate for the SISC analysis. North American Electric Reliability Corporation ("NERC") reliability standards require 30-minute balancing. There is no NERC reliability requirement to balance generation and load in the five-minute time frame (under non-contingency conditions). A more appropriate timeframe for the SISC analysis would be 20 or 25 minutes. By applying the unnecessarily stringent

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five-minute "flexibility violation" metric the 2021 Astrapé Study overstates needed reserves and artificially inflates the SISC value.

SACE recommends requiring Duke to revise the 2021 Astrapé Study accordingly and to re-calculate the SISC based on the revised study.

iii. QFs can provide positive ancillary services and should be compensated for doing so.

As one of the Sub 158 "additional issues," the Commission directed the Utilities to evaluate the potential for QFs to provide ancillary services and the proper compensation for doing so. In its Initial Statement, Duke dismisses the potential for QFs to provide ancillary services and the need to compensate them for doing so, but it is wrong on both counts.

1. QFS ALREADY PROVIDE POSITIVE ANCILLARY SERVICES AND COULD PROVIDE MORE.

It is SACE's understanding that other intervenors in this proceeding, NCSEA and CCEBA, are able to demonstrate that some QFs already provide ancillary services and could provide additional ancillary services with relatively low-cost modifications.

2. QFS ARE ENTITLED TO COMPENSATION FOR PROVIDING ANCILLARY SERVICES.

Under PURPA, a QF is entitled to compensation for the purchasing utility's avoided costs, meaning "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[70] In Order No. 69, FERC

[70] 18 C.F.R. § 292.101(b)(6); *see* 16 U.S.C. § 824a-3(d) (defining same); 16 U.S.C. § 824a-3(a) (purchase obligation); 18 C.F.R. § 292.304(b)(2) (setting rate at full avoided cost); N.C. Gen. Stat. § 62-156(b) (standard contract avoided cost rates).

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determined that the rate for purchases from QFs should equal this amount,[71] and the Supreme Court upheld FERC's decision to require utilities to purchase from QFs at this "full" avoided cost rate in order to encourage development of QFs and reduce reliance on fossil fuels.[72] FERC further explained that the purchase of "electric energy" under PURPA Section 210(a)(2)[73] includes both energy and capacity and was intended to refer to "all of the costs associated with the provision of electric service."[74] Similarly, the NCUC has declined to "agree that FERC's regulations prohibit the approval of any rate or charge other than those offered for energy and capacity."[75]

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[71] 45 Fed. Reg. 12214 (Order 69), https://www.ferc.gov/sites/default/files/2020-04/order-69-and-erratum.pdf; *see* 18 C.F.R. § 292.304(B)(2).

[72] *Am. Paper Inst., Inc. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 417 (1983).

[73] 16 U.S.C. § 824a-3(a)(2).

[74] 45 Fed. Reg. 12214, 12225, (Order 69), https://www ferc.gov/sites/default/files/2020-04/order-69-and-erratum.pdf. FERC's decisions concerning QF participation in organized markets affirm the view that QFs are entitled to sell ancillary services. Under Order No. 888, utilities must provide two ancillary services--(i) Scheduling, System Control and Dispatch and (ii) Reactive Supply and Voltage Control from Generation Services--and must offer to provide four others--(i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve—Spinning, and (iv) Operating Reserve—Supplemental. Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 Fed. Reg. 21540-01, 21587-88 (Order 888). Because a transmission provider is uniquely positioned to provide the first two ancillary services, a transmission customer must purchase them from the provider. *Id.* at 21587. Although the other four "must be provided by someone if the system is to be operated reliably," a transmission customer may decline to purchase them from the transmission provider if it can demonstrate that it has acquired them from another source. *Id.* In Order No. 888-A, FERC clarified that the other source may be supplied by a third party or self-supplied. Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 62 Fed. Reg. 12274-01, 12309 (Order 888-A). And in Order No. 888-B, FERC further clarified that ancillary services as defined in Orders Nos. 888 and 888-A "are part of the cost of transmission and therefore are included among the interconnection costs a QF is responsible for." Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 62 Fed. Reg. 64688-01, 64697 (Order 888-B). Accordingly, a QF operating in an organized market, but lacking nondiscriminatory market access and therefore eligible to sell under PURPA's purchase obligation, is entitled to compensation at the avoided cost rate for the energy and capacity that it provides, and may choose to be compensated for providing ancillary services by self-supplying and avoiding the charge for optional ancillary services under the transmission provider's OATT. Furthermore, the QF could provide ancillary services to other customers as a third-party provider.

[75] Sub 158 Order at 90 n.4, https://starw1 ncuc net/NCUC/ViewFile.aspx?Id=eff66bdb-e96f-417f-a526-e88dc8d3a6d9.

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Consistent with this mandate, the Commission indicated that a QF is entitled to compensation for ancillary services by repeatedly citing the benefits as well as costs of solar integration when the Commission approved the inclusion of the SISC as a decrement to avoided cost rates for solar. As the Commission explained, the provisions of 18 C.F.R. § 292.304(e) "not only allow but require the Commission to consider both the costs that the utility avoids by purchasing from a QF and the costs that the utility may incur, not otherwise accounted for, as a result of purchases from a QF."[76] Similarly, the Commission has twice explained that "it may be appropriate for the Utilities to include the costs and benefits related to solar integration in their avoided cost calculations when both the costs and benefits have been sufficiently evaluated and reviewed by the Commission so that a reasonable level of accuracy has been attained."[77] Whereas Duke now appears to take the view that only the cost of solar integration should be accounted for, by way of the SISC—a "heads, I win; tails, you lose" approach—the Commission clearly construes federal regulation to require factoring the benefits of solar integration as well. It would be inconsistent asymmetrically to include only integration costs.

Duke seemed to agree with this view in the past. When it proposed the SISC, Duke took the position that under PURPA the Commission is required to set standard-offer avoided cost rates based on "the costs that actually will be avoided by utilities when purchasing from QFs" and that these should recognize any "increased ancillary services

[76] Sub 158 Order 92, https://starw1 ncuc.net/NCUC/ViewFile.aspx?Id=eff66bdb-e96f-417f-a526-e88dc8d3a6d9.

[77] Sub 158 Order 92, https://starw1 ncuc.net/NCUC/ViewFile.aspx?Id=eff66bdb-e96f-417f-a526-e88dc8d3a6d9 (paraphrasing Sub 140 Order).

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costs not avoided by QFs."[78] Thus, Duke believed that QFs are entitled to compensation for at least some ancillary services that they do avoid.

Duke now makes four misguided arguments against compensating QFs for ancillary services. First, it argues that "QFs are already fully compensated for their capacity and energy output under the peaker method such that no additional compensation is appropriate under PURPA."[79] Duke reasons that "the value of positive ancillary services provided by a QF as part of the capacity and energy delivered to the utility, if any, is already incorporated into the calculation of the utility's full avoided cost rates."[80] Duke relies on a footnote in a FERC order concerning wholesale markets for the proposition that "energy sold under PURPA 'includes capacity, energy and ancillary services,'"[81] and appears to conclude from this that the "energy" component of avoided cost rates already includes ancillary services.

Duke has it backwards. The quoted footnote explains that when a QF sells "energy," "[i]n the context of PURPA, the term energy includes capacity, energy and ancillary services."[82] As discussed above, in Order No. 69 FERC explained that the word "energy" in PURPA includes both energy and capacity and was intended to refer to "all of the costs associated with the provision of electric service."[83] To the extent that a QF also allows the

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[78] Duke Reply at 76, Docket No. E-100, Sub 158, https://starw1 ncuc net/NCUC/ViewFile.aspx?Id=7c33d58d-fc8e-47ac-8f27-d96222c3ec38.

[79] Duke Initial Statement 34.

[80] Duke Initial Statement 37.

[81] Duke Initial Statement 37 (quoting Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. by Pub. Utils., 123 FERC ¶ 61,055, n.869, 2008 FERC LEXIS 788, (Apr. 21, 2008)).

[82] Mkt.-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. by Pub. Utilities, 123 FERC ¶ 61,055, 61,433 n.869 (2008) (Order 697-A).

[83] 45 Fed. Reg. 12214, 12225, (Order 69), https://www ferc.gov/sites/default/files/2020-04/order-69-and-erratum.pdf.

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utility to avoid providing or procuring ancillary services, the cost of those services may also be included in the avoided cost rate, depending on how the applicable rate is structured.

Duke's interpretation also leads to absurd consequences. For one thing, it would mean that not just the value of ancillary services but also the value of capacity costs are inherently included in the "energy" sold by a QF, and there would be no need to calculate avoided capacity costs. This conflicts with Order No. 69 and decades of PURPA implementation. Furthermore, the position that QFs are already fully compensated for ancillary services again treats ancillary services as having zero value by compensating resources that supply large amounts of ancillary services as providing the same value as those that provide little or none.

Duke also makes the related factual claim that it does not need additional ancillary services because its existing generating fleets are capable of providing all needed ancillary services.[84] This claim runs counter to a basic principle behind PURPA, that QFs are compensated for costs they allow the utility to avoid. The fact that a utility could have obtained energy, capacity, and ancillary services without the QF is the basis of avoided cost rates, i.e., the cost that the utility would have otherwise paid but for the QF. The question is the cost of ancillary services that Duke would otherwise provide itself. Duke's claim that ancillary services are not needed is irrelevant. It is also in tension with the high value that Duke assigns to the ancillary services that its generating fleet provides.[85] It also runs counter to Duke's general argument that increasing solar penetration increases the cost

[84] Duke Initial Statement 37.

[85] *See* Duke Initial Statement 32 (discussing SISC); *see also* Duke's OATT, Schedules 2, 3, 3A, describing value assigned to various ancillary services, https://etariff.ferc.gov/TariffBrowser.aspx?tid=1615. SACE opposes Duke's suggested proposal to, contrary to the Commission's prior decision on the question, revise the SISC applied to a QF throughout the term of its contract. *See* Duke Initial Statement 32 n.77.

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of integration,[86] which is based on the assumption that other resources must provide the ancillary services needed for integration. And it relies on a misapplication of PURPA. Even assuming *arguendo* that Duke's system has little need for additional incremental ancillary services that would affect only the avoided-cost *value* of the ancillary services provided by QFs, not their eligibility for compensation under PURPA.

Second, Duke argues that, at this time, it does not have sufficient control over the dispatch of QFs to operate them in a way to provide ancillary services.[87] That may be true at this time, but it does not credit QFs for any ancillary services they already provide. And it would be easy to solve with limited investments and contract revisions. It does not present a bar to compensating QFs for ancillary services in principle or in the long term. Moreover, Session Law 2021-165 requires all new resources procured from third parties to be controllable and dispatchable in the same manner as if they were Utility resources.

Third, Duke argues that a QF would need to produce less than its maximum energy and capacity in order to be able to provide ancillary services.[88] This is not necessarily true. Furthermore, there are contractual solutions to the potential mismatch between the value of energy in the value of ancillary services at any point in time. For example, an optional provision in the contract between a QF and a utility could specify that the utility will pay the QF according to its expected annual output while the QF hands control of daily operations to the utility, which can operate the QF however benefits the system most.

[86] *See* Duke Initial Statement 32 ("as solar penetration increases, the cost to integrate these variable and intermittent resources while maintaining operational reliability also increases").
[87] Duke Initial Statement 35.
[88] Duke Initial Statement 36.

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Fourth, Duke argues that QFs increase rather than decrease the need for ancillary services, as represented by the SISC.[89] However, any need for increased ancillary services as a result of a solar QF's generation already is captured by the SISC itself. The existence of the SISC does not prove that QFs should not be compensated for ancillary services that they provide; to the contrary, as discussed above, it shows precisely the opposite.

Accordingly, SACE recommends that the Commission consider establishing a way to compensate QFs for ancillary services that they provide. Recognizing the Commission has on previous occasions expressed the view that the costs and benefits of solar integration should be included "when both the costs and benefits have been sufficiently evaluated and reviewed by the Commission so that a reasonable level of accuracy has been attained,"[90] SACE recommends that the Commission begin by either requiring Duke to commission an independent and stakeholder-informed study of the potential for QFs to provide ancillary services and the appropriate compensation, or by establishing a pilot program for ancillary services, subject to clear guidelines and transparency requirements.

C. <u>"As-Available" Rates in Schedule PP</u>

Duke proposes to revise its Schedule PP tariff to use the hourly marginal cost of producing energy to calculate avoided costs for QFs that elect to sell energy to the Companies on an "as-available" basis, and to calculate Duke's marginal cost rates "ex-post at the end of the month for each hour in a given month based on the joint dispatch outcomes for DEC and DEP during that month using the incremental cost of production of the next megawatt hour," and as a result "QF compensation will be based on actual marginal costs

[89] Duke Initial Statement 36.

[90] Sub 158 Order 92, https://starw1 ncuc.net/NCUC/ViewFile.aspx?Id=eff66bdb-e96f-417f-a526-e88dc8d3a6d9 (paraphrasing Sub 140 Order).

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rather than market forecasts."[91] Duke argues that this approach is consistent with FERC's policy goals and analysis in Order No. 872.

The proposal to calculate rates ex-post at the end of the month is not appropriate. In Order No. 872, FERC rationalized allowing states to shift to avoided cost rates with variable energy components while maintaining a fixed capacity component because it determined this was a construct found elsewhere in the electric industry.[92] But calculation a month after the fact is not the industry standard.[93] Suppliers must account for revenue uncertainty in their financial models, and in general more revenue uncertainty imposes costs on suppliers. Ex-post-calculation causes additional uncertainty beyond what would otherwise be the case for a variable rate, imposing a cost and inflating QF overall project costs and effectively imposing a decrement on the rate received by the QF.[94] This will needlessly strain QF project economics, result in more difficult QF financing, and ultimately weaken the PURPA market and the competitive pressure that it places on the monopoly utility provider to operate efficiently. Recognizing that Duke has raised concerns with stakeholders about a perceived risk of over- or under-payment resulting from a fixed rate for as-available sales when fixed for two years, SACE submits that this concern still could be remedied by an price set ex-ante but adjusted more frequently.

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[91] Duke Initial Statement 39-40.

[92] Order No. 872 PP 35-38.

[93] *See* Francisco Flores-Espino, et al., NREL, Competitive Electricity Market Regulation in the United States: A Primer at 13 (2017), https://www.nrel.gov/docs/fy17osti/67106.pdf.

[94] *See* Anastasiya Ostrovnaya, et al., The High Cost of Electricity Price Uncertainty (2020), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3588288.

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D. Exclusion of carbon emission costs from the emission costs used in Duke's modeling of its avoided energy costs.

As in prior years, Duke has assumed that it will be allowed to continue emitting carbon dioxide pollution at no cost throughout the forecast period. Duke's input assumptions for the production cost modeling used to determine avoided energy costs include the emission costs for certain air pollutants, including criteria air pollutants such as NO_x and SO_2, but the inputs for the production cost runs used by DEC/DEP do not include CO_2 emissions costs over the forecast period.[95]

In light of the enactment of Session Law 2021-165 this position is no longer tenable. Session Law 2021-165 requires the Commission to take "all reasonable steps to achieve a seventy percent (70%) reduction in emissions of carbon dioxide (CO_2) 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 the year 2050."[96] This carbon-reduction mandate must guide Duke's procurement beginning immediately, and the Carbon Plan developed in order to carry out the carbon-reduction mandate will take the place of Duke's 2022 IRP.[97]

By limiting Duke's (and DENC's) carbon omissions, Session Law 2021-165 makes it possible to calculate a cost of carbon.[98] The law requires adopting the least-cost path to

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[95] *See* Duke response to PS DR 2-7 ("Portfolio A of the DEC and DEP 2020 IRPs, the Companies' Base Case without Carbon Policy portfolio, was used to calculate the Companies' avoided energy rates.").

[96] Session Law 2021-165, Part I, Section 1, https://ncleg.gov/Sessions/2021/Bills/House/PDF/H951v6.pdf.

[97] Order Requiring Filing of Carbon Plan And Establishing Procedural Deadlines at 3 (Nov. 19, 2021), Docket No. E-100, Sub 179, https://starw1 ncuc.net/NCUC/ViewFile.aspx?Id=12e88c31-1ed2-4581-85ab-2d396c780c1f.

[98] This is not to say that the law necessarily will make operating Duke's system more expensive. Because Duke's most carbon-intensive resources tend to be costly and inefficient, if implemented well the law could in fact save customers money. Multiple analyses indicate as much. *E.g.*, Rachel Wilson, et al., Clean, Affordable, and Reliable: A Plan for Duke Energy's Future in the Carolinas at 1 (2021) ("Synapse's model produces an alternate clean energy resource portfolio that reduces total system cost by $7.4 billion

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achieving the reductions quoted above.[99] There is a carbon price that will achieve these reductions.[100] And a carbon price is an efficient means of achieving the required reduction because it will drive actors to find the lowest-cost ways to reduce carbon emissions.[101] Accordingly, the carbon price necessary to achieve a 70% reduction in CO_2 emissions by the year 2030 and carbon neutrality by the year 2050 represents a reasonable proxy for the cost of carbon resulting from Session Law 2021-165.

The Commission need not require Duke to separately model this price or wait for the final Carbon Plan. Duke has used a carbon price in its IRP and that price represents a reasonable proxy. In Duke's 2020 IRP, its base case with carbon policy started at $5/ton in 2025 and escalated at a rate of $5/ton per year thereafter.[102] Similarly, Dominion has relied on ICF's commodity forecast for carbon dioxide.[103] In the alternative, the Commission could use the RGGI allowance price. Analysis prepared under the state Clean Energy Plan—which the Commission has directed Duke to build on in creating its draft Carbon Plan—already has showed that joining the Regional Greenhouse Gas Initiative

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and CO2 emissions by 74 percent compared to a scenario similar to Duke's modeled Base Case with Carbon Policy."), filed on behalf of SACE, et al., in the 2020 IRP proceeding, Docket No. E-100, Sub 165, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=be90482d-7f8e-4949-babc-c23d33e6d4c5; Kate Konschnik, et al., Power Sector Carbon Reduction: An Evaluation of Policies for North Carolina at 14, Table ES.3 (2021), https://nicholasinstitute.duke.edu/sites/default/files/publications/Power-Sector-Carbon-Reduction-An-Evaluation-of-Policies-for-North-Carolina-Revised_0.pdf (showing that joining the Regional Greenhouse Gas Initiative and using revenue to invest in energy efficiency saves money overall).

[99] Session Law 2021-165, Part I, Section 1, https://ncleg.gov/Sessions/2021/Bills/House/PDF/H951v6.pdf.

[100] It is essential to evaluate achieving both reductions at once. There are some investments that could seem to form part of the least-cost paths to achieving the 2030 reduction that would nonetheless dramatically increased costs to achieving carbon neutrality in 2050 and increase costs overall.

[101] *See* Marc Hafstead, Resources for the Future, Carbon Pricing 101 at 2 (2019), https://media.rff.org/documents/Carbon_Pricing_Explainer.pdf.

[102] Duke Energy Carolinas, LLC 2020 Integrated Resource Plan, 2020 REPS Compliance Plan, and 2020 CPRE Compliance Plan at 152-53, Docket No. E-100, Sub 165 (Sept. 1, 2020), https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=9752b166-f870-4b0c-8469-8f791405d95c.

[103] 2020 Integrated Resource Plan of Virginia Electric and Power Company, App'x 4O: ICF Commodity Price Forecasts for Virginia Electric and Power Company (PDF p.200), https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=8d39e2f8-252f-49f5-aa1e-cbd3906f42bc.

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("RGGI") would drive emissions reductions almost in line with the 2030 goal,[104] making the RGGI allowance price an alternative readily available proxy for the purpose of this proceeding.

The Commission has ample authority to require Duke to recalculate its avoided cost using a cost of carbon. First, carbon costs are now sufficiently certain to meet the Commission's standard for inclusion. The Commission originally declined to include them on the grounds that the costs were not "known and verifiable,"[105] explaining that the cost of carbon associated with complying with pending federal regulations under the Clean Air Act were "not sufficiently certain" because "[t]he end result of the proposed regulations is speculative at best."[106] That is not true now. The end result of Session Law 2021-165 is certain: electric generating facilities owned or operated by electric public utilities will reduce their carbon dioxide emissions at least 70% below 2005 levels by 2030 and will achieve carbon neutrality by the year 2050. This may be translated into a cost of carbon as discussed above.

Second, Session Law 2021-165 gives the Commission ample authority to include a cost of carbon in avoided cost rates and arguably requires it to do so. Under the law, the Commission "shall take all reasonable steps" to achieve the carbon-reduction mandates set out above.[107] Establishing a cost of carbon in avoided cost rates is a reasonable step. By

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[104] Kate Konschnik, et al., Power Sector Carbon Reduction: An Evaluation of Policies for North Carolina at 12, Table ES.2 (2021), https://nicholasinstitute.duke.edu/sites/default/files/publications/Power-Sector-Carbon-Reduction-An-Evaluation-of-Policies-for-North-Carolina-Revised_0.pdf (showing that "RGGI with 2030 CEP target" achieves 66% reduction from 2005 levels in in-state emissions in 2030); *id.* at 73 (showing sharp initial decline in emissions under RGGI with 2030 CEP target).

[105] Order Setting Avoided Cost Input Parameters at 44 (Dec. 31, 2014), Docket No. E-100, Sub 140, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=4d85c17b-ef0a-4dc4-a0fd-c84d4f39ef80.

[106] *Id.*

[107] Session Law 2021-165, Part I, Section 1, https://ncleg.gov/Sessions/2021/Bills/House/PDF/H951v6.pdf.

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effectively increasing the cost of carbon-emitting generation relative to zero-emitting generation, it would encourage the latter and reduce emissions. Accordingly, the Session Law 2021-165 authorizes and arguably requires the Commission to include a cost of carbon in avoided cost rates, and it provides a more than enough authority to revisit or alter the Commission's prior "known and verifiable" standard.

Duke explained its reasoning behind excluding a carbon price in a response to the Public Staff's Data Request No. 2, Item 2-8, as follows:

> The Sub 175 avoided cost filing was based on Portfolio A of the Companies' 2020 IRPs - the Base Case without Carbon Policy - and using updated fuel prices. HB 951 requires the NCUC to take all reasonable steps to achieve a 70% reduction in carbon emissions emitted in NC from 2005 levels by the year 2030, and carbon neutrality by the year 2050. HB 951 further directs the Commission to develop a Carbon Plan by December 31, 2022 to achieve these emissions reductions. Because HB 951 relates to the Companies' *future* planning (i.e., it does not impose any tax on the use of carbon or other similar mandate that must be immediately implemented), the law does not impact the avoided cost rates calculated and submitted for approval in Sub 175. Notably, the NCUC has directed the Companies to use the no carbon base case for the development of PURPA avoided cost rates in the initial Sub 140 Phase One Order issued December 31, 2014, as such costs were determined not to be known and verifiable. Most recently, the NCUC accepted the Companies' use of Portfolio A to calculate avoided cost rates in the Sub 167 avoided cost proceeding. Furthermore, PURPA QF solar contracts do not convey environmental attributes or curtailment rights to utility customers as is the case with current CPRE procurements and under future 951 procurements.[108]

Duke's response hinges on the assumption that the law only applies at some point in the future and is not self-executing or "immediately implemented." This is not an accurate view of Session Law 2021-165, which established carbon-reduction mandates effective the day the bill was signed into law, October 7, 2021,[109] three weeks before Duke filed its Initial Statement. Although the Carbon Plan will not be final for some time yet, the carbon-

[108] Duke response to Public Staff's Data Request No. 2, Item 2-8.
[109] Session Law 2021-165, https://ncleg.gov/Sessions/2021/Bills/House/PDF/H951v6.pdf.

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reduction mandates in Session Law 2021-165 may be relatively easily translated into a carbon price as discussed above. Duke's contrary approach of essentially ignoring the impact of the state's carbon-reduction mandate is untenable.

Accordingly, SACE recommends using the carbon price in the base case with carbon policy in Duke's 2020 IRP, starting at $5/ton in 2025 and escalating at a rate of $5/ton per year thereafter, or in the alternative the RGGI allowance price, as a proxy for the cost of carbon under Session Law 2021-165.[110]

IV. DISCUSSION OF DOMINION'S INITIAL STATEMENT

The following sections address concerns with Dominion's avoided capacity cost calculations followed by its avoided energy cost calculations.

A. Avoided Capacity Cost Calculations

Dominion used the 2021 EIA Annual Energy Outlook costs for an F class turbine to establish its avoided capacity cost.[111] For the same reasons set forth in Section III.A. above, this choice of avoided peaking resource is outdated and a more appropriate peaking resource would be an aeroderivative gas turbine in the very near term, and batteries or a 100% green hydrogen-powered turbine shortly thereafter.

B. Avoided Energy Cost Calculations

These comments address two salient features of Dominion's avoided energy cost calculations. First, Dominion has used a more reasonable overall natural gas commodity price forecast approach compared to Duke, though Dominion's fundamental forecast

[110] Because Dominion already included a cost of carbon in its proposed rates and that cost based on the RGGI allowance price due to Virginia's participation in RGGI, only Duke would need to update its rates with a cost of carbon.

[111] Dominion Initial Statement 20.

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sources should be improved. Second, Dominion's updated solar integration or "re-dispatch" charge and proposed protocol for avoiding it are inaccurate and unreasonable.

i. Natural gas commodity price forecast

Dominion developed avoided energy cost rates using 18 months of forward market prices, 18 months of blended prices and then market fundamental prices based on ICF forecasts starting in month 37.[112] As discussed above, SACE submits that this is a reasonable approach for combining forward prices and fundamental forecast components of an overall price forecast in this proceeding, and it contrasts with Duke's proposed approach described above. However, SACE reiterates its recommendation to average multiple fundamental price forecasts, as discussed above. Rather than rely solely on its private, opaquely derived ICF fundamental forecast, Dominion should be required to average the ICF fundamental forecast with the 2021 EIA Annual Energy Outlook Reference Case. This is analogous to SACE's recommendation above that Duke average its IHS fundamental forecast with the 2021 AEO Reference Case.

ii. Solar re-dispatch charge (RDC)

Dominion's updated solar integration or "re-dispatch" charge has increased significantly, from \$0.78/MWh in the 2018 and 2020 proceedings to \$1.87/MWh.[113] The methodology Dominion used to develop this charge is flawed, resulting in an RDC that does not reflect actual solar integration costs and may be too high.

First, as explained in the Kirby RDC Report, attached as **Exhibit B**, the methodology that Dominion used to determine the RDC does not time-synchronize solar generation with power system data. The two must be synchronized in order to produce

[112] Dominion Initial Statement 7.
[113] Dominion Initial Statement 12-15.

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accurate results. In addition, the historic solar data used to derive the RDC comes from twenty-two locations, all but three of which are outside of North Carolina, and many of which are far to the north.

Second, the increase appears to be based at least in part on an error. Dominion states that "[a]s more and more intermittent generation like solar PV or wind is added to the grid, the level of uncertainty about re-dispatch costs increases due to unpredictable cloud cover or changes in wind speed."[114] As a general rule, the opposite is true due to "geographic smoothing," the smoothing out of overall variability among renewable generation as generation is added in geographically distinct locations. Dominion should have captured this effect by modeling "the potential system cost impacts from intermittent resources outside the Company's service territory"[115] but if it interpreted the effect of geographic diversity to be to cause increased costs then modeling the broader region could have exacerbated the error.

There are problems with Dominion's updated protocol for avoiding the RDC as well. As Dominion explained the protocol:

> To be eligible for the re-dispatch cost reduction, a QF must provide DENC with an hourly generation output forecast for every hour of the year. For the first year of the contract, the QF must provide the forecast on or before 90 days prior to the facility's commercial operations date ("COD"). For subsequent contract years, the QF may update the forecast on or before 90 days before the start of every calendar year of the contract; if no updated forecast is provided, DENC will utilize the previously provided forecast to calculate the re-dispatch charge reduction credit. Every April, DENC will calculate the re-dispatch cost reduction using the prior calendar year forecast and metered data. DENC will provide the re-dispatch charge reduction as a line item credit with the first payment following the April calculation.[116]

[114] Dominion Initial Statement 13.
[115] Dominion Initial Statement 13.
[116] Dominion Initial Statement 16.

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This protocol is not reasonable. It requires each QF to predict and guarantee its hourly output over a year or more in advance. No other generation technology is required, or capable of, meeting this requirement. Thermal generators routinely require maintenance outages or deratings that were not forecast a year in advance, yet Dominion has not proposed a redispatch charge for them. An RDC based on day-ahead and hour-ahead forecasts would align more closely with Dominion's actual generation redispatch requirements.

First, the degree to which a solar QF's actual generation over the course of a year matches its generation projected over a year in advance does not bears any direct relationship to the variability or volatility of solar output, nor any consequent "re-dispatch" that solar generation might cause. The RDC avoidance protocol does not reflect the cost to Dominion, if any, caused by solar generation.

Second, the protocol relies on outdated information. Dominion appears to be requiring QFs seeking to avoid the re-dispatch charge to provide an hourly energy forecast covering the full upcoming year at least 90 days before the start of that year. However, Dominion then will calculate the re-dispatch charge in April of the year in question. Accordingly, the QF's forecast will be at least 6 months old and possibly as much as almost 1 ¼ years old (for the first forecast for a project beginning operations in May). This burdensome requirement is concerning in light of the fact that "no QFs (CSGs) have sought to avail themselves of the RDC avoidance protocol."[117]

Accordingly the Commission should (1) require Dominion to recalculate the RDC using a methodology that will accurately capture the system costs, if any, imposed by solar

[117] Dominion Initial Statement 17.

