March 1, 2021

Ms. Kimberley A. Campbell
Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Raleigh, NC 27603

Re: Docket No. E-100, Sub 165
2020 Biennial Integrated Resource Plans and Related 2020 REPS Compliance Plans
**Initial Comments of the North Carolina Sustainable Energy Association and the Carolinas Clean Energy Business Association on Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Integrated Resource Plans**

Dear Ms. Campbell,

Please find enclosed the Initial Comments of the North Carolina Sustainable Energy Association and the Carolinas Clean Energy Business Association[1] on Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Integrated Resource Plans in the above-caption docket. Exhibit 3 to the initial comments contains confidential information, and a redacted version is attached to these comments. A confidential version of Exhibit 3 will be filed separately. Please let me know if you have any questions or if there are any issues with this filing.

Respectfully yours,

/s/ Peter H. Ledford

[1] The North Carolina Clean Energy Business Alliance filed a petition to intervene in this proceeding on October 5, 2020, which was granted by the Commission on October 6, 2020. On January 19, 2021, the North Carolina Clean Energy Business Alliance changed its name to the Carolinas Clean Energy Business Alliance.

**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION**
**DOCKET NO. E-100, SUB 165**

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| **In the Matter of:** | ) | **INITIAL COMMENTS OF** |
| **2020 Biennial Integrated Resource Plans** | ) | **NCSEA AND CCEBA ON** |
| **and Related 2020 REPS Compliance Plans** | ) | **DUKE ENERGY** |
| | ) | **CAROLINAS, LLC AND** |
| | ) | **DUKE ENERGY** |
| | ) | **PROGRESS, LLC'S** |
| | ) | **INTEGRATED RESOURCE** |
| | ) | **PLANS** |

**INITIAL COMMENTS OF THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION AND THE CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION ON DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC'S INTEGRATED RESOURCE PLANS**

Pursuant to the North Carolina Utilities Commission ("Commission") Rule R8-60(k) and the Commission's January 8, 2021 *Order Granting Extensions of Time*, the North Carolina Sustainable Energy Association ("NCSEA") and the Carolinas Clean Energy Business Association ("CCEBA") submit the following comments on the 2020 integrated resource plans ("IRPs") submitted by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, Inc. ("DEP") (DEC and DEP, collectively, "Duke").[1]

[1] In addition to these Initial Comments, NCSEA and CCEBA are also filing Partial Initial Comments with the Southern Alliance for Clean Energy, the Sierra Club, and the Natural Resources Defense Council regarding Duke's capacity expansion modeling.

## I. INTRODUCTION

NCSEA is a 501(c)(3) non-profit organization that drives public policy and market development for clean energy. NCSEA's membership includes over 300 members, including individuals, businesses, industries, utilities, colleges and universities, and decision-makers who are committed to leading clean energy progress.[2] CCEBA, formerly the North Carolina Clean Energy Business Alliance, is a 501(c)(6) nonprofit trade association headquartered in Durham, North Carolina, representing all types of businesses in the clean energy sector, including over 80 developers, manufacturers, engineers and other professionals, and clean energy buyers in the Carolinas. NCSEA and CCEBA submit the comments below for the Commission's consideration.

## II. SUMMARY OF COMMENTS AND RECOMMENDATIONS

Duke's 2020 IRPs present six resource portfolios, each with several sensitivities, that contain differing assumptions about key characteristics such as fuel forecasts, coal retirement timeline, renewable energy addition limits, and carbon pricing. Duke has modeled these scenarios using its legacy capacity expansion and production cost models. Duke's two Base Cases are presented as "least cost" portfolios – one with and one without carbon policy – while the other four present pathways under various carbon constraints. Duke's six portfolios as presented in the IRPs are:

- Base Case without Carbon Policy: "least cost" portfolio assuming no carbon policy.
- Base Case with Carbon Policy: "least cost" portfolio assuming basic carbon policy.
- Earliest Practicable Coal Retirement: retires coal plants as soon as practicable and optimizes remaining portfolio to meet capacity need.

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[2] A number of NCSEA's members have provided comments or consumer statements of position in this docket. Those include Buncombe County, the City of Asheville, the City of Charlotte, the City of Durham, the City of Raleigh, the City of Wilmington, Durham County, Orange County, the Town of Boone, the Town of Carrboro, the Town of Chapel Hill, and the Town of Hillsborough.

- <u>70% CO2 Reduction: High Wind</u>: 70% $CO_2$ reduction constraint is modeled with higher deployment of solar, onshore wind, and offshore wind.
- <u>70% CO2 Reduction: High SMR</u>: 70% $CO_2$ reduction constraint is modeled with higher deployment of solar, onshore with, and small modular reactors ("SMR").
- <u>No New Gas Generation</u>: High $CO_2$ reduction targeted while not adding any new natural gas generation.[3]

Duke's IRPs contain major flaws with respect to the assumptions and methodologies incorporated into and relied upon in the IRP modeling. These errors increase the selection of new natural gas capacity, decrease the selection of new renewables and battery storage, and obscure the identification of a truly least-cost plan. The Joint Comments of NCSEA and CCEBA address the following flaws in Duke's IRPs:

1. **Risk Analysis –** Duke fails to present a sufficient risk analysis that would enable the Commission to better assess levels of risk associated with fuel supply limitations, high fuel costs, or regulatory risk. Duke's scenario sensitivities are primarily qualitative and do not provide sufficient context needed for a robust evaluation of portfolio options.

2. **Resource Modeling and Assumptions –** Duke's IRPs include assumptions regarding capacity costs and fuel forecasts that are fundamentally flawed, dramatically impacting the results of Duke's modeling. Specifically, Duke's IRPs erroneously model and account for (1) Solar costs; (2) Storage costs; (3) Natural gas capacity assumptions and forecasts; (4) Coal modeling; and (5) Available energy purchases.

3. **Resource Adequacy –** Duke's resource adequacy analysis is highly problematic and results in (1) the overstatement of winter-time loss-of-load risk in DEC and DEP, (2) the underestimation of solar and storage capacity contributions to peak load, and (3) the under-selection of solar and storage resources as least-cost options in Duke's capacity expansion modeling. Duke has failed to adequately consider the ability of storage and demand side management programs to address extreme winter peaks, has failed to appropriately calculate the Effective Load-Carrying Capability ("ELCC") of solar and storage, and has failed to use a capacity expansion model capable of identifying the synergies between complimentary resources such as solar and storage.

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[3] *Duke Energy Carolinas 2020 Integrated Resource Plan* at 16 (Nov. 6, 2020) ("DEC IRP").

4. **Regionalization Benefits –** Duke's IRP fails to consider or incorporate the reliability and cost-saving benefits of regionalization. Rather than seeking out opportunities to leverage its position as part of the Eastern Interconnection, Duke continues to model itself as an island or through limited joint dispatch between its balancing authorities. As a result, Duke forgoes opportunities for significant cost savings, adequate reliability at lower cost, and more efficient integration of intermittent resources.

5. **Transmission –** Duke's IRPs provide inadequate detail about its transmission planning assumptions or costs, including economies of scale with bulk transmission upgrades, the potential for collaborative planning efforts, improved asset management practices, and opportunities for imports.

NCSEA and CCEBA have retained the following expert consultants to evaluate Duke's IRP, critique Duke's assumptions and methodologies, and recommend specific steps that Duke can take in this proceeding to correct these flaws and modify its IRPs. These reports are referred to collectively in these comments as the "Expert Reports."

- Brendan Kirby, P.E. – Mr. Kirby is a professional engineer and independent consultant with 45 years of experience in the electric industry and a leading scholar in the areas of bulk system reliability, energy storage, demand side response, renewable power integration, distributed resources, and advanced analysis techniques. Mr. Kirby prepared the attached report entitled "Comments on Duke Energy Carolinas and Duke Energy Progress 2020 Integrated Resource Plan" (the "Kirby Report")[4] Mr. Kirby's curriculum vitae is included as an attachment to his report. The Kirby Report addresses flaws in Duke's resource adequacy methodology, including Duke's determination of winter loss-of-load risk using historical weather data and synthesized load data, application of storage and DSM options, and failure to adequately model Duke as part of the Eastern Interconnection.

- Energy and Environmental Economics, Inc. ("E3") – E3 is a leading economic consultancy focused on the energy industry, with an emphasis on electricity and the clean energy transition. E3 has engaged extensively on IRP processes across North America, working to develop future portfolios that balance cost, environmental objectives, reliability, and equity, specializing in resource adequacy analysis and modeling. E3 prepared the attached report entitled "Review of Duke's 2020

[4] Attached as **Exhibit 1**.

Integrated Resource Plan" (the "E3 Report")[5] The E3 Report critiques Duke's calculation of Effective Load-Carrying Capability values for solar and storage, and it identifies significant limitations in Duke's capacity expansion modeling that prevent the model from identifying, quantifying, and optimizing the benefits of complimentary resources on the grid, including solar and storage. This limitation results in lower modeled capacity contributions—and therefore higher modeled costs—of renewables and storage.

- Kevin Lucas – Mr. Lucas is Senior Director of Utility Policy and Regulation for the Solar Energy Industries Association ("SEIA"), the national trade association for the U.S. solar industry. Mr. Lucas has worked in the energy and environmental industry since 2010, focusing on renewable energy, energy efficiency, and greenhouse gas reduction. Mr. Lucas prepared the attached report entitled "Comments on Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Integrated Resource Plans" (the "Lucas Report").[6] Mr. Lucas's curriculum vitae is included as an attachment to his report. The Lucas Report critiques Duke's inadequate risk analysis, identifies numerous flaws in Duke's generation and fuel forecast assumptions, including significant problems with Duke's natural gas forecast, and addresses failure to consider the benefits of regionalization.

- Justin Sharp – Dr. Sharp is a Ph.D. Meteorologist with seventeen years of electric utility sector experience, with expertise in the area of weather-driven renewable energy integration, numerical weather prediction modeling, and climate science. Mr. Sharp prepared the attached report entitled "Duke Energy IRP Resource Adequacy Comments" (the "Sharp Report").[7] Dr. Sharp's curriculum vitae is included as an attachment to his report. The Sharp Report critiques Duke's synthesis of load and solar generation data as a function of weather data in the IRPs and discusses how identified flaws skew Duke's loss-of-load risk and resource adequacy analysis.

- Jay Caspary – Mr. Caspary is Vice President of Grid Strategies, LLC and has over 40 years of utility and RTO experience, including substantial experience in the areas of interregional transmission expansion and planning, grid operations and planning, and interconnection. Mr. Caspary prepared the attached report, entitled "Transmission Issues and Recommendations for Duke 2020 IRP" (the "Caspary Report").[8] Mr. Caspary's curriculum vitae is included as an attachment to his report. The Caspary Report addresses inadequate and inappropriate assumptions in Duke's

[5] Attached as **Exhibit 2**.
[6] Attached as **Exhibit 3**.
[7] Attached as **Exhibit 4**.
[8] Attached as **Exhibit 5**.

IRP regarding transmission planning, which fail to capture the benefits of optimized and least cost transmission planning.

These comments also incorporate by reference the modeling conducted by Synapse Energy Economics, Inc. ("Synapse"), filed concurrently in this proceeding with the Partial Initial Comments of the North Carolina Sustainable Energy Association, Carolinas Clean Energy Business Association, Southern Alliance for Clean Energy, Sierra Club, and Natural Resources Defense Council on Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Integrated Resource Plans ("Joint Synapse Comments"). As described in the Joint Synapse Comments, Synapse used the EnCompass capacity expansion and production cost model to correct several flaws in Duke's IRP modeling and assumptions. Even by correcting for only a subset of the issues identified by Synapse and in the Expert Reports, the Synapse modeling retires coal based on Duke's earliest practicable retirement schedule and builds no new gas, deploys significant volumes of solar and battery storage capacity, while maintaining a 17% reserve margin. The Synapse results clearly illustrate the dramatic changes to the identification of a least-cost plan that result from the correction of flaws identified in Duke's IRPs and emphatically demonstrate the need for Duke to modify and refile its IRPs in this proceeding.

Based on the analysis above, NCSEA and CCEBA recommend that the Commission disapprove Duke's IRPs and direct DEC and DEP to modify and refile their IRPs after completing the modifications recommended in these comments and in the Joint Synapse Comments.

## III. <u>Duke's Flawed Modeling Assumptions Produced IRP Scenarios That are Not Least Cost</u>

Commission Rule R8-60(g) requires that:

> As part of its integrated resource planning process, each utility shall consider and compare a comprehensive set of potential resource options, including both demand-side and supply-side options, to determine an integrated resource plan that offers the least cost combination (on a long-term basis) of reliable resource options for meeting the anticipated needs of its system. The utility shall analyze potential resource options and combinations of resource options to serve its system needs, taking into account the sensitivity of its analysis to variations in future estimates of peak load, energy requirements, and other significant assumptions, including, but not limited to, the risks associated with wholesale markets, fuel costs, construction/implementation costs, transmission and distribution costs, and costs of complying with environmental regulation. Additionally, the utility's analysis should take into account, as applicable, system operations, environmental impacts, and other qualitative factors.

However, Duke's evaluation of resource options is flawed and contains numerous and significant errors. If the evaluation is improved and the errors are addressed, modeling will produce portfolios that retire coal units sooner, add less natural gas, and add more solar and storage, particularly early in the planning horizon.[9]

As discussed below and as presented in the attached Expert Reports, Duke has failed to adequately consider and compare resource options to determine the least cost combination, on a long-term basis, of reliable resource options for meeting Duke's anticipated load. Duke has failed to sufficiently analyze potential resource options, and combinations of resource options, accounting for sensitivity of its analysis to a variety of assumptions about load, resource costs, and relevant risk.

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[9] Lucas Report at 15.

Specifically, Duke has (1) failed to present sufficient risk analysis to assess the robustness of its selected portfolios; (2) included numerous flawed assumptions in its modeling of generation resources; (3) conducted a resource adequacy analysis that overstates winter loss-of-load risk; (4) used a capacity expansion model that is incapable of accounting for synergistic benefits of resources; (5) inaccurately calculated the capacity contributions of solar and storage; (6) failed to account for the benefits of regionalization; and (7) failed to conduct a sufficient transmission analysis. As a result, Duke's IRP fails to comply with the applicable legal standard under North Carolina law and should be rejected and modified.

The sections below discuss these shortcomings, as further described in the attached Expert Reports, including specific recommendations that Duke should adopt to correct these flaws. These include the recommendations provided in the Joint Synapse Comments. As described in the Joint Synapse Comments, using the EnCompass capacity expansion and production cost model, Synapse identified and corrected multiple flaws in Duke's modeling assumptions.[10] Synapse then performed its own modeling to illustrate the substantial increase in renewable energy and storage resources, the reduction in natural gas capacity, and the significant cost savings that result from the correction of several of Duke's modeling assumptions.[11] Synapse's scenario retires coal based on Duke's earliest practicable retirement schedule and builds no new gas, instead deploying significant volumes of solar and battery storage capacity to maintain a 17% reserve margin, consistent with Duke's assumptions.[12] Significantly, Synapse maintained many of Duke's

[10] Joint Synapse Comments, Exhibit 1, pp. 2-3.
[11] *Id.* at 1-2.
[12] *Id.* at 13-21.

assumptions for the purposes of modeling and did not attempt to incorporate all of the recommendations contained in the Expert Reports, focusing only on certain of the most consequential egregious inputs.[13] Therefore, by adopting the recommendations in the Expert Reports, which include and exceed those used in the Synapse modeling, even more comprehensive results would be expected.

As a result, the recommendations discussed below and included in the Expert Reports and Joint Synapse Comments will, individually and in the aggregate, materially improve Duke's IRP modeling and result in the development of truly least cost resource scenarios, consistent with the requirements of North Carolina law.

### A. Duke Fails to Present Sufficient Analyses Required to Determine the Robustness of its Portfolios

Commission Rule R8-60 states that Duke must "analyze potential resource options and combinations of resource options to serve its system needs" taking into account sensitivity to "significant assumptions, including, but not limited to, the risks associated with wholesale markets, fuel costs, construction/implementation costs, transmission and distribution costs, and costs of complying with environmental regulation," as well as applicable "system operations, environmental impacts, and other qualitative factors." R8-60(g).

Duke's IRP presents six resource portfolios that contain different assumptions about commodity forecasts, unit retirements, carbon pricing, and other inputs. However, Duke fails to present a robust risk analysis that evaluates resource options to determine potential negative outcomes associated with fuel supply limitations[14] high fuel costs, and

[13] *Id.* at 13.
[14] Lucas Report at 1.

other sensitivities. Although Duke develops multiple scenarios and sensitivities, the risk analysis is primarily qualitative. Duke fails to adequately account for several fossil-fuel related risks, including limited availability of firm natural gas supply, regulatory risk associated with continued coal plant[15] stranded natural gas infrastructure investments for several of its portfolios. It assumes operational dates for non-commercial technologies such as SMRs and hard-to-permit technologies such as pumped hydro that are inconsistent with its own development timelines for these projects. Duke provides basic information on the portfolios themselves (e.g. MW of assets deployed), the estimated present value of the revenue requirement ("PVRR") of the portfolio over the planning horizon, and an estimate of transmission investment required to interconnect the resources in the portfolio.[16] However, Duke's presentation of these figures lacks context.

First, the primary overview of the IRP Report shows the PVRR excluding the explicit cost of carbon, despite the fact that five of the six portfolios assume a carbon price is present and impacts the results.[17] This makes it appear that the carbon reduction portfolios are considerably more expensive than the base portfolios. However, if one pieces together information from the separate IRP reports, Duke's data show that after including the cost of carbon, the incremental cost of the deep decarbonization portfolios is considerably lower than it initially appears when viewing Duke's IRP Report overview.[18]

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[15] Lucas Report at 1.
[16] DEC IRP at 16.
[17] Lucas Report at 5.
[18] *Id.* at 5-7.

Second, Duke's natural gas capacity buildout plan – the largest proposed natural gas expansion of any utility in the country[19] – is risky and inconsistent with Duke's 2050 net-zero goals. Duke performed very little risk analysis with respect to adding this much new natural gas capacity and simply assumes that firm capacity to deliver this gas to all its new CC units will be available from "new or upgraded capacity" at a constant price.[20] Further, Duke does not plan on contracting for firm natural gas delivery for its CT units, despite major natural gas additions in some scenarios that will be utilized during cold winter mornings and evenings at the exact same time when the natural gas distribution system will be under stress from building heating loads, a circumstance uncomfortably similar to that which appears to have contributed greatly to the recent near-collapse of the Electric Reliability Council of Texas ("ERCOT") power grid in Texas.[21] These factors create significant and unnecessary risk for Duke's customers with respect to both natural gas fuel prices and capacity investments. To increase the likelihood of attaining its net-zero goals while minimizing the risk of stranding natural gas assets, Duke should ramp up its deployment of renewable generation and storage in the near term, particularly as the recent federal investment tax credit ("ITC") extension provided an opportunity to more economically deploy solar and solar-plus-storage prior to 2025.[22]

Finally, Duke's risk analysis is insufficient and results in an IRP with fewer additions of renewables, later retirement of coal assets, and increased natural gas capacity.

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[19] *Id.* at 5-7, citing *The Dirty Truth about Utility Climate Pledges*, Sierra Club (January 2021), available at https://www.sierraclub.org/sites/www.sierraclub.org/files/blog/Final%20Greenwashing%20Report%20%281.22.2021%29.pdf.
[20] *Id.* at 8.
[21] *Id.*
[22] *Id.* at 9-10.

A more robust risk analysis, such as that conducted by Mr. Lucas, shows the benefit of the early coal retirement options relative to the no carbon base scenario.[23] Duke, however, did not perform any quantitative risk analyses in its IRP, relying instead on risk assessments that were largely qualitative in nature. Duke presented the results of its various scenarios and sensitivities but did not produce analyses to compare those portfolios across various input assumptions. Duke also did not model any increased regulatory costs that may impact the economics of continuing to run its coal plants. Duke did not construct a high- or low-cost sensitivity for fuel or fixed operations and maintenance ("O&M") costs for coal units, nor did it model retirement outcomes under different regulatory regimes. As discussed above, Duke's application of carbon pricing in its scenarios also creates apples-to-orange comparison of portfolios with higher penetrations of renewables.[24]

These scenario cost ranges can be more robustly investigated and compared through a cost range and "minimax regret" analysis. These straight-forward analyses provide insight on how portfolios may perform under a variety of future scenarios.[25] As described in detail by Mr. Lucas, a relatively simple risk analysis demonstrates the cost range of each scenario under multiple sensitivities and the "Max Regret" score for each scenario, which represents the difference between a portfolio's highest PVRR and the lowest PVRR of all the scenarios.[26] A Max Regret analysis determines the difference between a portfolio's highest possible cost and lowest possible cost in all the relevant scenarios, and by doing so provides a metric to identify the riskiness of different portfolios. Based on this analysis,

[23] *Id.* at 10-14.
[24] *Id.* at 10-14.
[25] *Id.* at 12.
[26] *Id.* at 13.

the lowest Max Regret score is from the Base with Carbon, followed closely by the Earliest Practicable Coal Retirement scenario. These have Max Regret scores $2.8 and $2.0 billion lower than the Base without Carbon Policy portfolio, suggesting that selecting these two portfolios is less risky than the Base without Carbon Policy.[27]

Duke should be required to conduct more robust risk analysis in the presentation of its IRP scenarios after correcting the other flaws identified in the Expert Reports, and the Commission should consider such analysis in its resource planning pursuant to G.S. 62-110.1(c), considering long-term risk covering all scenarios.

### B. DUKE'S MODELING OF GENERATION RESOURCES IS FLAWED

#### 1. SOLAR MODELING

Duke's analysis of solar generation in its IRP modeling is fundamentally flawed in the following respects, and the inputs should be changed and remodeled.

First, since Duke's IRP was filed, Congress has amended the federal ITC.[28] The ITC amendment allows Duke to include substantially more solar and solar plus storage generation early in the IRP planning horizon while allowing customers to reap the financial benefits. Although this legislative change occurred after Duke completed its modeling, it is of sufficient scale and consequence that the Commission should direct Duke to update its modeling to incorporate the new law.[29]

Second, Duke's operational assumptions for solar are flawed and should be corrected.[30] While Duke's capital cost assumptions for solar are reasonable, aside from the

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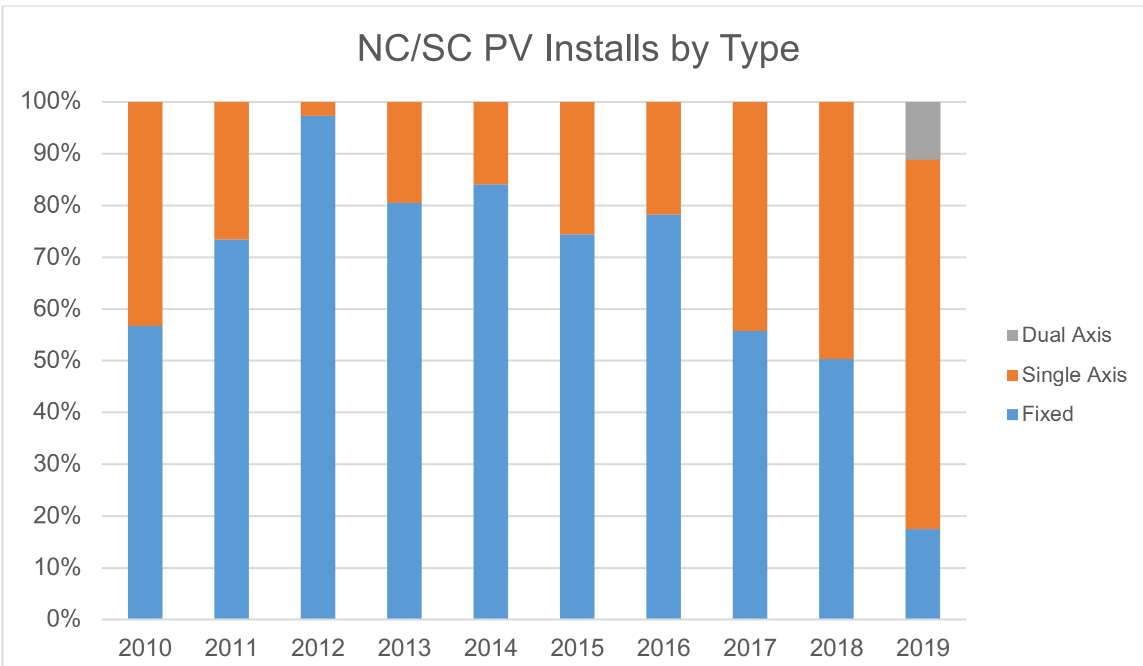
[27] *Id.*
[28] Consolidated Appropriations Act, 2021, Pub. L. No. 116-260, §§ 131, 141 (2020).
[29] Lucas Report at 15.
[30] *Id.* at 26-34.

amendments to the ITC noted above, Duke's assumptions about the system mix between fixed-tilt and single-axis trackers are outdated and do not reflect current market conditions. As the prices for tracking system hardware have decreased over the past decade, the solar market has shifted from fixed-tilt projects being the norm to single-axis tracker systems being more prevalent.[31] In 2019, more than 80% of solar capacity constructed used single-axis or dual-axis tracking systems.[32]

**Figure 1**[33]




Duke's assumptions regarding the rate of interconnection of solar and solar plus storage are also fundamentally flawed. Duke limited the amount of solar and solar plus storage that could be interconnected in any year to 500 MW (split 300 MW in DEC and 200 MW in DEP) in the base cases and 900 MW (split 500 MW in DEC and 400 MW in

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[31] *Id.* at 29-30.
[32] *Id.* at 31.
[33] *Id.* at 27.

DEP) in the high renewable cases.[34] However, Duke's IRPs fail to reflect the reality that Duke's capacity to interconnect solar and solar plus storage *far exceeds* this artificial limit. This capacity is not speculative, because Duke has already demonstrated its ability to interconnect large quantities of solar resources. In 2015 and 2017, respectively, Duke interconnected 718 MW and 744 MW of solar across its Carolinas service territories.[35] Moreover, at that time, Duke was interconnecting a large number of small projects; since then, the market has shifted towards a smaller number of large projects. Accordingly, Duke should be capable of interconnecting significantly more solar and solar plus storage than it historically has, given this shift in project size as well as the reforms made to Duke's interconnection process.[36] In its modeling, Synapse used much higher limits in its modeling, starting at 500 MW per year but rising to 1,800 MW in later years, a reasonable and feasible schedule of deployment.

Third, Duke's solar fixed O&M cost assumptions are too high.[37] Duke used a fixed O&M cost value that was developed by a third-party consultant, rather than relying on publicly-available and industry-standard sources, which resulted in inflated O&M costs. As solar capital costs fall, fixed O&M costs become a higher proportion of the lifecycle costs of a solar plant, providing a strong incentive to market participants to reduce costs over time, which is the expected result as lower O&M costs increase the competitiveness of projects. The National Renewable Laboratory ("NREL") Annual Technology Baseline ("ATB") forecast recognizes these factors and incorporates a cost decline over time.

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[34] *Id.* at 33.
[35] *Id.*
[36] *See*, *Order Approving Queue Reform*, Docket No. E-100, Sub 101 (Oct. 15, 2020).
[37] Lucas Report at 19-20.

Duke's forecasts, in contrast, do not incorporate these factors and therefore result in later-year solar O&M costs that are too high.[38]

Duke should model lower costs to mirror the discount from the NREL ATB that is used in the Company's capital cost forecast and assume a price decline at least as aggressive as the NREL ATB Moderate scenario to reflect the innovation occurring the in O&M space.[39]

2. STORAGE MODELING

Duke's storage cost estimates are substantially higher than other industry benchmarks and recent request-for-information results and were generated by a private third-party rather than based on one of several publicly available benchmarks.[40] While Duke claims the difference between its own estimate and multiple industry estimates is largely due to assumptions about depth of discharge ("DoD") and replenishment approaches, Duke erred in interpreting NREL's ATB battery cost methodology, which resulted in inflated storage cost estimates that disfavor storage in Duke's IRP modeling.[41]

Duke should instead base its battery costs on NREL's ATB Advanced scenario, recognizing that battery pack degradation is already accounted for in NREL's ATB fixed O&M cost and should not be used to artificially inflate the size of a modeled battery.[42] Duke should also use consistent costs for batteries in standalone storage and solar plus storage projects unless it can justify cost differences due to operational expectations.[43]

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[38] *Id.*
[39] *Id.* at 20.
[40] *Id.* at 20-21.
[41] *Id.* at 24.
[42] *Id.*
[43] *Id.*

Duke modeled energy storage at two-, four-, and six-hour durations in its 2020 ELCC Study. However, it modeled only four- and six-hour duration batteries in its IRP. Because battery packs represent a substantial share of an energy storage system's cost, allowing a limited quantity of less expensive two-hour batteries can help defer the need for other capacity, at a lower price. Duke should update its model to allow for the selection of two-hour batteries if the cost discount of short-duration batteries outweighs any reduction in capacity value relative to longer-duration batteries.[44]

### 3. NATURAL GAS MODELING

Commission Rule R8-60(g) requires that "The utility shall analyze potential resource options and combinations . . . taking into account the sensitivity of its analysis to variations in . . . significant assumptions, including . . . fuel costs . . . ." As set forth below, Duke's natural gas price forecast and sensitivities are seriously flawed and underestimate future gas prices. Set against its artificially high cost estimates for solar and storage, these low gas price estimates unduly favor the buildout of new gas generation.

The natural gas price forecast and corresponding high- and low-price sensitivities are critical inputs for Duke's IRP modeling. For a variety of reasons, Duke plans to close its coal facilities over the coming decades. The energy and capacity that these plants produce must be backfilled by some combination of resources. One of the primary goals of the IRP modeling is to determine which resource mix of demand-side management, renewable generation, fossil generation, and battery storage provides the most reasonable and appropriate blend. The natural gas fuel price input is particularly crucial in determining whether more renewables and batteries are selected by the model, or whether is it less

[44] *Id.* at 25-26.

costly to expand natural gas capacity (despite the stranded asset risk). Duke's near-term forecast – based on limited market prices – is well below the fundamentals-based models and is deeply flawed.[45]

As an initial matter, while Duke did perform a low and high natural gas fuel cost forecast sensitivity, it assumed that firm capacity to deliver natural gas to its new combined cycle ("CC") units would be available from "new or upgraded [pipeline] capacity" at a constant price.[46] However, given the recent cancellation of the Atlantic Coast Pipeline and the write-down of the Mountain Valley Pipeline, it is increasingly unlikely that new or upgraded pipeline capacity will be available.[47]

Second, Duke does not plan to contract for firm natural gas delivery to its combustion turbine ("CT") units, despite adding gigawatts of new CT capacity.[48] These CTs will be utilized during cold winter mornings and evenings – the exact same time when the natural gas distribution system will be under stress from building heating loads.[49] Unfortunately, the recent events in Texas have highlighted this concern and emphasize the need for Duke to include firm natural gas delivery in its models.

Third, NCSEA and CCEBA take issue in this proceeding, as they and other intervenors have in previous proceedings, with Duke's natural gas forecasts.[50] Any risk in natural gas forecast error is borne by ratepayers, and not by Duke's shareholders, since Duke's riders pass fuel costs through to retail customers.[51] Nevertheless, Duke's natural

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[45] *Id.* at 37.
[46] *Id.* at 8.
[47] *Id.*
[48] *Id.*
[49] *Id.*
[50] *Id.* at 37.
[51] *See generally*, N.C. Gen. Stat. § 62-133.2.

gas pricing assumptions can dramatically impact the capacity additions selected during the IRP modeling process. It is therefore essential for ratepayers that gas price projections are subjected to very close scrutiny. As detailed by Mr. Lucas, such scrutiny shows that Duke's forward market forecast, compared to a pricing forecast based more on fundamentals, provides less realistic and less reliable natural gas price projections for the mid-2020s through the mid 2030s, when Duke's capacity needs arise.[52] As Mr. Lucas explains, this more realistic natural gas pricing would have large implications on the economics of building and operating natural gas generation relative to other resource portfolio options analyzed as part of the IRP.[53] Furthermore, it is important to understand that Duke locked in its market price forecast on April 9, 2020, in the midst of a period of major futures market volatility, and very near to the lowest price point in the market in several years.[54] Had pricing been locked in on a different day, the natural gas prices for the first 15 years of the IRP would have been substantially different, resulting in different IRP results.

Finally, NCSEA and CCEBA note that Duke's IRP modeling and gas-dependent buildout are inconsistent with Duke's internal goals.[55] While Duke states that, "[a]ll portfolios keep Duke Energy on a trajectory to meet its near-term enterprise carbon-reduction goal of at least 50% by 2030 and long-term goal of net-zero by 2050,"[56] this will be very difficult to do with the amount of natural gas capacity DEC and DEP plan to build in the planning horizon. Building substantial amounts of natural gas capacity less than two

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[52] Lucas Report at 37.
[53] *Id.*
[54] *Id.* at 53.
[55] *Id.* at 6, 38.
[56] DEC IRP at 6.

decades before Duke's planned transition to net-zero risks stranding billions of dollars in assets.[57]

While Duke claims it conducted a "stress test case with an assumption of a shortened twenty-five-year life for natural gas units"[58] this shortened life assumption was not the default in the six main scenarios Duke presented in the IRP. Even using this shortened life, any new natural gas units constructed after 2025 would continue operating after Duke's 2050 net zero carbon emissions goal and would either seriously challenge Duke's ability to meet the 2050 goal or pose significant stranded asset risks to ratepayers.

#### 4. COAL MODELING

Duke's modeling of coal generation includes two major flaws. First, Duke did not construct a high- or low-cost sensitivity for fuel or fixed O&M costs for coal units.[59] Given recent developments at the federal level, this is imprudent, as it is very likely that new regulations will substantially increase the costs associated with keeping existing coal units online. Second, Duke's PVRR calculations for each scenario do not include the cost of carbon.[60] When the cost of carbon is taken into consideration, Duke's Earliest Practicable Coal Retirement portfolio becomes the most affordable of the scenarios that do not target deep decarbonization.[61]

Duke should be required to construct a high- and low-cost sensitivity for fuel and fixed O&M costs for coal units, and Duke's PVRR calculations should include a cost of carbon.

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[57] Lucas Report at 9.
[58] DEC IRP at 136.
[59] Lucas Report at 11.
[60] *Id.* at 12.
[61] *Id.*

### 5. Duke Has Not Adequately Assessed Reasonably Available Energy Options

Commission Rule R8-60(e) requires that "[a]s part of its integrated resource planning process, each utility shall assess on an on-going basis the *potential benefits of reasonably available alternative supply-side energy resource options*. Alternative supply-side energy resources include, but are not limited to, hydro, wind, geothermal, solar thermal, solar photovoltaic, municipal solid waste, fuel cells, and biomass." (emphasis added). Although Duke's IRP primarily addresses future *capacity* needs, Duke is also required to assess reasonably available supply-side *energy* resource options.

However, Duke has not adequately considered the availability of energy resources that could provide cost savings to customers even <u>before</u> Duke's next capacity need. Duke has constrained its model to limit new resource additions only to when a defined capacity need is identified. Because the IRP identifies the first capacity need as 2024 for DEP and 2026 for DEC, Duke forgoes between three and five years of potential cost savings if alternative energy resource options could provide energy at lower costs than Duke's existing portfolio. This is particularly significant given the recent extension of the federal ITC. Failing to advance renewable energy in the next several years will forego the sizable cost benefit that could be passed on to Duke's customers afforded by the ITC extension.

Notably, the South Carolina Public Service Commission ("SC PSC") recently addressed this specific issue, citing Dominion Energy South Carolina ("DESC") for failing to consider the addition of new resources or power purchase agreements ("PPAs") even when there was not a capacity need and for failing to recognize the potential for energy resources to provide savings compared to the operating costs of existing resources. The SC PSC directed DESC to model the addition of new resources earlier in its planning horizon even when no capacity need existed.[62] Similarly, the Commission should require Duke to allow its models to select cost-saving energy resources prior to identified capacity needs and present the results of that modeling to the Commission. If the model results demonstrate that energy purchases could result in customer savings, Duke should be required to pursue such purchases.

## C. Duke's Resource Adequacy Analysis and Application are Flawed

Ensuring that the electric system is reliable is central to integrated resource planning and reliability planning.[63] When conducting resource planning and selecting an optimal plan, it is critical that reliability planning and resource adequacy analysis be fully and appropriately incorporated into the IRP modeling process. The standard approach to ensuring reliability is establishing a quantity of generating capacity needed to meet a given reliability level, usually targeted to be one outage every ten years. This quantity of capacity is characterized through a planning reserve margin that specifies the level of generating capacity required in excess of peak demand.[64]

In recent years Duke has commissioned Astrapé Consulting ("Astrapé") to complete resource adequacy studies to determine the level of resource adequacy necessary to meet Duke's target reliability standard. Duke has also commissioned Astrapé to conduct studies to determine the ELCC of solar and storage. Applying the reserve margin requirements derived from the resource adequacy studies and the ELCC values derived from the ELCC studies, Duke then conducts capacity expansion and production cost

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[62] South Carolina Public Service Commission, Order No. 2020-832, pp. 32-33, Docket No. 2019-226-E (Dec. 23, 2020).
[63] E3 Report at 15.
[64] *Id.* at 15-16.

modeling to identify an optimal resource plan. However, as discussed below, Duke has embedded a number of flaws into its studies and modeling which have the effect of decreasing the capacity contribution—and therefore increasing the modeled cost—of solar and storage resources.

Before discussing the specific flaws in Duke's approach to assessing and modeling resource adequacy in the 2020 IRPs, it is instructive to first discuss how the dramatic cost reductions and increased adoption of renewable resources have necessitated a change in the way that utilities should approach resource adequacy within IRP. Some of the tools that utilities used in the past for modeling the capacity credit a given resource could contribute to the utility's load are poorly equipped for measuring the capacity contribution of intermittent resources, because most models and evaluation processes used to perform this analysis were developed during an era when the generation technologies available to utility planners were much more limited than the options available today.[65] Decisions often centered around which type of natural gas generator to invest in or whether a new coal or nuclear baseload unit was required. The objectives of IRP today have evolved from years past and seek to not only minimize cost but also to meet emission reduction or renewable energy goals. Additionally, the types of resources available to planners have also expanded greatly. Techniques that used to provide a reasonable proxy within planning models no longer capture the economic, operational, and reliability complexities of today's resources.[66] IRP must evolve to capture the characteristics of these resources in order to credibly produce least-cost plans that satisfy both reliability and environmental criteria.

[65] *Id.* at 8.
[66] *Id.* at 8-9.

While Duke has taken certain appropriate steps to modernize its IRP (e.g., the use of ELCC), Duke has fallen short in a number of the assumptions and applications of these methods and has entirely failed to adopt others.

As discussed below, and as presented in the attached Kirby Report, E3 Report, and Sharp Report, Duke's approach to resource adequacy assessment and modeling has resulted in (1) the overstatement of winter-time loss-of-load risk in DEC and DEP, (2) the underestimation of solar and storage capacity contributions to peak load, and (3) the under-selection of solar and storage resources as least-cost options in Duke's capacity expansion modeling. These flaws are discussed below, accompanied by specific recommendations that Duke should adopt to remedy these issues.

### 1. Duke's Resource Adequacy Analysis Overstates Winter Loss of Load Risk and Fails to Sufficiently Solve for Infrequent Winter Peaks

Duke has included in its 2020 IRP several studies conducted by Astrapé relating to resource adequacy and the capacity contributions of solar and storage. In previous IRP proceedings, parties have critiqued the Astrapé Resource Adequacy studies and Solar Capacity Value study, and the Commission has indicated that it is appropriate to continue to evaluate these studies as they are updated.[67] In its 2020 IRP, Duke has included new 2020 Resource Adequacy studies for DEC and DEP and an ELCC study for storage.

As described below, Duke's resource adequacy analysis contains major flaws that result in the significant over-estimation of winter-time loss-of-load probability and a failure to capture the actual capacity contribution of solar and storage.

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[67] *See, e.g.*, *Order Accepting Filing of 2019 IRP Update Reports and Accepting Filing of 2019 REPS Compliance Plans*, pp. 11-13, Docket No. E-100, Sub 157 (April 6, 2020) (discussing resource adequacy analysis iterations).

#### i. *Duke's Application of Historic Weather Data and Synthesized Load Leads to Inaccurate Results*

Duke's Resource Adequacy studies use 39 years of hourly historic weather data (1980-2018), but because actual load data corresponding with the weather data is available during many of those years, Duke has relied on synthesized load data that extrapolates results to cover extreme temperatures where no actual load data exists.[68] Critically, this synthetic load during years where actual data is unavailable results in many of the most extreme cold weather load spikes in Duke's modeling. These load spikes, projected during winter mornings, cause Duke's loss-of-load probability to skew heavily towards winter morning hours.[69]

Although the use of synthetic load data, where actual data is unavailable, is not inappropriate in concept, there are substantial problems with Duke's synthetic load model.[70] First, low-temperature synthetic loads were simply extrapolated to lower temperatures based on historic load regressions. This ignores the fact that many loads, especially residential heating loads, likely saturate at extreme cold temperatures and cannot continue to increase at the same rate as temperatures continue to drop.[71] As discussed by Mr. Kirby, because historic load data was limited, Duke applied synthetic data for all years of its modeling. However, for the coldest temperatures for which there is *actual* load data, when the actual load was compared to the synthetic loads, the synthetic loads used in the resource adequacy analysis exceed the actual loads. In other words, *the synthetic load model demonstrably overpredicts cold temperature loads*. This further demonstrates, along

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[68] Kirby Report at 6.
[69] *Id.*
[70] *Id.* at 13.
[71] *Id.*

with additional weather and load analysis conducted by Dr. Sharp, that Duke's synthetic load over-estimates cold temperature loads.

These flaws are major drivers in the IRP because Duke relies on the Resource Adequacy studies to establish that nearly all of its loss-of-load risk occurs during winter morning hours. Duke states that "[a]s in the 2016 study, winter load volatility remains a significant driver of the reserve margin requirement"[72] and that as a result "solar provides almost no capacity value in the winter."[73]

As explained by Mr. Kirby, Duke should be required to retrain and recalibrate its synthetic load model so that the model can be verified with actual temperature and load data. The model should also incorporate the two additional years of available historic load data (2019-2020) to improve the load model accuracy.[74]

Additionally, just as with the load data used in the Resource Adequacy studies, Duke does not have time-synchronized hourly solar data for use with the 39-year historic temperature data.[75] Duke used the NREL National Solar Radiation Database ("NSRDB") Data Viewer and "NREL's System Advisor Model (SAM) for each year and county to generate hourly profiles for both fixed and tracking solar profiles."[76] Because the NSRDB only contains hourly solar data for 1998 through 2019, Astrapé synthesized hourly solar data for 1980 through 1997 by attempting to match similar days from 1998-2019 with days from 1980-1997 based on peak load and time-of-year.[77] However, as described by Dr.

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[72] DEC IRP at 64.
[73] DEC IRP, Attachment III - DEC 2020 Resource Adequacy Study, p. 57 (Nov. 6, 2020) ("DEC RA Study").
[74] Kirby Report at 16.
[75] *Id.*
[76] DEC RA Study at 33.
[77] Sharp Report at 13-14.

Sharp, there is no foundation in atmospheric science to suggest that such a methodology will achieve accurate results. Duke applied a similar methodology in its Solar Capacity Value Study.[78]

To correct this flaw, the Commission should direct Duke to rerun the Resource Adequacy Study, ELCC studies, and IRP analysis based on the years 1998 through 2020 for which time-synchronized hourly locational NSRDB solar data is available.

*ii. Duke Has Failed to Appropriately Consider and Model Storage and DSM to Address Infrequent, Easily Forecasted Reliability Events*

As discussed above, the Resource Adequacy studies conclude that the hours of greatest reliability concern are during extremely cold winter mornings. These few extreme cold hours drive Duke's reliability requirements and in turn, the low capacity value assigned to solar. Unfortunately, Duke's resource adequacy analysis did not adequately consider cost-effective opportunities to mitigate these short-duration peak events and boost resiliency. Because these winter peaking events are rare, short in duration, and easily forecasted, emergency operating practices could be implemented to deal with these events without impacting economic operations during the vast majority of hours.[79] For example, as explained below, battery charging strategies could be adjusted when extreme cold was forecasted to assure that all or nearly all batteries – including both stand-alone and solar-coupled – were fully charged ahead of the emergency need. Demand response programs could also be refocused to obtain winter response specifically for these rare, extreme, easily forecasted, high-value events.

[78] *Id.* at 14.
[79] Kirby Report at 17.

With respect to storage, the Astrapé Storage ELCC study identified three modes of possible storage operation:

1. Preserve reliability mode: where the battery is dispatched strictly to maximize system reliability;
2. Economic arbitrage mode: where the battery is operated in order to maximize the economic value of the battery; and
3. Fixed dispatch mode: where the battery is operated relative to a pre-determined schedule that does not consider real-time system conditions.[80]

Both Mr. Kirby and E3 recommend that Duke model storage in a way that maximizes its ability to serve winter peak events. Specifically, E3 recommends the use of "preserve reliability" mode when incorporating the ELCC of storage into portfolio optimization. Using this mode of dispatch to quantify the ELCC value of storage assumes that storage is strictly operated to maximize system reliability only during the very limited number days/hours per year when the system is stressed and at risk of loss of load – it does not preclude an economic arbitrage mode of operation during all other times.[81] Due to the high value of electricity during loss of load events, a dispatch approach that maximizes reliability is also one that maximizes system economic value. To correct this flaw, Duke should update its ELCC study to model storage resources in preserve reliability mode, including existing pumped hydropower resources.

Additionally, Duke "assumed that the battery could be charged only from the solar array, and not from the grid."[82] This assumption unnecessarily limits the ability of storage

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[80] E3 Report at 27.
[81] *Id.* at 27-28.
[82] Kirby Report at 19, citing DEC IRP Report, Attachment IV - Storage ELCC Study, p. 7 (Nov. 6, 2020).

to meet winter morning peaks and substantially reduces the value of storage. Mr. Kirby explains that two hours of storage could completely eliminate over 70% of the loss of load events in Duke's base case; four hours of storage could eliminate almost 94%; and six hours could eliminate nearly all of the loss of load events.[83] Thus, storage capacity value should reflect this capability. Storage resources should also be modeled such that they can be charged from the grid ahead of likely reliability events.[84]

With respect to demand-side management ("DSM"), similar to storage, DSM can be ideal for dealing with rare, easily forecasted, high-value extreme events.[85] Duke's DSM efforts, both within the IRP and more generally, exclude consideration of these events and, consequently, find that DSM has little value in mitigating them. First, Duke's recent DSM studies – the DSM Market Potential Study included in the IRP filings, and the December 2020 Winter Peak Demand Reduction Potential Assessment – do not use the same data, conditions, and assumptions used in the IRP.[86] Specifically, the reserve requirements included in the IRP result from including rare extreme winter weather conditions in the IRP's statistical weather modeling that are not reflected in the simple 25-year load forecast used for the DSM analysis.[87] Had the DSM studies used the same data, conditions, and assumptions as the IRP study, Duke likely would have found a much larger DSM resource composed of different resources to be viable, reducing the extreme winter peak reserve requirement and increasing the capacity value of solar generation.[88] To correct this flaw,

[83] *Id.*
[84] *Id.* at 17.
[85] *Id.* at 20.
[86] *Id.* at 20-21.
[87] *Id.*
[88] *Id.* at 20.

Duke's DSM design and evaluation analysis should use the same data, conditions, and assumptions as the Resource Adequacy and ELCC studies in the IRP, including the changes recommended by CCEBA and NCSEA.

Additionally, Duke's DSM analysis indicates that only a limited amount of residential DSM will be economic, and Duke finds the commercial and industrial DSM potential to be very limited.[89] This is likely because Duke's DSM effort failed to focus on easily forecasted, rare, extreme winter weather conditions. Although Duke identifies residential load as most significantly impacting winter peaks, Duke's existing DSM analysis instead focuses on regular, relatively frequent response to daily winter peaks and does not adequately consider and evaluate targeted residential DSM programs that can address rare, extreme winter events with sufficient notice. As Duke admits, the short duration of these extreme events also means that there is ample generation capacity available both before and after the event, further demonstrating that well-designed DSM programs are ideally suited to help mitigate such events.[90]

*iii. Duke Has Inadequately Accounted for Expected Electric Vehicle Charging*

Duke's IRP views electric vehicles ("EVs") as contributing to winter morning peaks, rather than considering the possibility of utilizing them for winter morning supply.[91] However, given that future EV charging represents new load that is yet to be installed, Duke could develop rate design incentives, controls, and programs to defer EV charging until after the peak system load on extreme weather days. Given the rarity and emergency

[89] *Id.* at 22.
[90] *Id.*
[91] *Id.* at 23-24.

nature of extreme winter peaks, EVs could also provide additional benefits with vehicle-to-grid support for the power system. Therefore, Duke should be directed to develop an EV rate structure and programs that incentivize off-peak charging and an additional rate incentive to discourage charging during the extreme winter peak hours.

In sum, to correct the flaws identified by Mr. Kirby, E3, and Dr. Sharp, Duke should be required to revise its resource adequacy analysis and adjust the models and assumptions consistent with the recommendations described above.

2. DUKE'S CAPACITY EXPANSION MODELING FAILS TO OPTIMIZE SYNERGISTIC RESOURCES AND THEREFORE UNDER-SELECTS COMPLIMENTARY RESOURCES LIKE RENEWABLES AND STORAGE.

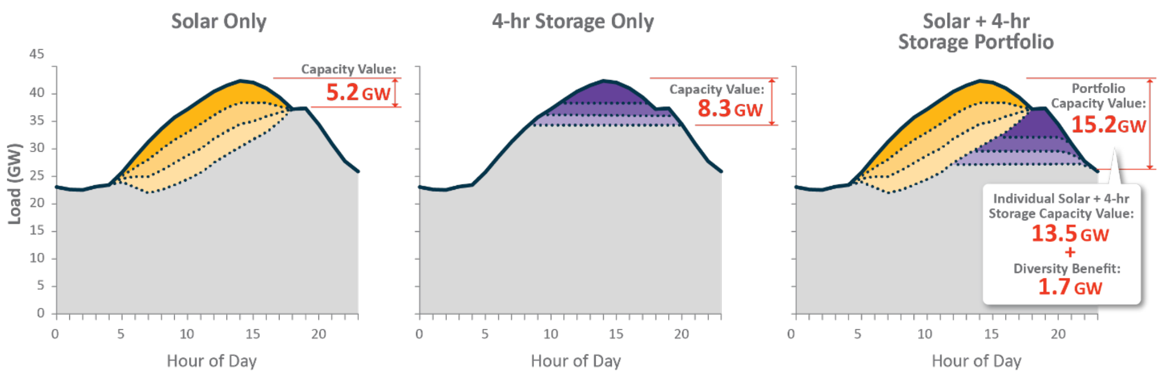
Capacity expansion modeling software dynamically evaluates combinations of resources to meet demand across all hours with a pre-defined level of reliability. The approach compares the various resource paths to meeting load and the reliability target in a least-cost manner while achieving any policy goals such as risk reduction, generation diversity, coal retirement guidelines, energy efficiency requirements, etc. To identify an optimal resource plan, a capacity expansion model must both have accurate inputs for individual resources such as capacity, efficiency, fuel costs, and outages, as well as identify optimal *combinations* of resources to meet the identified need.[92]

Some resources' contribution toward resource adequacy depends on the characteristics of other resources in the portfolio. Resources interact with one another, and their combinations can provide capacity contributions greater or smaller than the sum of individual resources.[93] For example, solar and storage have positive interactive benefits –

[92] E3 Report at 11-12.
[93] *Id.* at 17-18.

referred to as "diversity benefits" – with daytime solar narrowing the net peak period's duration, which in turn allows energy storage to meet that net peak more effectively. Figure 2 below, which is not specific to Duke, illustrates this point:

**Figure 2: Illustration of the Synergistic Effects of Solar and Storage[94]**




From left to right, the figure shows the impact on load from solar only, a 4-hour battery only, and solar and storage when combined. Considered separately, solar and storage would have a combined capacity value of 13.5 GW. But if both are added to a system, their combined capacity value is 15.2GW – a 1.7GW (12.6%) increase. This is because of the different ways in which the resources support peak load – solar shifts and narrows the net peak, which is then shorter in duration and can be more effectively met by storage. This interaction is a diversity benefit arising from the interaction of the resources versus other resource additions. However, that benefit will only be recognized in the IRP process if the portfolio optimization including capacity expansion modeling is able to co-optimize all resource technologies, i.e., if all components of the capacity expansion are optimized at the same time, as opposed to sequentially. Importantly, the diversity benefits arising from the differing natures of the resources, including solar and storage, does <u>not</u>

[94] *Id.* at 18.

require those resources to be co-located. The same benefits would accrue regardless of whether a solar project was co-located with storage or whether a solar facility and storage facility were sited in different locations.[95]

Duke did not model solar and storage in a manner that accounts for the synergies between these resources, which is necessary to accurately capture their capacity benefits on Duke's system. Because solar and storage were instead modeled sequentially – solar evaluated before storage was present to augment it, and with storage evaluated after the amount of solar to charge it was determined – their combined ability to reliably and cost-effectively provide capacity to meet load was obscured and limited.[96] Rather than co-optimizing solar and storage resources simultaneously in a single-step, Duke used multi-step optimization in its IRP. By failing to accurately capture the synergistic effects of solar and storage, Duke's approach artificially reduced the amount of solar and storage built on the system.[97] This flaw makes it impossible for Duke to even consider the possibility that solar and storage together are the most cost-effective solution to capacity needs in the near term, a conclusion that many other utilities around the country have reached.

Three examples of recent IRPs that contain stand-alone solar and storage to meet peak needs are:

- Nevada Energy ("NVE") – In its 2018 IRP, NVE announced 1,001 MW of new solar and 100 MW of battery storage to serve both energy and capacity needs.[98]

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[95] *Id.* at 18-19.
[96] *Id.* at 20.
[97] *Id.* at 20-21.
[98] Nevada Energy 2018 IRP, Vol 4 – Summary, available at https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/recent-regulatory-filings/nve/irp/NVE-18-06003-IRP-VOL4.pdf.

- Arizona Public Service Electric ("APS") – APS announced in its September 15, 2020 IRP Stakeholder Update buildout of 8,000 to 12,000 MW of solar and 5,000 to 10,500 MW of storage to support energy and capacity needs across all IRP scenarios.[99]
- El Paso Electric ("EPE") – EPE announced significant buildout of both stand-alone solar and storage through 2037 in its 2018 IRP. The "Most Cost-Effective Portfolio" includes 550 MW of solar and 95 MW of storage.[100]

To address this modeling shortcoming and accurately capture the full value of solar and storage, E3 recommends that Duke conduct capacity expansion modeling using single-step optimization of all resources to provide an accurate evaluation of the cost and reliability impacts of those options to meet projected energy and capacity needs.[101]

Given that Duke has indicated its intent to transition away from the System Optimizer capacity expansion model in the near future, this presents an ideal opportunity for Duke to select a capacity expansion model that is capable of single-step optimization and that will more accurately model resources such as renewables and storage. Given Duke's corporate carbon reduction goals, and likely future state or federal regulation establishing a cost of carbon or other similar policy, Duke's ability to accurately model renewable resources and storage will be critically important for robust resource planning now and in the future.

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[99] Arizona Public Service Company, September 15, 2020 Stakeholder Update, available at https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/2020IRPStakeholderUpdateSeptember152020.ashx?la=en&hash=F593DA8B8930DB07763816F44DF3D529.

[100] El Paso Electric, 2018 Amended IRP Report, Table 1, available at https://www.epelectric.com/files/Amended-2018-IRP%20Report.pdf.

[101] E3 Report at 21.

##### *i.* Duke's Reserve Margin Accounting Methodology Overvalues Thermal Resources

Duke's implementation of its planning reserve margin ("PRM") is flawed and skews the results to understate solar's actual capacity value relative to firm resources such as natural gas generation. In particular, when evaluating the relative capacity contributions of competing resources to load, Duke assumed 100% availability of fossil fuel generation – thus *excluding forced outages* – while utilizing ELCC for solar – a measure that *includes such outages*. This apples-to-oranges calculation inaccurately discounts solar's ability to meet projected energy and capacity needs.[102]

Duke uses a PRM calculation method called "installed capacity" planning reserve margin or "ICAP PRM". The ICAP PRM has historically been used by utilities to calculate reserve margins, but it does not compare firm and intermittent resources on an even playing field, and as a result, it overvalues firm resources relative to intermittent resources. Duke has adopted the ELCC approach for renewables, which is appropriate. However, Duke continues to use its existing ICAP PRM method for thermal resources, which is incompatible with ELCC and undervalues intermittent resources in comparison to firm resources. The "unforced capacity PRM" or "UCAP PRM" method, which more consistently accounts for both firm and intermittent resources, would be a more appropriate method for thermal resources. As described by E3, Duke should use the UCAP PRM method for thermal resources, while continuing to use ELCC for solar and storage. This will ensure that firm resources and intermittent resources are accounted for consistently and therefore more accurately modeled on Duke's system.[103]

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[102] *Id.* at 25-26.
[103] *Id.*

### 3. Duke's ELCC Calculations Contain Flaws that Underestimate the Capacity Contribution of Solar and Storage Resources

Duke's calculation of ELCC values utilized inaccurate methodologies and assumptions that significantly understate the effective capacity contribution of solar and of storage. Most significantly, Duke fails to identify the diversity benefits that arise from adding solar and storage together. As recommended by E3, Duke should model the combined effects through the use of an ELCC "surface" – in effect, a table of ELCC values that vary as a function of the penetration of both solar and storage. Duke also used outdated demand response assumptions; made inappropriate assumptions regarding the amount of fixed-tilt solar that will be built in the future; and failed to model ELCC values that are dynamic with load levels.

First, to capture the diversity benefits of multiple resources, Duke should utilize an ELCC surface.[104] An ELCC surface is a modeling output that characterizes the ELCC of multiple resources on a given system. The use of ELCC should capture how these values change as the penetration of renewable and energy storage resources change, capturing both diminishing benefits of incremental individual resources and the benefits of combining resources that have complimentary characteristics, like solar and storage. An ELCC surface is the output of this modeling that captures and standardizes these values for use in capacity expansion modeling or other relevant modeling. Table 1, below, represents an ELCC surface for solar and storage resources on an illustrative system.

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[104] *Id.* at 24.

**Table 1: Illustrative ELCC Surface**

| Combined ELCC Values (MW) | | |
|---|---|---|
| Installed Solar | Installed Storage | Combined ELCC |
| 0 | 0 | 0 |
| 100 | 0 | 50 |
| 100 | 100 | 168 |
| 200 | 100 | 216 |
| 200 | 200 | 312 |
| 300 | 200 | 348 |
| 300 | 300 | 432 |

| Stand Alone ELCC Values (MW) | | | |
|---|---|---|---|
| Installed Solar | Total ELCC | Installed Storage | Total ELCC |
| 0 | 0 | 0 | 0 |
| 100 | 50 | 100 | 90 |
| 200 | 90 | 200 | 170 |
| 300 | 120 | 300 | 240 |

As reflected in Table 1, the combined ELCC value of the solar and storage resources is higher than if they are evaluated separately. The use of an ELCC surface allows for the capacity expansion model to incorporate the dynamic synergies of the resources when added to the system. This is the diversity benefit discussed above.

As described in the E3 Report, E3 used its RECAP model to calculate the ELCC values of solar and of storage on Duke's systems, including a calculation of the diversity benefits when solar and storage are both included on the system. E3 concluded that the diversity benefit of solar and storage on the DEC system accounted for more than 20% of the total ELCC value.[105] It is important to note that the use of an ELCC surface to identify diversity benefits alone does not ensure that these ELCC values are correctly incorporated into a capacity expansion model. The use of a capacity expansion model that is capable of single-step optimization is necessary to capture those benefits.

Duke also used a number of assumptions in its ELCC calculations that have the effect of inappropriately decreasing ELCC values for solar and for storage.

[105] *Id.* at 32.

1. Duke failed to vary ELCC as a function of load.[106] The ELCC of a resource is a function of the loads and resources on the system. As more of a resource is added at constant load levels, it effectively provides a larger percentage of total capacity requirements, resulting in a declining ELCC. Duke should use ELCC values that are dynamic to the system including future load levels. If this is not possible given the modeling software used, Duke should use ELCC values calculated using load levels consistent to the last year in the planning horizon so that procurement is guided by the long-run capacity value of resources.

2. Duke has not used its most recent demand response assumptions in its ELCC calculations.[107] As discussed above, Duke should be required to revise many of its assumptions and inputs used to complete its DSM studies and analysis. However, even before those revisions are completed, Duke should be required to use its most recent demand response assumptions in its ELCC calculations. Duke's 2020 Winter Peak Demand Reduction Potential Assessment, completed after Duke's 2020 IRP was filed, includes significant increases in demand response potential in the winter relative to the levels assumed in Duke's ELCC studies used for the IRP. Duke should update its demand response assumptions in its ELCC study to reflect the assumptions it published in its December 2020 Winter Peak Assessment. After the additional recommendations described above related to Duke's DSM assumptions have been implemented, Duke should further revise its demand response assumptions at that time.

3. Duke improperly assumes that 40% of future solar is fixed-tilt and that 60% of future solar is single axis tracking.[108] Technological advancements and cost decreases in tracking systems for solar plants has resulted in an increasing dominance of tracking systems, to the point where very few fixed tilt systems are being installed.[109] Because it is highly likely that new solar projects constructed in Duke's North Carolina and South Carolina service territories will use tracking systems rather than fixed-tilt systems, E3 recommended that the marginal ELCC of solar be based on 100% tracking solar for new installations.

After correcting for the flaws in ELCC calculations identified above, E3 recalculated the ELCC values for solar in DEC and DEP.

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[106] *Id.* at 26.
[107] *Id.* at 27.
[108] *Id.* at 28.
[109] *Id.* at 28-29.

**Figure 3: E3 Modeling of Solar ELCC on the DEC System**[110]

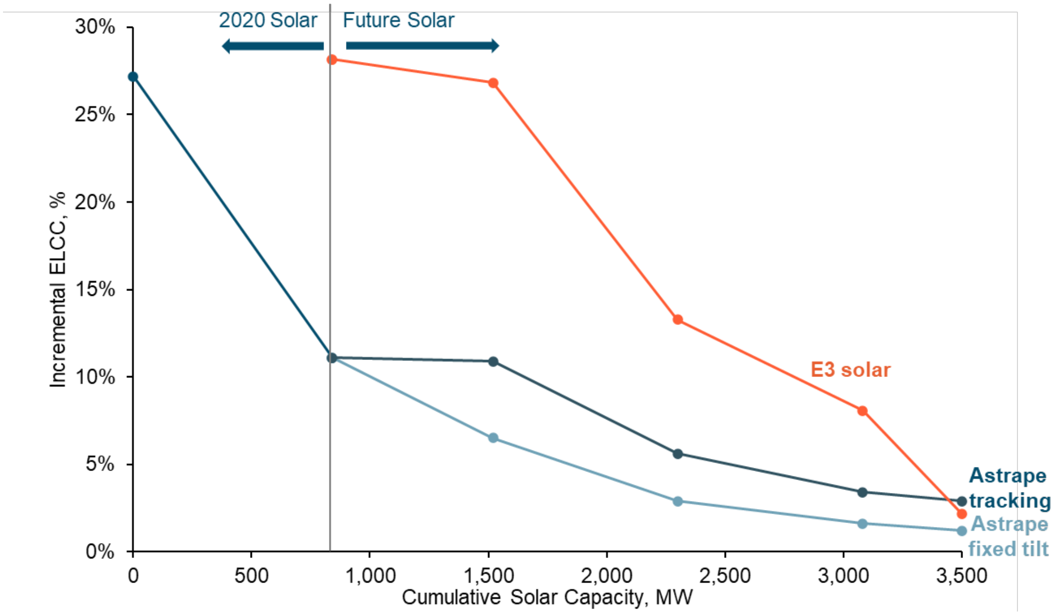


Figure 3 above shows the revised ELCC values for DEC. As shown, the initial E3 ELCC values of solar are significantly higher than Astrapé values, with the ultimate results converging at higher penetrations around 3,500 MW. Based on the modeling performed by E3, it is not possible to allocate the differences to each individual recommendation as they are modeled as a package. However, it is accurate to say that all of the recommendations made by E3 would have the effect of increasing the solar ELCC values compared to the Astrapé study. Notably, the results reflected in Figure 3 above incorporated Duke's forecasted winter peaking load for the purposes of modeling. Therefore, Duke's adoption of the recommendations of Mr. Kirby, discussed above, would further increase the ELCC value of solar if the loss-of-load probability was shifted away from winter morning hours. Duke should be required to revise its IRP modeling consistent with the recommendations above and provide the modified results to the Commission as soon as possible.

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[110] *Id.* at 31.

## D. DUKE'S IRPS OVERLOOK THE BENEFITS OF REGIONALIZATION

Pursuant to Rule R8-60(d), "each utility shall assess on an on-going basis the potential benefits of soliciting proposals from wholesale power suppliers and power marketers to supply it with needed capacity." However, Duke's IRP fails to comply with Rule R8-60(d) because it ignores the benefits provided by increased regionalization.

Duke's modeling shows the benefit of enabling capacity sharing between DEC and DEP, and that increasing import capacity from neighboring regions could further reduce costs and increase reliability.[111] These benefits include deferral of a combustion turbine resource starting in 2027 and lowering overall reserve margin which Duke estimates could lead to even a slightly lower reserve margin than the 17% they examined in the Joint Planning Case.[112] Despite these benefits, Duke continues to focus on operating DEC and DEP as islands even when the IRPs demonstrate the benefits of operating the two systems as one Balancing Authority, and has failed to pursue the regulatory approvals that would let it realize these benefits.[113] NCSEA and CCEBA submit that the Commission has a more than adequate basis to investigate how to realize the benefits of operating the two systems as a single Balancing Authority.