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generation; and (2) require Dominion to adopt an RDC avoidance protocol that accurately reflects the solar QF's avoidance of the system costs, if any, imposed by solar generation. To verify that Dominion's subsequent filing meets these requirements, the Commission should consider requiring review by an independent technical review committee with the opportunity for stakeholder input.

V. CONCLUSION

SACE values the stakeholder process that preceded this biennial avoided cost proceeding, recognizes that it resulted in fewer contested issues in this proceeding, and recommends that the Commission rely on it in future proceedings as well. However, as discussed above, there are still several areas of disagreement. SACE requests that the Commission order the Utilities to adjust their avoided cost calculations consistent with the recommendations in these Initial Comments. Specifically, SACE requests that the Commission:

1) With respect to Duke's avoided capacity cost calculations, require Duke to recalculate its avoided capacity costs using an aeroderivative gas turbine as the avoided peaking resource, or at a minimum, require Duke to explain how continued construction of CTs for peaking capacity is consistent with system needs and the requirements of Session Law 2021-165 and the forthcoming Carbon Plan;

2) With respect to Duke's avoided energy cost calculations:

    a. require Duke to recalculate its avoided energy costs using a more accurate natural gas commodity price methodology, using 18 months of forward market prices, followed by 18 months of blended prices, before

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switching fully to fundamental forecasts, comprising the average of the Spring 2021 IHS and EIA 2021 Reference Case;

b. require Duke to revise the 2021 Astrapé Study to resolve remaining flaws identified in the Kirby SISC Report, and to re-calculate the SISC based on the revised study;

c. establish a way to compensate QFs for ancillary services, beginning by either requiring Duke to commission an independent and stakeholder-informed study of the potential for QFs to provide ancillary services and the appropriate compensation, or by establishing a pilot program for ancillary services, subject to clear guidelines and transparency requirements;

d. reject Duke's proposal to calculate "as-available" rates ex-post at the end of the month, and instead continue to set the rate ex-ante but consider adjusting it more frequently;

e. establish an avoided cost of carbon component to avoided cost rates, using the carbon price in the base case with carbon policy in Duke's 2020 IRP, starting at $5/ton in 2025 and escalating at a rate of $5/ton per year thereafter, or in the alternative the RGGI allowance price, as a proxy for the cost of carbon under Session Law 2021-165;

3) With respect to Dominion's avoided capacity cost calculations, require Dominion to recalculate using the cost of an aeroderivative gas turbine as the more appropriate peaking resource;

4) With respect to Dominion's avoided energy cost calculations,

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a. require Dominion to recalculate the fundamental forecast components of its natural gas commodity price forecast, averaging the ICF fundamental forecast with the 2021 EIA Annual Energy Outlook Reference Case;

b. require Dominion to recalculate the RDC using a methodology that will accurately capture the system costs, if any, imposed by solar generation; and require Dominion to adopt an RDC avoidance protocol that accurately reflects the solar QF's avoidance of the system costs, if any, imposed by solar generation; and to verify compliance require review by an independent technical review committee with the opportunity for stakeholder input.

SACE thanks the Commission for considering these comments and looks forward to offering additional recommendations in reply comments and potentially through other avenues such as the stakeholder input provisions recommended above.

Respectfully submitted this the 24th day of February, 2022.

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CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing filing by electronic mail.

This the 24th day of February 2022.

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Exhibit A

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Overestimation in Duke Energy's Proposed Solar Integration Service Charge

Brendan Kirby, P.E.   24 February 2022

Introduction

The 2021 Solar Integration Service Charge Study (SISC Study or Study) is a major improvement over the 2018 Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study. The stakeholder recommended and Commission approved Technical Review Committee (TRC) has been a great influence. Duke adopted most of the stakeholder analysis methodology recommendations, some only in part. There are still concerns with some recommendations that were not fully followed or that were incorrectly interpreted.

Duke Energy's proposed solar integration charge is based on an analysis methodology that does not represent how the DEC and DEP power systems are physically operated or the reliability requirements imposed by NERC mandatory reliability standards.

The proposed solar integration charge was developed for Duke Energy by Astrapé Consulting and documented in an October 22, 2021 study titled "Duke Energy Carolinas and Duke Energy Progress Solar Integration Service Charge (SISC) Study" (*SISC Study* or the *Study*). The unreasonable assumptions and flawed methodology used in the Study will result in increasingly unrealistic estimates of required reserves and costs as solar penetration increases. The Commission should not approve a solar integration charge that is based on reserve requirements that Duke will not actually experience or costs that Duke will not actually incur.

There are several major errors in the SISC Study's assumptions, each of which results in the Study significantly overestimating the Companies' reserve requirements and artificially inflating solar integration cost projections:

(1) Solar incremental load following reserve requirements were imposed during hours when there is no solar generation.
(2) The DEC DEP Combined Case analysis failed to account for the reduction in solar load following reserves that are required under Joint Dispatch Agreement (JDA) operations. Reserve requirements are likely overstated by 10% (Tranche 1) to 20% (Tranche 2).
(3) The Flexibility Violations reliability metric is unrelated to mandatory NERC reliability requirements and is inappropriate for this analysis. Reserve requirements are significantly overstated.

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All of these assumptions result in overstating the solar load following reserve requirements and related costs that DEP and DEC will experience as solar penetration increases.

Concerns With Solar Incremental Load Following Reserve Requirements Timing

The SISC Study analysis methodology imposed Solar Load Following Reserve Requirements during hours when no solar generation is possible, no solar ramps are possible, no solar variability is possible, and it is not possible for solar generation to cause "flexibility violations".

The SISC Report states that "In response to stakeholders and the TRC, the Study added load following across the day to manage the solar ramps and volatility and targeted additions based on when the flexibility excursions were occurring." [1] (TRC Report, pg 37) While this is an improvement in study methodology over imposing solar reserve requirements 24 hours a day, as was done in the previous analysis, it is still unreasonable to impose solar reserve requirements before sunrise and after sunset.

The SISC Report includes an example average August solar profile (SISC Report Figure 7, pg 23). Graphs for the other 11 months were not provided. Hourly Load Following Targets for DEC and DEP for Tranches 1 and 2 were also presented in SISC Report Figures 15, 16, 20, and 21. All show Incremental Load Following Targets beginning at 6:00 and going for 16 hours through 21:00 – apparently imposing solar load following reserve requirements during hours when there is no solar generation.

In response to data request SACE DR 1-6, Duke provided the hourly solar load following requirements for Tranche 2 (TR2).[2] Duke also provided the hourly solar output for TR2 for the 39 years of 1980 through 2018. This report's **Error! Reference source not found.** below shows the hourly solar load following reserve requirements and the maximum hourly solar output for four example months.[3] All months show a similar pattern of reserves being required during many hours when there is no solar output.

Error! Reference source not found. shows maximum hourly solar generation (dotted curves) and Incremental Solar Load Following Reserve Target MW (solid curves) for DEC (blue) and DEP (orange). Clearly solar load following reserve requirements are being imposed during hours when there is little or no solar generation.

[1] The draft report used the wording "In response to stakeholders and the TRC, the Study added load following ***only during solar hours*** and targeted additions based on when the flexibility excursions were occurring." The incorrect *wording* was changed after it was pointed out that reserve requirements were being imposed during non-solar hours. Only the wording was changed, not the math or the hours reserve requirements were imposed.

[2] Data for Tranche 1 was also provided.

[3] Solar output is for the 15th of each month.

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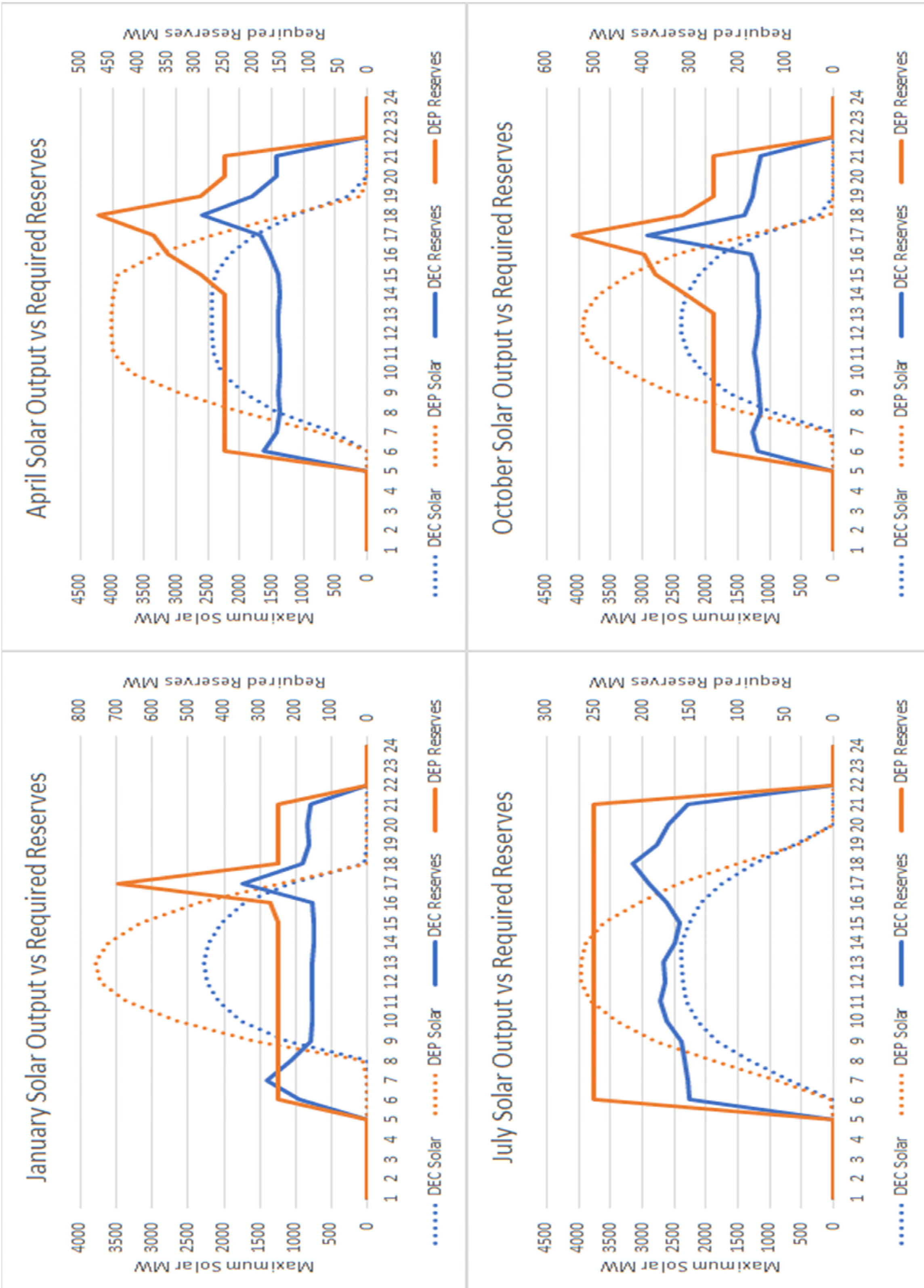
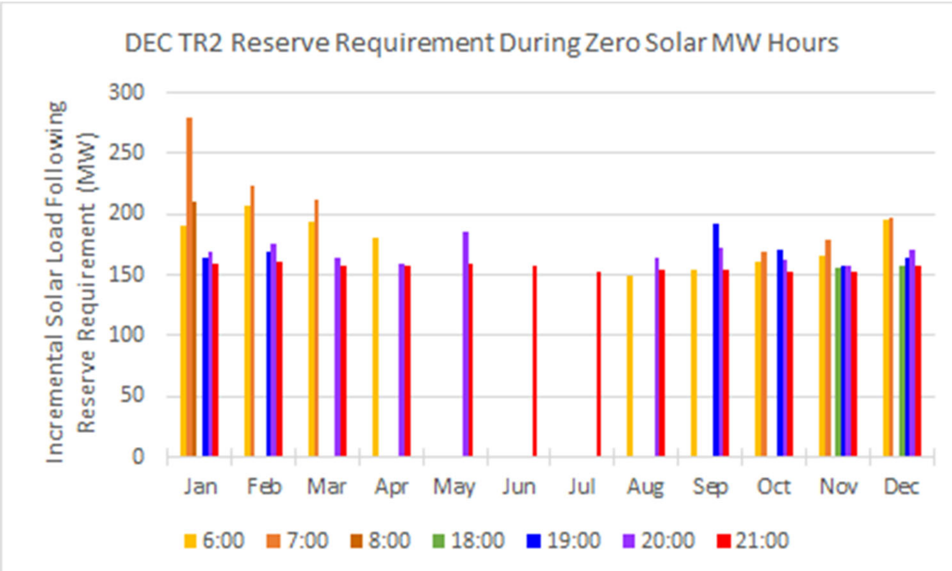


Figure 1 The SISC analysis imposed solar load following reserve requirements during hours when solar generation is not possible.

Figure 2 shows hours-of-the-day each month when the Solar Incremental Load Following Reserve Requirements were imposed during hours with no solar output. There are many more hours when Solar Incremental Load Following Reserve Requirements exceed the maximum potential solar generation.



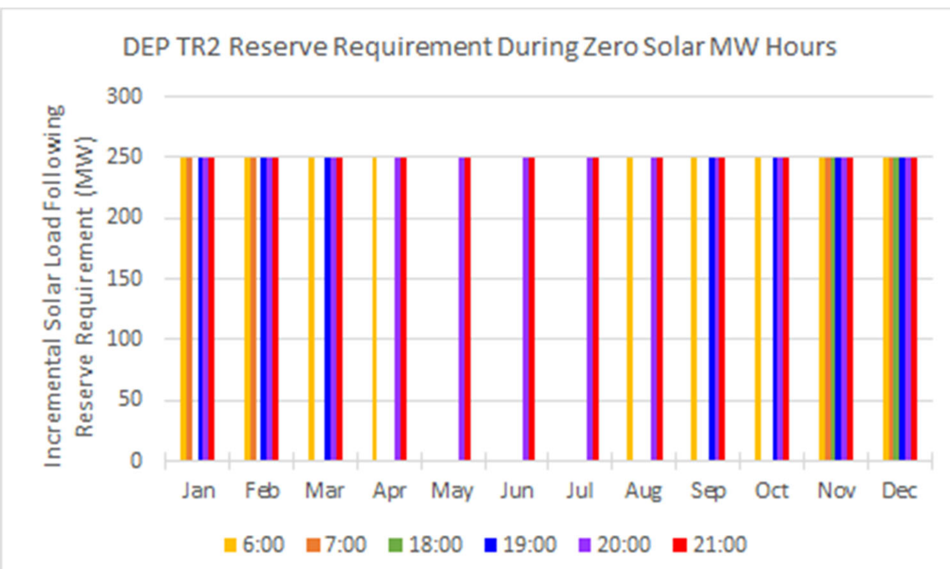


Figure 2 The SISC analysis imposed solar load following reserve requirements during non-solar hours every month.

The SISC Report analysis methodology imposed additional solar reserve requirements during six hours each day during of January, November, and December when there is no solar output for both DEC and DEP. Even in June and July additional solar reserve requirements were imposed during hours each day when there is no solar output.

It is not reasonable to impose solar load following reserve requirements "to manage the solar ramps and volatility" during hours when there is no possibility of solar generation.

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We suggest that the SISC analysis be performed with solar reserve requirements only in hours when solar is actually generating. Reserve requirements in the first and last hours should also be reduced or eliminated to reflect the very low solar output during those hours.

Duke Response to Concern of Imposing Solar Reserve Requirements During Non-Solar Hours

SACE brought the concern that additional Solar Load Following Reserve requirements were being imposed during hours with no solar output to Duke's attention in a technical memo dated September 16, 2021. The concern was further discussed with Duke during an October 1, 2021 conference call. On the call, Duke stated that it does see variability in the pre-dawn 5, 6, and 7 hours, as well as in the post-sunset hours, referencing Astrape's heat plots. However, those heat plots track all variability, not just variability from solar. Duke also stated that it needs to be positioned ahead of actual variability in order to be ready for that variability—but imposing a reserve requirement two hours ahead of actual need will make the problem worse because the model will pre-position the units ahead of the reserve requirement. Duke did not change the reserve requirements or perform any additional analysis. Duke did change the *wording* in the final SISC Report from "during solar hours" to "across the daytime hours" on 12 pages in numerous locations[4].

Additionally, on pg 38 the SISC Report now states that "As solar is added, the flexibility excursions move towards *later in the afternoon* ***or*** *during solar ramp up periods*." (emphasis added) The earlier version stated that "As solar increases, higher concentrations of the flexibility excursions are pushed towards *periods when solar is ramping down*." (emphasis added) By substituting "in the afternoon" for "when solar is ramping down" the new wording subtly avoids claiming that flexibility excursions which occur after sunset are caused by solar generation, though the methodology adds solar reserve requirements during non-solar hours. The report is silent concerning the flexibility violation causes.

In summary, Duke did not address the concern that additional Solar Load Following Reserve Requirements are being imposed, with costs allocated to solar generation, during hours when there is no solar generation possible. The methodology is still seriously flawed.

Concerns with the DEC DEP Combined Case

At the suggestion of stakeholders and the recommendation of the Technical Review Committee the SISC analysis was amended to include a Combined Case that modeled response from the aggregate DEC and DEP generation fleet. Previous analysis unrealistically treated DEC and DEP as islanded power systems.

Inclusion of the Combined Case in the SISC analysis is a major improvement. The combined case more accurately represents how the DEC and DEP generation fleet is actually operated and the savings that result from the Joint Dispatch Agreement (JDA).

The SISC Technical Review Committee (TRC) noted that:

[4] Interestingly the wording was not changed in three tables (Table 9, 10, and A.1) in the back of the report where the "Solar Hours" wording was left in.

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"After the merger of Duke and Progress, the combined company implemented the JDA between DEC and DEP to provide generation at a lower cost for customers of both utilities. Under the JDA, Duke performs a joint unit commitment and minute-by-minute energy dispatch subject to transmission availability between the two utilities. …

"In its previous estimate of the SISC, Astrapé modeled independent unit commitment and dispatch for the DEC and DEP generation resources. The previous Astrapé study also assumed that there was no transmission interconnection between the two utilities and no exchange of economic energy for the purpose of intra-hour load following. Similar assumptions are reflected in the "islanded" cases presented in the Astrapé Report in this estimate of the SISC.

"To reflect the operation of the JDA, the TRC requested that Astrapé simulate a scenario for the current study where DEC and DEP areas perform joint unit commitment and minute-by-minute dispatch subject to applicable transmission limitations. … The Astrapé Report presents the results of this case as the "combined" case.

"**The TRC recommended modeling the combined case because it better reflects Duke's current operations than the islanded cases**." (TRC Review of Duke Energy's SISC, pg III-6, emphasis in original)

Results from cases which modeled islanded or independent unit commitment and dispatch for DEC and DEP should not be considered as they do not represent how DEC and DEP actually operate with the JDA.

Continued Concerns with the Combined Case as Modeled in the SISC Study

In actual operations the JDA reduces load following balancing costs in two distinct ways. The JDA inherently reduces the *MW amount* of required load following response and it reduces the *per-unit $ cost* of supplying the load following response that is still required. The SISC Study only addresses the reduced per-unit cost of supplying load following response but does not correctly model the reduction in the MW amount of required load following.

That is, the SISC Study appears to correctly model the reduction in *per-unit costs for supplying* the additional Load Following Reserves. The way the SISC Study was conducted, however, does not reflect the *reduction in MW amount* of additional Load Following Reserves required with JDA operations.

Duke acknowledges that solar volatility declines with additional solar generation. The SISC Study analyzed a year of historic DEC and DEP 5-minute solar data and found that "the volatility declines with additional solar" generation (SISC Study pg 27). SISC Report Figure 9 (Figure 3 below) clearly shows the percentage decline in 5-minute deviations as solar installations increase. Red points show historic data and blue points show expected continued benefits at higher solar generation. Note especially that the historic "Combined DEC and DEP" point is below both the historic stand-alone DEC and DEP points. The total DEC plus DEP solar generation for Tranche 1 and 2 have been added in green showing the continued decline in expected 95th percentile 5-minute deviations.

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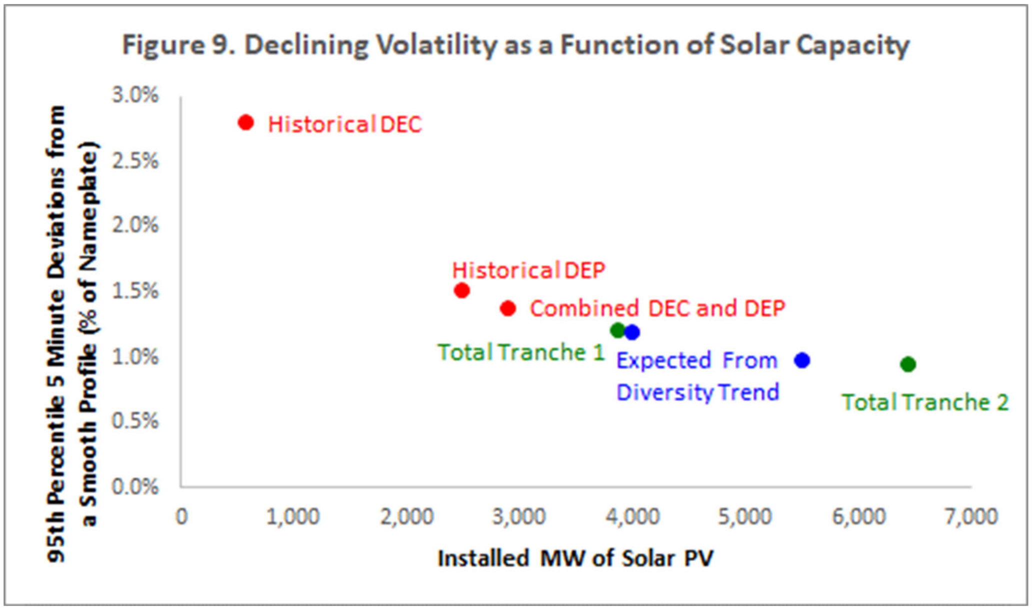

Figure 3 SISC Report Figure 9, with total TR1 and TR2 generation added, showing the decline in solar volatility as solar penetration increases.

In spite of the acknowledged decline in solar volatility with larger aggregations of solar generation, solar reserve requirements were not determined for the combined JDA region. Load following reserve requirements were determined for DEC and DEP as if they were islands operating without the JDA. The SISC Report states that "the Companies were modeled as islands for this analysis because each balancing area is responsible for its own NERC requirements. By modeling in this manner, *the required operating reserves and flexibility requirements are calculated for each of the Companies*." (SISC Report pg 33, emphasis added) The analysis determined that an additional 12 MW of Load Following Reserves were required to support DEC tranche 1 and 46 MW were required to support DEC tranche 2 while 95 MW were required to support DEP tranche 1 and 157 MW were required to support DEP tranche 2. Imposing load following reserve requirements that were based on DEC and DEP operating as islands greatly overstates the actual load following reserves that are required when DEC and DEP operate under the JDA. Modeling higher load following reserve requirements than are actually needed to maintain reliability increases modeled costs and the calculated SISC.

While added reserves *requirements* were established assuming the JDA did not exist, reserve *supply* was modeled as coming from the JDA. The SISC Report states that "TRC also requested the analysis be performed assuming the Joint Dispatch Agreement (JDA) between DEC and DEP was utilized. Astrapé accommodated this request and in this scenario, *each BA still holds its own operating reserves*, but economic exchanges are allowed to reduce the costs of the additional load following requirements." (SISC Report pg 33, emphasis added)

The SISC Combined Case analysis imposed the full additional Load Following Requirements, determined for DEC and DEP modeled as islands, on the system but allowed the JDA to meet these added reserve requirements with the combined DEC and DEP generation fleet. The SISC Report states that "the realized load following additions *determined in the island case* were targeted for the combined case except now

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economic transfers can be made on a 5-minute basis." (SISC Report pg 50, emphasis added) Table 12 from the Report is partially reproduced below.

SISC Report Table 12. Combined (JDA Modeled) Results with Load Following Cost Allocation

	DEC Tranche 1	DEP Tranche 1	Combined Tranche 1	DEC Tranche 2	DEP Tranche 2	Combined Tranche 2
Solar Capacity (MW)	967	2,908	3,875	2,431	4,019	6,450
Island 10-Minute Load Following Reserve Needed	12	95	**106**	46	157	**204**

Note that the analysis *imposed* the additional Load Following Reserve requirements (106 MW and 204 MW) on the JDA analysis – it did not model how the JDA actually deals with solar imbalances. This is a subtle but important point.

The JDA Inherently Reduces the MW Amount of Required Reserves

Operation of the DEC and DEP power systems with the JDA inherently reduces the MW amount of variability and volatility (from all sources) that must be responded to.

The SISC Study overstates the SISC because it does not model how the JDA actually meets DEC and DEP real-time balancing requirements. While "each balancing area is responsible for its own NERC requirements" they meet these requirements through the Joint Dispatch Agreement. That is, the DEC and DEP generation fleets are *Jointly Dispatched* to meet the minute-to-minute net energy and reserve needs of the DEC and DEP systems together.[5] This inherently reduces the *MW amount* of response required. For example, if DEC requires an additional 20 MW of up generation during one 5-minute interval due to a solar generation variation while DEP requires 5 MW of down generation at the same time the JDA would not move one generator up 20 MW and another down 5 MW. The efficiency and economics of the JDA come from the fact that it ***nets*** the dispatch needs before it orders generators to respond (to the extent allowed by transmission constraints) and only supplies 15 MW of total up generation during the example interval. Even though DEC and DEP continue to operate their own NERC Balancing Areas the JDA inherently provides aggregation benefits that reduces the net volatility and variability of the combined systems.

The SISC Report states "the volatility declines with additional solar". (SISC Report pg 27) SISC Report Figure 9 shows that the combined DEP and DEC systems have less solar volatility than the islanded systems. The

[5] The JDA is automated and operates in real-time, updating generation dispatch every 30 seconds. Duke response to SACE Data Request 1-5 states that "the JDA implementation is automated using an application running on the Duke Energy Carolinas Energy Management System (EMS)." The JDA "is automatically implemented in the DEC and DEP Net Scheduled Interchange variable of the Area Control Error (ACE) equations that are acted upon by the EMS algorithm determining generation setpoint dispatch signals." The JDA application updates "every 30 seconds".

JDA inherently captures this aggregation benefit by dispatching the combined DEC and DEP generation fleets to meet the combined DEC and DEP minute to minute net load.

When analyzing the Combined Case, the additional Load Following Reserve requirements should not be determined for DEC and DEP separately and then summed. Instead, the additional reserve requirements for the combined 3,875 MW for tranche 1 and 6,405 MW for tranche 2 should be determined as coming from the JDA generation fleet. This will likely reduce the tranche 1 additional Load Following reserves from 106 MW to 96 MW and the tranche 2 additional Load Following reserves from 204 MW to 164 MW.[6] The Combined Case SISC rates will likely be similarly reduced.

Table 1 The JDA Inherently Reduces Real-Time Balancing Requirements

	DEC Tranche 1	DEP Tranche 1	Combined Tranche 1	DEC Tranche 2	DEP Tranche 2	Combined Tranche 2
Solar Capacity (MW)	967	2,908	3,875	2,431	4,019	6,450
Island 10-Minute Load Following Reserve Needed	12	95	106	46	157	204
Likely JDA 10-Minute Load Following Reserve Needed	12	95	**96**	46	157	**164**

The JDA Also Reduces Solar Generation Curtailments

The Combined Case results (even without correctly determining the Combined additional Load Following Reserves) shows a dramatic reduction in Tranche 1 and 2 solar DEP curtailment. Tranche 1 DEP curtailment goes from 6.8% for the Island Case to 0.3% for the Combined Case. Tranche 2 DEP goes from 14.1% curtailment for the Island Case to 3.0% for the Combined Case. (DEC shows a small rise from 0.1% to 0.3% for Tranche 1 and from 0.8% to 3.0% for Tranche 2.) (SISC Report Tables 9, 10, and 13)

Duke Response to Concern with the Combined Case Analysis

SACE brought the concern that reserve requirements in the combined case were not reduced to reflect the aggregation benefits that operations under the JDA inherently provide in a technical memo dated September 16, 2021. The concern was further discussed with Duke during an October 1, 2021 conference call. Duke did not change the reserve requirements or perform any additional analysis.

Southeast Energy Exchange Market (SEEM) Benefits

The Southeast Energy Exchange Market (SEEM) should further reduce the SISC when implemented, similar to reductions provided by the JDA. Just as the JDA provides balancing over a larger generation pool, SEEM

[6] Required reserves estimated assuming short-term DEC and DEP solar fleet variability and uncertainty are uncorrelated and the reserve requirements add statistically. Full production cost analysis can confirm this assumption.

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will further expand the pool of potential balancing resources. The SISC should be updated as soon as SEEM is implemented to reflect this expansion of balancing resources.

Failing to update the SISC once SEEM is implemented would likely result in significantly overcharging for costs that Duke is not incurring as soon as SEEM is implemented. An argument that experience will need to be gained to determine if SEEM can work and how to best utilize it is not valid. Even ignoring IPP participation and only considering the founding utilities these are all sophisticated power system operators that are already operating and optimizing generation fleets on a minute-to-minute basis with 4-6 second automatic generation control (AGC). Once SEEM is in effect, operators should be able to immediately incorporate 5-minute transactions to and from other utility operators that are also running optimized dispatch systems.

Concerns with the "Flexibility Violations" Methodology and Metric

The 2021 SISC Study methodology is a major improvement over the 2018 effort but there are still significant concerns. The basic problem with the 2021 SISC analysis is that it is still based on five-minute balancing. NERC reliability standards require 30-minute balancing, not five-minute balancing.

The basic analysis methodology is sound (based on the method of studying the power system without solar generation and with solar generation and then comparing the costs) but the selected reliability metric is not appropriate (five-minute "flexibility violations"). There are NERC established mandatory reliability standards which clearly state that continuous balancing on a five-minute interval is not required or useful for maintaining reliability.[7] The calculated SISC is wrong because the selected flexibility violations metric is unrelated to actual NREC reliability standards requirements. The impact of the inappropriate five-minute flexibility violations metric on the SISC calculation is compounded by Duke's uniquely inflexible generation, as discussed further below.

This 2021 SISC analysis is greatly improved by the elimination of the unjustified $LOLE_{FLEX}$ metric and fixed limit. It would be ideal to base the SISC analysis directly on established NERC reliability criteria but as the SISC Report correctly notes, and we acknowledged during the 2018 proceeding:

> "Understanding how the increase in solar generation will affect the ability of a BA to meet the CPS1 and the Balancing Authority Area Control Error Limit (BAAL) would be ideal. However, simulating violations of these standards is not possible." Or at least it is very difficult. (SISC Report, pg 14)

Nonetheless, the analysis criteria and metrics should be – and can be – technically tied back to actual NERC reliability requirements. Unfortunately, the SISC Report methodology is not based on NERC reliability requirements. The SISC Report acknowledges that "the simulations performed in SERVM do not measure the NERC Balancing Standards" and "While there are operational reliability standards provided

[7] "BAL-001-2 – Real Power Balancing Control Performance", "BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event", NERC

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by NERC that provide some guidance in planning for flexibility needs, *there is not a standard for flexibility excursions as measured by SERVM*." (SISC Report, pg 14, emphasis added).

The basic problem with the 2021 SISC analysis is that it is still based on five-minute balancing. NERC reliability standards require 30-minute balancing, not five-minute balancing.

Acknowledging the inability to tie the SISC to actual NERC reliability requirements the SISC Report states: "Absent a standard, this Study assumes that maintaining the same level of flexibility excursions as solar penetration increases is an appropriate objective." (SISC Report, pg 14) Conceptually this is reasonable ***but only if the "flexibility excursions" are defined so that they reflect actual operating and reliability needs*.**

NERC Balancing Requirements

The SISC Report defines a "Flexibility Excursions" as the "number of days per year the system cannot meet a known *5-minute net load ramp* due to system flexibility shortfalls" (SISC Report, page 13, emphasis added) There is no NERC 5-minute balancing requirement or a mandatory reliability requirement to reliability requirement to meet "5-minute net load ramp[s]". Rather than requiring balancing during every 5-minute period NERC's BAL-001 – Real Power Balancing Control Performance standard has two balancing requirements: Control Performance Standard 1 (CPS1) and Balancing Authority ACE Limit (BAAL).

CPS1 limits the annual average imbalances. Further, not all imbalances are bad. When interconnection frequency is below 60 Hz overgeneration helps raise frequency and helps reliability. Similarly, when interconnection frequency is above 60 Hz under generation helps lower frequency and also helps reliability. CPS1 gives credit for those imbalances that help restore interconnection frequency. While an annual average CPS1 score of 100% is required CPS1 scores range from 0% to 200%, so 100% is not perfect balancing. There is no 5-minute balancing requirement in CPS1.

The Balancing Authority ACE Limit (BAAL) does not require 5-minute balancing either. BAAL only limits ACE deviations that exceed *30 consecutive minutes*. Further, like CPS1, BAAL only limits ACE deviations that hurt interconnection frequency. That is, over-generation is not limited when interconnection frequency is below 60 Hz and under-generation is not limited when interconnection frequency is above 60 Hz. ACE limits are lax when frequency is close to 60 Hz and get progressively tighter as frequency deviates farther from 60 Hz.

Neither of the applicable reliability metrics that DEC and DEP must follow require 5-minute balancing or in any way limit 5-minute "Flexibility Excursions" – they require 30-minute balancing.

The 2021 SISC Analysis Methodology and Flawed Reliability Metric

The SISC analysis methodology is correctly based on the principle of studying the power system without solar generation and with solar generation and comparing the costs. To keep the analysis fair the with-solar *reliability* should be equal to the without-solar *reliability*. Because there is no explicit NERC Load Following reliability metric the SISC Study created a unique five-minute "Flexibility Violations" metric, determined the value in the without-solar case, and added Load Following Reserves until the same value was obtained in the with-solar case. Conceptually that is not unreasonable, *but you must be very careful*.

The SISC Report states that "flexibility excursions [are] defined as an event where the online generation fleet is not able to ramp fast enough to match upward net load perturbations." (SISC Report, pg 5) The SISC Report further states that "These *flexibility excursions are not expected to represent firm load shed events*, but rather are simply a measure of the fleet's ability to follow net load changes given a particular set of operating guidelines." (SISC Report, pg 5, emphasis added) The SISC Report further notes that "In the 2018 Study these were referred to as $LOLE_{FLEX}$ events. Recognizing that *these events do not correspond to load shed*, they are now referred to as flexibility excursions. (SISC Report, footnote 3, pg 11, emphasis added) Flexibility Violations are still not reliability events and are still not even explicitly tied to reliability requirements. This metric does not reflect maintaining power system reliability.

Evidence that the Flexibility Violations Metric is Inappropriate

As discussed above, there is no NERC reliability requirement to balance generation and load in the five-minute time frame, consequently there are no five-minute "Flexibility Violations". Power system five-minute balancing, and changes to power system five-minute balancing performance are not related to reliability or operating requirements. There is a requirement to balance within 30-minutes and changes to the power system's ability to balance within 30 minutes would be a reliability concern.

The SISC analysis Base Case established the no-solar Flexibility Violations performance as 2.6 events per year for DEC and 0.6 events per year for DEP. (SISC Report pg 7) The inconsistency between the DEC and DEP base case no-solar Flexibility Violations performance should give an analyst pause to question if what is being measured is relevant to reliability. At a minimum one wonders if the Flexibility Violations metric is accurately reflecting actual reliability when the base case "performance" for DEC is 4.3 times higher than for DEP. Why is the DEP no-solar Flexibility Violations performance 4.3 times "better" than for DEC? If 5-minute Flexibility Violations reflect reliability do DEP customers need higher reliability than DEC customers? Do DEP customers actually receive higher reliability than DEC customers? Or is the 5-minute Flexibility Violations Limit performance unrelated to reliability?

The Table 2 compares the Load Following Reserves, proposed SISC cost, solar curtailments, and the imposed Flexibility Violations limit for DEC, DEP analyzed as islands and for the Combined Case.

Table 2 The flawed Flexibility Violations Limit is dramatically different for DEC and DEP, indicating it is unrelated to actual reliability performance.

	DEC		DEP		Combined	
	Tranche 1	**Tranche 2**	**Tranche 1**	**Tranche 2**	**Tranche 1**	**Tranche 2**
Flexibility Violations Limit (Events/Year)	**2.6**		**0.6**			
Total Solar (MW)	967	2,431	2,908	4,019	3,875	6,450
Solar Penetration	2.2%	5.9%	9.1%	13.2%	4.8%	8.7%
Solar Load Following Reserve (MW)	12	46	**95**	**157**	107	203
Additional Curtailment (MWh)	2,338	43,003	392,280	1,187,332	25,333	407,012
Solar Generation (MWh)	1,887,495	5,279,075	5,677,218	8,312,633	7,564,713	13,591,708
Solar Curtailment	**0.12%**	**0.81%**	**6.9%**	**14.3%**	***0.3%***	***3.0%***
2021 Proposed SISC ($/MWH)	**$0.63**	**$1.05**	**$1.68**	**$2.26**	$1.42	$1.79

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Note that the proposed Solar Integration Charge is 2.4 times higher for DEP than DEC (average of tranche 1&2), curtailments are 37 times higher, and the required Load Following Reserves are 5.7 times higher – presumably because the DEP % solar penetration is 3.2 times higher than DEC. But the Flexibility Violations Limit is also 4.3 times tougher for DEP than DEC. So, which is the cause of the higher curtailments and higher cost – the higher solar penetration or the tougher Flexibility Violations limit?

Analysis Could Determine if "Flexibility Violations" Are an Actual Reliability Concern

Examining system balancing (total generation, total load, total solar generation, available spinning and non-spinning reserves) time-series performance for each time step from an hour before to an hour after the event would show if system reliability was actually a concern. It would show how long the event was, how large any imbalance was (MW), and what resources were available and addressing the imbalance. With only 0.6 to 2.6 Flexibility Violations per year analysis would not be difficult.

SACE requested data to analyze power system performance during flexibility violations, but Duke declined to provide it. SACE Data Request 1-6 c asked: "Please list all Flexibility Excursions for DEC and DEP for the modeled no-solar cases as well as for Tranche 1 and Tranche 2." Duke responded:

> "Response: **The model aggregates the results across iterations into events per year** as shown in the results of the report and SACE DR 6-1a(v).xls on the ftp site, as well as the heat maps generated for Figures 12, 13, 14, 17, 18, 19 on pages 38 to 44 of the Astrapé SISC Study Report for the timing of the events by month and hour." (emphasis added)

SACE reiterated the request for flexibility violation time-series data in SACE DR 2-1. Duke again refused to provide the data stating:

> "Response: The Companies object to this data request on the ground that it is **seeks to have the Companies prepare data and analysis that is not reasonably available or does not exist**, and therefore would be **unduly burdensome to create**. Notwithstanding the above objections, the Companies provide the following in response:
>
> "**Time series data for each 5-minute step from 1 hour before the violation to 1 hour after the flexibility violation is not available.**
>
> "*The model is run at 5-minute dispatch steps, so providing this data would require re-running the models and outputting 5-minute intra-hour results for 8,760 hours for each of the 1,950 iterations*, which are made up of 39 weather years, 5 load forecast errors, and 10 unit outage draws for both the base and change cases. **Hourly reports for all iterations are not normally turned on for full simulations due to run time and file sizes**"[8] (emphasis added)

[8] Duke appears to be implying that SACE DR2-1 is requesting a large amount of data which it is not. With only 2.6 flexibility violations per year for DEC and 0.6 for DEP the amount of data is less than 1/700th of that supplied by Duke in response to SACE DR 1-6b; hourly solar profile data.

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Duke states that the five-minute time-series data is not available. It seems reasonable to conclude that Duke has not analyzed the five-minute data to understand if the flexibility violations do in fact represent a reliability concern.

The implication of Duke's refusal to provide reasonably requested 5-minute flexibility violation time series data is that Duke has not analyzed the flexibility violations themselves to understand if there is a reliability concern is more troubling. Duke appears to have defined a reliability event (a 5-minute flexibility violation) that drives the entire SISC analysis but apparently has not looked to see if there is any potential reliability impact on modeled power system operations.

Analyzing Flexibility Violations

Flexibility Violation performance can readily be analyzed by first identifying the flexibility violations themselves (there are only 2.6 per year for DEC and 0.6 per year for DEP) in the modeling runs. They can be characterized by imbalance length (minutes) and depth (MW) as well as by time of day, day of year, system load, and solar generation. Once identified, a few typical as well as a few extreme events can be selected for further analysis. Extract the time-series data for each event from an hour before the event to an hour after. Look at the total system imbalance at each time step: total system load, total system generation, solar generation, total spinning reserves, and total non-spinning reserves. For any events that were large enough or long enough to be of potential reliability concern look at the performance of each of the generators providing responsive reserves. Determine why aggregate ramping capacity was not available during that event and identify mitigation measures.

The Distinction Between 5-Minute and 30-Minute Balancing Requirements Is Especially Important

The distinction between 5-minute and 30-minute violations is especially important because Duke's slower conventional generators can provide much more response in 10 to 20 minutes than they can in 5 minutes. Perhaps more importantly non-spinning reserves can also be used. Non-spinning reserves are fully deployable in 10 to 15 minutes. Duke's Joint Initial Statement says that DEC and DEP have 1.3 GW of non-spinning reserves available. (Duke Joint Initial Statement, pg 37) Use of non-spinning reserves is especially appropriate for events that only occur a few times a year.

A More Appropriate Flexibility Violations Limit

NERC mandatory reliability standards require balancing within 30 minutes. As discussed above, a 5-minute Flexibility Violation metric is completely unrelated to reliability requirements. A 25-minute Flexibility Violation limit would be consistent with the NERC mandatory 30-minute reliability balancing requirements and would be technically justified.

Duke Conventional Generation Inflexibility Contributes to Flexibility Violations

Inflexibility of Duke's conventional generation fleet compounds problems with the 5-minute flexibility violations metric. The SISC Independent Technical Review Committee found that Duke generators are less flexible, and load following is consequently more expensive, than that of Duke's neighbors. Slow conventional generator response can fail to meet the arbitrary 5-minute flexibility violation criteria while having no adverse impact on power system reliability. Slower responding generators could easily fail to

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maintain 5-minute balancing but easily maintain robust reliability by responding within the 30 minutes allowed by NERC.

The TRC Report states:

> "H. Benchmarking the Estimated Cost of Reserves: The TRC compared the estimated cost of load following reserves with similar reserve products in PJM. The estimated cost of load following for DEC and DEP are higher than they are in PJM, which is expected and reasonable given the size of Duke's footprint relative to PJM and ***given the relative inflexibility of Duke's generation resources.***" (TRC Report, pg III-5, emphasis added)

> "The TRC finds that the estimated cost of additional load following reserves is reasonable given the size of DEC's and DEP's footprint relative to PJM and given the ***relative inflexibility of Duke's generation fleet*** (specifically the CTs that are block loaded and the narrow operating range of the two pumped storage resources)." (TRC Report, pg III-13, emphasis added)

The TRC Report further states that "The TRC compared the estimated cost of load following reserves with similar reserve products in PJM. The estimated cost of load following for DEC and DEP are higher than they are in PJM". (TRC Report, pg III-5) The TRC concern with the inflexibility of Duke's CT and pumped storage resources is even greater. The TRC Report states:

> "This review led the TRC to raise questions about the modeling assumptions used for two particular resource types: combustion turbines (CTs) and pumped storage hydro resources. The modeling assumptions used to represent these two resource types indicated that the resources were ***less flexible than TRC members expected***. In light of the fact that CTs and pumped storage hydro are typically ideal resources for providing load following, the TRC requested additional information from Duke on the operational characteristics of these resources." (TRC Report, pg III-10, emphasis added)

The comparison with PJM costs is also overly generous to Duke. The TRC compared Duke's Load Following Reserve (a 10-minute reserve) costs with PJM's Regulation (a 5-minute ancillary service) costs. The faster PJM Regulation is a higher value and typically more expensive product:

> "The Regulation Ancillary Services product in PJM is not an exact benchmark for the 10-minute load following reserves modeled in the Astrapé study, because the PJM Regulation product requires 5-minute response. However, there is no exactly comparable product in PJM's market, as there is no market in PJM for load following reserve similar to the load following deployed by Duke. *The 5-minute Regulation product in PJM is likely more expensive than a hypothetical 10-minute product* in PJM that would be more directly comparable to the 10-minute load following reserves used in the study." (TRC Report, pg III-13, emphasis added)

It seems that Duke is justifying higher reserve requirements and penalizing solar with a higher SISC based on the inflexibility of Duke Load Following resources. Duke may further benefit from generator inflexibility because Duke inflexible resources operate more than flexible resources would. Generators with higher minimum loads and an inability to cycle quickly are forced to operate longer and at higher output than flexible generators with lower minimum loads and faster cycling capabilities.

Conclusions

The analysis methodology presented in the October 22, 2021 Duke Energy Carolinas and Duke Energy Progress Solar Integration Services Charge (SISC) Study is flawed, and the resulting solar integration charges are unjustified. Duke's proposed SISC should be rejected by the Commission and Duke should be directed to redo the analysis with corrected analysis methods and metrics.

As a result of the deficiencies discussed above, the solar integration costs developed in the SISC Study do not reflect actual increased reserve requirements or actual impacts on the operating costs that the Companies will likely experience as a result of increased solar generation. The Commission should reject the proposed SISC and direct Duke to revise the analysis method and metrics to reflect actual utility operations and mandatory NERC reliability requirements. The solar load following reserve requirements should only be imposed during hours when solar generation is possible and should never exceed the amount of possible hourly solar generation. Analysis should always incorporate the full benefits of the JDA (combined case) in order to reflect actual operations, including the benefit of reducing the required balancing reserves as well as reducing the cost of supplying those reserves. The Flexibility Violations metric should be based on 25-minute balancing requirements instead of 5-minute balancing, to reflect mandatory NERC reliability requirements.

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Exhibit B

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Concerns with Dominion Energy's Analysis of Solar Variability and Uncertainty Impacts

Brendan Kirby P.E. 24 February 2022

Dominion Energy's "Updated Solar Integration (Re-Dispatch) Cost" analysis methodology is flawed because it failed to synchronize the power system data with solar data, resulting in analysis of conditions that do not represent reality. The Commission should not approve a solar integration charge that is based on faulty analysis.

Dominion Energy has proposed an "Updated Solar Integration (Re-Dispatch) Cost" based on production cost modeling comparing system costs without solar generation with production costs with solar generation. Dominion's November 1, 2021 Initial Statement describes the analysis process:

> "In the 2021 IRP Update, the Company took a chronological approach to modeling the re-dispatch cost, by utilizing one build plan from the 2020 IRP (Alternative Plan D) and **studying 16 years** chosen based on when resources were introduced or retired in the 2020 IRP Alternative Plan D build plan. **For each simulation year, the Company performed a base case Aurora simulation** by using the base hourly renewable generation profiles to establish the base case commitment decisions. Using these commitment decisions, the **Company performed an additional 200 simulations but applied different hourly renewable profiles** from NREL's historical weather patterns studies to reoptimize the system cost.
>
> "The total system cost for each simulation was compared to the base case system cost of the same year. This delta of the system cost is composed of the respective differences in fuel, variable operation and maintenance costs, emissions, and purchase/sale of energy and power costs. The **re-dispatch cost is the delta of the system cost** divided by the Company's expected total renewable generation." (page 14, emphasis added)

The basic methodology of comparing production cost modeling results from cases without and with solar generation is reasonable. To produce accurate results, however, the solar generation must be time-synchronized with the power system data, because weather conditions drive both. It would not be useful or reasonable, for example, to model mid-day hours of high system load driven by clear skies and high intense sun combined with low solar output data taken from rainy conditions.

Dominion's analysis did not synchronize solar generation and power system data. It did not even use actual historic hourly loads. Instead, Dominion used a "predefined hourly shaping table that transforms the monthly average and peak values into hourly load" that is built into the Aurora model. The hourly system loads are unrelated to actual weather conditions.

The treatment of solar data is problematic as well. Dominion states that 'The historic solar data is based on the NREL National Solar Radiation Database for the locations listed in "Attachment SACE

3.2a1(KFM).xls” in tab “Expected Capacity Factor.”’ (Dominion Response to SACE DR-3, question 2) It is not clear how the 22 locations listed in the workbook were selected:

- NY-NewYorkCity_PV_Fixed_SolarShape
- IL-Chicago_PV_Fixed_SolarShape
- MI-GrandRapids_PV_Fixed_SolarShape
- PA-Pittsburgh_PV_Fixed_SolarShape
- PA-Philadelphia_PV_Fixed_SolarShape
- PA-Harrisburg_PV_Fixed_SolarShape
- NJ-AtlanticCity_PV_Fixed_SolarShape
- OH-Cleveland_PV_Fixed_SolarShape
- OH-Dayton_PV_Fixed_SolarShape
- OH-Mansfield_PV_Fixed_SolarShape
- MD-Baltimore_PV_Fixed_SolarShape
- IN-FortWayne_PV_Fixed_SolarShape
- KY-Lexington_PV_Fixed_SolarShape
- SC-Charleston_PV_Fixed_SolarShape
- VA-Roanoke_PV_Fixed_SolarShape
- WV-Charleston_PV_Fixed_SolarShape
- WV-Elkins_PV_Fixed_SolarShape
- VA-Chesterfield_PV_1-Axis_SolarShape
- VA-Portsmouth_PV_1-Axis_SolarShape
- NC-Charlotte_PV_Fixed_SolarShape
- NC-Greensboro_PV_Fixed_SolarShape
- NC-Raleigh_PV_Fixed_SolarShape

In summary, the “Updated Solar Integration (Re-Dispatch) Cost” analysis methodology is not based on time-synchronized load and solar data from solar locations that Dominion will actually be integrating. The Commission should not approve a solar integration charge that is based on load and solar data that is not time-synchronized or on data from solar plants that are located up to 800 miles to the north.

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Exhibit C

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Duke Energy Carolinas Carbon Plan Stakeholder Meeting 1

Virtual Meeting – January 25, 2022

**Please note, this meeting is being recorded. Presentations will be posted on the Carolinas Carbon Plan website, and discussion portions will be kept for internal purposes only to ensure accuracy of meeting notes.*

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Today's Approach

Part 1:
Overview & Key Considerations

The morning session will be focused on introductions, process, level-setting and core objectives of the Carolinas Carbon Plan.

Part 2:
Inputs & Assumptions

The afternoon session will provide an opportunity to provide feedback to the technical inputs and assumptions that drive the modeling underlying the Carbon Plan

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Great Plains Institute (GPI)

Doug Scott,
Vice President, Electricity & Efficiency

Trevor Drake,
Senior Program Manager

Alissa Bemis,
Meeting & Administrative Coordinator

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Related GPI Work

- Integrated Resource Planning
- Power Plant Host Community Impacts
- Time-Varying Rate Designs
- Electric Vehicle Investments and Programs
- Distribution System Planning
- Load Flexibility and Demand Response Programs
- Utility Performance Metrics

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Duke Welcome

Stephen De May
State President, North Carolina

Mike Callahan
State President, South Carolina

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Stakeholder Process Objectives

1. Ensure the Carolinas Carbon Plan is informed by input from a wide range of stakeholders.

2. Enable a transparent conversation about how to plan an energy transition that prioritizes affordability and reliability for NC and SC customers.

3. Build on areas of agreement, clarify areas of disagreement, and seek opportunities for collaboration in advance of filing the Carolinas Carbon Plan.

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Stakeholder Process Timeline

Stakeholder Engagement

Jan. 25 | Feb. 23 | March 22

Proposed Plan Development

Finalized Proposed Plan

Supplemental Engagement

Carolinas Carbon Plan

January – March | April – Mid-May | Mid-May - December

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Meeting Ground Rules

- **Respect each other:** Help us to collectively uphold respect for each other's experiences and opinions, even in difficult conversations. We need everyone's wisdom to achieve better understanding and develop robust solutions.

- **Focus on values and outcomes:** Today's discussion is about what stakeholders value in the energy future, and how the Carolinas Carbon Plan can align with those values. Pending legal issues are outside the scope of this conversation.

- **Chatham House Rule**: Empower others to voice their perspective by respecting the "Chatham House Rule;" you are welcome to share information discussed, but not a participant's identity or affiliation (including unapproved recording of this session).

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Meeting Ground Rules

- **Respect the time:** Our time together is limited and valuable, and we have a large group, so please be mindful of the time and of others' opportunity to participate.
- **Use the chat:** Please submit your comments and questions in the chat. GPI staff will monitor the chat to pull out questions for Q&A portions. Please be respectful and focus on issues, not people.
- **Raise your hand:** During dedicated Q&A portions of the meeting, use the "Raise Hand" feature to indicate you would like to voice a question or comment.

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Meeting Dates

1. Tuesday, January 25th
2. Wednesday, February 23rd
3. Tuesday, March 22nd

Future meeting agendas will be based on feedback received today

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Additional Participation

Meeting materials/recordings will be uploaded to the website:

www.duke-energy.com/CarolinasCarbonPlan

Information/feedback can be sent to:

DukeCarbonPlan@gpisd.net

Meeting recordings (Q&A portions of meetings will be removed to adhere to the non-attribution rule) and meeting summaries will be uploaded to the website for participants to access.

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Today's Agenda

Part 1: Overview and Key Considerations

9:00am: Welcome and Introductions

9:15am: Stakeholder Engagement Process and Objectives

9:45am: Introduction to Resource Planning and Decarbonization in the Carolinas

10:15am: Road to 70% Emissions Reduction and Net-Zero Future

10:45am: BREAK

11:00am Discussion

12:00pm LUNCH BREAK

Part 2: Modeling Inputs and Assumptions

1:00pm Introduction to Modeling

1:30pm Economic Coal Retirements Modeling Methodology

2:00pm Load Forecast: Key Drivers

2:45pm BREAK

3:00pm Other Key Modeling Assumptions:

- Solar Interconnection Forecast
- Technology Forecasts
- Natural Gas Price Forecast

3:45pm Next Steps

4:00pm Adjourn

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Introduction to Resource Planning and Decarbonization in the Carolinas

Glen Snider, Managing Director, Carolinas Integrated Resource Planning

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Guiding Principles for Decarbonization: Sustainability, Affordability, Reliability

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Sustainability

- Carbon reduction targets
  - 70% reduction 2030
  - Net zero by 2050
- Continually reducing environmental impact to ensure
  - Cleaner air
  - Cleaner water
  - Cleaner land

Affordability

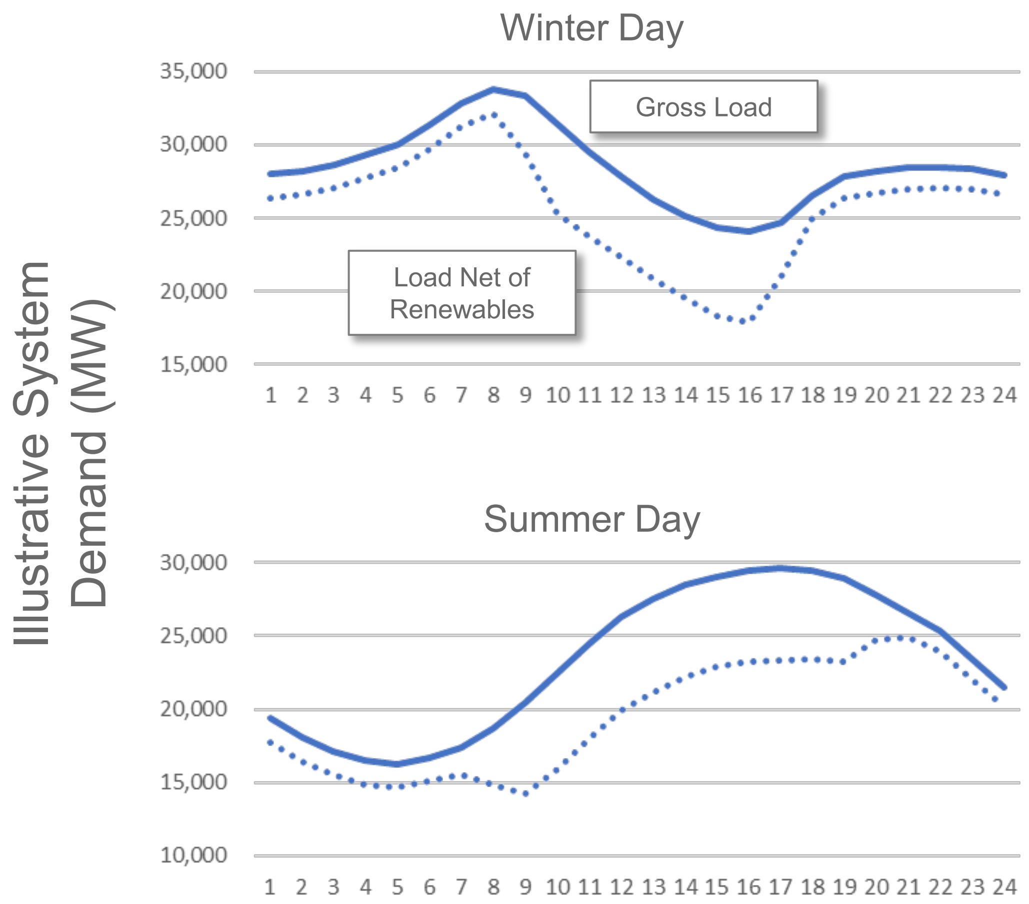
- Capital, land, operations and maintenance (O&M), and fuel costs vary by resource type
- Cumulative costs over time represented as present value of costs
- Evaluation of forecasted annual bill impacts shows costs & benefits at snapshots in time