Duke's IRPs also largely ignore the reliability and economic benefits that DEC and DEP inherently receive by being interconnected to neighboring utilities.[114] Duke's treatment of DEC and DEP as physical islands in the Resource Adequacy studies results in inflated reserve requirements and only modeled support from utilities *one tie away*.[115] In

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[111] Lucas Report at 68-72.
[112] DEC IRP at 200.
[113] Lucas Report at 68.
[114] Kirby Report at 25-26.
[115] *Id.* at 27.

comparison, PJM aggregates generation and load over 12 states, while MISO aggregates generation and load over 15 states and one Canadian province.[116] Duke's approach assumes extremely limited support despite Duke being imbedded in the massive Eastern Interconnection, which spans from North Dakota to Florida, and the fact that Duke is now proposing the Southeast Energy Exchange Market ("SEEM"), an energy trading market that, if approved, will span the southeast.[117] At a minimum, the Commission should require Duke to assume interconnection support availability from the entire SEEM footprint.[118]

NCSEA and CCEBA submit that Duke should incorporate into its IRPs the potential benefits of broader regionalization through structures such as energy imbalance markets ("EIM"), independent system operators ("ISO"), or regional transmission organizations ("RTO").[119] The Southeast is the last region in North America without an EIM, ISO, or RTO.[120] Duke's modest proposal to create SEEM continues the limited vision of its IRPs. SEEM would provide only a fraction of the benefits of broader regionalization.[121]

### E. <u>DUKE'S TRANSMISSION ANALYSIS IS INADEQUATE</u>

Commission Rule R8-60(*i*)(5) requires that each "utility shall also include a discussion of the adequacy of its transmission system (161 kV and above)." Transmission assumptions in the Duke IRP are critically important given the flexibility provided by

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[116] *Id.*
[117] *See*, *Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Joint Informational Filing*, Docket Nos. E-2, Sub 1268 and E-7, Sub 1245 (December 11, 2020).
[118] Kirby Report at 27.
[119] Lucas Report at 71-72. *See also*, *Petition of the North Carolina Sustainable Energy Association, Sierra Club, and the Southern Alliance for Clean Energy for Investigation and Rulemaking to Implement N.C. Gen. Stat. § 62-154*, Docket No. E-100, Sub 171 (December 18, 2020).
[120] Kirby Report at 27.
[121] *Id.*; Lucas Report at 72.

increased connectivity that cannot be provided by power supply generation and demand response assets. Duke did not provide enough detail about its transmission planning assumptions or costs in the 2020 IRP, and NCSEA and CCEBA recommend that the Commission require Duke to revise its IRPs to include more detail to capture:

1. Transmission investment deferral and transmission congestion relief arising from the strategic positioning of modular energy storage and renewable energy facilities on Duke's transmission system, along with other non-wire alternatives.[122]

2. The economies of scale with bulk transmission upgrades to enable better integration of its Carolinas operating companies, as well as integration of large- scale renewable developments;

3. The results of improved collaborative planning efforts with neighboring systems such as the ongoing North Carolina Transmission Planning Collaborative ("NCPTPC") study with scenarios from the Southeast Wind Coalition that are in process;

4. Better asset management planning practices to inform planning decisions regarding long-range transmission expansion needs to leverage existing corridors; and

5. More rigorous analyses and assumptions regarding projects and costs to support future resource needs, in particular imports and off-shore wind developments that may be best addressed in partnership with neighboring systems.[123]

### F. The Commission Should Plan Now for Future Generation Additions

N.C. Gen. Stat. § 62-110.1(c) requires that "The Commission shall develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina[.]" As described in the Joint Synapse Comments, the Synapse modeling results in immediate additions of renewable capacity,

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[122] Joint Synapse Comments, Exhibit 1, p. 20.
[123] Caspary Report at 1.

beginning in 2023 and every year thereafter throughout the planning period. This includes 3,100 MW of renewable additions from 2021-2026, followed by 9,000 MW of additions from 2027 through 2031. These volumes account for reasonable limits on annual renewable capacity additions, with a cap of 500 MW starting in 2021. The model assumes this annual cap rises incrementally over time due to greater learning and industry resources, increasing to 1,800 MW by 2030. The generation will need to come online gradually over a longer timeframe, and the Commission should start planning those additions now. Moreover, Duke's corporate goals will require massive quantities of new renewable energy generation and energy storage by 2050, but much of these additions will not come online until after the IRP planning horizon.[124] Under either Duke's IRPs or the Synapse scenario, Duke should be required to accelerate the deployment of renewable energy generation so that manageable amounts of generation are added gradually over time, instead of large amounts of generation being added to the grid during accelerated timeframes.

## IV. GOALS AND IMPACT OF IRPS

The Commission has been directed by the General Assembly to

> develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity, the probable needed generating reserves, the extent, size, mix and general location of generating plants and arrangements for pooling power . . . and other arrangements with other utilities and energy suppliers to achieve maximum efficiencies for the benefit of the people of North Carolina. . . .

In doing so, the Commission must also consider the various policies set forth in N.C. Gen. Stat. § 62-2, which "require[s] energy planning and fixing of rates in a manner to result in

[124] Lucas Report at 9.

the least cost mix of generation and demand-reduction measures which is achievable[,]"[125] "consistent with long-term management and conservation of energy resources by avoiding wasteful, uneconomic and inefficient uses of energy[]"[126] while "promot[ing] harmony between public utilities, their users and the environment"[127] and "foster[ing] the continued service of public utilities on a well-planned and coordinated basis."[128]

As is demonstrated in these comments and in the associated reports, minor changes in assumptions can have a major impact on whether a utility's IRP represents the least cost portfolio, avoids wasteful, uneconomic, and inefficient uses of energy, or promotes harmony between utilities, ratepayers, and the environment. However, while the Commission has historically accepted IRPs for planning purposes,[129] the Commission's decision in this proceeding will have a direct impact on resource procurement, and not just procurement. N.C. Gen. Stat. § 62-110.8(a) was adopted by 2017's House Bill 589 ("HB589")[130] and establishes the Competitive Procurement of Renewable Energy ("CPRE") program. The initial CPRE program established a procurement process for renewable energy

> over a term of 45 months beginning when the Commission approves the program. . . . In addition, at the termination of the initial competitive procurement period of 45 months, the offering of a new renewable energy

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[125] N.C. Gen. Stat. § 62-2(a)(3a).
[126] N.C. Gen. Stat. § 62-2 (a)(4).
[127] N.C. Gen. Stat. § 62-2 (a)(5).
[128] N.C. Gen. Stat. § 62-2 (a)(6).
[129] See, e.g., *Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses*, pp. 91-92, Docket No. E-100, Sub 157 (August 27, 2019) ("IT IS, THEREFORE ORDERED as follows: That the IRPs filed herein by Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, are *adequate for planning purposes* during the remainder of 2019 and for 2020, subject to DEC's and DEP's 2019 IRP Updates, and *the Commission hereby accepts the IRPs*, subject to the questions raised in this Order concerning the underlying assumptions upon which the IRPs are based, the sufficiency or adequacy of the models employed, or the resource needs identified and scheduled in the IRPs beyond 2020.") (emphasis added).
[130] Competitive Energy Solutions for NC, Sess. L. No. 2017-192 (2017).

> resources competitive procurement and the amount to be procured shall be determined by the Commission, based on a showing of need evidenced by the electric public utility's most recent biennial integrated resource plan or annual update *approved by the Commission* pursuant to G.S. 62-110.1(c).[131]

The initial CPRE program was approved by the Commission on February 21, 2018.[132] Thus, pursuant to N.C. Gen. Stat. § 62-110.8(a), the initial CPRE program will expire in November 2021. While Duke will file IRP update reports on September 1, 2021, by function of Rule R8-60(l), those will not be approved prior to the expiration of the original CPRE program. Thus, the Commission's decision in this proceeding will directly impact the amount of solar energy procured in the CPRE.

## V. CONCLUSION

For the reasons set forth in these comments, and in the Joint Synapse Comments, Duke's 2020 IRPs have failed to comply with the statutory and regulatory requirements, as well as with the Commission's previous orders. NCSEA and CCEBA respectfully request that the Commission disapprove Duke's IRPs and direct DEC and DEP to modify and refile their IRPs after completing the modifications recommended herein.

[131] N.C. Gen. Stat. § 62-110.8(a) (emphasis added).
[132] *See*, *Order Modifying and Approving Joint CPRE Program*, Docket Nos. E-2, Sub 1159 and E-7, Sub 1156 (February 21, 2018).

Respectfully submitted, this the 1st day of March 2021.

/s/ Peter H. Ledford
Peter H. Ledford
N.C. State Bar No. 42999
4800 Six Forks Road, Suite 300
Raleigh, NC 27609
919-832-7601 Ext. 107
peter@energync.org

Benjamin W. Smith
N.C. State Bar No. 48344
4800 Six Forks Road, Suite 300
Raleigh, NC 27609
919-832-7601 Ext. 111
ben@energync.org

*Counsel for NCSEA*

John D. Burns
N.C. State Bar No. 24152
811 Ninth Street, Suite 120-158
Durham, NC 27705
919-306-6906
Counsel@CarolinasCEBA.com

*Counsel for CCEBA*

**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 hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

This the 1st day of March 2021.

/s/ Peter H. Ledford
Peter H. Ledford
N.C. State Bar No. 42999
4800 Six Forks Road, Suite 300
Raleigh, NC 27609
919-832-7601 Ext. 107
peter@energync.org

**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION**
**DOCKET NO. E-100, SUB 165**

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|---|---|
| **In the Matter of:** | ) |
| **2020 Biennial Integrated Resource** | ) |
| **Plans and Related 2020 REPS** | ) |
| **Compliance Plans** | ) |
| | ) |

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**INITIAL COMMENTS OF NCSEA AND CCEBA ON DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC'S INTEGRATED RESOURCE PLANS**

**EXHIBIT 1**

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# Comments on Duke Energy Carolinas and Duke Energy Progress 2020 Integrated Resource Plans

**Brendan Kirby, P.E.**

www.ConsultKirby.com 865-250-0753 Kirbybj@IEEE.ORG

February, 2021

# Duke 2020 IRP Comments

**B. J. Kirby, P.E.**[1]

## Introduction

Ensuring reliability is a critical component of electric power system planning and is critical for the successful integration of renewable generation. Integrated resource planning (IRP) provides an initial step in assuring continued power system reliability by developing a reliability-based, economically optimal, plan through appropriate assessment of resource adequacy. Reliability is assured by (among other things) establishing a quantity of generation, demand side management, and storage resources in excess of expected load – a planning reserve margin – which is sufficient to ensure a reliability target of (typically) no more than one outage every ten years.

Duke Energy's Resource Adequacy (RA) studies are performed by Astrape Consulting. These RA studies determine the planning reserve margin required to meet the no-more-than-one-outage-every-ten-year reliability target. Duke also relies on Astrape to determine the Effective Load-Carrying Capability (ELCC) of solar generation and storage. Duke utilized the reserve margin requirements and ELCC values determined by Astrape in their capacity expansion and production cost modeling that is the basis of their IRP optimal resource plan. Unfortunately, as discussed below, there are numerous flaws in the RA and IRP assumptions and modeling methods. Weather, solar, and load data are inconsistently and incorrectly handled in the modeling. DSM, EV, and storage resources are inconsistently and ineffectively utilized. Consequently, the capacity contributions of solar and storage resources are undervalued and modeled costs are overstated.

## Study Methodology is Sound but There Are Deep Flaws in the Implementation

Astrape's use of production cost modeling to simulate power system operations under years of expected future conditions while adjusting the planning reserve margin to maintain an acceptable loss of load probability (LOLP) is a well-established and sound planning methodology. Giving excessive weight to extreme weather events results in an overstating of reserve requirements and an undervaluing of the capacity contribution of solar, storage, and DSM. Rare, short, easily forecasted extreme cold weather events drive the IRP and Resource Adequacy Study (RA) results. Dr. Sharp notes that meteorological evidence does not support including these events in the IRP with the same weight as more recent decades of actual weather:

> "Typically, the atmospheric sciences community uses the most recent 30 consecutive years to develop climatological normals, as recommended by the

[1] Attached as Exhibit 1, C.V. of B. J. Kirby, P.E.

> World Meteorological Organization for about a century. However, recently, the National Climate Data Center (NCDC) has begun providing supplemental data with 5-, 10-, 15- and 20- year periods, because 30-year averages are often unrepresentative of the *current* climate because it is changing, and the longer record dampens the trends. Ironically, some of the new shorter duration products being provided by NCDC have been provided in response to stakeholder feedback from the energy industry.[2]

Further, Dr. Sharp explains that climatic changes are warming the Carolinas and that extreme cold temperatures are much less likely:

> [T]he climate record Duke uses indicates that the extreme peak that occurred in January 1985 was an extremely rare event, that the number of cold events is declining over time, and thus, so are wintertime loads, including extreme loads. … Climate science backs up these findings and indicates that the number of exceptionally cold days will continue to decline in the future.[3]

The extreme cold events of the 1980's are not included in other Duke analysis like the Duke Energy Winter Peak – Demand Reduction Potential Assessment / Analysis and Solution set / Targeted DSM Plan. Further, neither the proposed DSM programs nor the storage analysis were designed to address the extreme weather events because they were not included in that analysis. Consequently, Duke found that neither DSM nor storage were effective in helping integrate solar generation.

There are similar problems with Duke's synthesis of hourly solar data. Prior to 1998 there is no time-synchronized solar data from the NREL National Solar Radiation Database. As Dr. Sharp notes, there is no scientific basis for the way Duke generated pre 1998 time-synchronized hourly solar data.

The Resource Adequacy (RA) study is short on details concerning the assumptions and specifics on how the modeling was conducted. It is difficult to tell if operational strategies and equipment mixes were truly optimized to minimize costs and maximize the integration of renewables or if specific scenarios were simply proposed and tested. Planning, modeling, and analysis should focus on understanding the power system and its reliability concerns and then finding the best way to meet the environmental and economic goals.

The analysis methodology treated solar and wind generation first and then considered storage and demand side management (DSM) as potential add-on resources. Because solar, wind, storage, and DSM where not simultaneously co-optimized, synergistic values were completely

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[2] Justin Sharp, *Duke Energy IRP Attachment 3 (Resource Adequacy Study) Comments* at 2-3 (Feb. 2021) ("Sharp").
[3] Sharp at 8-10.

missed. For example, solar generation reduces the duration of the system peak load, making storage and DSM more effective.[4]

### *Duke's 2020 IRP Does Not Propose Ambitious Goals: Others Already Reliably and Economically Integrate Much Larger Amounts of Solar and Wind*

Duke's current capacity mix is only 10% solar.[5] The 2020 IRP Base Case With Carbon only increases variable renewable penetration (solar + wind) to 22% by 2035.[6] Others already integrate much larger amounts of wind and solar variable generation reliably and economically. The Southwest Power Pool (SPP) has operated with 73% wind penetration for one hour and 62% wind penetration for one day, over 20 GW. "In 2020, we [SPP] became the first US RTO to report wind as our main fuel source." In 2020 wind supplied 32% of the SPP fuel mix, exceeding coal's 30.6% (Figure 1).[7]

[4] Energy and Environmental Economics, Inc., Arne Olson et al., *Review of Duke's 2020 Integrated Resource Plan* at 10 (Jan. 2021).

[5] Duke Energy Carolinas 2020 Integrated Resource Plan, pp. 16, 215, 209 (November 6, 2020) ("DEC IRP Report"). Note the DEC IRP and RA reports are referenced for page numbers. Essentially identical language is in the Duke Energy Progress (DEP) reports.

[6] DEC IRP Report at 15, 18.

[7] Kassia Micek, *SPP Sets New Wind Peak Record of 20.1 GW After Record-Breaking 2020* (Rocco Canonica ed., Feb. 5, 2021) *available at*: https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/020521-spp-sets-new-wind-peak-record-of-201-gw-after-record-breaking-2020-year.

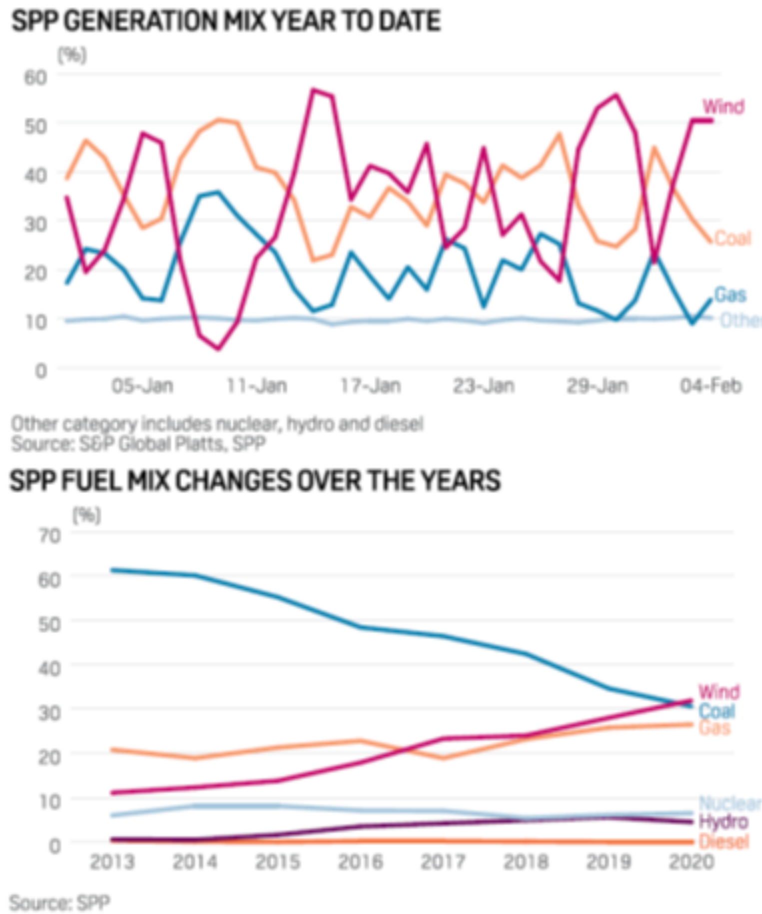


*Figure 1: Wind is regularly SPP's main source of generation.*

SPP markets have selected renewables because they are economic and reliable. Duke's 15-year IRP goals are modest by comparison with other's current operating practices.

## Rare Extreme Weather Events Drive the IRP/RA Reserve Requirements

The Duke/Astrape RA and IRP results are driven by a few extreme, rare, cold weather peak load events. Over-weighting of synthesized load data for extreme cold weather events from the 1980's dramatically impacted the RA Study results. Duke analysis shows that required reserve margins drop to 13.25% for DEC and 14.75% for DEP if historic weather years beginning in 1990 are used instead of 1980.[8]

Duke repeatedly concludes that it is extreme winter morning peak loads that result in near zero capacity value for solar generation. For example: "The analysis shows all of the LOLE falls in the

[8] Duke Response to AGO DR1-11, pg. 3.

winter"[9], "[S]olar provides almost no capacity value in the winter"[10], and "As in the 2016 study, winter load volatility remains a significant driver of the reserve margin requirement."[11]

Duke compounded the extreme weather winter peak concerns by arbitrarily increasing conventional generation outages: "Generator outages remained in line with 2016 expectations, but additional cold weather outages of 260 MW for DEC were included for temperatures less than 10 degrees."[12] An additional 140 MW of cold weather outages were included for DEP.

### *Inclusion of Rare, Extreme Cold Events Is Not Justified*

Astrape states in the RA Reports that "[I]ncorporation of tail end reliability risk in modeling should be from statistically and historically defendable methods; not from including subjective risks that cannot be assigned probability."[13] Unfortunately, the tail end reliability risk that results from rare extreme cold weather events was not based on sound statistical analysis. Instead of using the artificial neural network model that was developed to synthesize load data based on temperature for more reasonable temperatures for which Duke has actual load data, Astrape resorted to extrapolating results to cover extreme temperatures where no actual load data exists:

> "Because recent historical observations only recorded a single minimum temperature of six degrees Fahrenheit, ***Astrapé estimated the extrapolation for extreme cold weather days*** using regression analysis on the historical data."[14]

This is troubling because it is the extreme cold weather load spikes that drive the reserve requirements and solar's near zero capacity value.[15] All of the 39 years of weather and load artificial neural network analysis is replaced with an "extrapolation" because there is no actual data for the critical low temperatures. The RA report results appear to hinge on an extrapolation. With such rare events it is possible that the residential heating load saturates and is unable to rise as much as predicted by extrapolation.

Duke does not have historic load data from extreme cold weather events because they occurred too long ago. The RA study effort attempted to synthesize loads that might occur during extreme cold by extrapolating results based on actual load levels recorded at higher temperatures. Figure 4 in both the DEP and DEC RA study Reports (Figure 2 in this report) proport to show how the actual temperatures and loads compare.

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[9] DEC IRP Report, Attachment III - DEC 2020 Resource Adequacy Study, pp. 45, 46 (November 6, 2020) ("DEC RA Study").
[10] DEC RA Study at 57.
[11] DEC IRP Report at 64.
[12] DEC RA Study, graph 5.
[13] DEC RA Study at 17.
[14] *Emphasis added*, DEC RA Study at 25.
[15] Sharp at 4.

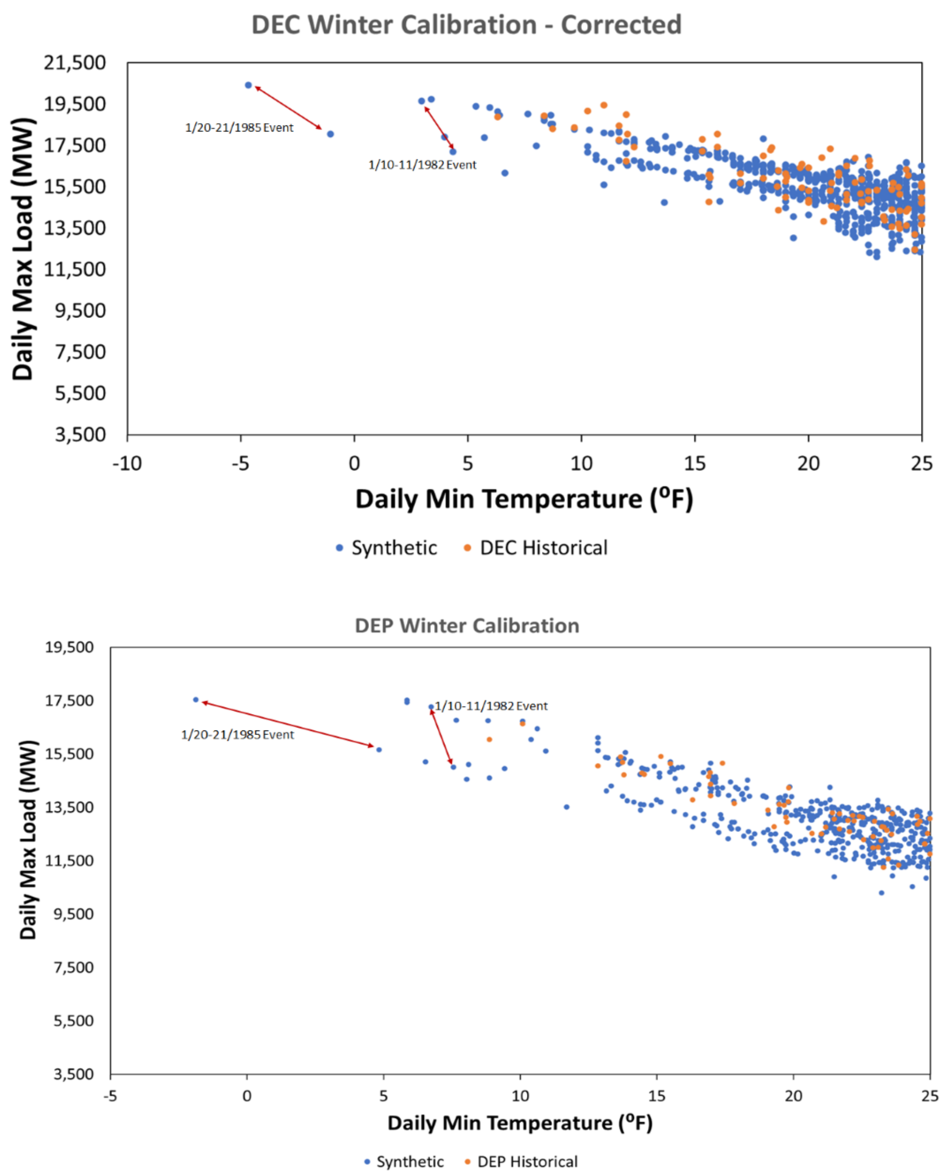
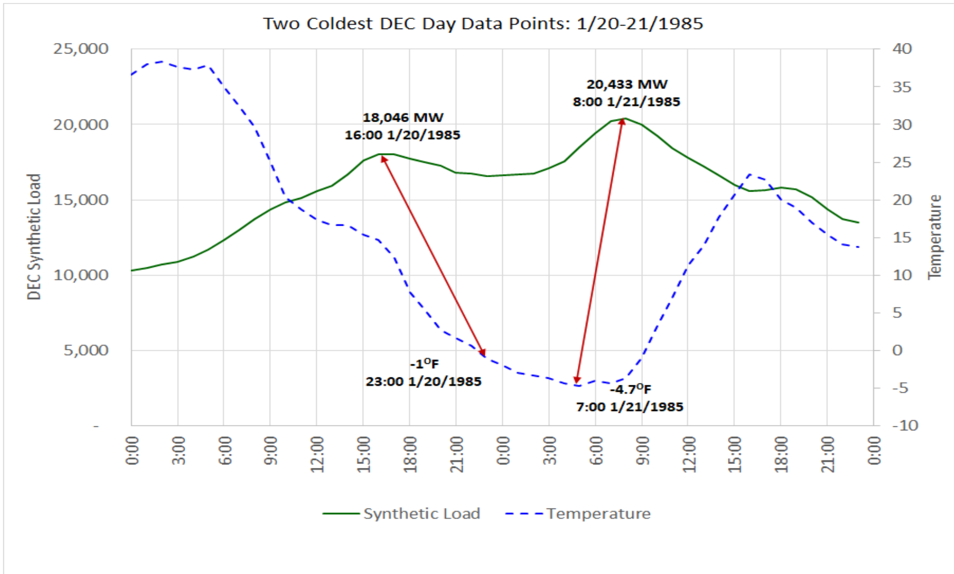



*Figure 2: DEC and DEP RA Study Figure 4*

Care must be taken when interpreting Figure 4 from the RA Study (Figure  in this report). Figure 3 shows the actual hourly temperatures and synthesized loads for DEC and DEP for the two days. Temperatures were relatively high on the morning of 1/20/1985: 38 degrees for DEC and 44 degrees for DEP at 6am. Even Duke's synthesized load was reasonably low. Temperatures dropped throughout the day and minimums for 1/20/1985 were set at 11pm. Temperatures continued to drop until 7am on 11/21/1985.



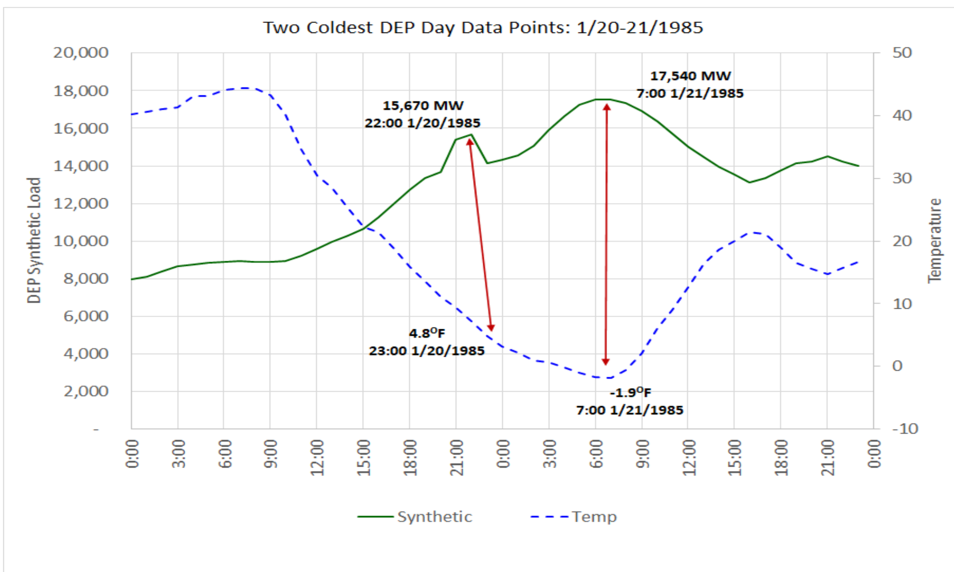
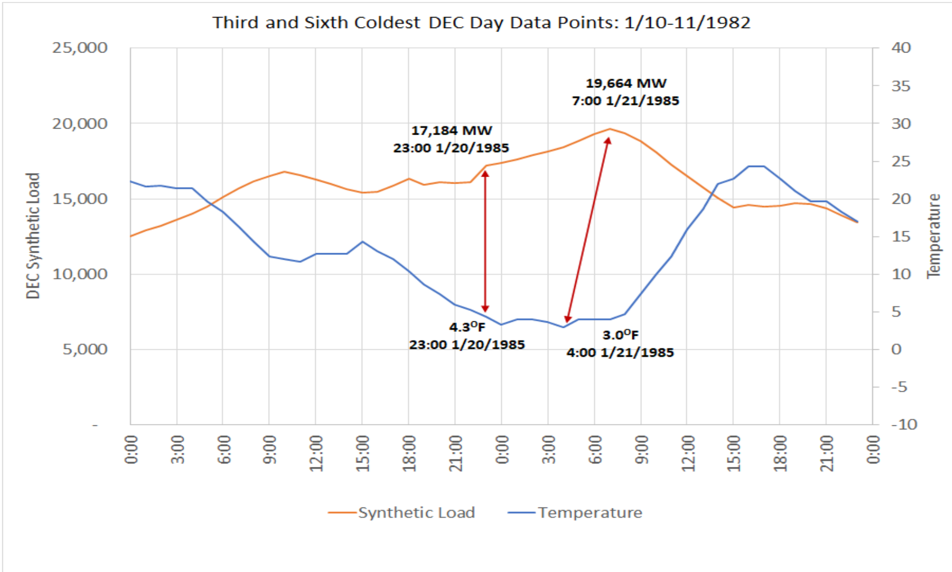




*Figure 3: DEC and DEP historic temperatures and synthesized (extrapolated) loads for the two coldest days used in the RA analysis.*

Clearly, 1/20/1985 was not an extreme cold weather load day with an extreme morning load. It gets included only because temperatures started dropping before midnight heading into 1/21/1985. Figure 4 shows that DEC's third and sixth and DEP's sixth and tenth coldest days were also single events rather than two events each. There are additional extreme cold weather days in the analysis that are linked.



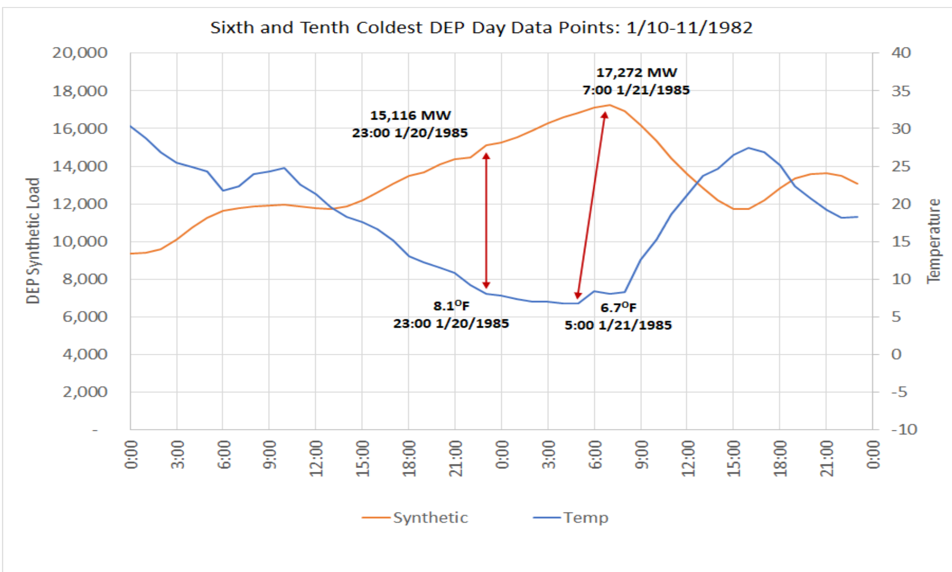




*Figure 4: 1/10-11/1982 was also a single cold event, not two.*

The important point is that the extreme cold weather events, which the IRP and RA study admit are rare[16], are actually even rarer than Duke's analysis indicates, and concentrated in years that Duke has no actual load data for.

## *Trends in Temperature and Temperature Driven Load*

Dr. Sharp analyzed the 39-year climate record Duke used in the IRP and RA analysis and found that the extreme cold that occurred in January 1985 was an extremely rare event, that the number of cold events is declining over time, and thus, so are winter time loads, including

[16] The RA Study Report states that the "recent historical observations only recorded a single minimum temperature of six degrees Fahrenheit." DEC RA Study at 25.

extreme loads.[17] Dr. Sharp grouped the temperature data into five 8-year periods and then quantified what percentage of temperature events occurred during each of those 8-year periods. Figure 5 clearly shows that the 1980-1987 period is unique.[18] All of the coldest hours (-2.5°F to +2.5°F in Temperature Bin 0°F) occurred in the 1980-1987 period. 75% of the 5°F hours occurred during 1980-1987 with 25% occurring during 1988-2003. In fact, Figure 5 shows that hourly temperatures are reasonably consistent in all years other than 1980-1987.

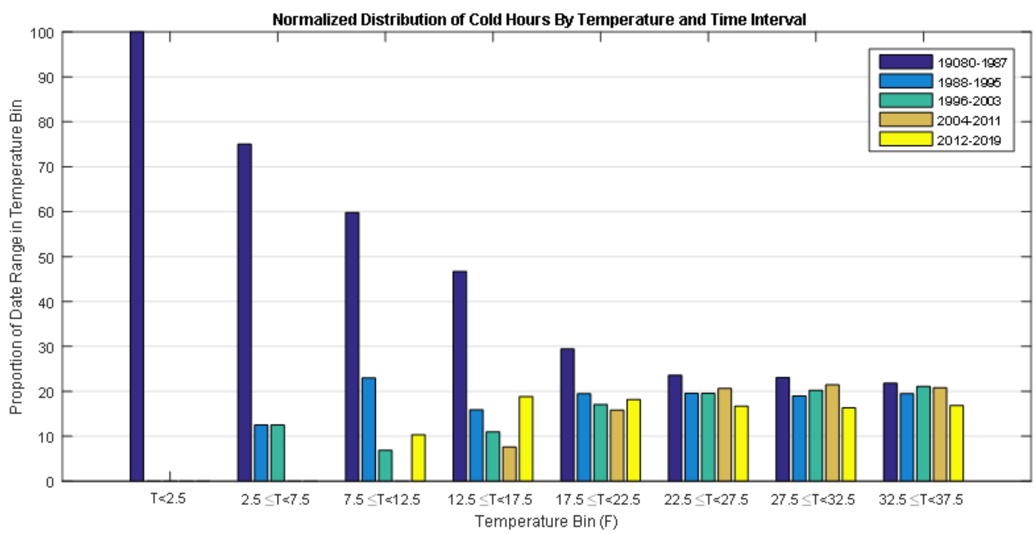



*Figure 5: DEP normalized temperature distribution for different time periods*

### *Extreme Cold Weather Events Are Rare and Getting Rarer: The North Carolina Climate Science Report*

The North Carolina Institute for Climate Sciences has published a peer reviewed report that shows that the number of cold hours is diminishing over time, especially the number of exceptional cold hours, and that the number of exceptionally cold days is expected to continue to decline in the future. The North Carolina Climate Science Report (NCCSR) shows that extreme cold weather events are extremely rare and getting rarer.[19] Figure 6: Minimum annual temperatures (NCCSR Figures 3.9, 3.25, and 3.41)shows the historic and forecast minimum temperatures for all three regions of North Carolina (coastal plain, piedmont, and Western Mountains) are dramatically rising. Figure 7 shows that extreme cold events are rare and getting rarer.

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[17] Sharp at 8.

[18] Results are shown for DEP. DEC results are similar.

[19] North Carolina Institute for Climate Studies, Kenneth E. Kunkel et al., *North Carolina Climate Science Report* (Sept. 2020) *available at*: https://ncics.org/programs/nccsr/ ("NCCSR").

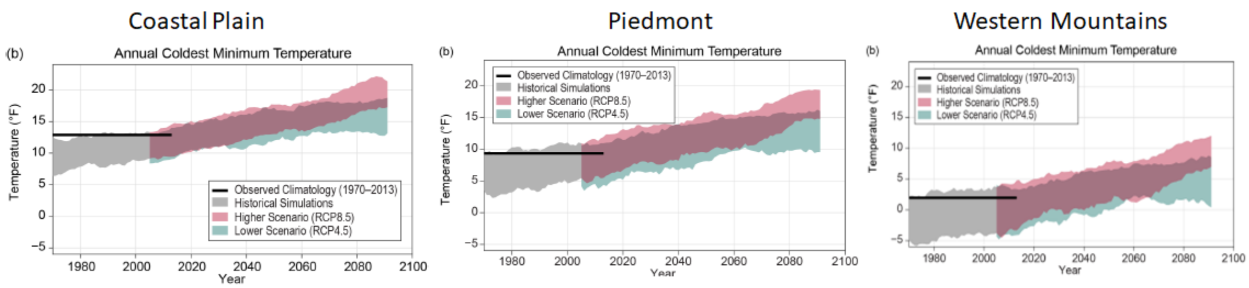


*Figure 6: Minimum annual temperatures (NCCSR Figures 3.9, 3.25, and 3.41)*

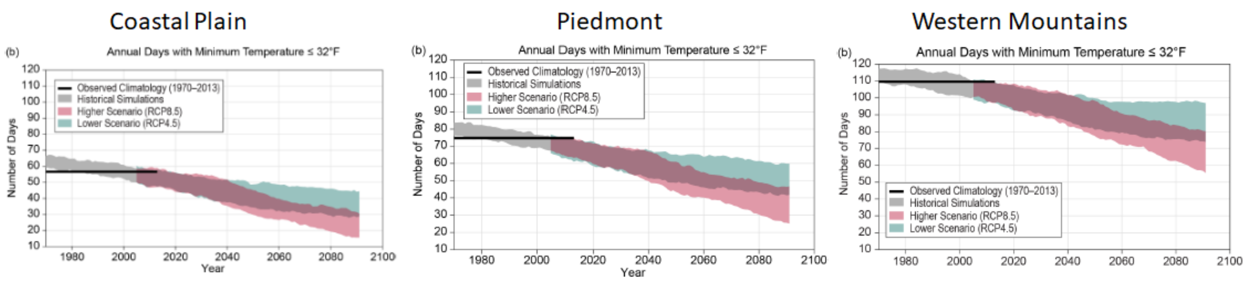


*Figure 7: Number of days with temperatures below 32º (NCCSR Figures 3.8, 3.24, and 3.40)*

The report explains that the "[h]istorical simulations (gray shading) are shown for 1970–2005. Projected changes for 2006–2100 are shown for a higher scenario (RCP8.5; red shading) and a lower scenario (RCP4.5; green shading). Shaded ranges indicate the 10% to 90% confidence intervals".

The report states that minimum temperatures are rising:

> ***"Since 1970***, there has been no strong trend in the annual hottest temperatures averaged over the Piedmont region, but ***there has been an increase in the annual coldest temperatures***. …
>
> "The projections for increases in annual coldest temperature are consistent with recent observations. Because of this consistency, **it is *very likely* that the model-projected increases in annual coldest temperature will occur.**"[20]

The report also states that the number of cold days is decreasing:

[20] *Emphasis added*, NCCSR at 127.

> "Occurrences of cold days (maximum temperature of 32˚F or lower) are relatively infrequent … By the end of the century, climate models project that the annual number of cold days will be at or close to zero under both scenarios."[21]

### *Duke Does Not Include Extreme Cold Weather Events in Its DSM Program Design*

Duke's Winter Peak Targeted DSM Plan did not evaluate a DSM program designed to address rare, extreme winter peak loads.[22] The Winter Peak Analysis and Solution Set report states that "[we] reviewed hourly load data for 2017 and 2018."[23] While the DSM study report does discuss winter morning peaks, the Winter Peak Demand Reduction Potential Assessment did not consider the rare, extreme cold driven loads synthesized from hourly weather data from the 1980s.[24] The report states that the "standard peak day load curve for the electric system is defined by taking an average of the load shape from each of the top ten winter peak days in the forecasted hourly load data."

### *Weighting of Extreme Cold Weather Is Significant*

The AG Office recommended performing the analysis based on weather and load data starting in 1990 rather than 1980.[25] The impact on reserve requirements is dramatic: "[u]sing historic weather years beginning with 1990 instead of 1980 results in a reserve margin of 13.25% for DEC and 14.75% for DEP to meet an LOLE of 1 day in 10 years."

Duke argues that excluding the 1980's temperature data would be unwise because it would exclude possible future weather conditions. Including the 1980's overstates the extreme cold impact, however, because each year is treated with equal probability, denying the climatological evidence of a trend towards warmer winter minimum temperatures.

Synthetic loads based on 1980's temperature data should be appropriately weighted to reflect the decreased probability of occurrence. Duke's analysis gives the 1980's slightly more than a one-in-four probability (ten out of 39 years). Dr. Sharp recommends reducing the weighting of the cold 1980's decade by a factor of 2.5, reflecting a one decade per century probability as more realistic.

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[21] NCCSR at 125.

[22] Duke Energy Winter Peak Targeted DSM Plan (Dec. 2020) *available at:* https://cleanenergy.org/wp-content/uploads/Duke-Energy-Winter-Peak-Targeted-DSM-Plan-Final-Report.pdf ("Winter Peak Targeted DSM Plan").

[23] Duke Energy Winter Peak Analysis and Solution Set at 9 (Dec. 2020) *available at:* https://cleanenergy.org/wp-content/uploads/Duke-Winter-Peak-Analysis-Solution-Set-Final-Report.pdf ("Winter Peak Analysis and Solution Set").

[24] Duke Energy Winter Peak Demand Reduction Potential Assessment (Dec. 2020) *available at:* https://cleanenergy.org/wp-content/uploads/Duke-Winter-Peak-Demand-Reduction-Potential-Assessment-Final-Report.pdf.

[25] Duke Response to AGO DR1-11; DEC and DEP 2020 Resource Adequacy Study Responses to AG Office Recommendations at 3 (June 26, 2020).

### *Recommendations*

The Commission should direct Duke to reduce the probability of 1980's extreme cold events in the synthetic load derivation to once in a century (a factor of 2.5) to reflect the lowering likelihood of extreme cold events in all of the analysis: IRP, RA, DSM, Storage, to assure that resources are aligned with need and are consistently valued.

## Problems with Duke's Synthetic Load Model

Duke's IRP and RA analysis is based on 39 years (1980—2018) of hourly historic temperature data but only five years and nine months of actual coincident load data were available (1/2014—9/2019).[26] In order to use the longer historic temperature record in the IRP and RA studies Astrape developed an artificial neural network model to create "synthetic" hourly loads for each hour of the 39-year historic temperature record.

The use of an artificial neural network model to synthesize coincident load data for years without actual data sounds reasonable. Unfortunately, there are major problems with Duke's synthetic load data model. Dr. Sharp's review of the RA Study's load modeling effort found serious concerns. First, with no actual load data for extreme cold temperatures Astrape had to extrapolate results rather than have the artificial neural network develop a load model based on historic performance: there is no history. Second, for the coldest temperatures for which there is actual load data the artificial neural network load model is particularly inaccurate.

### *Low Temperature Loads Were Extrapolated – Not Artificial Neural Network Modeled from Historic Data*

Low temperature synthetic loads were not generated with an artificial neural network trained with actual data. Instead, they are an extrapolation of the historic loads to lower temperatures. This is troubling because many loads, especially residential heating loads, likely saturate at extreme cold temperatures and cannot continue to increase at the same rate as temperatures continue to drop.

The RA Study Report states that "[b]ecause recent historical observations only recorded a single minimum temperature of seven degrees Fahrenheit, ***Astrapé estimated the extrapolation for extreme cold weather days*** using regression analysis on the historical data."[27] In response to data requests Duke stated that "[i]n general, days with temperatures less than 20 degrees and greater than 92 degrees were adjusted using the regression analysis."[28]

[26] DEC RA Study at 22.
[27] *Emphasis added*, DEC RA Study at 25.
[28] Duke Response to SELC DR7-2.

Dr. Sharp analyzed the occurrences of high loads in the synthetic data set used for the RA and IRP analysis. He found that the top 100 load hours for DEP are all from winter peaks.[29] Of these:

- 67 are from the 1980's (10 unique events, several spanning multiple days)
- 18 are from the 1990's (2 unique events)
- 3 are from the 2000's (2 unique events)
- 12 are from the 2010's (3 unique events)
- There is no synthetic load above 16,637 MW since 1996. Compare this to the 1985 synthetic peak of 17,539 MW
- The 16,637 occurred on 2/20/15 and was itself an extreme outlier within recent data. The minimum temperature was 10F. Compare to -2F on 1/21/1985, and single digits on 2/5/96.
- The nearest comparable in the 2010's with a synthetic load of 16,123 MW on 1/7/2014. But the actual load was only 15055 MW.

It is worth noting that historical data was available for all the loads in the top 100 list that occurred post 2014. (See below)

The top 500 hours were also examined:

1. Fully 247 of them were winter peaks from the 1980's
2. Other winter peaks: 69 from the 1990's, 52 from the 2000's, and 106 from the 2010's
3. The remaining 22 peak hours occurred during summer months, with 4 in the 1980's, 8 in the 2000's and 10 in the 2010's.

### *The Synthetic Load Model Accuracy Declines at Low Temperatures*

Dr. Sharp compared the synthesized loads with the actual loads to assess the accuracy of the artificial neural network load model (ANN) used to generate the hourly synthetic loads used in the IRP/RA analysis. Note that the ANN was trained with this data, so the synthesized loads would be expected to be very close to the actuals. (The appropriate way to verify an ANN is discussed below.) Figure 8 compares the synthesized load values from the ANN with the actual historic load values based on temperature. Note that the mean absolute error and the root mean square error rise dramatically, and the correlation between the synthesized and actual loads drop significantly at the lower temperatures for both DEP and DEC.[30] It seems probable that errors in synthesized load data will be even larger as results are extrapolated to the extreme low temperatures modeled for the 1980s, but with no actual load data that is impossible to verify.

[29] Sharp at 11.
[30] Sharp at 8.

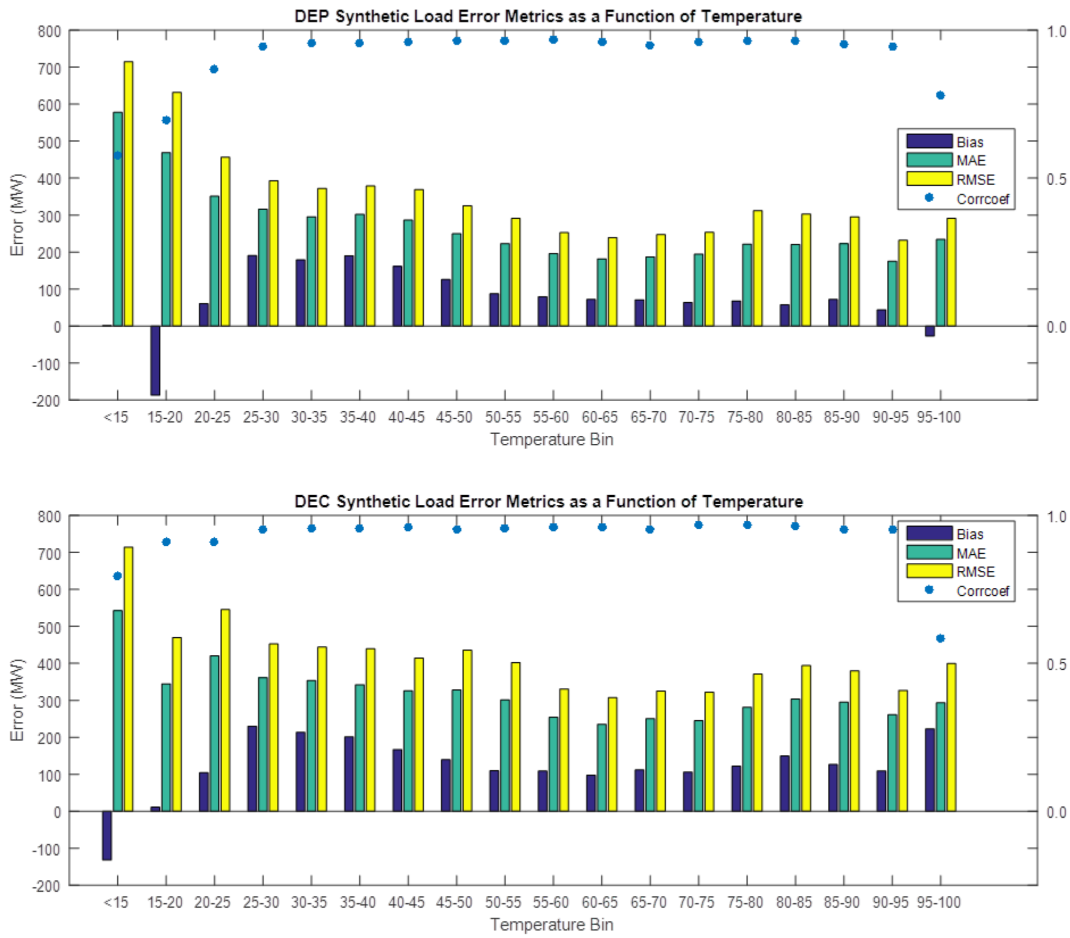


*Figure 8: Artificial neural network load modeling accuracy drops significantly at lower temperatures.*

### *Failure to Verify the Synthetic Load Model*

As noted above, five years and nine months of coincident load and temperature data were used to develop an artificial neural network (ANN) synthetic load model for the DEC and DEP service areas. Dr. Sharp notes that little information was provided concerning how the model was developed or the algorithms that were used.[31] Duke did explain that separate instances of the ANN were trained for winter, summer, and shoulder seasons. Typically, when training a model, model accuracy and fitness is tested by denying data from a period where inputs and outputs are available and then using the denied data to see how well the model works. This verification analysis was not performed.

### *Modeling Neighboring Systems*

Page 27 of the RA Study briefly explains that a 39-year synthetic load record was also produced for neighboring service territories in order to capture weather diversity in regions importing and

[31] Sharp at 3.

exporting from/to DEP or DEC. The report says that a similar methodology was used to develop load timeseries data for 39 years in neighboring service regions. However, no other information is provided.[32] It is not clear if extrapolation or an ANN was used, and if so what temperature and load data was used to train it. It is not clear how accurate the synthetic load record is.

### *Recommendations*

The synthetic load model should be retrained and recalibrated. Recalibration should include holding back some actual load data from the model training so that the model can be verified with actual temperature and load data that the model has not been exposed to during training. Having an additional two years of historic load data should help improve the load model accuracy.

## Problems with Duke's Solar Data

Just as with the load data used in the IRP and RA analysis, Duke does not have time-synchronized hourly solar data for use with the 39-year historic temperature data. Duke used the National Renewable Laboratory (NREL) National Solar Radiation Database (NSRDB) Data Viewer and "NREL's System Advisor Model (SAM) for each year and county to generate hourly profiles for both fixed and tracking solar profiles."[33] Unfortunately, the NSRDB only contains hourly solar data for 1998 through 2019. Dr. Sharp found that Astrape synthesized hourly solar data for 1980 through 1997 by attempting to match similar days from 1998-2019 with days from 1980-1997 based on peak load and time-of-year.[34] Dr. Sharp found this method of synthesizing hourly solar data that proports to be time synchronized with load data to be without merit: "Further, though solar generation and load are both driven by atmospheric parameters, **there is categorically no foundation in atmospheric science to suggest any skill in such a methodology**. We suspect that it is likely no better than using a random number generator to assign the shapes."[35] Dr. Sharp also notes that a similar methodology for creating solar data was also deployed in the document, "Duke Energy Carolinas and Duke Energy Progress Solar Capacity Value Study", which is used to determine the ELCC of solar, and used in the IRP.

### Recommendations

The Commission should direct Duke to rerun the Resource Adequacy Study, Solar Capacity Value Study, and IRP analysis based on the years 1998 through 2020 for which time-synchronized hourly locational NSRDB solar data is available.

[32] Sharp at 12.
[33] DEC RA Study at 33.
[34] Sharp at 13.
[35] Sharp at 13.

## Storage and DSM Are Ideal Resources to Address Infrequent, Easily Forecast, Reliability Events – But Duke Failed To Consider Them Properly

The high reserve requirements and low capacity value assigned to solar generation in the IRP are driven by the inclusion of high winter peak loads resulting from rare, short, and easily forecast extreme cold weather events. These events should not be included in the IRP or RA analysis BUT if they are then storage and DSM solutions should be designed to address them. Unfortunately, Duke did not apply the same winter peak load criteria to the selection of DSM and storage as it applied to the IRP and consequently the correct *types* of DSM and storage were not valued or selected.

As discussed more fully below, the types of DSM technologies and programs that Duke allowed to be considered in the IRP and RA analysis, and as more fully documented in Duke's Winter Peak Demand Reduction Potential Assessment, Winter Peak Targeted DSM Plan, and Winter Peak Analysis and Solution Set, were designed to address typical winter peak load reduction, not extreme cold weather events. The IRP and RA analysis were not offered DSM resources designed to respond to very rare, easily forecast, high value events so. Similarly, storage operating modes were not adjusted in the IRP and RA analysis to deal with very rare, easily forecast, high value events so. While the IRP and RA analyses included DSM and storage the misapplication of the technologies resulted in a finding of limited value.

### *Hours of Reliability Concern and Low Solar Capacity Value*

The 2020 RA study found that the hours of reliability concern are extremely cold winter mornings. Appendix B, Table B.1 (Table 1 of these comments) shows the hours when LOL events were found for the base case. The hours 7, 8, & 9 AM in January dominate as the hours of concern. These few extreme cold hours drive Duke's reliability requirements and the low capacity value assigned to solar.

Unfortunately, the RA study did not focus on ways to mitigate this reliability problem while maximizing solar penetration at minimal cost. These are rare, short, and easily forecast, events. Emergency operating practices could be implemented to deal with these events without impacting economic operations during the majority of the time. For example, battery charging strategies could be adjusted when extreme cold was forecasted to assure that all batteries (stand-alone and solar-coupled) were fully charged ahead of the emergency need. Demand response programs could also be refocused to obtain winter response specifically for these rare, extreme, easily forecast, high-value events.

*Table 1: Data from the RA Study, Appendix B, Table B.1 shows that 99.8% of LOL events can be covered with 6 hours of storage,*

| Table B.1 Percentage of Loss of Load by Month and Hour of Day for the Base Case | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Month | | | | | | | | | | | |
| Hour of Day | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| 1 | | | | | | | | | | | | |
| 2 | | | | | | | | | | | | |
| 3 | | | | | | | | | | | | |
| 4 | 0.16% | 0.16% | | | | | | | | | | |
| 5 | 0.98% | 0.49% | | | | | | | | | | |
| 6 | 4.43% | 1.48% | | | | | | | | | | |
| 7 | 16.56% | 5.74% | | | | | | | | | | 0.33% |
| 8 | 32.79% | 7.87% | | | | | | | | | | 2.62% |
| 9 | 15.57% | 0.82% | | | | | | | | | | 0.16% |
| 10 | 4.43% | | | | | | | | | | | |
| 11 | | | | | | | | | | | | |
| 12 | | | | | | | | | | | | |
| 13 | | | | | | | | | | | | |
| 14 | | | | | | | | | | | | |
| 15 | | | | | | | | | | | | |
| 16 | | | | | | | | | | | | |
| 17 | | | | | | | | 0.16% | | | | |
| 18 | | | | | | | 0.33% | 0.98% | | | | |
| 19 | | | | | | | 0.49% | 1.15% | | | | |
| 20 | | | | | | | 0.16% | 0.33% | | | | |
| 21 | | | | | | | | | | | | |
| 22 | | | | | | | | | | | | |
| 23 | | | | | | | | | | | | |
| 24 | | | | | | | | | | | | |
| Sum | 74.92% | 16.56% | 1.80% | | | | 0.98% | 2.62% | | | | 3.11% |
| | 70.66% | Percentage of LOL covered by 2 hours of storage | | | | | | | | | | |
| | 93.77% | Percentage of LOL covered by 4 hours of storage | | | | | | | | | | |
| | 99.83% | Percentage of LOL covered by 6 hours of storage | | | | | | | | | | |

### *Storage*

IRP Attachment IV, Duke Energy Carolinas and Duke Energy Progress Storage Effective Load Carrying Capability (ELCC) Study, simulated three storage "operating modes": "(1) Preserve Reliability Mode (2) Economic Arbitrage Mode and (3) Fixed Dispatch Mode based on a set rate schedule."[36] Duke acknowledges that two of the operating modes (1&3) do not attempt to capture the full benefits of storage. It is not clear that the "economic arbitrage" mode is the best either.

In fact, the storage operating mode should change as the reliability needs of the power system change. More specifically, the optimal operating mode for storage is likely very different for the few extreme cold nights when peak loads are forecast for the following morning. On those days, all storage (stand-alone and solar-coupled) should be fully charged (with grid power if necessary) during the overnight hours to assure that it is fully available for the high-stress morning hours. Storage could be economically dispatched at other times.

[36] DEC IRP Report, Attachment IV – Storage ELCC Study, pp. 8. (Nov. 6, 2020) ("Storage ELCC Study").

The range of modeled scenarios was significantly constrained, and even the modeled modes were somewhat wasteful.[37] Three operating modes were modeled; "(1) Preserve Reliability Mode (2) Economic Arbitrage Mode and (3) Fixed Dispatch Mode based on a set rate schedule."[38] The report then notes that the "Preserve Reliability Mode" was "largely an academic exercise that provides a theoretical maximum capacity value but is not directly useful for planning purposes." Similarly, the "Fixed Dispatch Mode based on a set rate schedule" does not optimize the value of storage and would only be done under an outdated, rigid, contract rate schedule. Simulating each of these operating modes is simply documenting the cost of poor policy and technology implementation. The report conclusion "For solar plus storage projects subject to PURPA rates, Astrapé recommends that IRP capacity values reflect the results for Fixed Dispatch Mode" is ill advised.

### Only Charging Storage from Solar

Duke "assumed that the battery could be charged only from the solar array, and not from the grid."[39] This limits the benefit of dealing with winter morning extreme peaks. Winter peak mornings are easy to predict. It is possible that a cold winter morning would follow a day with little solar generation. It is hard to see why storage would not be fully charged, from the grid if necessary, going into an expected emergency winter peak morning.

Table 1 shows that two hours of storage could completely eliminate over 70% of the LOL events for the base case. Four hours of storage could deal with almost 94% and six hours of storage could deal with essentially all of the LOL events. Storage capacity value should reflect this capability and only be reduced from 100% if there is excess capacity and no capacity is required, obviating the need for additional CTs. Oddly, the Resource Adequacy study report says that "the small amount of battery capacity was counted at 80%"[40] capacity value for the 2024 base case. It is unclear why a small amount of storage would not receive a higher capacity credit based on Duke's results shown in Table 1.

Table 1 suggests that storage would be more valuable if it was strategically poised to deal with LOL events. Storage should not be dedicated to contingency reserves 8760 hours a year. Instead make sure all storage (stand-alone and solar coupled) is fully charged on extremely cold January mornings. Note that there is 0% LOL from noon to 3am on January days so there is ample time to forecast extreme cold and ample resources available to charge storage from conventional generation if solar is unavailable.

[37] The Storage ELCC Study points out that computational requirements are high for this type of production cost simulation modeling. See "the number of iterations and run times are extensive."
[38] Storage ELCC Study at 8.
[39] Storage ELCC Study at 7.
[40] DEC RA Study at 44.

### Additional Strategies to Consider

It is not clear if Duke considered curtailing storage charging as a reliability reserve. Storage could go from full charging to full discharging, potentially doubling its reserve capacity, to supply contingency reserves. This would require sufficient inverter and transformer capacity. Use of this capability only during rare system emergencies would not increase battery cycling significantly.

#### *DSM*

DSM can be an ideal resource for dealing with rare, easily forecast, high-value, extreme events. Unfortunately, Duke's DSM efforts, both within the IRP and more generally, exclude consideration of these events and, consequently, find that DSM has little value in mitigating them.

Duke's DSM studies'[41] conclusions about the limited amounts and types of DSM resources that are economically viable are not applicable to the IRP because the data, conditions, and assumptions used in the DSM studies are different than the data, conditions, and assumptions that drive the IRP reserve requirements and low solar capacity value. More specifically, the high IRP reserve requirements result from including rare extreme winter weather conditions in the IRP's statistical weather modeling that are not reflected in the simple 25-year load forecast used for the DSM analysis. Had the DSM studies used the same data, conditions, and assumptions as the IRP study Duke likely would have found a much larger DSM resource composed of different resources to be viable, reducing the extreme winter peak reserve requirement and increasing the capacity value of solar generation.

The EE and DSM Market Potential Study states "The primary data source used to determine when DSM resources will be needed was the DEC system load forecast. This forecast contains forecasted loads for all 8,760 hours of each year in the study period (2020-2044)." "First and foremost, **forecasted loads shapes are relatively unchanged over time** as the total magnitude of projected load increases. In addition, the summer loads have a similar maximum to winter loads. Thus the potential study focuses on the current summer peak hour, 4-5 pm, and the current winter peak hour, 7-8 am."[42] The study also notes that "overall **DEC's peak is expected to become slightly less concentrated over time**, and so resources such as DSM will have to be dispatched for a larger number of hours to provide the same benefit that they do now."[43] Finally, the DSM

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[41] The DSM Market Potential Study included in the IRP (Attachment V) as well as the 12/2020 Winter Peak Demand Reduction Potential Assessment / Winter Peak Analysis and Solution Set / Winter Peak Target DSM Plan.

[42] *Emphasis added*, DEC IRP Report, Attachment V – Duke Energy EE and DSM Market Potential Study, pp. 27-28 (Nov. 6, 2020) ("EE and DSM Market Potential Study").

[43] *Emphasis added*, EE and DSM Market Potential Study at 29.

study notes that "[t]he results in Figure 3-16 show the **highest hours of usage are concentrated in summer evening hours** … winter peaks can still be of concern."[44]

Figure 3-16: Forecasted Patterns in DEC System Load (2020 vs 2044)

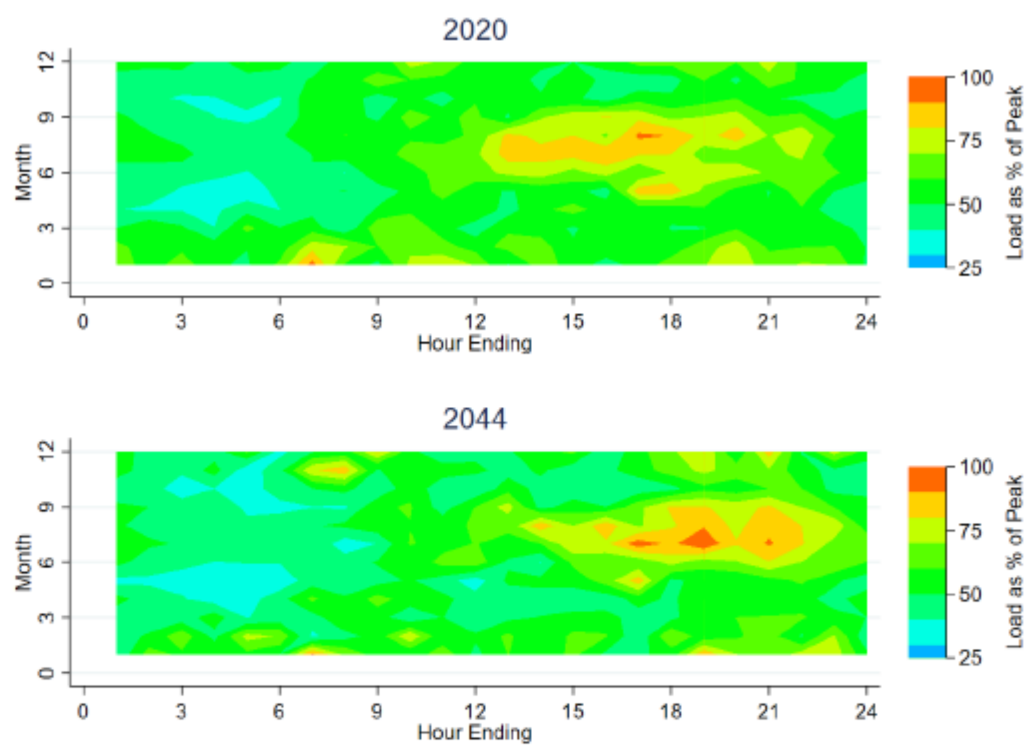


*Figure 9: Integrated Resource Plan, Attachment V, Duke Energy EE and DSM Market Potential Study, Figure 3-16*

The extreme winter morning loads that Duke says drive the capacity need and low solar capacity value are hardly discernable in Duke's Figure 3-16 (Figure 9 of these comments).

Duke's Winter Peak Demand Reduction Potential Assessment (December 2020) is an improvement, but it still is based on typical expected conditions rather than addressing the rare extreme winter conditions that drive the IRP capacity needs.

The IRP/RA solar capacity credit analysis and the DSM design/evaluation analyses should use the same data, conditions, and assumptions.

## More Appropriate DSM

Duke's DSM analysis has largely found that only a limited amount of residential DSM will be economic. Duke finds the commercial and industrial DSM potential to be very limited. This is

[44] *Emphasis added*, EE and DSM Market Potential Study at 29.

likely because the DSM effort failed to focus on conditions that limit renewables value: easy-to-forecast, rare, extreme winter weather conditions.

The IRP notes that the extreme winter peaks are short (a few hours), at known times (morning), and easily forecast hours or days ahead. There is time for loads to prepare for the event (pre-heat, for example, or take manual actions to interrupt processes). Duke notes that the short duration also means that there is ample generation capacity available both before and after the event: the rebound is not a concern. All three factors (known times/lots of warning, short duration, lots of capacity before so loads can prepare and lots of capacity after so rebound is not a problem) make DSM an ideal candidate to address the winter peak.

Duke notes that residential loads dominate the winter peak while C&I loads are relatively flat and do not rise at the winter peak time (Figure 10).[45] Duke concludes that residential DSM is a better opportunity. This makes sense for addressing the regularly occurring winter peak, and we encourage Duke to continue, but it misses the point for solar integration.