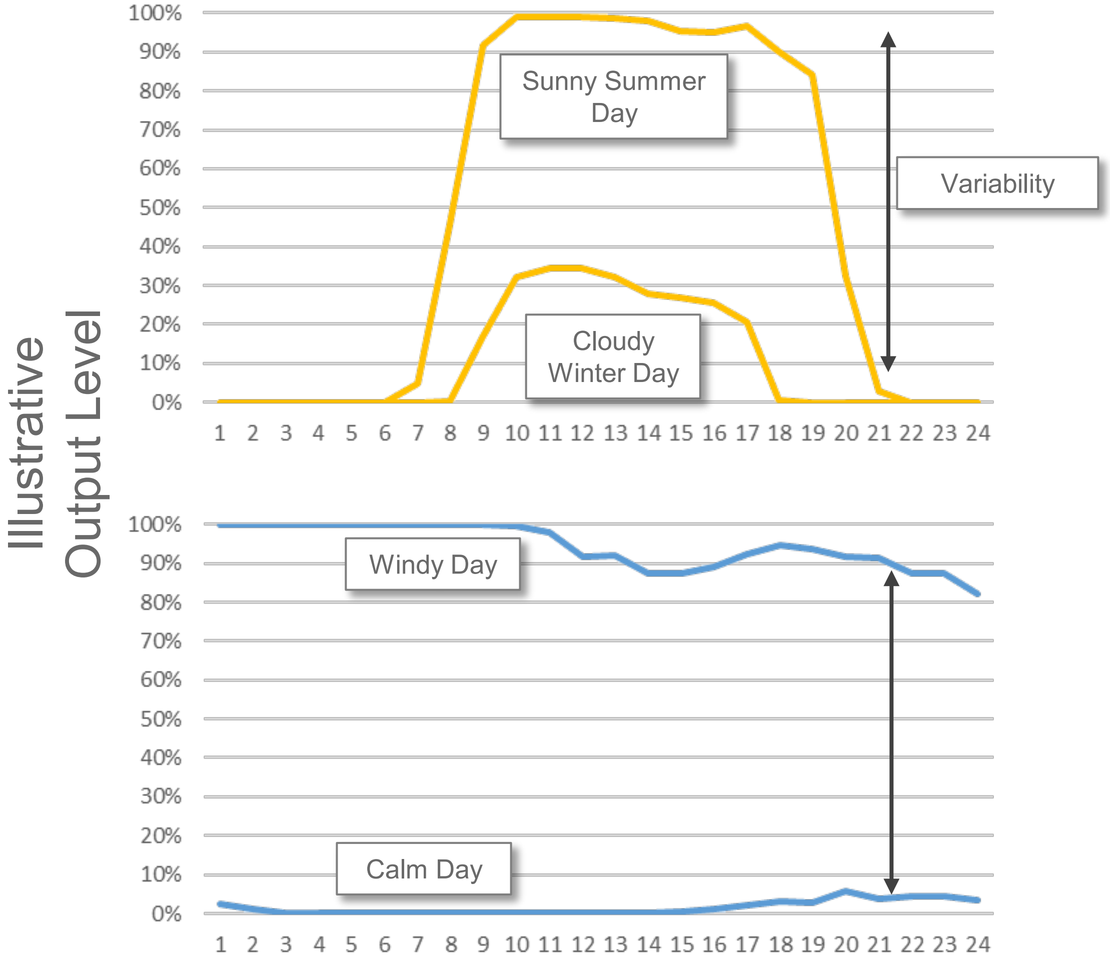
Reliability

- Serve customer demand that varies year-to-year, month-to-month, hour-to-hour, and minute-to-minute
- Maintain adequate long-term reserves to meet customer needs during peak demand periods
- Maintain adequate system flexibility to respond to changing real-time operating conditions

Reliability Requires Responding to Variability

- Variable generation compounds challenges of variable load, increasing importance of resources able to rapidly increase or decrease output to balance supply and demand in real time





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Elements of Decarbonization

Shrink the Challenge	Grid Edge & Customer Programs	Load Reduction, Modification
Add Carbon-Free Resources	Renewables	Advanced Technologies
Ensure Reliability	Dispatchable Resources	Energy Storage

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Executing a Plan Within a Plan

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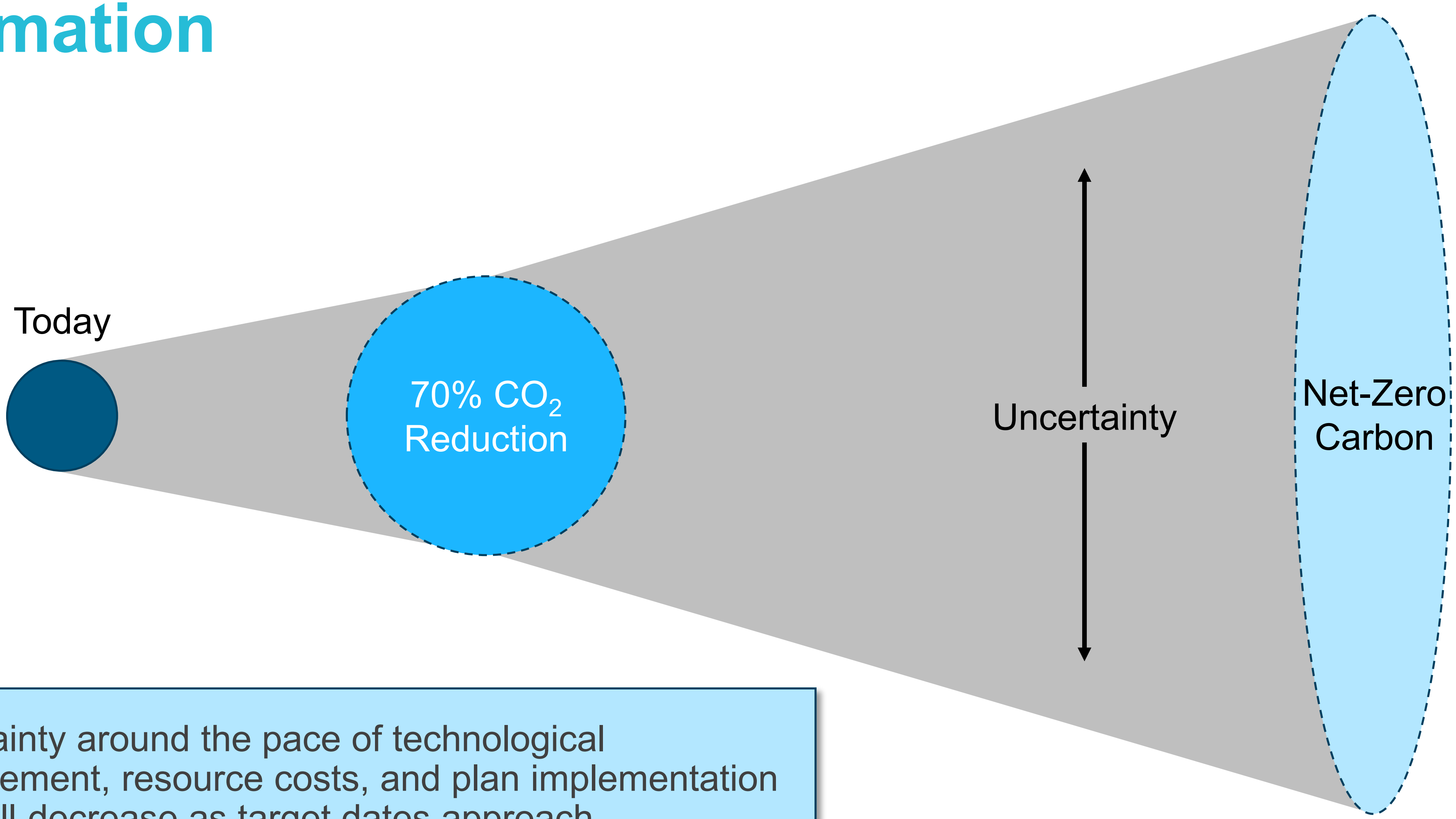
70% CO_2 Reduction → **Carbon Neutrality**

- Available Technologies
- Near-term Execution
- Supporting Actions to Enable Implementation

- Deployment of New Resource Types
- Advanced Nuclear
- Offshore Wind

- Emerging Technologies
- Preparation for Future Action
  - Research & Development
  - Technology Pilots
- Signposts Indicating Pace of Advancement

Periodic Carbon Plan Updates Will Incorporate New Information



Uncertainty around the pace of technological advancement, resource costs, and plan implementation risks will decrease as target dates approach

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Road to 70% Emissions Reduction and Net-Zero Future

Mark McIntire, Director, Government and Environmental Affairs

Mike Quinto, Integrated Resource Planning, Lead Engineer

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Requirements for CO_2 Emissions Reduction

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- ✓ 70% Reduction in Emissions
- ✓ Of Carbon Dioxide (CO_2)
- ✓ Emitted in the State (NC)
- ✓ From electric generating facilities owned or operated by (or on behalf of) electric public utilities
- ✓ From 2005
- ✓ Carbon Neutrality by 2050

CO_2 Emissions Data Considerations

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- Publicly Available
- Credible
- Reliable
- Repeatable

EPA eGRID

- Environmental Protection Agency (EPA) Emissions and Generation Resource Integrated Database (eGRID)

"The Emissions & Generation Resource Integrated Database (eGRID) is a comprehensive source of data on the environmental characteristics of almost all electric power generated in the United States. The preeminent source of emissions data for the electric power sector, eGRID is based on available plant-specific data for all U.S. electricity generating plants that provide power to the electric grid and report data to the U.S. government" – eGRID Technical Guide

- Used for environmental disclosures, emission inventories, and RPS and RECs Tracking

- Used by Federal Government, state and local governments, the EPA, National Labs, ISOs, non-governmental organizations, academia, and companies

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eGRID Emissions Data Sources

- eGRID uses EPA's Clean Air Market Division (CAMD) Power Sector Emissions Data
  - Data reported to EPA by electric generating units to comply with the regulations in 40 CFR Part 75 and 40 CFR Part 63
    - Emissions data primarily uses Emissions Tracking Systems (ETS)/Continuous Emissions Monitoring Systems (CEMS)
      - Actual measurements of CO_2 in stack emissions
    - Where CEMS data is not available, eGRID uses EIA reported fuel data (EIA-923) to estimate emissions
      - Estimates emissions based on fuel consumed and standard emissions based on fuel type

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CO_2 Emissions included in Baseline and Reduction Goals

- Owned
- Operated by
- Operated on behalf of

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CO_2 Emissions included in Baseline and Future Actual Emissions

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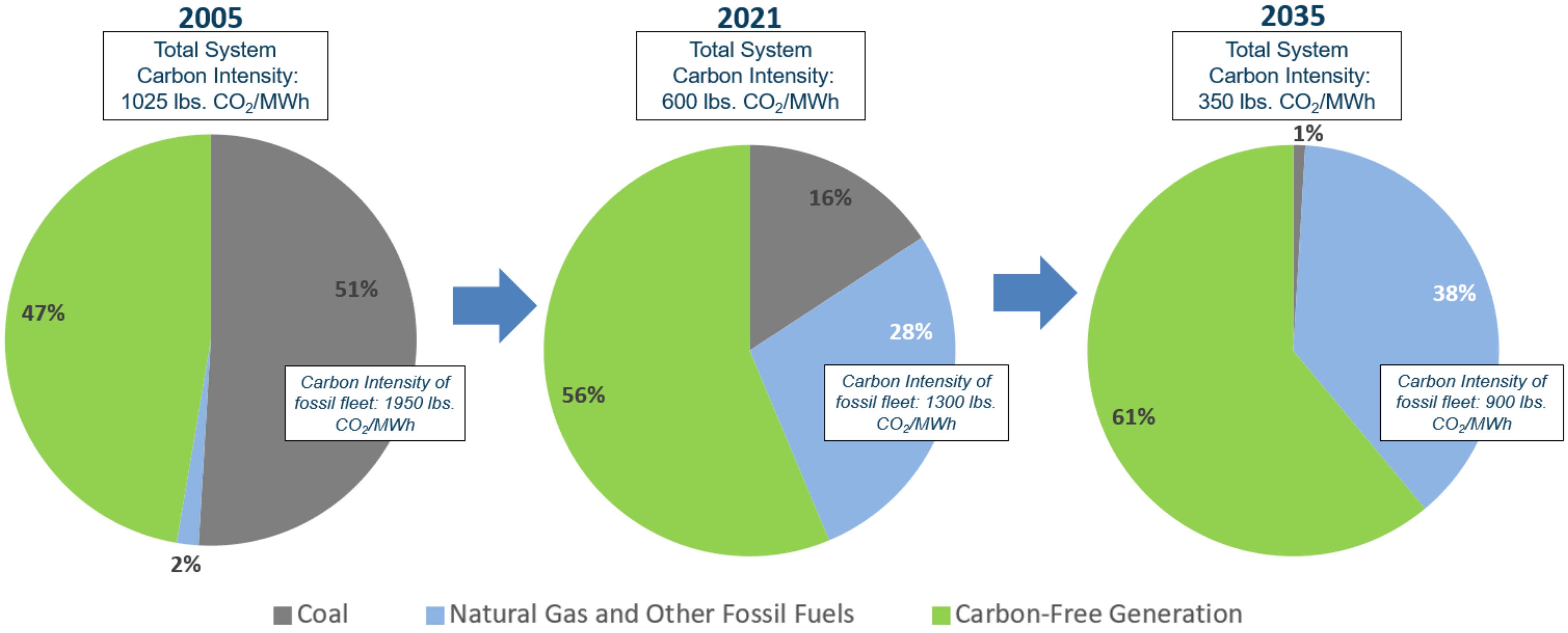
Owned	Operated by	Operated on behalf of
Stack emissions associated with the ownership share of electric generation facilities located in North Carolina owned by DEC/DEP	Stack emissions associated with electric generating facilities located in North Carolina operated by DEC/DEP	Stack emissions associated with electric generating facilities located in North Carolina not owned or operated by DEC/DEP, but contracted to sell electrical output to DEC/DEP

Carolinas Combined Fleet Transition Progress

The combined DEC/DEP fleet is a national leader in low carbon intensity energy, with a current rate 37% lower than the industry average of 957 lbs. CO_2/MWh[1]



1Source: MJ Bradley, “Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States” – July 2020, p. 30

Note: 2021 and 2035 energy mix and carbon intensity projections are based on the 2020 IRP Base w/ Carbon Policy

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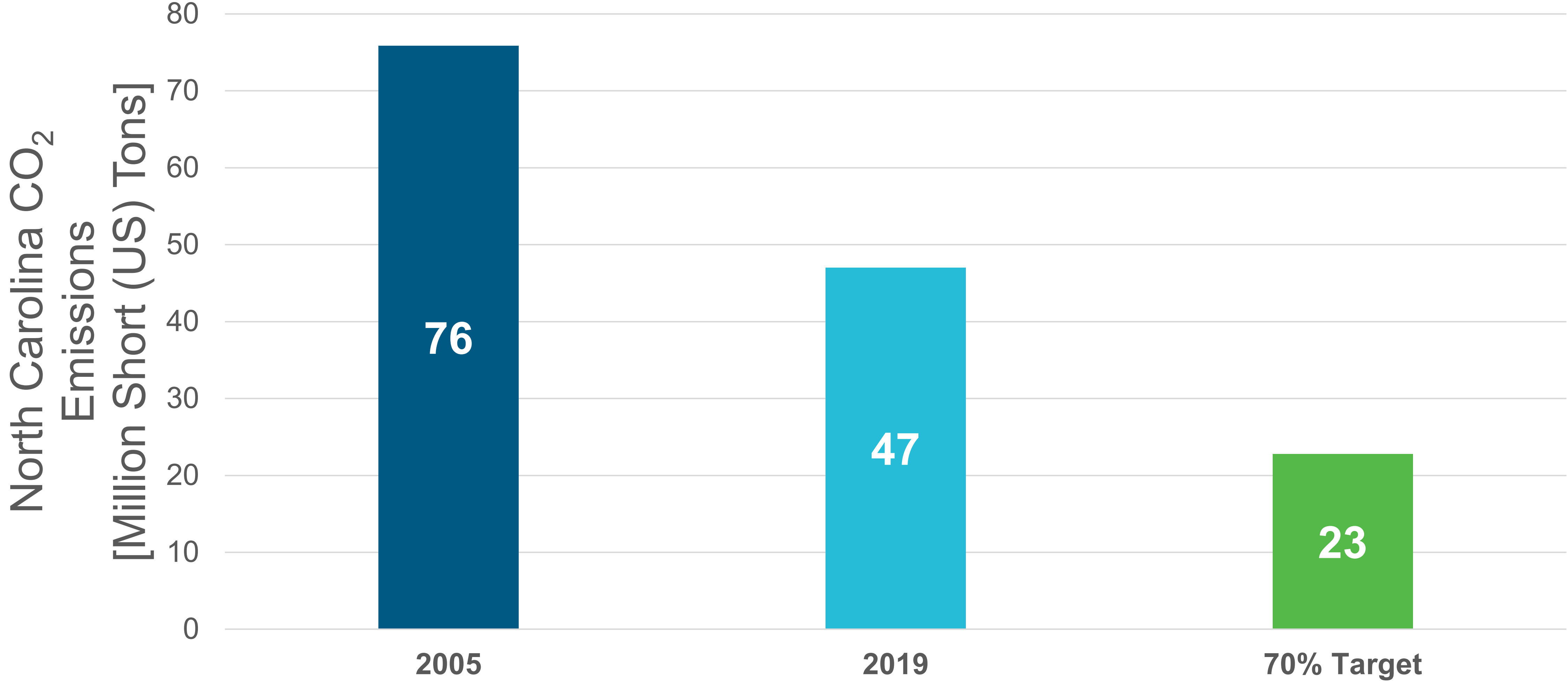
CO_2 Emissions Baseline, Progress, and 70% Reduction Target



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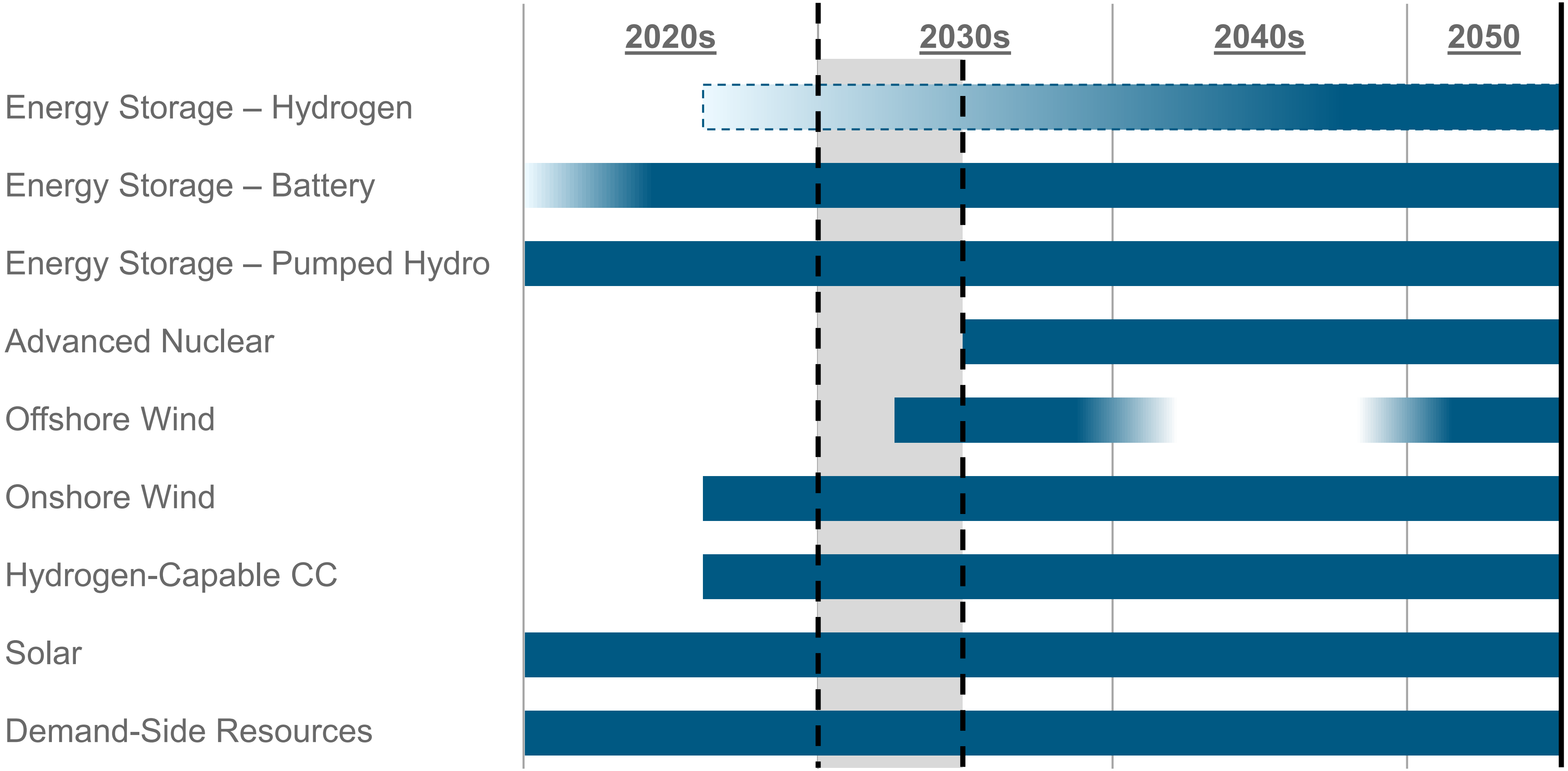
Decarbonization Replacement Resources



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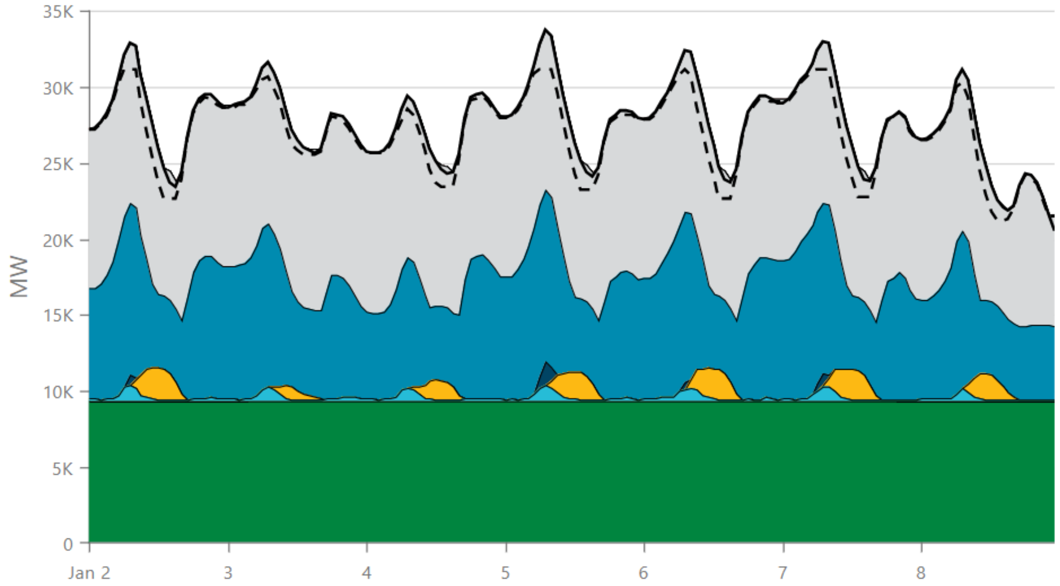
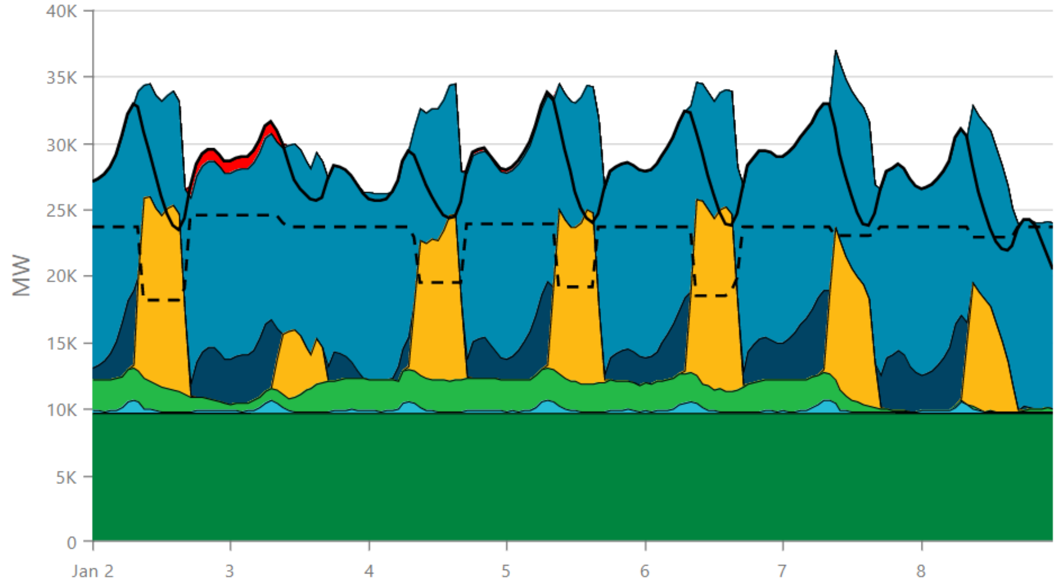
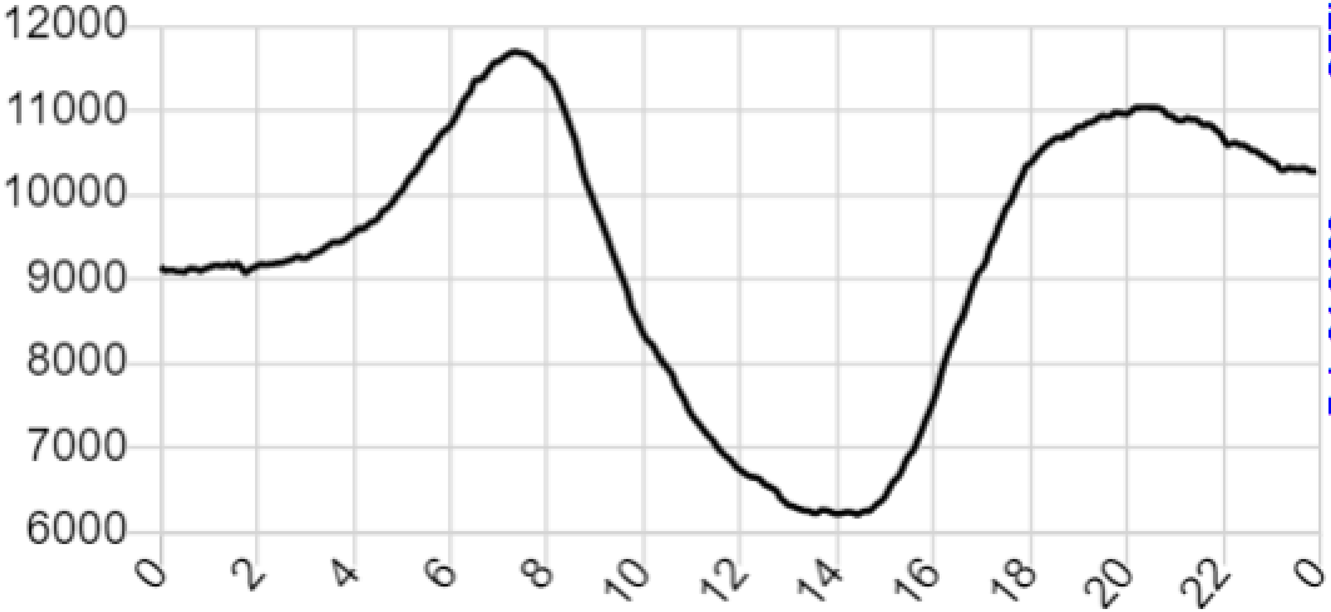
The NC/SC System Must be Built Preserving Reliability







- Net Load
- Load (2018)
- Curtailment
- Unserved
- New Demand Response
- Imports (Fossil)
- Coal
- Gas
- Storage
- Solar+Storage
- Solar
- Wind
- Hydropower
- Nuclear

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Break

Please return at 11:05AM.

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Clarifying Questions

What information would help you better understand the content presented this morning?

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Discussion:

What are your criteria for a successful carbon plan?

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Lunch Break

Please return at 1:00PM.