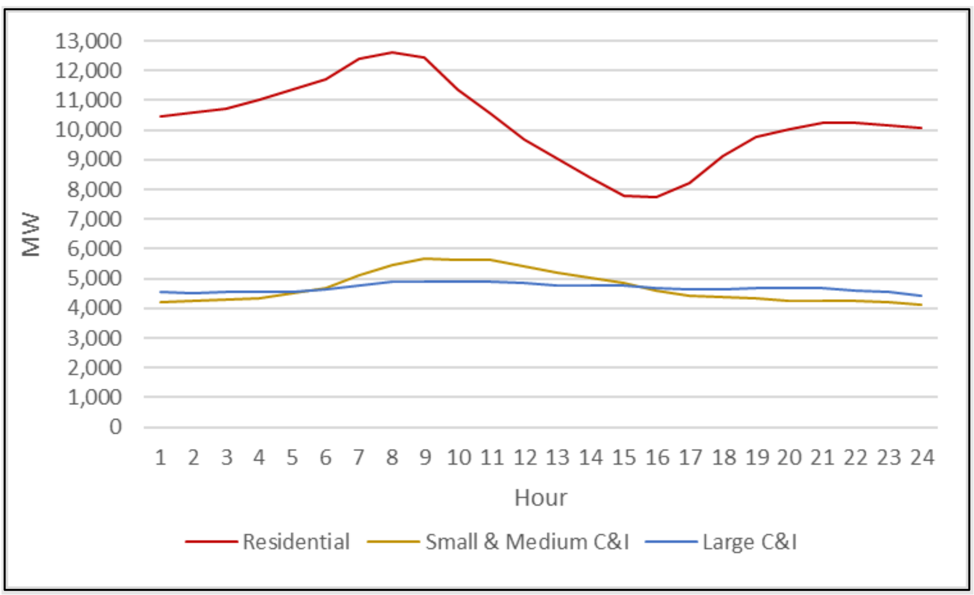


*Figure 10: Duke Energy Winter Peak Analysis and Solution Set: Figure 2. Overlay of Demand Profile by Market Segment – Study Peak Day*

Duke misses addressing the rare extreme events that drive reliability and reserve requirements in the IRP. The Duke DSM program is focused on regular, relatively frequent response to daily winter peaks, mostly from residential loads. Duke should also address the rare, extreme peaks, if these are an actual reliability concern. Easily forecast events makes this easier. Duke should seek

[45] Winter Peak Analysis and Solution Set.

response that can be available on rare occasions with ample (hours) notice. Given the rarity of the events response payments for the individual event ($/MWH paid for performance) can be quite high and still have an overall low-cost program. Large C&I loads are likely a better resource for this type of event. Automated response may not be required for a once-in-a-decade response. As Figure 10 shows, there is significant C&I load available for potential response during the winter morning peak.

### Wrong Incentives for Rare Events

Duke's DSM programs largely provide continuous capacity payments in exchange for the right to curtail consumption. This is appropriate when addressing routine peak loads. For rare extreme peaks it is more appropriate to pay for performance. Duke could offer, for example, $10,000/MWH for rare demand reductions at lower overall cost than installing CTs. With conventional DSM programs the load is accepting the continuous payment and hoping that the interruption does not occur. Penalties are the only incentive to actually provide response and even then, it will be minimal response. With pay for performance the incentive is reversed and the load is hoping to be called. The greater the response the greater the payment. Unfortunately, Duke defines away the most promising DSM resource by labeling it as "voluntary" and providing no capacity credit. Consequently, Duke finds essentially no resource potential.

### Additional Residential DSM Opportunities

The Winter Peak Targeted DSM Plan report states that "71% of all hot water heating systems are electric, and hot water heating represents about ***10% of electric home demand during peak load periods*** where appliances and heat pumps are also operating coincident with the water heater."[46] Water heaters alone would then provide a potential 1,200 MW extreme winter peak DSM, based on Duke's profile presented in Figure 10. The Winter Peak Targeted DSM Plan discusses water heaters, but in the cost/benefit context of reducing the normal winter peaks. Fuller utilization of the DSM capabilities might be accepted as an emergency measure for rare, extreme weather events.

## *Electric Vehicles – Duke Turns A Resource into a Problem*

The IRP views EVs as contributing to winter morning peaks, rather than considering the possibility of utilizing them for winter morning supply (Figure 11).[47]

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[46] *Emphasis added*, Winter Peak Targeted DSM Plan at 3.
[47] DEC IRP Report, Appendix C - Load Forecast, pp. 232 (Nov. 6, 2020).

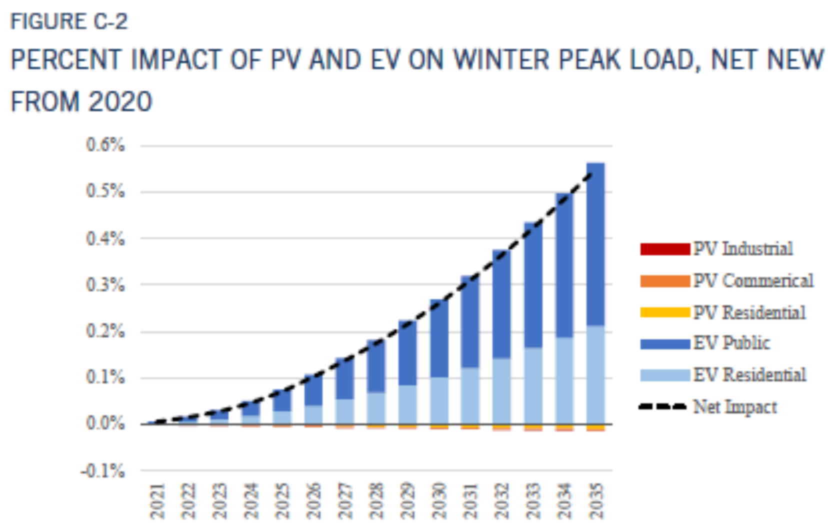


*Figure 11: The IRP views EVs as a winter peak problem rather than a resource.*

The Duke Energy Winter Peak Targeted DSM Plan states that "[a]s outlined in the winter peak characterization assessment, the load profile of EV charging for light vehicles at workplace charging stations typically experiences peak demand from 8-10am. This emerging energy demand is coincident with Duke's overall winter system peaks, that occur, on average, between the hours ending 8 and 9. Current EV load forecast data provided by Duke estimates approximately 100 MW of coincident peak demand at hour 9 by 2030."[48] Figure 12 shows the expected EV charging profile. Given that this is a new load that is yet to be designed or installed it would seem to be relatively easy to build in incentives and controls to delay the start of commercial EV charging until after the peak system load on extreme weather days.

[48] Winter Peak Targeted DSM Plan at 82.

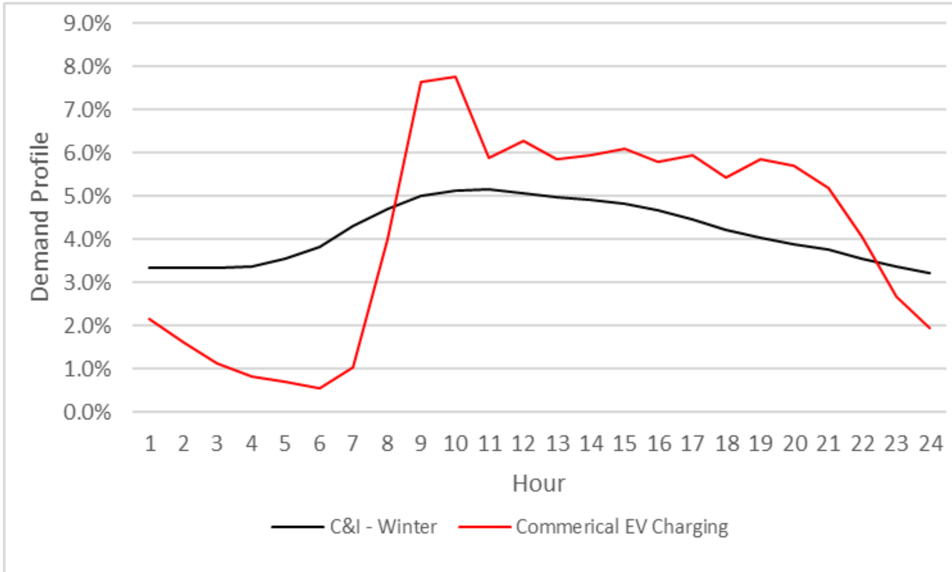


*Figure 12: Winter Peak Targeted DSM Plan: Figure 7. Comparison of C&I and Commercial Workplace Charging Winter Peak Demand Profiles*

Given the rarity and emergency nature of extreme winter peaks it is possible that EVs could provide additional benefits with vehicle-to-grid (V2G) support for the power system.

It is also not clear why residential EV charging should be adding so significantly to the early morning winter peak load (Figure 11). One would think that residential EVs would be done charging by 6am and ready for the morning commute. If residential EV charging is just starting in the early morning it could be delayed to reduce the extreme winter peak, similar to commercial EV charging.

### *Recommendations*

The Commission should direct Duke to use the same load and weather data in all of the analysis to assure consistency of results: IRP, RA, DSM, Storage.

The Commission should direct Duke to design DSM and storage programs to meet the needs identified in the IRP and RA Studies.

The Commission should direct Duke to develop an EV rate structure that incentivizes off-peak charging and an extra rate incentive to avoid charging during the extreme winter peak hours.

## Inadequate Regional Interconnection Modeling

Duke continues to include modeling results for operating DEC and DEP as islands. This is irrelevant and potentially misleading. DEC and DEP are imbedded in the Eastern Interconnection and never operate as islanded power systems. Duke's modeling of joint DEC and DEP operations is a bit better, but even this is irrelevant, again because DEC and DEP are part of the Eastern Interconnection and should always be modeled as such. When Duke did model DEC and DEP as interconnected, they only modeled neighbors that are one tie away (Figure 13).[49] This is overly conservative and ignores the reliability and economic benefits Duke continuously inherently receives through interconnected operations.

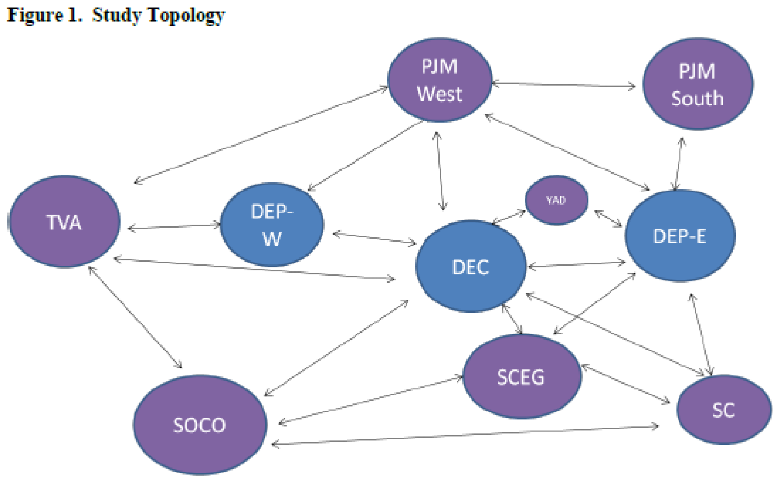


*Figure 13: RA Study Figure 1 shows the modeled limited interconnection topology.*

Duke elected to use a 17% reserve margin in the 2020 Integrated Resource Plan (IRP). The 17% value was derived by averaging results for DEC (16.5%) and DEP (17.5%) presented in their respective 2020 Resource Adequacy Studies. Most importantly, the 16.5%, 17.5%, and combined 17% reserve margins are ***not*** the values calculated to meet a one day in 10-year Loss of Load Expectation (LOLE of 0.1).

Astrape calculated reserve requirements to meet a 0.1 LOLE *with limited interconnection support* as 16% for DEC, 19.25% for DEP, and 16.75% for combined DEC/DEP. If a strict *physical* 0.1 LOLE limit is required, then realistic interconnection support should be included. Unfortunately, the reserve requirements for a 0.1 LOLE with reasonable interconnection support have not been calculated.

### *Comparisons With PJM and MISO Are Disingenuous*

The RA report states that “Astrapé believes Duke Energy has taken a moderate to aggressive approach (i.e. taking significant credit for neighboring regions) to modeling neighboring assistance compared to other surrounding entities such as PJM Interconnection L.L.C. (PJM) and the Midcontinent Independent System Operator (MISO).”[50] This is misleading at best.

[49] DEC RA Study.
[50] DEC RA Study at 7.

The RA study does show the benefits of interconnected operations, but it does not reflect the full benefits DEC and DEP actually receive from the interconnection. Treating DEC and DEP as physical islands in the RA study resulted in 22.5% (DEC) and 25.5% (DEP) reserve requirements. Astrape then modeled support from utilities *one tie away*. This is extremely limited support considering Duke is imbedded in the massive Eastern Interconnection. Duke justifies limiting interconnection support by noting that PJM and MISO limit market assistance from outside their regions in their RA analysis. This is disingenuous. PJM aggregates generation and load over 12 states and has a peak load of 151,000 MW. MISO spans 15 states (and one Canadian province) with a peak load of 127,000 MW. PJM and MISO internally incorporate massive interconnection support and yet they still assume help is available from their neighbors. PJM and MISO each aggregate nearly as much generation and load as all of SERC, which now extends to west of the Mississippi. To be comparable to PJM and MISO analysis, Duke should assume interconnection support availability from the entire Southeast Energy Exchange Market (SEEM) footprint.

The IRP/RA Study approach to modeling interconnected operations is also at odds with the increasing regional benefits experienced by the rest of the country and Duke's own promotion of the Southeast Energy Exchange Market. An Energy Imbalance Market (EIM) is long overdue in the Southeast, the last region in North America without an EIM, RTO, or ISO. Contingency reserves are already aggregated through a reserve sharing pool. Balancing under normal (non-contingency) conditions should also be modeled assuming greater regional diversity.

### *Transmission is a Valuable but Lumpy Asset*

Transmission exhibits strong benefits of scale. This is unfortunate from a regulatory and planning perspective. Figure 14 shows that higher voltage transmission lines are both lower cost (red) and take up less land for right of way (green). A 765 kV line costs just 24% and requires only 12% as much land as a set of 230 kV lines to transfer the same amount of power. Unfortunately, the minimum capacity of a 765 kV line is 17 times that of a 230 kV line. Consequently, incrementally adding just enough transmission capacity just as it is needed tends to be the most expensive solution, both in terms of dollars and land. It tends to ultimately be much lower cost to build as much transmission initially as you are going to ultimately need.

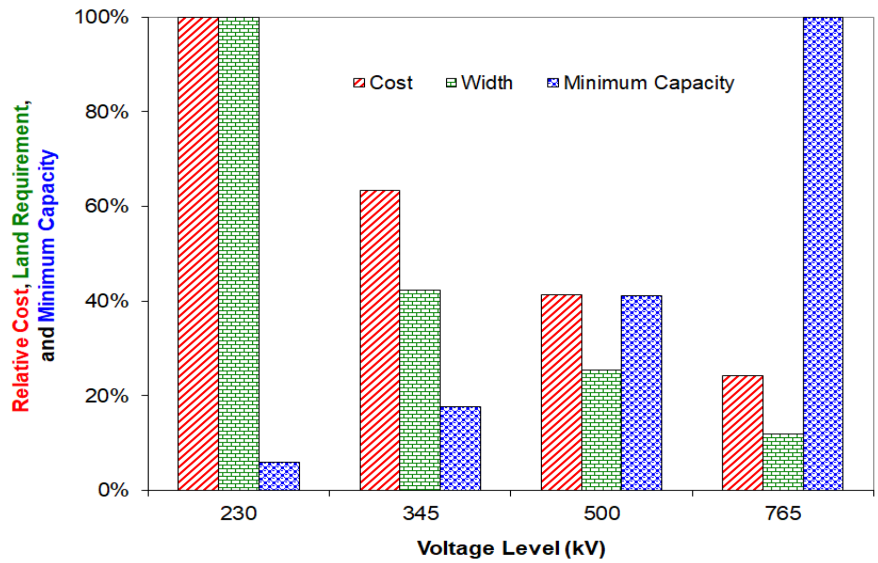


*Figure 14: Transmission shows strong economies of scale for both cost and land requirements.*

## Recommendations

The Commission should direct Duke to recognize that DEC and DEP operate within the Eastern Interconnection. Modeling should fully represent the opportunities for reliability support and economic exchanges that the interconnection provides. Duke should also be directed to expand efforts to coordinate regionally, both operationally and for transmission expansion. More specifically, Mr. Caspary recommends that the Commission direct Duke to improve future IRPs by including:

- the economies of scale with bulk transmission upgrades to enable better integration of its Carolina operating companies, as well as integration of large-scale renewable developments, specifically off-shore wind resources;
- the results of improved collaborative planning efforts with neighboring systems such as the ongoing North Carolina Transmission Planning Collaborative ("NCTPC") study with scenarios from the Southeast Wind Coalition that are in process;
- better asset management planning practices to inform planning decisions regarding long range transmission expansion needs to leverage existing corridors; and
- more rigor in analysis and assumptions regarding projects and costs to support future resource needs, in particular imports and off-shore wind developments that may be best addressed in partnership with neighboring systems.

## Duke's "Economic Reliability Results" Miss the Critical Point

The RA study includes an analysis of economically determined reserve margins to supplement the analysis that (incorrectly) forces a 0.1 LOLE regardless of cost.[51] Duke's idea is that if the value of Expected Unserved Energy (EUE) (customer curtailment) can be quantified then a reserve margin that minimizes overall customer costs can be calculated. It may be that the cost of holding enough reserves to always guarantee a 0.1 LOLE exceeds the value and wastes customer's money. This is a reasonable approach that reflects the true reliability impacts on customers. Unfortunately, Duke distorted this analysis as discussed below.

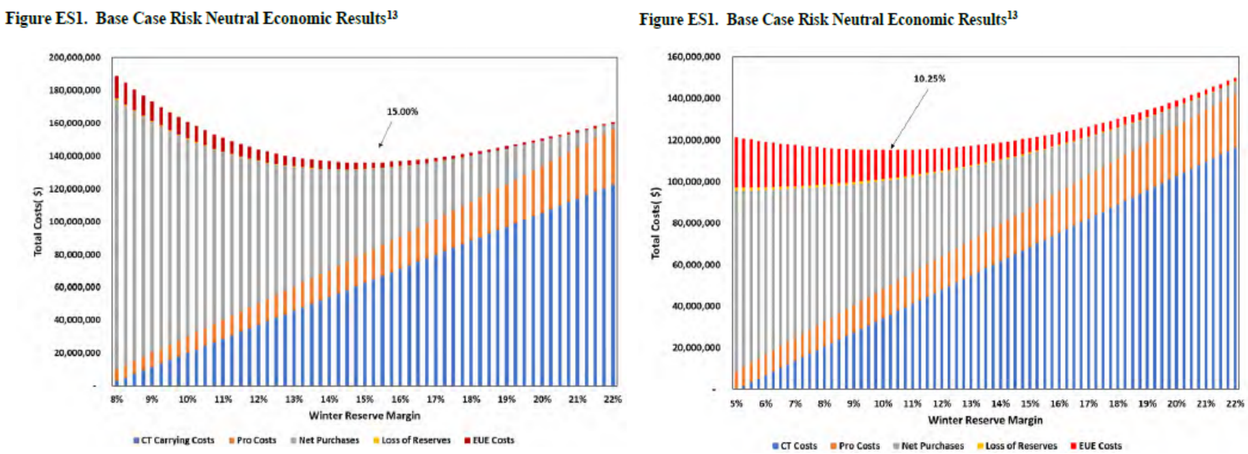


*Figure 15: Economic Reserve Requirements for DEC (left) and DEP (right)*

Figure 15 shows that DEC reserves of 15% and DEP reserves of 10.25% result in the lowest cost for customers based on analysis of all weather years, load forecast uncertainty, and unit performance. Unfortunately, Astrape did not perform a similar analysis for DEC and DEP combined. Nor did they perform the analysis with reasonable assumptions for interconnection support.

DEC RA Study, pp. 11-18.

Rather than simply use these least-cost results Duke and Astrape decided reserves should be increased in order to reduce the chance that reserve costs would be higher in a few rare weather years. They speculate that customers would prefer to pay guaranteed higher costs for additional reserves every year to avoid some chance of higher operating costs in a few rare years. Figure 16 shows the reserve levels that would limit higher cost risks 5%, 10%, and 15% of the time (95th 90th and 85th percentiles).[52]

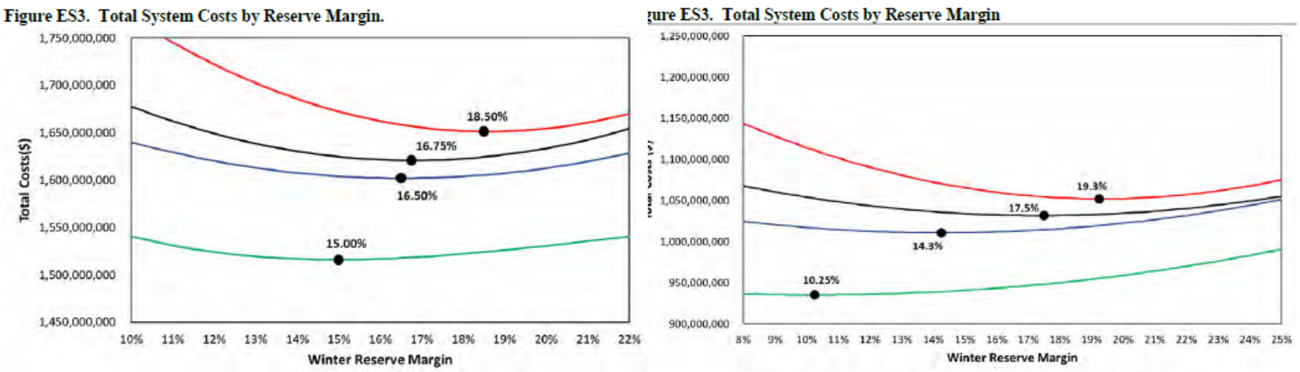


*Figure 16 Limiting high reserve cost risk through higher reserve margins for DEC (left) and DEP (right)*

Astrape concluded that DEC customers would prefer to pay $1.85 million more every year to reduce the 15% chance of higher reserve costs of $14.7 million in rare years by increasing reserves from 15% to 16.5%. Astrape concluded that DEP customers would prefer to pay $13.1 million more every year to reduce the 10% chance of higher reserve costs of $70.35 million in rare years by increasing reserves from 10.25% to 17.5%.

Said differently, Astrape recommends that Duke customers pay $15 million more every year for increased reserves as an insurance policy against possible higher costs in a few years. Note that there is no consistency between the percentile risk reduction or dollar risks when selecting the increased reserves to recommend. Also note that realistic interconnection support, which reduces the risk of higher costs, was not considered.

### *More Than Economic Consequences*

Duke and Astrape note in the RA studies that the customer cost curves shown in Figures 15 and 16 are relatively flat as reserve margins are increased. The implication is that the reserve margin can be increased with little consequence and that a higher reserve margin is therefore wiser: the insurance policy against high costs in some years is relatively cheap.

This misses a critical point. While total customer cost may be relatively insensitive to the required reserve margin the selected generation mix is likely not. Requiring higher reserves not only increases customer costs, it also likely shifts the selected optimal generation mix away from solar, wind, storage, and demand response and to fossil fuel fired generation. Customers are being

[52] DEC RA Study at 53.

asked to pay more to receive reduced environmental benefits with the justification being that customers are not being asked to pay a lot more for the lost benefits.

### *Recommendations*

The Commission should direct Duke to set reserve requirements on a risk neutral economic basis rather than forcing a 0.1 LOLE regardless of cost.

## Conclusions

As shown above, Duke has embedded a number of serious flaws into its IRP and RA studies and modeling so that they do not reflect reality. These flaws have the effect of decreasing the capacity contribution—and therefore increasing the modeled cost—of solar and storage resources. I have made several recommendations that I respectfully urge the Commission to consider.

### *Treat Extreme Weather Events Appropriately*

The Commission should direct Duke to reduce the probability of 1980's extreme cold events in the synthetic load derivation to once in a century (a factor of 2.5) to reflect the lowering likelihood of extreme cold events in all of the analysis: IRP, RA, DSM, Storage, to assure that resources are aligned with need and are consistently valued.

### *Appropriately Synthesize Load for Modeling*

The synthetic load model should be retrained and recalibrated. Recalibration should include holding back some actual load data from the model training so that the model can be verified with actual temperature and load data that the model has not been exposed to during training. Having an additional two years of historic load data should help improve the load model accuracy.

### *Only Use Solar Generation Data That Is Truly Time Synchronized with Load*

The Commission should direct Duke to rerun the Resource Adequacy Study, Solar Capacity Value Study, and IRP analysis based on the years 1998 through 2020 for which time-synchronized hourly locational NSRDB solar data is available.

### *Design DSM, EV, and Storage Programs to Meet the IRP and RA Needs*

The Commission should direct Duke to design DSM and storage programs to meet the needs identified in the IRP and RA Studies.

The Commission should direct Duke to develop an EV rate structure that incentivizes off-peak charging and an extra rate incentive to avoid charging during the extreme winter peak hours.

*Recognize the Reliability and Economic Value of Interconnection and Transmission*

The Commission should direct Duke to recognize that DEC and DEP operate within the Eastern Interconnection. Modeling should fully represent the opportunities for reliability support and economic exchanges that the interconnection provides. Duke should also be directed to expand efforts to coordinate regionally, both operationally and for transmission expansion. More specifically, Mr. Caspary recommends that the Commission direct Duke to improve future IRPs by including:

1. the economies of scale with bulk transmission upgrades to enable better integration of its Carolina operating companies, as well as integration of large-scale renewable developments, specifically off-shore wind resources;
2. the results of improved collaborative planning efforts with neighboring systems such as the ongoing North Carolina Transmission Planning Collaborative ("NCTPC") study with scenarios from the Southeast Wind Coalition that are in process;
3. better asset management planning practices to inform planning decisions regarding long-range transmission expansion needs to leverage existing corridors; and
4. more rigor in analysis and assumptions regarding projects and costs to support future resource needs, in particular imports and off-shore wind developments that may be best addressed in partnership with neighboring systems.

*Use Duke's Economic Reliability Results*

The Commission should direct Duke to set reserve requirements on a risk neutral economic basis rather than forcing a 0.1 LOLE.

Curriculum Vitae

# Brendan Kirby

(865) 250-0753 KIRBYBJ@IEEE.ORG WWW.CONSULTKIRBY.COM

Professional Experience:

2008-Present: **Consulting**, Consulting privately with numerous clients including the Florida Power and Light, NextEra, Hawaii PUC, National Renewable Energy Laboratory, ESIG, AWEA, Oak Ridge National Laboratory, EPRI, and others. He served on the NERC Standards Committee. He has 44 years of electric utility experience and has published over 180 papers, articles, and reports on ancillary services, wind integration, restructuring, the use of responsive load as a bulk system reliability resource, and power system reliability. He coauthored a pro bono amicus brief cited by the Supreme Court in their January 2016 ruling confirming FERC demand response authority. He has a patent for responsive loads providing real-power regulation and is the author of a NERC certified course on Introduction to Bulk Power Systems: Physics / Economics / Regulatory Policy.

1994-2008: **Sr. Researcher,** Power Systems Research Program, Oak Ridge National Laboratory. Research interests included electric industry restructuring, unbundling of ancillary services, wind integration, distributed resources, demand side response, energy storage, renewable resources, advanced analysis techniques, and power system security. In addition to the research topics listed above activities included: NYISO Environmental Advisory Council, assignment to FERC Technical Staff to support reliability efforts including NERC/FERC reliability readiness audits, Technical Advisory Committee for the 2006 Minnesota Wind Integration Study, DOE Investigation Team for the 2003 Blackout, the IEEE SCC 21 Distributed Generation Interconnection Standard working group, DOE National Transmission Grid Study, staff to the DOE Task Force on Electric System Reliability, and NERC IOS Working Group. Conducted research projects concerning restructuring for the NRC, DOE, EEI, numerous utilities, state regulators, and EPRI.

**Consulting**, Consulted privately with utilities, renewable generators, AWEA, ISO/RTOs, IPPs, loads, interest groups, regulators, manufacturers and others on power system reliability, ancillary services, responsive load, wind integration, electric utility restructuring and other issues. Testified as an expert witness in FERC and state litigation.

1991 to 1994: **Power Analysis Department Head,** Technical Analysis and Operations Division. Primary responsibility was to support the Department of Energy in the management of 7000 MW of uranium enrichment capacity. The most significant feature of this load was that 2000 MW were procured on the spot energy market from multiple suppliers requiring rapid response to changing market conditions. Support included technical support for power contract negotiations, development of the real-time energy management strategy, managing the development of a computer based operator assistant to aid in making real-time power purchase decisions. Conducted computer based simulations of the loads and the interconnected network which supplies them. Simulations included large scale load flows, short circuit studies, and transient stability studies. They also included extensive specialized modeling for analysis of electrical, mechanical, and thermal performance under balanced and unbalanced conditions. Responsible for maintaining close ties with technical personnel from the various utilities which supplied power to the diffusion complex to exchange data and perform joint studies.

Provided consultation services on a large range of power system concerns including: cogeneration opportunities, power supply for the Lawrence Livermore National Laboratory Mirror Fusion Test Facility, capacity at EURODIF, power supply for the Strategic Petroleum Reserve, power supply for large pulsed fusion loads, and wheeling.

1985 to 1991: **Electric Power Planning Section Head,** Enrichment Technical Operations Division with substantially the same responsibilities as stated above.

1977 to 1985: **Technical Computing Specialist,** Electrical Engineering and Small Computing Section, Computing and Telecommunications Division. Time was evenly divided between power system studies as described above and minicomputer work. The minicomputer work supported laboratory data collection and experiment control.

1975 to 1976: **Engineer,** Electrical Engineering Department, Long Island Lighting Company, Hicksville, New York. Responsible for electrostatic and magnetic field strength modeling as well as sound level testing and analysis.

<u>Education:</u>

1977 - M.S.E.E., power option, Carnegie-Mellon University, Pittsburgh, Pa.
Worked under a Department of Transportation contract studying more efficient means of energy use in rail systems.

1975 - B.S.E.E., Lehigh University, Bethlehem, Pa., cum laude, Eta Kappa Nu, the Electrical Engineering Honorary, and Phi Eta Sigma, the freshman Honorary.

<u>Professional Affiliations and Awards:</u>

- Licensed professional engineer
- Patent 7,536,240: Real Power Regulation For The Utility Power Grid Via Responsive Load
- 1985, 1986, 1987, 1990, and 1992 Awards for power system related work
- Life Senior Member of the IEEE
- Former DOE Q clearance

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**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION**
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| **In the Matter of:** | ) |
| **2020 Biennial Integrated Resource** | ) |
| **Plans and Related 2020 REPS** | ) |
| **Compliance Plans** | ) |
| | ) |

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**INITIAL COMMENTS OF NCSEA AND CCEBA ON DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC'S INTEGRATED RESOURCE PLANS**

**EXHIBIT 2**

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# Review of Duke's 2020 Integrated Resource Plan

Prepared for Cypress Creek Renewables

January 2021

Energy+Environmental Economics

# Review of Duke's 2020 Integrated Resource Plan

January 2021



Energy and Environmental Economics, Inc.
44 Montgomery Street, Suite 1500
San Francisco, CA 94104
415.391.5100
www.ethree.com

**Project Team:**
Arne Olson
Zachary Ming
Stuart Mueller
Louis Linden
Robbie Shaw

# Table of Contents

# Acronyms

| | |
|---|---|
| **DEC** | Duke Energy Carolinas |
| **DEP** | Duke Energy Progress |
| **ELCC** | Effective Load Carrying Capability |
| **ICAP** | Installed Capacity |
| **IRP** | Integrated Resource Planning |
| **LOLE** | Loss of Load Expectation |
| **PRM** | Planning Reserve Margin |
| **RECAP** | Renewable Energy Capacity Planning Model |
| **UCAP** | Unforced Capacity |

# 1 Executive Summary

This report was prepared by Energy and Environmental Economics, Inc. (E3) on behalf of Cypress Creek Renewables (CCR) and for use by the Carolinas Clean Energy Business Association (CCEBA) as a technical review of the 2020 Duke integrated resource plan (IRP). Although we address a larger number of topics in this report, our primary focus is on the capacity expansion methodology used by Duke and the ELCC values that were generated by Astrapé in its accompanying 2018 Solar Capacity Value Study.

Electric resource planning is the process of identifying longer-term investments to meet reliability and public policy objectives at the least cost.[1] Historically, IRP processes focused on the balance of dispatchable generation technologies that would meet baseload, seasonal and peaking requirements in a least-cost manner. The evolution of generation technologies and storage options in parallel with developing policy obligations has increased the complexity of IRP processes across North America and around the world. The 2020 Duke IRP is effective at addressing some of these challenges but falls short of best practice on others. This report will outline these areas and provide two primary recommendations for improvement.

## Capacity Expansion Modeling Review

The capacity expansion stage of an IRP is the focal point of balancing resource cost, policy and reliability to ensure a least-cost resource plan. It is this modeling stage in which all existing and future resource mix

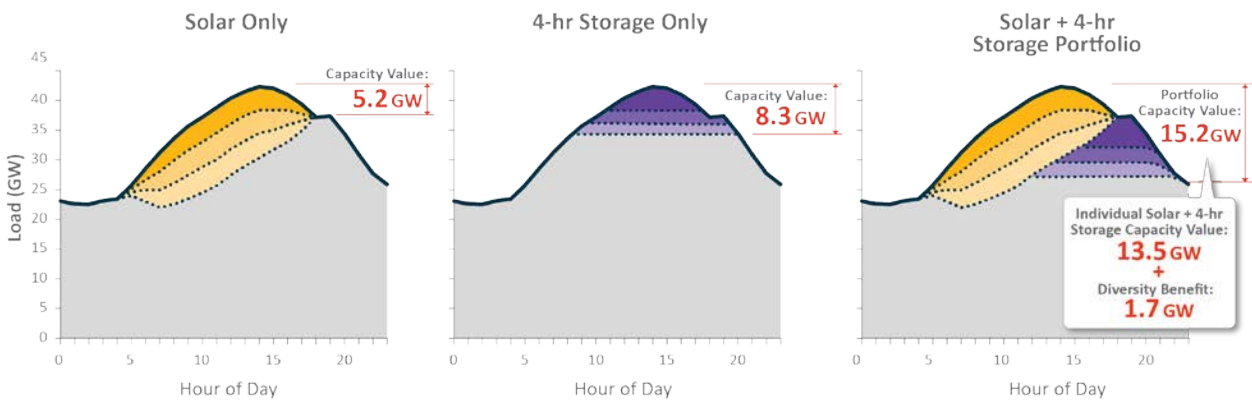
[1] Kahrl, Fredrich, Andrew Mills, Luke Lavin, Nancy Ryan and Arne Olson, *The Future of Electricity Resource Planning*, Report No. 6 of Lawrence Berkeley National Laboratory's series The Future of Electricity Regulation, September 2016

possibilities are investigated, constrained by policy, and a least-cost solution to meet reliability requirements and policy goals is achieved.

The Duke IRP uses a multi-step methodology for its capacity expansion in which battery storage is evaluated as a replacement option for combustion turbine generation based on a side-by-side comparison with the rest of the portfolio held constant. While this method can produce acceptable results for two resources with somewhat similar characteristics, it ignores the synergistic effects that exist between storage and other resources such as solar. When solar generation and battery storage are considered in tandem, their combined capacity contribution is greater than if the two resources are considered separately – i.e., the whole is greater than the sum of the parts. Duke's methodology fails to account for those combined benefits.

This phenomenon is illustrated in Figure 1, which shows an example in which solar alone has an effective capacity of 5.2 GW and storage alone contributes 8.3 GW. However, because batteries can soak up solar energy and use it for energy production at night, and because the presence of solar energy narrows the net peak, making it easier to serve with short duration batteries, the combined capacity contribution is 15.2 GW, 1.7 GW higher than the sum of standalone solar and standalone storage.

**Figure 1: Illustration of the Synergistic Effects of Solar and Storage**




Duke's capacity expansion methodology considers solar and storage independently, at different steps of the process, ignoring these synergistic benefits. As a result, the Duke IRP likely fails to identify a least-cost solution for its ratepayers.

## Effective Load Carrying Capability Review

A key input to the capacity expansion modeling phase on an IRP process is the assumed capacity contribution from each resource type. Duke should be commended for its use of Effective Load Carrying Capability (ELCC) metrics to determine the capacity credit for renewables and energy storage, in keeping with industry best practice. However, E3's review of the 2018 Astrapé Solar Capacity Value study reveals a number of implementation details that, taken together, appear to significantly and unreasonably diminish the capacity value of solar. Specifically, these are:

1. Duke improperly assumes that dispatchable resources do not suffer forced outages in its capacity expansion modeling, disadvantaging renewable resources.

2. The ELCC values of solar and storage are not dynamic with load growth on the system. As peak load grows, the ability of solar and battery storage to contribute also increases, which should be reflected in Duke's modeling.
3. Duke's use of outdated demand response assumptions reduces the capacity value of solar due to seasonal effects. The assumptions from Duke's Winter Demand Peak Reduction Potential Assessment should be used instead.
4. Duke's modeling of storage in "economic arbitrage" mode rather than "preserve reliability" mode diminishes the reliability value of both storage and solar.
5. Duke's assumption of fixed-tilt solar instead of tracking diminishes the capacity value of solar. Currently, nearly all the utility scale solar being built in the US is tracking solar which has improved ELCCs due to its ability to track the sun.

## Recommendations

The review of both the capacity expansion and the ELCC methodologies has revealed several assumptions and processes that are not aligned with a best-in-class IRP that delivers a reliable plan at least-cost while respecting policy constraints.

E3 provides the following recommendations:

+ Duke should adopt a single-step capacity expansion modeling methodology that co-optimizes all resources and policy constraints simultaneously. This is the only way to ensure that the synergistic properties of solar and storage be represented, and a true least-cost solution can be found.
+ Duke should correct its assumption that dispatchable resource do not suffer from forced outages by utilizing an unforced capacity (UCAP) planning reserve margin in capacity expansion modeling.
+ Duke should update its 2018 Solar Capacity Value Study to:
    - Include updated demand response assumptions,
    - Express ELCC values as a function of peak demand, rather than as static values,

- Model storage resources in “preserve reliability” mode rather than “economic arbitrage” mode in SERVM, and
- Assume all new utility scale solar to be built in the future uses single-axis tracking.

# 2 Overview

## 2.1 Purpose of Report

E3 was retained to perform a technical review of Duke Energy's integrated resource plan ("IRP"). The review focused on two primary areas: 1) the methodology used by Duke to develop optimal portfolios via capacity expansion modeling, and 2) the effective load carrying capability ("ELCC") results calculated by Astrapé Consulting to value the capacity contribution of solar and storage resources in the Duke portfolio. This report provides several recommendations to improve the overall optimal portfolio development methodology employed by Duke to align it with best practices in evaluating high renewable electricity systems. In addition, this report contains a detailed review of the methodology and input assumptions used in Astrapé Consulting's solar ELCC study. Finally, to quantify the impact of several of E3's modeling recommendations, E3 has used its own loss-of-load-probability model (RECAP) to calculate updated ELCC values for both solar and storage and compared them to the values in the Astrapé study.

## 2.2 Overview of E3

E3 is a leading economic consultancy focused on the energy industry, with an emphasis on electricity and the clean energy transition. For over 30 years, E3 has served as an independent, data-driven technical consultant that diverse stakeholders can trust to provide fair and unbiased analysis and strategic guidance. Over the last 15 years, E3 has engaged extensively in IRP processes across North America, working to develop future portfolios that balance cost, environmental objectives, reliability, and equity. E3 provides advisory services and energy systems modeling to investor-owned utilities, public power agencies, project developers, regulators, grid operators, government agencies, and public interest advocacy groups across North America.

## 2.3 Report Contents

The remainder of this report is organized as follows:

+ Section 3 provides an overview of IRP best practices and an assessment of Duke's approach focusing on resource adequacy;
+ Section 4 provides a critique of the solar and storage ELCC studies from Astrapé Consulting and alternative ELCC results from E3 that rectify several issues; and
+ Section 5 synthesizes all key findings with recommendations and actions that Duke could take to improve their IRP.

Additional detail on methods, inputs, and assumptions are summarized in the appendices attached to this report.

# 3 Integrated Resource Planning Review

## 3.1 Introduction

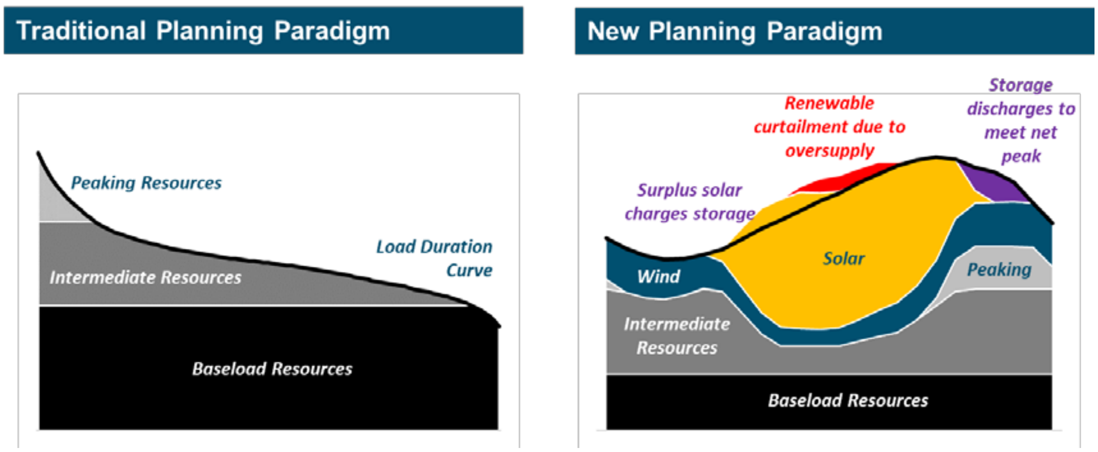
This section provides an overview of best practices in the execution of deeply decarbonized and high renewable IRPs with a special emphasis on capacity expansion modeling and optimization. It then reviews Duke's IRP in the context of these best practices. Finally, this section provides several recommendations for improvements to Duke's IRP and an evaluation of the impact these improvements would have.

## 3.2 IRP Best Practices

Integrated resource planning (IRP) is a long-established practice in the utility industry to evaluate different supply and demand measures while balancing multiple criteria including cost, reliability, the environment, and equity. Most models and evaluation processes used to perform this analysis were developed during an era when the generation technologies available to utility planners were much more limited than the options available today. Decisions often centered around which type of natural gas generator to invest in or whether a new coal or nuclear baseload unit was required.

The objectives of IRP today have evolved from years past and seek to not only minimize cost but also to meet emission reduction or renewable energy goals. Additionally, the types of resources available to planners have expanded greatly. Heuristics that used to provide a reasonable proxy within planning models no longer capture the economic, operational, and reliability complexities of today's resources. IRP must evolve to capture the uniqueness of these resources in order to credibly produce least-cost plans that satisfy both environmental and reliability criteria.

**Figure 2: Depiction of Changing Resource Planning Paradigms**




As the goals and tools available to integrated resource planners have evolved in recent years, best practices for IRP need to evolve as well. The traditional technologies used in electricity generation (dispatchable coal and natural gas generators) were simply matched with baseload, seasonal and peak load using fixed and variable cost. More recently, significant changes with respect to both policy and available generation technologies have necessitated the evolution of IRP processes. Specific examples of recent ongoing changes in the electricity sector include:

- Reduction in cost of alternative energy resources including wind, solar, and energy storage;
- Increasingly stringent policy goals to limit carbon emissions or increase renewable generation;
- Customer demand for more control over their energy decisions; and
- Technological advances in telemetry and metering that enable customers to engage more directly with their energy use.

Taking these new factors into account, a best-in-class IRP today must incorporate all of the following practices in order to ensure that the result is reliable and complies with policy requirements while identifying a least-cost portfolio for ratepayers:

## 1. Incorporate climate policy and the impacts of climate change

Climate change is affecting electric utilities in a variety of ways that can no longer be ignored. There are at least three ways in which climate change should be incorporated into integrated resource planning:

- **Physical risks:** Climate change is affecting the magnitude and duration of peak load events in increasingly measurable ways. IRPs should explicitly consider climate-induced changes in hourly load shapes, particularly during extreme hot or cold weather events. IRPs should also consider other physical risks such as higher forced outage rates and the potential for degrading asset performance due to higher winds during storm events, sea level rise, and others.

- **Direct carbon policy risks.** Climate policy will increasingly favor lower-emitting generating resources such as wind, solar, or nuclear relative to higher emitting resources such as coal or natural gas. Every utility in North America that owns or plans to own fossil resources faces significant regulatory risk related to GHG emissions that must be considered through an IRP process.

- **Higher electric loads.** Climate policy is already resulting in changes in electric load due to proliferation of electric vehicles, heat pumps, and other electrified technologies in many jurisdictions. Utility IRPs should include an assessment of the potential size, likelihood and timing of new sources of electric load.

## 2. Include renewable and energy storage resources as candidate resources

The capacity expansion stage of an IRP is the focal point of balancing resource cost, policy and reliability to ensure a least-cost resource plan. It is this modeling stage in which all existing and future resource mix possibilities are investigated, constrained by policy, and a least-cost solution to meet reliability requirements is achieved. IRPs should utilize a single-step capacity expansion modeling methodology that co-optimizes all resources and policy constraints simultaneously. This is the only way to ensure that the synergistic properties of renewables, energy storage and customer resources can be accurately quantified, and a true least-cost solution can be found.

- **Diversity benefits or synergistic effects.** Renewable and storage resources must be modeled in a way that incorporates storage's ability to shift non-dispatchable renewable energy to later in the day, not just simply accounting for the contribution of each resource individually.

- **Variability and weather correlations.** Load and generation profiles should capture meaningful fluctuations in the output of load, wind, and solar as well as correlations among them, to accurately capture renewable integration costs and anti-correlations between renewable output and peak load.

- **Operating reserves.** Portfolio modeling should consider the increased need for operating reserves and grid flexibility associated with higher penetrations of renewable resources.

- **Capacity contribution.** Portfolio modeling must capture synergistic dynamic interactions among and between renewable resources and storage with respect to their contribution toward meeting capacity needs.

### 3. Capacity need should be determined through robust loss of load probability (LOLP) modeling

Resource adequacy is an increasingly important topic as retirement of older, high-emitting resources accelerates and implementation of variable resources increases. Industry best practice related to resource adequacy includes:

- **Planning Reserve Margin established through Loss-of-Load Probability Modeling.** Robust LOLP modeling should be used to establish capacity needs based on a reliability standard of 1-day-in-10-years. The total need, which considers loads and resources during all hours of the year, can be translated into a Planning Reserve Margin (PRM) by dividing by the median peak load forecast and subtracting one.

- **Use of UCAP or PCAP for dispatchable resources.** Unforced capacity (UCAP) or perfect capacity (PCAP) should be used in PRM accounting. This ensures that the capacity accreditation of both dispatchable resources includes forced outage conditions that diminish performance during potential loss-of-load events.

- **Use of ELCC for dispatch-limited resources.** The capacity contribution of dispatch-limited resources such as solar, wind, energy storage and demand response should be evaluated using the Effective Load-Carrying Capability (ELCC) approach to accurately characterize their contribution toward reducing the frequency of loss-of-load events.

- **ELCC should capture interactive effects.** The LOLP modeling and ELCC calculations should capture both synergistic and antagonistic interactive effects of dispatch-limited resources.

**4. IRP should consider the total resource cost (TRC) benefits that can be provided by demand side resources**

There is increasing interest in distributed energy resources (DERs) due to technology improvement and electric customer's desires to control their energy bills. DERs offer advantages relative to supply-side resources due to their co-location with electric load, including reduced system losses, the potential to defer transmission or distribution system investments, and the ability to provide other services such as voltage control. At the same time, DERs may involve increased operational complexity and may require special arrangements to enable optimal dispatch based on system needs. Moreover, if compensation for DER services deviates from the utility's avoided costs, cost shifting may occur between customers with and without DERs. In order to accurately capture both the benefits and the complexities of incorporating increased DER penetration, IPRs should:

- **Consider the potential benefits of DERs using a Total Resource Cost perspective.** IRPs should consider potential benefits of customer resources including energy efficiency, demand response, and flexible loads using a Total Resource Cost (TRC) perspective that maximizes total ratepayer benefits.

- **Capture all benefits of DERs.** IRPs should capture all benefits from demand side resources including avoided transmission and distribution (T&D) infrastructure as well as avoided T&D energy losses in addition to avoided energy and capacity benefits.

- **Capture synergistic effects of DERs.** To the extent that DER penetration creates synergistic benefits with other resources such as customer storage and solar, DER penetration should be optimized alongside supply-side resources to ensure that the IRP identifies an optimal portfolio that maximizes ratepayer benefits. To the extent that synergistic effects are small, practical considerations may suggest that DERs be evaluated in a separate proceeding using an avoided cost methodology.

## 5. Operational flexibility needs should be addressed in a detailed operational study

Ensuring sufficient operational flexibility is an increasing source of concern for system planners as penetration of variable resources increases. Integration of variable resources requires increased levels of operating reserves to deal with variability and uncertainty, along with flexible resource to provide these services. At the same time, the value of flexibility is not infinite, and variable resources can themselves be a source of operational flexibility.[2] Operational flexibility is an important topic that should be considered in a detailed study of system operations.

- **Operational study should include operating reserves.** The operational study should include a detailed representation of operating reserve needs, which will likely increase as generation uncertainty from renewables compounds on historical load uncertainty and contingency requirements. The operating reserve needs should be calculated using advanced statistical measures that capture the full range of diversity among load, wind, and solar resources at different locations across the system.

- **Operational study should utilize time-series production simulation modeling.** Time-series modeling includes the impact of commitment decisions that must be made in advance, e.g., day-ahead, utilizing imperfect information about real-time dispatch conditions as well as an assessment of the headroom and footroom that would be required to accommodate real-time output variability.

## 6. Robust, transparent, stakeholder process

Given the increasing public policy-based interest in energy resources, a utility IRP should include a robust, transparent stakeholder process.

- **Process should seek out diverse perspectives.** IRP should incorporate opportunities for a diverse array of stakeholders to be meaningfully involved in the conception, execution, interpretation, and outcomes of the IRP process.

[2] Energy and Environmental Economics, Inc., *investigating the Economic Value of Flexible Solar Power Plant Operation*, October 2018, https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf

- **Process should include multiple rounds of stakeholder comment.** Stakeholders should be given an opportunity to comment on modeling methodologies, data inputs, draft results, and final results.

While E3 is not aware of any utility that is currently adhering to all of the six components of a best-in-class IRP listed above, we are aware of a number that incorporate components into their process.

+ Nova Scotia Power IRP uses a UCAP PRM with ELCC curves in capacity expansion modeling as well as a robust stakeholder engagement process.
+ Public Service Company of New Mexico (PNM) uses a capacity expansion model that co-optimizes solar and storage using ELCC curves in addition to a stakeholder process, climate change policy objectives, and a UCAP PRM accounting convention.
+ CPUC IRP captures declining solar and storage capacity contributions and incorporates the climate policy and the impacts of climate change.

## 3.3 Specific Subjects for E3's Review of Duke's IRP

E3's scope of work was limited to reviewing select aspects of the Duke IRP, namely the ELCC of solar and storage resources as well as the methodology to develop optimal portfolios. The following sections provide greater detail on IRP best practices for these two components and a contrast with the approaches used by Duke. E3 was not retained to evaluate the Duke IRP on any other criteria and as such information regarding additional topics is not included in this report.

### 3.3.1 RELIABILITY PLANNING

Central to integrated resource planning is ensuring that the electric system is reliable for its customers. The standard approach to ensuring reliability is to establish the quantity of generating capacity needed to ensure a given reliability level, usually targeted to be one outage every ten years. This quantity of capacity is characterized through a planning reserve margin (PRM) that specifies the level of generating capacity required in excess of peak demand.

There are two types of PRM accounting: (1) installed capacity PRM (“ICAP PRM”) defined as the level of nameplate capacity needed to meet a reliability level and (2) unforced capacity PRM (“UCAP PRM”) which defines the amount of de-rated capacity – nameplate capacity that has been reduced to account for outages – required to meet a reliability level.[3] ICAP or UCAP PRM are simply accounting conventions, so each can accurately quantify the required reserve margin to meet a reliability threshold. However, a UCAP PRM that accounts for the requirement in terms of de-rated capacity is more straightforward to use when the system has growing levels of renewable generation and energy storage.

In the past, PRM accounting (ICAP or UCAP) has been relatively simple because most generating capacity has been “firm” – available at full capacity except in the unplanned outages. However, with the unprecedented growth of non-firm capacity, namely renewables, the nature of reliability is changing. As the level of renewables increases, reliability challenges will be driven more and more by lack of wind or sun as opposed to peak load hours. As discussed in Section 4.1.1, below, using UCAP rather than ICAP ensures that non-firm capacity and firm capacity are compared on a level playing field.

A wide range of approaches and conventions has been used to incorporate these “non-firm” resources into resource adequacy programs. Increasingly, the industry has turned to effective load carrying capability (ELCC) as the preferred method for measuring the resource adequacy contribution of intermittent or dispatch-limited resources. ELCC, typically denoted in MW, is defined as the equivalent amount of “perfect capacity” that could be replaced with a specified resource while maintaining the same

[3] For example, a system which requires 1,150 MW of installed firm capacity serving a peak load of 1,000 MW represents an ICAP PRM of 150 MW or 15%. Assuming a forced outage rate of 5%, this same system’s UCAP PRM would be 1,150 MW x (1 – 5%) – 1,000 MW = 93 MW or 9.3%. Whether measured using ICAP or UCAP, the system has the same reliability level and the same capacity need.

level of reliability. ELCC is derived directly from the loss-of-load probability modeling that system planners have long utilized to determine the PRM.

The ELCC of a resource depends not only on the characteristics of load in a specific area (i.e. how coincident its production is with load) but also upon the resource mix of the existing system (i.e. how it interacts with other resources). For instance, ELCCs for variable renewable resources are generally found to be higher on systems with large amounts of inherent storage capability (e.g. large hydro systems) than on systems that rely predominantly on thermal resources and have limited storage capability. ELCCs for a specific type of resource are also a function of the penetration of that resource type; in general, most resources exhibit declining capacity value with increasing scale. This is generally a result of the fact that continued addition of a single resource or technology will lead to saturation when that resource is available and will shift reliability events towards periods when that resource is not available. The diminishing impact of increasing solar generation as the net peak shifts to the evening illustrates this effect. This effect is further described in Section 3.3.2 outlining the interaction between the nature and shape of demand on a system and the ability of resources to meet them.

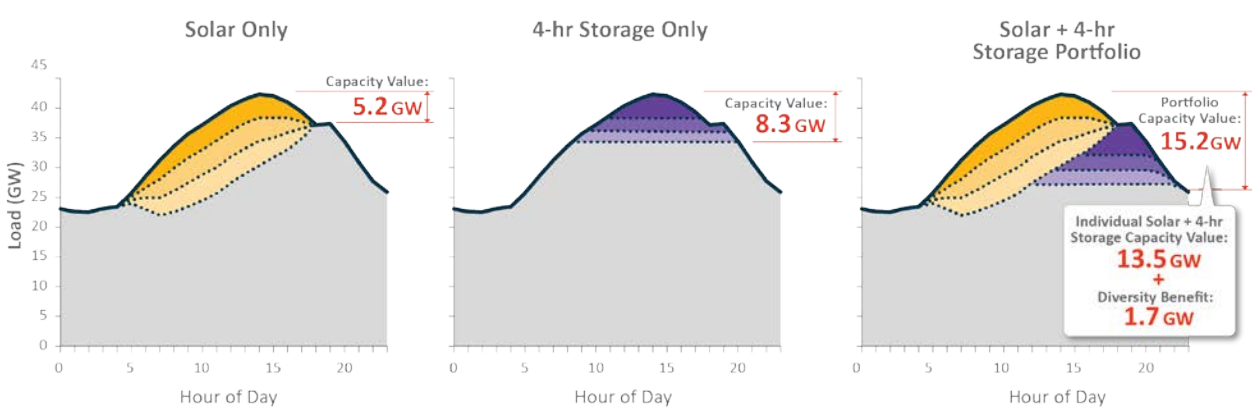
### 3.3.2 CAPACITY EXPANSION MODELING

Using a reliability metric (whether it is ICAP or UCAP), the IRP process focuses on ensuring that enough generation capacity is available so that the electric system can meet a targeted reliability standard, typically limiting loss-of-load events to often one outage every ten years. The capacity expansion modeling phase of an IRP uses the capacity contribution of each resource to ensure that the overall system can meet demand across all hours with a pre-defined level of reliability. The goal of the optimization model is to meet load at the selected level of reliability in a least-cost manner while also achieving any policy requirements within the jurisdiction (including renewable portfolio standards, coal retirement guidelines, energy efficiency requirements, etc.).

Due to the interactions between resources, analyzing the capacity value of future solar on its own will not result in accurate planning of reliability requirements. The contribution of a resource towards system resource adequacy depends on the characteristics of the other resources in the portfolio; resources have interactive effects with one another such that a portfolio of resources may provide a capacity contribution that is greater than (or smaller than) the sum of individual resources on their own. Solar and storage, for example, tend to have a positive interactive effect when added to a portfolio. These positive interactive effects are commonly referred to as "diversity benefits."

The solar generation during the day effectively narrows the duration of the net peak period, and this in turn allows energy storage to more effectively meet the net peak. The solar resources help to satisfy daytime energy demand, while the energy storage resources can help to satisfy evening or morning energy demand. Other resource combinations may produce similar interactive effects; for instance, a portfolio that combines wind and solar typically provides positive interactive effects. These dynamics with respect to solar and storage are shown in Figure 3 below, which is not a Duke-specific figure but illustrates these concepts.

**Figure 3: Illustration of the Synergistic Effects of Solar and Storage**



There are synergistic interactions between solar and storage. Due to the dynamics above, storage is more effective at satisfying short peaks found in the winter (for example two hours from 7:00 to 9:00am) as opposed to longer-duration peaks that typically occur in the summer. Thus, on a dual-peaking system like Duke's, adding storage can shift the likelihood of loss of load events from winter to summer, when solar is more effective.

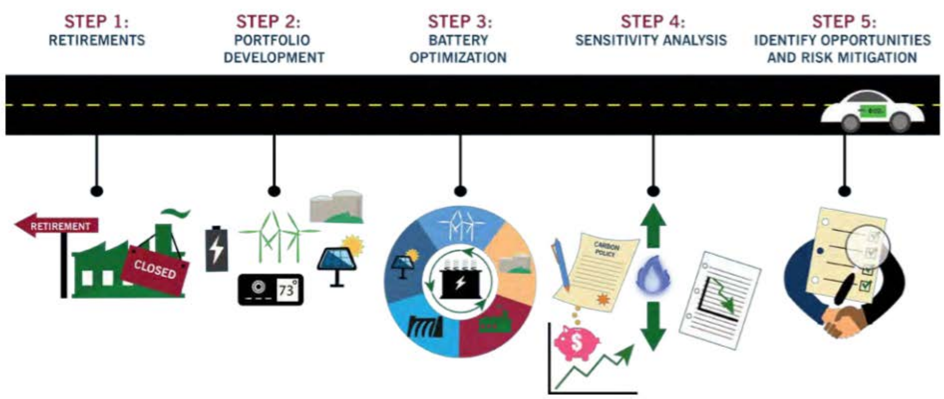
It is critical that any IRP portfolio optimization, including capacity expansion modeling, is done in a single step. Single-step optimization occurs when all components of the capacity expansion are optimized at the same time, as opposed to sequentially. This is crucial due to the interactive effects renewable and storage resources that can only be captured when they are evaluated simultaneously. A capacity expansion model with single step optimization will consider the interactions described in Figure 2 and appropriately measure the combined value of solar and storage resources on the system. By contrast, in a multi-step optimization, one where different resources are evaluated sequentially, solar might not be added as it would not contribute to the evening peak, while storage might not be added because of insufficient duration. Only a single-step optimization, evaluating all generation resources simultaneously, can take into account these synergistic effects.

When considering diversity benefits of renewable resources and energy storage, it is important to note that these resources do not have to be co-located or share an ownership structure. In other words, diversity benefits do not depend on solar being paired directly with storage at the same site – independent solar facilities and storage facilities on a utility's system provide the same benefits. The diversity benefits of both of these resources being installed on a system come from their different operational characteristics as opposed to their geographic location. For example, a battery will be able to charge equally if it is next to a solar plant, or 100 miles away connected by the transmission system. There are times when co-located storage and solar should be modeled as a unique resource due to the operational realities of the facility, however these are unique circumstances, and their modeling would be no different than any other generating asset with unique operations.

## 3.4 Assessment of Duke Approach

In conducting its 2020 IRP, Duke sequentially analyzed coal retirements, portfolio development, and battery optimization. In other words, Duke used multi-step optimization rather than single step optimization in its IRP. An illustration of this process from Duke's IRP is provided in Figure 4.

**Figure 4: Visual Representation of the Duke IRP Process[4]**




One of the key attributes of renewable and storage resources is that the economic, reliability, and environmental benefits that these resources provide can only be realized in conjunction with one another. For example, see Section 4.2 for more information on the ELCC diversity benefits that result from adding solar and storage together.

Unfortunately, Duke's sequential approach which analyzes firm retirements, renewable additions, and storage additions in isolation from one another fail to capture key benefits that the model can only recognize when these resources are evaluated jointly. Duke's capacity expansion methodology indicates that energy storage is added *after* the optimization is completed by economically replacing natural gas

[4] Duke Energy Progress and Duke Energy Carolinas, 2020 IRPs, Figure A-3

CT's with energy storage. In other words, Duke's model does not even consider storage until CTs have already been chosen, and then storage is evaluated based on its ability to replace those CTs. This methodology for building energy storage does not account for diversity benefits. For example, renewable energy is less valuable without storage, so evaluating renewables before storage will add fewer renewables than is optimal. Since storage is most valuable at higher penetrations of renewables, if a sub-optimal amount of renewables were added, then a sub-optimal amount of storage will be added. Duke's approach to capacity expansion artificially reduces the amount of solar and storage built on the system as the model is unable to accurately account for the synergistic effects.

## 3.5 Recommended Approach

An enhanced approach for Duke's IRP requires jointly evaluating all resource additions and retirements in a single-step optimization that fully recognizes the benefits (economic, environmental, reliability) each resource can provide. This approach is markedly different from the sequential approach currently in use. Jointly evaluating resources in a single-step optimization can be computationally complex, so a sophisticated approach must be used to ensure the process can be controlled and efficient. The steps below describe a workable improvement to the Duke IRP process in this proceeding which would capture the joint benefits of solar and storage.

### Step 1: Develop an ELCC Surface

The first step in this proposed approach involves developing a set of inputs for the optimization model that quantifies the relationship between the installed capacity of resources and their ELCC. By evaluating portfolios with different penetrations of solar and storage, this approach properly captures both the declining ELCC of incremental solar or storage as well as the synergistic benefits that result from adding both together. The ELCC values in this step can be calculated using a loss-of-load-probability model such as the one Duke already uses to create ELCC curves for individual resources.

The result of this analysis is a 'surface' of ELCC values with the x and y axis representing the penetration of solar and storage and the height of the surface representing the combined ELCC of the resources. An example is illustrated Figure 5.

**Figure 5: Depiction of Using a Surface to Model ELCCs for Varying Penetrations of Resources**

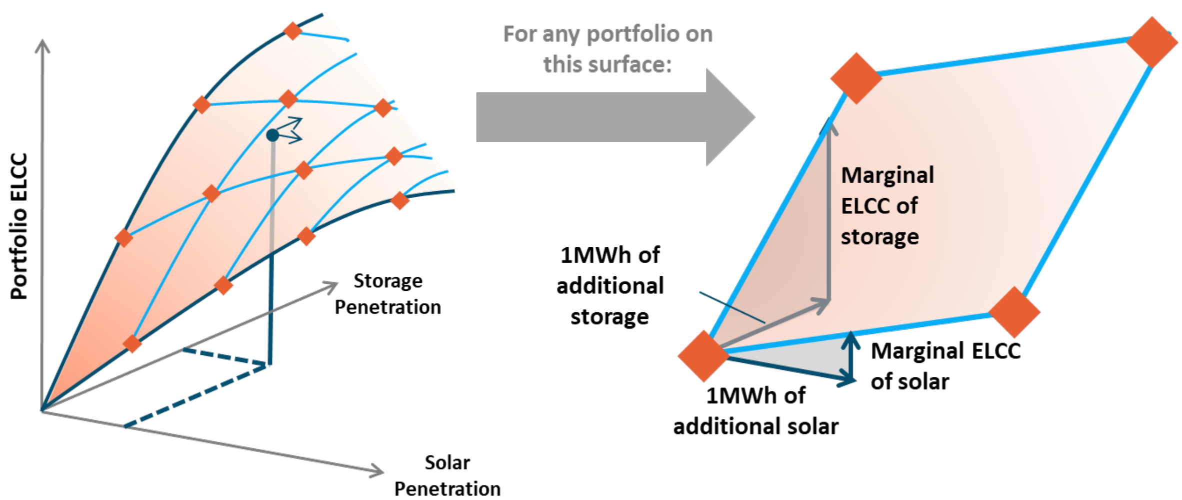


**Table 1: Illustrative Values for an ELCC Surface**

| Combined ELCC Values (MW) | | |
|---|---|---|
| Installed Solar | Installed Storage | Combined ELCC |
| 0 | 0 | 0 |
| 100 | 0 | 50 |
| 100 | 100 | 168 |
| 200 | 100 | 216 |
| 200 | 200 | 312 |
| 300 | 200 | 348 |
| 300 | 300 | 432 |

ELCC Surface

Stand Alone ELCC Values (MW)

| Installed Solar | Total ELCC |
|---|---|
| 0 | 0 |
| 100 | 50 |
| 200 | 90 |
| 300 | 120 |

| Installed Storage | Total ELCC |
|---|---|
| 0 | 0 |
| 100 | 90 |
| 200 | 170 |
| 300 | 240 |

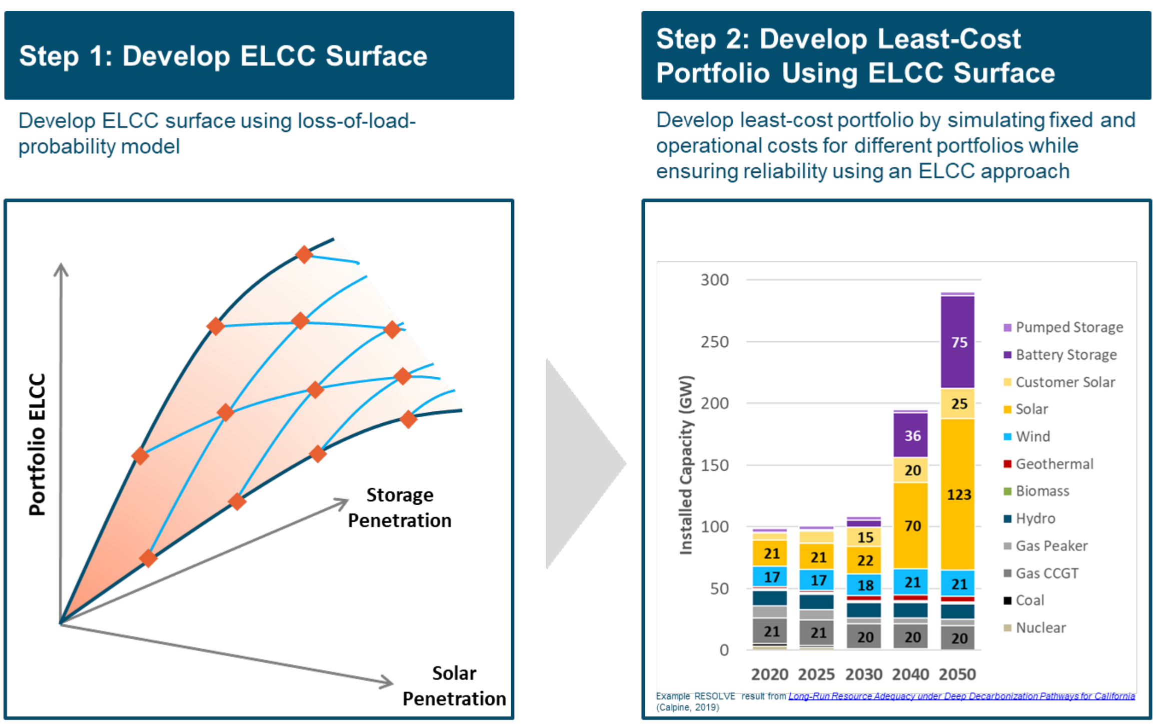
Table 1 shows an illustrative ELCC surface for solar and storage resources on a system. As can be seen, the combined ELCC value of the solar and storage resources is higher than if they are evaluated separately. As an example, 200 MW of both solar and storage on the system has an ELCC of 312 MW while if evaluated separately 200MW of solar and storage would show 260 MW of ELCC (90 MW and 170 MW of ELCC respectively). The use of an ELCC surface allows for the capacity expansion model to incorporate the dynamic synergies of the resources when added to the system.

While this example surface is illustrated for two resources (solar and storage), this framework could be applied to any number of resources to create a multi-dimensional surface that captures the interaction of all various resources. While visualizing a surface with three or more resources is difficult, it is not difficult for an optimization model to incorporate.

**Step 2: Develop Least-Cost Portfolio Using ELCC Surface and Single-step Optimization**

Portfolio optimization is performed in the electricity industry using a class of 'capacity expansion' models that simultaneously evaluate the capital and operational costs of different portfolios over the long run and select the least-cost portfolio of resources. The capacity expansion model used by Duke should be able to incorporate an ELCC surface in order to evaluate the combined ELCC provided by any combination of solar and storage. This set of values can then be directly compared to the ongoing cost of maintaining or retiring existing coal resources as well as adding new resources such as natural gas. Ultimately, the capacity expansion model should ensure that the system has a sufficient quantity of effective capacity to meet a target level of reliability i.e. peak load plus planning reserve margin.

**Figure 6: Illustration of Interaction between the ELCC Surface and Portfolio Results**



# 4 Effective Load Carrying Capability Review

## 4.1 Astrapé's Solar ELCC Study Critique

Duke recognizes that the capacity contribution of intermittent resources, like solar, decreases with penetration and is aligned with IRP best practices in this regard. While Duke quantifies the capacity value of solar and storage resources using ELCC, many of the assumptions made by both Astrapé and Duke in the preparation of the IRP are not aligned with other aspects of IRP best practices. In this Section, E3 will review the Duke IRP and the 2018 Astrapé Solar Capacity Value Study outlining areas where updates should be made to represent the capacity values of solar and storage accurately and effectively for resource planning.

### 4.1.1 ERROR IN ACCOUNTING FOR ELCC IN THE PLANNING RESERVE MARGIN

In its IRP, Duke ensures its portfolios meet an "installed capacity PRM", or ICAP PRM to ensure reliability. For firm resources, the seasonal capacity of Duke's firm resources count toward meeting the PRM. For solar and storage, Duke uses the ELCC to determine these resources' contribution to the ICAP PRM. In doing so, Duke's system is under-valuing renewable resources.

By definition, the ICAP approach used by Duke relies on a PRM that is large enough to account for forced outages from existing resources (outages that are unplanned). At the same time, Duke uses ELCC to calculate the equivalent "perfect" capacity contribution of renewable resources to the system – which means that the capacity credit has already been reduced to account for outages. Under this framework, Duke compares apples to oranges by crediting thermal generators with a nameplate capacity credit and renewable and storage resources with reduced capacity credit.

Because of this mismatch, Duke should switch to a UCAP PRM (for planning purposes) that measures all resources on a "perfect" capacity basis.

### 4.1.2 ELCC SHOULD BE DYNAMIC WITH LOAD LEVELS

The ELCC of a resource is a function of the loads and resources on the system. As more of a resource is added at constant load levels, it effectively provides a larger percentage of total capacity requirements, resulting in a declining ELCC. Conversely, as loads grow, a given resource effectively provides a lower percentage of total capacity requirements, resulting in an increasing ELCC. For example, the ELCC of 100 MW of solar on a system of a 15,000 MW peak load, is going to be approximately 50% greater than 100 MW of solar on a smaller but otherwise equivalent system of 10,000 MW peak load.

Duke calculates solar ELCCs relative to 2020 load levels and storage ELCCs relative to 2024 levels. This approach effectively underestimates the ELCC of solar and storage in years beyond 2020 and 2024 when load levels will be higher.

Duke should use ELCC values which are dynamic to the system including the level of other renewables resources on the system (synergistic effects), as well as future load levels. If this is not possible given the modeling software used, Duke should use ELCC values calculated using load levels consistent to the last year in the planning horizon so that procurement is guided by the long-run capacity value of resources.

### 4.1.3 DEMAND RESPONSE ASSUMPTIONS ARE OUT-OF-DATE

In its Winter Peak Demand Reduction Potential Assessment report, Duke shared an updated forecast for the potential of demand response programs.[5] This forecast showed a significant increase in demand response potential in the winter relative to the levels assumed in its ELCC studies. More demand response capacity in the winter would move loss-of-load expectation to the summer, increasing the capacity value of solar. Duke's current ELCC values do not reflect this and should be updated to account for the additional 766MW and 507MW of demand potential identified under the Mid Scenario for DEC and DEP respectively.[6]

It should be noted that E3 has not investigated the technical feasibility of the forecasted DR resource amounts and simply is indicating that the IRP should reflect Duke's own most up to date calculations.

### 4.1.4 STORAGE SHOULD BE DISPATCHED TO PRESERVE RELIABILITY

In the Astrapé ELCC study, three modes of possible storage operation are identified:

- **Preserve reliability mode:** where the battery is dispatched strictly to maximize system reliability;
- **Economic arbitrage mode:** where the battery is operated in order to maximize the economic value of the battery; and
- **Fixed dispatch mode:** where the battery is operated relative to a pre-determined schedule that does not consider real-time system conditions.

E3 recommends the use of "preserve reliability" mode when incorporating the ELCC of storage into portfolio optimization. Using this mode of dispatch to quantify the ELCC value of storage only assumes that storage is operated this way during the very limited days/hours per year when the system is stressed

[5] Duke Energy, Winter Peak Demand Reduction Potential Assessment, December 2020
[6] Duke Energy, Winter Peak Demand Reduction Potential Assessment, December 2020 – Table 14

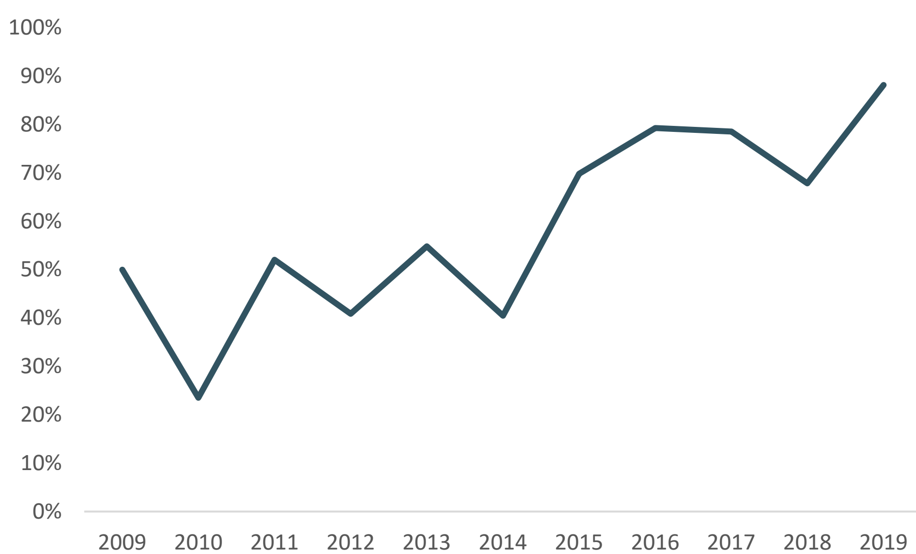
and at risk of loss of load and does not preclude an economic arbitrage mode of operation during all other times. Due to the large economic losses incurred with loss of load, a dispatch approach that maximizes reliability is also one that maximizes system economic value.

In order to effectively use storage to meet system needs during peak events – such as critical winter peaks – Duke's system operators must have enough foresight of these stressed system conditions to charge and hold batteries to serve these periods. Fortunately, given that these stressful system events are driven by highly forecastable weather events, system operators are able to see these events coming with ample time to charge and hold batteries to discharge when they are needed the most. Duke inherently agrees with this assessment since it gives full capacity credit to thermal resources that cannot start instantaneously and must have sufficient foresight to forecast when they will be needed for reliability events. Duke should treat storage resources equivalently and incorporate ELCC values consistent with a preserve reliability mode.

### 4.1.5 SOLAR TRACKING ASSUMPTIONS ARE LOW

In its Solar Capacity Value Study, Astrapé assumes that 40% of future solar is fixed-tilt and that 60% of future solar is single axis tracking. Technological advancements and cost decreases in tracking systems for solar plants has resulted in near zero future installations of fixed-tilt solar across U.S. jurisdictions.

**Figure 7: Utility Scale Tracking Solar Installed as a Percentage of Total**[7]




Furthermore, decreasing costs of tracking devices has resulted in the 2018 installed price of solar being roughly equal for fixed-tilt and tracking projects at $1.40/$W_{ac}$ and $1.46/$W_{ac}$ respectively.[8]

Given the near price parity and the clear industry shift to tracking, E3 recommends that the marginal ELCC of solar be based on 100% tracking solar for new installations.

## 4.2 E3's Effective Load Carrying Capability Modeling

To quantify impact of the combined recommendations identified above in Section 4.1, E3 used its RECAP model, documented in Appendix 1, to calculate both solar and storage ELCCs for the DEC and DEP systems.

[7] Berkeley National Lab and Energy Information Administration. Utility Scale Solar Data Update: 2020 Edition
[8] Id.

Data for this modeling was sourced from Duke's IRP, provided through data requests, and where data was not provided by Duke, E3 used reasonable assumptions.

#### 4.2.1 E3 SOLAR ELCC

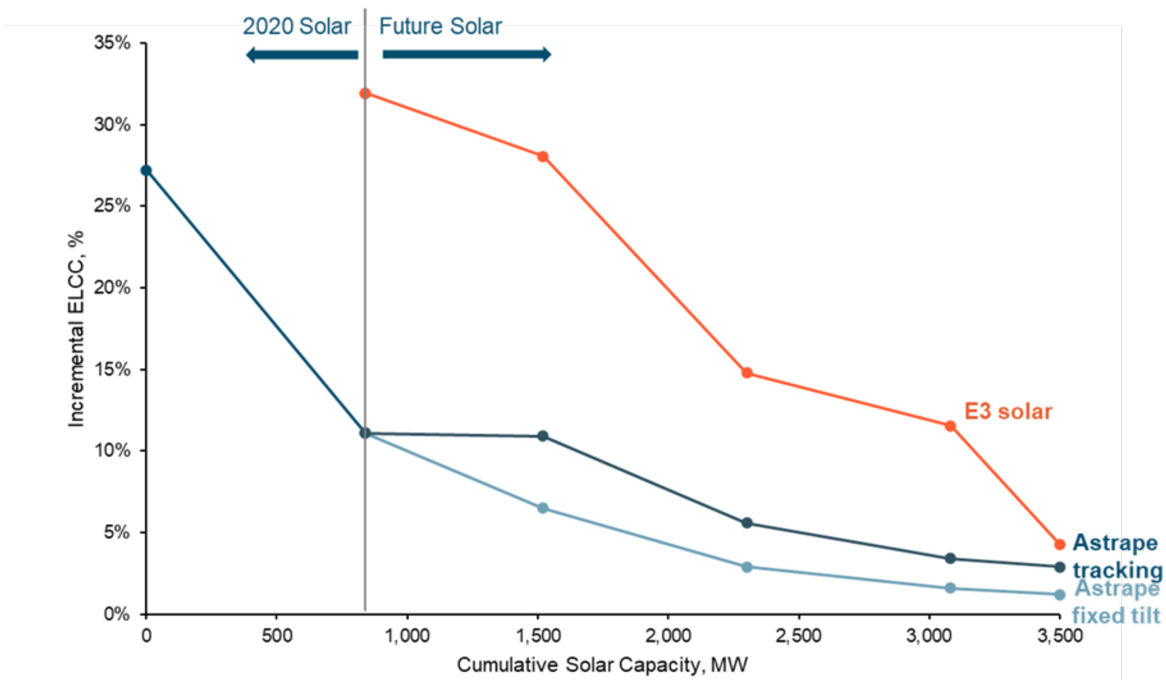
E3 used its RECAP model to calculate the ELCC of solar on the DEC system, incorporating recommended updates outlined in Section 4.1. Specific modeling changes include:

+ The use of 2040 load levels as opposed to 2020 levels;
+ Increased levels of demand response aligning with the Winter Peak Demand Reduction Potential Survey[9] update;
+ Existing pumped hydro resources were modeled in preserve reliability mode; and,
+ All new solar was modeled as tracking.

The resulting increases in solar ELCC for the DEC system are shown in Figure 8 along with Astrapé's 2018 Solar Capacity Value Study results.

[9] Duke Energy, Winter Peak Demand Reduction Potential Assessment, December 2020

**Figure 8: E3 Modeling of Solar ELCC on the Duke Energy Carolina's System**




As shown, the initial E3 ELCC values of solar are significantly higher than Astrapé's values, with the ultimate results converging at higher penetrations around 3,500 MW. Based on the modeling performed by E3, it is not possible to allocate the differences to each individual recommendation as they are modeled as a package. However, it is accurate to say that all the recommendations made by E3 would have the effect of increasing the solar ELCC values compared to the Astrapé study.

Finally, it should be noted that due to the lack of availability of data, the following assumptions were made in E3's modeling efforts.

+ **Hydro energy budgets** were approximated at the annual level from the Astrapé study and split evenly between months. The data request for actual historical hydro data was denied by Duke.
+ **Imports** were modeled as firm capacity rather than regional production simulation.

+ **Forced outage rates** were modeled as an average rate by unit received for data request response. Astrapé aggregates historical outages from the NERC Generating Availability Data System.

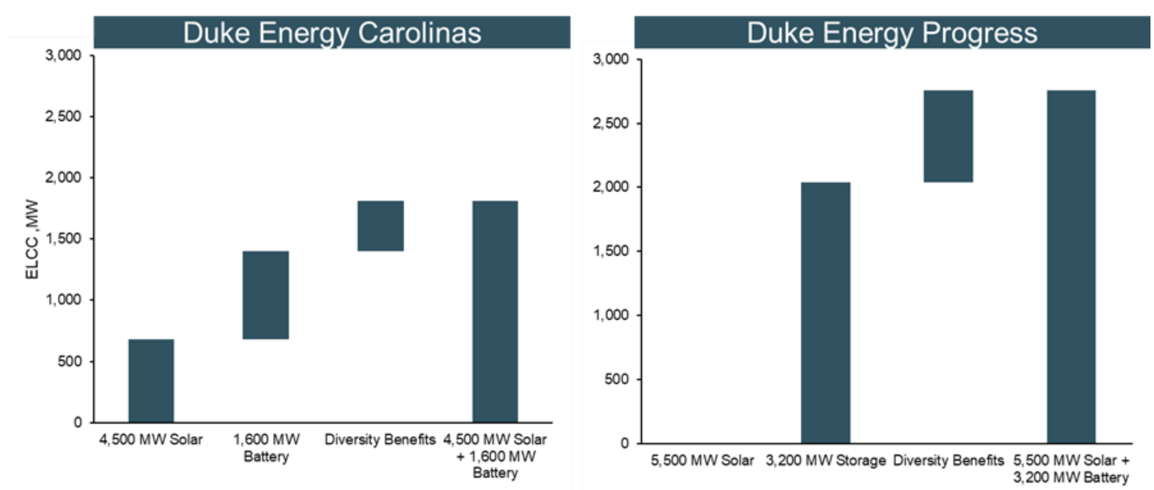
+ **Demand Response** was modeled based on average duration from historical calls. Astrapé models demand response with hourly flexibility.

### 4.2.2 DIVERSITY BENEFITS BETWEEN SOLAR AND STORAGE

As discussed in Section 3.4, Duke's IRP does not accurately account for the diversity benefits between solar and storage additions to the system. The Astrapé 2018 Solar Capacity study presents ELCC values for solar and storage independently, assuming no new installation of either resource. Under this framework the synergistic value of installing both new solar and storage assets is lost.

Using the RECAP model, E3 quantified the relative amounts of diversity benefits under a specific scenario for each of the DEP and DEC systems, the results are shown in Figure 9.

**Figure 9: Quantification of ELCC and Diversity Benefits from Solar and a 4-hour Storage Device**




In the Duke Energy Carolina system, 4,500 MW of solar and 1,600 MW of batteries have an ELCC of 1,800 MW. Yet, 400 MW, or 20% of that value comes from the synergistic interactions of solar and storage.

Likewise, for Duke Energy Progress, 5,500 MW of solar and 3,200 MW of batteries have a combined ELCC of 2,800 MW, with 670 MW, or 25%, due to diversity benefits.

Figure 9 clearly shows that under a multi-step optimization, where solar and storage would be considered independently, 20-25% of the capacity value would be un-accounted for. The ultimate consequence of this is that both solar and storage are under optimized.

# 5 Recommendations

## 5.1 IRP Modeling Recommendations

Section 3 outlines a best-in-class approach to IRP, areas where Duke Energy falls below that standard, and recommendations for improvement. The recommendations are summarized here.

### 5.1.1 USE OF A SINGLE STEP OPTIMIZATION WITH DYNAMIC ELCCS

Duke's use of a multi-step portfolio development process does not adequately capture the diversity benefits associated with renewables and storage. By evaluating the benefits of solar and storage at separate points in the capacity expansion process, diversity benefits are ignored, leading to other technologies being chosen at a higher cost.

E3 recommends that Duke re-run the capacity expansion component of their IRP using a single-step optimization methodology that allows for the diversity benefits of solar and storage to be captured. This will likely lead to more solar and storage being selected by the model and is the most significant improvement that can be made within the scope of this report.

### 5.1.2 USE OF UCAP PRM

Duke's current use of an ICAP PRM, paired with ELCC values for solar and storage compares apples with oranges and disadvantages renewables and storage assets. Currently, thermal firm resources are credited their full nameplate capacity while renewable and storage assets are credited with an ELCC value that is by definition equivalent to perfect capacity.

To allow for an accurate accounting, Duke should move to the use of a UCAP PRM under which thermal resources, renewable resources, and storage resources would be de-rated based on both their forecasted outage rates and variability. E3 also understands that this would require a significant re-design of the current PRM process and thus as a potential work around, the ELCC values for solar and storage could be grossed up by the outage rates of a standard thermal unit in order to create a level playing field.

## 5.2 Effective Load Carrying Capability Recommendations

In Section 4, E3 reviewed Astrapé 2018 Solar ELCC Study, provided recommendations for improvements, and provided modeling results indicating the impact of those recommendations. Those recommendations are summarized here:

### 5.2.1 GENERATE AN ELCC SURFACE FOR SOLAR AND STORAGE

The interactive effects of solar and storage on the DEC system can only be fully understood by developing an ELCC surface that determines the combined capacity value of different portfolios of solar and storage (see Figure 5).

Duke should update the 2018 Solar ELCC Study to include an ELCC surface analysis that demonstrates the increasing diversity benefit associated with solar and storage installations. This recommendation is also critical in developing an optimized capacity expansion.

### 5.2.2 UPDATE 2018 SOLAR CAPACITY VALUE STUDY

As described in Section 4.1, E3 has a number of recommendations to increase the accuracy of ELCC calculations for solar on the DEC system. These recommendations are also applicable to the calculation of an ELCC surface. Specifically, Duke should:

+ Vary ELCC as a function of load level. By limiting the ELCC calculation to the 2020/2024 load levels, ELCC are being artificially depressed in future years by not taking into account load growth. If Duke or Astrapé is unable to vary ELCC levels with load, then Duke should base ELCC values on 2040 load levels to reflect the long-lived nature of the assets.
+ Update DR values to include those identified in the Winter Peak Demand Reduction Potential Assessment.
+ Model energy storage resources on a preserve reliability basis as opposed to an economic arbitrage basis.
+ Change future solar technology assumption from 60% tracking to 100% tracking.



# 6 Conclusion

As technologies and policies have evolved in the electricity industry, the long-term planning of electric systems has become increasingly complex. The increasing installation of renewables and energy storage necessitates an evolution of IRP to accurately account for the potential benefits brought to the system and achieve a least-cost solution.

E3’s four recommendations, moving to a single-step optimization, moving to a UCAP PRM, using an ELCC surface to account for diversity benefits, and aligning the demand response benefits to the most recent Duke study, are instrumental in achieving an IRP outcome that is least-cost. Without taking these steps, Duke’s generation resource options will not have been compared on an apples-to-apples basis and as such will have resulted in a higher cost solution.

E3 recommends that Duke be required to re-file its IRP updating the assumptions and methodologies to align with the findings of this report.

# 7 Appendix 1 – E3 RECAP Model

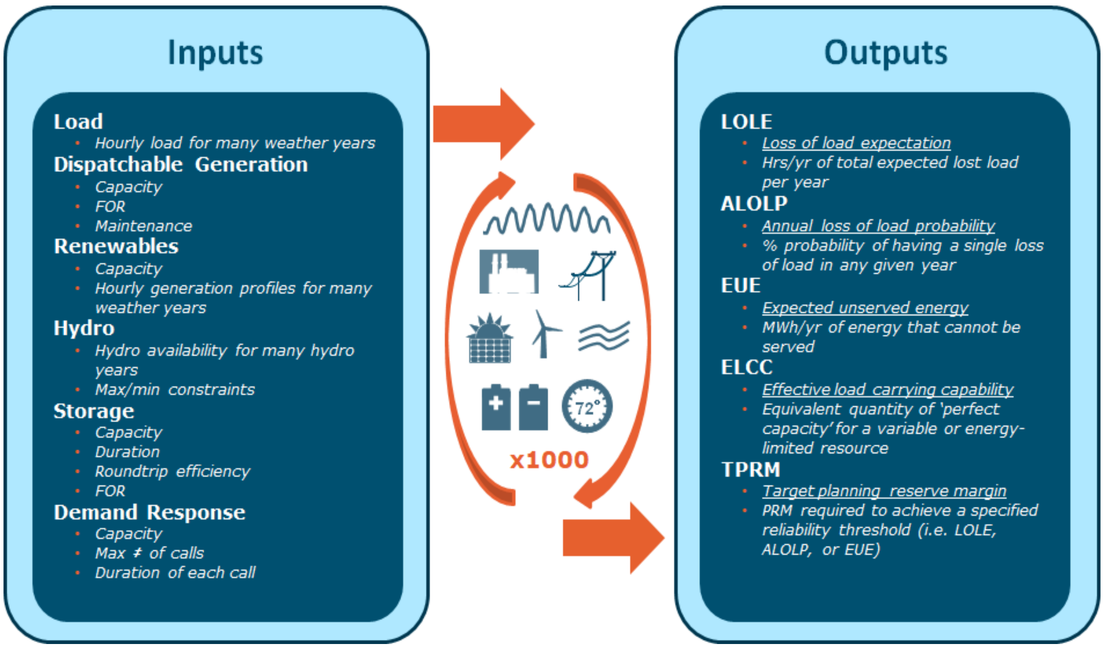
### 7.1.1 E3'S RENEWABLE ENERGY CAPACITY PLANNING MODEL (RECAP)

RECAP is a loss-of-load-probability model designed to evaluate the resource adequacy of electric power systems, including systems with high penetrations of renewable energy and other dispatch-limited resources such as hydropower, energy storage, and demand response. RECAP was initially developed for the California Independent System Operator (CAISO) in 2011 to facilitate studies of renewable integration and has since been adapted for use in many jurisdictions across North America.

RECAP evaluates resource adequacy through time-sequential simulations of thousands of years of plausible system conditions to calculate a statistically significant measure of system reliability metrics as well as individual resource contributions to system reliability. The modeling framework is built around capturing correlations among weather, load, and renewable generation. RECAP also introduces stochastic forced outages of thermal plants and transmission assets and time-sequentially tracks hydro, demand response, and storage state of charge. Through modeling the electric system under different combinations of these characteristics, loss-of-load expectation (LOLE) for the electric system is calculated.

Figure 10 provides a high-level overview of RECAP including key inputs, Monte Carlo simulation process, and key outputs.

**Figure 10: RECAP Model Overview**




### Effective Load Carrying Capability Calculation

RECAP's simulation of LOLE for a given electric system enables the calculation of ELCC for individual resources. These ELCCs for individual resources (or combinations of resources) are calculated through iterative simulations of an electric system:

1. The LOLE for the electric system without the specified resource is simulated. If the resulting LOLE does not match the specified reliability target, the system "adjusted" to meet a target reliability standard (most commonly, one day in ten years). This adjustment occurs through the addition (or removal) of perfect capacity resources to achieve the desired reliability standard.
2. The specified resource is added to the system and LOLE is recalculated. This will result in a reduction in the system's LOLE, as the amount of available generation has increased.

3. Perfect capacity resources are removed from the system until the LOLE returns to the specified reliability target. The amount of perfect capacity removed from the system represents the ELCC of the specified resource (measured in MW); this metric can also be translated to percentage terms by dividing by the installed capacity of the specified resource.

**Figure 11: Iterative Approach to Determining Effective Load Carrying Capability**


This approach can be used to determine the ELCC of any specific resource type evaluated within the model. In general, ELCC is not widely used to measure capacity value for firm resources (which are generally rated either at their full or unforced capacity) but provides a useful metric for characterizing the capacity value of renewable resources and storage.

# Arne Olson

44 Montgomery Street, Suite 1500, San Francisco, CA 94104 415.391.5100, ext. 307
arne@ethree.com

**ENERGY AND ENVIRONMENTAL ECONOMICS, INC.** San Francisco, CA
*Senior Partner*

Mr. Olson joined E3 in 2002 and became a partner in 2010. Mr. Olson helps clients navigate changes to bulk electric system operations and investment needs brought about by policies promoting clean and renewable energy production. He led the technical analysis and drafting of the landmark 2014 report *Investigating a Higher Renewable Portfolio Standard for California*, prepared for the five largest utilities in California, which delineated the challenges of achieving higher renewable penetrations as well as the many solutions that are available to ease the integration burden. Since that time, he has overseen E3's fast-growing resource planning practice which has completed numerous studies of deeply-decarbonized and highly-renewable power systems in California, Hawaii, the Pacific Northwest, the Desert Southwest, New York, South Africa, and many other regions.

He has also led the development of E3's industry-leading resource planning software including the RESOLVE model that develops optimal portfolios of renewable, conventional and energy storage resources to meet electric energy, capacity, and reliability needs while meeting specified policy goals including GHG caps and minimum renewable penetration levels and the RECAP model that calculates Loss-of-Load Probability and related statistics to ensure that power systems can meet load reliably under high renewable penetrations. His clients have included most of the major utilities and market participants in the West including the California Independent System Operator, Pacific Gas and Electric, Southern California Edison, Puget Sound Energy, PacifiCorp, Arizona Public Service, Sacramento Municipal Utilities District, Los Angeles Department of Water and Power, the Bonneville Power Administration, Calpine, NextEra, NRG, TransAlta and many others. He also works extensively with government agencies and industry organizations such as the California Public Utilities Commission, California Energy Commission, Oregon Public Utilities Commission, the Western Electric Coordinating Council, and the Western Interstate Energy Board. Other clients have included Florida Power & Light, Tampa Electric Company, Nova Scotia Power, Hydro-Quebec TransEnergie, TransElect, Long Island Power Authority, and others.

*Resource Planning and Valuation:*

- Led an award-winning project that investigated the value of operating solar power plants flexibly, including for the provision of essential grid services, on behalf of First Solar and with the assistance of Tampa Electric Company.
- Led a project that investigated the cost-effectiveness of alternative policies for decarbonizing the Northwest electric system on behalf of a group of generation-owning public power utilities.
- Led a team that is evaluating the need for flexible generation capacity on behalf of Portland General Electric.
- Led a team that assessed electricity-natural gas infrastructure issues on behalf of the Western Interstate Energy Board.

- Led a team that investigated the capacity contribution of new wind, solar and demand response (DR) resources on behalf of the Sacramento Municipal Utilities District.
- Assisted the Colorado Public Utilities Commission in developing long-term scenarios to use across a range of energy infrastructure planning dockets.
- Assisted BC Hydro in evaluating the impact of BC's provincial greenhouse gas reduction policies on future electric load as part of BC Hydro's 2011 Integrated Resource Plan.
- Provided expert testimony in front of the California Public Utilities Commission on rates and revenue requirements associated with several alternative portfolios of demand-side and supply-side resources, on behalf of Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric.
- Served as lead investigator in assisting the California Public Utilities Commission (CPUC) in its efforts to reform the long-term procurement planning process in order to allow California to meet its aggressive renewable energy and greenhouse gas reduction policy goals.
- Prepared an integrated resource plan (IRP) on behalf of Umatilla Electric Cooperative, a 200-MW electric cooperative based in Hermiston, Oregon. The IRP considered a number of different resource and rate product options, and addressed ways in which demand-side measures such as energy efficiency, distributed generation and demand response can help UEC reduce its wholesale energy and bulk transmission costs.
- Served as lead investigator in developing integrated resource plans for numerous publicly-owned utilities including PNGC Power, Lower Valley Energy, and Platte River Power Authority.
- Provided generation and transmission asset valuation services to a number of utility and independent developer clients.

*Renewables and Emerging Technology:*

- Currently leading a team that is advising Portland General Electric Company on potential strategies for cost-effective procurement of distributed or utility scale solar generation.
- Led a project that evaluated flexible capacity needs under high renewable penetration across the Western Interconnection on behalf of the Western Electric Coordinating Council and the Western Interstate Energy Board. The team included technical contributions from E3, NREL and Energy Exemplar.
- Led the technical analysis and drafting of the influential report *Investigating a Higher Renewable Portfolio Standard for California*. The report evaluated the operational challenges, costs and solutions for integrating a 40% or 50% Renewable Portfolio Standard on behalf of the five largest utilities in California.
- Led the team that developed the Renewable Energy Flexibility (REFLEX) model, commercial software that assesses power system flexibility needs under high renewable penetration.
- Led the team that developed the Renewable Energy Capacity Planning (RECAP) model, commercial software that calculates reliability metrics such as Loss of Load Probability (LOLP), Loss of Load Expectation (LOLE) and Planning Reserve Margin (PRM), along with Effective Load-Carrying Capability (ELCC) of wind and solar resource, demand response programs, and other dispatch-limited resources.
- Currently advising the CPUC on renewable energy resource policy and procurement.
- Currently leading the California Independent System Operator's (CAISO) renewable integration needs studies. The studies are evaluating the need for firming capacity and flexible resources to accommodate the variable and unpredictable nature of wind and solar generation. Results of the studies will be used to determine the need to procure new, flexible resources.

- Led the team that developed renewable and conventional resource cost and performance characteristics for use in the WECC's Regional Transmission Expansion Planning process.
- On behalf of the Wyoming Governor's Office, developed a model of the cost of developing wind resources in Wyoming relative to neighboring states to inform policy debate regarding taxation. The model included detailed representations of state-specific taxes and capacity factors.
- On behalf of the CPUC, investigated a number of strategies for achieving a 33% Renewables Portfolio Standard in California by 2020, and estimated their likely cost and rate impacts using the 33% RPS Calculator, a publicly-available spreadsheet model developed for this project.
- Evaluated market opportunities and provided strategic advice for renewable energy developers in California and the Southwest.
- Investigated for Bonneville Power Administration (BPA) the economics and feasibility of investing in new, long-line transmission facilities connecting load centers in the Pacific Northwest with remote areas that contain large concentrations of high-quality renewable energy resources. The study informed BPA about cost-effective strategies for procuring renewable energy supplies in order to meet current and potential future renewable renewables portfolio standards and greenhouse gas reduction targets.
- Co-authored *Load-Resource Balance in the Western Interconnection: Towards 2020*, a study of west-wide infrastructure needs for achieving aggressive RPS and greenhouse gas reduction goals in 2020 for the Western Electric Industry Leaders (WEIL) Group, comprised of CEOs and executives from a number of utilities through the West, and presented results indicating that developing new transmission infrastructure to integrate remote renewable resources can result in cost savings for consumers under aggressive policy assumptions.

*Transmission Planning and Pricing:*

- Currently serving as technical support to the Western Electric Coordinating Council's Scenario Planning Steering Group (SPSG). The SPSG is developing scenarios for long-term transmission planning in the Western Interconnection.
- Currently advising several transmission developers seeking approval for projects through the CAISO's Transmission Planning Process.
- Led a team that investigated the use of Production Cost Modeling for the purpose of allocating costs of new transmission facilities on behalf of the Northern Tier Transmission Group, and contributed to NTTG's Order 1000 compliance filing.
- Served as an expert witness in front of the Alberta Utilities Commission in a case regarding the Alberta Electric System Operator's proposed methodology for allocating Available Transmission Capacity among interties during times of congestion.
- Led studies in 2009, 2011 and 2012 to develop generation and transmission capital cost assumptions for use in WECC's Transmission Expansion Planning and Policy Committee (TEPPC) studies.
- Contributed to a study of the benefits of North-South transmission expansion in Alberta on behalf of AltaLink.
- Led a study for WECC to estimate the benefits of developing a centralized Energy Imbalance Market (EIM) across the Western Interconnection. The study estimated benefits due to increased generation dispatch efficiency resulting from reduced market barriers and increased load and resource diversity among western Balancing Authorities. Led several follow-up studies of alternative Western EIM footprints for potential EIM participants.
- Retained by a consortium of southwestern utilities and state agencies including the Wyoming Infrastructure Authority, Xcel Colorado, Public Service Company of New Mexico, and the Salt

River Project to perform an economic feasibility study of the proposed High Plains Express (HPX) transmission project, a roadmap for transmission development in the Desert Southwest and Rocky Mountain regions.

- Provided assistance to the Seattle City Council to develop guidelines for the evaluation of large electric distribution and transmission projects by Seattle City Light (SCL). Guidelines specified the types of evaluations SCL should perform and the information the utility should present to the City Council when it seeks approval for large distribution or transmission projects.
- Conducted screening studies of long-distance transmission lines connecting to remote renewable energy zones for multiple western utilities.
- Assisted in the development of a methodology for evaluating the renewable energy benefits of the Sunrise Powerlink transmission project in support of expert testimony on behalf of the California ISO.
- Assisted British Columbia Transmission Corporation and Hydro-Quebec TransEnergie with open access transmission tariff design.
- Represented BC Hydro in RTO West market design process in areas of congestion management, ancillary services, and transmission pricing.

*Energy and Climate Policy:*

- Developed policy themes and integrated them into the four long-term planning scenarios under consideration by WECC's Scenario Planning Steering Group.
- Led a team that developed a model of deep carbon dioxide emissions reductions scenarios in the western United States and Canada on behalf of the State-Provincial Steering Committee, a body of western state and provincial officials that provides oversight for WECC.
- Led a study of likely changes to power flows and market prices at western electricity trading hubs following California's adoption of a cap-and-trade system for regulating greenhouse gas emissions in 2013.
- Served as advisor, facilitator and drafter to the Interim Committee in developing Idaho's first comprehensive, statewide energy plan in 25 years. The Interim Committee and subcommittees held 18 days of public meetings and received input from dozens of members of the public in developing state-level energy policy recommendations. This process culminated in Mr. Olson drafting the 2007 Idaho Energy Plan, which was approved by the Legislature and adopted as the official state energy plan in March 2007.
- Developed a model that forecasted renewable and conventional generating resources in the WECC region in 2020 as part of an E3 project to advise the California Public Utilities Commission, California Energy Commission and California Air Resources Board about the cost and feasibility of reducing greenhouse gas emissions in the electricity and natural gas sectors.

**WASHINGTON OFFICE OF TRADE AND ECONOMIC DEVELOPMENT** Olympia, WA
*Senior Energy Policy Specialist* 1996-2002

- **Electricity Transmission**: Lead responsibility for developing and representing agency policy interests in a variety of regional forums, with a primary focus on pricing and congestion management issues. Lead negotiator on behalf of agency in IndeGO and RTO West negotiations in areas of Congestion Management, Ancillary Services, and Transmission Planning. Participated in numerous subgroups developing issues including congestion zone definition, nature of long-term transmission rights, and RTO role in transmission grid expansion.

- **Western Regional Transmission Association, 1996-2001:** Member, WRTA Board of Directors. Participated in WRTA Tariff, Access and Pricing Committee. Participated in sub-groups examining "seams" issues among multiple independent system operators in the West and developing a proposal for tradable firm transmission rights in the Western interconnection.
- **Wholesale Energy Markets:** Monitored and analyzed trends in electricity, natural gas and petroleum markets. Editor and principal author of Convergence: Natural Gas and Electricity in Washington, a survey of the Northwest's natural gas industry in the wake of the extreme price events of winter 2000-2001, and on the eve of a significant increase in demand due to gas-fired power plants. Authored legislative testimony on the ability of the Northwest's natural gas industry to meet the demand from new, gas-fired power plants.
- **Electricity Restructuring:** Co-authored Washington Electricity System Study, legislatively-mandated study of Washington's electricity system in the context of ongoing trends and potential methods of electric industry restructuring. Authored legislative testimony on the impact of restructuring on retail electricity prices in Washington, electric industry restructuring and Washington's tax system, and the interactions between restructured electricity and natural gas markets.
- **Energy Data:** Managed three-person energy data team that collected and maintained a repository of state energy data. Developed Washington's Energy Indicators, a series of policy benchmarks and key trends for Washington's energy system; second edition published in January 2001.

**DECISION ANALYSIS CORPORATION OF VIRGINIA** Vienna, VA
*Associate* 1993-1996

- **Energy Modeling and Analysis:** Developed energy demand forecasting models for Energy Information Administration's National Energy Modeling System. Results are published each year in EIA's Annual Energy Outlook.

## Education

University of Pennsylvania Philadelphia, PA
Institut de Francais du Petrole Rueil-Malmaison, France
*M.S., International Energy Management & Policy*

University of Washington Seattle, WA
*B.S., Mathematical Sciences, B.S. Statistics*

## Citizenship

United States

## Expert Witness Testimony

1. *Oregon Public Utilities Commission, 2017, testified on behalf of Commission staff regarding methodologies for assessing the value of customer-owned solar resources.*

2. *Oregon Public Utilities Commission, 2016, testified on behalf of Portland General Electric Company regarding methodologies for assessing the capacity contribution of variable renewable energy resources.*

3. *Province of Ontario, Commercial Arbitration, 2015, testified regarding policies related to renewable energy procurement and determination of available transmission capacity.*

4. *California Energy Commission, 2014, testified on behalf of Abengoa and BrightSource Energy regarding the cost and feasibility of distributed generation and energy storage alternatives to a large, concentrating solar power plant project in the context of a power plant siting case.*

5. *California Energy Commission, 2013, testified on behalf of BrightSource Energy regarding the cost and feasibility of distributed generation alternatives to a large, concentrating solar power plant project in the context of a power plant siting case.*

6. *Alberta Electric Utilities Commission, 2012, testified on behalf of Powerex Corporation reviewing industry practices regarding treatment of existing transmission capacity, in the case when new transmission lines are interconnected.*

7. *California Public Utilities Commission, 2011, provided testimony on behalf of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company regarding cost, revenue requirement, average retail rates, and cost of carbon reductions from alternative resource portfolios in the Long-Term Procurement Planning Proceeding.*

8. *California Energy Commission, 2010, testified on behalf of BrightSource Energy regarding the cost and feasibility of distributed generation alternatives to a large, concentrating solar power plant project in the context of a power plant siting case.*

## Publications

1. *Woo, C.K., J. Zarnikau, Y. Chen, A. Olson, J. Moore, T. Ho, Y. Liu, and X. Luo (2017) "An empirical analysis of California's hybrid capacity options" Electricity Journal, forthcoming*

2. *Woo, C.K., A. Olson, Y. Chen, J. Moore, N. Schlag, A. Ong, and T. Ho (2017) "Does California's CO2 price affect wholesale electricity prices in the Western U.S.A.?" Energy Policy, 110, 9–19*

3. *Olson, A., C.K. Woo, N. Schlag and A. Ong (2016) "What Happens in California Does Not Always Stay in California: The Effect of California's Cap-and-Trade Program on Wholesale Electricity Prices in the Western Interconnection," The Electricity Journal, 29(7), 18-22.*

4. *Woo, C.K., J. Moore, B. Schneiderman, T. Ho, A. Olson, L. Alagappan, K. Chawla, N. Toyama, J. Zarnikau (2016) "Merit-order effects of renewable energy and price divergence in California's day-ahead and real-time electricity markets," Energy Policy, 92, 299-312.*

5. *Woo, C.K., J. Moore, B. Schneiderman; A. Olson; R. Jones; T. Ho; N. Toyama; J. Wang; and J. Zarnikau, "Merit-order Effects of Day-ahead Wind Generation Forecast in the Hydro-rich Pacific Northwest", The Electricity Journal, Vol. 28, Issue 9, November 2015*

6. *Olson, A., A. Mahone, E. Hart, J. Hargreaves, R. Jones, N. Schlag, G. Kwok, N. Ryan, R. Orans and R. Frowd, "Halfway There: Can California Achieve a 50% Renewable Grid?", IEEE Power and Energy Magazine, Volume:13, Issue: 4, pp. 41-52, July-Aug. 2015*

7. *Olson, A., R. Jones, E. Hart and J. Hargreaves, "Renewable Curtailment as a Power System Flexibility Resource," The Electricity Journal, Volume 27, Issue 9, November 2014, pages 49-61*

8. *Hargreaves, J., E. Hart, R. Jones and A. Olson, "REFLEX: An Adapted Production Simulation Methodology for Flexible Capacity Planning," IEEE Transactions on Power Systems, Volume:30, Issue: 3, September 2014, pages 1306 - 1315*

9. *Woo, C.K., T. Hob, J. Zarnikau, A. Olson, R. Jones, M. Chait, I. Horowitz, J. Wang, "Electricity-market price and nuclear power plant shutdown: Evidence from California", Energy Policy,* 2014, vol. 73, issue C, pages 234-244

10. *Woo, C.K., Zarnikau J, Kadish J, Horowitz I, Wang J, Olson A. (2013) "The Impact of Wind Generation on Wholesale Electricity Prices in the Hydro-Rich Pacific Northwest," IEEE Transactions on Power Systems, 28(4), 4245-4253.*

11. *Orans, R., A. Olson, J. Moore, J. Hargreaves, R. Jones, G. Kwok, F. Kahrl, and C.K. Woo (2013) "Energy Imbalance Market Benefits in the West: A Case Study of PacifiCorp and CAISO," Electricity Journal, 26:5, 26-36.*

12. *Olson A., R. Jones (2012) "Chasing Grid Parity: Understanding the Dynamic Value of Renewable Energy," Electricity Journal, 25:3, 17-27.*

13. *Woo, C.K., H. Liu, F. Kahrl, N. Schlag, J. Moore and A. Olson (2012) "Assessing the economic value of transmission in Alberta's restructured electricity market," Electricity Journal, 25(3): 68-80.*

14. *DeBenedictis, A., D. Miller, J. Moore, A. Olson, C.K. Woo (2011) "How Big is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest," Electricity Journal, 24:3, 72-76.*

15. *Woo, C.K., I. Horowitz, A. Olson, A. DeBenedictis, D. Miller and J. Moore (2011) "Cross-Hedging and Forward-Contract Pricing of Electricity in the Pacific Northwest," Managerial and Decision Economics, 32, 265-279.*

16. *Moore, J., C.K. Woo, B. Horii, S. Price and A. Olson (2010) "Estimating the Option Value of a Non-firm Electricity Tariff," Energy, 35, 1609-1614.*

17. *Olson A., R. Orans, D. Allen, J. Moore, and C.K. Woo (2009) "Renewable Portfolio Standards, Greenhouse Gas Reduction, and Long-line Transmission Investments in the WECC," Electricity Journal, 22:9, 38-46.*

18. *Moore, J., C.K. Woo, B. Horii, S. Price, A. Olson (2009) "Estimating the Option Value of a Non-firm Electricity Tariff," Energy, 35, 1609-1614.*

19. *Woo, C.K., I. Horowitz, N. Toyama, A. Olson, A. Lai, and R. Wan (2007) "Fundamental Drivers of Electricity Prices in the Pacific Northwest," Advances in Quantitative Analysis of Finance and Accounting, 5, 299-323.*

20. *Lusztig, C., P. Feldberg, R. Orans, and A. Olson (2006) "A survey of transmission tariffs in North America," Energy-The International Journal 31, 1017-1039.*

21. *Woo, C.K., A. Olson, I. Horowitz and S. Luk (2006) "Bi-directional Causality in California's Electricity and Natural-Gas Markets," Energy Policy, 34, 2060-2070.*

22. *Woo, C.K., I. Horowitz, A. Olson, B. Horii and C. Baskette (2006) "Efficient Frontiers for Electricity Procurement by an LDC with Multiple Purchase Options," OMEGA, 34:1, 70-80.*

23. *Woo, C.K., A. Olson and I. Horowitz (2006) "Market Efficiency, Cross Hedging and Price Forecasts: California's Natural-Gas Markets," Energy, 31, 1290-1304.*

24. *Woo, C.K., A. Olson and R. Orans (2004) "Benchmarking the Price Reasonableness of an Electricity Tolling Agreement," Electricity Journal, 17:5, 65-75.*

25. *Orans, R., A. Olson, C. Opatrny, Market Power Mitigation and Energy Limited Resources, Electricity Journal, March, 2003.*

## Selected Public Presentations

1. *"Customer Engagement: An Adaptive Survival Strategy for Electric Utilities", invited speaker, Energy NewsData Utility Customer Engagement Conference, Portland, Oregon, November 17, 2017*

2. *"Customer Engagement: What Does Success Look Like?", invited speaker, Energy NewsData Utility Customer Engagement Conference, Portland, Oregon, November 17, 2017*

3. *"Grid of the Future, Industry of the Future", Platinum Seminar at the Northwest and Intermountain Power Producer Coalition Annual Meeting, Union, Washington, September 11, 2017*

4. *"California's Solar Buildout: Implications for Electricity Markets in the West", invited speaker, EPIS Electric Market Forecasting Conference, Las Vegas, Nevada, September 7, 2017*

5. *"Value of Hydro in a GHG-Constrained World", invited panelist, HydroVision International, Session 1A: How Does Hydro 'Play' in the Energy Playground? Welcome to the New Wild West, Denver, Colorado, June 28, 2017*

6. *"Resource Adequacy and Planning Reserve Margins", invited speaker, Technical Conference on Capacity Planning and Resource Adequacy, Montana Public Service Commission, Helena, Montana, June 8, 2017*

7. *"That Faint Whooshing Sound: California Solar and Changing Western Power Markets", invited speaker, Northwest Power Markets: Mapping the Road Ahead, presented by Energy NewsData and CJB Energy, Portland, Oregon, May 24, 2017*

8. *"Observations on Current Resource Adequacy Practices", invited speaker, Committee for Regional Electric Power Cooperation/Western Interconnection Regional Advisory Body, Boise, Idaho, April 13, 2017*

9. *"Assessing Flexibility Needs in Highly Renewable Systems," invited speaker, Wärtsilä Symposium, Portland, Oregon, September 27, 2016*

10. *"Review: Natural Gas Infrastructure Adequacy in the Western Interconnection," invited speaker, Committee for Regional Electric Power Cooperation/Western Interconnection Regional Advisory Body, San Diego, California, October 31, 2016*

11. *"PATHWAYS to Deep Decarbonization: California", Western Electric Coordinating Council, Transmission Expansion Planning and Policy Committee, Salt Lake City, Utah, August 17, 2016*

12. *"Renewable Euphoria and the 'Big Long': How Renewable Energy Will Impact Western Markets", invited speaker, Mid-C Seminar, Wenatchee, Washington, July 27, 2016*

13. *"The Role of Renewables in Meeting California's Greenhouse Gas Goals", invited speaker, Renewable Energy Integration Summit, San Diego Regional Chamber of Commerce, July 18, 2016*

14. *"Essential Reliability Services", invited panelist, Western Electric Coordinating Council, Western Reliability Summit, Salt Lake City, Utah, May 18, 2016*

15. *"Meeting a 50% RPS for California", invited panelist, Infocast California Energy Summit, Santa Monica, California, May 11, 2016*

16. *"The Future of Resource Planning", invited keynote speaker, Great Plains Institute's e21 Initiative, St. Paul, Minnesota, April 5, 2016*

17. *"Market Driven Distributed Generation in the Western Interconnection", invited panelist, Committee on Regional Electric Power Cooperation biennial meeting, Salt Lake City, Utah, March 22, 2016*

18. *"Is Solar the New Hydro?", invited panelist, Northwest Hydroelectric Association 2016 Annual Conference, Portland, Oregon, February 17, 2016*

19. *"The Role of Energy Storage as a Renewable Integration Solution under a 50% RPS", invited panelist, Joint California Energy Commission and California Public Utilities Commission Long-Term Procurement Plan Workshop on Bulk Energy Storage, Sacramento, California, November 20, 2015*

20. *"Planning for Variable Generation Integration Needs", invited panelist, Utility Variable-generation Integration Group, Operating Impact And Integration Studies Users Group Meeting, San Diego, California, October 13, 2015*

21. *"The Role of Renewables in a Post-Coal World", invited panelist, Energy Foundation, Beyond Coal to Clean Energy Conference, San Francisco, California, October 9, 2015,*

22. *"Implications of a 50% RPS for California", invited panelist, Argus Carbon Summit, Napa, California, October 6, 2015*

23. *"Western EIM: Status Report and Implications for Public Power", Keynote speaker, Large Public Power Council meeting, Seattle, Washington, September 16, 2015*

24. *"California's 50% RPS Goal: Opportunities for Western Wind Developers", Keynote speaker at a meeting of the Wyoming Infrastructure Authority, Berkeley, California, July 28, 2015*

25. *"Western Interconnection Flexibility Assessment", Western Electric Coordinating Council Board of Directors, Salt Lake City, Utah, June 24, 2015*

26. *"California's New GHG Goals: Implications for the Western Electricity Grid", invited panelist, National Association of State Energy Officials, Western Regional State and Territory Energy Office Meeting, Portland, Oregon, May 14, 2015*

27. *"Replacing Aging Fossil Generation," invited panelist, Northwest Energy Coalition NW Clean & Affordable Energy Conference, Portland, Oregon, November 7, 2014*

28. *"Investing in Power System Flexibility," invited panelist, State/Provincial Steering Committee & Committee on Regional Electric Power Cooperation System Flexibility Forum, San Diego, California, October 20, 2014*

29. *"Opportunities and Challenges for Higher Renewable Penetration in California", invited panelist, Beyond 33%: University of California at Davis Policy Forum Series, Sacramento, California, October 17, 2014*

30. *"Renewable Curtailment as a Power System Flexibility Resource," Boise State University Energy Policy Research Conference, San Francisco, California, September 4, 2014*

31. *"Natural Gas Infrastructure Adequacy: An Electric System Perspective", Pacific Northwest Utilities Conference Committee Board of Directors, Portland, Oregon, August 8, 2014*

32. *"The Future of Renewables in the American West," invited panelist, Geothermal Energy Association Annual Meeting, Reno, Nevada, August 6, 2014*

33. *"Long-Term Natural Gas Infrastructure Needs", invited panelist, U.S. Department of Energy Quadrennial Energy Review, Public Meeting #7, Denver, Colorado, July 28, 2014*

34. *"Meeting the Demands of Renewables Integration—New Needs, New Technologies, Emerging Opportunities", invited panelist, InfoCast 2nd Annual California Energy Summit, San Francisco, California, May 28, 2014*

35. *"Power System Flexibility Needs under High Renewables", EUCI Utility Resource Planning Conference, Chicago, Illinois, May 14, 2014*

36. *"Natural Gas Infrastructure Adequacy: An Electric System Perspective", Western Interstate Energy Board Annual Meeting, Denver, Colorado, April 24, 2014*

37. *"Power System Flexibility Needs under High RPS", invited panelist, joint meeting of the Committee on Regional Electric Power Cooperation, State-Provincial Steering Committee and Western Interconnection Regional Advisory Body, Tempe, Arizona, March 26, 2014*

38. *"Natural Gas Infrastructure Adequacy: An Electric System Perspective", joint meeting of the Committee on Regional Electric Power Cooperation, State-Provincial Steering Committee and Western Interconnection Regional Advisory Body, Tempe, Arizona, March 25, 2014*

39. *"Investigating a Higher Renewables Portfolio Standard for California", 19th Annual Power Conference on Energy Research and Policy, University of California Energy Institute, Berkeley, California, March 17, 2014*

40. *"Investigating a 50 Percent Renewables Portfolio Standard in California", invited panelist, Northwest Power and Conservation Council, Portland, Oregon, March 12, 2014*

41. *"Investigating a 50 Percent Renewables Portfolio Standard in California", invited panelist, Western Systems Power Pool, Spring Operating Committee Meeting, Whistler, B.C., March 5, 2014*

42. *"Investigating a Higher Renewables Portfolio Standard for California", invited speaker, Western Electric Coordinating Council, Transmission Expansion Planning and Policy Committee, Salt Lake City, Utah, February 25, 2014*

43. *"Investigating a 50 Percent Renewables Portfolio Standard in California", invited speaker, Committee on Regional Electric Power Cooperation, State-Provincial Steering Committee and Western Interconnection Regional Advisory Body, Webinar, February 12, 2014*

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 165

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| **In the Matter of:** | ) |
| **2020 Biennial Integrated Resource** | ) |
| **Plans and Related 2020 REPS** | ) |
| **Compliance Plans** | ) |
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**INITIAL COMMENTS OF NCSEA AND CCEBA ON DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC'S INTEGRATED RESOURCE PLANS**

**EXHIBIT 3**

**[PUBLIC]**

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February 2021



# Comments on Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Integrated Resource Plans

Kevin Lucas[1]

Senior Director of Utility Regulation & Policy

**www.seia.org**

Solar Energy Industries Association®

[1] Mr. Lucas's CV is attached hereto as Exhibit 1 to this report.

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## Tables and Figures

## I. Executive Summary

The integrated resource plans ("IRP") of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (DEC and DEP, collectively, "Duke" or "the Company") present a suite of six resource portfolios, each with several sensitivities, that contain differing assumptions on key characteristics such as coal retirement timeline, renewable energy addition limits, carbon pricing, and fuel forecasts. The two Base Cases are described as "least cost" portfolios (one with and one without carbon policy), while the other four explore pathways under various carbon constraints.[2] The six portfolios are:

- **Base Case without Carbon Policy**: "least cost" portfolio assuming no carbon policy.
- **Base Case with Carbon Policy**: "least cost" portfolio assuming basic carbon policy.
- **Earliest Practicable Coal Retirement**: retires coal plants as soon as practicable and optimizes remaining portfolio to meet capacity need.
- **70% CO2 Reduction: High Wind**: 70% $CO_2$ reduction constraint is modeled with higher deployment of solar, onshore wind, and offshore wind.
- **70% CO2 Reduction: High SMR**: 70% $CO_2$ reduction constraint is modeled with higher deployment of solar, onshore with, and small modular reactors ("SMR").
- **No New Gas Generation**: High $CO_2$ reduction targeted while not adding any new natural gas generation.

Despite having a 2050 net-zero goal, Duke proposes a massive buildout of natural gas infrastructure in five of the six portfolios, much of which is brought online just after the 2035 IRP planning horizon ends. Duke underestimates the risk associated with its fuel supply assumptions, modeling availability at constant prices for firm gas delivery to its new natural gas combined cycle units despite the recent cancellation and write down of two local pipelines. Its stranded asset analysis is woefully inadequate if it has any intention of meeting its 2050 net-zero goals.

Duke fails to present a robust risk analysis that would enable the North Carolina Utilities Commission ("Commission") to determine potential negative outcomes associated with fuel supply issues or high fuel costs. Although Duke develops multiple scenarios and sensitivities, the risk analysis is primarily qualitative. The Company fails to adequately account for several fossil-fuel related risks, including limited availability of firm natural gas supply, regulatory risk associated with continued coal plant operation, and stranded natural gas infrastructure investments for several of its portfolios. It assumes operational dates for non-commercial technologies such as SMRs and hard-to-permit technologies such

[2] *Duke Energy Carolinas 2020 Integrated Resource Plan*, pp. 11-12 (November 6, 2020) ("DEC IRP Report").

as pumped hydro that are inconsistent with its own development timelines for these projects.

Duke's IRP portfolio modeling also fails to fairly evaluate the range of demand-side, storage, and other technologies and services available to meet the utility's service obligations. Duke bypassed or limited opportunities for the model to find optimal solutions, instead hardcoding many results rather than allowing the model to solve for the best solution. This was particularly true for energy-only resources, which were prohibited from selection by the model absent a capacity need. Duke's solar capital costs are reasonable, although they need to be updated based on the recent extension of the federal investment tax credit ("ITC"), but its operation and maintenance ("O&M") costs do not reflect industry trends occurring in this space. The Company also erroneously inflates its energy storage cost assumptions, incorrectly claiming that other public forecasts do not adjust for factors such as depth-of-discharge limitations and battery degradation. It also fails to account for any benefit from shorter-duration or behind-the-meter energy storage systems. The result is a substantial overestimate of energy storage costs that may have prevented the modeling software from selecting the most cost-effective quantities.

The recent extension of the federal ITC is a major development that has not been included in the Company's IRP. While this is understandable given the extension occurred in late December 2020, the impact on the IRP's portfolios could be large enough to warrant inclusion at this point. Effectively, projects that are completed before the beginning of 2026 are now able to obtain higher ITCs than was assumed during Duke's IRP development. This argues in support of pulling up solar and solar plus storage procurements to capture the credit for the benefit of Duke's customers.

Aside from failing to properly analyze the risk associated with fossil fuel generation, Duke also uses highly questionable methodologies in the natural gas price forecast used in its modeling. Duke relies on financial instruments priced on illiquid and volatile ten-year market natural gas futures contract prices before shifting over five years to a fundamentals-based forecast. The result is gas prices that are substantially lower than fundamentals-based forecasts for 15 years – the entire duration of the IRP planning period. Duke also assumes available natural gas firm fuel supply at a reasonable cost despite the recent cancellation of the Atlantic Coast Pipeline ("ACP") and $1.2 billion write down of the Mountain Valley Pipeline ("MVP"). Coupled with this is a total lack of a coal fuel cost and fixed O&M cost sensitivity, despite the sizable regulatory risks associated with the continued operation of Duke's coal fleet. These fossil-fuel related risks are all asymmetrical, leading to scenarios that are more likely to understate than overstate the cost of operating a fossil-fuel-heavy fleet.

Much of Duke's modeling assumes that it operates on an islanded network with little ability to share capacity between its operating units or to import capacity from the many surrounding balancing areas. Despite this baseline assumption, Duke's own modeling shows the benefits of a more coordinated approach to planning; allowing DEC and DEP to plan as one unit delays the need to build new capacity and produces savings for its customers. Expanding this concept further through a regional market could bring even deeper savings to customers, increase the ability to integrate renewable energy, and increase reliability in extreme events.

If Duke were to rerun its models with the recommended updated methodologies and input assumptions, optimal portfolios will retire coal sooner and build less natural gas capacity, while also selecting more solar, storage, and solar plus storage projects earlier in the planning horizon. These portfolios will be more robust against potential fossil fuel price increases and regulatory risks associated with existing and new fossil fuel assets. It will also jump start Duke's progress towards its own net-zero goals by leveraging the extension of the ITC to the benefit of its customers. The additional analysis and results will enable the Commission to determine whether it is the most appropriate plan for meeting the Company's future needs.

## Recommendation on Modeling Methodologies and Input Assumptions

1. Duke should update modeling to incorporate the impact of the extension of the federal ITC on solar and solar plus storage projects.
2. Duke should adjust its fixed O&M costs for solar to reflect the same regional discount from National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB") as in its capital costs and mirror its price decline over time.
3. Duke should use NREL ATB Advanced capital costs for its energy storage costs.
4. Duke should use an annual battery replenishment model for both its standalone storage and solar and storage projects.
5. Duke should not inflate its battery pack size assumptions as battery degradation and enhancement is already accounted for in NREL ATB's fixed O&M costs.
6. Duke should allow its model to select up to 1,500 MW and 1,000 MW of two-hour batteries in DEP and DEC, respectively.
7. Duke should perform an analysis to determine the actual mix of fixed-tilt and single-axis tracking systems in its territories and use that for all analyses that model existing solar.
8. Duke should update its assumptions on future builds of solar to be 100% single-axis tracking systems for large projects and at least 80% single-axis tracking systems for future PURPA projects.

9. Duke should eliminate the 500 MW per year interconnection limit for solar in all cases, instead using the higher 900 MW limits in its high renewables case.[3]

10. Duke should adjust the development timelines of SMR and pumped hydro to at least be consistent with its own assumptions and preferably to be more in line with development timelines from recent projects.

## Recommendations on Natural Gas Price Forecast and Coal Price Forecast

11. Duke should produce a more robust risk assessment of its proposed buildout of natural gas infrastructure, including risks associated with obtaining firm fuel supply and stranded assets.

12. Duke's natural gas price forecast should calculate three years of monthly market prices based on the average of the previous month's market settlement prices from the NYMEX NG futures contract.

13. Duke should calculate the average price from at least two fundamentals-based forecasts, at least one of which should be the most recent Energy Information Administration ("EIA") Annual Energy Outlook ("AEO") reference case.

14. Duke should create a composite natural gas price forecast by using market prices for months 1 through 18, linearly transition between market prices and the fundamentals-based forecast average from months 19 through 36, and use the fundamentals-based forecast average form month 37 forward.

15. In constructing its high- and low-price sensitivities, Duke should utilize its current "geometric Brownian Motion model" to construct 25th and 75th percentile projections for 36 months. It should also calculate the average of the appropriate high- and low-price scenario from two or more fundamentals-based forecasts and perform the same blending method over 36 months as was done in the base natural gas price forecast.

16. Duke should construct a high-cost scenario for coal that reflects the potential increase in capital costs or fixed O&M costs that may come with future regulations.

## Recommendations on The Benefits of Regionalization

17. Duke should study the impact of enhancing its Joint Dispatch Agreement ("JDA") to allow for joint planning and firm capacity sharing between the DEC and DEP.

18. Duke should study potential benefits associated with forming or joining a regional transmission organization ("RTO") or energy imbalance market ("EIM").

[3] All references to solar capacity are in $MW_{AC}$.

## II. Duke Fails to Present Sufficient Analyses Required to Determine the Robustness of its Portfolios

Duke provides basic information on the portfolios themselves (e.g., MW of assets deployed), the estimated present value of the revenue requirement ("PVRR") of the portfolio over the planning horizon, and an estimate of transmission investment required to interconnect the resources in the portfolio.[4] However, Duke's presentation of these figures lacks context.

The primary overview of the IRP Report shows the PVRR excluding the explicit cost of carbon, despite the fact that five of the six portfolios assume a carbon price is present and impacts the results. This makes it appear that the carbon reduction portfolios are considerably more expensive than the base portfolios.[5] However, if one pieces together information from the separate IRP reports, Duke's data shows that after including the cost of carbon, the incremental cost of the deep decarbonization portfolios is considerably lower than it initially appears.

For example, the incremental cost of the 70% $CO_2$ Reduction: High Wind over the Base without Carbon Policy is shown as $20.7 billion (35% higher than the base case) in Executive Summary, but this value falls to $12.4 billion (12.5% higher) with the base $CO_2$ and fuel cost assumptions when including the explicit cost of carbon in the PVRR, and to $6.0 billion (5.2% higher) under the high $CO_2$ and fuel cost assumptions when including the explicit cost of carbon in the PVRR.[6] Additionally, these figures are based on Duke's modeling, which as discussed later, contains several questionable assumptions that, when corrected, could lower the incremental cost of the deep decarbonization portfolios further. and potentially shift which portfolio becomes least-cost. Duke should be directed to clearly present comparisons with potential carbon pricing.

The Company did produce a heuristic denoted as "Dependency of Technology and Policy Advancement."[7] This qualitative measure represents the Company's observation on the complexity of realizing certain portfolios given the current state of policy and technology. For instance, it considers the Base Case without Carbon Policy portfolio as "Not dependent" on policy and technology evolution, indicating it can accomplish the portfolio's deployment within the existing constructs. The 70% reduction scenarios are denoted as "mostly dependent" (High Wind) and "completely dependent" (High SMR), suggesting that without substantial technology and policy development these portfolios cannot be realized.[8]

[4] *Duke Energy Progress 2020 Integrated Resource Plan*, p. 16 (November 6, 2020) ("DEP IRP Report").
[5] DEP IRP Report at 16.
[6] DEP IRP Report, Tables 12-B and 12-C; DEC IRP Report, Tables 12-B and 12-C.
[7] DEP IRP Report at 15.
[8] DEP IRP Report at 16.