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Introduction to Modeling

Bobby McMurry, Director, Production Cost Modeling & Analytics





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Models, Inputs and Assumptions

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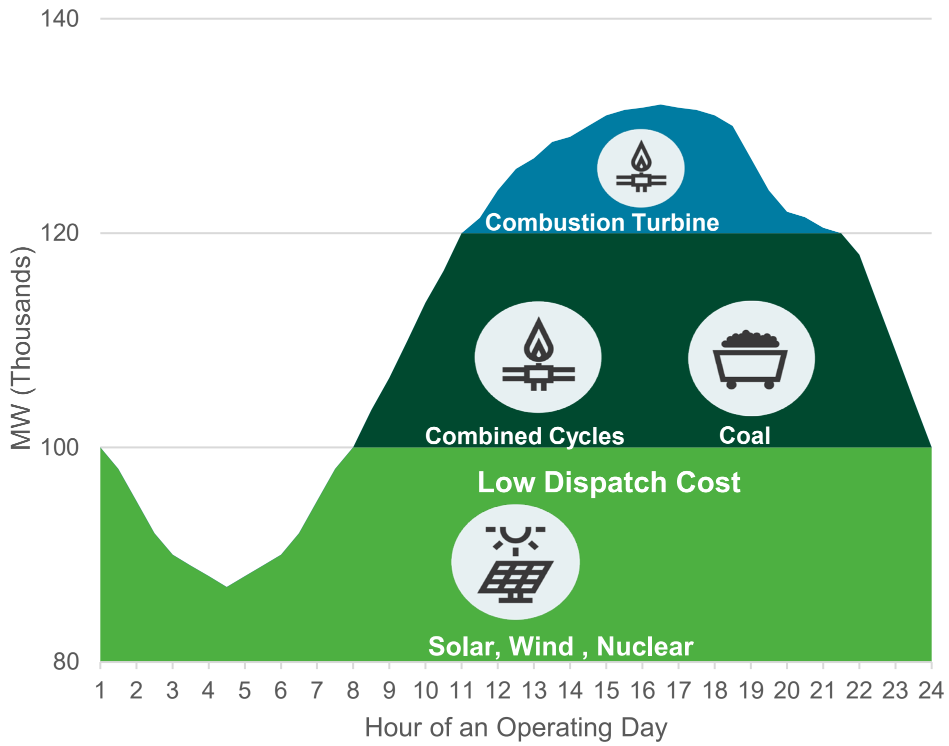
In-depth Modeling Simulates the Power System Operations Over Time

- Capacity expansion modeling optimizes the set of resources between existing and new generation sources over long timeframe
    - Expansion tools consider the fit of resource to the type of demand: Is it needed every hour? Is it needed occasionally over the year? Is it only needed as load goes above a certain level?
- Production cost modeling optimizes the use of resources in hourly, seasonal, and annual complexities of actual power systems



Models

- EnCompass Power Planning Software
  - New Capacity Expansion, Production Cost and Regional Power Flow Model
    - Integration – 2020 and 2021
    - Advantages
    - Mixed Integer Linear Programing – model all constraints at the same time
      - Unlimited Ancillaries
      - Emission Caps
      - Specific Renewable Requirement
      - Reserve margin – monthly
      - Advanced storage logic
      - Dual Fuel Optimization
      - Economic Retirement

- Reliability
  - Regulating & Balancing Reserves (Ancillaries) – Provides reserves needed to account for day ahead forecast changes and inter-hour volatility
  - SERVM – Reliability check to assure portfolios will not exceed 1 loss of load event per 10-year period
    - SERVM = Strategic Energy & Risk Valuation Model

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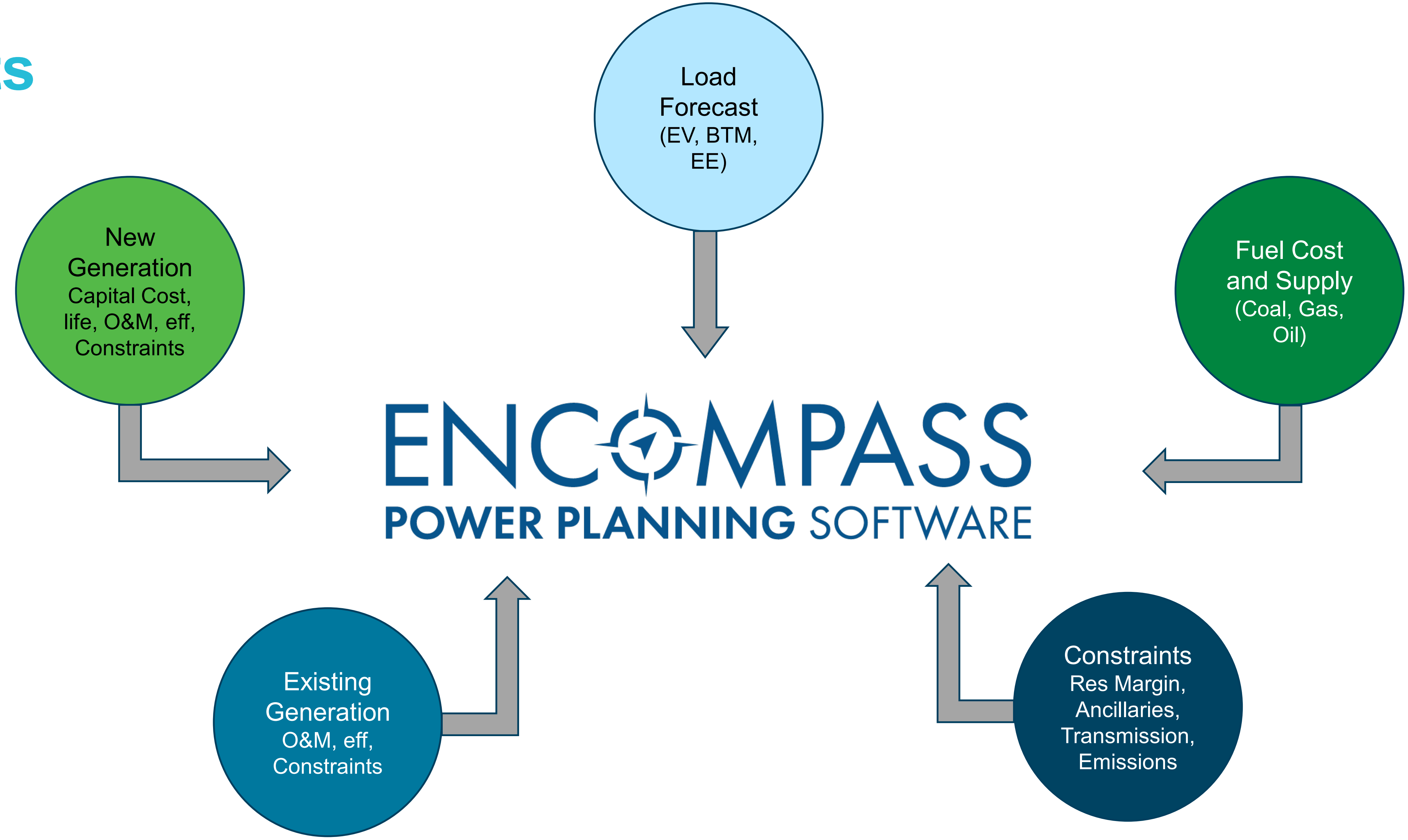
Inputs



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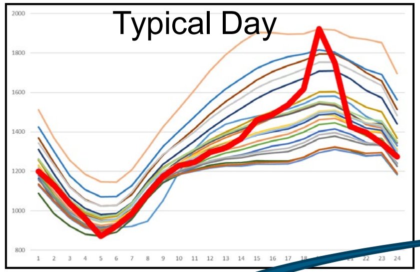
Reliability & Affordability Require Detailed Modeling



Test to assure technology selection does not change when evaluated on hourly basis.

Scenario

Capacity Expansion
(Screening)

Production Cost
(Hourly)

Optimized Plan

Reliability

Ancillary Requirements

- Reliable energy long and short term and considering extreme weather
- Transmission & Distribution requirements

Optimized Plan – Each portfolio will be evaluated over a range of sensitivities in selection of the optimized plan.

- Load, Fuel, Emissions cap, Technology Cost, Financial impact

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Q&A

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Coal Retirements Modeling Methodology

Mike Quinto, Integrated Resource Planning, Lead Engineer

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Coal in the Carolinas (as of 2020 IRP)

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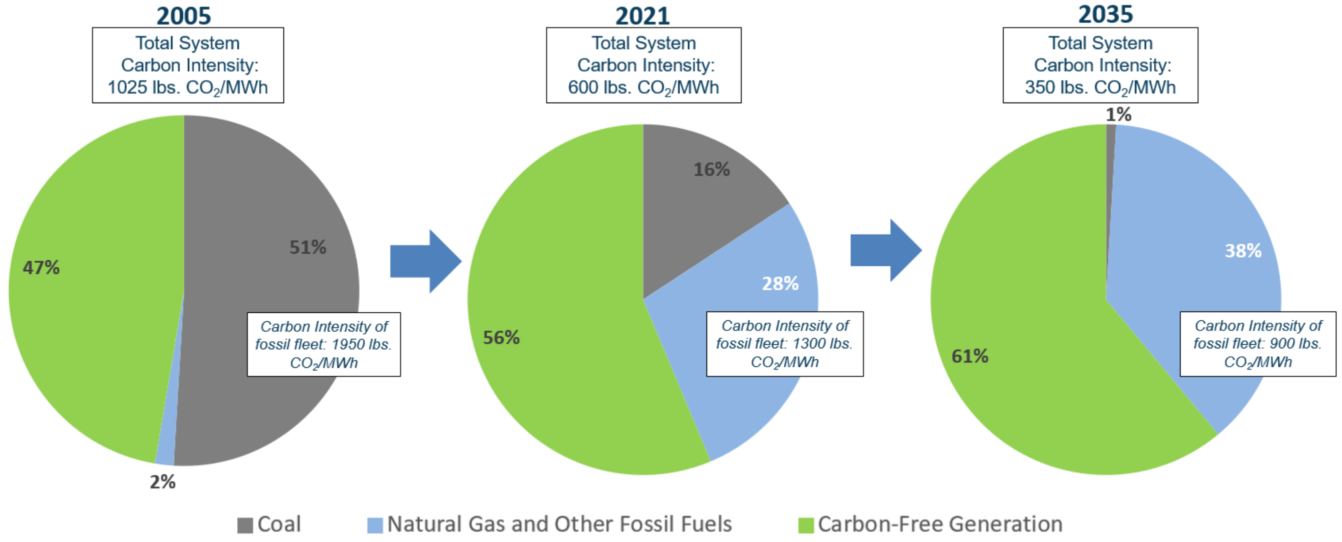
- Coal assets in the DEC and DEP fleet have provided reliable capacity and energy to customers for decades
- Remaining coal assets continue to provide year-round dispatchability that is especially critical during high load winter conditions
- As the industry landscape changes and market forces drive down costs of replacement resources, it is important to develop a transition plan that recognizes where replacement resources become more economic and carry less risk for customers

The combined DEC/DEP fleet is a national leader in low carbon intensity energy, with a current rate 37% lower than the industry average of 957 lbs. CO_2/MWh[1]



1Source: MJ Bradley, "Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States" – July 2020, p. 30

*2021 and 2035 data reflects projections from 2020 DEC/DEP IRP Base Case with Carbon Policy – 2022 Carbon Plan will update this analysis

Coal Retirement Analysis Background

- Previous IRPs utilized the retirement dates of coal units consistent with DEC/DEP's most recently approved depreciation study
- Economic coal retirement analysis was performed as a part of the 2020 IRPs
- Coal retirement analysis methodology was a topic in the NCUC's Second Technical Conference in the 2020 IRP
- Analysis in the 2020 IRPs and the methodologies presented in the Second Technical Conference lay the foundation to refine retirement analysis in support of carbon reduction targets in the new legislation
- Coal retirement analysis will be refined and incorporated into Carbon Plan

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Retirement Analysis

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Existing Capacity Costs:

- Incremental Maintenance CapEx
- Ongoing Fixed O&M
- Environmental Compliance CapEx
- System Production Cost Value

Replacement Capacity Costs:

- New Generation CapEx
- New Fixed O&M
- Retiring & New Generation Transmission CapEx
- System Production Cost Value

When a unit is retired and **what** it is replaced can change the inputs and balance of this equation

DEC/DEP Coal Fleet Statistics

Unit	Fuel Capabilities	Maximum Natural Gas Co-firing Capability	Unit Capacity (Winter)	Unit Capacity (Summer)	In-Service Date	2020 IRP Economic Coal Retirement Analysis Retirement Date (YE)	Current Depreciation Study "Probable Retirement Year" (YE)
Allen 1	Coal		167	162	1957	2023	2024
Allen 5	Coal		259	259	1961	2023	2026
Cliffside 5	Coal/Gas	40%	546	544	1972	2025	2032
Roxboro 3	Coal		698	694	1973	2027	2033
Roxboro 4	Coal		711	698	1980	2027	2033
Roxboro 1	Coal		380	379	1966	2028	2028
Roxboro 2	Coal		673	668	1968	2028	2028
Mayo 1	Coal		713	704	1983	2028	2035
Marshall 1	Coal/Gas	40%	380	370	1965	2034	2034
Marshall 2	Coal/Gas	40%	380	370	1966	2034	2034
Marshall 3	Coal/Gas	50%	658	658	1969	2034	2034
Marshall 4	Coal/Gas	50%	660	660	1970	2034	2034
Belews Creek 1	Coal/Gas	50%	1,110	1,110	1975	2035+	2037
Belews Creek 2	Coal/Gas	50%	1,110	1,110	1975	2035+	2037
Cliffside 6	Coal/Gas	100%	849	844	2012	2035+	2048

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Stakeholder Feedback for Coal Retirement Analysis

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- General Comments on Coal Retirement Analysis
  - **Magnitude** and **complexity**
  - **Modeling limitations**
  - **Transparency** in results
  - Straight-forward, **standard methodology**
  - Remove **objectivity** from analysis

- Key Considerations for Coal Retirement Analysis
  - **Retirements** should be **considered simultaneously**, timing and order determined by model endogenously
  - Replacement resources should include the option of **multiple resource to fill resource gap**
  - **Retirements** should be **co-optimized with replacement resources**
  - Retirements determined by **net exchange** in investment, maintenance, and operations **cost of the system**
  - Impacts to the transmission system
  - Recognize investment decreases as generating units approach retirement
  - Need for retirement dependency and capturing shifting costs
  - Sunk costs should be excluded, only avoidable costs should be considered

Carbon Plan Coal Retirement Analysis Approach

- Endogenous economic selection of coal retirement in Encompass's capacity expansion model
  - Leverage dynamic cost modeling tool
  - Model determination of order and timing of retirements
  - Co-optimization of retirements and replacement resources
  - Captures net cost differences in investment, maintenance, and operations cost of system
- Still evaluating capabilities of model to handle complexity of analysis
- Option to also evaluate coal retirements in sequential process in detailed production cost model
- Retirements are dependent on replacement resources and may be shifted slightly in execution to support orderly transition of the fleet or to maintain the reliability of the system

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Q&A

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Load Forecast Drivers

Brian Bak, Manager, DSM Analytics

Tim Duff, General Manager, Retail Customer and Regulatory Strategy

Matt Kalemba, Director, Distributed Energy Technologies Planning & Forecasting

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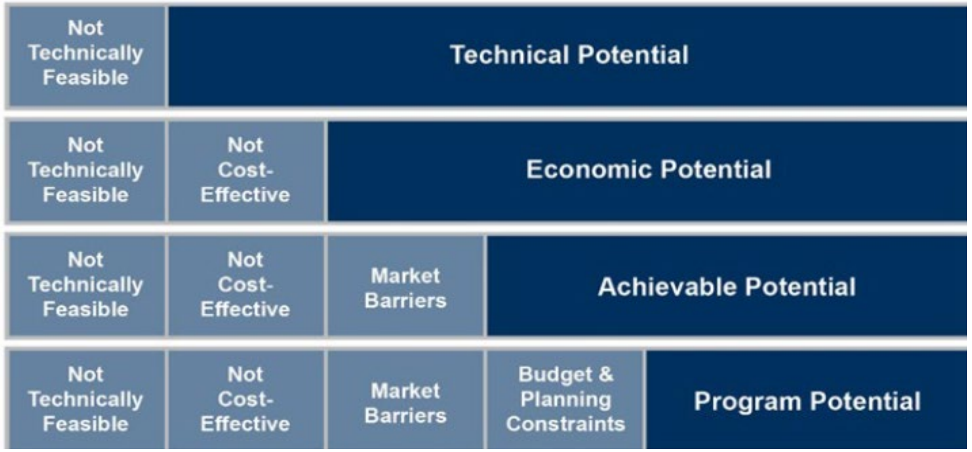
Energy Efficiency (EE) Forecasting

Market Potential Study (MPS)

- Performed by third party expert consulting firms
- Used to inform our EE portfolios as well as IRP EE forecasts
- Provide a comprehensive assessment of EE/DSM potential using the best data available at the time to support the study with results specific to the service territory and customer base
- Include all currently known technologies, estimated costs, and energy and demand reduction impacts for these EE and DSM measures

EE Potential Level Estimates

- **Technical** - Maximum savings possible, regardless of cost. Assumes 100% customer adoption
- **Economic** - All cost-effective measures, again with *100% customer adoption*
- **Achievable** - Potential of cost-effective measures based on *realistic customer adoption assumptions*, unlimited program budget and rate rider impact.
- **Program** - Potential of cost-effective measures based on *realistic customer adoption assumptions and reasonable program budgets and rate rider impacts*



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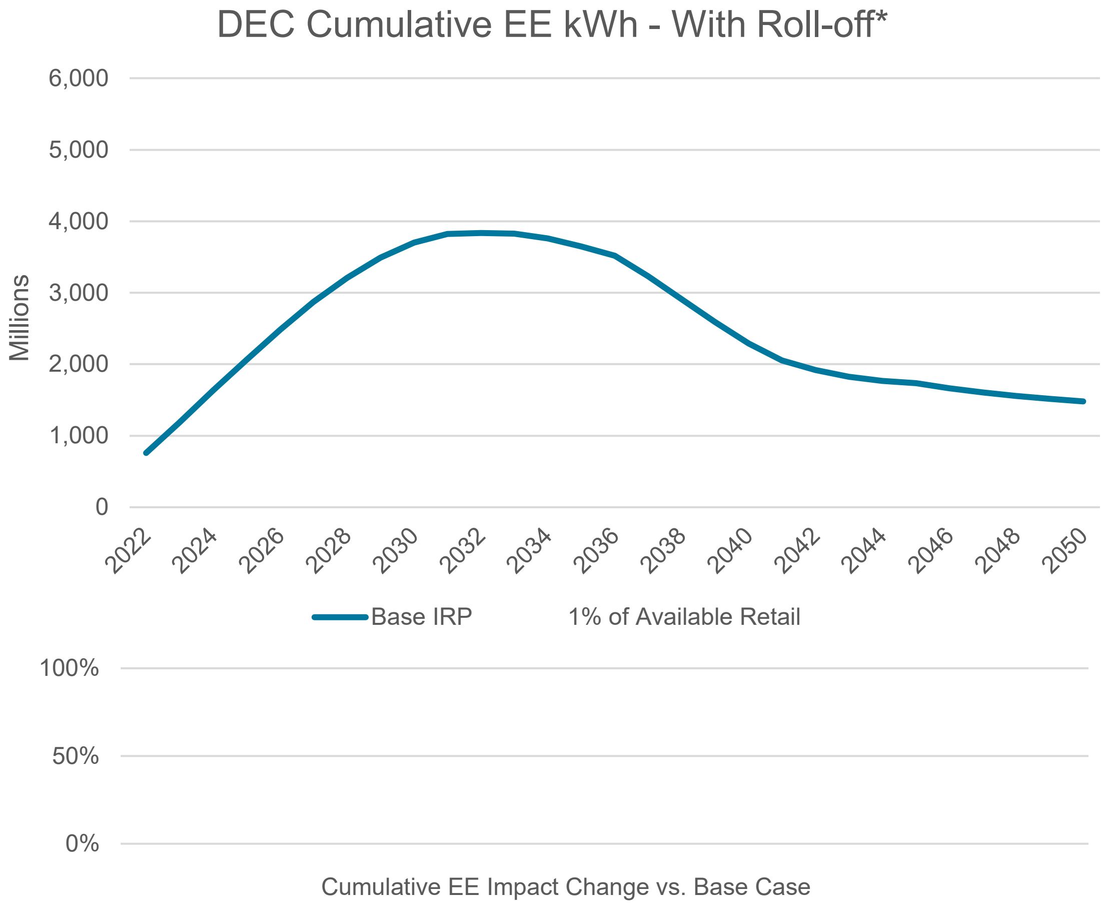
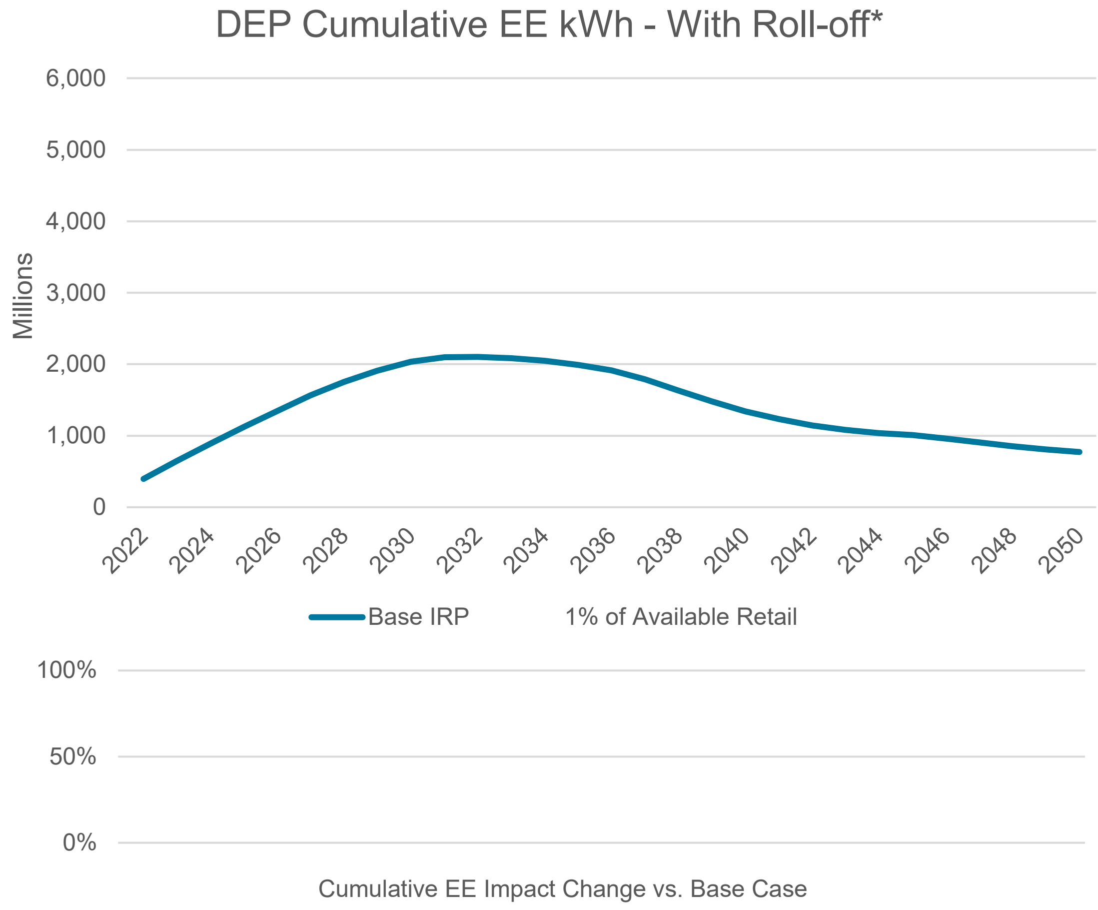
Forecast – Base Case





* Roll-off:

- Energy saving impacts no longer represented in our EE forecast as measures reach “end of life”
- Ongoing savings are accounted for in the load forecast.

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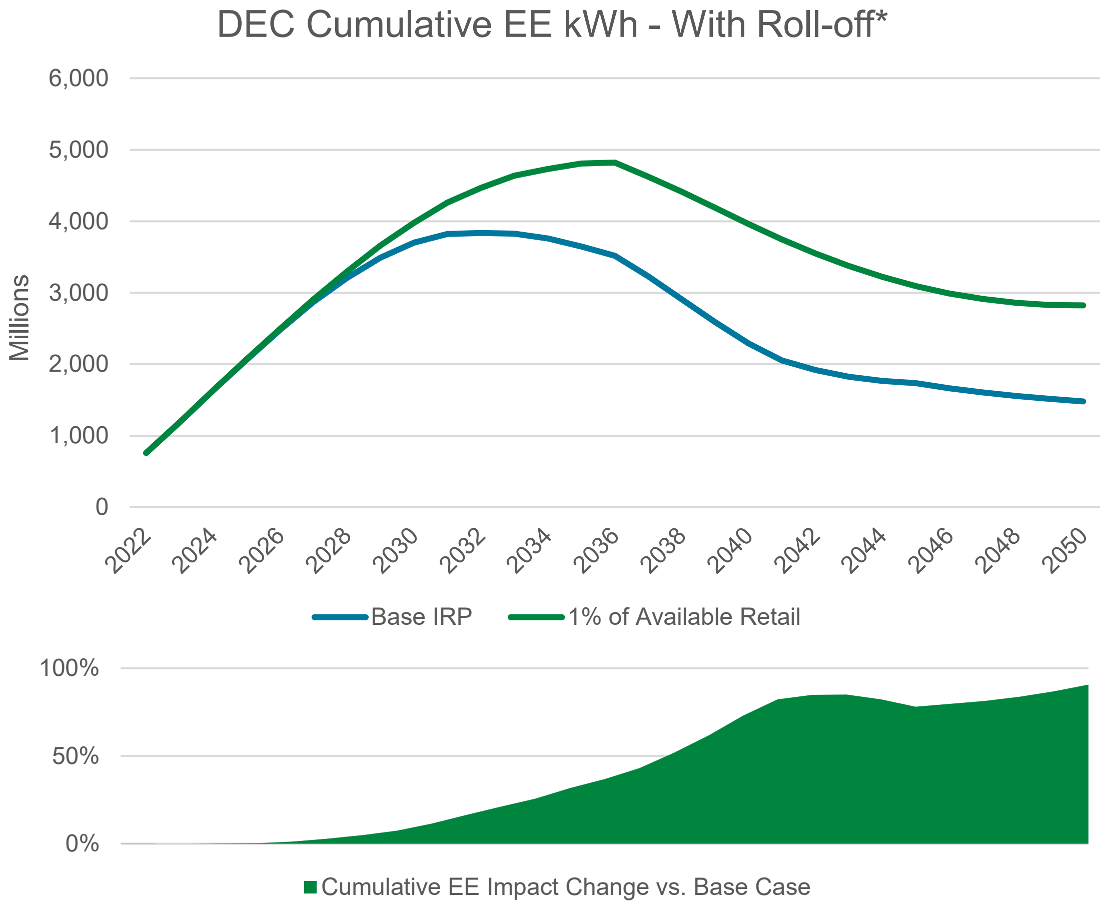
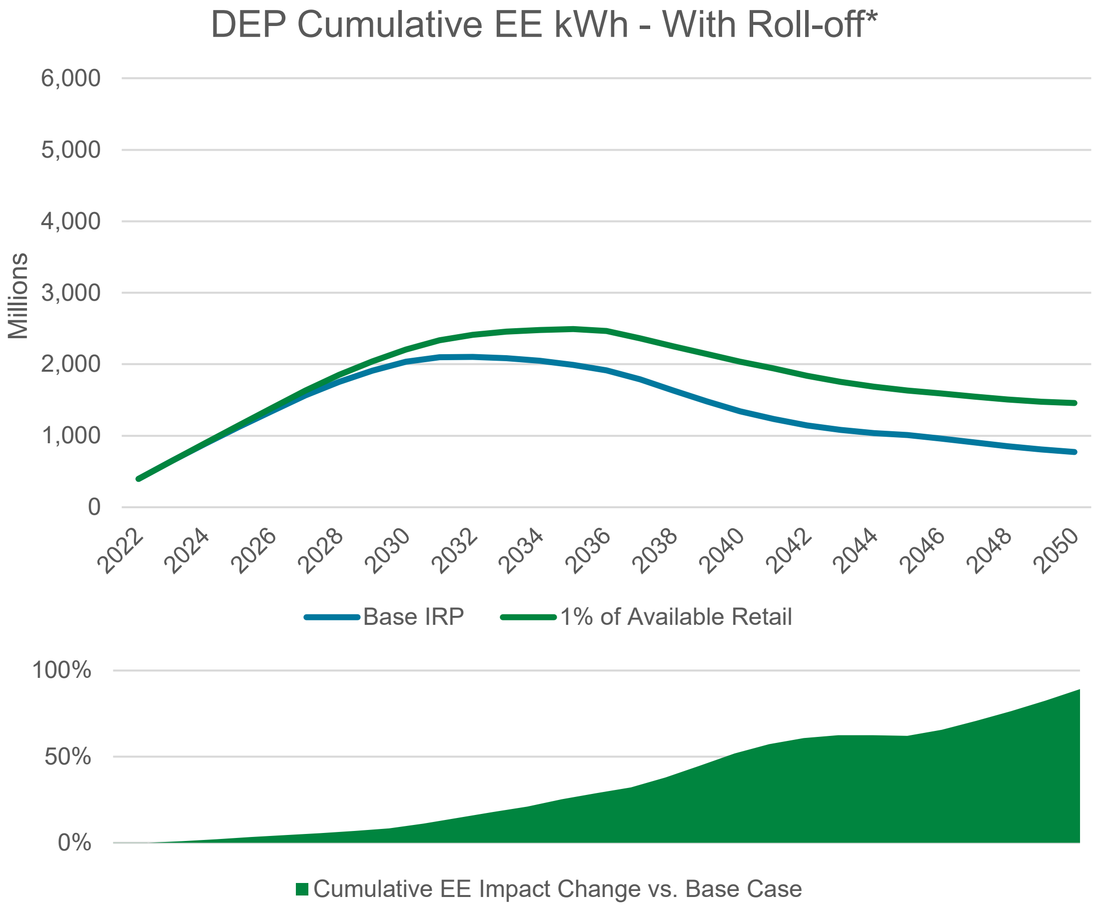
Forecast – 1% of Available Retail Load





* Roll-off:

- Energy saving impacts no longer represented in our EE forecast as measures reach “end of life”
- Ongoing savings are accounted for in the load forecast.