However, Duke's analysis of this heuristic is not rigorous. The Company notes challenges such as technology advancements, operational risks, siting/permitting/interconnection issues, and supply chain development. However, there is no discussion regarding how much of these advances will occur as a baseline in the next ten years, nor discussion about how feasible the policy changes would be to enact. While one can generally agree with the directionality of Duke's assessments (for instance, it is likely true that deploying SMRs will require more policy and technology advancement than deploying solar and storage), there is insufficient evidence in Duke's IRP reports to assign a specific dependency score for each portfolio.

## Duke's Natural Gas Capacity Buildout Plan is Risky and Inconsistent with its 2050 Net-Zero Goals

There is a considerable variance in the natural gas build out between the portfolios. The Company currently operates 10,460 MW of natural gas units, split roughly equally between combustion turbine ("CT") and combined-cycle ("CC") units.[9] Table 1 below shows the proposed incremental capacities under the portfolios.

| | By 2035 | | | By 2041 | | |
|---|---|---|---|---|---|---|
| | CC | CT | **Total** | CC | CT | **Total** |
| **2020 Capacity** | 4,940 | 5,520 | **10,460** | 4,940 | 5,520 | **10,460** |
| **Incremental Capacity** | | | | | | |
| **Base without Carbon Policy** | 3,672 | 5,941 | **9,613** | 4,896 | 12,796 | **17,692** |
| **Base with Carbon Policy** | 3,672 | 3,656 | **7,328** | 4,896 | 10,054 | **14,950** |
| **Earliest Prac. Coal Retirement** | 3,672 | 5,941 | **9,613** | 3,672 | 10,968 | **14,640** |
| **70% CO2: High Wind** | 3,672 | 2,742 | **6,414** | 3,672 | 5,484 | **9,156** |
| **70% CO2: High SMR** | 2,448 | 3,656 | **6,104** | 2,448 | 6,398 | **8,846** |
| **No New Gas Generation** | 0 | 0 | **0** | 0 | 0 | **0** |

*Table 1 - Natural Gas Additions by Portfolio*

By 2035, the first three scenarios add three new 1,224 MW CCs while increasing CT capacity by roughly two-thirds (Base with Carbon Policy) or more than double (Base without Carbon Policy and Earliest Practicable Coal Retirement). The 70% CO2: High Wind adds fewer CTs through 2035, offset by increasing battery deployment. Unsurprisingly, the No New Gas Generation portfolio adds no new gas generation.

As dramatic as are the additions by 2035, the additional builds through 2040 are truly staggering. The two Base Cases each add another 1,224 MW CC facility. The Base without Carbon Policy more than doubles incremental CTs, bringing nearly 7 GW of additional capacity online by 2041. The Base with Carbon Policy portfolio adds nearly as much, with 6.4 GW of new CTs. These additions represent the largest proposed natural gas expansion

[9] DEC IRP Report, Appendix B; DEP IRP Report, Appendix B.

of any utility in the country by far.[10] Figures 1 and 2 below show the annual additions under each scenario, revealing that much of the natural gas build that was modeled rests just outside of the 15-year planning horizon in Duke's IRP.

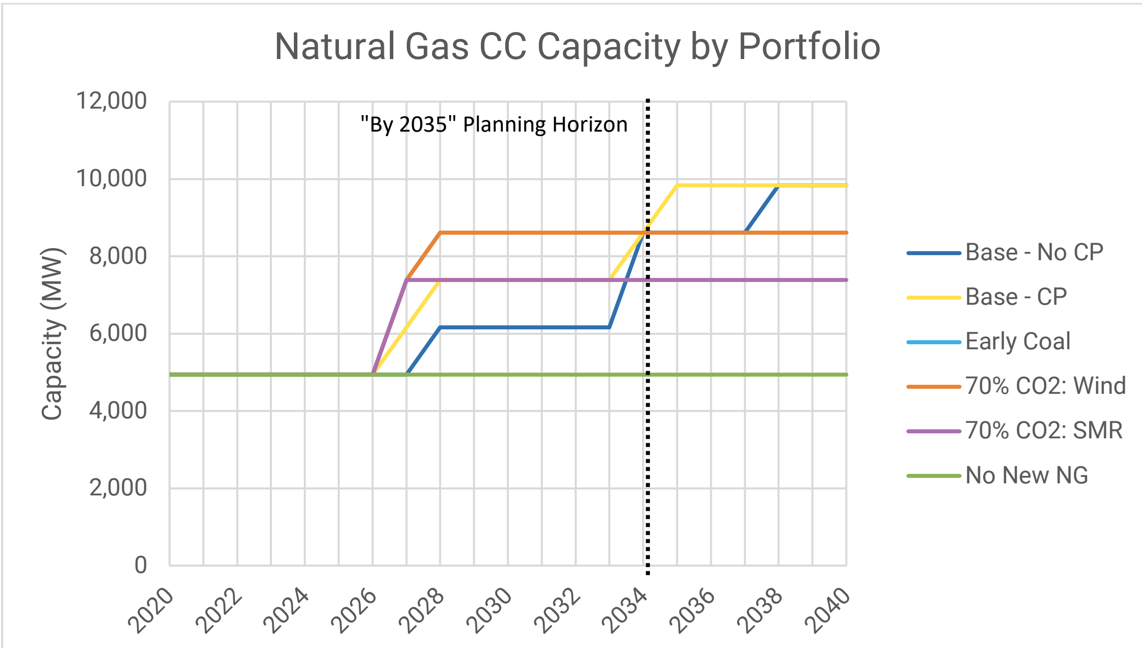


*Figure 1 - Natural Gas CC Additions by Scenario*

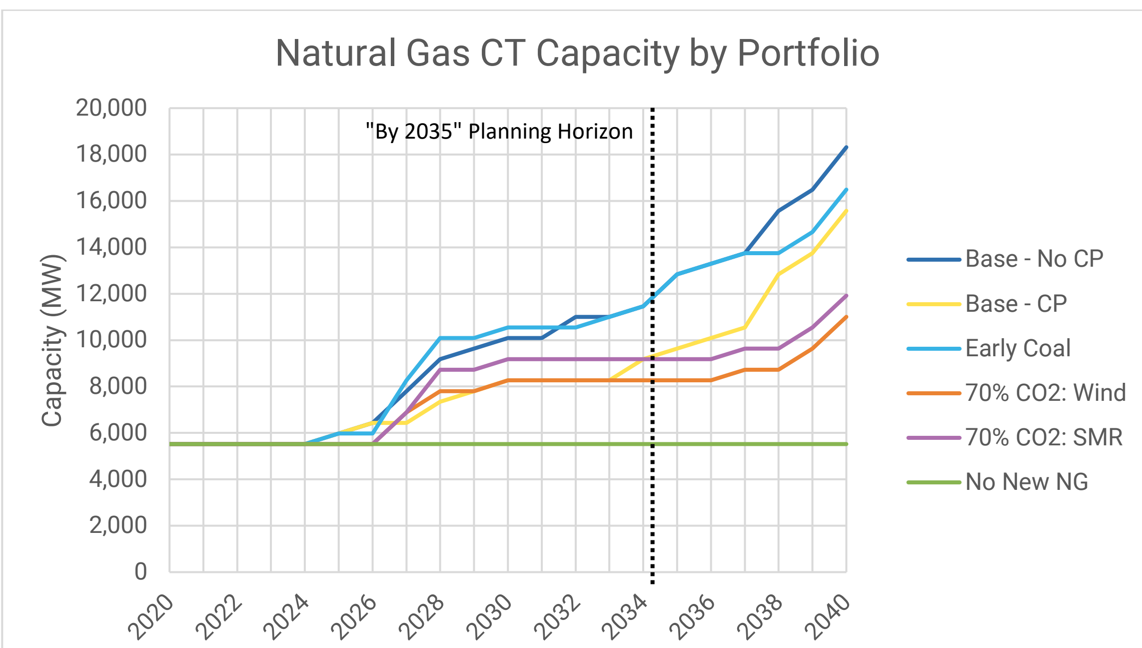


*Figure 2 - Natural Gas CT Additions by Scenario*

[10] *The Dirty Truth about Utility Climate Pledges*, Sierra Club, January 2021, available at https://www.sierraclub.org/sites/www.sierraclub.org/files/blog/Final%20Greenwashing%20Report%20%281.22.2021%29.pdf.

Duke performed very little risk analysis with respect to adding this much new natural gas capacity. Duke did include a low and high natural gas fuel cost forecast sensitivity,[11] but it simply assumes that firm capacity to deliver this gas to all its new CC units will be available from "new or upgraded capacity" at a constant price.[12] Given the recent cancellation of the ACP, the recent $1.2 billion write down by NextEra on its MVP project, and the increasingly challenging siting and permitting environment for new or upgraded capacity, this assumption is not without risk.[13]

Further, the Company does not plan on contracting for firm natural gas delivery for its CT units, despite adding nearly 6 GW by 2035 and up to 12.8 GW by 2040 in some scenarios that will be utilized during cold winter mornings and evenings at the exact same time when the natural gas distribution system will be under stress from building heating loads. The risk associated with this decision has played out to tragic effect in the recent polar vortex in Texas, where a lack of natural gas fuel supply contributed to the outage of tens of thousands of MW of natural gas generators.

Duke's plans regarding the addition of new natural gas units are inconsistent with its plans to decarbonize by 2050, at least not without significant risk of stranding assets or becoming overly dependent on emerging technology. Duke has a corporate goal to have net-zero carbon emission by 2050.[14] This is not the same as emitting zero carbon, as Duke specifically contemplates the deployment of carbon capture and sequestration technology in the future.[15] It also assumes renewable gas and hydrogen will be widely available to power units that previously ran on natural gas and that "zero emission load following resources" ("ZELFRs"), such as SMRs and CC units with carbon capture and sequestration ("CCS"), will be commercially available by 2035.[16]

These technologies are not yet commercialized. Although the energy industry will certainly change over the coming 15 years, there is much uncertainty as to whether resources such as SMRs and CCs with CCS will have been commercialized by that time, or, if they are, if they will be cost effective compared to other technologies. There is also an open question of whether the infrastructure required to sequester the $CO_2$ captured from CC units will be cost-effective or whether Duke's geographic territory has suitable reservoirs. Notably, Duke acknowledges this uncertainty and does not include any $CO_2$ transport costs outside

[11] Which has its own substantial issues, as discussed in Section IV *infra*.
[12] Duke Response to NCSEA DR2-45; Duke Response to NCSEA DR2-55.
[13] In a telling signal, NextEra's announcement of its $1.2 billion write down on its pipeline was coupled with an announcement of adding as much as 30 GW of renewable projects to its portfolio, well above analyst estimates of 20 GW. https://www.reuters.com/article/nextera-energy-results/update-1-nextera-energy-posts-loss-on-pipeline-write-down-idUSL4N2K12N3.
[14] https://www.duke-energy.com/Our-Company/Environment/Global-Climate-Change
[15] Duke Energy 2020 Climate Report, p. 4 ("Climate Report"), available at https://www.duke-energy.com/_/media/pdfs/our-company/climate-report-2020.pdf?la=en (accessed January 20, 2021).
[16] Climate Report at 5.

the fence line, noting these costs are "highly depending on location, as well as the cost of injection."[17]

Renewable natural gas and hydrogen infrastructure to displace natural gas has recently emerged as an area of intense interest. It is possible that a new industry will emerge that can supply zero-carbon fuel to Duke's natural gas fleet, but current units cannot burn pure hydrogen without modifications. It is unclear whether Duke will install units that have this capability in the future ahead of widespread deployment of hydrogen as a fuel stock. If they do not, then additional assets will be at risk of stranding or require substantial and costly modifications if and when a switch to hydrogen becomes commercially viable.

Duke assumes that its natural gas fleet will "shift from providing bulk energy supply to more of a peaking and demand-balancing role."[18] This is consistent with the deployment of large quantities of renewable energy and energy storage that are also required in the net-zero scenarios. However, Duke's Base Case portfolios in the IRP doubles the capacity of high-capacity factor CC units by 2040, while other scenarios add between 50% and 75% more CC capacity. Much of this capacity is added after 2032, only 18 years before the planned net-zero date.

These units are designed to run at high capacity factors and are not as flexible as CT units. Building this much new CC capacity, with less than two decades until the Company's planned transition to net-zero, risks stranding billions in dollars of assets. While Duke did perform a nominal stranded asset sensitivity, it assumed that natural gas units would have a 25-year life.[19] However, if Duke is serious about reaching net zero in 2050, this assumption appears incorrect for the thousands of MW of new capacity added after 2030.

Duke's IRP foresees a massive ramp up in both renewable generation capacity and energy storage. In its illustrative example, the Company projects going from 5 GW of renewables in 2019 to 31 GW in 2040 and 47 GW in 2050. Energy storage increases from 2 GW in 2019 to 7 GW in 2040 and 13 GW in 2050.[20] These deployment levels are not without their challenges, but unlike some of Duke's other resource assumptions, the underlying renewable and energy storage technologies are mature and widely available.

Duke can take steps now to increase the likelihood of attaining its net-zero goals while minimizing the risk of stranding natural gas assets. The Company should ramp up its deployment of renewable generation and storage in the near term. Duke's 2050 goals call for massive quantities of new renewables and storage over the next 30 years, and yet it backloads much of these capacity additions. The recent passage of the ITC offers a chance

[17] Climate Report at 24.
[18] Climate Report at 2.
[19] DEC IRP Report at 137. DEP IRP Report at 137.
[20] Carbon Report at 26.

to more economically deploy solar and solar plus storage projects prior to 2025 to jumpstart Duke's progress towards its goals.

In summary, Duke models huge increases in natural gas capacity, both from CC and CT units. While it presented results primarily through 2035, it modeled scenarios through 2040. The latter build schedules show even more natural gas deployment in the second half of the 2030s, less than two decades before the Company's net-zero pledge. Further, the construction of more natural gas capacity will increase the Company's customers' exposure to natural gas prices. Since Duke is able to pass through fuel costs as an expense, it would be the retail customers who would see higher bills from elevated natural gas prices.

In the near term, Duke assumes firm fuel transport for its CC units will be readily available at the same price as today, despite the increasing regulatory risk associated with new pipeline capacity. It does not assume firm fuel delivery for its CTs, despite their increasing usage during winter mornings and evenings when building heating load is highest. It also does not consider the risk associated with a lack of fuel availability during extreme weather events. These are substantial cost and operational risks that are not well accounted for in the IRP.

Duke assumes substantial technological evolution in its 2050 net-zero goal, which directly informs the 70% $CO_2$ reduction scenarios in the IRP. CC with CCS or broadly-available hydrogen fuel is required to continue to run its turbines. Further, turbines that are designed for hydrogen combustion would need to become the norm and Duke would need to begin to install these well before 2050 lest then-existing assets would require major upgrades. The energy sector will certainly evolve in the coming decades, but Duke's decarbonization scenarios rely very heavily on technology with speculative commercial viability.

By contrast, renewable generation and energy storage are mature technologies that can be incorporated earlier and in larger quantities than assumed in Duke's plan. Although the Company's IRP scenarios include sizable renewable buildouts, more could be done earlier in the timeline to reduce reliance on construction of substantial natural gas capacity later in the planning period. This is particularly true given the recent extension of the federal ITC for solar and solar plus storage systems.

## A Basic Risk Analysis Shows the Benefit of the Early Coal Retirement Option

Duke did not perform any quantitative risk analyses, relying instead on risk assessments that were largely qualitative in nature. It presented the results of its various scenarios and sensitivities but did not produce analyses to compare those portfolios across various input assumptions.

Duke modeled a carbon price as a production cost adder in all portfolios except for the Base Case without Carbon Policy. The carbon price commences in 2025 at $5/ton and increases by $5/ton and $7/ton annually in the base and high $CO_2$ price sensitivities.[21] By 2050, the carbon price has escalated to $130/ton and $180/ton in the base and high case, respectively. This carbon price is substantially under several other recent $CO_2$ pricing announcements that Duke mentions in its IRP, including Energy Innovation and Carbon Dividend Act (H.R. 763) ($15/ton escalating at $10 /ton per year) and the American Opportunity Carbon Free Act of 2019 (S. 1128) ($52/ton escalating at 8.5% per year).[22] It is also substantially under the recently announced carbon price from New York Department of Environmental Conservation, which was calculated at $125 / ton in 2020 before increasing to $373 / ton in 2050.[23]

Duke did not model any increased regulatory costs that may impact the economics of continuing to run its coal plants. Duke did not construct a high- or low-cost sensitivity for fuel or fixed O&M costs for coal units, nor did it model retirement outcomes under different regulatory regimes. Given recent developments at the federal level, it is highly likely that new regulations will be enacted that substantially change the cost of keeping coal units online, and the risk of such regulations is likely highly asymmetric towards increasing costs rather than reducing them.[24]

The Company did provide basic information regarding the performance of their portfolios under different fuel and $CO_2$ cost assumptions. It included the PVRR values for each scenario, highlighting the base fuel case that excluded the explicit cost of carbon.[25] Under this approach, it appears the Base without Carbon Policy has the lowest PVRR across all sensitivities, with the Base with Carbon Policy and Earliest Practicable Coal Retirement costing about 1% to 6% more and the 70% $CO_2$ Reduction and No New Gas portfolios costing about 13% to 41% more.

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[21] DEC IRP Report at 153.
[22] DEC IRP Report at 153.
[23] 2050 carbon price is $178 / ton in $2020. Assuming inflation at 2.5% per year produces a 2050 nominal price of $373.37 / ton. https://www.dec.ny.gov/press/122070.html.
[24] President Biden's highly publicized commitment to 100% decarbonization of the electric power sector by 2035 will necessarily require much more stringent regulation of coal-fired power plants than exists today. *See*, https://www.washingtonpost.com/climate-environment/2020/07/30/biden-calls-100-percent-clean-electricity-by-2035-heres-how-far-we-have-go/?arc404=true. Moreover, in his January 20 Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis, President Biden called for the U.S. Environmental Protection Agency ("EPA") to review and consider suspending, revising, or rescinding many Trump Administration actions weakening the regulation of coal-fired power plants, including, but not limited to "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units – Reconsideration of Supplemental Finding and Residual Risk and Technology Review," 85 Fed. Reg. 31286 (May 22, 2020). In addition, the D.C. Circuit Court of Appeals recently affirmed EPA's finding that greenhouse gas emissions endanger public health and welfare, and that EPA is thus required by the Clean Air Act to adopt to regulations to address such emissions from new and existing power plants. With respect to existing power plants, that means that EPA must, under 42 U.S.C. § 7411, establish the "best system of emission reduction ["BSER"] that has been adequately demonstrated." The D.C. Circuit rejected the Trump Administration's conclusion – contrary to that of the Obama Administration – that BSER may not include measures beyond the fence line of the power plant, such as mandating the replacement of existing carbon-emitting resources with new zero-emission resources. *American Lung Association et al. v. Environmental Protection Agency et al.*, Case No. 19-1140 (D.C. Cir. Jan. 18, 2021). None of this bodes well for the future of existing coal-fired power plants.
[25] DEC IRP Report at 17.

However, these figures do not tell the complete picture, as, with the exception of the Base without Carbon Policy, they do not include the cost of carbon that is modeled in the scenario. When these costs are added back in, the performance of the portfolios change substantially. After making this change, the Base Case without Carbon Policy does not have the lowest PVRR in 5 of the 6 sensitivities with a carbon price, and the cost premium for the Earliest Practical Retirement portfolio is nearly erased, from an average of 5% without carbon costs to an average of 1% with carbon costs. Further, the calculated cost premium of the deep decarbonization scenarios fall substantially to 3% to 24% (down from an increase of 13% to 41%), despite Duke's questionable inputs assumptions.[26]

These cost ranges can be investigated through a cost range and minimax regret analysis on Duke's scenarios. These straight-forward analyses provide insight on how portfolios may perform under a variety of future scenarios. Although fairly simple, they highlight the importance when determining the most reasonable and prudent plan of looking beyond a portfolio that is assumed least-cost in limited scenarios.

The result of these analyses is telling. When the explicit cost of carbon is considered, the Earliest Practical Retirement portfolio emerges as the most robust of those scenarios that do not specifically target deep decarbonization. Table 2 shows the cost range and minimax regret analysis for each of the portfolios and the $CO_2$ and fuel cost sensitivities. Note that these values still contain Duke's flawed natural gas price forecasts, which are substantially lower than fundamentals-based forecasts, and inflated energy storage costs. If the Commission were to require Duke to update its natural gas forecasts, scenarios with higher natural gas usage would be more costly.

[26] DEP IRP Report, Tables 12-B and 12-C; DEC IRP Report, Tables 12-B and 12-C.

| PVRR ($b) | Base w/o Carbon | Base w/ Carbon | Earliest Coal | 70% CO2: High Wind | 70% CO2: High SMR | No New NG |
|---|---|---|---|---|---|---|
| **High CO2-High Fuel** | 116.5 | 113.7 | 114.5 | 122.5 | 117.3 | 129.7 |
| **High CO2-Base Fuel** | 106 | 104.5 | 105.3 | 115.6 | 110.4 | 123.1 |
| **High CO2-Low Fuel** | 99.1 | 98.4 | 99.3 | 110.8 | 105.6 | 118.4 |
| **Base CO2-High Fuel** | 109.6 | 107.8 | 108.9 | 118.5 | 113.4 | 125.8 |
| **Base CO2-Base Fuel** | 99.2 | 98.8 | 99.7 | 111.6 | 106.5 | 119.2 |
| **Base CO2-Low Fuel** | 92.4 | 92.6 | 93.7 | 106.9 | 101.8 | 114.6 |
| **No CO2-High Fuel** | 89.2 | 90.4 | 93.3 | 107.4 | 102.3 | 114.3 |
| **No CO2-Base Fuel** | 79.8 | 82.2 | 84.2 | 100.5 | 95.5 | 108.2 |
| **No CO2-Low Fuel** | 73.3 | 76.4 | 78 | 95.8 | 90.7 | 103.5 |
| **Cost Range** | 43.2 | 37.3 | 36.5 | 26.7 | 26.6 | 26.2 |
| **Max Regret** | 43.2 | 40.4 | 41.2 | 49.2 | 44 | 56.4 |

*Table 2 - Cost Range and Minimax Analysis – Carbon Cost Included*

The Cost Range of each scenario represents the highest PVRR less the lowest PVRR. It is a measure of sensitivity of a scenario to fuel and $CO_2$ cost inputs. Unsurprisingly, the deep decarbonization scenarios on the right side of the table have the lowest cost range as they contain the least fossil fuel, and thus the lowest exposure to both $CO_2$ and natural gas prices.[27] The Base Case Without Carbon Policy has the highest range of the set, demonstrating the risk of assuming low costs and no $CO_2$ costs and finding oneself in a policy world with high fuel costs and high $CO_2$ costs. Of the three scenarios on the left side, the Earliest Practicable Coal Retirement has the lowest Cost Range result, again showing that eliminating coal earlier while adding more renewables reduces exposure to $CO_2$ and natural gas costs.

The Max Regret value represents the difference between a portfolio's highest PVRR and the lowest PVRR of all the scenarios. This represents the worst-case outcome of choosing an alternative portfolio compared to selecting the lowest possible portfolio under the least cost option. The low PVRR is established by the Base without Carbon No $CO_2$-Low Fuel sensitivity at $73.3 billion. Based on this figure, the lowest Max Regret score is from the Base with Carbon, followed closely by the Earliest Practicable Coal Retirement scenario. These have Max Regret scores $2.8 and $2.0 billion lower than the Base without Carbon Policy portfolio, suggesting that selecting these two portfolios is less risky than the Base without Carbon Policy.

The Base Case with Carbon has the lowest Max Regret value at $40.4 billion, followed by the Earliest Practical Coal Retirement at $41.2 billion. The difference between the two amounts is less than 1% of the total PVRR of the portfolios. Importantly, these results do not contemplate new federal or state regulations that may require substantial capital cost investments to maintain the compliance of fossil fuel plants which would be in addition to

[27] DEC IRP Report at 8.

any variable costs such as fuel and $CO_2$ that are included. Further, the risk of these new regulations is much higher in the Base Cases where coal is assumed to operate longer than the deep decarbonization portfolios when coal plants are retired earlier. This likely understates the cost of owning and operating coal plants compared to baseline included in Duke's IRPs. If this risk were more rigorously quantified, it very well may have an expected value greater than the $0.8 billion noted above.

The relatively high Max Regret results for the 70% $CO_2$ reduction and No New Gas scenarios are not of much concern. Much of the incremental cost of the 70% $CO_2$: High Wind portfolio over the Earliest Practical Coal Retirement is due to Duke's assumptions of transmission cost. However, the Company has not rigorously analyzed these costs nor considered the cost savings that may come from broader regionalization.[28] Similarly, the No New Natural Gas scenario is hampered by Duke's unreasonable energy storage cost assumptions. Had more reasonable costs been included, the cost of adding standalone storage and solar plus storage would have been reduced and closed the gap between the deep decarbonization portfolios and the others.

Duke failed to present robust, quantitative risk analyses. It focused primarily on the portfolio PVRR under different natural gas and $CO_2$ cost assumptions but did little to compare the relative risk of the portfolios against each other. The basic minimax analysis above shows that despite the Base without Carbon Policy scoring the lowest PVRR, it was not the least risky plan. Although the analysis above is hampered by Duke's unreasonable input assumptions, a strong case can be made that the Earliest Practicable Coal Retirements case is the most robust of the non-deep decarbonization portfolios. This result is also supported by the asymmetric likelihood that regulatory costs will rise on coal plants before they fall, further increasing the risk associated with the continued operation of Duke's coal fleet.

[28] Duke Response to NCSEA DR2-6.

# III. Duke's Modeling Assumptions Require Modification

The opportunity afforded by the ITC extension should not be bypassed. The two-year extension opens a window where Duke could deploy substantially more solar and solar plus storage projects early in its IRP planning horizon while allowing customers to reap the financial benefits. Although this change occurred after Duke completed its modeling, it is of sufficient scale and consequence that the Commission should direct Duke to update its modeling to incorporate the new law.

Overall, Duke's cost and operation assumptions on solar and storage are mixed. Its capital cost assumptions for solar are reasonable (although must be updated to account for the ITC extension), but its fixed O&M cost assumptions do not reflect the technology improvements in that sector. Duke's battery capital costs are substantially overinflated and inconsistent with other benchmarks, in part due to an incorrect interpretation of NREL's ATB forecast methodology. Duke's assumption on system mix between fixed-tilt and single-axis trackers is outdated compared to the movement of the market.

Several of Duke's portfolios rely on new SMR and pumped hydro capacity. While acknowledging the challenges of permitting, developing, and constructing these assets, Duke also included documentation that directly contradicts its timeline projections. If Duke is correct on how long these projects will take to develop, it cannot also be correct on when they will be in service.

The impact of these changes in input assumptions and modeling methodologies will likely produce portfolios that retire coal sooner, add less natural gas, and add more solar and storage, particularly early in the planning horizon. Each of these reduces risk of an updated portfolio, reducing substantial regulatory risk associated with the ongoing operation of coal plants and blunting the impact of a potential increase in fossil fuel costs.

## The Recent ITC Extension Materially Changes Solar and Solar Plus Storage Economics in the Near Term

The federal ITC is a tax credit that developers can use to offset a portion of the qualified capital costs of a solar project. It applies to both stand-alone solar projects and solar-plus-storage projects, with the ITC applying to both solar and storage capital costs in the latter. In a typical financing structure, developers will partner with "tax equity" providers that have significant federal tax liability and thus the ability to utilize the tax credits. These tax equity investors will contribute a portion of the up-front cost of the project in exchange for the right to claim the tax credits. This financing method supports the development of assets such as solar PV in which most of the life-cycle costs are incurred up front and that have very low operating costs over the life of the project. The ITC has been a critical driver of solar deployment over the past decade.[29]

Until recently, the federal ITC was in the process of stepping down. It had been equal to 30% of the eligible project costs for projects commenced in 2019, 26% for 2020, 22% for 2021, and was on schedule to fall to 10% for non-residential projects and 0% for residential projects in 2022 and beyond. To be eligible for any credit in excess of 10% a project also had to be placed in service within four years and also by December 31, 2023. These values were codified in the then-current statute and were thus properly assumed in Duke's IRP modeling completed in summer 2020.

However, Congress passed legislation in December 2020 that extended the stepdown by two years. Now, projects begun by December 31, 2022 will enjoy the 26% credit and those started by December 31, 2023 will receive the 22% credit. Congress also extended the "safe harbor" provisions of the tax credit, which allows developers to "lock in" the ITC for up to four years based on the commencement of construction of the project as long as they are in service by December 31, 2025. This means that a project that begins in December 2022 can lock in the 26% credit as long as it is placed into service before January 1, 2026.[30]

The extension of two years is very meaningful to the economics of solar projects. Figure 3 below compares the two schedules showing Duke's assumptions and the current law. The two-year extension provides a relatively modest incremental tax benefit of 4% in 2021, but a much larger 16% and 12% increase in 2022 and 2023, respectively. Further, the drop-dead date for placing a project in service while still being able to safe harbor ITCs higher than 10% has also been pushed back two years. This is a critical period in Duke's IRP as it continues to ramp up renewable energy.

[29] For more information, please see https://www.seia.org/initiatives/solar-investment-tax-credit-itc.

[30] Projects that incur 5% of total costs or have started "physical work of a significant nature" can claim to have "commenced construction" and thus can claim "safe harbor" for the ITC for the entire project cost. For more information, see https://www.seia.org/initiatives/commence-construction-guidance.

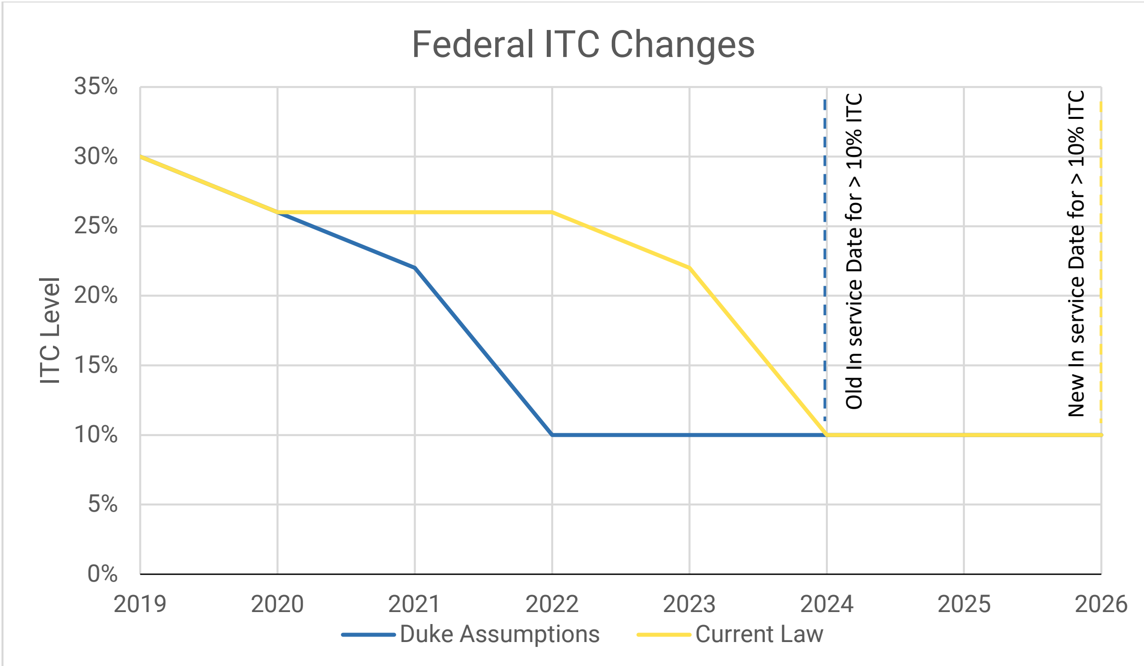


*Figure 3 - Federal ITC Changes*

Enabling developers to claim a tax credit equal to an incremental 4%, 16%, and 12% of the total capital cost of the project will have a meaningful impact on the economics of new solar and solar plus storage projects. NREL's ATB workpaper calculates the levelized cost of energy ("LCOE") for several locations. While cities in Duke's territories are not specifically modeled, ATB does include data for Kansas City which has similar insolation as Duke's North Carolina and South Carolina territories.

Table 3 below shows the LCOE using NREL ATB's Advanced cost parameters under the old and new ITC paradigm for Kansas City. While neither the production figures nor the financial assumptions are the same as assumptions that Duke or other solar developers would use in North Carolina, the figures serve as a good proxy for the magnitude of impact that the ITC change may have on Duke's modeled results. The percentage reduction in the LCOE of the project is nearly equivalent to the incremental ITC benefit. For projects coming online in 2022 and 2023, there could be a $3-4 / MWh reduction in levelized cost, pushing solar costs into the low-$20s per MWh. This change will make solar even more competitive to new generation, much less with the running costs of existing generation. But capturing these cost reductions will only be possible by increasing solar and solar plus storage deployments in the early portion of Duke's planning horizon.

| LCOE ($/MWh) | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| **Duke ITC Assumptions** | $24.62 | $24.82 | $27.07 | $25.91 | $24.73 |
| **Current Law** | $24.62 | $23.69 | $22.74 | $22.80 | $24.73 |
| **$ Delta** | $0.00 | ($1.13) | ($4.33) | ($3.11) | $0.00 |
| **% Delta** | 0.0% | -4.5% | -16.0% | -12.0% | 0.0% |

*Table 3 - LCOE Under Duke ITC Assumptions and Current Law*

Given the four-year safe harbor provisions, it is possible to push out the online date of projects while still capturing a higher ITC level. Developers can capture the higher ITC by ordering adaptable interconnection equipment that it applies to various RFPs. As such, as long as Duke continues with annual RFPs on schedule, developers should be able to lock in the higher ITC for RFPs out to 2023. This would allow equipment to be placed into service in 2025 while still capturing the higher ITC. The Commission should direct Duke to update its modeling to reflect the new reality of the federal ITC extension and safe harbor provisions.

## Duke's Solar PV Capital Cost Assumptions Must Incorporate the ITC Extension but are Otherwise Reasonable

Duke relied on capital cost assumptions for offshore wind, solar, and energy storage from Navigant for the years [redacted] through [redacted].[31] For [redacted] forward, Duke escalated costs based on the capital cost increase index from the 2020 EIA AEO.[32] The resulting blended capital cost forecast reflects Carolina-specific factors such as labor costs and land rental while capturing the national-level longer-term cost reduction trends as solar technology evolves.

Because Duke's forecast utilizes regional-specific data rather than NREL ATB's general nationwide averages, Duke's near-term forecast reflects the lower costs associated with doing business in the Carolinas. Directionally, Duke's forecast represents a downward step of roughly [redacted]% from the NREL ATB Moderate scenario in 2020. Annual cost reductions are shallower than the NREL ATB Advanced scenario from 2020 through 2030, before [redacted] with the ATB Advanced scenario in 2030 and beyond. The resulting forecast is shown in Figure 4 below.

[31] Duke Response to PSDR3-7 (Confidential - IRP Generic Unit Summary DEC 2020).
[32] DEP IRP Report at 322.

[redacted]

Figure 4 - PV Capital Cost from NREL ATB and Duke

On balance, Duke's solar capital cost forecast is reasonable, although these values must be updated to incorporate the ITC extension. It properly adjusts for local construction and land rent cost factors and shows an overall cost reduction trajectory that, while not as aggressive as the NREL ATB Advanced scenario, does [redacted] the ATB Moderate scenario. Duke should monitor the evolution of solar capital costs and revisit them frequently as the industry has more often than not seen faster cost reductions than anticipated. If in the future costs are falling faster than currently anticipated, Duke could readily update its forecast.

## Duke's Solar Fixed O&M Costs are Too High

Duke used a value of $[redacted] / kW-year for fixed O&M costs based on an "[redacted] This was [redacted] through the analysis period.[33] This value is relatively higher than the capital cost forecast, and unlike that metric, Duke does not project a [redacted] in prices over time in the fixed O&M cost category. The NREL ATB Moderate and Advance cases have fixed O&M costs for 2020 of $16.65 and $16.48 / kW-year, respectively, falling steadily to $15.24 and $14.11/ kW-year, respectively, in 2025. Duke's 2020 figure is roughly [redacted]% lower than NREL ATB's, a notable divergence from its capital cost adjustment. By 2025, Duke's figure [redacted] while the NREL ATB has fallen 8.5% and 14.5% even after accounting for inflation.

[33] Duke Response to PSDR3-7 (Confidential - IRP Generic Unit Summary DEC 2020).

Figure 5 below shows the original and adjusted NREL ATB values along with Duke's forecast. The adjustment applies the same average [redacted]% discount to the fixed O&M costs as was projected on the capital costs. By comparison, Duke's projection for fixed O&M begins and stays too high.

[redacted]

*Figure 5 - Fixed O&M*

As capital costs fall, fixed O&M costs become a higher proportion of the lifecycle costs of a solar plant, providing a strong incentive to industry players to reduce costs over time. Solar is a competitive industry seeking to apply new technologies and data analytics to proactively and predictively anticipate outages to minimize system downtime. Companies that can bid lower cost O&M costs will be able to win competitive procurements, and penalty provisions in PPA documents ensure that operators will hold up their end of the bargain lest face financial penalties. The NREL ATB forecast recognizes these factors and price in a decline over time.

Duke should model lower costs to mirror the discount from the NREL ATB that is used in the Company's capital cost forecast and assume a price decline at least as aggressive as the NREL ATB Moderate scenario to reflect the innovation occurring the in O&M space.

## Duke's Energy Storage Cost and Operational Assumptions are Inappropriate

Duke relied on a third-party to produce its energy storage cost estimate rather than relying on one of several publicly available benchmarks. The Company admits that its prices "appear higher than published numbers" but claims this is due to differing assumptions.[34] Specifically, Duke claims that its higher prices are impacted by:

- Using a 20% depth of discharge ("DoD") limit
- Historic DEC/DEP interconnection costs
- Higher software and control costs
- More expensive HVAC and fire suppression equipment
- High integration costs due to the Company's lack of experience with energy storage[35]

Despite calculating higher initial prices than other benchmarks, Duke does forecast a 34% price decrease between 2020 and 2029.[36] However, other benchmarks also project steep cost declines and thus Duke's costs continue to be above other estimates through 2029.

Duke claims that a standalone [redacted] MW / [redacted] MWh battery connected at the transmission level and online in 2021 would cost $[redacted] / kW.[37] This figure is compared to other benchmarks in Table 4 below.

| | Capital Cost ($/kW) | | | Fixed O&M ($/kW-year) | | |
|---|---|---|---|---|---|---|
| **Online Date** | 2021 | 2025 | 2029 | 2021 | 2025 | 2029 |
| **Duke** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **NREL ATB Advance** | $1,204 | $926 | $800 | $30.10 | $23.16 | $20.00 |
| **NREL ATB Moderate** | $1,469 | $1,194 | $1,121 | $36.74 | $29.84 | $28.03 |
| **Lazard v 5.0 (2019)[38]** | $898 - $1,874 (2019) | | | | | |
| **Lazard v 6.0 (2020)[39]** | $752 - $1,401 (2020) | | | | | |
| **Santee Cooper RFI** | $1,324 (2022) | | | | | |

*Table 4 - Energy Storage Cost Comparison*

Part of the discrepancy between Duke's figures and other benchmarks is due to the Company's battery degradation and depth of discharge assumptions. Duke stated that "NREL benchmarked costs against publicly available 3rd party data. If another source did not includes [sic] costs for DoD, NREL did not add additional costs in their benchmarking."[40] While it is true that NREL noted "a number of challenges inherent in developing cost and performance projections based on published values", its methodology insulates the final cost projection from this issue:[41]

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[34] DEC IRP Report at 341.
[35] DEC IRP Report, Appendix H.
[36] DEC IRP Report at 341.
[37] Duke Response to PSDR3-7 (Confidential - IRP Generic Unit Summary DEC 2020).
[38] Lazard's Levelized Cost of Storage Analysis – Version 5.0 (November 2019), available at https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf.
[39] Lazard's Levelized Cost of Storage Analysis – Version 6.0 (November 2020) available at https://www.lazard.com/media/451418/lazards-levelized-cost-of-storage-version-60.pdf ("Lazard v6.0).
[40] Duke Response to DR NCSEA 3-14, Attachment NCSEA DR 3-14_BatteryCostComparison.
[41] Cost Projections for Utility-Scale Battery Storage: 2020 Update, NREL (June 2020) ("NREL 2020 Update"), available at https://www.nrel.gov/docs/fy20osti/75385.pdf.

> To develop cost projections, storage costs were normalized to their 2019 value such that each projection started with a value of 1 in 2019. We chose to use normalized costs rather than absolute costs because systems were not always clearly defined in the publications. For example, it is not clear if a system is more expensive because it is more efficient and has a longer lifetime, or if the authors simply anticipate higher system costs. With the normalized method, many of the difference [sic] matter to a lesser degree. Additionally, as will be shown in the results section, the 2019 benchmark cost that we have chosen for our current cost of storage is lower than nearly all the 2019 costs for projections published in 2017. By using normalized costs, we can more easily use these 2017 projections to inform cost reductions from our lower initial point.[42]

NREL's approach uses third-party data to develop an average cost decline over time and applies that to a benchmark 2019 price of $380 / kWh to create its projections.[43] As long as the individual studies in the third-party data maintained internally consistent assumptions (an entirely reasonable assumption), the specific DoD and degradation assumptions of the individual research reports are less important.

Duke is correct that Lazard's 2019 energy storage report assumed 100% DoD and did not account for degradation. However, Lazard's 2020 energy storage analysis corrected these issues, assuming a 90% DoD assumption and oversizing batteries by 10% to allow for degradation over time.[44] These results produced the more robust results shown in Table 4 above.

Batteries degrade with usage. To maintain a minimum performance threshold, one can either oversize the battery at the beginning or augment the battery capacity over time to counteract the degradation. In the overbuild approach, one may install 120 MWh of battery packs in a battery rated at 100 MWh. This would allow for 20 MWh of degradation over the lifetime and still enable the battery to charge and discharge 100 MWh. Under an augmentation strategy, one would install a 102 MWh battery and add roughly 2 MWh of new capacity each year to counteract the degradation of the original capacity. This would also allow the battery to charge and discharge 100 MWh through the life of the project.

Duke approaches this issue differently for standalone storage and for solar plus storage installations. For standalone storage, Duke utilizes an annual replenishment strategy.[45] The annual replenishment cost for the standalone storage is in addition to (and slightly higher than) its annual fixed O&M costs and explains why Duke's estimates are so much higher than NRELs. By contrast, NREL allocates all operating costs to the fixed O&M bucket and uses the higher of the fixed O&M estimates from third parties, thus "in essence

[42] *Id.* at 3.
[43] *Id.* at 5.
[44] Lazard v6.0 at 4.
[45] DEC IRP Report at 340.

assum[ing] that battery performance has been guaranteed over the lifetime, such that operating the battery does not incur any costs to the battery operator."[46] It is unclear why Duke has total fixed O&M costs so much higher than NREL's given that NREL's costs already include everything required for turnkey operation of the project, including the impacts of degradation.

For solar plus storage installations, Duke assumes the lifetime of the battery is equal to the [redacted]-year life of the solar asset, [redacted] the initial battery, and makes [redacted].[47] The [redacted] is substantial. For a [redacted] MW solar PV, [redacted] MW / [redacted] MWh ("usable") battery configuration with a 20% DoD limitation, Duke first assumes that [redacted] MWh of storage is required for [redacted] MWh of "usable" storage. Then, to account for degradation, Duke further assumes a [redacted] ratio to allow the battery to [redacted] for [redacted] years at roughly [redacted] before being overhauled. It also assumes a very high inverter load rating ("ILR") of [redacted], adding further to the total costs of the project.[48]

Duke's approach is unlikely to be the least-cost solution. Energy storage costs are declining rapidly, a fact that Duke itself readily admits and assumes. Under this case, it is inexplicable that Duke would [redacted] its solar plus storage batteries upfront by a total of [redacted]% ([redacted] MWh for an [redacted] MWh "usable" battery) at today's higher costs. The much more rational approach would be to replace energy storage packs as needed on an annual basis to capture the benefit of the cost declines, as it did in its standalone storage approach and as is done in NREL ATB.

Failing to do so greatly exaggerates the cost of storage within the solar plus storage project. This can be seen by comparing the projected cost of two [redacted] MW / [redacted] MWh standalone batteries to the cost of the [redacted] MW / [redacted] MWh storage asset in the solar plus storage project. The 2020 total cost for the standalone battery project is $[redacted] million, but the corresponding total cost of battery portion of the solar plus storage project is $[redacted] million, more than [redacted] higher. This cost differential was explained by Duke to be related to the choice [redacted].

Aside from this issue, Duke's calculation contains an error. In its calculation for the levelized fixed cost of [redacted] through the [redacted]-year life, Duke's calculation erroneously assumes that [redacted]% of the battery pack must be replaced. Its formula further assumes the incorrect date for the [redacted]. In the calculation for a 2020 solar plus storage battery replacement (due to be done in [redacted] for a system installed in 2020), Duke calculates the cost of replacing [redacted]% of the battery pack, [redacted]% of the power electrics, [redacted]% of the system integration cost, and [redacted]% of the site installation

[46] NREL 2020 Update at 10.
[47] Duke Response to NCSEA DR5-2.
[48] Duke Response to PSDR3-7 (Confidential - IRP Generic Unit Summary DEC 2020).

costs. However, these costs are taken from [redacted] not [redacted] shorting the expected cost reduction for the replacement capacity by [redacted] years.

Further, the calculation assumes that 100% of the battery must be replaced. Recall that Duke had overbuilt an [redacted] MWh "usable" battery to [redacted] MWh to account for DoD, and then further overbuild by [redacted]% to [redacted] MWh to allow for degradation. After [redacted] years of degradation, the battery should still be providing [redacted] MWh of capacity. For Duke to [redacted] this battery at zero residual value, despite its sizable remaining capacity, is inconsistent with its own assumptions. At a minimum, Duke should account for some residual value from this battery. More appropriately, it should only replace the [redacted] MWh of overbuild needed to return the battery to the original overinflated capacity with some allowance for incremental capacity to account for the higher likelihood of battery failure past year [redacted] If the Commission allows Duke to use this approach, it should at least require it to use the proper year for the replacement capacity calculation and require some level of credit for the residual value of the battery.

Also problematic is that Duke appears to be using a different capital cost estimate for its battery packs in a solar plus storage project than in a standalone storage project. For standalone storage projects, battery packs in 2020 are projected to cost $[redacted] / kWh of storage. This value is consistent across all sizes and durations of standalone projects. However, for the [redacted] MW / [redacted] MWh solar plus storage project, the battery pack is assumed to cost $[redacted] / kWh if measured on a "usable" basis (i.e. [redacted] MWh), $[redacted] / kWh if measured after a DoD adjustment (i.e. [redacted] MWh), or [redacted] / kWh if based on the actual storage amount installed (i.e. [redacted] MWh).

Considering that Duke plans to initially install the [redacted] MWh battery for this project, it appears the lowest cost estimate is the most appropriate. However, that begs the question as to why the battery pack cost would be so much lower in this configuration than for a standalone storage project, particularly considering the degradation strategies and other costs such as power electronics are independent from this cost. Duke's internally inconsistent projections, all of which have been marked confidential, lend further weight to using a publicly available benchmark such as NREL's ATB.

Duke's cost estimates are substantially higher than other benchmarks and recent RFI results. While Duke claims the difference is largely due to assumptions on DoD and replenishment approaches, it erred in interpreting NREL's ATB battery cost methodology. Duke should base its battery costs on NREL's ATB Advanced scenario, recognize that battery pack degradation is already accounted for in NREL's ATB fixed O&M cost and should not be used to artificially inflate the size of a modeled battery, and use consistent costs for batteries in standalone storage and solar plus storage projects unless it can justify differential in cost due to operational expectations.

Duke modeled energy storage at two-, four-, and six-hour durations in its 2020 ELCC Study.[49] However, it decided to model only four- and six-hour duration batteries in its IRP, stating that "[t]wo-hour storage generally performs the same function as DSM programs that, not only reduce winter peak demand, but also tend to flatten demand by shifting energy from the peak hour to hours just beyond the peak."[50]

Two-hour batteries provide useful capacity during winter and summer peak load hours. Duke included several analyses that show that while two-hour batteries tend to produce lower capacity contribution levels than 4- or 6-hour batteries, they can contribute significantly to winter and summer peak loads. Figure 6 below is the ELCC curve of various battery sizes for DEC and DEP.[51] The two-hour battery (in blue) is somewhat lower than the four-hour (orange) and six-hour (green) lines, but it maintains more than 85% of its capacity value up to about 1,100 MW and 70% of its capacity value up to about 2,500 MW of storage.

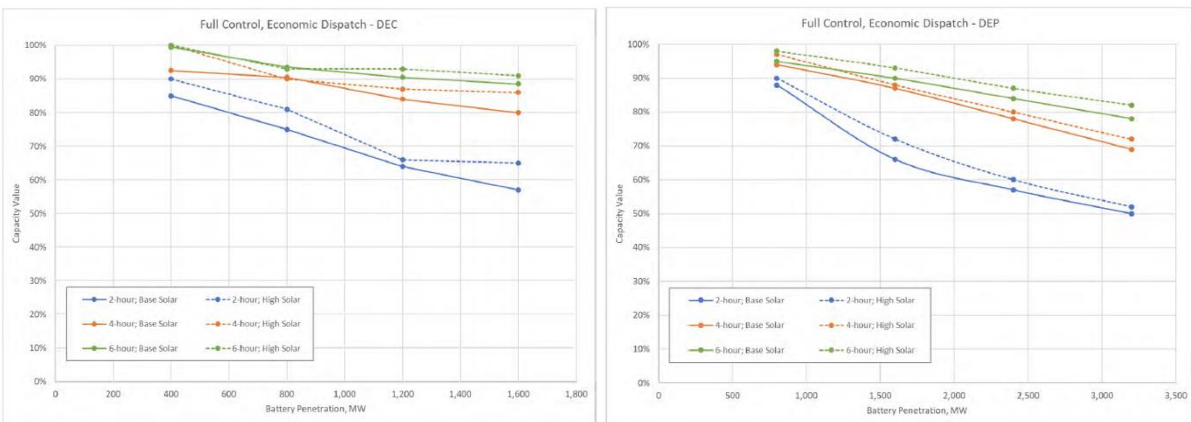


*Figure 6 - DEP and DEP Battery ELCC*

Considering that battery packs represent a substantial share of an energy storage system's cost, allowing a limited quantity of less expensive two-hour batteries can help defer the need for other capacity at a lower price.

Duke claims that two-hour batteries "generally perform the same function as DSM programs," but this is an inaccurate characterization. DSM programs typically have limits on how often they can be activated, and even if they did not, participant fatigue could diminish the response after multiple consecutive calls. By contrast, two-hour batteries are independent of business or behavioral decisions and can reliably perform every single day for years on end.

[49] DEC IRP Report at 345.
[50] DEC IRP Report at 349.
[51] DEC IRP Report at 346, Figure H-4; DEP IRP Report at 340, Figure H-4.

Duke should update its model to select up to 1,500 MW and up to 1,000 MW of two-hour batteries in DEP and DEC, respectively. These levels correspond to capacity values of 70%. Considering the cost discount that one can obtain from shorter-duration batteries, the tradeoff for capacity value may be selected in the model's optimization routines.

## Duke's Operational Assumptions for Solar Should be Improved

Solar PV installations come in two common forms: fixed-tilt arrays and single-axis tracking arrays. Fixed-tilt arrays feature fixed solar panels that are typically tilted toward the southern horizon. The level of tilt depends on several factors, but typical installations in the Carolinas will have tilts in the 20-30 degree range to increase the total amount of energy produced over the year. Single-axis tracking arrays feature panels that are typically oriented flat in north-south rows that can turn east to west as the day progresses. This tracking enables the panels to face the sun more directly through the day, increasing the amount and duration of energy production.

Over the past decade, there has been a steady shift from fixed-tilt projects to single-axis trackers that has corresponded to a decrease in the price premium of tracking system hardware.[52] Under today's economics, the benefit from added production outweighs the higher cost of tracking hardware, making it an economic decision to install trackers in most locations.

This trend exists in the Carolinas as well. Figure 7 below shows the share of PV systems install by type in North Carolina and South Carolina.[53] There has been a notable increase in tracker deployment since the mid-2010s. More than 80% of PV capacity completed in 2019 used single-axis or dual-axis trackers. Based on conversations with our solar industry members, there is every expectation that this growth trend will continue and that single-axis trackers will remain the dominant type of system installed in the future.

[52] EIA Form 860, available at https://www.eia.gov/electricity/data/eia860/.
[53] *Id.*

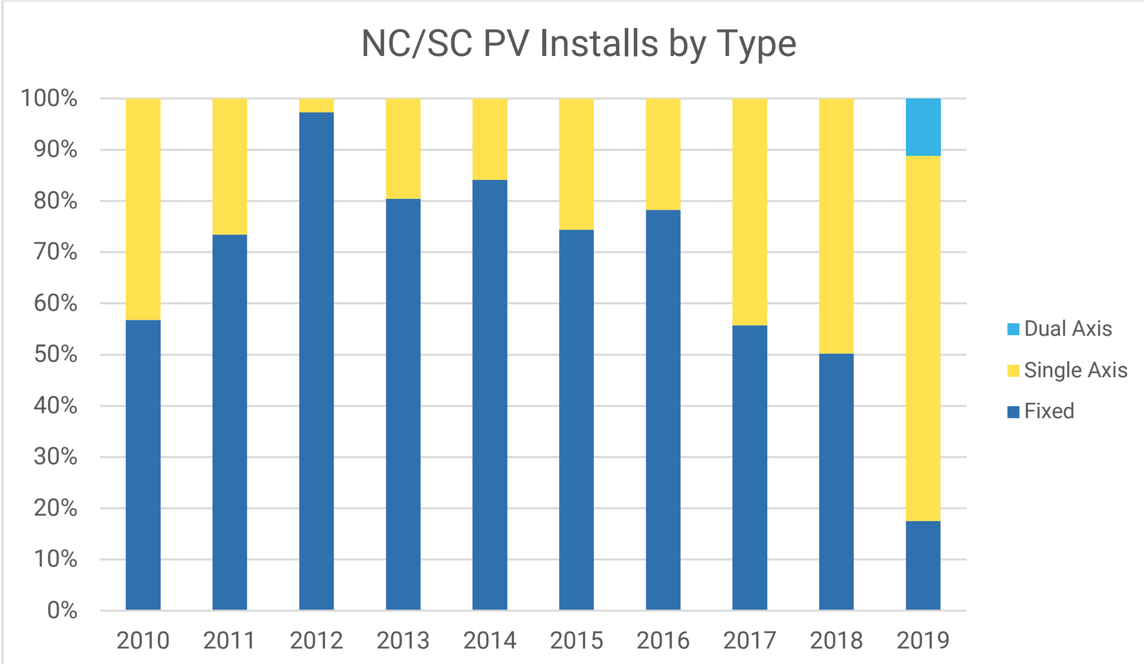


*Figure 7 - NC/SC PV Installs by Type*

Solar production from single-axis tracking systems is notably different from fixed-tilt systems. In general, single-axis tracking systems climb to their peak output earlier in the morning and maintain their generation levels later in the afternoon, resulting in a sizable production premium over fixed-tilt systems. Single-axis tracking systems' ability to maintain production later in the afternoon increases the capacity value compared to fixed-tilt installations. Figure 8 below is taken from Astrapé Consulting's "Duke Energy Progress 2020 Resource Adequacy Study" and shows the difference between fixed-tilt and tracking systems at different ILR assumptions.[54] The incremental generation in the morning and the evening adds up over the year, resulting in tracking systems producing 19% more energy in total than fixed-tilt systems.[55]

[54] DEP IRP Report, Attachment 3, p. 35 ("DEP RA Study"). The inverter load rating is the ratio of the DC capacity of the panels to the AC capacity of the inverter. While the PV system cannot exceed its AC capacity, increasing the ILR allows the system to produce at its maximum level for more hours, increasing total output.
[55] Duke Response to NCSEA DR7-7.

**Figure 7. Average August Output for Different Inverter Loading Ratios**

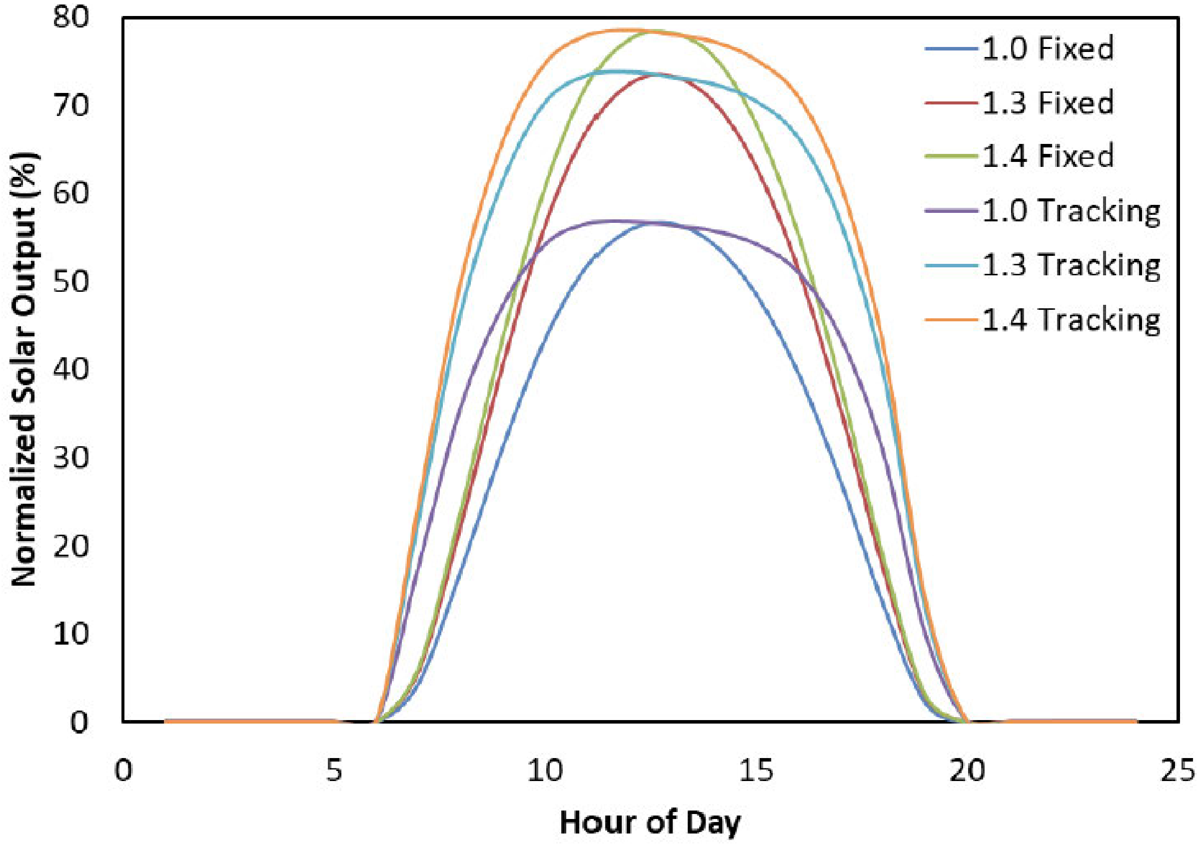


*Figure 8 - Fixed vs. Tracking Generation Profile*

Duke's methodology of incorporating solar in its IRP is anything but straightforward. It relies on a 2018 report from Astrapé Consulting ("2018 Astrapé") to establish the solar-only capacity credit at different levels of penetration.[56] Astrapé modeled different tranches of solar deployment with different system types and ILR assumptions. From this, it estimated the summer and winter capacity credits of 20% and 1%, respectively.[57] These values were used in the IRP modeling for standalone solar projects.

Astrapé assumed 2,950 MW of existing plus "transitional" PV projects in its baseline forecast.[58] Of this nearly 3 GW of capacity, only 297 MW was assumed to be single-axis tracking, with the remainder fixed-tilt. It then added four tranches of capacity in DEP and DEC, assuming 75% was fixed-tilt and 25% single-axis tracking. At the end of its projected deployment, Astrapé assumed that of the 7 GW of solar deployed, only 1,120 MW or 16% would be single-axis trackers as shown in Figure 9 below.

[56] Duke Response to NCSEA DR3-8 ("Duke Energy Carolinas and Duke Energy Progress Solar Capacity Value Study").
[57] *Id.* The "capacity credit" is the fraction of solar nameplate capacity that is assumed to be available to meet summer and winter peak demands.
[58] Transitional projects are not defined in the Astrapé study, but appear to be similar to Duke's "designated" capacity.

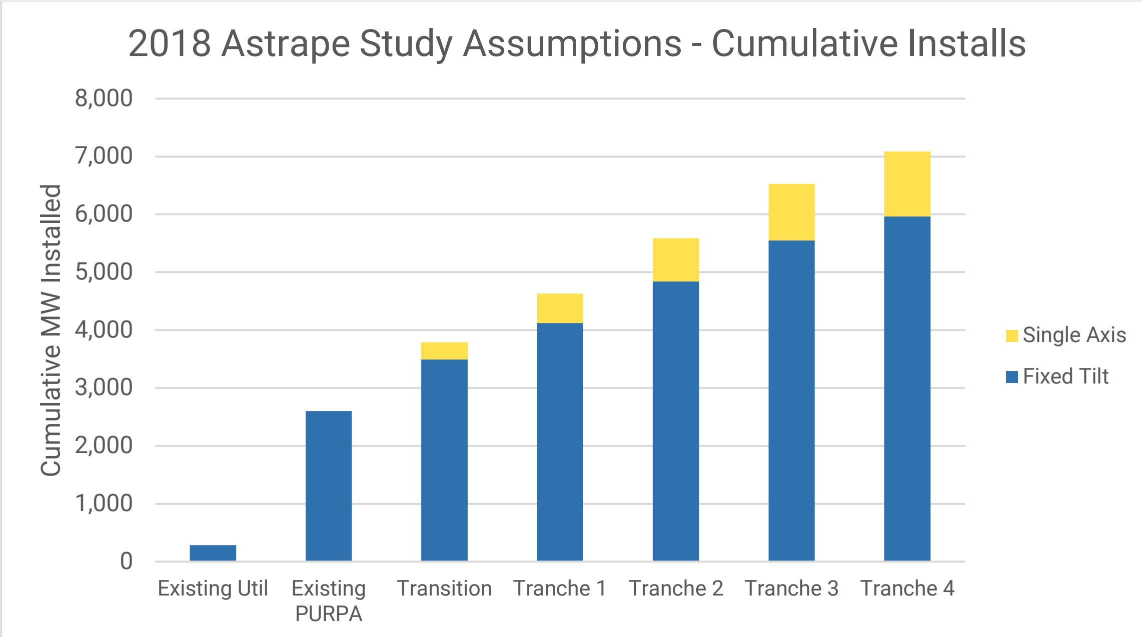


*Figure 9 - 2018 Astrapé Study Assumptions - Cumulative Installs*

By comparison, 5.2 GW of large-scale solar had been deployed in North Carolina and South Carolina through 2019.[59] At that point, single- and dual-axis trackers already comprised 40% of installed capacity, and based on recent trends, will be projected to increase further in the future. Figure 10 below shows the cumulative installation by type through 2019.

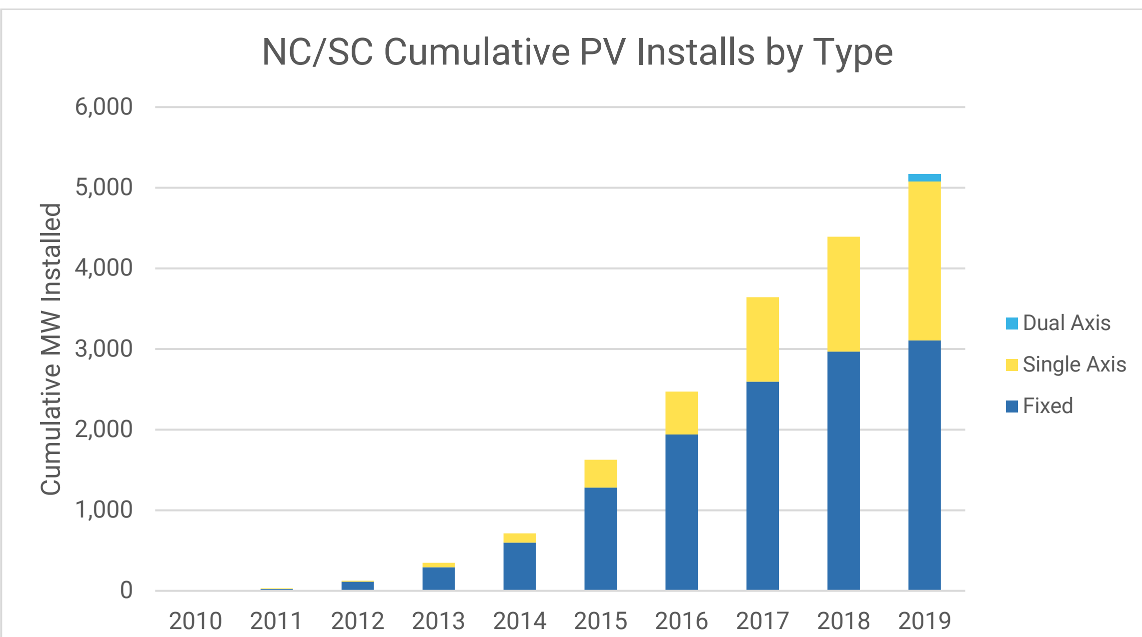


*Figure 10 - NC/SC Cumulative PV Installs by Type*

[59] Based on data reported to EIA Form 860 in 2019.

This distinction is important because by underestimating the share of single-axis trackers, Astrapé is underestimating solar's capacity contribution. Its analysis shows that single-axis tracking systems provide substantially more winter capacity than fixed-tilt systems; tracking systems provided 4-5 times the winter capacity benefit as fixed tilt in DEC's territory, and 8-9 times the capacity benefit in DEP's territory.[60] Although the relative level of solar winter capacity contribution is small under Astrapé's assumptions, when deployed over many thousands of MW, it produces a meaningful difference in the winter capacity contribution of solar-only resources.

Further, because daily generation of single-axis trackers exceeds fixed-tilt systems, solar systems paired with storage will have more opportunity to charge their battery during winter months. This can increase the amount of stored energy that is available to meet both morning and evening winter peaks, further increasing the capacity value of solar and storage systems.

Duke did not use the same capacity contribution assumptions for its standalone solar projects as it did for its solar plus storage projects. While the standalone solar capacity contribution came from a 2018 Astrapé Consulting report, the storage and solar plus storage capacity contribution came from a 2020 Astrapé Consulting ELCC study.[61] In this report, Astrapé modeled new solar plus storage systems as single-axis trackers with a 1.5 ILR, but it is unclear what assumptions it used for the existing fleet of standalone solar.[62] The assumption that all new systems be trackers with high ILR is appropriate, but if Astrapé assumed an existing fleet mix that contained too few tracking systems, it could suffer the same underestimate in solar contribution as the 2018 study.

Additionally, Duke did not use the same system mix assumptions in its IRP as it does in its capacity contribution studies. After establishing the capacity contribution of standalone solar from the 2018 Astrapé study, and solar plus storage and standalone storage from the 2020 ELCC study, Duke creates another set of assumptions for the deployment of solar going forward. The Company assumes that 100% of existing PURPA projects are fixed-tilt and will be replaced with fixed-tilt systems.[63] It assumes that development to meet "designated" and "mandated" demand (e.g., builds from existing programs such as CPRE and GSA) will be split 60/40 between single-axis trackers and fixed tilt systems.[64] Finally, Duke assumes future "undesignated" builds will be optimized based on modeling runs.

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[60] Duke Response to NCSEA DR2-19 ("Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study" Prepared for Duke Energy by Astrape Consulting, 11/2018).

[61] *Duke Energy Carolinas and Duke Energy Progress Storage Effective Load Carrying Capability (ELCC) Study*, Astrapé Consulting (September 2020) ("ELCC Study").

[62] ELCC Study at 7.

[63] Duke Response to NCSEA DR3-5.

[64] *Id.*

The designation of 100% of PURPA projects as fixed-tilt appears to be based on a simple assumption: "This segment represents the existing capacity associated with standard PURPA contracts which are assumed to be fixed tilt configurations."[65] Duke did not provide any data to support this choice.

The decision to model "designated" and "mandated" system mix was based on the winning bids of the CPRE Tranche 1 RFP, which were received during summer 2018. While these bids may have been reflective of the state of the market at that time, they are no longer reflective of where the industry has moved. The modeling optimization adds single-axis tracking systems over fixed-tilt systems for all the reasons that were discussed previously.

Duke's assumptions on these elements are not valid. Duke appears to have blanketly assumed that 100% of PURPA projects are current fixed-tilt and will all be replaced with fixed-tilt systems in the future. This assumption is clearly contradicted by the data. Figure 11 below shows the evolving mix of small systems in the Carolinas that are most likely to have been built under PURPA. While Duke's assumption that all PURPA projects are fixed-tilt may have been more valid through 2016, in the past five years the market has evolved and even these smaller projects are shifting to single-axis trackers. Of the 243 MW of systems under 10 MW built in 2019, a full 80% were single- or dual-axis trackers.

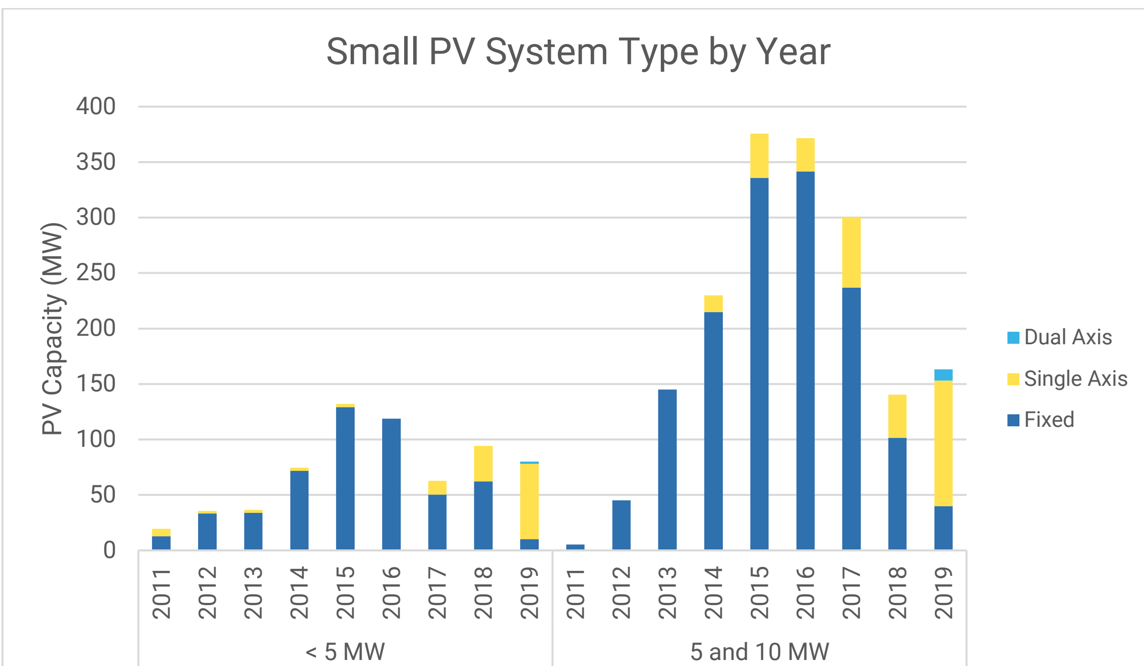


*Figure 11 - Small PV System Type by Year*

Larger projects show the same trend. Figure 12 below shows a similar chart for systems between 20 and 50 MW and over 50 MW. These are the projects that are winning CPRE

[65] *Id.*

bids; Duke noted that the median proposal for Tranche 2 RFP was 50 MW in DEC and 75 MW in DEP, with winning bids averaging 55.8 MW in DEC and 80 MW in DEP.[66] Duke's assumption that 40% of these systems will be fixed-tilt is out of date. In 2019, fixed-tilt systems only constituted 15% of capacity in these size categories. Based on trends across the country and in the Carolinas, there can be little expectation that the trend towards tracking systems will be reversed.

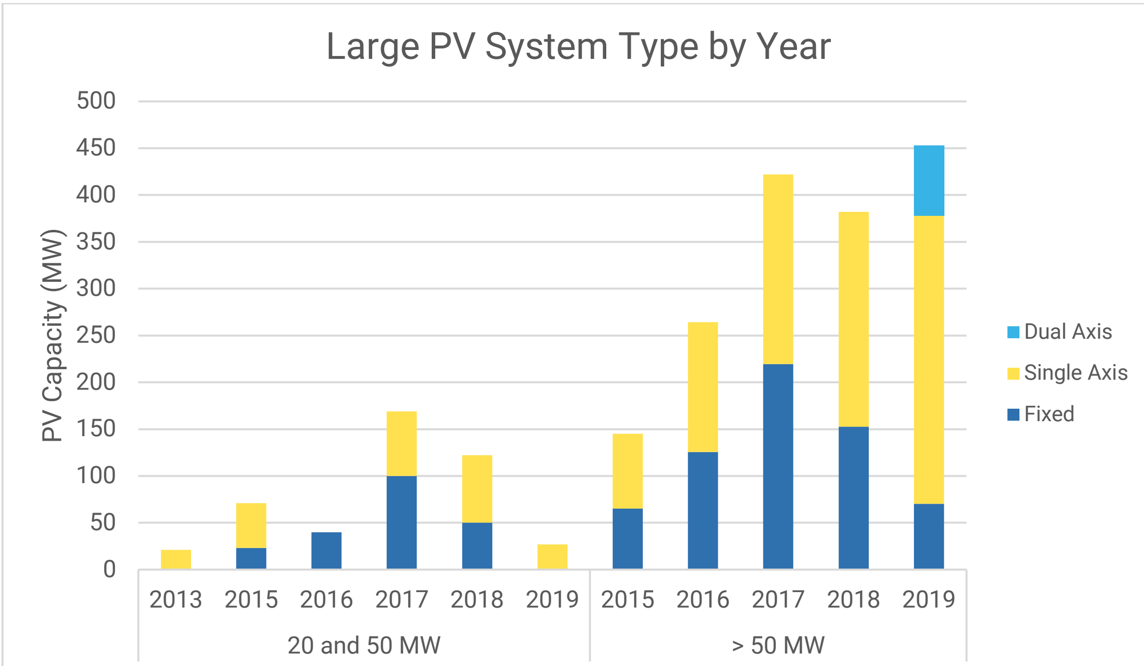


*Figure 12 - Large PV System Type by Year*

The system type assumptions affect a substantial amount of solar capacity. Figure 13 below shows the breakdown of solar additions by program. The PURPA/NC REPS category (assumed to be 100% fixed-tilt) dominates the early mix, with CPRE capacity additions (assumed to be 60% tracker 40% fixed-tilt) growing through 2026. Only towards the end of 2029 does the future growth category (100% tracker) get deployed in earnest.

[66] DEC IRP Report, pp. 7-8; DEP IRP Report, Attachment II, pp. 7-8

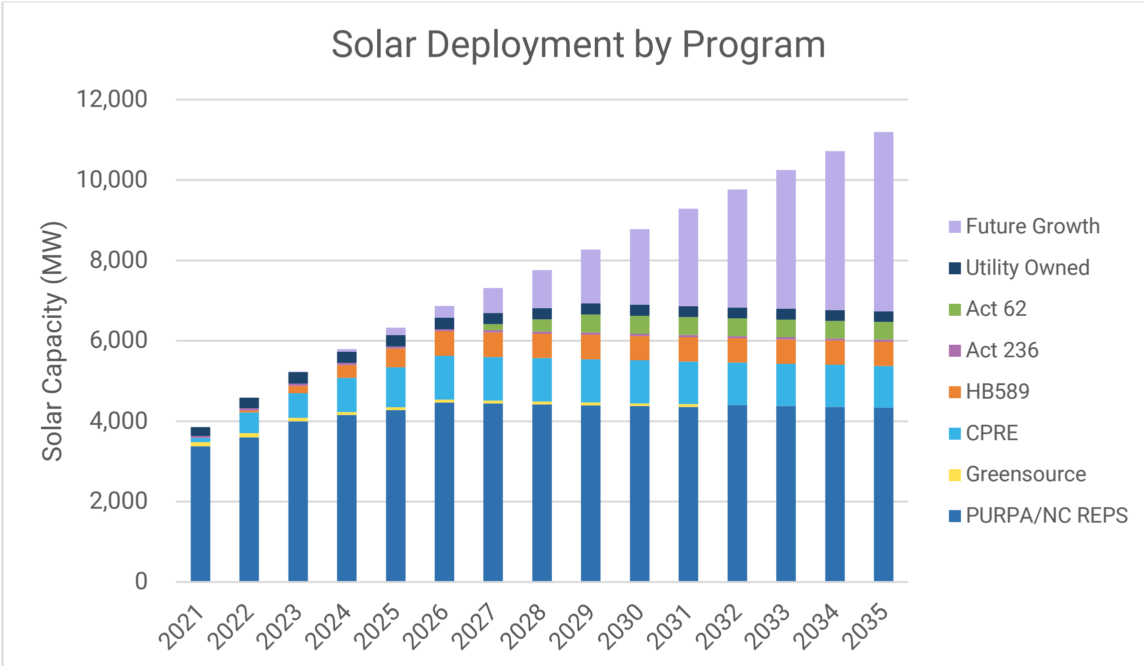


*Figure 13 - Solar Deployment by Program*

Duke's assumptions on system mix produce a model that relies too heavily on fixed-tilt systems and does not reward the multiple benefits of single-axis tracking systems that are being deployed in the market. This in turn negatively affects the economics of solar and solar plus storage facilities in the Company's modeling.

Duke placed a hard limit on the quantity of solar and solar plus storage that could be interconnected in any year to 500 MW (split 300 MW in DEC and 200 MW in DEP) in the Base Cases and 900 MW (split 500 MW in DEC and 400 MW in DEP) in the high renewable cases.[67] This limit affected all solar, not just those added through the modeling optimization.

Despite these limits in its IRP, Duke interconnected 718 MW and 744 MW in the two territories in 2015 and 2017, respectively. Its highest single year in DEC was 190 MW in 2016 and its highest year in DEP was 633 MW in 2017.[68]

One would also hope that that the experience of recent years will enable it to become more efficient at processing interconnection applications in the future. Duke's IRP scenarios contemplate major build-outs of renewable energy and energy storage. To meet its 2050 net zero goals, the rate must accelerate even further. It is imperative that Duke continue to pursue all options to increase its interconnection capacity for new renewable projects. In addition, Duke's history with interconnection of solar facilities involved large numbers of

[67] Duke Response to NCSEA DR2-18.
[68] *Id.*, Attachment, NCSEA_E-100_Sub165_DR2-18A.xlsx.

smaller individual projects. Given the growing trend toward a smaller number of larger projects, Duke's interconnection capability should increase significantly.

Duke should update several of its assumptions related to system mix. It is clearly not the case that 100% of PURPA projects are currently, or will be always in the future, fixed-tilt. Duke should perform an analysis on its current PURPA fleet to determine the actual mix of fixed-tilt and single-axis tracking projects and use these in its baseline assumptions. If, for some reason, it is unable to obtain these figures, Duke should utilize the latest data from EIA Form 860. It should further adjust its assumptions on replacement of these projects by recognizing the shift towards tracking that is occurring even at the small system sizes, with at least 80% of new PURPA projects be assumed as single-axis tracking based on an extrapolation of 2019 data, and that Duke incorporate this into its assumption of replacement capacity from existing PURPA projects.

For larger systems that are being built to meet Duke's "designated" and "mandated" programs, Duke should assume that 100% of future builds will be single-axis trackers. The cost premium of tracking systems has declined over time, and as shown by the market evolution, the additional energy and capacity benefits that come from trackers more than compensates for the price premium.

Duke should remove the 500 MW limit from its Base Case and instead model the higher 900 MW limit from its high renewables sensitivity. Duke's own plans will require much higher levels of interconnection in the future, making it imperative that the Company pursue changes that will allow higher rates now.

## Duke's Development Timeline for SMR and Pumped Hydro Resources is Inconsistent with Its Own Data

Duke assumes that SMRs will be utilized in two of its six portfolios. The first, "70% $CO_2$ Reduction: High SMR", assumes that 1,368 MW of SMR capacity will be online by 2029. The second, "No New Natural Gas", assumes 684 MW of SMR capacity will be online by 2035.[69] It also assumes that 1,620 MW of new pumped hydro capacity will be online in 2034 in three portfolios: both 70% $CO_2$ reduction portfolios and the No New Natural Gas portfolio. These resources were not selected through the modeling optimization process, but rather added manually after the fact in each of these portfolios.[70]

Duke provided information related to the development timeline of these resources in response to a question when SMRs are assumed to be online:

> SMRs modeled for the IRP have eight (8) year capital spend, with the first two (2) year [sic] primarily focused around licensing, and the final six (6)

[69] Duke Response to PS DR3-14.
[70] Duke Response to NSCEA DR7-3.

> year [sic] being construction, testing, and commissioning. As stated in the IRP, the company recognizes the challenges with integrating a first of a kind technology in a relatively compressed timeframe are significant. Therefore, these cases are intended to illustrate the importance of advancing such technologies as part of a blended approach that considers a range of carbon-free technologies to allow deeper carbon reductions.[71]

In other words, Duke would have to begin activities related to SMR deployment this year in order for these units to be online in 2029. Given this case will not be decided until the middle of 2021, and Duke is not requesting approval to build an SMR in its IRP, Duke's own development timelines are incompatible with its assumption that SMR capacity would be online in 2029.

Notwithstanding Duke's assumptions, there is considerable uncertainty whether SMRs will be commercially available and economically viable in the time horizon of the IRP. There is an SMR project under development by Nuscale in Idaho that had secured offtake agreements from a number of municipal utilities in Utah. Nuscale spun out of Oregon State University in 2007 and began development of the SMR. The project proposes using twelve 60 MW SMRs to form a single 720 MW facility housed at the Department of Energy's ("DOE") Idaho National Laboratory.

Last fall, after another round of project delays and cost increases pushed the cost estimate from $4.2 billion in 2018 to $6.1 billion in 2020, several of the municipal utilities exited their positions.[72] The project recently received $1.4 billion in financial support from DOE to help keep the eventual price of power from the SMR to under $55/MWh, the maximum amount provided by the agreement with the municipal utilities.[73]

Even with this financial support from DOE and having been under development for more than a decade, the facility has not yet received its design certification from the Nuclear Regulatory Commission, although it did pass a key milestone in receiving its safety evaluation report in August 2020. Nonetheless, Nuscale plans to begin construction by December 2025 and have the first module in service by 2029, the same year Duke contemplates a fully-operational SMR facility.[74]

Developing new pumped hydro facilities is also very challenging. Duke provided a confidential study performed by [redacted] in [redacted] for [redacted] regarding potential greenfield locations for additional pumped storage located on or about [redacted]

[71] Duke Response to NCSEA DR5-1.
[72] Matthew Bandyk, Design Updates, Financial Shakeup Prompt Utilities to Rethink Structure of NuScale's $6.1B SMR Project, Utility Dive (November 25, 2020), https://www.utilitydive.com/news/design-updates-financial-shakeup-prompt-utilities-to-rethink-structure-of/589262/.
[73] DOE Approves Award for Carbon Free Power Project, available at https://www.energy.gov/ne/articles/doe-approves-award-carbon-free-power-project.
[74] Adrian Cho, Several U.S. Utilities Back Out of Deal to Build Novel Nuclear Power Plant, Science (November 4, 2020), https://www.sciencemag.org/news/2020/11/several-us-utilities-back-out-deal-build-novel-nuclear-power-plant.

[redacted].[75] This study included cost estimates for [redacted] sites and an environmental, regulatory, and licensing analysis on new pumped hydro. The key details for these projects are shown in Table 5 below.

| Project Name | Capacity (MW) | Total Cost ([redacted] | Total Cost ($2020)[76] | Cost / kW ($2020) |
|---|---|---|---|---|
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

*Table 5 - Pumped Hydro Study Summary*

[redacted] projected a [redacted]-year development timeline for each of the facilities. This included [redacted] years of engineering, environmental, and regulatory studies followed by [redacted] years of construction. Based on this schedule, for these units to be online in 2034, development would have to begin in [redacted] Given this case will not be decided until the middle of 2021, and Duke is not requesting approval to build pumped hydro capacity in its IRP, Duke's own development timelines are incompatible with its assumption that new pumped hydro capacity would be online in 2034.

Based on Duke's own assessments, the timelines projected for SMR and pumped hydro are unattainable. While Duke admits that some of its portfolios are "intended to illustrate the importance of advancing such technologies", it is unfortunate that all three of Duke's deep-decarbonization portfolios rely on resources that, based on Duke's own assumptions, are not likely to be deployed in time to attain the carbon reduction. The Commission should request that Duke construct a deep-decarbonization portfolio that does not require resources with unachievable development timelines, but rather focuses on more robust deployment of existing resources such as solar, wind, and storage.

[75] Duke Response to NCSEA DR2-36.
[76] Converted using BLS CPI Inflation Calculator, available at https://www.bls.gov/data/inflation_calculator.htm.

## IV. Duke's Natural Gas Price Forecast and Sensitivities are Flawed and Biased Downward

The natural gas price forecast is one of the most important input assumptions in Duke's modeling. This input impacts how Duke's modeling selects between resources as it optimizes capacity additions across the IRP planning horizon, which in turn impacts the selected portfolio's exposure to factors such as fuel supply and fuel costs. In the model, Duke enters the IRP planning period with substantial coal capacity and generation, with 18% of capacity and 16% of total generation coming from coal under the Base Case with Carbon Policy.[77] By 2035, most of the coal has been retired, and the amount still operating only produces 1% of total generation. How this coal capacity and energy will be replaced is the fundamental question of this case and mirrors the broader evolution of the electricity sector across the country.

Duke's model currently favors natural gas over renewables and storage to replace the retiring coal, as demonstrated by the small amounts added by the model optimization under the two Base Cases.[78] However, this modeling outcome is not a reflection of the merits of natural gas over renewables, but is instead a mathematical result of the model's assumptions. Further, this mathematical result is heavily influenced by the natural gas price forecast that Duke uses, which is in turn based on low market prices from the illiquid portion of the natural gas futures price curve. By exclusively using ten years of market prices, and relying on those same forecasts for five more years, the model is biased towards building and running natural gas assets. This means that natural gas CC units built in 2027 and 2028 clears out the capacity need for many years to follow, which, under Duke's modeling set up, prevents any more capacity from being built.

But this modeling relies on flawed inputs. A natural gas forecast based more on fundamentals-based forecasts and less on volatile market prices is not only more robust but also presents the model with higher natural gas prices during the critical mid-2020s through mid-2030s period, when the first capacity needs arise. Under this scenario, the economics of building and operating natural gas CCs and CTs will be relatively more expensive than deploying renewables and storage, and the model optimization may reach a very different result that instead is weighted towards zero-carbon renewables and storage.

This has a meaningful impact on the relative riskiness of Duke's portfolios. Duke has already acknowledged the need to transition away from fossil fuels. However, its modeling assumptions, driven in large part by its natural gas forecast, result in the addition of massive quantities of natural gas generation well into the future. In fact, Duke's Base Case

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[77] DEC IRP Report at 107.

[78] The model does not select any solar in the Base case without Carbon Policy beyond what Duke manually added, and only selects 25% of the total solar in the Base case with Carbon Policy.

with Carbon Policy shows generation from natural gas CCs growing from 21% in 2021 to 31% in 2035, only to be bolstered further by additional CCs past 2035.[79] It has not adequately analyzed the risk associated with firm fuel supply and costs or potential carbon policy in the future, must less reconciled these new gas plants with its 2050 net-zero goal.

Simply put, Duke's flawed natural gas forecast leads to portfolios that are heavily weighted towards natural gas generation instead of ones based more on renewables and storage. If Duke were to follow this path, it would unnecessarily expose its customers and its shareholders to substantial and avoidable risk.

For the reasons discussed above, these comments contain extensive testimony that walks the reader from Duke's construction of its forecast through the likely final impacts of its choice. Duke's methodology of using market prices for ten years before fully switching to a fundamentals-based forecast by year sixteen is critiqued in constructing its natural gas forecast and high- and low-price sensitivities. There is a straight line from the lack of liquidity in the futures market to the lack of robust long-term price formation for the specific financial instrument Duke used to establish the market prices. It can also be shown that long-term futures prices primarily reflect short-term volatility rather than being reflective of the macroeconomic dynamics that influence long-run prices. Finally, the flaws in Duke's approach to producing its high- and low-price sensitivity are highlighted before concluding with observations about the potential collective impact of these choices on Duke's IRP modeling that may have resulted in more natural gas and less solar and storage resources being added in the future.

Duke's natural gas forecast is highly problematic. It begins with a flawed assumption that its ability to purchase *de minimis* quantities of natural gas on ten-year contracts justifies its decision to base the first ten years of its model entirely on market prices. Prices from the financial instrument it used to secure the gas supply are directly derived from futures contracts, and the prices for those futures contracts beyond two years are based on almost no market transactions.

Near-term price volatility in the natural gas futures market works its way into the long-term portion of the futures price curve. It is clear from this part of this analysis that the sizable week-to-week volatility that occurred in 2020 meant that if Duke had locked in its gas forecast a few weeks earlier or a few weeks later, it would have produced a meaningfully different result.

The fact that a key input, like the first ten years of natural gas prices, is so exposed to short-term volatility is a clear sign that it should not be relied upon for more than a few years. To counter this, an alternative forecast methodology that would smooth the short-term

[79] DEC IRP Report at 107.

volatility in the market prices and only rely on them exclusively for 18 months before transitioning over 18 months to a fundamentals-based forecast is proposed.

Next, the comments discuss the methodology that Duke used to construct its high- and low-price sensitivities. Because the Company's method is entirely based on the short-term price volatility of futures contracts, extrapolating out ten years produces a "random walk" result that deviates substantially from fundamentals-based forecasts. The resulting sensitivities contain disjointed segments that would require a bizarre sequence of massive policy shifts to bring to fruition.

Finally, the impact of Duke's natural gas price forecast on its IRP results can be seen in the alternative modeling performed by Synapse, highlighting why it is critical that Duke's modeling be updated with better assumptions. These forecasts impact asset selection, PVRR, and carbon emissions, and play a key role in the risk assessment that Duke should have produced between its several portfolios. Leaving this many outcomes dependent on a flawed natural gas price forecast is highly inappropriate.

## Duke's Use of Market Prices for Ten Years is Inappropriate

Duke based its forecast on "market prices" from financial instruments that were prices based on natural gas futures contracts for years 1 through 10, transitioned linearly to a fundamentals-based forecast from years 11 to 15, before utilizing a fundamentals-based forecast from year 16 forward. The Company also developed a high- and low-price sensitivity, applying a statistical methodology to market prices before transitioning to two EIA AEO fundamentals-based forecast scenarios.[80] The resulting annualized forecast is shown below in Figure 14. This is a recreation of Figure A-2 from the DEC IRP Report and clearly delineates the three disjointed sections of 100% market prices and 100% fundamentals-based forecast, joined by the five-year transition between the two.

[80] DEC IRP Report at 157-158.

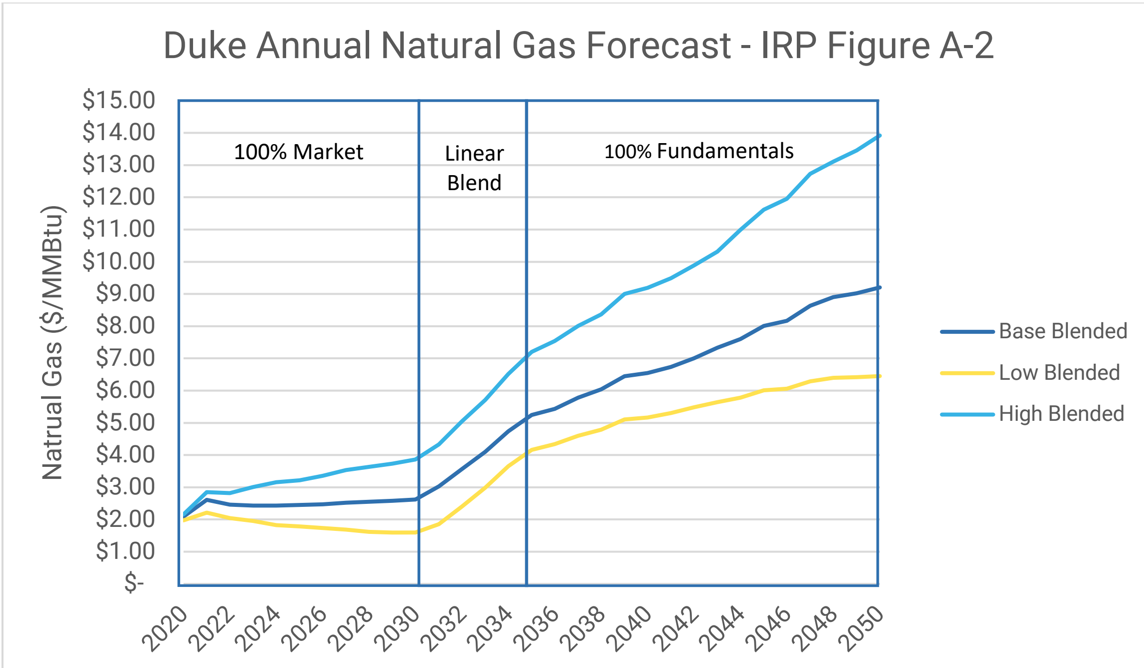


*Figure 14 - Duke Annual Natural Gas Forecast - IRP Figure A-2*

Duke uses market prices based on a 116-month fixed price swap for 2,500 dts/day for May 2020 through December 2029.[81] The fixed-price swap (or swap) is a financial derivative that allows market players to hedge their future purchases or sales of a commodity by locking in a fixed price now rather than facing the market price in the future. For a purchaser of natural gas such as Duke, buying a swap allows it to lock in its natural gas fuel price in the future and reduces the risk associated with market price fluctuations. If the market price in the future is higher than the swap price, then Duke will save money, but if it is lower, it will lose money. That said, the point of hedging in general is not to speculate on the future price of natural gas (there are other ways to accomplish that), but to reduce risk of Duke's financials associated with natural gas price fluctuations.

The monthly price of the swap is based on another financial product called a futures contract (also referred to as just futures). These contracts are financial instruments between two parties (a buyer and a seller) that gives the buyer the right to receive and obligates the seller to deliver a certain quantity of natural gas at a certain price at a certain place in the future.[82] For example, one can purchase a futures contract that would give the buyer the right to receive 10,000 MMBtu of natural gas in July 2024 at Henry Hub at $2.433 / MMBtu.[83] If in July 2024 the spot price (i.e. the then-current market price) for natural gas

[81] Duke Response to NCSEA DR5-3.
[82] Futures rarely result in physical delivery of the product. Instead, holders of the contracts typically close their positions prior to physical delivery.
[83] Henry Hub Natural Gas Futures and Options, CME Group, available at https://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_globex.html.

is $3.00 / MMBtu, the holder of the futures contract would have the right to receive it from the seller for $2.433 / MMBtu for gas rather than the higher market price.

Swaps and futures are different but related products. Futures contracts are standardized (same quantity, same delivery location) and settle through the NYMEX exchange and obligate physical delivery or receipt of a product. Swaps, by contrast, can be customized to meet the requirements of the buyer or seller, such as changing the location of delivery, and can be purchased through brokers or through commodities exchanges.

Much like equities in the stock market, futures prices are affected by market participants buying and selling contracts and by factors such as weather or policy changes that may affect future natural gas supply and demand. Futures prices can be very volatile and reflect the short-run impacts of factors such as weather and natural gas storage capacity. Futures are also used by produces or consumers of natural gas to hedge their planned natural gas sales or purchases and can be traded by anyone simply looking to speculate on expected changes in price. All of these factors, including purchases by companies like Duke and commodities speculators halfway around the world, impact the price of these financial derivatives.

By contrast, a fundamentals-based forecast uses a model that simulates entire sectors of the economy to determine supply, demand, and prices for commodities. The EIA AEO uses the National Energy Modeling Systems ("NEMS") model for this purpose. EIA describes NEMS as

> a computer-based, energy-economy modeling system for the United States. NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics.[84]

A fundamentals-based forecast such as AEO eliminates much of the short-term noise from commodities traders and weather, focusing instead on the underlying factors and policies that drive long-term behavior. AEO contains numerous policy scenarios that determine how prices will respond to, for example, the introduction of a carbon price or federal clean energy legislation, or a sudden increase or decrease in the availability of natural gas or oil at low prices. These changes filter through the entire model, meaning that the supply, demand, and prices that emerge reflect the holistic result of the fundamentals, not short-term trends driven by weather or trading activity.

[84] *The National Energy Modeling System: An Overview 2018*, available at https://www.eia.gov/outlooks/aeo/nems/overview/pdf/0581(2018).pdf.

The robustness or "efficiency" of market prices[85] is heavily driven by a market's liquidity; illiquid markets or products that have few trades and low volume are less robust and produce less efficient prices than liquid markets with many participants. The most popular natural gas future is the Henry Hub Natural Gas ("NG") future found on the NYMEX exchange.[86] While there is considerable volatility in the price of these contracts, as the third-largest physical commodity futures contract in the world by volume, it is very liquid – for some time periods.

Trading exchanges list two metrics of market activity: volume and open interest. Volume reflects the total amount of activity in a day (i.e. the total number of contracts that were bought or sold) while open interest reflects the total number of contracts that are outstanding (i.e. how many open contracts exist between buyers and sellers). The NG future offers monthly prices for the current year and next 12 calendar years, meaning that one can in theory lock in the price for delivery of natural gas between next month and December 2033. However, the overwhelming majority of market activity is constrained to contracts less than a year in the future, and there is almost no market activity for contracts more than two years in the future.

This fact is important because higher market activity leads to more accurate price formation, and conversely, low market activity leads to poor price formation. Imagine a saleswoman is selling a blue widget and wants to know what its value is to purchasers. If the saleswoman asks only one person what they would pay for it, the answer may be dependent on somewhat random factors such as whether that person liked the color blue or if they already had a widget. If she happened to ask a prospective customer who liked blue, the perceived value of the widget may be higher than if she happened to ask someone who preferred red. But if the saleswoman asks 100 people, or 1,000 people, or 1,000,000 people, more information can be incorporated into the price and the saleswoman will have a much better sense of how much customers will pay for the widget.

In the case of natural gas futures, the market activity drops substantially as one moves into the future.[87] Figure 15 below shows the cumulative trading volume of all NG futures contracts averaged over the days of January 20, 2021 to February 2, 2021. On those days, 77% of all volume was for futures contracts no more than six months in the future, 94% for contracts up to a year out, and 99.1% for contracts up to eighteen months out. There was no trading at all for contracts past May 2024.

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[85] In this context, efficient pricing is one that incorporates sufficient relevant information that allows buyers and sellers to make informed decisions about the value of the assets they are trading.
[86] NYMEX: Your Home for Henry Hub Natural Gas, CME Group, available at https://www.cmegroup.com/trading/energy/nymex-natural-gas-futures.html#tab1.
[87] Market activity obtained from CME Group, available at https://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_globex.html.

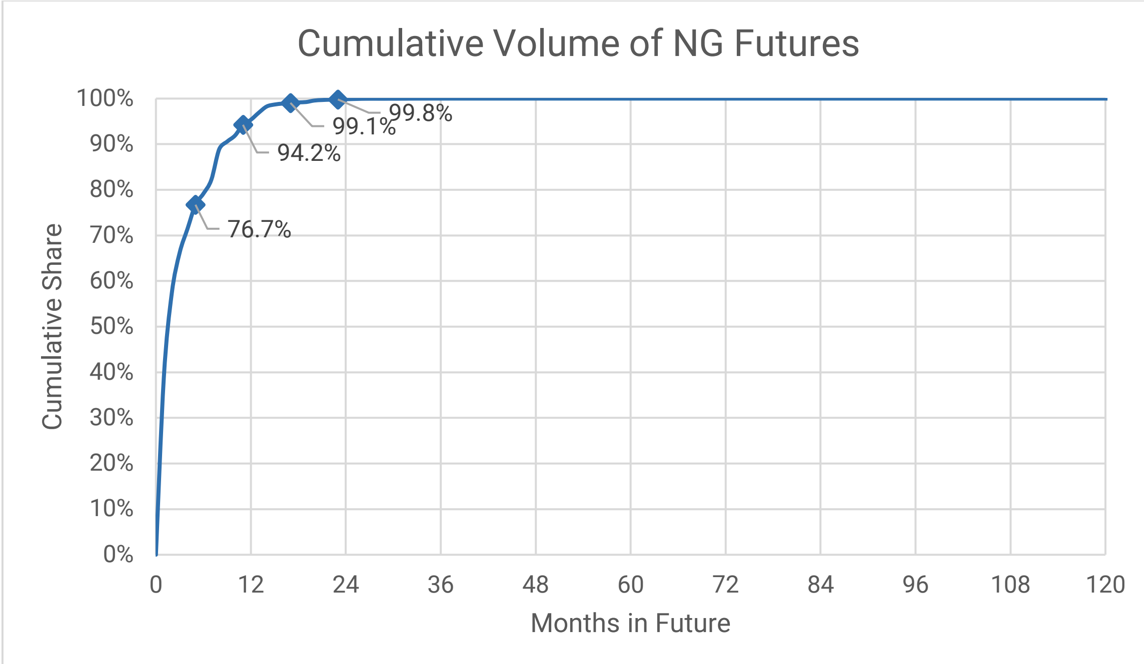


*Figure 15 - Cumulative Volume of NG Futures*

Figure 16 below shows a similar chart but for open interest. The curve is slightly flatter, with 86.2% of open interest for contracts within one year and 98.1% for contracts within two years. Only 0.083% of all open interest in the most liquid natural gas exchange in the world is for contracts from January 2026 and beyond. To put that in perspective, the number of open contracts in the next 12 months is roughly equal to 85% of the natural gas volume used by the entire U.S. electricity power sector in 2019. By contrast, the total number of open contracts from January 2026 through December 2033 would only be enough to power a single 1,200 MW CC plant for two and a half months.[88] This paltry volume does not support robust price formation.

[88] As of closing on January 28, 2021, there were 973,194 open contracts of 10,000 MMBtu each for March 2021 through February 2022. This is equal to 9,732 bcf. According to EIA, the U.S. electricity power sector used 11,287 bcf of natural gas in 2019. On that same day, there was a total of 1,317 open contracts for January 2026 through December 2033. In a typical 7,000 heat rate CC unit, this would produce 1,881 GWh, the same amount from running the plant for 78 days.

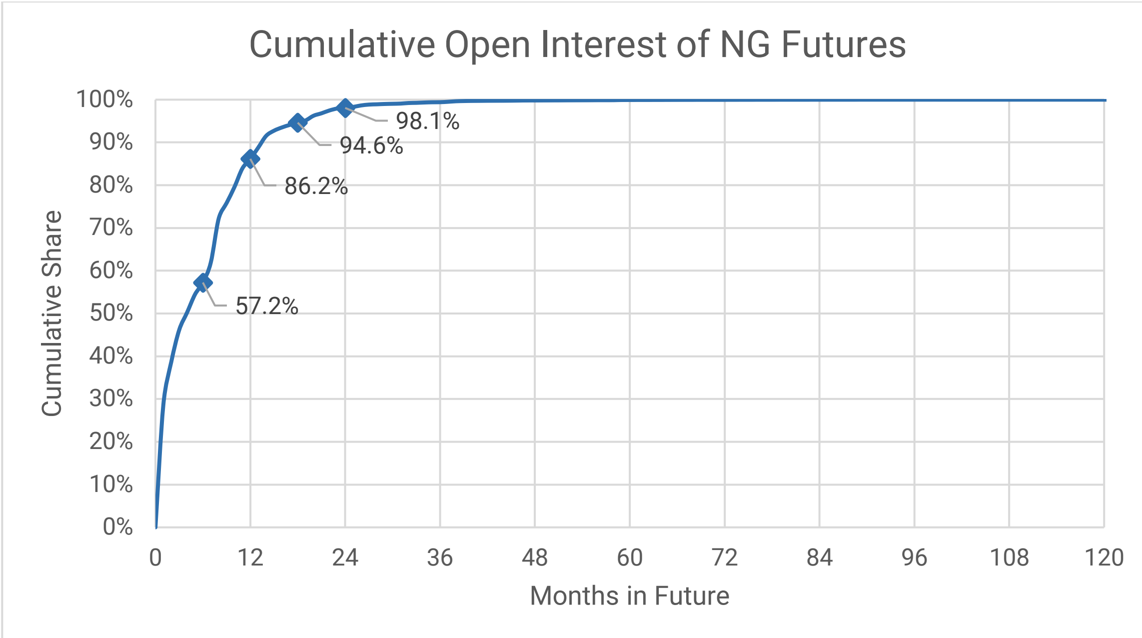


*Figure 16 - Cumulative Open Interest of NG Futures*

This lack of liquidity in the long-term futures market translate into swaps. While swaps are not the same product as futures, they are priced based on futures contracts with potential incremental charges for brokers fees or risk premiums. This relationship is clear when one inspects the price of Duke's swap with the corresponding futures contract from that day, as shown in Figure 17 below. The prices of the two instruments are [redacted], with only a [redacted] in the swap in the out years.

[redacted]

*Figure 17 - Duke Swap vs. Future Price*

Because of this, the lack of liquidity in the market for futures more than five years out becomes embedded in the price of a swap. So, while Duke may be able to procure small amounts of natural gas through 10-year swaps, it does not mean that the prices on which they are based have been robustly set by the market.

Duke has argued that its ability to purchase small amounts of gas on a ten-year forward basis demonstrates the market is sufficiently liquid to rely on its prices.[89] It procured 2,500 decatherms/day, equal to 2,500 MMBtu per day. In a CC unit with a typical heat rate of 7,000, this is sufficient to generate about 357 MWh per day or 130 GWh per year. Considering that DEC and DEP combined have forecasted sales of 154,228 GWh in 2020, the natural gas fuel needed to supply 0.08% of Duke's annual generation secured the swap is simply *de minimis*.[90]

If Duke wishes to use market prices for up to ten years in its gas forecast, it should obtain market quotes from reliable brokers for a meaningful quantity of gas to see if they are available and at prices comparable to small purchases. For instance, it would be instructive to see the price to purchase 50% of Duke's projected natural gas consumption for the next ten years on a fixed price contract. If there is even a counterparty willing to sell this contract, it will likely contain a price premium that makes it substantially more expensive what Duke has demonstrated through relatively tiny purchases.

Further, Duke does not actually limit its use of market prices to ten years. Despite what Duke claims in its IRP report, it is using market prices to define or influence its natural gas forecast for a full 15 years. Duke relies entirely on market prices for the first 10 years of its forecast. Only after this point does it switch linearly from the market prices to the fundamentals-based forecast. So, while the influence of market prices diminishes each year after year 10, it continues to impact the final forecast until year 16.[91]

Despite this, Duke obtain market prices for this full 15 years. The market prices from the 10-year swap stop in December 2029. Monthly futures available on April 9, 2020, the date when Duke locked in its natural gas market price forecast and its high- and low-price forecasts, only went through December 2032.[92] To extend these prices to 2035, Duke simply applied the "year-over-year growth from the last year of market data."[93] The complete lack of market data available for prices this far in the future should preclude Duke from applying any weight whatsoever to market prices past twelve years to its natural gas forecast.

[89] See e.g., Reply Comments of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, p. 17, Docket No. E-100, Sub 158 (March 27, 2019).
[90] DEC IRP Report, Appendix B; DEP IRP Report, Appendix B.
[91] DEC IRP Report at 157.
[92] Duke Response to NCSEA DR2-35.
[93] *Id.*

### Futures Prices are Highly Volatile and Incorporate Short-Term Volatility into Long-Term Prices

Prices of natural gas futures are best described as highly volatile. The natural gas industry is a sprawling, complex sector of the economy. Natural gas is used not only by the electric sector for electricity generation but used heavily in residential and commercial buildings for space and water heating and by industry as feed stocks for many products. Production, transmission, and storage of natural gas involves an entire other set of market participants, and there is a vibrant commodity market where traders and speculators seek profits on natural gas financial derivatives.

Demand for natural gas is highly dependent on weather and storage capacity, leading to major swings in prices during extreme weather events that affect demand or natural disasters that impact supply. Because the market is affected by myriad factors, many of which are unknowable more than a few days out, daily prices are highly volatile. Figure 18 below shows the daily Henry Hub spot price from 1997 through 2021.[94] Major events such as Hurricane Katrina in 2005, Hurricane Ike in 2008, and the Polar Vortex in 2014 can be clearly seen through their impact on prices.

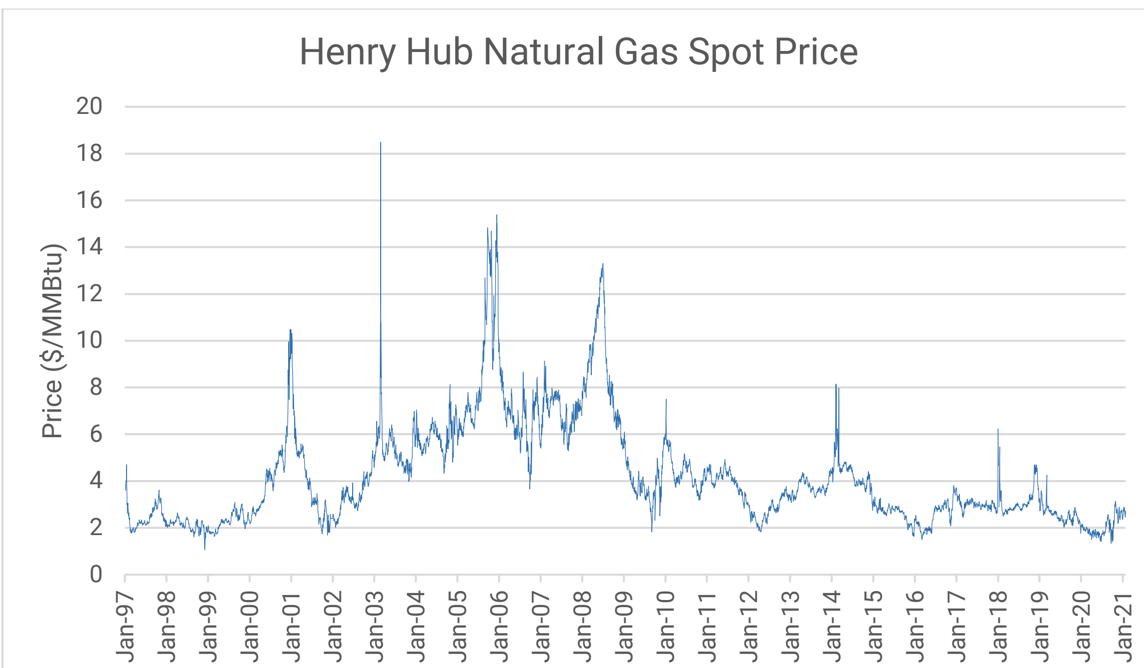


*Figure 18 - Henry Hub Natural Gas Spot Price*

This volatility in prices and corresponding futures contracts can be analyzed and visualized. EIA maintains a data set of Henry Hub spot prices and corresponding futures

[94] Natural Gas Spot and Futures Prices (NYMEX), U.S. Energy Information Administration, available at https://www.eia.gov/dnav/ng/NG_PRI_FUT_S1_D.htm.

contracts for one, two, three, and four months in the future back to 1997.[95] Figure 19 below shows the ratio of the future contract price to the eventual spot price for each month.[96] While some periods have been more volatile than others, there have been few if any periods where the futures price ended up aligned with spot prices. In times of extreme volatility, futures prices for four months in the future can easily be more than 40% higher or lower than the spot price.

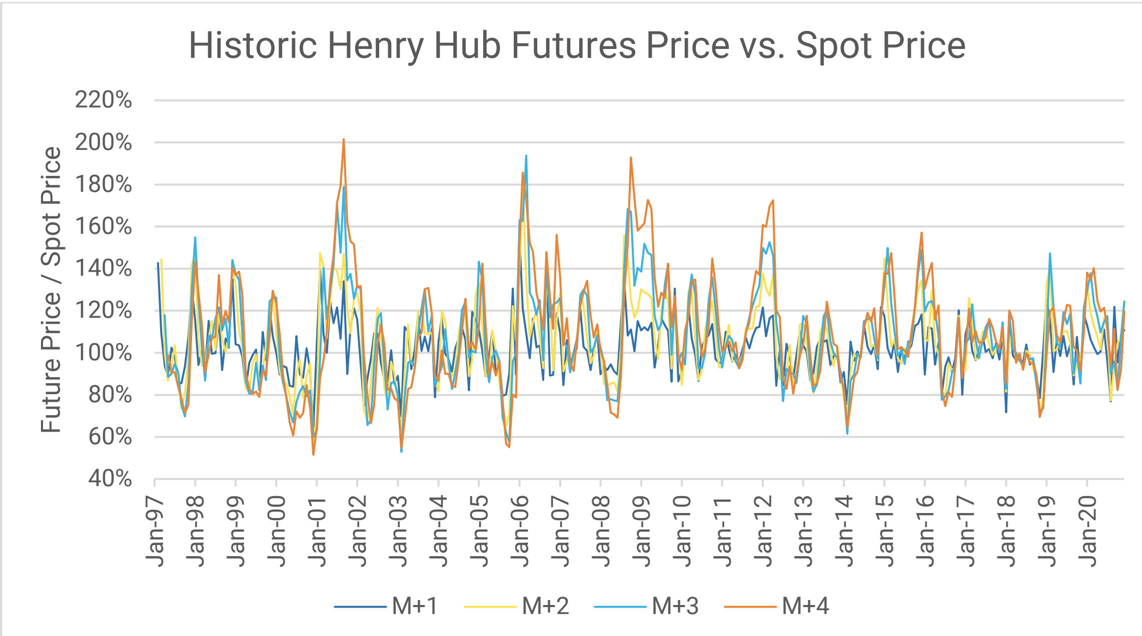


*Figure 19 - Historic Henry Hub Futures Price vs. Spot Price*

The price volatility of futures spans the time horizon of offered contracts, although the price swings are most pronounced for contracts in the subsequent 12 months. Figure 20 below shows changes to the daily settlement curve for futures from January 20, 2021 through January 28, 2021.[97]

[95] *Id.*
[96] The values associated with January 2020 show the ratio of the price of the January 2020 future contract from December 2019 ("M+1"), November 2019 ("M+2") October 2019 ("M+3"), and September 2019 ("M+4") divided by the January 2020 spot price.
[97] Data obtained from CME Group, available at https://www.cmegroup.com/ftp/settle/.

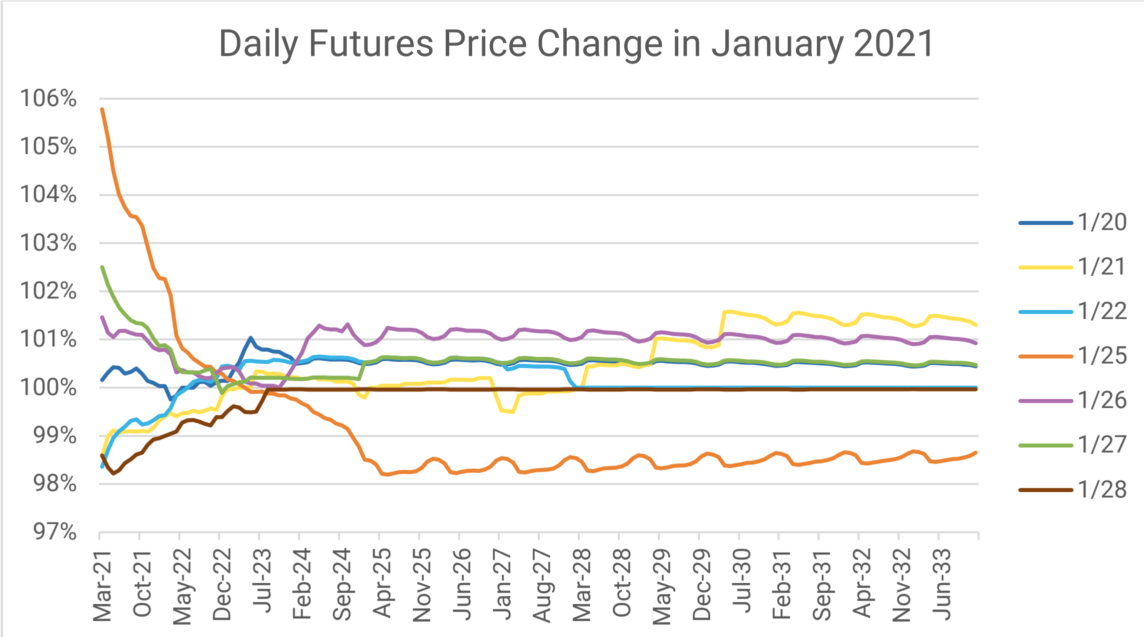


*Figure 20 - Daily Futures Price Change in January 2021*

The lack of liquidity's impact on price formation is clearly delineated in this chart. Daily changes for near-term futures on the left side of the graph show sizable, variable, and continuous changes from month-to-month, reflecting the higher volume of trades across those contracts. By contrast, the daily changes past January 2024 are almost always constant step-changes of 0.5% increments overlaid with small seasonal variations. For instance, the yellow line representing the change from 1/24/21 to 1/22/21 (the previous market day) reduced out-year contract prices by roughly 1.5% from 2025 through 2033. The very next day, the light blue line showing the change from 1/25/21 to 1/26/21 increased prices by roughly 1% from 2024 forward.

There is no rational underlying explanation for why the price of natural gas between four and twelve years in the future would suddenly and uniformly drop by 1.5% in a day only to rise suddenly and uniformly 1% the next day. And yet these types of daily moves are common, despite a complete dearth of daily policy changes that in theory could drive long-term shifts in supply and demand in the physical natural gas market that affect prices. Because of this arbitrary shifting, if Duke had obtained its 10-year swap on 1/25/21 instead of 1/22/21, its long-term price forecast would have been 1.5% lower for the duration of the IRP planning horizon.

## The Price Volatility Around Duke's Forecast Lock In Timing Highlights the Flaw of Using Futures for Long-Term Pricing

These price swing trends persist over longer time frames. Figure 21 below is a graph of the weekly price of a January 2022 futures contract going back to 2010.[98] When this future was first offered, the long-term forecasts for natural gas were suggesting much higher prices. As the fracking boom occurred and supply was increased, the price of the futures contract fell. Notice that while the January 2022 contract price followed the long-term downward trend consistent with new natural gas supply, major swings still occurred back in 2010 through 2012 that were not supported by the trading volume that was present over the past year (indicated by the bars in the lower-right corner of the graph).


*Figure 21 - January 2022 Futures Contract Weekly Price History*

While Figure 21 above represents the price of only one futures contract for January 2022 as it evolved over time, Figure 22 below is a complex chart showing the price history of the January futures contracts from 2022 through 2030, with 2022 in blue, and 2023 through 2030 in progressively lighter shades of green.[99] The small inset charts that show the

[98] Henry Hub Natural Gas Futures and Options, CME Group, available at https://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_globex.html.
[99] This chart can be interpreted as snapshots of the shape of the futures curve graph that has price on the y axis and time on the x axis.

futures price curve on specific dates, demonstrating the relationship between the spacing of lines on the main chart and that day's futures curve shape (high or low, inclined or flat).[100]

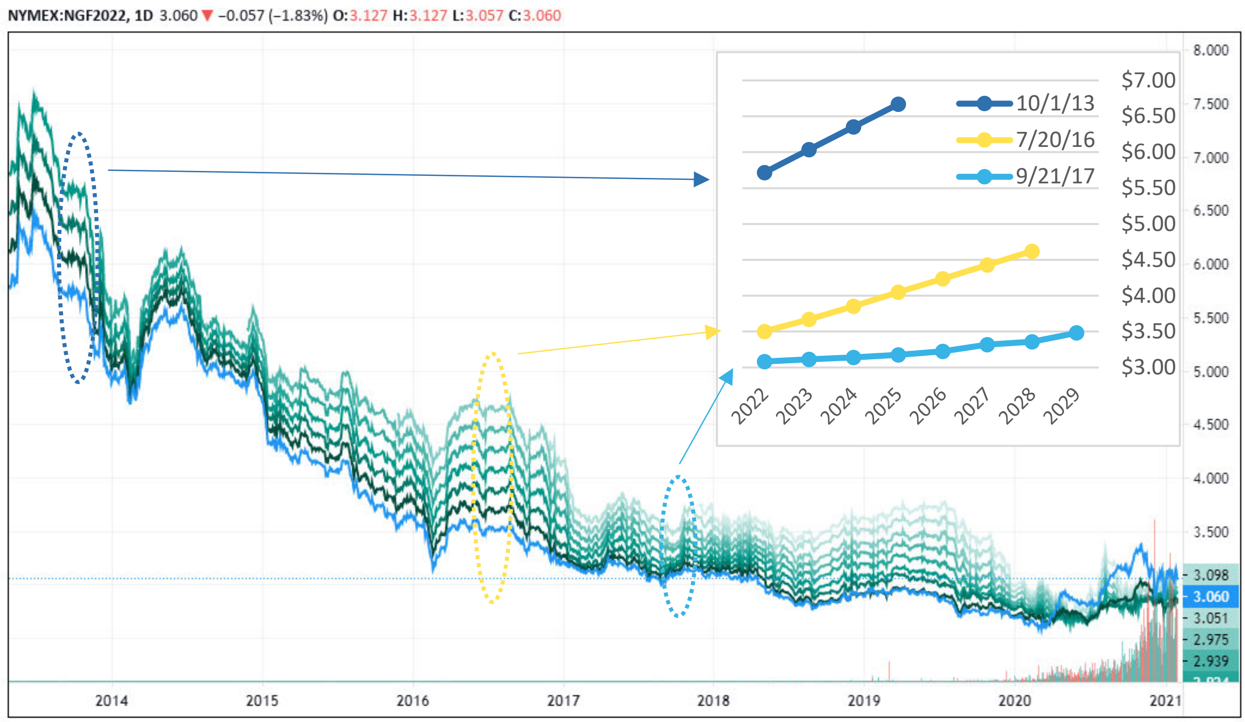


*Figure 22 - Evolution of Natural Gas Futures Prices 2013-2021*

On its own, this chart is somewhat difficult to interpret, but two key observations emerge. First is that for most of the past ten years, the graph of the futures prices had an upward-sloping trajectory. This is visible in the higher prices for successive years showing up in order of color. Sometimes, such as in 2013, the lines are further apart, indicating a steeper upward slope. Other times, such as in the summer of 2014, they are closer together, indicating a flatter slope. Second, the overall curve has fallen in absolute value over time, from in the $5.00 - $6.00 per MMBtu range in 2014 to the $2.75 - $3.75 per MMBtu range in 2019, reflecting the long-term increase in supply brought on by the fracking boom.

This consistent, upward-sloping futures curve has not persisted into the recent past. Beginning in 2020, the dynamics of the futures contract market changed. Figure 23 below zooms in on the past eighteen months of data. The left side of the chart from summer 2019 mirrors the historic trends, with an upward sloping futures curve, albeit at lower absolute levels than in prior years. However, 2020 has broken from the past trends. The futures

[100] The futures price curve is a chart with price on the y axis and time on the x axis. The inset charts represent the price of January forwards that were available on those dates.

curve has moved around substantially, sometimes inverting (where short-term prices (blue) are higher than long-term prices (green)) only to quickly revert back weeks later.


*Figure 23 - Evolution of Natural Gas Futures Prices 2019 - 2021*

The rapid movement of the futures curve in 2020 means that the market prices that form the first ten years of Duke's natural gas price forecast were locked in at a time when volatility was at a recent high. Figure 24 below shows the January futures contract prices for 2022 through 2030 for selected dates in the past 10 months.[101] On March 9, 2020, the futures curve was still sloped steadily upward. By April 9, 2020, the front portion of the curve had inverted, while the out years' price had fallen roughly 7%.[102] A bit more than a month later, on May 14, 2020, the inversion deepened, and long-term prices fell further.

[101] January contracts typically have the highest prices of the year and are used as a proxy for the underlying fuel price over time.
[102] April 9, 2020 was the date that Duke used to establish its natural gas market price forecast and its high and low natural gas price forecasts. Duke Response to NCSEA DR2-35.

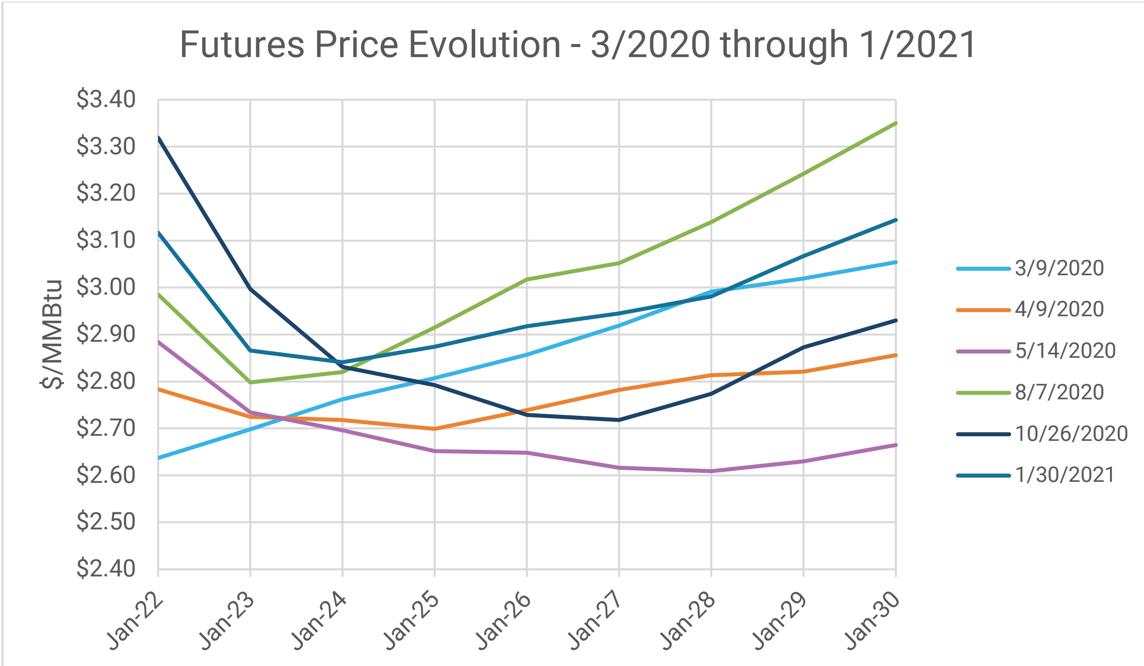


*Figure 24 - Futures Price Evolution - 3/2020 through 1/2021*

But this position was not held for long. By August 7, 2020, there had been a steep climb of the curve, with the inversion gone for all but 2022 and 2030 prices rising more than 25% from their May lows. By the end of October 2020, the curve shifted dramatically again; the inversion was back and stronger than any time in the previous year. Finally, at the end of January 2021, the inversion shifted again, with near-term prices falling while long-term prices rose.

These rapid and major shifts in the futures curve signal correspondingly major shifts in the fundamental dynamics of the natural gas markets. Rather, the fluctuations in 2020 are most likely due to short-term supply, demand, and storage constraints combined with the sizable uncertainty due to COVID working their way into long-term forecasts. This is similar to what was shown above in Figure 20, where out-years had identical changes from day to day. If one strings together enough consecutive days of hot summer weather or mild winter weather expectations on top of the rapidly evolving coronavirus situation, the 0.5% daily changes can add up.

But to suggest that the fundamentals of the U.S. natural gas that drive long-term supply and demand jerked up and down in 2020 to this degree is to misstate the nature of "fundamentals". Figure 25 below shows a simplified version of Figure 23 above with only a few selected dates. The darker green lines represent near-term contracts while the lighter represent long-term contracts.

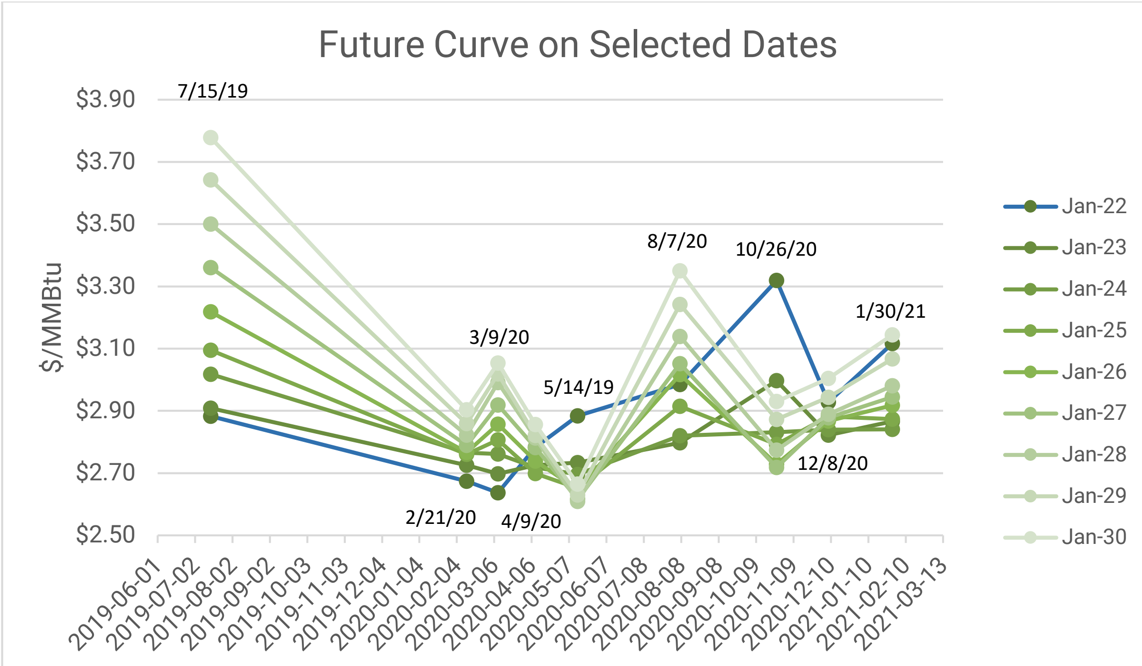


*Figure 25 - Future Curve on Selected Dates*

This price volatility means that the specific timing of Duke's forecast impacted the result in an outsize manner. Duke locked in its market price forecast for natural gas and its high- and low-price natural gas price sensitivities on April 9, 2020, right in the middle of a major period of volatility in futures markets, and very near to the lowest price point in the market in several years. Had the swap been priced a bit earlier or later, the natural gas prices for the first 15 years of the IRP would have been substantially different, potentially producing substantially different IRP results as well. Figure 26 below shows the percent change in the January futures contracts on certain dates compared to Duke's annual market price forecast.

[redacted]

*Figure 26 - January Futures Price vs. Duke Swap Price*

If Duke had locked in prices a month earlier, its gas price forecast from 2025 through 2030 would have been [redacted]% to [redacted]% higher, a non-trivial amount. If they locked in prices a month later, the prices would have been [redacted]% to [redacted]% lower. If they had refreshed their forecast in the summer, prices could have been [redacted]% to [redacted]% higher. These are not small variations, nor can they be considered forecast sensitivities. They are simply the result of relying too long on highly volatile prices from financial derivatives to establish or influence prices for all 15 years of the IRP planning horizon.

Nor can this issue be blamed on the strange and hopefully-not-repeated circumstances of 2020 and the COVID crisis. As shown in Figure 22 above, there have been plenty of times in the past when the entire futures curve shifted up or down substantially in a short period. For instance, early 2016 saw prices falls rapidly only to recover a few months later, and early 2017 featured a substantially flattening of the futures curve over the span of weeks.

## Duke Should Utilize Only Eighteen Months of Market Prices Before Transitioning to a Fundamentals Forecast

Despite the major issues associated with market prices discussed above, market prices do have a useful role in establishing Duke's natural gas forecast, although their role should be limited. The price of the ten-year swap that Duke uses is nearly identical to the price of futures contracts, and thus the issue with illiquidity and volatility in futures market prices translates into to swap prices. The long-term portion of the futures curve reflects short-term volatility in a manner that is inconsistent with deep structural changes to the natural gas market that would drive such divergence in actual long-term prices. Finally, locking in a forecast mere weeks earlier or later can have outsized impacts on ten years of market prices.

In response to this, Duke should limit its use of market prices to the near-term and take steps to avoid the daily volatility inherent in natural gas derivative markets. The Company should calculate the market price of futures contracts three years forward using the average of the daily settlement price for the month preceding the earliest contract closing date. It should also calculate the average based on the most recently available report from at least two fundamentals-based forecasts such as EIA AEO or IHS Markit. Further, Duke should use market prices for 18 months, transition linearly between market prices and a fundamentals-based forecast over the next 18 months and proceed fully on the fundamentals forecast for month 37 and forward.