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Moving Beyond the Carolinas’ Base EE/DSM Forecast

Program Potential	Budget/ Planning Constraints	Market Barriers	Not Cost Effective	Not Technically Feasible	Program additions and modifications to optimize existing program portfolio impacts
Achievable Potential*		Market Barriers	Not Cost Effective	Not Technically Feasible	Structural modifications and mechanisms that remove market barriers to program participation
Economic Potential			Not Cost Effective	Not Technically Feasible	Modifications that will enhance the cost effectiveness of new programs and enable program modifications
Technical Potential				Not Technically Feasible	Modifications that will expand the number of potential measures and offers reducing consumption from the grid

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Potential Enablers for Delivering More EE/DSM in the Carolinas

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Structural modifications and mechanisms that remove market barriers to program participation

On-Tariff Financing	Establishing an on-tariff financing program and the necessary recovery mechanism consistent with HB951 to reduce upfront capital costs and credit barriers to undertaking energy efficiency
Marketing enhancements	AMI and other customer data allows better target marketing of programs to customer with high energy savings potential from specific measures

Modifications enhancing the cost effectiveness of new programs and enabling program changes

Recognition of the value of carbon	A financial value recognizing the value of avoided carbon emissions from energy efficiency programs in cost effectiveness evaluation (UCT).
As Found Energy Savings Recognition	Currently energy savings only recognize savings versus a device's efficiency standard despite the fact true carbon reduction is the energy reduction versus the actual device replace
Recognition of localized customer programs values	Identify overloaded circuits/substations and target localized customer programs to offset specific required high T&D spend

Modifications expanding the potential measures and offers reducing consumption from the grid

Utility Codes and Standards Program	Currently advancement of building codes and appliance standards reduces potential savings. Creating opportunity for attribution associated with code advancement and compliance
Customer owned assets that reduce grid consumption	Opportunity to incentivize customers to adopt assets like rooftop solar that reduce energy consumption and carbon emissions from the utility grid.not currently shown as potential
Development of energy efficiency programs for new electrification loads	Currently electrification adds load to the forecast, but little to no energy efficiency opportunities associated with load that actually reduces non-utility carbon emissions
Modifications to Non-Residential Customer Opt Out	Currently energy and carbon savings associated with efficiency potential for industrial and customers using over 1,000,000 KWH not able to be achieved through utility programs
Expand EE Programs to wholesale customers	Opportunity to expand potential EE savings and carbon savings to include potential from customers that take generation from the Duke Carolinas' system.

Carolinas Net Metered (NEM) Solar Forecast

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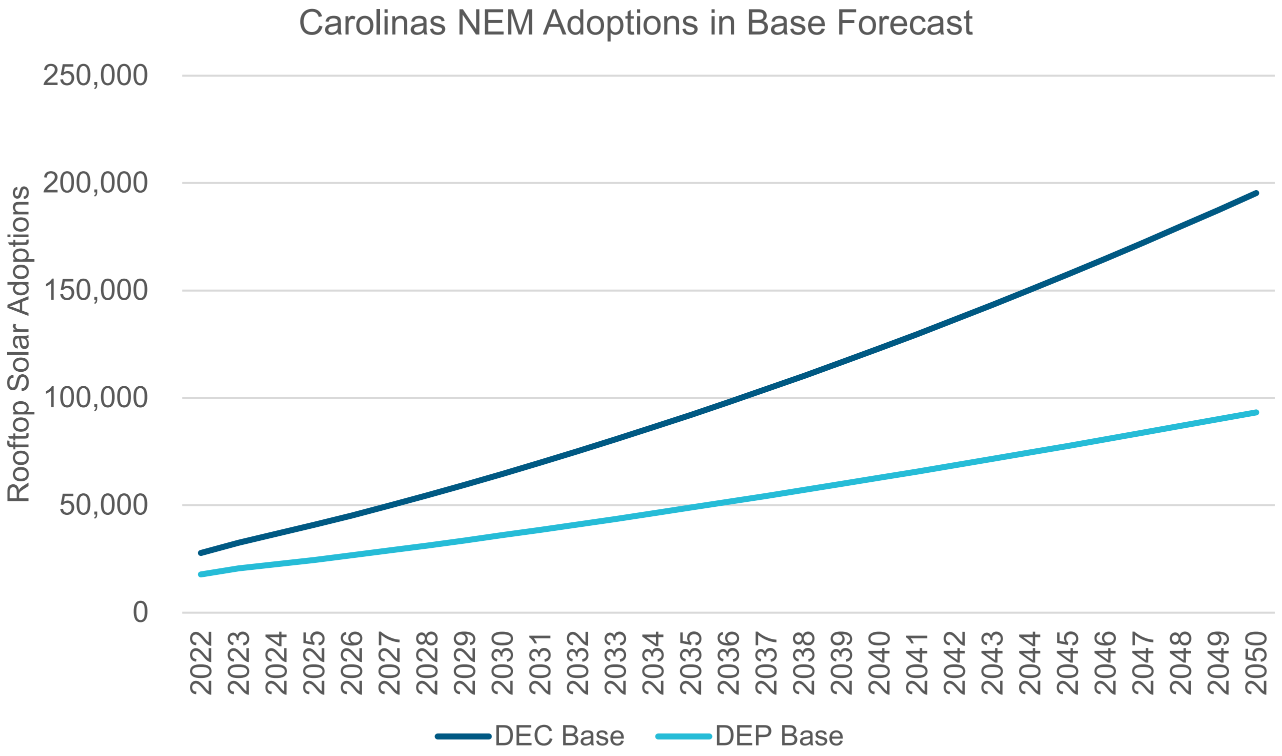
NEM Projections

- Base Case projections use currently approved tariffs in North Carolina and South Carolina
- Other suggested NEM Projections?
  - Aggressive price declines
  - 30% ITC
  - **Other options?**



Jurisdiction	Base NEM as % of Total System Energy
2023	
Duke Energy Carolinas	0.5%
Duke Energy Progress	0.6%
2025	
Duke Energy Carolinas	0.6%
Duke Energy Progress	0.7%
2030	
Duke Energy Carolinas	0.9%
Duke Energy Progress	1.0%

Electric Vehicle Adoption Assumptions for the Carolinas

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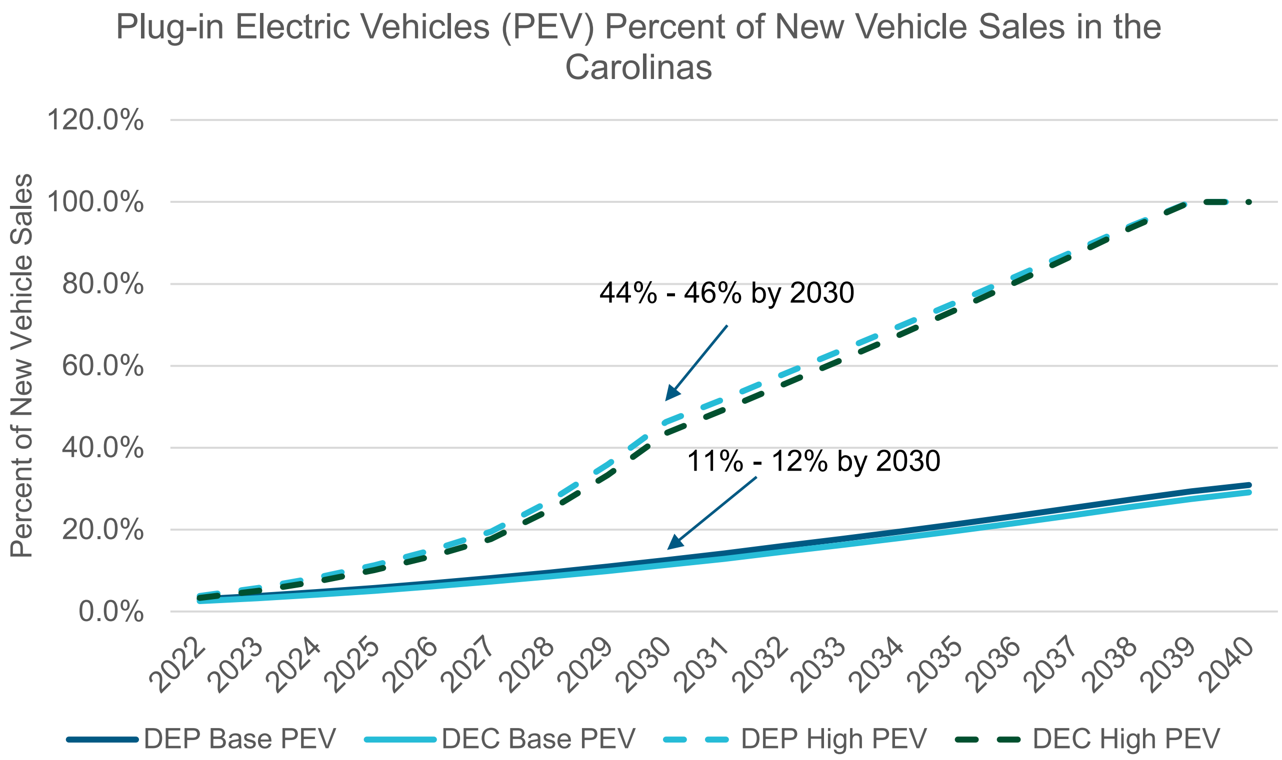
Base EV Projections

- Base projections based on mid-2021 data shows continued steady adoption of EVs across the Carolinas
- Includes projections for light duty (LD), medium duty (MD), and heavy duty (HD) EV adoption

Alternative Projections

- Updated Base Scenario accounting for increased commitments from EV manufacturers and accelerated adoption in 2021
- High Case: Achieve President Biden's goal of PEVs making up 40% - 50% new vehicle sales by 2030
- **Other suggested forecasts?**



Jurisdiction	Base EV Energy - % of Total Energy	High EV Energy - % of Total Energy
2023		
Duke Energy Carolinas	0.1%	0.1%
Duke Energy Progress	0.1%	0.1%
2025		
Duke Energy Carolinas	0.2%	0.4%
Duke Energy Progress	0.3%	0.5%
2030		
Duke Energy Carolinas	1.4%	3.2%
Duke Energy Progress	1.6%	3.9%

Q&A

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Break

Please return at 3:05PM.

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Solar Interconnection Forecast

Matt Kalemba, Director, Distributed Energy Technologies Planning & Forecasting

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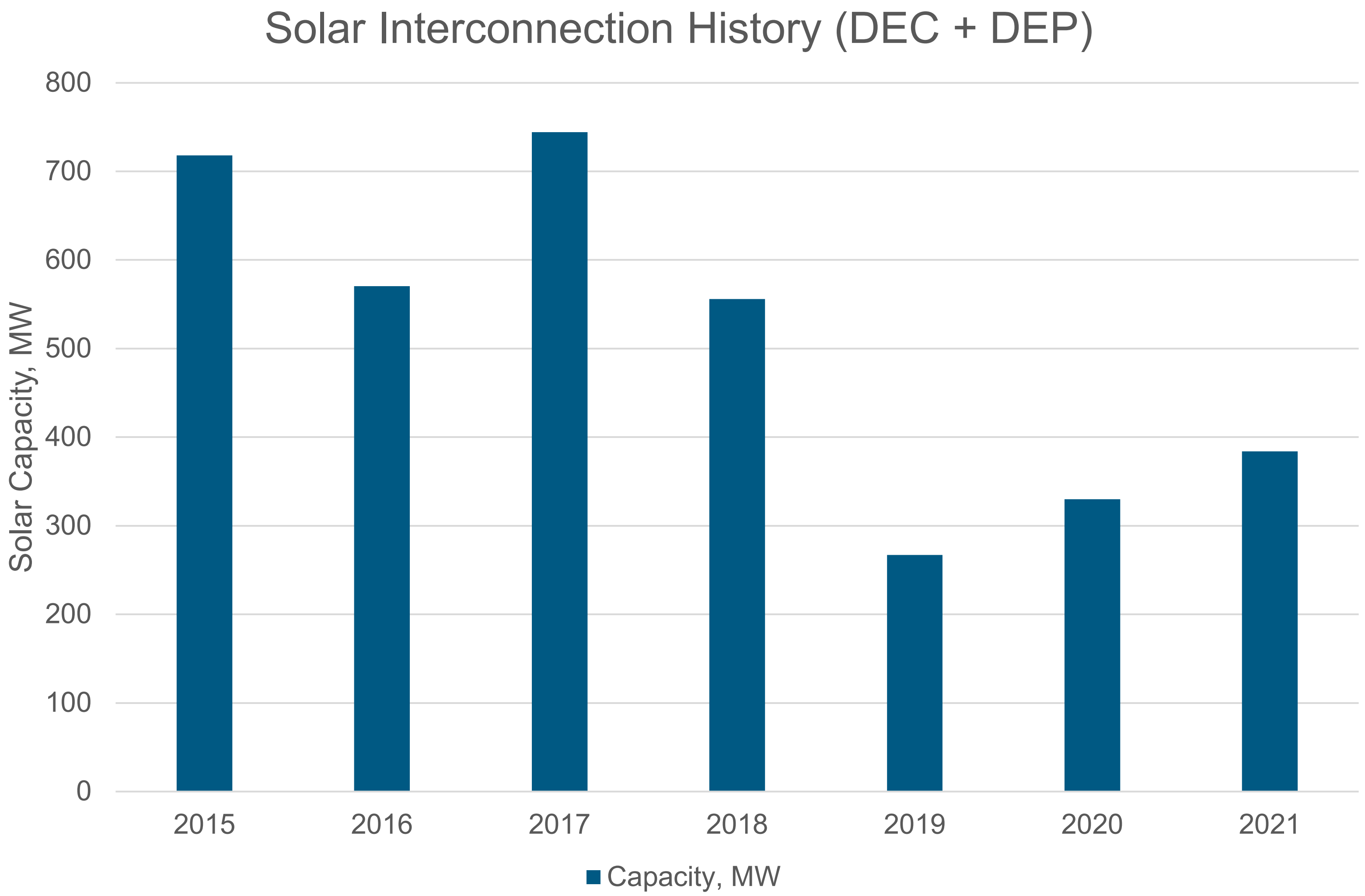
Annual Solar Interconnection Capability - History

- Average about 510 MW/year of solar interconnections since 2015
- Average approximately 9 transmission interconnections annually



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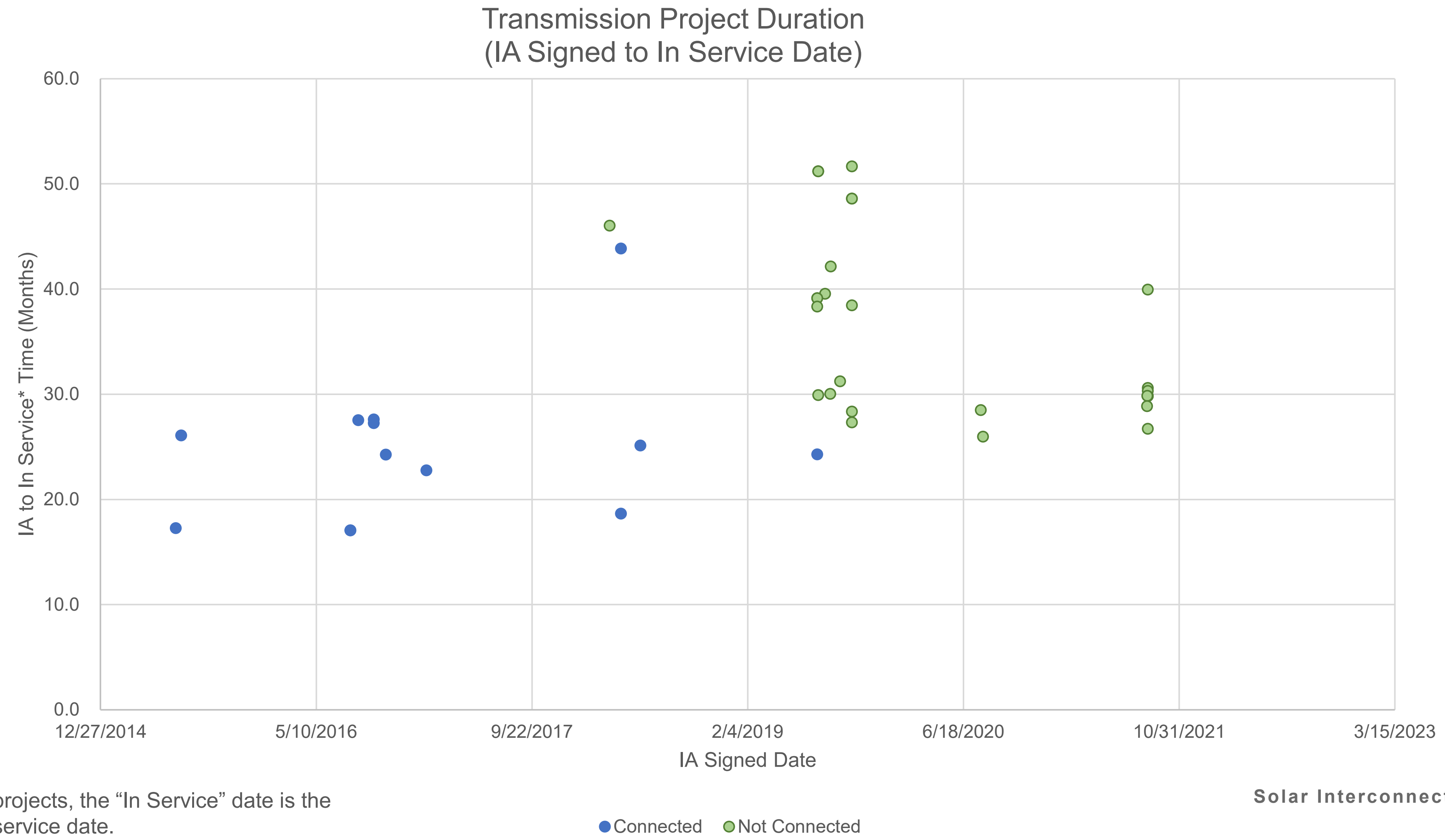
Annual Solar Interconnection Capability – Time to Interconnect Trends



*For “Not Connected” projects, the “In Service” date is the currently estimated in service date.

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Annual Solar Interconnection Capability – Model Sensitivities

- Land availability, supply chain, increasing transmission reliability and resiliency upgrades, and other resource additions / retirements are headwinds to increasing annual solar interconnections
- Shift from smaller, distribution tied solar to larger transmission projects may increase efficiency
- No regrets, proactive strategic transmission investments would enable shorter interconnection timelines

Range of Interconnection Capability Sensitivities

(Annual Nameplate MW Interconnections)

	2026	2027	2028	2029	2030	Potential Connected Solar by 2030
Transmission Constrained	*up to* 500	500	400	400	400	~9,400
Progressive	*up to* 750	750	750	750	750	~11,000
Enhanced Transmission Policy	*To Be Determined*					*TBD*

- *Transmission Constrained* – Decreasing land availability in unconstrained transmission areas increasingly restricts growth opportunities
- *Progressive* – Land availability less constraining than expected, cluster study process leads to more efficient interconnections as upgrade costs are shared among more participants, and / or shift to larger solar facilities leads to steady solar interconnections at historically high levels
- *Enhanced Transmission Policy* – Proactive strategic transmission investments lead to more efficient solar interconnections and increased possibility of larger solar projects

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Technology Forecast

Adam Reichenbach, Generation Technology, Lead Engineer

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Technology Information

Technology[1]	Role	Dispatchability	Annual Capacity Factor
Solar PV with Tracking	Variable	Partial	25-30%
Offshore Wind	Variable	Partial	40-45%
Onshore Wind	Variable	Partial	20-30%
Battery Storage	Storage/Peaking	Full	15-25%
Pumped Hydro Storage[2]	Intermediate	Full	25-35%
Advanced Nuclear	Baseload	Partial/Full	60-95%
Combined Cycle[3]	Baseload	Full	40-80%
Combustion Turbine[3]	Peaking	Full	< 25%

Note 1: Sources of data for Duke modeling are Burns & McDonnell, Guidehouse, and EPRI.
Note 2: Pumped Hydro Storage has both pumping and generating capabilities.
Note 3: Hydrogen is under consideration as an emergent fuel source.

- This table represents existing technologies or near-term emerging technologies that we believe will be available within the planning horizon.
- Duke's Emerging Technology Assessment Team (ETAT) is actively looking at other potential energy solutions

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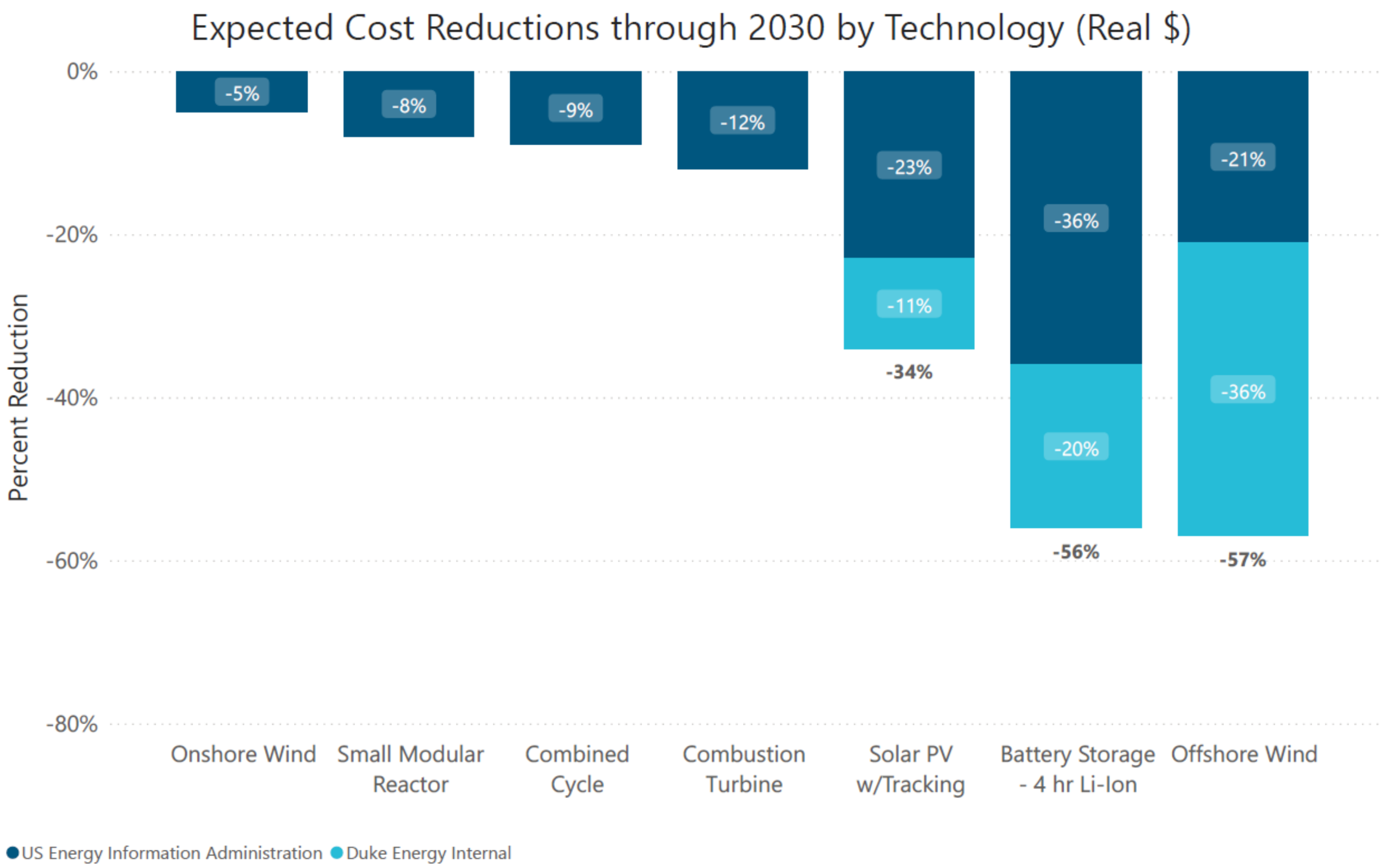
Technology Learning Curves



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Natural Gas Price Forecast

Bobby McMurry, Director, Production Cost Modeling & Analytics

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Natural Gas Forecasting Methodology

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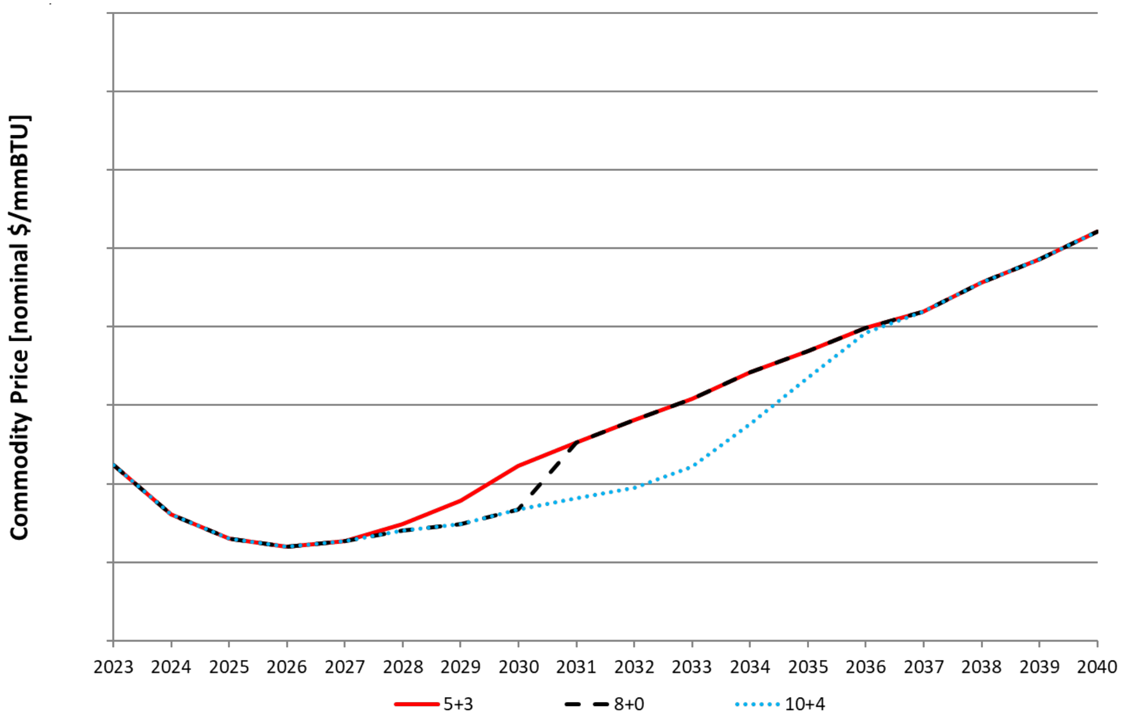
- Historically
  - Use of 10 years of market gas with 5 years blend to 100% fundamentals
  - Fundamentals - Provided by IHS biannually
  - Avoided Cost (NC) – Use of 8 years Market and 100% fundamentals year 9.

- Proposed Change of Methodology
  - Use of 5 years of market gas w/ 3 year blend to fundamentals
    - Coal and gas on the same blending basis
  - Fundamentals – Use an average of EIA, EVA, IHS and Wood MacKenzie.
    - Decrease volatility in fundamental fuel price from one year to another.



Q&A

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Next steps:

- Information/feedback can be sent to DukeCarbonPlan@gpisd.net
- The next meeting will take place on Wednesday, February 23rd. GPI will be sending out an email later this week with the link to register.