Suppose Duke decided to update its modeling in this case at the end of June 2021. In that instance, Duke should update its modeling to use market prices starting in July 2021. The Company would determine the forward market price by averaging the settlement prices between May 17, 2021 and June 28, 2021 for July 2021 through June 2024 futures contracts.[103] There is no need for Duke to obtain or procure quotes from ten-year fixed swaps as it has been shown that these prices are functionally equivalent to the futures prices in the near term for small contract quantities.

Duke would then obtain the most recent fundamentals-based forecast from at least two reputable sources. One of these sources should be EIA's AEO as it is a broadly available, open-source model that is readily available to intervenors. Duke would use market prices for the first 18 months, transition linearly to the average of the fundamentals-based models, and exclusively use the average of the fundamentals-based model after month 36.

This approach would be consistent with how market prices are handled by other utilities. The Public Staff conducted a survey of several utilities in the Southeast and around the country and "did not identify any utilities other than DEC and DEP that rely wholly on forward prices for terms greater than six years."[104] Further, other Duke subsidiaries in Florida, Kentucky, and Indiana relied on market prices for five years before transitioning over five year to fundamentals-based forecasts.[105]

Other utilities studied by the Public Staff included TVA (which transitioned fully to fundamentals-based forecast in year six), Georgia Power (using the current year plus two years of market prices), Southwestern Public Service Company (a simple average of market prices and three fundamentals-based forecasts from the beginning of the planning

[103] Futures contracts close three days before the end of the calendar month.
[104] Initial Statement of the Public Staff, p. 22, Docket No. E-100, Sub 158 (February 12, 2019).
[105] *Id*.

horizon), and Puget Sound Energy (three years of market prices before switching to a fundamentals-based forecast). DEC and DEP are clear outliers.

Duke has complained in the past that fundamentals-based models in general and EIA's AEO in particular lag market prices and are thus ineffective in predicting prices in the near term. Its critique that fundamentals-based forecasts are slower to react to short-term pricing trends is not without merit; however, the directionality of the time lag cuts both ways. In its arguments in North Carolina's Avoided Cost proceeding, Duke suggested that its market purchases "demonstrate the stability of long-term natural gas market prices over the past few years" compared to fundamentals-based forecasts.[106] In support of this statement, it produced a low-resolution graph showing that market prices had flatter increases and were more closely bunched than fundamentals-based forecasts. This figure is reproduced below as Figure 27.

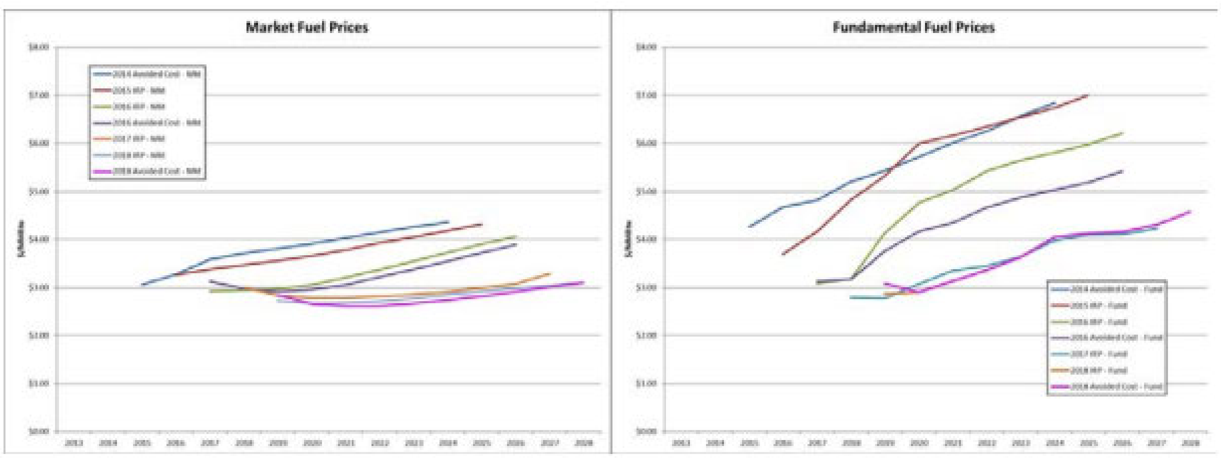


*Figure 27 - Duke NC Avoided Cost Proceeding Market Prices vs. Fundamentals Chart*

The left graph shows the ten-year forward price of market purchases made between 2014 and 2018 in IRP and avoided cost proceedings, while the right graph shows "fundamental fuel prices" over the same time frame. Duke did not publicly disclose the sources of these figures, but one can reasonably assume that the market prices are based on previous small swap purchases and the fundamentals based on forecast from groups such as EIA AEO or IHS Markit.[107]

As an initial matter, the projections embedded in these charts are of little consequence. These figures were produced on March 27, 2019, meaning that any price projection past that time was unknown and could not be verified against actual results.[108] Duke cannot

[106] See, e.g., Reply Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, p. 18, Docket No. E-100, Sub 158 (March 27, 2019).
[107] DEP IRP Report at 5.
[108] And as shown above, these whims can be quite significant.

claim that market price forecasts are more accurate than fundamentals-based forecasts in the future until we reach the future.

EIA has produced a retrospective analysis of its forecasts going back to 1993 that compares the projections of future years to the actual prices that are realized.[109] Figure 28 below shows the forecast error for its AEOs from 1994 through 2020, with darker lines corresponding to earlier forecasts and lighter lines corresponding to more recent forecasts. Forecasts from early AEOs (darker lines) were consistently below eventual market prices, while those from later AEOs (lighter lines) were consistently above eventual market prices.

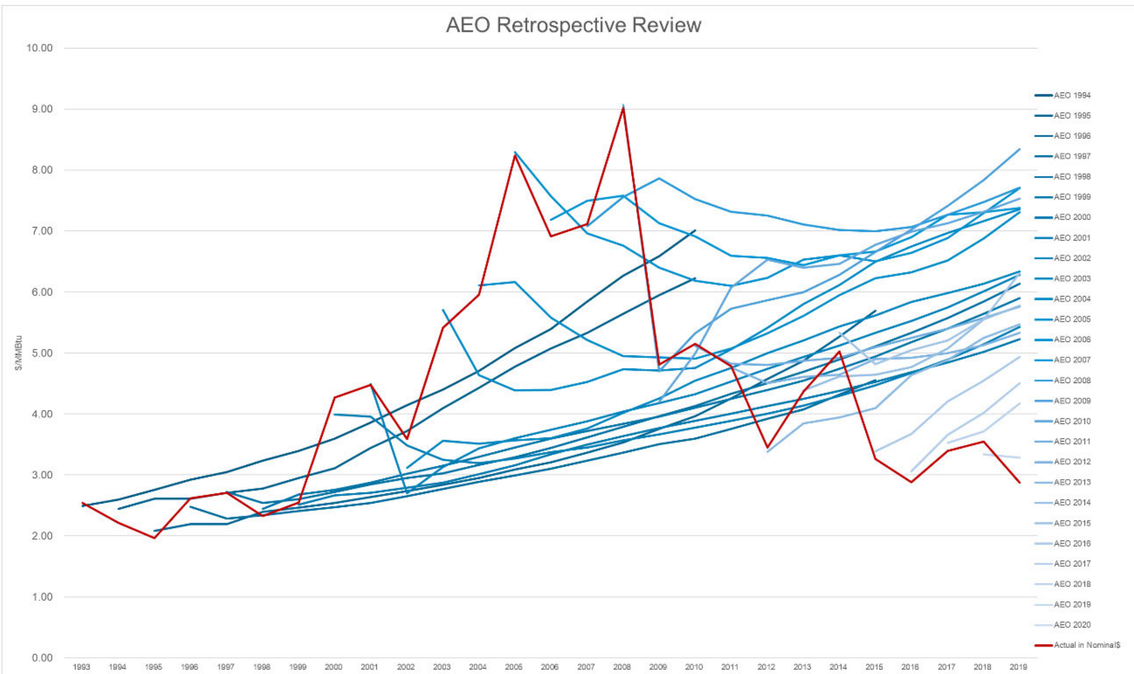


*Figure 28 - AEO Retrospective Review – Natural Gas Prices*

Figure 29 below shows the forecast error of the myriad AEOs. The lagging nature of fundamentals-based forecasts is evident, although the magnitude of its error has fallen in recent years. In forecasts just before the fracking boom drove down prices (e.g., AEO 2008-2010), estimates for future prices were substantially higher than prices that were eventually realized. But during periods when natural gas prices were rising faster than anticipated (e.g., AEO 2000-2003), forecasted prices were substantially under market prices.

[109] Annual Energy Outlook Retrospective Review, available at https://www.eia.gov/outlooks/aeo/retrospective/.

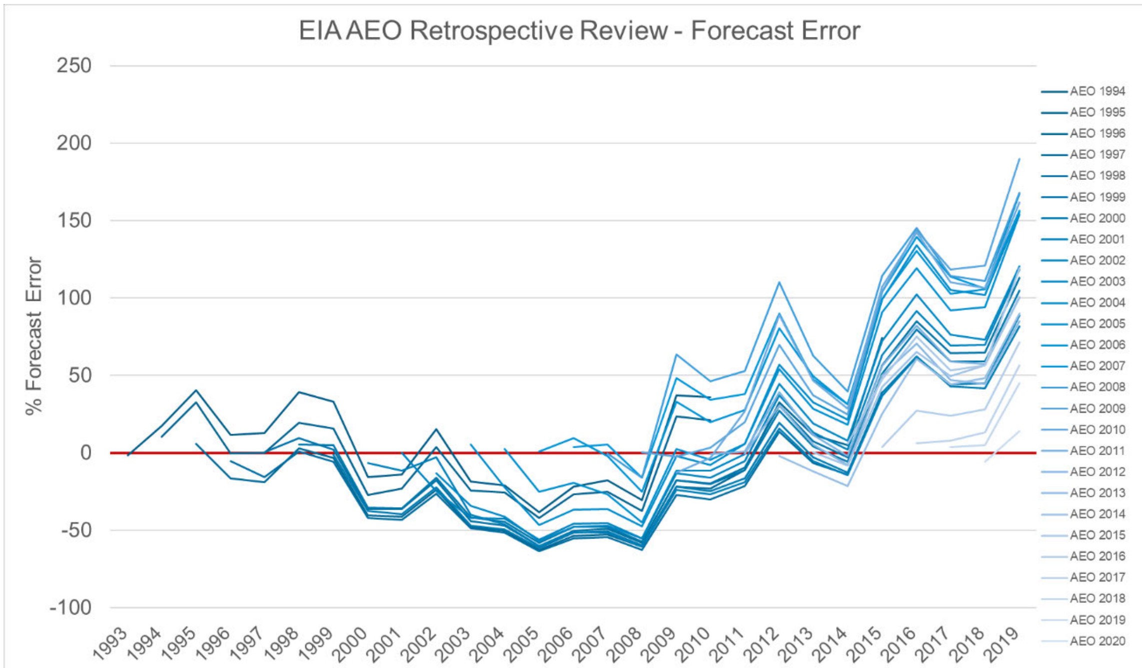


*Figure 29 - EIA AEO Retrospective Review - Forecast Error*

Despite Duke's previous protestations, similar forecast errors are also present in market prices. Figure 21 above showed the price of the January 2022 future dating back to 2013. In the summer of 2013, corresponding to the release of AEO 2012, the market projected that the price of natural gas in January 2022 would be $6.42 / MMBtu. AEO 2012 projected that it would be $6.022 / MMBtu.[110] In March 2020, the market thought the price for January 2022 natural gas would be $2.70, in October 2020 it thought it would be $3.20, and in late January 2021, it thinks it will be $3.12. Regardless of where the actual price of natural gas falls in January 2022, both the market and AEO long-term forecasts missed by similar amounts. This informs my recommendation to use the average of at least two fundamentals-based forecasts for the long-term portion of the natural gas price forecast.

These types of forecast errors present in other critical data points in this IRP. Duke's load forecast shows a similar forecast error, albeit with a slower correction than appears to be occurring in the AEO natural gas forecast. Figure 30 below shows the running ten-year forecast for DEC summer peak demand from 2012 through 2020.[111] DEC's summer peak demand actually shrunk at a compound annual growth rate ("CAGR") of -0.37% between 2010 and 2020 (solid red), while the weather-normalized values rose at a mild 0.06% CAGR (dashed red). Despite these consistent results, each year between 2010 and 2020, Duke's annual forecast for DEC summer peak demand continued to project load growth. Its forecast increased at rates of roughly 1.7% per year in the early 2010s before falling to

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[110] Natural Gas: Production: Dry Gas Production, U.S. Energy Information Administration, available at https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2012&cases=ref2012&sourcekey=0.
[111] Duke Response to NCSEA DR3-12.

roughly 1.0% per year in recent years, despite clear evidence of flat to declining load growth.

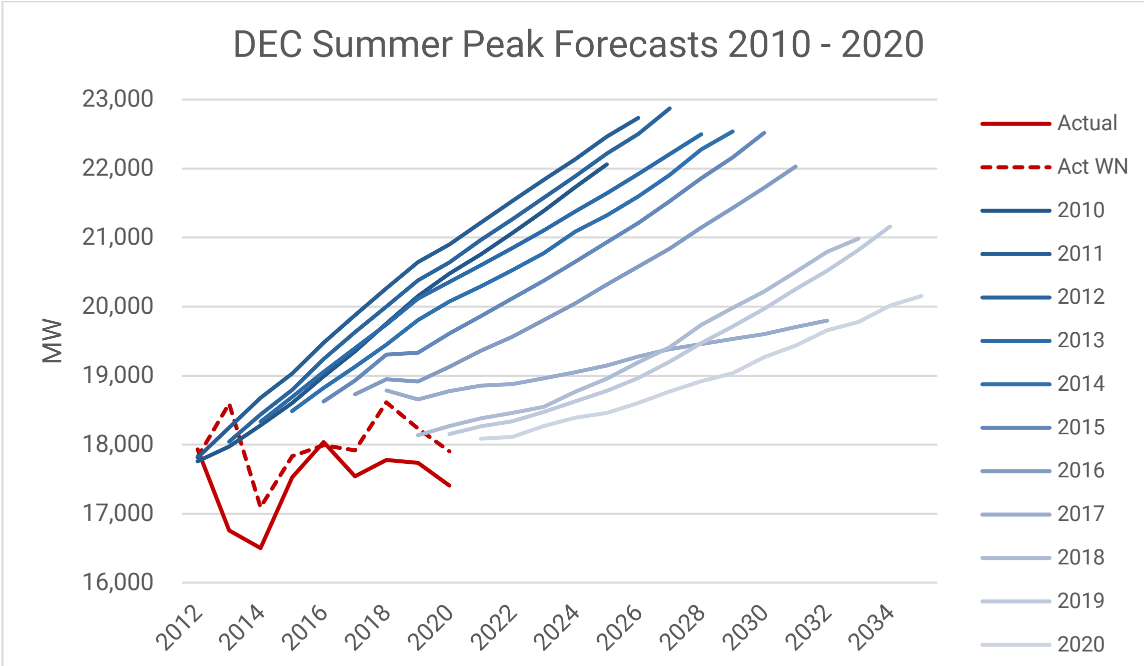


*Figure 30 - Duke DEC Ten Year Summer Forecast*

## Duke's High and Low Natural Gas Price Sensitivity Methodology Exacerbates the Flaws of Using Market Prices in the Long-Term

Duke produced a high and low natural gas price sensitivity. However, it did not produce any price sensitivities on coal, using a single base value for that fuel cost in all of its scenarios.[112] Duke's high and low natural gas price sensitivities once again used a blended approach. It first produced a high- and low-price sensitivity for its market price forecast for years 1 through 10 before transitioning linearly to the high and low sensitivities of the AEO forecast from years 11 through 15 before moving fully to the AEO high and low sensitivities in year 16 forward.

The market price sensitivities were constructed through a statistical approach called a "geometric Brownian Motion model."[113] This model iterates through time, applying random increases or decreases in prices based on observed volatility of the natural gas futures market. Each run of the model will produce a slightly different futures curve, reflecting the randomness of Brownian motion.[114] Duke produced 1,000 futures price curve simulations and sorted them high to low, averaging the 95th through 105th result for the low price (10th percentile) estimate and 895th through 905th result for the high price

[112] DEC IRP Report at 157.
[113] Duke Response to NCSEA DR2-35.
[114] Brownian motion describes small, random motion of particles in a medium. It is the mechanism through which diffusion occurs.

(90th percentile) estimate. This process was repeated 10 times with Duke averaging each run's high and low price to produce the final high and low simulated futures curve.

Under this method, the underlying cause of the resulting 10th and 90th percentile fuel forecast schedules is randomness. This approach is roughly equivalent to using a Plinko board to produce fuel price sensitivities.[115] The underlying price volatility (i.e. daily price fluctuations driven by factors such as weather) is a measure of how quickly each iteration can deviate from that month's central value price. As the model iterates, most results will "revert to the mean" and remain relatively close to the baseline forecast central value. But in some runs, like in Plinko, the final value manages to migrate substantially to the high or low side of the distribution through random chance. If one were to graph the results of the 10,000 runs, one would expect to see a progressively wider normal distribution around each successive month's central value.[116]

While Duke's market price sensitivities rely on randomness to determine high and low prices, fundamentals-based models tweak parameters in their highly-integrated model to simulate shifts in supply or demand that will cause prices to rise or fall. EIA's AEO has two scenarios that specifically adjust production and supply of oil and natural gas: "In the High Oil and Gas Supply case, lower production costs and higher resource availability allow higher production at lower prices. In the Low Oil and Gas Supply case, EIA applied assumptions of lower resources and higher production costs."[117] In these scenarios, prices are not based on random price volatility in a futures market already struggling to deliver robust long-term projections, but rather rise and fall in a manner that simulates and incorporates the economic feedback loops that would come along with supply changes.

The limitations of Duke's methodology are revealed when comparing its forecast sensitivities to the different AEO scenarios. The baseline market price forecast limits the range of the high and low market price sensitivities in the early years given they do not have sufficient time to "diffuse" away from the central value. This produces a result where the high market price sensitivity is actually lower than the AEO Reference case between 2025 and 2034, and is much lower than the price projected in the AEO Low Supply (i.e. high price) case. Similarly, AEO's High Supply (i.e. low prices) case is well above the low market price sensitivity. Figure 31 below shows this relationship, with NYMEX representing Duke's market price forecast.

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[115] Plinko was a popular game that debuted on the Price is Right in 1983. It featured a pegboard with many rows of offset pegs set in a hexagonal pattern. Contestants would drop discs in the top of the board where they would randomly bounce left and right while falling through the rows of pegs. The discs eventually finished in a slot at the bottom of the board which contained a specific cash prize.

[116] This assumes the volatility of price swings is symmetric. If the initial data set has a higher chance of prices increases than price decreases, then the distribution will be skewed towards higher prices.

[117] *Critical Drivers and Model Updates*, EIA AEO (2020), available at https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Critical%20Drivers%20and%20Model%20Updates.pdf.

[redacted]

Figure 31 - Fuel Price Sensitivity Comparison

Duke's merger of a random-walk forecast and a fundamentals-based alternative scenario forecast sensitivity to produce a unified high-price and low-price natural gas sensitivity makes no sense. There is no correlation between the statistical analysis Duke applied to the market prices to simulate high- and low-price sensitivities and the scenario-based AEO cases used to build the high- and low-price sensitivities in the fundamentals-based forecast. Merging the two together carries forward the flaws of Duke's baseline forecast into the natural gas price sensitivities.

The arbitrary nature of the resulting forecast is evident in the low gas price scenario. Figure 32 below, a reproduction of the DEC IRP Report Figure A-2, shows the implausible result that Duke's approach produces. Duke expects the natural gas industry to reduce prices after inflation by 3.5% per year in the 2020s, then increase at an annual rate of more than 18% between 2030 and 2035, before slowing growth to an annual rate of 2.9% from 2036 and beyond. It is difficult to fathom a combination of policy scenarios that would produce this curve exactly because no combination of policy scenarios would produce this curve.

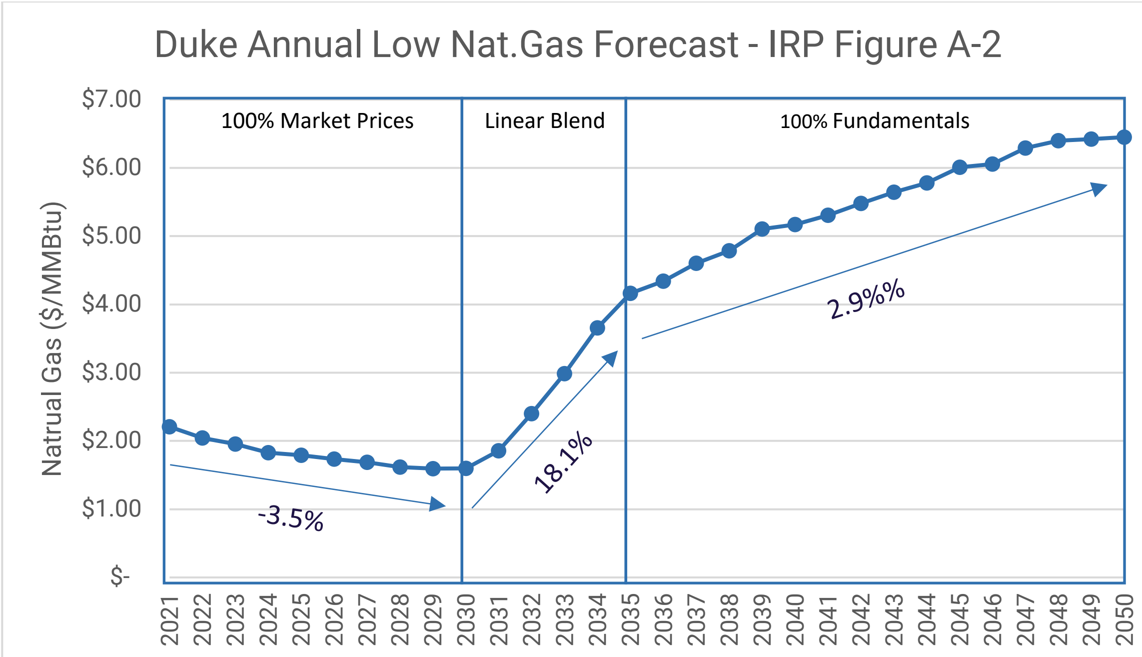


*Figure 32 - Duke Annual Low Natural Gas Forecast - IRP Figure A-2*

By contrast, the low-price scenario from AEO is internally consistent. Figure 33 below shows the annual results from this case overlaid with Duke's low-price sensitivity. Gone is the rapid directional switching, replaced by more modest moves as the feedback mechanisms in the fundamentals-based model incorporate higher supplies and lower prices.

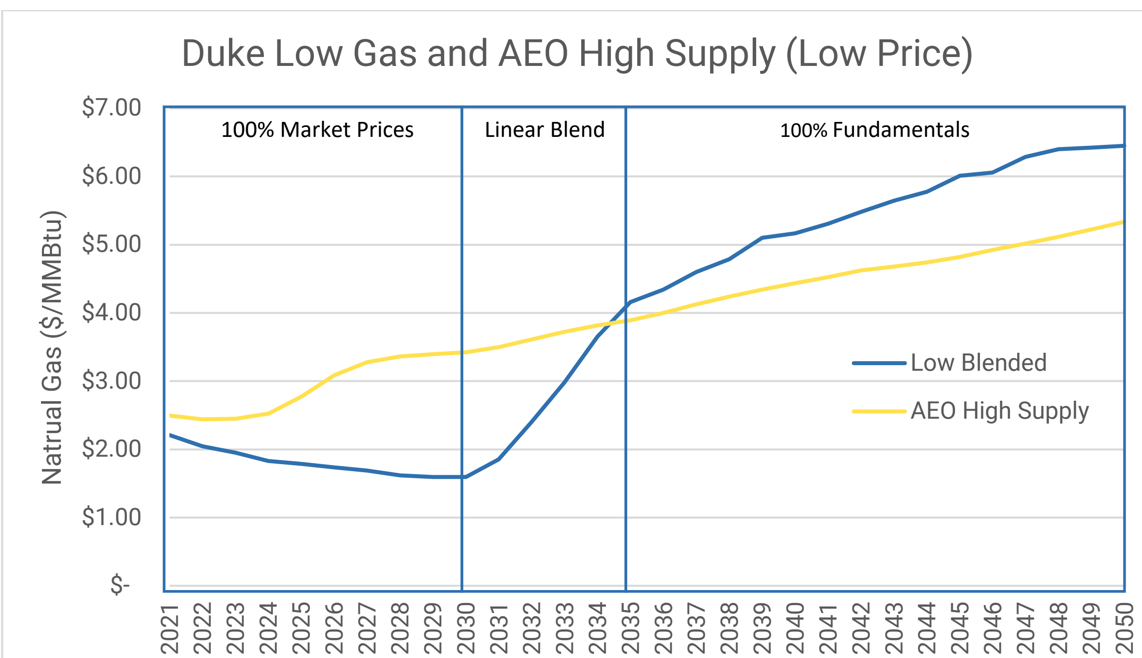


*Figure 33 - Duke Low Gas and AEO High Supply (Low Price) Sensitivities*

The use of the 10th and 90th percentile results drove a larger discrepancy between the market prices and the fundamentals-based forecast. The high- and low-price sensitivities are important to demonstrate how Duke's fleet will respond to changes in the market, but using values from one-in-ten likelihood forecasts are more extreme and less likely than necessary for this purpose.

Even though the recommended forecast methodology limits the use of market prices to 36 months, the construction of the high- and low-price scenarios in that timeframe is still based on random chance based on the volatility of the market. To counter this, Duke should instead use the 25th and 75th percentile results from this analysis. By selecting relatively more likely outcomes from the 25th and 75th percentile, the potential for the market prices to move too far from the central value is reduced.

As previously noted, Duke did not perform a price sensitivity for coal and limited its fuel cost sensitivities to natural gas, stating: "By only changing natural gas prices, the impact on resource selection (CC vs CT vs Renewables) and dispatch (coal vs gas) can be evaluated."[118] Duke's failure to develop and analyze a high coal price scenario from either market conditions or regulatory changes, is problematic. Coal generation faces outsized regulatory risk and market pressures in the near future compared to the past. Changes in federal regulations may either require costly upgrades to maintain compliance or increase the running costs of coal units. For instance, EPA estimates that installing SCRs on units such as those at Marshall would cost roughly $100 million for a 300 MW unit and roughly $200 million for a 700 MW unit.[119] This could in turn impact the economic timeline for coal unit retirements, which could require additional replacement capacity to come online earlier.

Many of the issues discussed above will disappear if Duke switches to the forecast methodology described for the base scenario of relying on market prices for eighteen months before transitioning over eighteen months to the average of at least two fundamentals-based forecasts. The random nature of the Brownian model cannot move too far away from the central baseline market price forecast after only 36 months as there are simply fewer iterations to produce deviations. Maintaining the same blending method between 18 and 36 months will allow near-term market volatility to initially displace and then phase into the average of the early years prices from at least two fundamentals-based models. Further, Duke should construct a high coal price scenario to reflect the increasing regulatory and market risk associated with the continued operation of its coal plants.

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[118] DEC IRP Report at 157.
[119] EPA Platform v6, available at https://www.epa.gov/sites/production/files/2018-05/documents/epa_platform_v6_documentation_-_chapter_5.pdf.

## Duke's Reliance on Market Prices for Ten Years has Likely Skewed the IRP's Results

The natural gas price forecast and corresponding high- and low-price sensitivities are critical input assumptions to Duke's modeling. For a variety of reasons, Duke plans to close its coal facilities over the coming decades. The energy and capacity that these plants produce must be backfilled by some combination of resources. One of the primary goals of the IRP modeling is to determine which resource mix of demand-side management, renewable generation, fossil generation, and battery storage provides the most reasonable and appropriate blend. The natural gas fuel price input is particularly crucial in determining whether more renewables and batteries are selected by the model, or whether is it less costly to expand natural gas capacity (despite the stranded asset risk discussed previously).

Figure 34 and 35 below overlays Duke's annual central natural gas cost assumption with the additions from its modeling runs in the Base with Carbon Policy and Earliest Practicable Coal Retirement portfolios. Several thousand MW of new CC plants are added in 2027 and 2028 in part based on the low natural gas prices that are prevalent through the early 2030s. If Duke's natural gas price forecast had reflected the recommended market price / fundamentals approach discussed above, prices in the mid-2020s and early 2030s would have been higher, increasing the PVRR of building and running natural gas plants.

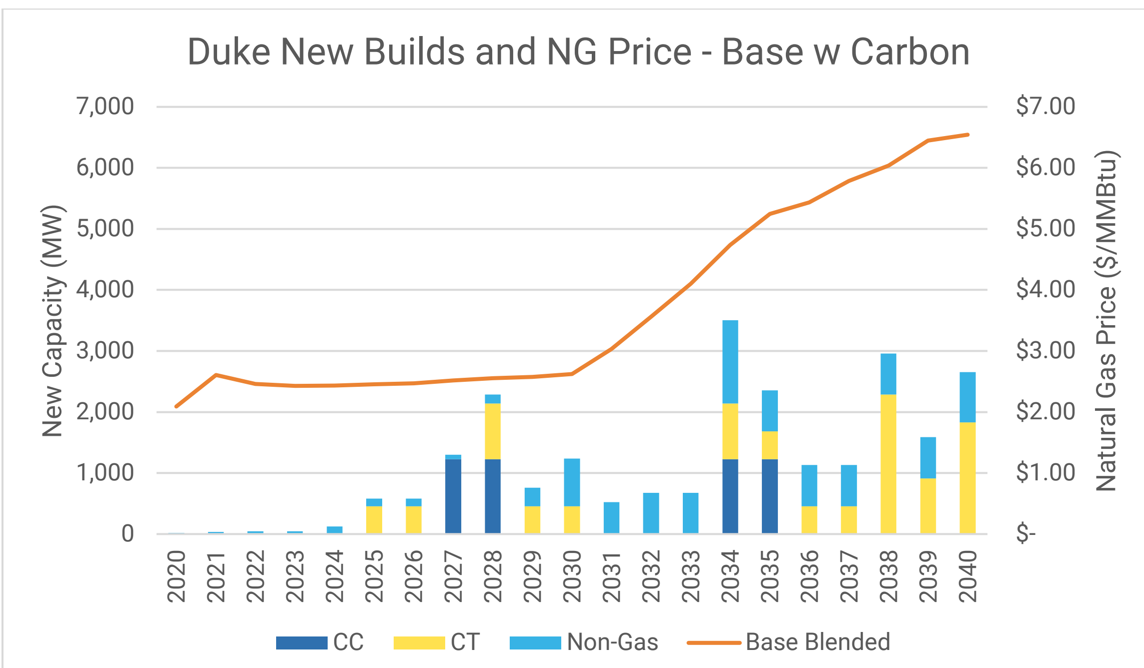


*Figure 34 - Duke New Builds and NG Price - Base w Carbon*

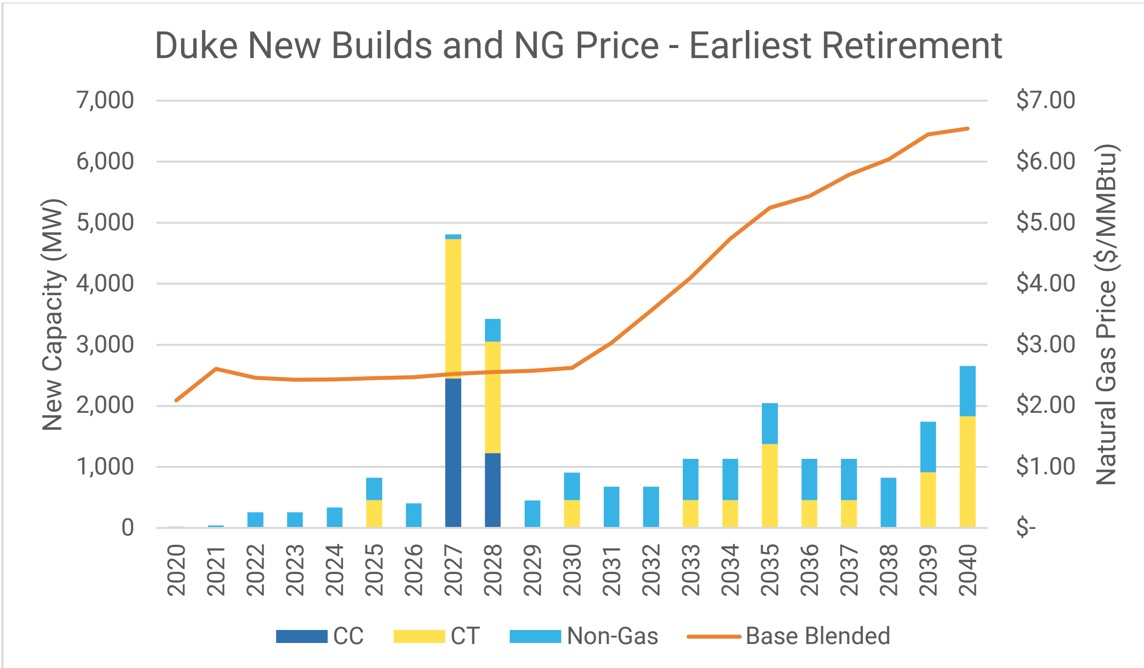


*Figure 35 - Duke New Builds and NG Price - Earliest Retirement*

The low natural gas price forecast could affect the model's decision whether to add new renewable generation even when there is no capacity need, although as discussed in Section III above, Duke has not enabled this option. With a higher natural gas price forecast, running existing or constructing new natural gas facilities would be relatively more expensive. This would provide an opportunity for solar, wind, and battery resources to economically displace new builds of natural gas or substitute new renewable builds for existing natural gas generation.

Duke's central near-term forecast based on market prices is well below the fundamentals-based models. Figure 36 below shows the annualized prices for the Duke's base forecast ("Duke Blend"), a newly updated blend based on my recommended methodology ("Updated Blend"), and the full range of market prices ("NYMEX"), [redacted] forecast ("[redacted]"), and the 2020 AEO Reference case ("AEO Ref").[120]

[120] Duke Response to ORS DR2-3.

[redacted]

*Figure 36 - Original and Updated Natural Gas Price Forecast*

The two fundamentals-based models track each other closely through roughly 2035, when [redacted] rises above AEO. By taking the average of these two forecasts, prices are projected to be quite a bit higher in the 2020s and the early 2030s than in Duke's original base forecast. This change would present the model's optimization routines with a very different picture when natural gas is at $[redacted] / MMBtu than when it is at $[redacted]/ MMBtu.

It's tough to make predictions, especially about the future. But Duke's preference for long-term market price forecasts is fundamentally flawed. Ten years is simply too long to rely on contracts priced on highly volatile financial derivatives. The contracts that underpin Duke's market price forecast are subject to sizable and frequent price shifts. The long-term prices that form the basis for the first ten years of Duke's natural gas price forecast are derived from illiquid markets and inappropriately reflect short-term volatility in long-term prices. Further, the prices of these contracts can fluctuate wildly in the span of a few weeks. It is wholly inappropriate to base ten years of future fuel prices on what is essentially a toss of the dice.

Duke's refutation of fundamentals-based forecasts made in other proceedings falls flat. It is true that market prices, which settle daily, move faster than fundamentals-based models, which are updated once or twice a year. Yet the frequency with which market prices move is not necessarily reflective of more accurate pricing. The rapid and sizable price swings of 2020 clearly demonstrates that market prices ten years out can be substantially impacted by short-term market volatility. It is a fallacy to believe that policies that could drive 10% to 15% price changes ten years in the future would shift back and forth week to week.

Duke should change its natural gas forecast methodology to leverage market prices where they are most liquid, while appropriately blunting the natural volatility in natural gas futures markets. By constructing a market price forecast based on a full month of futures contracts settlement prices, Duke can temper the abundant short-term market price volatility. Using this market price forecast over eighteen months before fully transitioning to a fundamentals-based forecast over the next eighteen months leverages the information from the liquid futures market while not allowing it to overstay its welcome. This approach should also be applied to the high- and low-price sensitivities; Duke's current "random walk" approach to price variation has no place beyond three years.

The fundamentals-based forecast should be derived from the average of at least two reputable sources, including EIA's open-source AEO. This approach limits the reliance on one single forecast in much the same way that averaging a month of futures prices mitigates overweighting a single set of market prices. Marrying these two forecasts together should provide Duke with a much more robust natural gas forecast on which to base its IRP.

## V. Duke Overlooks the Benefits of Regionalization

Duke has already performed modeling that shows the benefits associated with basic levels of regionalization, that is, firm capacity sharing between DEP and DEC and allowing for imports from neighboring systems. However, it has failed to pursue regulatory approvals that would let it operationalize some of these steps. Duke should proactively seek changes that would allow it to file joint IRPs between DEC and DEP and plan and operate its two utilities in a manner that minimizes costs for all its customers.

Duke should also explore the potential benefits of broader regionalization through structures such as EIMs or RTOs. While Duke has supported the creation of the Southeast Energy Exchange Market ("SEEM"), due to its limited scope that organization would provide only a fraction of the potential benefits that a broader regionalization approach could bring.

### Increasing Regionalization Can Reduce Costs and Increase Reliability

Astrapé Consulting identified the basic topology of Duke's power grid as modeled in its resource adequacy study. In its DEP and DEC 2020 Resource Adequacy study ("RA Study"), Astrapé properly assumed that Duke's companies were interconnected to several neighboring systems. Figure 37 below is taken from the RA Study and shows the east and west region of DEP and DEC along with other systems such as TVA, PJM, and Southern Company.

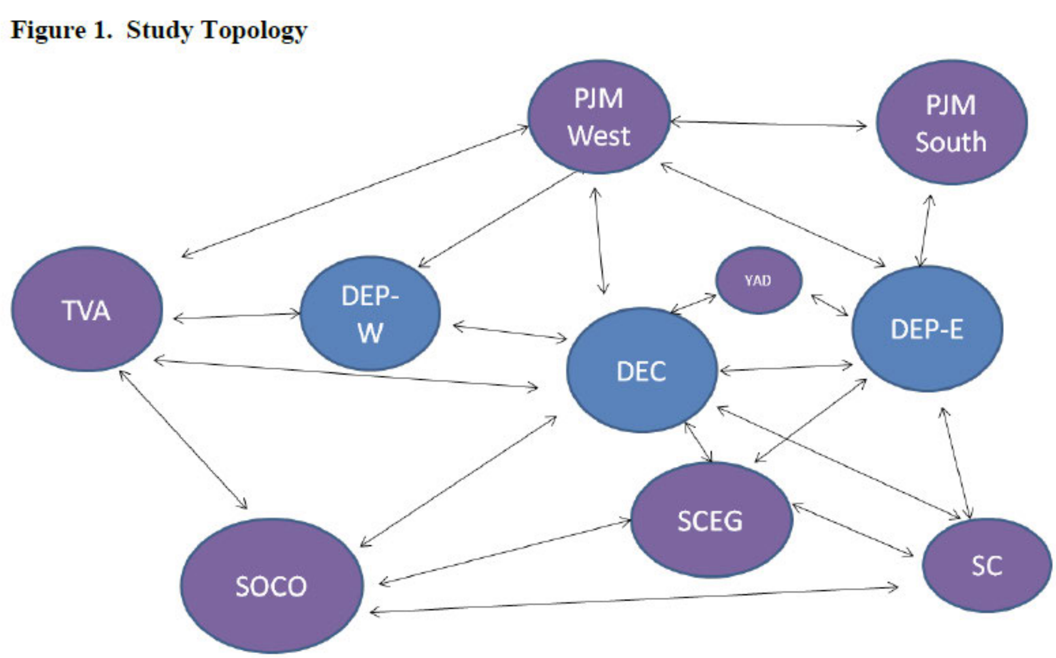


*Figure 37 - Resource Adequacy Study Topology*

The ability of Duke to import power varies based on the region. Table 6 below shows the import limits from each region in the summer and winter.[121] In addition to the figures below, DEC can export [redacted] MW to DEP-E, [redacted] MW to DEP-W, and transmit [redacted] MW from DEP-E to DEC to DEP-W. For reference, DEP's and DEC's 2021 winter peak load forecast is 14,118 MW and 17,725 MW, respectively.[122]

| From | Summer | | | Winter | | |
|---|---|---|---|---|---|---|
| | DEC | DEP | Total | DEC | DEP | Total |
| SC | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| SCEG | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| SOCO | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| TVA | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| PJM West | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| PJM South | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Yadkin | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| CPLE | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| CPLW | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Total | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

*Table 6 - DEP and DEC Import Capacity*

Together, DEP and DEC have the ability to import [redacted] MW from neighboring balancing areas in the winter, in addition to DEC's transfer ability to DEP. This represents a substantial fraction of Duke's winter peak demand level.

These other regions do not experience peaks at the same time as DEC and DEP. Astrapé performed a load diversity analysis and found that neighboring utilities had spare capacity during the times when either the regional system or DEC and DEP individually were at their peaks. During the overall winter system peak, individual regions were roughly 2%-9% below their individual peaks. Further, when DEC was at its peak, DEP was 2.8% below its peak load and other regions were between 3%-11% below their peak loads.[123] When DEP was at its peak, DEC was 2.7% below its peak load and other regions were between 3%-9% below their peak loads.[124] This suggests that not only do these other regions have the physical ability to provide capacity to DEP and DEC during their winter peaks, but they have capacity to spare as well.

Astrapé and Duke ran several scenarios that modified the import capacity limits. The first case was an "island" case, where all resources must be in the physical footprint of DEC or DEP. Unsurprisingly, this required a very high reserve margin to meet the standard of 0.1 loss of load expectation ("LOLE") per year, with a 22.5% requirement in DEC and a 25.5%

[121] DEP RA Study, Confidential Appendix, DEC IRP Report, Attachment 3 ("DEC RA Study"), Confidential Appendix.
[122] DEC IRP Report, Appendix B; DEP IRP Report, Appendix B.
[123] DEC RA Study at 28.
[124] DEP RA Study at 27.

requirement in DEP.[125] This island configuration is not reflective of how Duke's systems are physically configured, and thus Astrapé ran the Base Case allowing imports from neighboring regions. This reduced the reserve requirement in DEC to 16.0% and in DEP to 19.25%[126]

Astrapé also modeled a "combined case" where both utilities were treated as a single entity. This model produced a combined reserve margin requirement of 16.75%.[127] One last sensitivity was performed that limited the imports into the combined utility to 1,500 MW, well below the actual import capacity. This adjustment increased the reserve margin to 18.0%, showing the cost benefits associated with utilizing spare regional capacity.[128]

By modeling a Joint Planning case with a combined DEC and DEP, Duke was able to delay the addition of several CTs. It also resulted in a lower overall reserve margin. As Duke indicated, "[t]he ability to share resources and achieve incrementally lower reserve margins from year to year in the Joint Planning Case illustrates the efficiency and economic potential for DEC and DEP when planning for capacity jointly."[129]

Despite the obvious benefits associated with planning and managing capacity jointly, the Company does not currently plan and manage capacity jointly between DEC and DEP. While the Company has a JDA in place, outside of emergency situations, it is limited to economic non-firm energy transfers.[130] It also does not perform a unified IRP for the combined companies, nor plan for capacity jointly between the two companies.

Duke's decision to not integrate its operations and planning efforts more thoroughly is in part based on its position that it does not currently have authorization to either submit a unified IRP[131] or share long-term capacity.[132] It further noted that such authorization would be required from the Federal Energy Regulatory Commission, the Commission, and the Public Service Commission of South Carolina.[133]

There does not appear to be anything preventing the Company from pursuing these changes. Duke stated "[i]f and when a decision were to be made to file a unified IRP that covers both territories or to merge the balancing areas across [North Carolina] and [South Carolina], the Company would seek appropriate regulatory approvals."[134] The response is

[125] DEP IRP Report at 67, DEC IRP Report at 65. The 0.1 LOLE is roughly equivalent to experiencing one load shed event in ten years.
[126] DEP IRP Report at 67, DEC IRP Report at 65.
[127] DEC IRP Report at 66.
[128] DEP RA Study at 61.
[129] DEC IRP Report at 200.
[130] Duke Response to NCSEA DR2-12.
[131] Duke Response to NCSEA DR2-13.
[132] Duke Response to NCSEA DR2-12.
[133] *Id.*
[134] Duke Response to NCSEA DR4-2.

ambiguous as to who would be making the decision, but Duke did not identify any legal roadblocks to seeking a change in status.

The Commission should direct Duke to study the impact of joint planning of and long-term capacity sharing across its two systems and prepare a feasibility study on merging these functions across the two utilities. Based on high-level analyses presented in this docket, it appears that cost savings are available through this effort. Arrangements could be made between DEC and DEP that would realize and pass these cost savings onto the customers of each utility.

## Duke Should Analyze the Benefits of Broader Regionalization

Aside from potentially deepening its JDA to include planning and firm capacity transfers, there are other regionalization benefits that Duke could consider to further reduce costs to its customers. Duke has already expressed interest in joining SEEM, a very small step towards regionalization that would allow companies to voluntarily execute bilateral contracts for as-available energy in fifteen-minute blocks. This marketplace could potentially save participating utilities in the Southeast $40-50 million annually in the near term, potentially increasing to $100-$150 million in the long term.[135]

These savings are miniscule compared to the potential volume of electricity sales from the founding members. Founding members of SEEM are expected to include some of the largest utility companies in the southeast, including Associated Electric Cooperative, Dalton Utilities, Dominion Energy South Carolina, Duke Energy Carolinas, Duke Energy Progress, ElectriCities of North Carolina, Georgia System Operations Corporation, Georgia Transmission Corporation, LG&E and KU Energy, MEAG Power, NCEMC, Oglethorpe Power Corp., PowerSouth, Santee Cooper, Southern Company, and TVA.[136] Considering DEC and DEP spend billions of dollars annually apiece on electricity, $40 million per year from this consortium of large utilities is a drop in the bucket of what benefits broader and deeper regionalization could bring.

Duke appears to acknowledge that SEEM will not be integral to its operations or planning going forward. When asked about how SEEM will change their IRP assumptions, Duke responded: "Since SEEM is a sub-hourly non-firm energy only market, SEEM is not expected to be foundational to future IRPs."[137]

Other structures exist that could increase savings further compared to SEEM. The Western EIM has more robust features, including both a 15-minute and 5-minute market and an

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[135] Southeast Electric Providers to Create Advanced Bilateral Market Platform, Duke Energy (December 11, 2020), https://news.duke-energy.com/releases/southeast-electric-providers-to-create-advanced-bilateral-market-platform.
[136] *Id*.
[137] Duke Response to NCSEA DR2-6.

independent market monitor.[138] Since its formation in in November 2014, the Western EIM has saved its participants $1.2 billion, including $325 million in 2020 alone.[139]

But even the Western EIM does not currently feature a day-ahead market, where the vast majority of energy transactions are handled, nor implement transparent nodal pricing (e.g., LMPs). These are features associated with RTOs and represent an even deeper commitment to regionalization. RTOs such as PJM and MISO function as transmission system operators and coordinate wholesale markets in energy, capacity, and ancillary services. By extending planning and dispatch over a broad geographic area, RTOs can maximize the benefits of geographic diversity in load shape, weather, and generation assets. In contrast to the limited SEEM proposal, a broader southeast RTO could save customers up to $384 billion through 2040.[140]

There have been recent activities on regionalization in Duke's Carolinas territory. South Carolina governor McMaster signed H. 4940 into law last fall.[141] This law creates a legislative committee and advisory board that has until fall 2021 to study changes to the electricity sector in South Carolina, of which the South Carolina President of Duke Energy is a member. The study must investigate potential reforms such as creating a new RTO, joining an existing RTO, establishing an EIM, restructuring power generation, and offering full customer retail electric choice.[142]

Duke should bring its expertise to the committee and help detail the potential benefits and challenges associated with regionalization. It will be critical that Duke provide information objectively, recognizing that some benefits of that come with regionalization could put downward pressure on Company revenues and profits. However, as shown by the buildouts needed to transform the electricity sector in South Carolina, there will be no shortage of investment opportunities in new, clean generation and transmission assets.

[138] Western Energy Imbalance Market, How It Works, available at https://www.westerneim.com/Pages/About/HowItWorks.aspx.
[139] Western Energy Imbalance Market, Benefits, available at https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.
[140] Jim Day, South Carolina Law Pushes for Power Market Reform, Floats Creation of RTO, Center for Advanced Power Engineering Research (October 7, 2020), https://caper-usa.com/news/south-carolina-law-pushes-for-power-market-reform-floats-creation-of-rto/.
[141] S.C. Act No. 187 (2020), available at https://www.scstatehouse.gov/sess123_2019-2020/bills/4940.htm.
[142] *Id.* § 2(B).

## VI. Conclusion

Duke's IRP requires modifications. The Company fails both to identify a single Preferred Resource Plan and to provide the Commission with sufficient information from which it could determine what is the most reasonable and prudent means to meet Duke's identified energy and capacity needs. Duke's risk analysis is very limited and does not adequately address regulatory risks associated with its natural gas buildout or continued operation of coal plants in its Base portfolios. These risks are readily identified using a straight-forward analysis, demonstrating the downside economic risk of carbon prices, regulatory changes, or high fossil fuel on any scenario that does not rapidly move away from fossil fuels.

Duke's modeling methodology and input assumptions must be revisited. The recent extension of the federal ITC must be incorporated into solar and solar plus storage capital costs. Similar to DESC, Duke erroneously did not allow the model to add new capacity or PPAs unless there was a capacity need, eliminating the potential to incorporate less-expensive energy-only resources earlier in the planning horizon. Duke also overstated its PV fixed O&M cost assumptions and did not accurately reflect the existing or likely future mix of fixed-tilt vs. single-axis tracking systems. The Company failed to allow two-hour batteries despite their ability to provide meaningful capacity credit at lower costs. Finally, Duke's development timeline for SMR and pumped hydro do not comport with the Company's own data.

Duke's natural gas forecast relies far too long on fickle market prices, a fatal flaw of that permeates its entire IRP planning horizon. This approach codifies long-term prices that are disproportionately impacted by short-term volatility and diverge substantially from prices projected by fundamentals-based forecasts, as is demonstrated vividly in the Company's high- and low-price sensitivities. The Company should instead rely on market prices for a much shorter period, using them for eighteen months before switching fully over to a fundamentals-based forecast by 36 months. It should also adjust its high- and low-price scenarios to reflect the 25$^{th}$ and 75$^{th}$ percentile results and develop a high-cost coal case to account for the myriad regulatory risks faced by coal generation.

Finally, the Company should embrace the cost savings that come with broader regionalization and explore the implications of unifying its planning and operations of DEC and DEP. Duke should not be satisfied with the limited benefit of joining SEEM but should explore more robust regionalization strategies such as forming or joining an RTO.

If Duke were to make these updates to its modeling, it is likely that cost-optimal portfolios will feature earlier coal retirements, lower natural gas builds, and higher and earlier solar, solar plus storage, and standalone storage deployment. These updated portfolios will enable Duke's customer to reap the benefit of the federal ITC extension while jumpstarting Duke's progress towards its own 2050 net zero goals.

# KEVIN M. LUCAS

## SOLAR ENERGY INDUSTRIES ASSOCIATION

Mr. Lucas is Senior Director of Utility Policy and Regulation for the Solar Energy Industries Association (SEIA). SEIA is the national trade association for the U.S. solar industry. SEIA is leading the transformation to a clean energy economy, creating the framework for solar to achieve 20% of U.S. electricity generation by 2030. SEIA works with its 1,000 member companies and other strategic partners to fight for policies that create jobs in every community and shape fair market rules that promote competition and the growth of reliable, low-cost solar power.

Since 2010, Mr. Lucas has worked in the energy and environment industry focusing on renewable energy, energy efficiency, and greenhouse gas reduction. In his role at SEIA, Mr. Lucas develops expert witness testimony for rate cases, integrated resource plans, and other regulatory proceedings. He has also been actively involved in the ongoing New York Reforming the Energy Vision docket, focusing on distributed energy resource valuation and rate design. Prior to joining SEIA, Mr. Lucas worked for the Alliance to Save Energy, a Washington DC-based nonprofit focused on reducing energy use in the built environment. Before the Alliance, he worked for the Maryland Energy Administration, the state energy office, on numerous legislative and regulatory issues and developed and presented testimony before the Maryland General Assembly and the Maryland Public Service Commission.

Prior to entering the energy and environment field, Mr. Lucas was a manager at Accenture, a leading consulting firm. Mr. Lucas implemented enterprise resource planning software for Fortune 500 companies in industries such as consumer electronics, oil and gas, and manufacturing.

### *AREAS OF EXPERTISE*

- Renewable Energy Policy Analysis: extensive experience analyzing renewable energy policy issues and communicating results to both expert and general audiences.
- Energy Efficiency Policy Analysis: detailed understanding of energy efficiency policies, including the development of potential studies and utility efficiency program design and implementation.
- Quantitative Analysis: deep expertise in quantitative analysis across a broad range of topics including analyzing financial and operational data sets, constructing models to explore electricity industry data, and incorporating original analysis into expert witness testimony.
- Energy Markets: studies interaction of renewable energy and energy efficiency policies with wholesale market operation and price impacts.
- Legislative Analysis: reviews legislation related to energy issues to discern potential impacts on markets, utilities, and customers.

### *EDUCATION*

Mr. Lucas holds a Masters of Business Administration from the University of North Carolina, Kenan-Flagler Business School (2009) and a Bachelor of Science in Engineering, Mechanical Engineering from Princeton University (1998).

### *ACADEMIC HONORS*

- Beta Gamma Sigma Honor Society
- Paul Fulton Fellowship, Kenan-Flagler Business School
- Graduated *cum laude* from Princeton University

## *EXPERT WITNESS TESTIMONY*

**Arizona Corporation Commission**

- Docket No. E-01345A-19-0236 **-** *In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return.*
    - Analyzing and modifying APS's class cost of service study, arguing for changes to time of use rate design, proposing new rate designs for solar plus storage installations, proposing improvements to non-residential rate designs, advocating for a "bring your own device" program.

**Public Utilities Commission of the State of Colorado**

- Docket 17A-0797E – *Public Service Company - Accelerated Depreciation - AD/RR*
    - Advocating for appropriate structure to utilize renewable energy funds to support the early retirement of coal facilities and to continue to support distributed resources
- Docket 19A-0369E – *In the Matter of The Application of Public Service Company of Colorado For Approval of Its 2020-2021 Renewable Energy Compliance Plan*
    - Advocating for changes to better support solar and solar plus storage installations
- Docket 19AL-0687E - *In the Matter Of Advice No. 1814-Electric of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8 – Electric Tariff to Reflect a Modified Schedule RE-TOU and Related Tariff Changes to be Effective on Thirty-Days' Notice*
    - Designed and advocated for new data-based default time of use rate

**Maryland Public Service Commission**

- Case 9153, 9154, 9155, 9156, 9157, 9362 - *In the Matter Of Maryland Utility Efficiency, Conservation And Demand Response Programs Pursuant To The Empower Maryland Energy Efficiency Act Of 2008*
    - Multiple filings regarding the design and implementation of Maryland's energy efficiency portfolio standard

- Case 9271 - *In re the Merger of Exelon Corp. & Constellation Energy Grp., Inc.*
    - Analysis of renewable energy commitments in merger proposal

- Case 9311 - *In re the Application of Potomac Elec. Power Co. for an Increase in its Retail Rates for the Distrib. of Elec. Energy*
    - Supporting the implementation of a limited cost tracker to accelerate reliability investments after 2012 Derecho

- Case 9326 - *In re the Application of Balt. Gas & Elec. Co. for Adjustments to its Elec. & Gas Base Rates.*
    - Supporting the implementation of a limited cost tracker to accelerate reliability investments after 2012 Derecho

**Maryland Public Service Commission (cont.)**

- Case 9361 - *In re the Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc.*
    - Policy analysis of merger proposal

**Michigan Public Service Commission**

- Case U-18419 – *In the matter of the application of DTE ELECTRIC COMPANY for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.*
    - Arguing against DTE Electric's proposal to construct a new natural gas combined cycle generating facility and instead meet its future capacity and energy needs with a distributed portfolio of solar, wind, energy efficiency, and demand response.
- Case U-20162 – *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*
    - Arguing against DTE Electric's proposal for a net energy metering successor tariff that improperly undervalued the contribution of distributed solar.
- Case U-20165 - *In the matter of the application of Consumers Energy Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief.*
    - Discussing Consumers Energy Company's integrated resource plan, arguing for advancing the deployment of solar to meet its capacity requirements, arguing against Consumers' proposed financial compensation mechanism for third-party PPA contracts, supporting a robust PURPA market, and supporting transparent and equitable competitive procurement guidelines.
- Case U-20471 - *In the matter of the Application of DTE Electric Company for approval of its integrated resource plan pursuant to MCL 460.6t, and for other relief.*
    - Evaluating DTE's integrated resource plan, arguing for the Company to modify its modeling assumptions for solar, analyzing the operation and reliability of DTE's aging peaker fleet, demonstrating that solar and solar plus storage could replace some of DTE's peakers, advocating for robust competition and third-party access to new resources.

**Public Utility Commission of Nevada**

- Docket Nos. 17-06003 & 17-06004 Phase III – Rate Design – *Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.*
    - Arguing against Nevada Power Company's proposal to increase fixed customer charge

**Public Service Commission of South Carolina**

- Docket Nos. 2019-224-E and 2019-225-E - South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC
    - Advocating for modifications to Duke Energy's IRP, including assumptions on capital and O&M costs, operational assumptions, and natural gas forecast methodology

**Public Utility Commission of Texas**

- Docket 46831 – *Application of El Paso Electric Company to change rates*
    - Critiquing El Paso Electric's proposal to implement a three-part rate for residential and small commercial net metered customers

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 165

| | |
|---|---|
| **In the Matter of:** | ) |
| **2020 Biennial Integrated Resource** | ) |
| **Plans and Related 2020 REPS** | ) |
| **Compliance Plans** | ) |
| | ) |

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**INITIAL COMMENTS OF NCSEA AND CCEBA ON DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC'S INTEGRATED RESOURCE PLANS**

**EXHIBIT 4**

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# Duke Energy IRP Attachment 3 (Resource Adequacy Study) Comments

Justin Sharp[1] | Sharply Focused LLC | February 10, 2021

## Summary

Sharply Focused LLC is a consultancy owned and operated by a Ph.D. Meteorologist with seventeen years of electric utility sector experience, that seeks to employ a synergistic understanding of atmospheric sciences and the electric business to improve outcomes where the two intersect. We undertook a review of the Duke Energy Resource Adequacy Studies (RAS) for both the DEP and DEC service areas, that is Attachment 3 of their 2020 IRP. Emphasis was placed on examining how load and solar generation timeseries data was synthesized as a function of weather data and opining on the representativeness of this data. Most references and page numbers in this document refer to the DEP service area, but the findings universally apply to both the DEP and DEC RAS documents, as the methods employed were identical.

Below is a summary of key findings and recommendations followed by more detail of each:

1. The methodology used for creating the 39-year synthetic load timeseries is not transparent or reproducible and has not been properly validated:
    a. It also depends on extrapolations that use a limited number of data points in the tails of the dataset to determine the extreme peak loads that drive modeling results. This finding applies to the load data for the DEC, DEP, and external service area.
    b. The model developed to create the synthetic loads has not been adequately validated. Standard validation methods of denying training data and using the model to predict the denied values were not employed. Our own validation analysis and statistics suggest that while overall model bias on correlation were reasonable on the majority of typical days, large errors were common, and skill degraded substantially for tail events that had the greatest implications on RA, Effective Load-Carrying Capability (ELCC), and thus resource selection.
    c. The load model overpredicts historical loads for the majority of the highest synthesized loads when comparing to the same data it was trained with.
    **d. Recommendation: Duke be required to fully defend all assumptions and methods used to develop the synthetic load record to an independent review panel or redo the exercise with stakeholder participation and utilizing additional load data that is now available.**

[1] Attached as Exhibit 1, Resume of Justin Sharp, Ph.D.

2. The period of record chosen to explore weather variability is longer than is standard for evaluating climatology (39 years versus 30 years) and the data used in developing the load record indicates significant trends in temperature through time.
    a. The record contains worst case events that occurred over 30 years ago and does not place these events in context or note that they are extremely rare.
    b. It also does not acknowledge that their likelihood of repeating is much diminished in a warming climate.
    c. Importantly, the number of hours per year below freezing is decreasing and the 1980's account for more than 50% of the days below 20F in the record. These trends are confirmed by external sources. Yet all years are weighted equally.
    d. The record is also inconsistent with that used for the demand side management studies in other parts of the IRP process, which utilize just 30-years of data and, thus reach inconsistent conclusions.
    e. The events in Texas during February 2021 provide a reminder that tail cold events do still occur and cannot be completely ruled out, however, we do not see evidence of such events becoming more common or severe. Ground truth data suggests the opposite.
    **f. Recommendation: While standard meteorological practice would be for Duke Energy to use 1989 through 2018 to address weather uncertainty, and recent NOAA recommendations suggest weight the later years in the record slightly more, we propose that if Duke retain the 1980's record but weight the decade at 10% of the total versus the current 25.64% this will bake in an appropriate degree of conservatism. The demand side management study should be updated to reflect the use of these years.**
3. The methodology for creating solar resource data for years not available from the National Solar Resource Database (NSRDB) is unscientific and results in inputs that are not appropriately linked to load data. In addition, the 2018 Solar ELCC is also flawed because it used the same methodology.
    **a. Recommendation: Duke needs to develop a new solar record that is coincident with the temperature record from an atmospheric standpoint. The current method is insufficient and *not supported at all* by science. Inputs resulting from the 2018 ELCC also need to be recreated in a more robust way.**

## Development of the load record for DEP and DEC

Astrape used five years and nine months of coincident load and temperature data to construct relationships between temperature and load data in the DEC and DEP service areas. The model was then used to build 39-years of synthetic load data to try to capture weather variability on the projected 2024 load year based on 1980 through 2018 temperatures. The rationale for using 39 years is not given. Typically, the atmospheric sciences community uses the most recent 30 consecutive years to develop climatological normals, as recommended by the World

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Meteorological Organization for about a century.[2] However, recently, the National Climate Data Center (NCDC) has begun providing supplemental data with 5-, 10-, 15-, and 20-year periods, because 30-year averages are often unrepresentative of the *current* climate because it is changing, and the longer record dampens the trends.[3] Ironically, some of the new shorter duration products being provided by NCDC have been provided in response to stakeholder feedback from the energy industry. It is troubling that a longer period was selected, particularly because this period includes the 1980's which are known to be an anomalously cool decade in the Carolina's, and because observations and projections (some of which will be presented below) indicate that the climate in Duke's service territory is warming. Using data from a period where temperatures were well below current climatological normal will bias any downstream conclusions in the direction of more capacity to serve heating load than is likely needed. It also skews the expected peak load hours away from summer afternoons and towards winter mornings. This has profound implications for the capacity value of solar generation.

According to the RAS, hourly temperature and rolling averages derived from these temperatures, along with time of day, were used by an artificial neural network (ANN) to develop a model of the load. 8-hr, 24-hr and 48-hr rolling averages of temperature were used. Temperature from eight weather stations (5 in the DEP service area and 3 in the DEC area) was used along with coincident load data from January 2014 through September 2019 to train the ANN model. The station inputs were given equal weighting.[4] No rationale was provided for the selection of the stations and when requested the response from Duke was a, "Work in progress."[5] The input load data was scaled upwards by factors of 0 to 6% so that it was representative of the same base 2019 load year. No details were provided for the selection of the different scaling factors, but they were predominantly less than 3%.[6] Separate instances of the ANN were trained for winter, summer, and shoulder seasons.[7] Typically, when training a model, model accuracy and fitness is tested by denying data from a period where inputs and outputs are available and then using the denied data to see how well the model works. **This analysis was not performed.[8]**

It is not possible to reproduce the load modeling results based on the information Duke provided in the RAS and in discovery responses. The RAS says that once the model was trained, it was used to construct a 39-year hourly timeseries of synthetic load based on 39 years of temperature data for DEP and DEC, for the period January 1980 through December 2018. The

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[2] World Meteorological Organization, *WMO Guidelines on the Calculation of Climate Normals* at 1 (2017) *available at:* https://library.wmo.int/doc_num.php?explnum_id=4166.
[3] See https://www.ncdc.noaa.gov/news/defining-climate-normals-new-ways for a full discussion of this.
[4] Duke Response to NCSEA DR 11-4.
[5] Duke Response to NCSEA DR 11-3.
[6] Duke Response to NCSEA DR 11-6; Duke Response to SELC DR 3-7.
[7] Duke Response to NCSEA DR 11-5. Note Winter was defined as DJF, Summer as JJA, with the remaining months being shoulder.
[8] Duke Response to NCSEA DR 11-7.

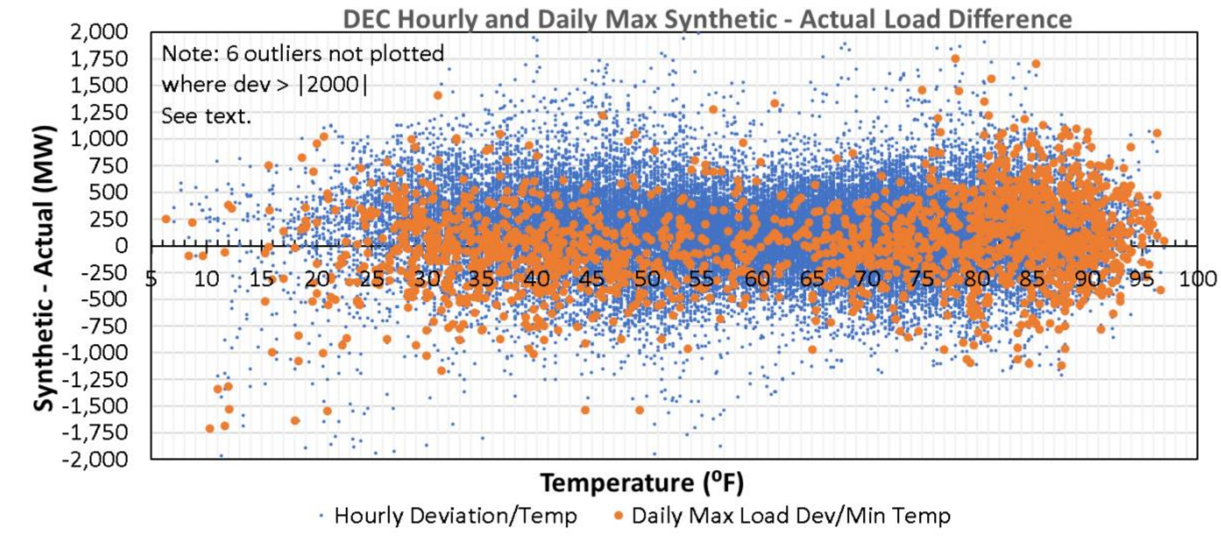
RAS notes that additional steps were taken to move the output from the neural network to the final load shapes used for the IRP modeling. In particular, "Because recent historical observations only recorded a single minimum temperature of seven degrees Fahrenheit, Astrapé estimated the extrapolation for extreme cold weather days using regression analysis on the historical data."[9] NCSEA and other intervenors enquired about the process used in this extrapolation. We were provided with a spreadsheet, some limited information about how the data in the sheet were manipulated and a note that, "To move from the Smoothing column to the Final column, the loads were scaled using the proprietary VBA code developed by Astrapé which loops through all 39 years of loads."[10] The DR response also noted that, "In general, days with temperatures less than 20 degrees and greater than 92 degrees were adjusted using the regression analysis." No mention is made in the body of the RAS about extrapolation for warm days. Nor is any mention given in the main text or the DRs of how daily peaks found using regression analysis are transformed to daily load shapes.