Meeting materials/recordings will be uploaded to the website:

www.duke-energy.com/CarolinasCarbonPlan

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Exhibit D

Solar Interconnection Forecast for Carbon Plan Modeling

Carolinas Carbon Plan Technical Subgroup Stakeholder Meeting

FEBRUARY 18, 2022

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Introductions

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Duke Presenters and Panelists:

- Bailey McGalliard
  - Lead Strategy & Analytics Consultant
- Sammy Roberts
  - General Manager, Transmission Planning and Operations
- Matt Kalemba
  - Director, Distributed Energy Technologies Planning and Forecasting
- Support Panelists:
  - Kerry Powell
    - VP Transmission and Fuels Strategy and Planning
  - Maura Farver
    - Director, Distributed Energy Technologies Strategy and Policy
  - Ken Jennings
    - General Manager, Renewable Integration and Operations

Stakeholder Panelists:

- Tyler Norris, Cypress Creek Renewables
- Jeff Thomas, NCUC Public Staff
- Dustin Metz, NCUC Public Staff
- Steve Levitas, Pinegate Renewables
- Kirsten Millar, Rocky Mountain Institute
- Maggie Shober, Southern Alliance for Clean Energy
- Tyler Fitch, Synapse Energy Economics
- Ed Burgess, Strategen Consulting

Agenda and Level Set

- Goal: Discuss the model inputs to be used to forecast how much new solar Duke can safely interconnect each year.
  - A forecast is an **estimate** of future conditions, using **the best information available today**

- Topics to cover today:
  - ***Historic*** pace of interconnection and increasing complexity of interconnection on DEC/DEP systems → *how to translate this into future predictions*
  - Describe factors impacting ***future*** pace of interconnection:
    - Length of time from Interconnection Agreement to In-Service Date
    - Volume of transmission network upgrades that can be completed each year

- Topics that are out of scope:
  - Policy debates as to the "merits" of solar as a resource
  - Cost or operational assumptions of solar included in the model (separate session on this)
  - Transmission investments that could be identified and evaluated through the FERC-jurisdictional local transmission planning process
  - Affected systems generator interconnection studies/policies

- ***Intent*** is to discuss appropriate modeling assumptions, not to solve the policy debates around transmission planning and generator interconnection

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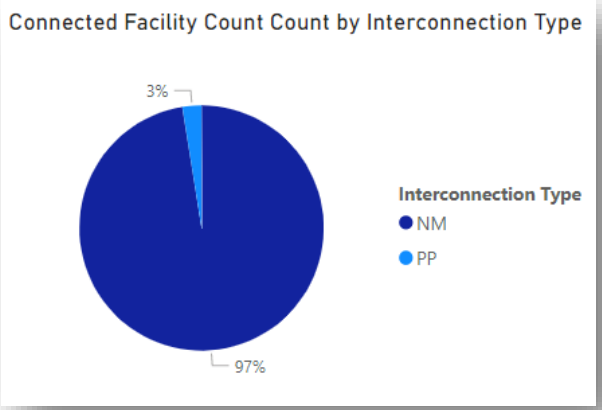
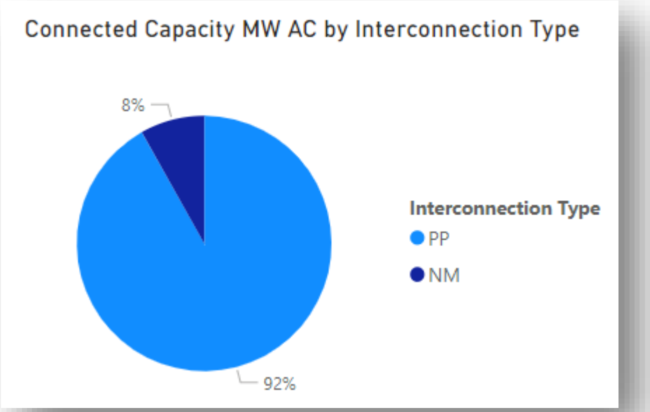
Defining Scope of this Historic Look

- Two most prominent configurations in our service territory can be categorized as follows:
  - **Net Metering** (customer offsets utility usage)
  - **Purchased Power** (customer sends generation to the grid)

- **Purchased Power** represents **3%** of the **count** of interconnections and **92%** of the **Installed Capacity** connected to our grid in the Carolinas through 2021.





- For the purposes of this historical interconnection recap, we will focus on **Purchased Power** configured solar

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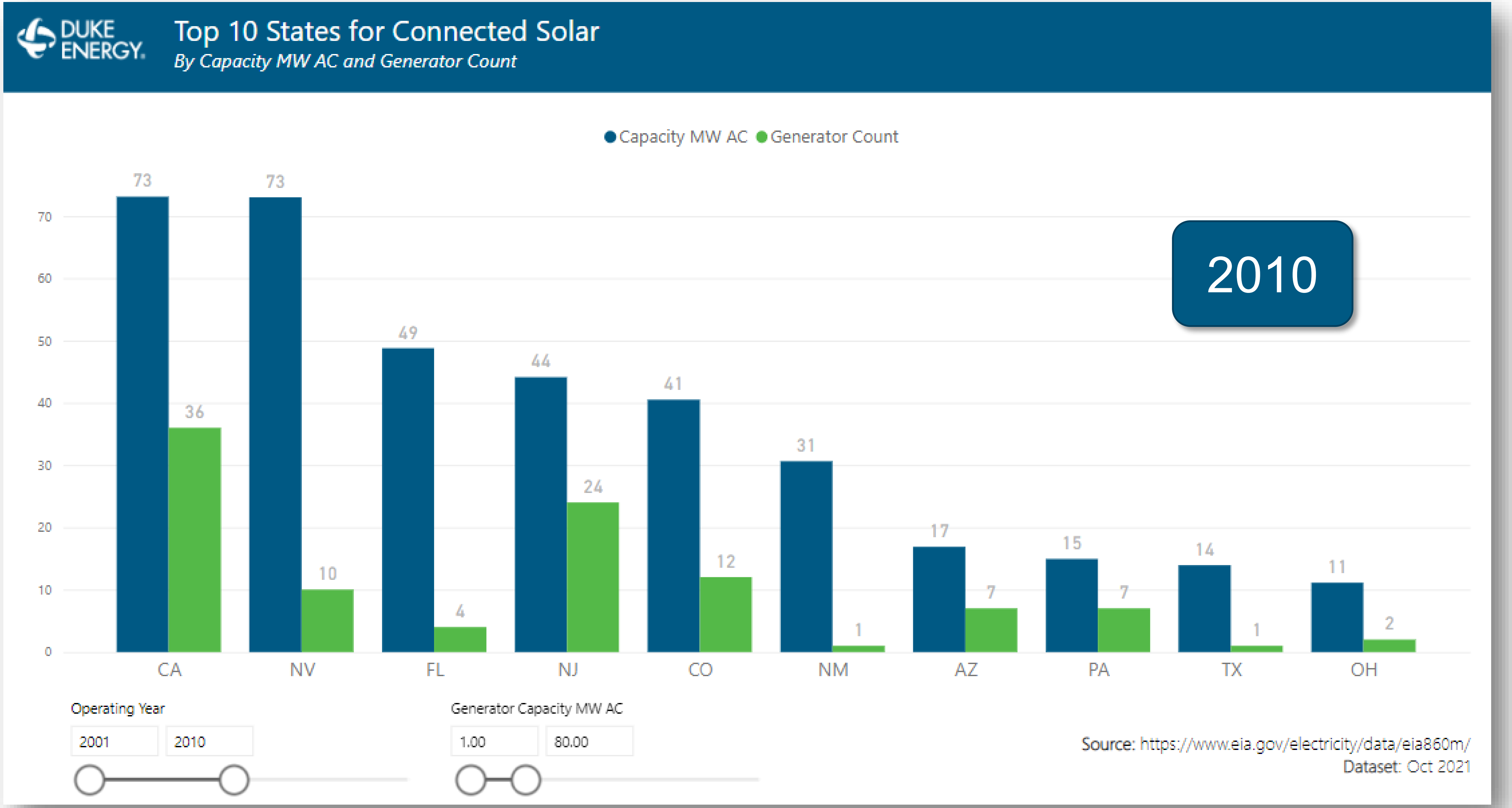
A Quick Look at US Solar Interconnection Trends

- Data Source: EIA 860 M, October 31
- Data Context: Qualified Facility generators (purchased power intent, 80 MW or less)



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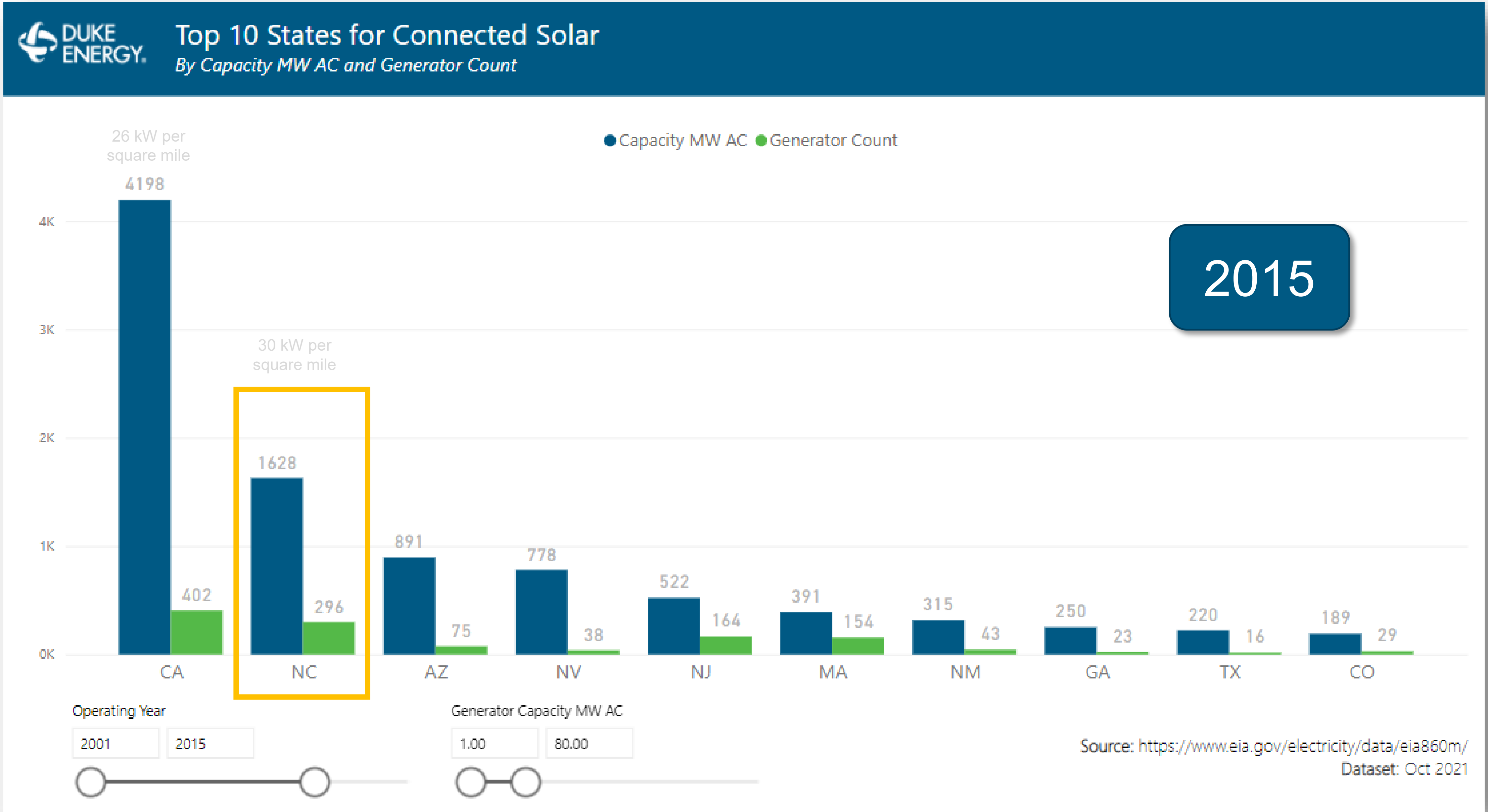

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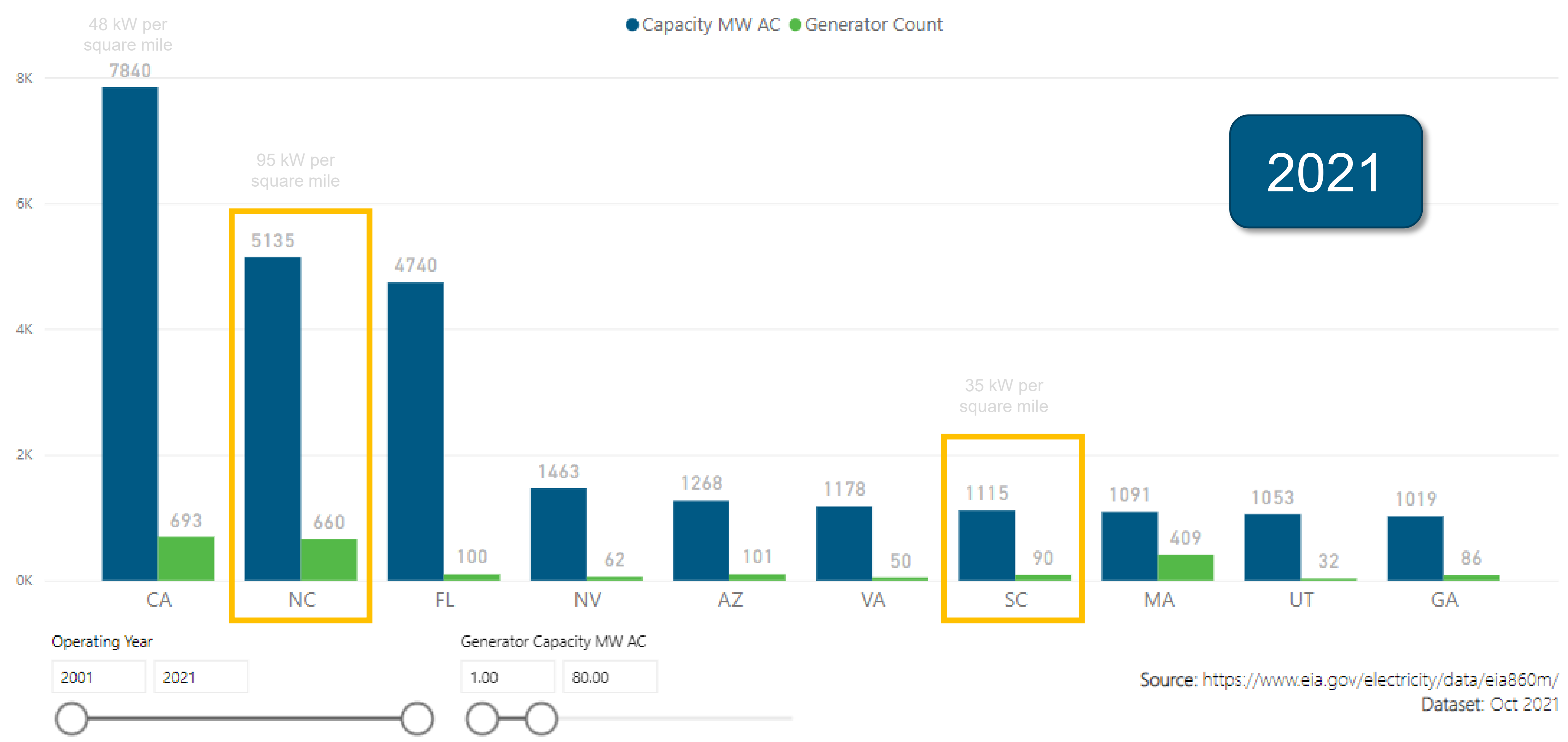
Top 10 States for Connected Solar

By Capacity MW AC and Generator Count



Source: https://www.eia.gov/electricity/data/eia860m/
Dataset: Oct 2021

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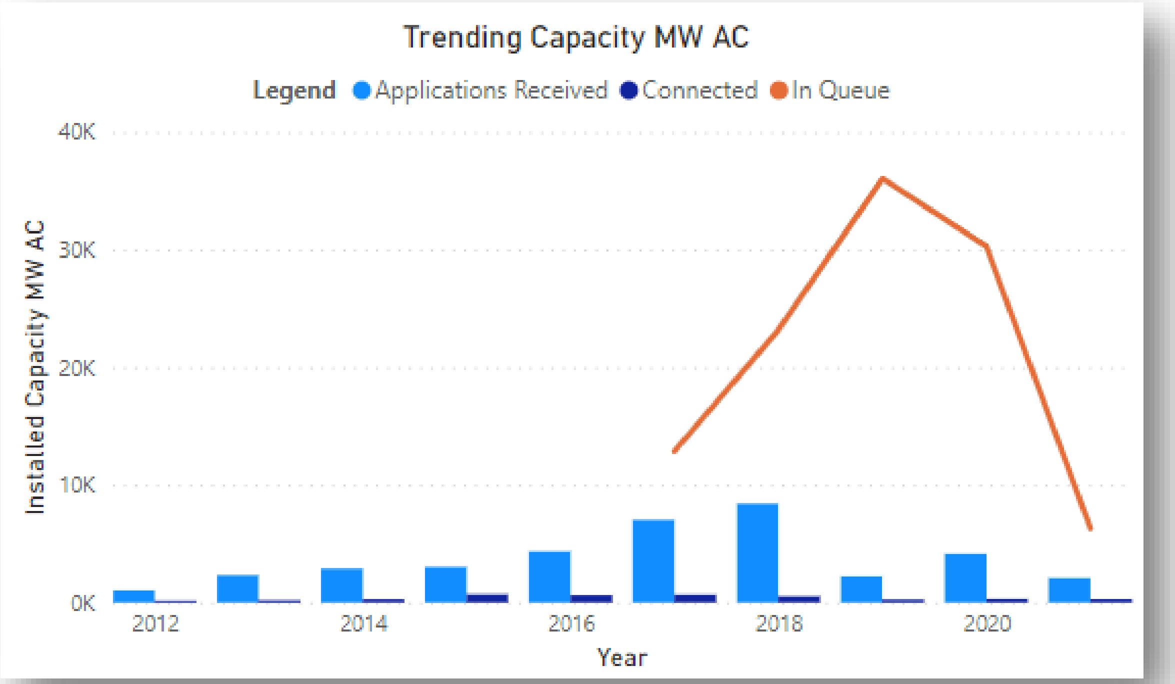
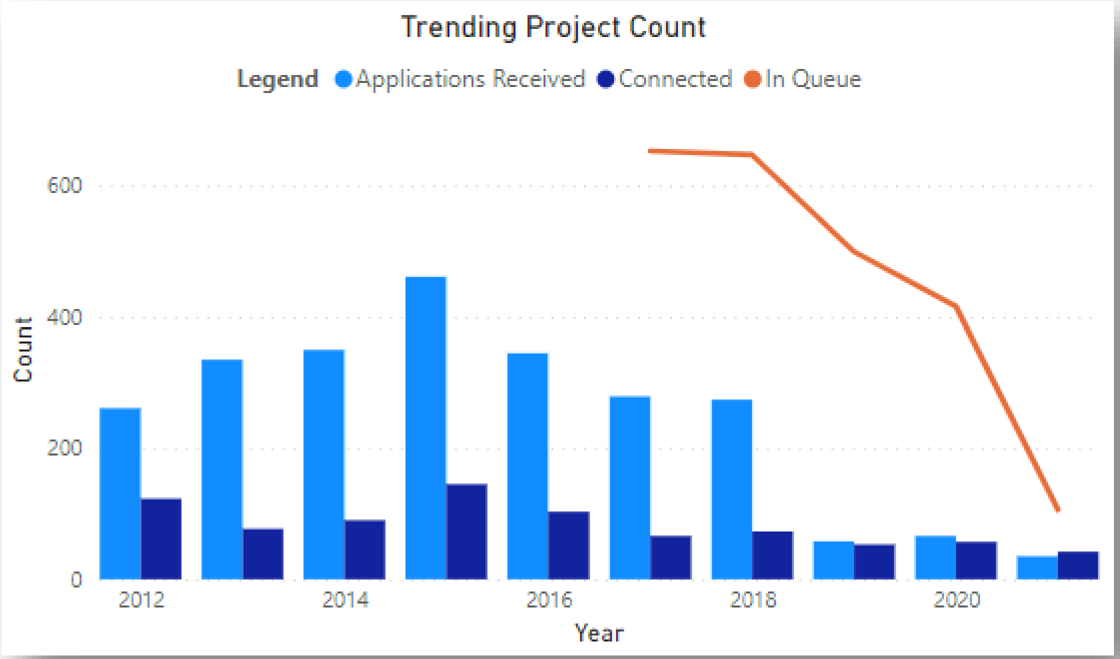
Duke Energy Service Area

Duke Energy has cumulatively connected approximately **4,300** MW universal scale solar in the Carolinas to-date.





Two key takeaways:

1. Highlight movement of projects In Queue
2. Visible movement in the **application count and capacity**, while the **connected count and capacity remains relatively consistent**.

Let's discuss.

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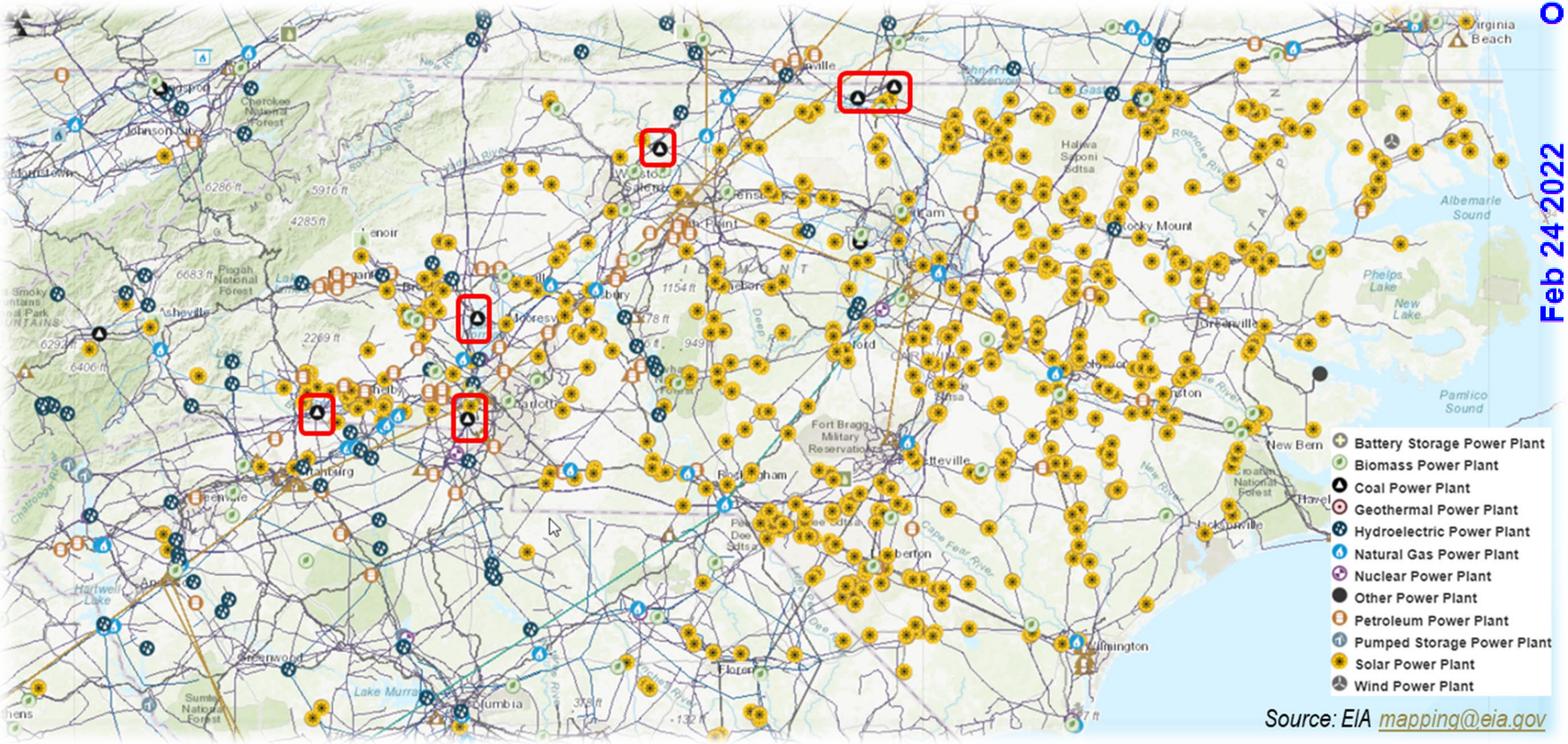
Distributed Generation and Transmission Transformation

- Distributed Generation is requiring a transformation of the grid
- Coal retirements could be impactful
- Pace of transformation will quicken
- Reliability will not be sacrificed



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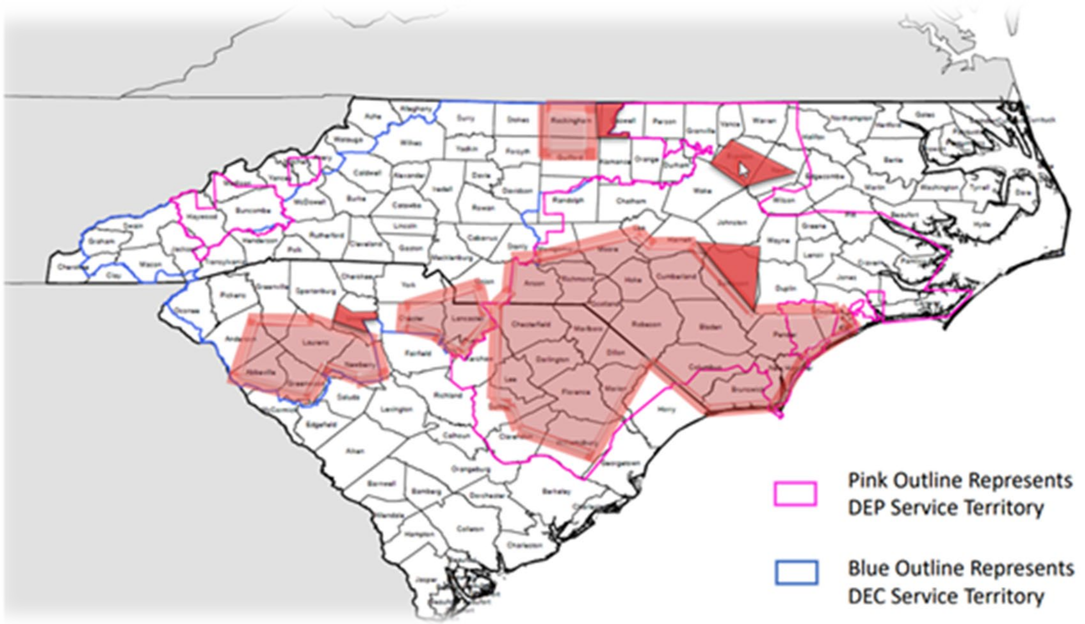
Unlocking the Red Zone

- Generator location in red zone areas will likely require significant upgrades
- Network upgrades required to unlock red zone areas
- Network upgrades require coordinating transmission outages
- Working to make process more efficient
- Reliability will not be sacrificed



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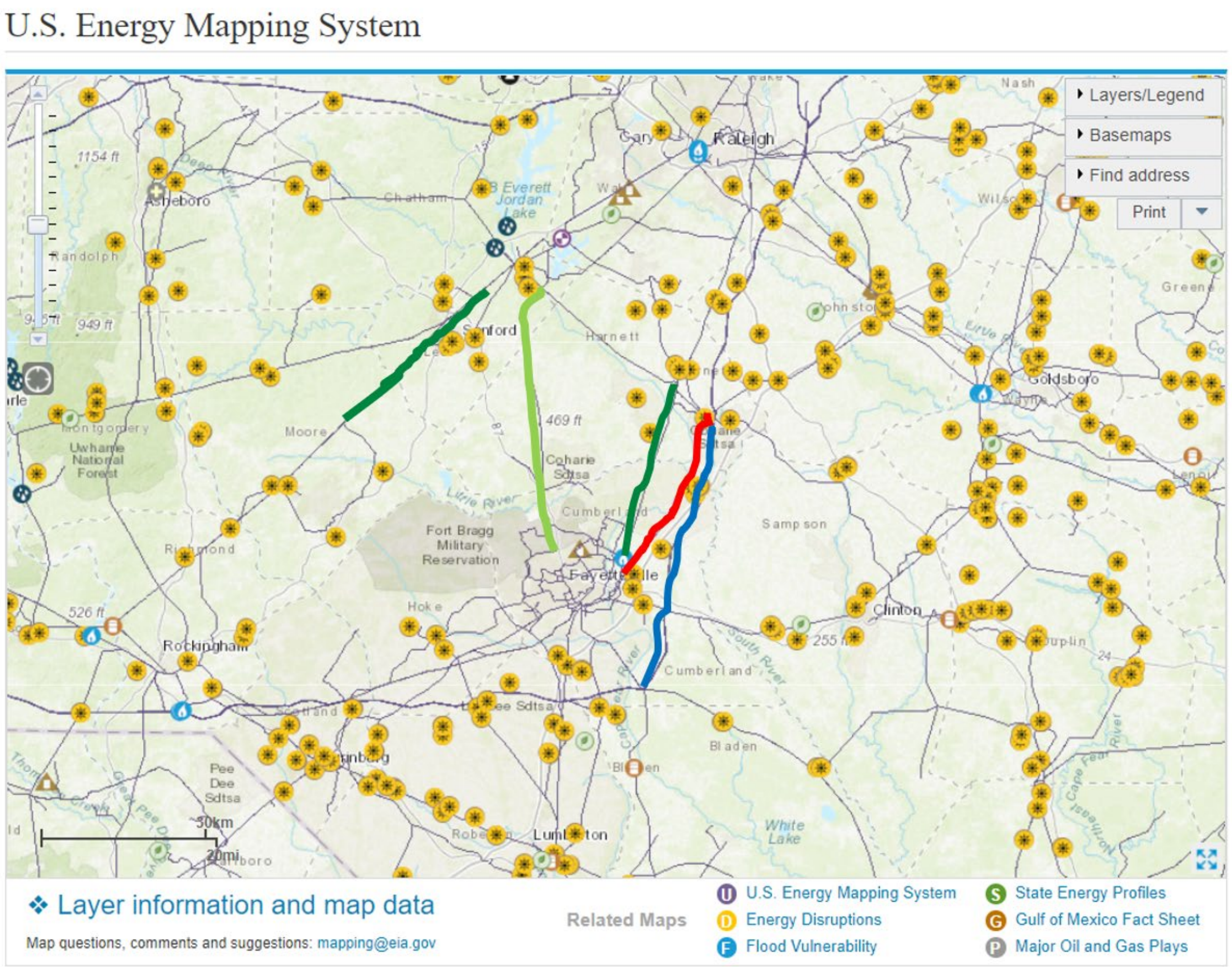
Constructing Network Upgrades



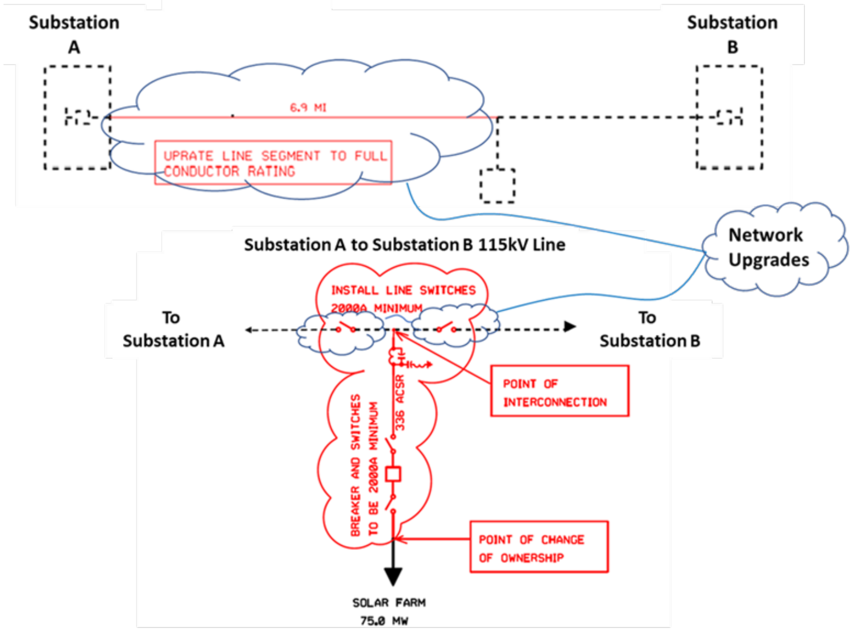


Figure 1 – Network Upgrades Associated with Interconnecting 75MW Solar Facility

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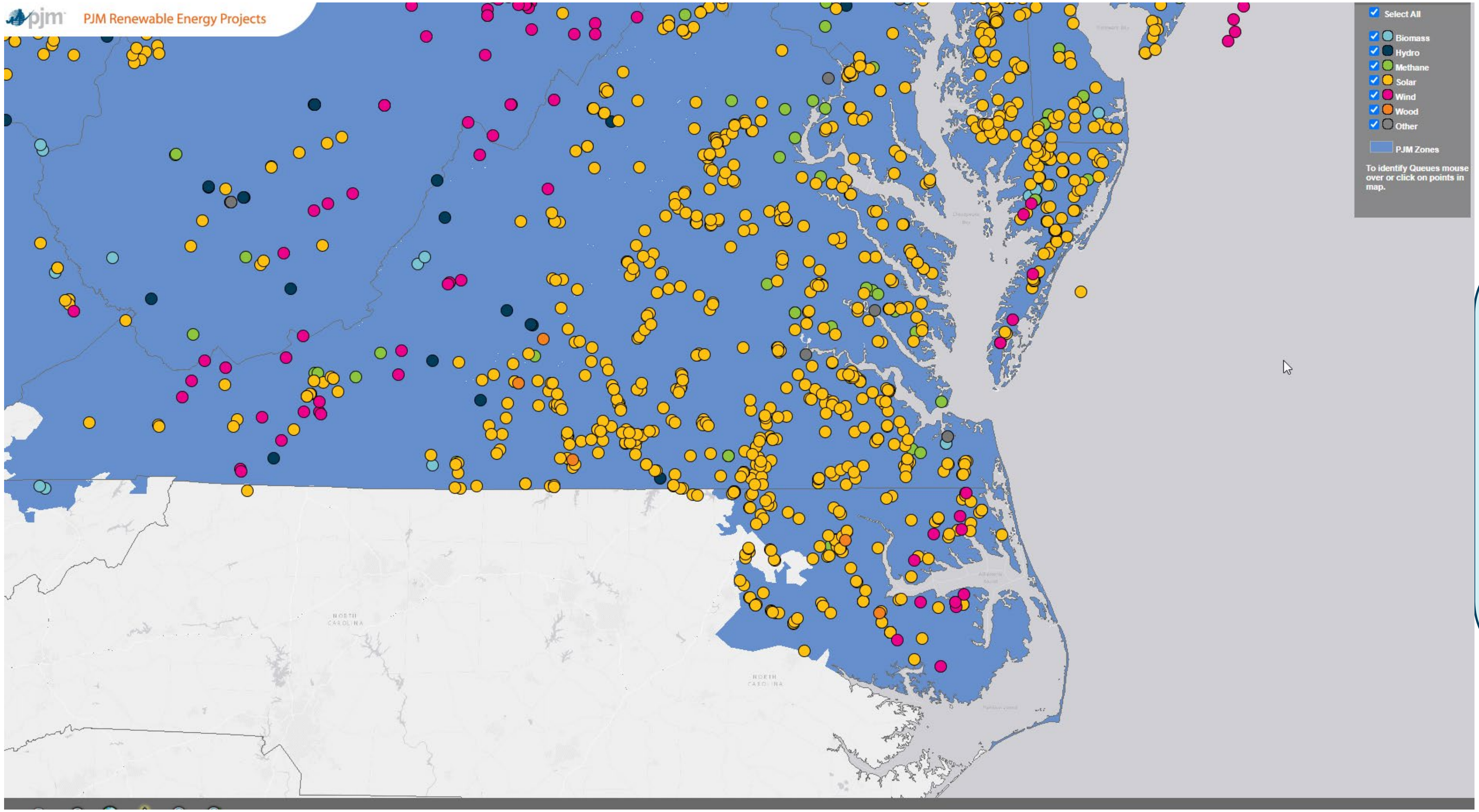
Challenges are not unique to Duke

PJM recently proposed two-year delay on approximately 1,250 projects in the queue

- New projects not eligible for review until 4Q 2025



Federal Energy Regulatory Commission

"A piecemeal approach to expanding the transmission system is not going to get the job done. We must take steps today to build the transmission that tomorrow's new generation resources will require."
FERC Chairman Glick
(July 15, 2021)

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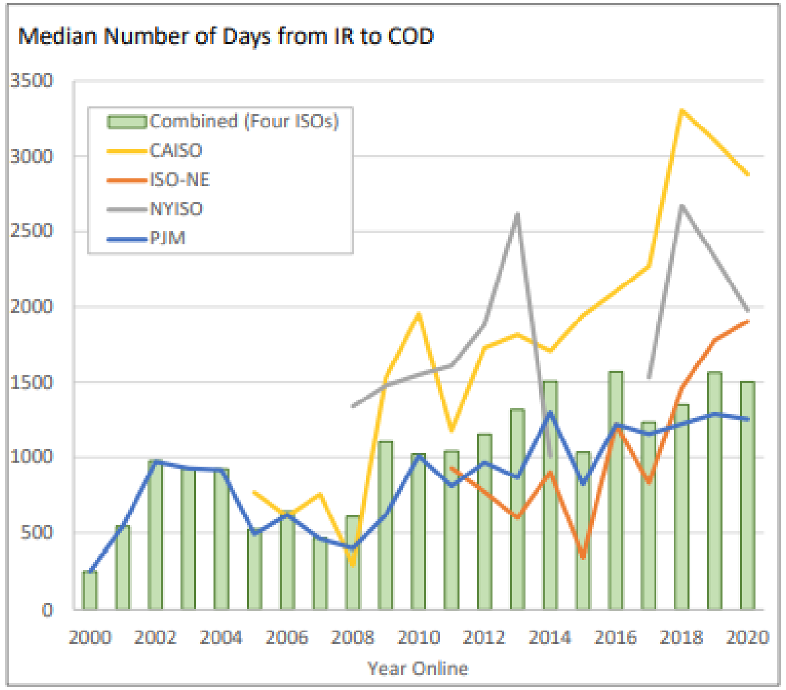
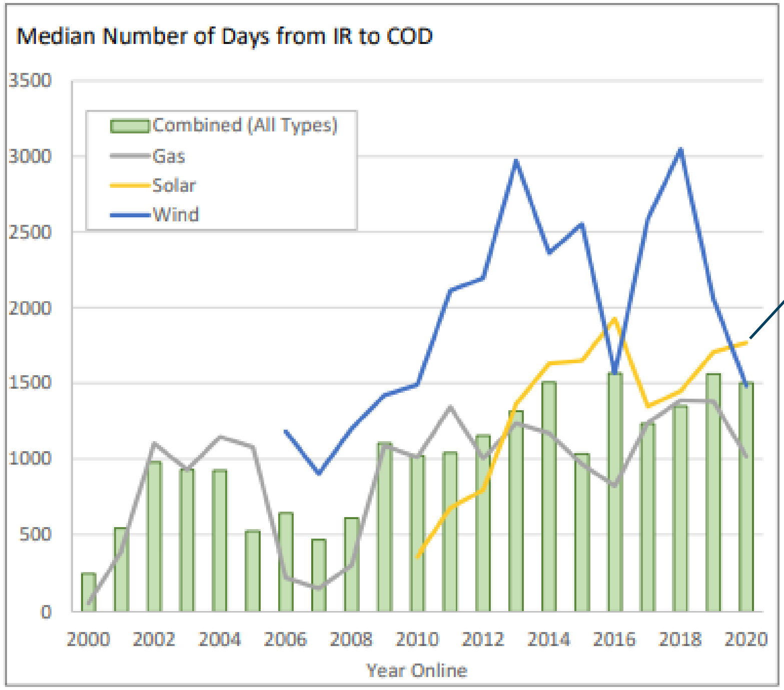
2021 LBNL Report Shows Lengthy Interconnection Timelines

The time from interconnection request (IR) date to commercial operations date (COD) is increasing for some regions and generator types; typically longer for CAISO and for wind

Completed Projects: Time in Queue, by ISO



Completed Projects: Time in Queue, by Resource



Year	Completed Projects
2000	10
2001	20
2002	27
2003	23
2004	28
2005	25
2006	37
2007	49
2008	69
2009	52
2010	60
2011	81
2012	76
2013	82
2014	72
2015	114
2016	134
2017	82
2018	88
2019	71
2020	73

2020 = ~1750 days
~4.8 years

Notes: (1) Data on completed projects were only collected for five ISOs, though only the four shown provided COD. (2) Data are only shown where sample size is >3 for each year. (3) "Time in queues" is calculated as the number of days from the queue entry date to the commercial operations date

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Lawrence Berkeley National Laboratory, May 2021 Report, https://emp.lbl.gov/publications/queued-characteristics-power-plants

Solutions to Explore

- Revised interconnection process ✓
  - Cluster studies with cost sharing mechanism for network upgrades

- Create efficiencies to reduce timeframe from Interconnection Agreement to COD

- Follow local transmission planning process to explore and facilitate transmission upgrades for public policy needs

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OATT Attachment N-1 – Local Transmission Planning

- FERC has exclusive federal jurisdiction over transmission planning
- Follow the FERC approved Orders 890 and 1000 Local Transmission Planning process in the OATT
  - North Carolina Transmission Planning Collaborative covers DEC and DEP transmission systems in NC and SC
    - OSC – Oversight Steering Committee
    - PWG – Planning Working Group
    - TAG – Transmission Advisory Group
  - Process must consider all transmission customer stakeholders that wish to provide input
  - Annual Local Transmission Planning cycle
  - Considers Reliability Projects, Economic Projects, and Public Policy Need

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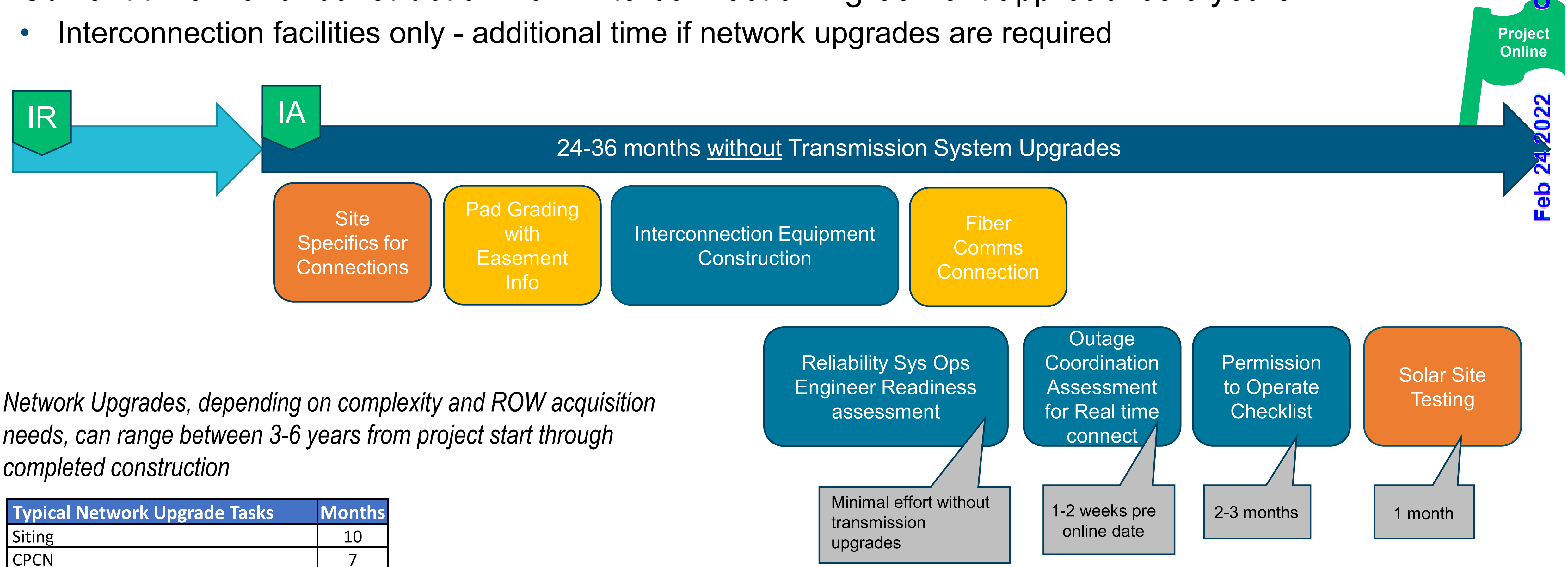
Current Carolinas Interconnection Timeline
Signed IA through Construction

Current timeline for construction from Interconnection Agreement approaches 3 years

- Interconnection facilities only - additional time if network upgrades are required



Network Upgrades, depending on complexity and ROW acquisition needs, can range between 3-6 years from project start through completed construction

Typical Network Upgrade Tasks	Months
Siting	10
CPCN	7
Line Design	24
Prepare Permits	6
Obtain Permits/Construction Planning	12
Construction per mile per crew	2

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Solar Interconnections in Model

- The Carbon Plan must be an executable plan that achieves the Carbon reductions under HB951 and that maintains or enhances reliability

- The timing and ability to interconnect resources should be reflected in the model

- Solar is unique
  - One of the few carbon free resources readily available pre-2030
  - Most optimal areas for solar development are in the most transmission constrained areas
  - Timing to interconnect solar will primarily be driven by timing of transmission system upgrades

- The timing, number, and volume of solar interconnections, and the costs required to increase the pace of solar deployment on the system should be modeled
  - Model solves based on capacity (i.e. MW), but limitation is a combination of number of projects and capacity

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Annual Solar Interconnection Capability – Model Sensitivities

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Range of Interconnection Capability Sensitivities

Nameplate MW	2026	2027	2028	2029	2030	Potential Connected Solar by 2030*
Progressive	*About* 10 projects @ 75 MW Average = 750 MW	750	750	750	750	~10,250
Enhanced Transmission Policy (Base)	About 10 projects @ 75 MW Average = 750 MW	1,000	1,360	1,360	1,360	~12,300

- *Progressive* – Land availability less constraining than expected, cluster study process leads to more efficient interconnections as upgrade costs are shared among more participants, and / or shift to larger solar facilities leads to steady solar interconnections at historically high levels
- *Enhanced Transmission Policy* – Proactive strategic transmission investments lead to more efficient solar interconnections and increased possibility of larger solar projects

**Assumes 6,500 MW connected by 2025 including CPRE Tr3 and NC GSA*

Transmission Cost Adder

(Illustrative DRAFT)

Incremental Solar MW	Transmission Cost Adder, $/kw
< 2,000	$X
2,000 – 3,000	$X+
3,001 – 5,000	$X++

Stakeholder Questions and Discussion

Questions
Feedback
Comments

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Exhibit E

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HB951 2022 Solar Procurement

Stakeholder Meeting 1





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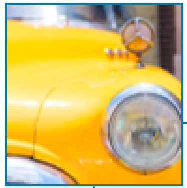
Safety Moment – Winter Driving

Prepare Your Vehicle

- Test your battery
- Make sure the cooling system is in good working order
- Check your tires
  - Winter tires with a deeper, more flexible tread put on your car
  - All-season tires, check the tread on your tires and replace if less than 2/32 of an inch
- Check the tire pressure
- Check your wiper blades and replace if needed
- Add wiper fluid rated for -30 degrees
- Keep your gas tank at least half full to avoid gas line freeze



Before You Drive

- Clean your car's external camera lenses and side view mirrors so you'll be able to see what's around you
- Remove dirt, condensation, ice and snow from sensors to allow the assistive-driving features like automatic emergency braking to work
- Prevent carbon monoxide poisoning, never leave a vehicle running in your garage – even with the garage door up

Avoid a Crash

- AAA offers the following driving tips:
  - Avoid using cruise control in wintry or wet conditions
  - Steer in the direction of a skid, so when your wheels regain traction, you don't have to overcorrect to stay in your lane
  - Accelerate and decelerate slowly
  - Increase following distance to 8 to 10 seconds
  - If possible, don't stop when going uphill

- If visibility is severely limited due to a whiteout, heavy fog or sudden downpour, pull off the road to a safe place and do not drive until conditions improve.
- Avoid pulling off onto the shoulder unless it is an absolute emergency. Limited visibility means other vehicles can't see yours on the shoulder.

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Agenda

Topic	Presenter	Time
Welcome and Safety Moment	Terri Edwards	10:00 am
High Level NC HB 951 Overview	Rebecca Dulin	10:05 am
Overview of NC HB 951 2022 Solar Procurement Provisions	George Brown	10:10 am
2022 Solar Procurement Timing Considerations	Maura Farver	10:25 am
RFP Process & Mechanics	Maura Farver	10:40 am
Q&A	All	11:10 am
Next Steps and Adjourn	Rebecca Dulin	11:25 am

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HB951's Clean Energy Transition

2022

Initial carbon plan approved by NCUC targeting **70%** reduction

2030

Reach **70%** reduction*

2050

Reach carbon neutrality

Other Aspects of H951

- Performance-based rates to support generation transition and track utility performance
- Renewable programs for customers
- 2022 Solar Procurement
- Securitization
- On-utility-bill repayment program
- "Blend and extend"

* Subject to NCUC discretion, development of wind/nuclear, and impact on reliability

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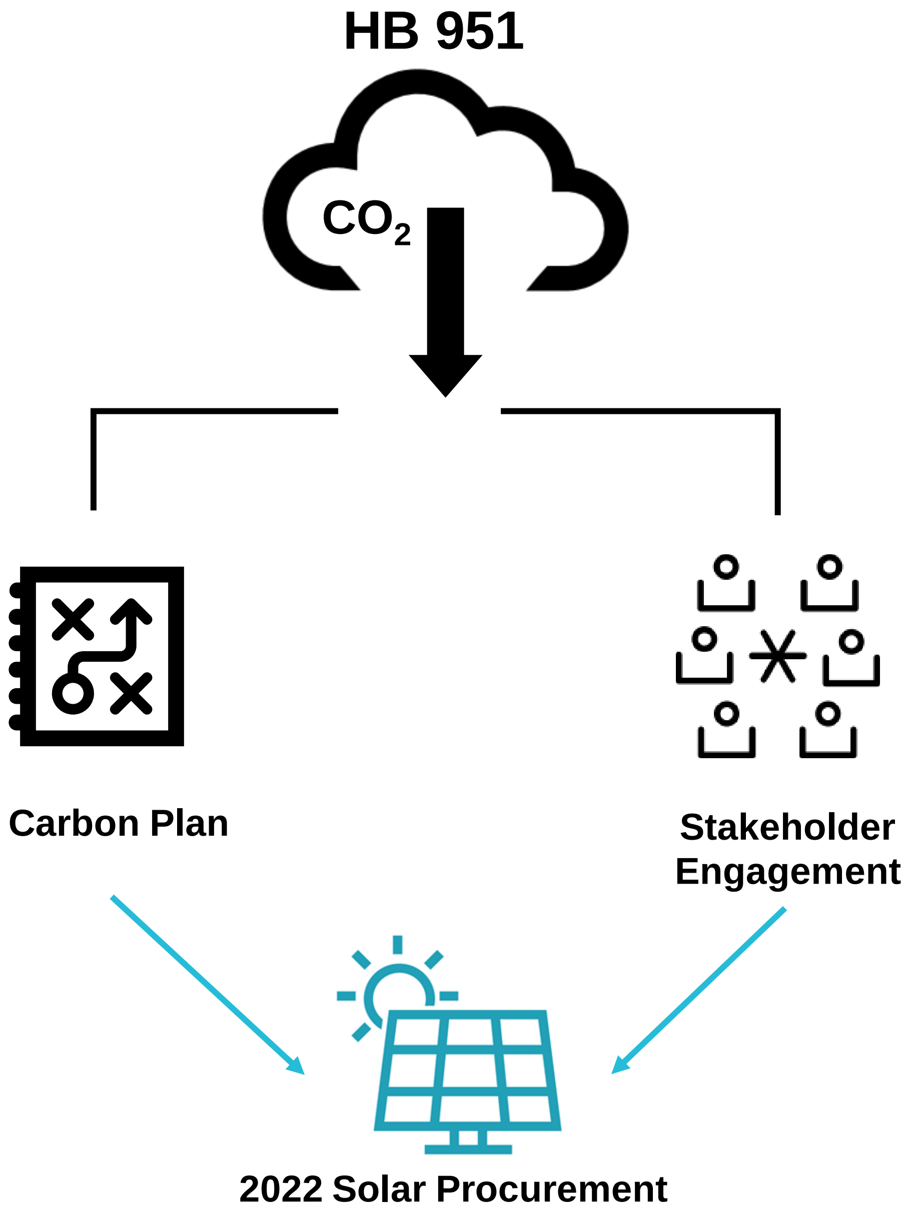
HB951 Carbon Plan

- NCUC shall develop a plan in 2022 with utilities and stakeholder input to achieve reduction goals and may consider power generation, transmission and distribution, grid modernization, storage, energy efficiency measures, demand-side management, and the latest technology breakthroughs.
- Commission discretion to determine timing and resource mix to achieve
  - **least cost compliance**
  - **CO_2 reduction goals**
- Preservation or improvement of grid adequacy and reliability as generation and resources change.
- NCUC authorized to direct the procurement of solar energy facilities in 2022.



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Summary of HB 951 Solar Provisions

Solar that is selected by the NCUC as part of Carbon Plan is subject to the following:

- Volume is based upon Least Cost planning requirements to meet carbon emission reduction goal.
- 45% of the volume will be sourced via Power Purchase Agreements (PPAs) with third parties
  - Facilities must be no larger than 80 MW
  - PPAs must grant control rights of the facility to Duke
  - Contract conveys solar energy, capacity, environmental and renewable attributes to Duke
- 55% of the volume shall be owned by Duke and put into rates based upon cost of service
  - Utility-built/acquisition projects not limited to 80 MW or less.
- These ownership requirements include solar plus storage and any solar for Voluntary Customer Programs.

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HB 951 2022 Solar Procurement

HB 951 provides for the Commission to direct a 2022 procurement based upon the NCUC determination of the need for such procurement:

Part 1 Section 2.(c) "The Commission is **authorized to direct the procurement of solar energy facilities in 2022** by the electric public utilities if, **after stakeholder participation** and **review of preliminary analysis** developed in preparation of the initial Carbon Plan, the **Commission finds that such solar energy facilities will be needed** in accordance with the criteria and requirements set forth in Section 1 of this act to achieve the authorized carbon reduction goals."

Requires stakeholder participation and review of preliminary analysis developed in preparation of the initial Carbon Plan

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High Level Comparison of HB 589 and HB 951

Stipulation	HB 589 CPRE	HB 951 2022 Solar Procurement
Is it a legislatively mandated program?	Yes	No; NCUC may authorize.
Specified volume?	2,660 MW subject to adjustment for Transition MWs	None; should be based on preliminary analysis for Carbon Plan
Power Purchase Agreement (PPA) Cost Cap	NCUC approved Avoided Cost Cap	None specified
PPA vs Utility Ownership Share	No more than 30% utility ownership	45% PPA, 55% utility owned (of total solar selected)
Location	Anywhere in Duke Service Territories	None specified
Third party oversight	Independent Administrator required and selects winning bids	None specified
PPA Contract Term	20 years	None specified

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2022 Procurement Preliminary Analysis and Need

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- While there is more modeling to be done, Duke believes there will be an identified need for incremental solar.
  - Prior modeling work from the NC/SC 2020 IRPs supports additional solar.
- Procurement cycles should align with annual interconnection cycles for maximum efficiency.
- There are 4 annual DISIS clusters (Definitive Interconnection System Impact Study) that could realistically be used to procure solar that could be placed in service by 2030.
  - Projects in the 2022 DISIS cluster will likely not come online until 2026.
- System-wide procurement would need alignment between NC and SC.
- 2022 Solar Procurement does not dictate future procurement processes, which will continue to evolve.

2022 Procurement Timing Considerations

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- Interconnection cost estimates are a key input to evaluating the RFP and determining the least cost resources overall.
- 2022 Solar RFP bids would be part of the 2022 DISIS Interconnection cluster, with interconnection requests due June 29th, 2022.
    - This would also be the bid window closing date.
    - Bid window would open 30 days prior to that.
    - Working backwards to establish the other steps and date requirements.
    - CPRE pre-solicitation process provides good framework for Duke-administered 2022 procurement

Draft Timeline to Align with Interconnection Process

Task	Target Completion Date
22P Pre-filing Stakeholder Meeting 1	1/20/2022
22P Pre-filing Stakeholder Meeting 2 (additional mtgs as needed)	Early Feb
File “Procurement Plan” with Commission(s) (overall structure)	Target 3/1/2022
Post draft RFP documents and pro formas for MP feedback	4/1/2022
Comment period on RFP documents	4/1 - 4/15/2022
Incorporate comments, post final RFP documents/pro formas	4/16 - 4/30/2022
Commission(s) (requested) approval date for Procurement Plan	4/30/2022
2022 PV RFP bid window	5/31/2022 - 6/29/2022

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Procurement Mechanics Overview

Topics to be addressed in stakeholder process:

- Preference for Independent Evaluator (IE)
- Establishing 2 tracks: PPAs and Asset Acquisition
- How to determine selection of “least cost” resources
- Target MW quantity and target allocation (DEC/DEP)
- PPA contract term
- Network upgrade costs
- RFP eligibility requirements
- RFP evaluation factors

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Independent Evaluator

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Under HB 951 structure, Duke plans to hire an Independent Evaluator (IE)

- Cost of IE will be born by the bidders and may add some time to the process
- Aim to have IE selected by April 1, 2022

Scope of IE Responsibilities:

- Provide input on RFP documents
- Report to the Commission(s) on the RFP evaluation and selection process.
  - ➢ Adherence to RFP evaluation methodology
  - ➢ Open and transparent process
  - ➢ No undue preference between market participants

Do stakeholders have feedback on IEs for Duke to consider?

PPAs and Asset Acquisition

- When the MW quantity is established, 45% will be the PPA target and 55% will be the utility-owned target for this RFP.
- Current thinking is that the pro forma PPA would be very similar to the CPRE T3 PPA.
- Asset Acquisition projects:
  - Contemplating utilizing the same proposal types and agreement structures from CPRE (i.e. asset transfer, an asset transfer plus EPC, or build-own-transfer).

Should bidders be allowed/required to submit the same project for both a PPA and asset acquisition?

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Selection of Least Cost Resources

- HB 951 requires **least cost** procurement to achieve carbon reduction goals; in contrast to HB 589, it does not require a pre-determined cost cap.
    - Determining the appropriate value of carbon-free energy and environmental attributes is part of the work being established in the Carbon Plan.
- Even without a pre-determined cost cap, an Independent Evaluator would verify that there was a competitive outcome achieving least cost.
- Commission(s) would verify the selection achieves least cost procurement and would approve CPCNs (if applicable) for winning proposals.

Do stakeholders believe a pre-determined cost cap is necessary for a March filing?

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Target MW Quantity

- Duke will not have complete Carbon Plan modeling until after the March filing.
- To execute an RFP in 2022, Duke could seek Commission(s) approval to hold an RFP and establish a market clearing price and volume later.
- DEC/DEP allocation does not need to be pre-determined.

Duke supports a single, system-wide procurement. Do stakeholders agree?

Is there a need to determine a target quantity before Carbon Plan modeling is complete? When is a target quantity needed?

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PPA Contract Term

Is a 20 year contract term still appropriate?

Should the RFP allow bids of 15, 20, and 25 year contract term lengths?

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Network Upgrades

- How are upgrades funded?
- CPRE approach took upgrade cost uncertainty out of bidding.
    - Diverges from State jurisdictional approach where interconnecting customer pays for network upgrade costs at time of IA.
- FERC jurisdictional approach requires interconnecting customer to fund network upgrades at IA but provides for reimbursement after COD is achieved.

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You may continue to submit written questions to:

2022SolarRFP@duke-energy.com

Q&A

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