Initially, we tried to understand how extreme low temperature loads were synthesized by filtering the record for hours where the DEP or DEC average temperature was below 20F. For DEP, we found 172 unique hours across the period for which historical load data was made available. 169 of those hours fell in the period 2014 through 2018 inclusive, with the other three hours occurring on January 18, 2019 for which no synthetic load was calculated. The 169 hours occurred on 24 unique days and comprised of 11 unique weather events. Thus, it appeared that the number of days from which to determine a linear regression based on daily minimum temperature and daily maximum load was limited to less than a dozen unique events. However, we note that the regressions presented in SELC DR 3-9 in some cases contain less than half that number of points and no explanation (objective or subjective) is given for this. Further analysis of the spreadsheet revealed that the methodology utilized was to average the daily maximum load for one-degree Fahrenheit bins (ending at 20-21F) of minimum temperature occurring on non-holiday weekdays. These averages were then plotted against the respective minimum temperatures and a linear trend line was calculated for the data. For DEPW only values below 15F were used. The formula was then used to extrapolate load at lower temperatures. The spreadsheet indicates that this same methodology appears to have been used to calculate afternoon peak loads for cold days (based on afternoon temperatures below 20F) and summertime peaks for hot days (based on days with temperatures above 88F) though no mention is made of this in any documentation. The averaging process means that the calculations of morning peak loads below 20F are based on regressions equations formulated by fitting a straight line through 10 data points for DEC, 9 points for DEPE, and 8 points for DEPW. Further, each of these points is an average of peak loads from 12 days for DEC, 9 days for DEPE, and 11 days for DEPW and the timing of those peaks is not a factor that is

[9] Duke Energy Carolinas 2020 Integrated Resource Plan, Attachment III - DEC 2020 Resource Adequacy Study, pp. 25 (November 6, 2020).
[10] Duke Response to NCSEA DR 11-10; Duke Response to SELC DR 3-9; Duke Response to SELC DR 5-1; Duke Response to SELC DR 6-4; Duke Response to SELC DR7-2.

considered. For extrapolations of afternoon peak loads even less data is used; 7 points for DEC, 5 for DEPE and 10 for DEPW. It appears that few points were used because this was the best way to achieve a linear fit, but no testing was done of the reasonableness of this approach by Astrape; there is no data to test it against!

Figure 4 of the DEC and DEP RAS document did not provide an adequate validation of the quality of the model since the large number of synthesized days plotted made it impossible to see how well days with both actual and synthetic data matched. Given our concerns about the methodology, we compared the synthetic and actual loads by plotting the delta resulting by subtracting the historical from the synthetic load (so positive values are where the synthetic load is too high, negative where it is too low). The results are shown in Figure 1, where one can see that some of the errors are large, even during periods of relatively moderate temperatures where loads are typically low. Some values had to be excluded in order to reasonably scale the y-axis. See caption for details.



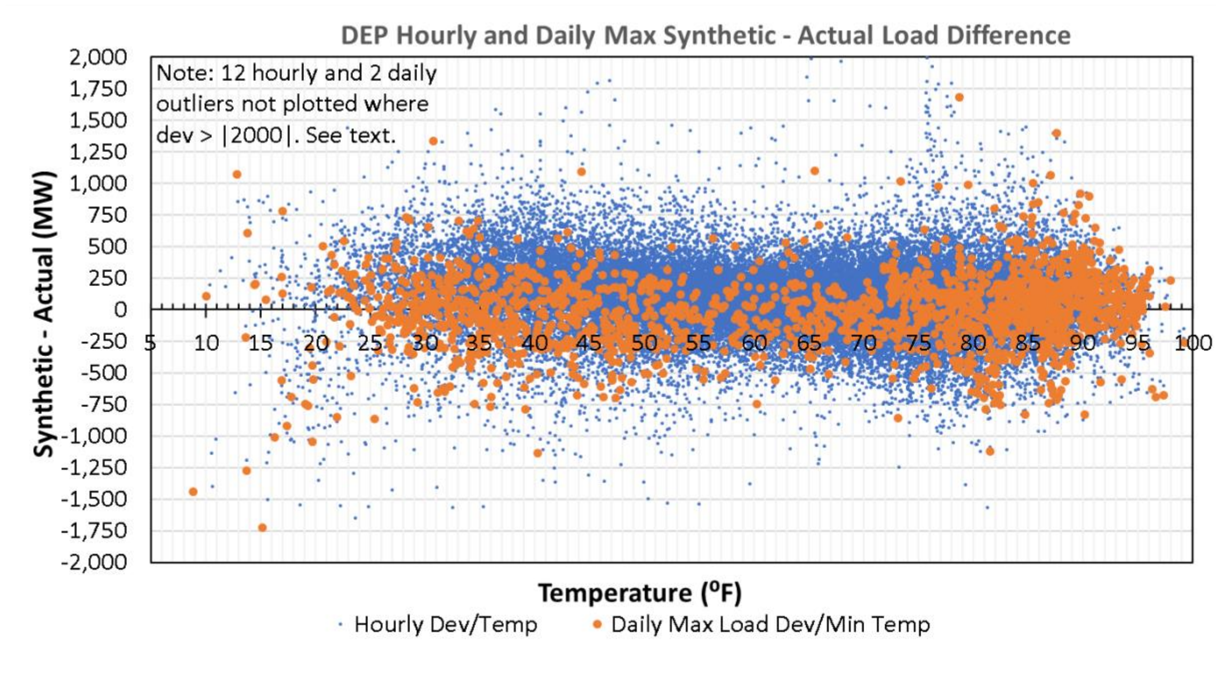




*Figure 1: Plot of deviations (positive where synthetic load is higher than historical) for hourly temperature/load pairs and daily peak load/daily minimum temperature pairs for the training dataset (2014 – 2018). 5 outlier hourly values are excluded from the DEC plot because they are too large to allow a reasonable y-axis scale. They are -2494, -2351, -2218, -2173, -2139 and +2098. Similarly, 12 hourly and 2 daily values are excluded from the DEC plot. They are -4239, -3282, -2464, -2243, -2083, 2059, 2060, 2131, 2143, 2191, 2316, and 2325 (hourly) and -3131 and -2860 (daily).*

Because we were concerned that the fit was quite poor, we calculated several standard statistics and plotted some of these as a function of temperature. A summary of statistics for the overall dataset is shown in Table 1, and a figure of key statistics as a function of temperature is shown in Figure 2. The table and figures show that the correlation coefficient was good for most temperatures (which when comparing data fitted with a trained ANN, to that same training data, it should be), but declines significantly at the tails of the distribution. Overall, the daily peak load exhibited little bias, but bias was large in the tails, while the full hourly dataset exhibited a positive bias such that the model was over-predicting load on average. Since there are only a small number of points in the tails and these are fit with a regression, it is not surprising that bias is large there. The direction of the bias in the training set does not indicate the expected direction when predicting historical loads. The standard error metrics (MAE and RMSE) are moderately large everywhere considering this validation is of the same data the model was trained with, and it grows rapidly in the cold tails. The outlier errors in both the daily and hourly datasets for both regions are **very** large. The fact that in the cold tails, where load is high, and the results matter most to the resource planning in the IRP, the quality of the model declined significantly, is worrisome. While the overall bias indicates that load is underpredicted in this region, Figure 1 illustrates that large under- and over-prediction is present in the tail. This is also where details about rationale for the decisions made in deriving the methodology for determining the synthetic load are least clear.

*Table 1: Statistics comparing synthetic load predictions to historical load for daily peak maximum load and the full dataset of hourly loads for which there is coincident historical load (training data) and synthetic load. Ideally, some actual data should be excluded from the training set to test the model. Despite no data denial, the metrics are concerning.*

| | DEC Hourly | DEC Daily | DEP Hourly | DEP Daily |
|---|---|---|---|---|
| Minimum Deviation (MW) | -2494 | -1710 | -4239 | -3131 |
| Maximum Deviation (MW) | 2098 | 1752 | 2325 | 1684 |
| Bias (MW) | 129 | 38 | 89 | -4 |
| Standard Deviation (MW) | 352 | 421 | 285 | 313 |
| Correlation Cowfficient (%) | 98.73 | 98.42 | 98.87 | 98.76 |
| Mean Absolute Error (MW) | 286 | 322 | 223 | 225 |
| Root Mean Square Error (MW) | 376 | 423 | 298 | 313 |

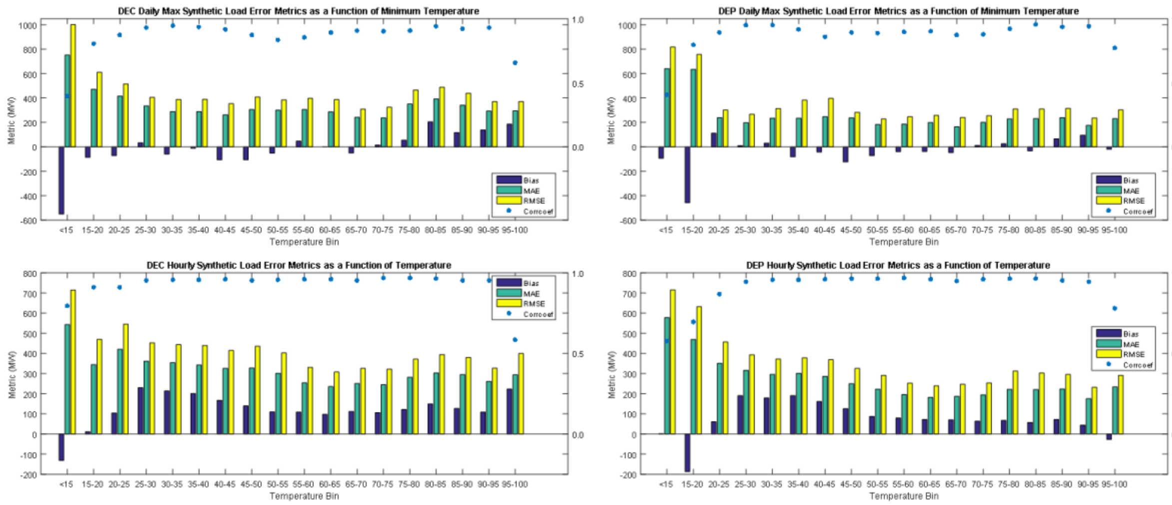



*Figure 2: Plots of common error metrics as a function of temperature for DEC and DEP hourly and daily load calculations.*

Overall, there is not enough information provided to be able to fully assess the merits of the methodology or be able to replicate it. The results above place serious questions on the validity of Duke's claims to need additional winter capacity to deal with extremely cold days because the input data is suspect. A simple analysis of the model quality produced troubling results when analyzing the fit between historical data and the data the model produced when trained with it. The lower the temperature, the worse the results even when trying to predict data that the model was trained with. The cold temperature outliers earlier in the time series are considerably colder than in the training data, and we believe that there is reason to expect even larger errors in the load estimates during these periods, especially since load for extreme low temperatures are based on an extrapolation, not the ANN. **Given that these calculations of peak load are central to the final determination of capacity and peak load timing for resource adequacy, we believe it is crucial that Duke and Astrape provide full transparency into the methodology or use another method that can be made publicly available. In addition, weather years should be weighted according to their future likelihood for reasons that will be described in the next section.**

## Trends in Temperature and Temperature Driven Load

Significant weight is placed upon representing the winter morning peak during extremely cold winter days, but the climate record Duke uses indicates that the extreme peak that occurred in January 1985 was an extremely rare event, and that the number of cold events is declining over time, and thus, so are wintertime loads, including extreme peaks.

The table below bins the hourly data provided for the DEP service area into 5F bins centered on the value listed for 5 periods of 8 years each.[11] This data is also shown in a bar plot, where it has been normalized against the total population so that the trends in each bin are not swamped by the much larger population in the warmer bins.

*Table 2: Comparison of the number of hours in different temperature bins for five increasingly recent 8-year periods using the DEP temperature data provided by Duke.*

| | Temperature Bin Center in F (bins are 5F wide) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Period | 0 | 5 | 10 | 15 | 20 | 25 | 30 | 35 |
| 1980-1987 | 9 | 12 | 52 | 191 | 372 | 854 | 2096 | 3290 |
| 1988-1995 | 0 | 2 | 20 | 65 | 246 | 708 | 1726 | 2939 |
| 1996-2003 | 0 | 2 | 6 | 45 | 216 | 709 | 1841 | 3178 |
| 2004-2011 | 0 | 0 | 0 | 31 | 200 | 749 | 1951 | 3140 |
| 2012-2019 | 0 | 0 | 9 | 77 | 231 | 618 | 1543 | 2660 |

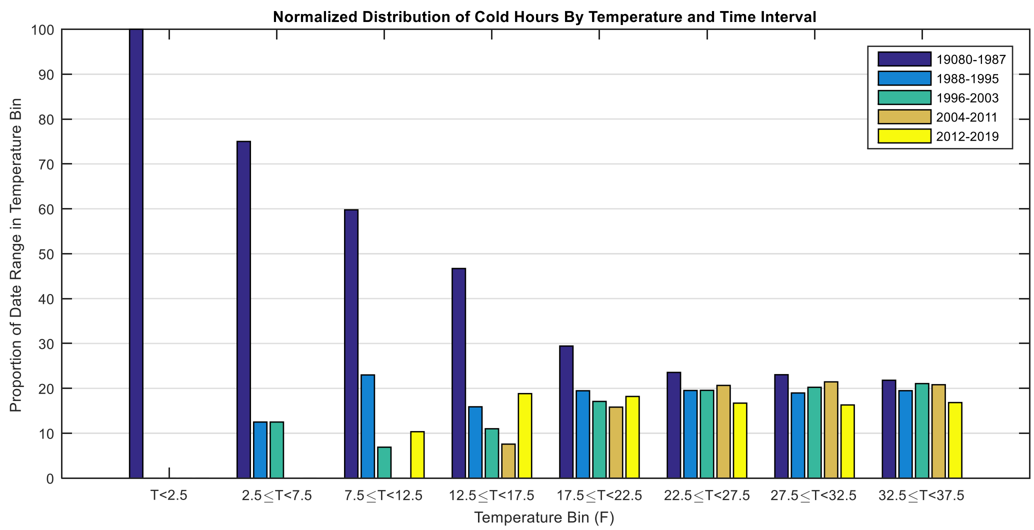



*Figure 3: Companion to Table 2, showing the normalized distribution of each bin for different time periods.*

[11] Duke did not provide temperature data for October through December 2019. To account for the missing period, the counts for 2012-2019 have been increased by the average number of OND days/yr in that bin during the 2012-2018. Note that this period was anomalously cool relative to prior periods, so our methodology is likely to produce a higher count than reality. Note also that, since 1990, only 5 hours of average temperatures below 17.5F have occurred in the dataset in OND (all in December).

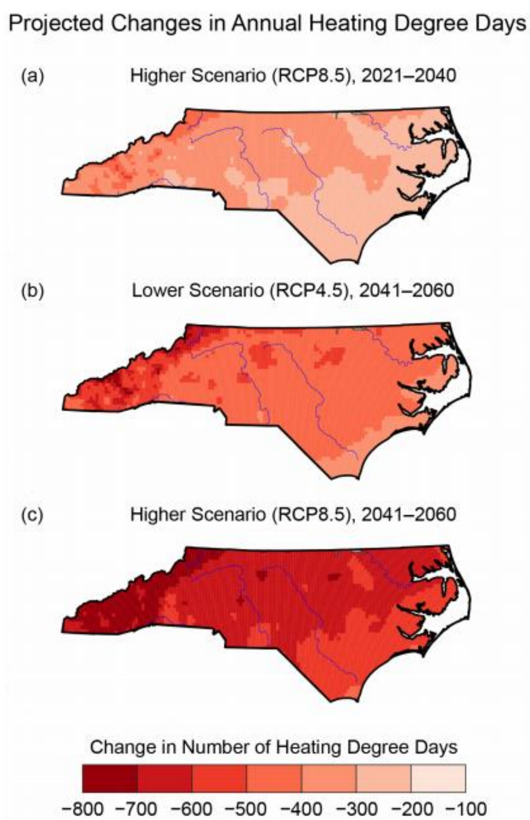



*Figure 4: Projected changes in annual heating degree days (HDDs) for North Carolina. All projected values are shown as changes compared to the 1996–2015 average. Darker shades of red indicate decreases in HDDs, indicative of overall warmer conditions. Sources: NCICS and The University of Edinburgh. (Adapted from Figure 2.25 of the North Carolina Climate Sciences Report).*

The table and plot show that, while there is natural climate noise in the data, the number of cold hours is clearly diminishing over time, especially the number of exceptional cold hours. Similar results were obtained for the DEC service area and are available upon request.

Climate science backs up these findings and indicates that the number of exceptionally cold days will continue to decline in the future. The North Carolina Institute for Climate Sciences has published a peer reviewed report that strongly supports this assertion.[12] Figure 4 is taken from this report. It shows a significant decrease in the expected number of heating degree days (HDD) across the state.

As well as providing statewide information of the evolving climate, the report also breaks the state into three climate regions and provides analysis of the actual and expected trends for climate variables in each. The figure below shows how all three North Carolina climate regions have seen the frequency of cold temperatures decline and it indicates that this is expected to continue. The North Carolina Climate Sciences Report (NCCSR) contains other analyses of temperature, HDD, and CDD trends that show the same trends in temperature.

[12] North Carolina Institute for Climate Studies, Kenneth E. Kunkel et al., *North Carolina Climate Science Report* (Sept. 2020) *available at*: https://ncics.org/programs/nccsr/.

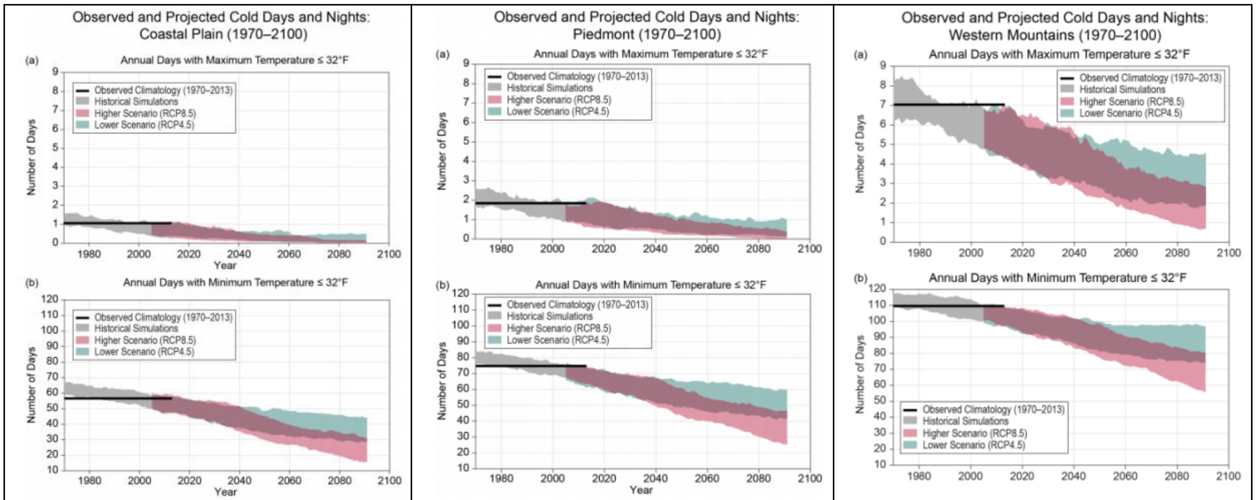



*Figure 5: Expectations for the number of cold days in the three North Carolina Climate zones. Adapted from Figures 3.8, 3.24 and 3.40 of the NCCSR.*

The reduction in extreme cold events is seen to translate into the historical and synthetic load record as well. The following analysis was done based on the *synthetic* DEP loads provided by Duke. The top 100 load hours in this record are all from winter peaks. Of these:

- 67 are from the 1980's (10 unique events, several spanning multiple days)
- 18 are from the 1990's (2 unique events)
- 3 are from the 2000's (2 unique events)
- 12 are from the 2010's (3 unique events)[13]
- There is no synthetic load above 16,637 MW since 1996. Compare this to the 1985 synthetic peak of 17,539 MW
- The 16,637 MW peak occurred on 2/20/15 and was itself an extreme outlier within recent data. The minimum temperature was 10F. Compare to -2F on 1/21/1985, and single digits on 2/5/96.
- The nearest comparable event in the 2010's with a synthetic load of 16,123 MW on 1/7/2014. But the actual load was only 15055 MW.

It is worth noting that historical data was available for loads in the top 100 list that occurred post 2014. Of these, every single hour was overstated in the synthetic load calculations relative to the historical loads, some, like the one on 1/7/2014, by over a 1000 MW. Also, of the top 100 synthetic loads occurring *only* after 2014, 74 of 100 for DEP and 73 of 100 for DEC are overstated relative to historical loads. This is a concerning finding with respect to the validity of

[13] No synthetic loads are available for 2019, and no historical loads are available for October through December 2019. However, the highest historical cold day load in January and February 2019 was 13715 MW, which would rank 526th among the synthetic loads. For comparison, the 100th highest synthetic load was 15,198 MW. High loads in December are rare, with only 19 hours in the top 100 synthetic load list, the last occurring on December 26, 1985. No December load has made the top 500 list since 2010. Thus, it is reasonable to assume that the statistics given above for the 2010's are representative of the entire decade, including 2019.

the modeling process for synthesizing loads during cold periods as it indicates an over-prediction bias on a per event basis even if the overall bias for lower temperatures is due to a few extreme under-prediction errors (see Figure 1).

The top 500 hours were also examined:

- Fully 247 of them were winter peaks from the 1980's!!!
- Other winter peaks: 69 from the 1990's, 52 from the 2000's, and 106 from the 2010's
- The remaining 22 peak hours occurred during summer months, with 4 in the 1980's, 8 in the 2000's and 10 in the 2010's.

## Development of the load record for neighboring service areas

Page 27 of the RAS briefly explains that a 39-year synthetic load record was also produced for neighboring service territories to capture weather diversity in regions importing and exporting from/to DEP or DEC. No other information is provided in the RAS, though through data requests we were able to ascertain that the methodology was essentially the same as used for developing the DEP and DEC records, except that different weather stations were used, and the training interval was different.[14] The weather locations used in the analysis were revealed but the data was not provided. Duke responded to requests for the data with, "The temperature profiles for the external regions are a part of Astrapé's proprietary data set and have been developed over time."[15] Because the data was not provided, we are unable to comment on its representativeness for the task it was employed for. Nor are we able to assess the accuracy of the synthetic load models. Nevertheless, all the issues described above with respect to the representativeness of the DEC and DEP load shapes, also apply to load shapes developed for external regions. These include, but are not limited to:

- Use of a record length that is atypical for climate normal (39 years versus 30 years)
- Inclusion of the 1980's which is known to be anomalously cool relative to current and future expectations
- Lack of transparency around how the data is manipulated, and what methods are applied for what criteria
- Use of extrapolations based on limited amounts of data to capture tail events in the temperature record
- Lack of acknowledgement that the climate is changing and that the number of cold hours is declining.

[14] Duke Response to NCSEA DR 11-11.
[15] Duke Response to SELC DR 3-5.

## Development of the solar resource record:

Section G (p33-35) of the RAS described solar and battery modeling. The report states, "The solar units were simulated with thirty-nine solar shapes representing thirty-nine years of weather. The solar shapes were developed by Astrapé from data downloaded from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB) Data Viewer. The data was then input into NREL's System Advisor Model (SAM) for each year and county to generate hourly profiles for both fixed and tracking solar profiles. The solar capacity was given 20% credit in the summer and 1% in the winter for reserve margin calculations based on the 2018 Solar Capacity Value Study. Figure 6 shows the county locations that were used, and Figure 7 shows the average August output for different fixed-tilt and single-axis-tracking inverter loading ratios." No more information was provided. Through data requests[16], we were able to glean some additional details, though limited justification was provided for the choice of many of the modeling assumptions that were made. This is worrisome considering that solar is now one of the cheapest forms of additional capacity, and that solar combined with storage can provide cost effective and reliable dispatchable generation if intelligently deployed.

The response to DR 3-5 indicates that the solar and load years used in the study were coincident. This is important, because the primary modulator of load is date, time, and weather, while solar generation is defined by date, time, and weather, so the days must be coincident to capture the interconnections between the two datasets. **However, as explained below, upon further examination, we found that it is NOT the case that the 39-years of solar data are coincident with the 39-years of synthetic load.**

Astrape used data from NSRDB to develop their solar generation dataset. This dataset covers the period 1998 through 2019. To create data for 1980 through the end of 1997, Astrape used the following methodology for each day from January 1, 1997[17]:

- Determine the peak load for the day in the synthetic load timeseries
- Scan the 1998-2018 synthetic load timeseries for the most closely matching peak load from +/- 2 days from the same calendar date. For example, for 1/6/1980, find the closest peak load from January 4 through January 8 between 1998 – 2018.
- Use the solar profile for the most closely matching day.

While this methodology is attractive for its simplicity, no basis is given for it, nor is any validation presented. Further, though solar generation and load are both driven by atmospheric parameters, **there is categorically no foundation in atmospheric science to suggest any skill in this methodology**. We suspect that it is likely no better than using a random number generator to assign the shapes from days in the same month. Solar generation magnitude and shape is based on time of year, time of day, cloud cover, cloud type, wind

[16] Duke Response to NCSEA 11-12; Duke Response to NCSEA 11-13; Duke Response to NCSEA 3-5.
[17] Adapted from Duke Response to NCSEA DR 3-5(d).

speed, temperature, relative humidity, and aerosol concentration. Some colder than normal winter days have better than normal solar resource, and conversely, hot humid days in the summer do not always exhibit good solar resource. Also, the peak load may occur early in the day and be followed by a dramatic shift in the weather so that solar resource changes dramatically. The converse is also true. While some of the same factors determine peak load, the interactions are non-linear and far more nuanced than the methodology deployed accounts for. **Thus, the solar resource shapes being used as inputs for 18 of the 39 years being modeled cannot be deemed as consistent with the load shapes for the purposes of determining effective load carrying capacity and resource adequacy, or for conducting production cost modeling**. This is especially important since the majority of the peak load hours occur in the 1980's.

**It is also crucially important to note that a similar methodology for creating solar data was also deployed in the document, "Duke Energy Carolinas and Duke Energy Progress Solar Capacity Value Study", which is used to determine the ELCC of solar, and used in the IRP. For the reasons just cited, the conclusions of this study must also be viewed with skepticism.**

## Variable Generation, Load Correlations and Climate Change

We recommend that Duke Energy undertake a study to better understand the evolution of peak load in a changing climate. We believe that it is unlikely that the 1985 minimum temperatures will recur, and even if they do, such occurrences will be rare and shorter lived. The lowest temperatures driving peak loads occur near sunrise, typically under clear skies, fresh snow cover, and low winds. As accumulating snow becomes increasingly uncommon in the Carolinas, the conditions for record setting lows become increasingly unlikely. Snow cover also inhibits temperature rise in the morning as it reflects the sun, so not only are the types of load peaks seen in the 1980's increasingly unlikely, when high peaks do occur, their duration will likely be shorter.

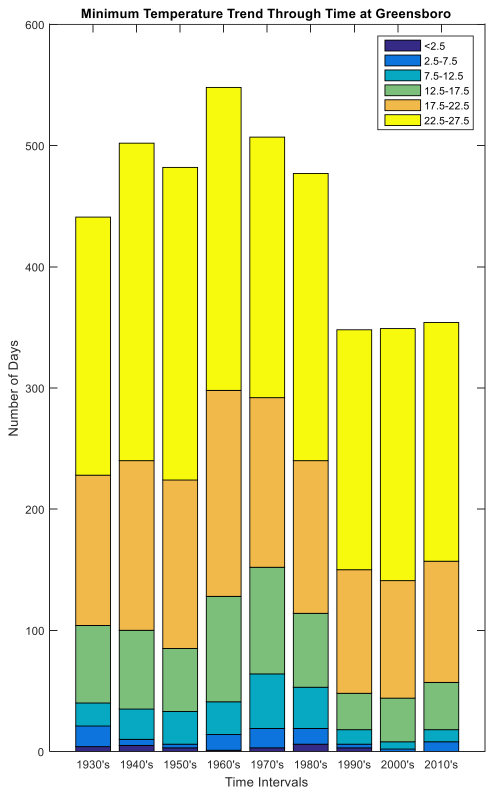



*Figure 6: Evolution of the Greensboro, NC minimum temperature climate record for cold days.*

We acknowledge that the events in Texas in February 2021 indicate that historic, long duration cold waves are still possible, and it is important for the utility sector to understand how their frequency, extent and longevity are evolving in time. The media has speculated that cold waves like the one that impacted Texas are becoming more likely due to climate change. This is due to a misrepresentation of an active and evolving research area on the impacts of a warming Arctic on the stability of the polar vortex. Some atmospheric scientists believe that the polar vortex is now more likely to break up, sending cold air south as it does.[18] Because the air in the Arctic is now warmer, these cold waves will not be as intense, but there is speculation that they may penetrate further south. However, this work is in its early stages, is not supported by meteorological observations or global climate model simulations at this time[19] and there is no scientific consensus on it. The Texas event was not without precedence; similar extreme events occurred in 1989, 1983, and 1949 with slightly less intense events in the 1950's, 1960's, and 1970's. We do not believe that the 2021 Texas event foreshadows a return of an anomalously cold decade in the Carolina's like was seen in the 1980's. Figure 6 shows the trends in climate at one of the eight stations that Duke uses in its analysis. We clearly see that the 1970's and 1980's were outlier decades (the late 70's to mid-80's experienced strong and unusually frequent cold waves). While the record is too short to allow for extrapolating long term trends due to climate change with certainty, the number of cold days has diminished since the 1980's in a way not seen in earlier decades. It is not

[18] *See* Marlene Kretschmer et al., *The Different Stratospheric Influence on Cold-Extremes in Eurasia and North America*, 44 Nature Partner Journals Climate and Atmospheric Science 1 (Nov. 2018) *available at:* http://centaur.reading.ac.uk/92433/1/Kretschmer_etal_2018_npj.pdf; J. Cohen at al., *Divergent Consensus on Arctic Amplification Influence on Midlatitude Severe Winter Weather*, 10 Nature Climate Change 20 (Jan. 2020) *available at:* https://www.nature.com/articles/s41558-019-0662-y.epdf.

[19] *See* Russell Blackport & James A. Screen, *Weakened Evidence for Mid-Latitude Impacts of Arctic Warming*, 10 Nature Climate Change 1065 (2020) *available at:* https://www.nature.com/articles/s41558-020-00954-y?; *Is the Texas Cold Wave Caused by Global Warming*, Cliff Mass Weather Blog (Feb. 17, 2021) *available at:* https://cliffmass.blogspot.com/2021/02/is-texas-cold-wave-caused-by-global.html; Adam Sobel, *The Phony Blame Game on Texas Weather*, CNN, Feb. 17, 2021 *available at:* https://www.cnn.com/2021/02/17/opinions/texas-weather-snow-sobel/index.html.

impossible that temperatures and cold duration like seen in 1980's could return, but it is much less likely than the even weighting currently assigned by Duke.

In addition, Duke should evaluate ways in which the peak loads correlate to wind and solar resources in their service territory and the surrounding areas during different seasons. As the volume of variable generation increases, understanding these relationships, and how storage, demand response, and imports/exports can be utilized to leverage them, will become increasingly valuable to efficiently plan and operate the electric system. For example, consider that wintertime cold waves are accompanied by strong winds as the cold moves across the country, and that as the cold air settles in place, skies often clear. How do these conditions affect the available renewable (and for that matter thermal) generation available in the service territory or for import? Can storage be strategically charged using prior day resources? These are questions that the author of this report and others are investigating, and utilities should start considering them too.

# JUSTIN SHARP, Ph.D.

2837 NE 63rd Avenue
Portland, OR 97213

Cell: 503-709-9781
Email: Justin@sharply-focused.com

Meteorology Ph.D. and weather driven renewables integration subject matter expert with a proven track record. Seeking research/though leadership/policy opportunities that drive energy transition to mitigate climate change.

## ***Key Skills/Attributes***

- Almost sixteen years of experience in the electric utility industry, with fifteen years specializing in Renewable Energy
- Atmospheric Sciences Ph.D. from leading graduate program. Excellent Grades. Research focus in numerical weather prediction modeling. Graduate level understanding of climate change science. Experience teaching climate science to undergraduates.
- Experienced and respected leader, well known in the industry for thought leadership and advocacy
  - Expert knowledge of how Atmospheric Science and Climate Science are used (and misused) by the sector
  - Broadly versed in the electric utility industry including knowledge of market structure and operating rules of many RTO's and BA's. Considered to be one of the thought leaders in VG grid integration
  - Contributor to, and peer reviewer for IEEE, AMS and Institute of Mechanical Engineers publications on variable generation
  - Well-developed industry contacts with national labs/research entities, technical advocates, operators, utilities and developers
  - Knows when to delegate, when to engage and when to challenge. Solicits suggestions of others, including subordinates
  - Honed analysis skills enable focused direction of others and individual contribution as appropriate
  - Have briefed congressional staffers, White House OSTP staff, State Department staff, DOE, non-profits and senior NOAA leadership on renewable industry challenges and vision
  - Service on numerous boards and committees including: Chair of the American Meteorological Society (AMS) Renewable Energy Committee, the AMS Board on Enterprise and Economic Development
- Holistic systems thinker: strongly believes that effective solutions require reconciliation of the big picture
- Experienced in both writing winning grant proposals and reviewing proposals of other
- Self-disciplined; achieving goals within deadlines to a high standard. Communicates effectively in written and verbal form.
- Responds well to challenges, rapidly adapting to new tasks and learning new skills with enthusiasm.
- Extremely computer literate (former software engineer with five years of IT industry experience)

## ***Education***

| | | |
|---|---|---|
| University of Washington, WA | Ph.D. Atmospheric Sciences (2005). M.S. Atmospheric Sciences (2002). GPA: 3.59 | **1997-2005** |
| Rutgers University, NJ | M.S. Meteorology. GPA: 3.88 | **1995-1997** |
| University of Liverpool, UK | B.Sc. Physics and Computer Science Joint Honors (**First Class**) | **1988-1991** |
| G.M.A.T. | 94th Percentile score | **January 1993** |
| G.R.E. | 91st Percentile score | **July 1995** |

## ***Career/Experience***

### Sharply Focused LLC — Principal and Owner — March 2012 – Present

- Founder, owner and Principal of Sharply Focused LLC, a successful consultancy that provides meteorological expertise tailored to the energy sector, especially renewable energy transition needs, forecasting, performance analysis and grid integration.
- Examples of service offerings include: assessing VER grid resiliency impact; sector transition gap analysis for utilities, training in renewable energy meteorology and integration, renewable resource/portfolio assessment and characterization; candidate recruitment and screening for renewable energy meteorology positions; variable generation PPA and trading strategies; VER performance and forecast performance analysis.
- Clients include the NREL, Electric Power and Research Institute, Department of Energy, NOAA, Global Weather Corporation, EUCI, Envision Energy, MISO, IBM, United States Energy Association, Center for Resource Solutions/The Energy Foundation of China, Vaisala Inc, Portland General Electric, Lockheed Martin, NaturEner, Meteo Group, and Precision Wind.
- Presents technical material for US-AID to a diverse range of governments and utilities around the world including China, India, South Africa, and Thailand.
- Major DOE project grants (key roles from proposal forward): The Wind Forecast Improvement Project 2, Solar Forecasting 2, The Impact of Meteorological Tail Events at High Renewable Penetrations
- Active industry spokesperson advocating sound renewable energy integration methods and policy directions and proponent for appropriate application of atmospheric and climate science to drive and optimize the renewable energy transition.

### Iberdrola Renewables, USA — Director, Operational Meteorology — September 2005 – March 2012

- Director of commercially focused wind meteorology group overseeing all meteorology associated with operations of the US portion of the world's largest wind power portfolio. Manages staff, infrastructure and budget
- Company lead and industry expert on the role of forecasting and meteorological analysis in variable generation integration.

    - Develops and advocates company policy positions on weather driven integration issues. Author of forecasting responses to FERC NOI. Co-author of AWEA forecasting policy white paper.
    - Regular presenter/chair at technical workshops and seminars.
    - Co-author of peer reviewed articles in meteorological and engineering journals. Peer reviewer for several journals.
- Witness in two BPA rates cases. Key participant in developing testimony that helped reduce BPA wind integration charges by over 50% saving Iberdrola over $20M/year.
- Founded and led Iberdrola's program utilizing NWP to assess wind resource and resource variability
    - Program has saved Iberdrola $millions in consulting fees, and now provides key input into meteorological and financial analysis of all pipeline and existing projects reducing risk and adding value
    - Built and led team to create an internal system to provide all aspects of this type of analysis that was provided by vendors
- Founded, expanded and led Iberdrola's wind forecaster team providing 24/7 custom forecasts to trading, generation dispatch, and Asset Management. This was the first renewable energy meteorology team in the country and is still one of the largest today.
    - Important component of the Iberdrola/BPA customer supplied generation imbalance project
- Manages Iberdrola's relationship with wind energy forecast vendors. Handles contract negotiations and scope of work, including contract changes that have saved Iberdrola several $100K/year. Oversees ongoing forecast validation/improvement work.
- Manager/technical lead of meteorological analysis for performance reporting and budget analysis of operational wind farms
- Keeps abreast of advancements in NWP. Advocates internally and externally for better forecasts within the wind energy sector
- **Key Tools:** PI Historian (ProcessBook, Datalink etc), MS-Office, Matlab, Google Earth, WRF.



### <u>Bonneville Power Administration</u> Meteorologist October 2004 – September 2005

- Provided temperature and quantitative precipitation forecasts (QPF), under strict deadlines, to support stream flow prediction, load forecasting and power trading operations for the Pacific Northwest's largest producer of hydropower.
- Communicated forecasts and forecast confidence to users, including senior management, in written and verbal form
- Technical authority on NWP and advanced forecasts methods at BPA.
- Maintained the computer systems used for reception, decoding and display of meteorological data:
- Implemented automation methods that improved efficiency and product accuracy
- Worked with outside agencies and research groups to gain access to new data sources. Created code to ingest these data streams
- **Key Tools:** Perl, F77, Matlab script, Shell scripts / Linux / Gempak Suite, LDM, Matlab, MS Office.

### <u>University of Washington</u> Graduate Student & Research Assistant Sept 1997 – Jan 2005

- ***MS/Ph.D. research to improve understanding and forecasting of gapflow, a phenomenon that greatly affects PNW weather***
    - Evaluated Columbia Gorge climatology using climate data, and statistical examination of NCEP reanalysis data
    - Customized the MM5 mesoscale model to investigate the dynamical mechanisms responsible for Columbia Gorge gap flow
    - Published in peer-reviewed scientific journals. Produced and delivered oral and poster presentations at conferences
        - First place student poster at 10th Conference on Mesoscale Processes, June 2003
    - Peer reviewer of papers submitted to professional journals. Contributed material to COMET gapflow module
- ***Teaching Activities - Served as a teaching assistant for two academic quarters:***
    - Responsible for developing and delivering recitation and review sessions. Created and graded assignments and exams
    - Designed and performed classroom demonstrations that clarify meteorological and climate science principles. Developer of several class websites
    - Highly commended by professors and students (supervisor professor reports and student evaluations available on request)
        - "...has made a lasting contribution to the teaching of Atmospheric Sciences 101…I suggest that he be in consideration for the department's teaching award" [Prof. R. Houze]; "I was very fortunate indeed to have Justin as my TA…did an outstanding job…pleasant to work with and I recommend him without reservation as a fine teacher." [Prof. C. Leovy]
- ***Expert PNW weather forecaster. Highlights include:***
    - Flight scientist on IMPROVE I and II meteorological field projects. Led flight forecast briefings and flew on several missions
    - Chief meteorologist for two record setting hot air balloon flights including only ever traverse of Mount Rainier by balloon
    - Winner of University of Washington forecast contest in 2001 and 2004. Top three placement in 1998 - 2000, 2002 and 2003
- University of Washington Graduate School Fellowship Recipient, 1997-98.
- **Key Tools:** MM5, Matlab, F77, F90, Perl, HTML, Shell scripts, Gempak suite, RIP, MS-Office.

### <u>Smiths Industries, DSNA</u> Senior Software Engineer February 1997 – September 1997

- Designed and coded software units for a laser guided air-to-ground missile system

### <u>AeroSystems International</u> Freelance Software Engineer May - Sept. 1996 & June - Dec. 1994

- Contracted between August 1994 and December 1994 and again during Summer 1996 university recess
    - Technical team lead in the design and coding of the Eurofighter jet Engine Management Monitoring and Setup Unit
    - Tester of Rolls Royce BR710 engine controller software. Safety critical, demanding rigorous analysis of requirements.

**Rutgers University** **Student And Part-time Lecturer** **September 1995 - July 1997**

- Classes and research (*Clear Air Echoes and their Application in the Analysis of Sea-Breezes*) resulting in Meteorology MS
- Part-time calculus lecturer; lecturing, setting and grading assignments and exams.

**Summary of Prior Employment** **Software engineer (Permanent & Freelance)** **09/1991 – 09/1995**

***Andersen Consulting (now Accenture)*** ***IT Solutions Consultant/SW Engineer*** ***January 1995 - September 1995***
***Aerosystems International (also 1996 - details above)*** ***June 1994 - December 1994***
***Myriad Computer Services,*** ***IT Recruitment Professional*** ***November 1993 - June 1994***
***Data Sciences LTD (now part of IBM)*** ***Software Engineer*** ***September 1991 - November 1993***

## *Professional Affiliations/Service/Honors:*

- Environmental Information Systems Working Group – A NOAA Advisory Board reporting to Congress Dec 2015-Present
- American Meteorological Society:
  - Renewable Energy Committee Chair Jan 2016-Present
  - Renewable Energy Committee Board Member Jan 2012-Dec 2015
  - Board on Enterprise Economic Development Board Member Jan 2014-January 2018
  - Forecast Improvement Group Board Member August 2012-2018
  - National Member 1998-Present
  - Oregon Chapter Member 2005-Present
- Energy Systems Integration Group – Individual Consultant Member 2013-Present

## *Peer Reviewed Publications:*

Pichugina, Y., J. Sharp, and co-authors, 2020, Evaluating the WFIP2 updates to the HRRR model using scanning Doppler lidar measurements in the complex terrain of the Columbia River Basin. Accepted for publication in Journal of Renewable and Sustainable Energy.

Julie K. Lundquist, Rochelle P. Worsnop, Larry K. Berg, James M. Wilczak, Darren L. Jackson, Garrett Wedam, Yelena Pichugina, Justin Sharp, Duli Chand: Mountain waves impact wind power generation. Wind Energy Science (2020 Preprint form)

Robert M. Banta, Yelena L. Pichugina, W. Alan Brewer, Aditya Choukulkar, Kathleen O. Lantz, Joseph B. Olson, Jaymes Kenyon, Harindra J.S. Fernando, Raghu Krishnamurthy, Mark J. Stoelinga, Justin Sharp, Lisa S. Darby, David D. Turner, Sunil Baidar, and Scott P. Sandberg: Characterizing NWP Model Errors Using Doppler-Lidar Measurements of Recurrent Regional Diurnal Flows: Marine-Air Intrusions into the Columbia-River Basin. *Mon. Wea. Rev.* (2020) **148** (3): 929–953.

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Mark Ahlstrom and Drake Bartlett, Craig Collier, Jacques Duchesne, David Edelson, Alejandro Gesino, Marc Keyser, David Maggio, Michael Milligan, Corinna Möhrlen, Jonathan O'Sullivan, Justin Sharp, Pascal Storck, Miguel de la Torre, 2013: Knowledge is Power – Efficiently Integrating Wind Energy and Wind Forecasts. *IEEE, Power and Energy*, **Vol. 11, No. 6**

Somnath Baidya Roy, Justin Sharp, 2013: Why Atmospheric Stability Matters in Wind Assessment. *North American Wind Power,* **Vol.9 No.12**

Mark Ahlstrom, James Blatchford, Matthew Davis, Jacques Duchesne, David Edelson, Ulrich Focken, Debra Lew, Clyde Loutan, David Maggio, Melinda Marquis, Michael McMullen, Keith Parks, Ken Schuyler, Justin Sharp, and David Souder, 2011: Atmospheric Pressure: Weather, Wind Forecasting, and Energy Market Operations, *IEEE, Power and Energy*, **Vol.9 No.6**

Melinda Marquis, Jim Wilczak, Mark Ahlstrom, Justin Sharp, Andrew Stern, J. Charles Smith, Stan Calvert, 2011: Forecasting the Wind to Reach Significant Penetration Levels of Wind Energy, *Bulletin of the American Meteorological Society*, **92**, p1159–1171.

Sharp, J., 2005: *The Structure and Dynamics of Columbia Gorge Gap Flow Revealed by High-Resolution Numerical Modeling*, Doctoral Dissertation, University of Washington. **190pp**.

Sharp, J. and C. F. Mass, 2003: The Climatological Influence and Synoptic Evolution Associated with Columbia Gorge Gap Wind Events, *Weather and Forecasting,* **83***,* p970-992.

Sharp, J. and C. F. Mass, 2002: Columbia Gorge Gap Flow: Insights from Observational Analysis and Ultra-High Resolution Simulation, *Bulletin of the American Meteorological Society*, **83**, p1757–1762.

Sharp, J., 2002: *The Mesoscale Meteorology of the Columbia Gorge*, Masters Thesis, University of Washington. **248pp**.

Sharp, J, 1997: *Clear-air Radar Observations and their Application in Analysis of Sea Breezes*, Masters Independent Study Paper, Rutgers University **52pp**.

## ***Selected Conference, Workshop and Symposia Presentations:***

Sharp, J. and Holmgren, W.: Solar Forecast Arbiter: An Open Source Evaluation Framework for Solar Forecasting, IEA Wind Forecasting Task 36 Conference, Online, June 25, 2020

Sharp, J.: Extreme Weather and the Grid of the Future. ESIG Meteorology & Market Design for Grid Services Workshop, Online, June 18, 2020

Sharp, J.: Course planner, organizer and lead instructor of 1½-day Meteorology for Renewable Energy course offering from EUCI. Denver, CO. September 2019

Sharp, J.: Weather Events in NREL's Wind and Solar Datasets. ESIG Meteorology & Market Design for Grid Services Workshop, Denver, CO. June 2019

Sharp, J. (presenter), Holmgren, W., Tuohy, A., Hansen, C: An Open Source Evaluation Framework for Solar Forecasting. ESIG Meteorology & Market Design for Grid Services Workshop, Denver, CO. June 2019

Sharp, J. (invited): A primer in the use of Meteorology and Forecasting in Power Systems Operations. Colorado Rural Electric Association Energy Innovations Summit, Denver, CO. October 2018.

Sharp, J.: Session Chair: Solar and Wind R&D Advances. ESIG Forecasting Workshop, St. Paul, MN, June 2018

Sharp, J.: It's the Meteorology, Stupid…Planning for High Penetration Renewable Energy. EUCI Intermediate Resource Planning Summit, Portland, OR, April 2018.

Sharp, J.: Course planner, organizer and lead instructor of 1½-day Meteorology for Renewable Energy course offering from EUCI. Denver, CO. February 2018

Sharp, J., Aidan Touhy: Organizer and Co-Chair for Themed Joint Session: Communicating Information and Risk in the Energy Sector. 9th AMS Conference on Weather, Climate and the New Energy Economy. Austin, TX, January 2018.

Sharp, J., Aidan Touhy: Research to Operations Needs in Renewable Energy Forecasting. 9th AMS Conference on Weather, Climate and the New Energy Economy. Austin, TX, January 2018.

Sharp, J.: Soup to Nuts: Meteorology for Renewable Energy. EUCI Renewable Energy Grid Operations Conference. Austin, TX, September 2017.

Sharp, J.: The Importance of Atmospheric Science in the Renewable Energy Revolution. UVIG Forecasting Workshop, Atlanta, GA, June 2017

Sharp, J.: The Core Role of Atmospheric Science in the Renewable Energy Transition. Session organizer, chair and intro speaker. Successfully secured a heavy weight panel of executives, including a keynote from Congressman Earl Blumenauer. American Meteorological Society Washington Forum, May 2017

Sharp, J.: The Role of Forecasting and Resource Assessment in the Power System of the Future. UVIG Spring Technical Workshop. Tucson, AZ. March 2017.

Benjamin, S., Justin Sharp, Skip Dise: Forecasting Applications for Power Systems. Panel member in UVIG webinar. February 2017

Sharp, J.: The Role of Atmospheric Science in Enabling the Renewable Energy Revolution. AMS 8Energy/5Climate Joint Session Symposium. Seattle, WA January 2017

Sharp, J.: The Politicization of Science and Scientific Integrity at NOAA. Meeting of the Environmental Information Systems Working Group under the NOAA Science Advisory Board. Washington DC, December 2016.

Sharp, J.: System Planning for a High Renewables Future, Intro Presentation and Session Moderator, UVIG Forecasting Workshop, Denver, CO, September 2016

Sharp, J: Integrating and Implementing Forecasting of Variable Renewable Energy, USAID Greening the Grid Boot Camp, New Delhi, India, July 2016. Co-instructor through 3-day workshop and consultant to POSOCO. Developed for about 25% of the course content material together with other industry specialists

Sharp, J., Christopher Clack, Melinda Marquis, John Moore: Webinar to NRDC staff on the importance of weather informed grid policy. May 2016.

Sharp, J. (Invited Speaker): The Role of Atmospheric Science in Mitigating Challenges of the Renewable Energy Revolution. University of Washington Colloquium Series, April 2016

Sharp, J., Melinda Marquis: A New Framework For A New Power System. Co-organizer, chair and presenter. American Meteorological Society Washington Forum Renewables Session, April 2016

Sharp, J: Integrating and Implementing Forecasting of Variable Renewable Energy, USAID Greening the Grid Boot Camp, Bangkok, Thailand, February 2016. Co-instructor through 3-day workshop. Developed for about 25% of the course content material together with other industry specialists

Sharp, J: Integrating and Implementing Forecasting of Variable Renewable Energy, USAID Greening the Grid Boot Camp, Mexico City, Mexico, January 2016. Co-instructor through 3-day workshop. Developed for about 25% of the course content material together with other industry specialists

Sharp, J. (Invited Speaker): Weather Forecasting for Load and Renewables – A primer, North American Energy Markets Association, Las Vegas, October 2015

Sharp, J.: The Value of (Improved) Renewable Energy Forecasts to Operational and Market Stakeholders, AWEA WindPower 2015, Orlando, FL, May 2015

Sharp, J.: Session Chair - How to Run a Forecasting Trial and How to Get the Most Value from a Set of Multiple Forecast Vendors, UVIG Forecasting Workshop, Denver, CO, February 2015

Sharp, J., K. Barr: The Case for Long-Range Scanning Lidar in Offshore and Complex Terrain WRA - Does it Pencil?, AWEA Wind Resource and Energy Assessment Workshop, Orlando, FL, December 2014

Sharp, J., K. Barr: The Potential of Long Range Scanning Lidar in Very Short Term Wind Power Forecasting - A Scientific and Economic Evaluation, UVIG Spring Workshop, Anchorage, AK, May 2014

Sharp, J., K. Barr: A Comparison of Lidar Wind Vector Retrievals with In-Situ and Vertical Lidar Measurements Pt 2, AWEA Windpower Expo, Las Vegas, NV, May 2014

Sharp, J.: The Role of Forecasting in Market and System Operation, Evolving Approaches to RE Generation Forecasting and Integration Workshop, ESKOM Academy of Learning, Johannesburg, South Africa, December 2013

Sharp, J.: Session Chair - Forecasting, Reserves and Efficient Market Operation: What Have We Learned, UVIG Forecasting Workshop, Salt Lake City, Utah, February 2013

Sharp. J: Seminar containing four units on wind and solar energy forecasting ranging from introductory to advanced topics, China Meteorology Administration Wind and Solar Energy Resources Center International Seminar on Wind and Solar Energy Prediction, Beijing, China, December 2012.

Sharp, J., with contributions from John Zack, Mark Ahlstrom and Eric Grimmit: US Weather Prediction (invited), An Alternative Model. American Meteorological Society Board on Enterprise Communication Discussions on the Future of the Weather Enterprise, Silver Spring, MD, November 2012

Sharp, J.: The Enabling Role of Variable Energy Forecasting and Load Forecasting in an Energy Imbalance Market. EUCI Energy Imbalance Concepts in the Western Interconnect Market, Portland, OR. August 2012.

Sharp, J.: Renewable Generation Data: Who needs it? How much is enough? Presenter and Session Chair, UVIG Spring Meeting, San Diego, CA. April 2012.

Sharp, J.: Atmospheric Science Breakthroughs That Impact Renewable Energy Viability: An Industry Perspective, AGU Annual Meeting, San Francisco, CA. December 2010.

Sharp, J.: Wind Ramp Forecasting: What's at Stake, The State of the Science, Priorities and Ways Forward, UWIG Spring Forecasting Workshop, Albuquerque, NM. February 2010.

Sharp, J.: The Meteorological Challenges For Renewable Energy, AGU Annual Meeting, San Francisco, CA. December 2009.

Sharp, J.: Meeting the Needs of the Renewable Energy Industry: Understanding Sector Roles, AMS Summer Community Meeting, Norman, OK. August 2009.

## ***Interests***

- Renewables advocacy, Weather and forecasting, Traveling, Skiing, Forecasting for special projects (e.g. balloonists).

**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION**
**DOCKET NO. E-100, SUB 165**

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|---|---|
| **In the Matter of:** | **)** |
| **2020 Biennial Integrated Resource** | **)** |
| **Plans and Related 2020 REPS** | **)** |
| **Compliance Plans** | **)** |
| | **)** |

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**INITIAL COMMENTS OF NCSEA AND CCEBA ON DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC'S INTEGRATED RESOURCE PLANS**

**EXHIBIT 5**

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**Transmission Issues and Recommendations for Duke 2020 IRP**

**Jay Caspary**[1]

**Vice President**

**Grid Strategies, LLC**

Transmission assumptions in the Duke IRP are critically important given the flexibility provided by increased connectivity that cannot be provided by power supply generation and demand response assets. The optionality provided by a strong electric transmission network are significant and will not be captured to the benefit of customers with incremental, least cost expansion planning, especially if planning models are based on known commitments and do not reflect expected conditions for the future. Duke did not provide enough detail about its transmission planning assumptions and costs in the 2020 IRP, and we recommend that Duke refine future IRPs to capture:

1. The economies of scale with bulk transmission upgrades to enable better integration of its Carolina operating companies, as well as integration of large-scale renewable developments, specifically off-shore wind resources;
2. The results of improved collaborative planning efforts with neighboring systems such as the ongoing North Carolina Transmission Planning Collaborative ("NCTPC") study with scenarios from the Southeast Wind Coalition that are in process;
3. Better asset management planning practices to inform planning decisions regarding long-range transmission expansion needs to leverage existing corridors; and
4. More rigor in analysis and assumptions regarding projects and costs to support future resource needs, in particular imports and off-shore wind developments that may be best addressed in partnership with neighboring systems.

Decisions regarding transmission need not be an afterthought as a result of power supply resource plans, but must be part of a co-optimization long term planning effort that is pro-active and holistic. Iterative solutions may be a required approach to identify optimal expansion plans given the lack of software tools and robust algorithms to solve these complex issues.

Electric power transmission is a very critical component of the bulk power system that is too frequently discounted in terms of its value. A coordinated and collaboratively planned electric

[1] Attached as Exhibit 1, C.V. of Jay Caspary.

power network is a tremendous asset, which can enable efficient and effective decisions regarding future supply options. Transmission enables and defines markets. The lack of robust transmission capability can be very costly not only in terms of limiting supply choices, but also in the flexibility it provides for system operations to accommodate necessary rebuilds to replace aging infrastructure as transmission lines approach end of life. Decisions regarding transmission need not be an afterthought as a result of power supply resource plans, but must be part of a co-optimization long-term planning effort that is pro-active and holistic. Iterative solutions may be the best approach to identify optimal expansion plans given the lack of software tools and robust algorithms to solve these complex issues.

Transmission is lumpy with tremendous economies of scope and scale that need to be leveraged by utilities who may be reluctant to work with neighboring systems to achieve the potential benefits from larger regional network solutions. The Duke IRP makes broad assumptions regarding transmission expansion costs, which may not reflect the rigor that one would expect to properly inform decisions. As shown in response to NCSEA Data Request 8-9, no modeling was performed to support transmission expansion planning project assumptions to facilitate 5-10GW of imports.[2] In addition, the transmission expansion costs to support imports of 10GW would not be expected to be 2 times the cost to support upgrades for imports of 5GW. That seems overly simplistic and doesn't capture any of the expected economies of scale one would normally see for EHV transmission planning to support aggressive clean energy goals. As noted in response to NCSEA Data Request 8-7, Duke did not consider any economies of scale for assumed renewable developments beyond the first 2GW of developments in this IRP.[3] Long-range plans must capture the large economies of scale associated with major transmission upgrades or new expansion projects. As shown in Table 1 below, high-voltage transmission lines can carry far more power than lower-voltage lines, and are far more cost effective due to economies of scale.[4]

[2] Duke Response to NCSEA DR8-9.
[3] Duke Response to NCSEA DR8-7.
[4] http://image.sustainablemfr.com/a/sage-supplier-wind-power-transmission-provides-manufacturing-opportunities-cost-voltage-wind-powerjpg.jpg

| Transmission Voltage (kV) | Cost per Mile ($/mile) | Capacity (MW) | Cost per Unit of Capacity ($/MW-mile) |
|---|---|---|---|
| 230 | $2.077 million | 500 | $5,460 |
| 345 | $2.539 million | 967 | $2,850 |
| 500 | $4.328 million | 2040 | $1,450 |
| 765 | $6.578 million | 5000 | $1,320 |

**Table 1: Economies of scale for high-voltage transmission**

Not only are higher-voltage lines more effective in moving large amounts of power, but they greatly reduce losses compared to lower-voltage lines. 765-kV AC lines, the highest voltage in operation in the U.S., experience one-eighth to one-quarter the losses of more common 345-kV AC transmission lines per amount of power transferred.[5] This is possible because the power transfer capacity of a line is determined by the voltage times the current (or amperage), while losses generally increase in proportion to the square of the current. As shown in the following table created by PJM, increasing the voltage allows far more power to be transmitted at the same current, and thus a comparable amount of losses.[6] In the following table, two numbers are shown for each voltage class to represent lower and upper bounds for power and current.

[5] American Electric Power, *Transmission Facts* at 4, *available at:* https://web.ecs.baylor.edu/faculty/grady/_13_EE392J_2_Spring11_AEP_Transmission_Facts.pdf.
[6] PJM Interconnection LLC, *The Benefits of the PJM Transmission System* at 9 (Apr. 16, 2019) *available at:* https://pjm.com/-/media/library/reports-notices/special-reports/2019/the-benefits-of-the-pjm-transmission-system.ashx?la=en.

| VOLTAGE CLASS | POWER (MVA) | CURRENT (AMPS) |
|---|---|---|
| 765 kV | 4,000 | 3,079 |
| | 5,400 | 4,157 |
| 500 kV | 2,500 | 2,887 |
| | 3,500 | 4,041 |
| 345 kV | 1,000 | 1,673 |
| | 2,000 | 3,347 |
| 230 kV | 420 | 1,054 |
| | 1,250 | 3,138 |

**Table 2: Higher voltage increases power transfer while minimizing current, and thus losses**

Modeling by Synapse suggests that significantly more clean energy developments will provide lower cost solutions regarding resource plans, and that would result in the ability to realize even better economies of scale with more efficient and effective bulk transmission expansion projects.

Seams issues and affected system study costs can be very large and must be considered in any resource planning decisions. Yet, this Duke IRP does not consider these costs at all. While these costs can be difficult to quantify absent detailed studies, assessments can be made in collaboration with neighbors. The cost of affected system studies can very well drive business decisions for projects as witnessed by the affected system study costs assigned by SPP for recent MISO West clusters. The challenges with planning generation interconnection upgrades as well as cost responsibilities for network upgrades on or around the seam of adjacent systems may be difficult problems to solve, but they can be addressed if transmission service providers are willing to work together.

Import and export limitations are critical and it is important that these assumptions are reasonable when it comes to assessments to support integrated resource planning decisions. While it may not be appropriate to extrapolate historical imports/exports for planning purposes, that data can provide insights regarding the system's capability that may not be reflected in planning assumptions. EIA historical transactions data is posted separately for Duke Carolinas and the eastern and western systems of Duke Progress Carolina. This data can help with investigating the merits of improved connections between the separate systems within Duke territory, and help determine if they need to be considered as one unit for long-range planning purposes. A quick analysis of the aggregate data demonstrates that the Duke systems in the Carolinas has been able to import more than 2,000MW in periods near peak winter demand in mid-January of 2018. Extreme weather events are easy to predict many days in advance and power system operations commit resources well in advance of need to ensure availability of critical resources during peak consumption periods. It's no surprise that Duke was importing significant amounts of power near peak demands as weather fronts move across the southeast and mid-Atlantic states because utilities preposition their fleets to accommodate forecasted peak demands. Neighboring utilities typically have excess capacity in periods adjacent to their own coincident peaks. This provides opportunities for adjacent systems to exchange capacity and energy. The bulk power system is a very valuable asset to move capacity and energy. Seasonal diversity exchanges were common place decades ago to leverage the resources in power supply fleets and load diversity. An efficient and effective bulk power system should take advantage of that diversity, but it is only available as a result of adequate transmission planning and expansion projects to capture those benefits. The flexibility provided by EHV transmission capability is extremely valuable for the interconnected system during periods of stress. That applies within the Duke Carolina systems as well as with its neighboring systems in PJM, TVA, Southern Company, and others.

Robust transmission expansion provides operational benefits which are not captured with traditional planning models and tools. Reliability models which often make optimistic assumptions about generation availability are typically the basis for long-term reliability and economic transmission expansion planning simulations. Reliability and economics are inseparable when it comes to the value proposition of prudent transmission expansion planning. Today's reliability need provides economic benefits to support grid operations. Conversely, economic upgrades in the near term will also provide reliability benefits that are difficult to quantify since operating conditions rarely mirror planned scenarios. The benefits associated with the flexibility and optionality provided by a strong electric transmission network are significant and will not be realized if incremental least cost planning is performed with limited planning horizons, particularly if those do not align with corporate, institutional, state, and municipal commitments to decarbonize their electric power supply resources by date certain.

The Duke electric power systems in the Carolinas have an opportunity to capture benefits for both DEC and DEP customers if Duke utilizes effective planning and strategic decisions regarding the upcoming replacement of aging assets in, around, and between the two systems. Planning for infrastructure must be long term and incorporate reasonable assumptions regarding the remaining life of transmission lines, particularly those in critical corridors. Unfortunately, according to the response to NCSEA Data Request 8-10, it appears that Duke could do more to investigate the merits of potentially rightsizing select facilities which are reaching the end of life in key corridors to accommodate future needs.[7] In that response, Duke states that "Duke's Transmission Asset Management group advises on replacement internals for transmission equipment nearing end of life and coordinates such replacements with

[7] Duke Response to NCSEA DR8-10.

Transmission Planning”. Asset replacement has become a major issue as it now drives capital budgets for transmission projects in most, if not all utilities. Transmission planning to address future needs must take advantage of asset management information to better inform investment decisions. Planning should not just incorporate asset management decisions as an input into its studies, but rather those efforts need to work together in a proactive, holistic manner to identify opportunities for rightsizing aging assets that can defer or displace traditional transmission expansion needs from conservative planning assessments done in isolation. A particular focus on critical corridors is warranted to ensure that transmission expansion plans are not short sighted and only focus on local needs, but support the long-term needs for a decarbonized grid in and around Duke’s system in the Carolinas.

Regional and interregional planning has not been very effective recently with most transmission investment focused on rebuilding existing infrastructure due to end-of-life needs without any consideration of optimal designs to support future needs. Cooperative and collaborative transmission expansion planning was challenging enough prior to FERC inserting aspects of potential competition into the process. ACEG released its "Planning for the Future: FERC’s Opportunity to Spur Cost Effective Transmission Expansion" report on January 27 2021. This report demonstrates not only why FERC needs to update Order 1000, but also offers potential solutions using existing authorities to require more proactive, holistic planning to support grid decarbonization. Regulatory reforms to improve regional and interregional planning can expect to be initiated in 2021 and should be reflected in future IRPs for Duke in the Carolinas. The ACEG report has a dedicated webpage at https://cleanenergygrid.org/planning-for-the-future/.

Effective interregional planning is a critical success factor for efficient offshore wind development and integration. The assumptions reflected in this IRP regarding offshore transmission expansion costs are almost 10 years old and need to reflect outstanding assessments which have not yet been included as part of the NCTPC 2020-2030 Plan published January 15, 2021. For this 2020 NCTPC study, the Southeast Wind Coalition identified several scenarios to evaluate the impacts of offshore wind development that include:

- the potential for 2,400 MW of wind development injecting into Dominion’s Landstown 230kV area to be wheeled into the DEC/DEP areas assuming 60%/40% allotments, respectively, and
- separately, determine 3 least-cost injection points along the NC coast and determine the transmission cost breakpoints for varying amounts of generation injection at those sites up to 5,000 MW with a similar split in deliveries to DEC and DEP.

The results of this analysis are expected to be completed in the early 2021 and need to be reflected in Duke’s 2021 IRP update. The economic benefits of pro-active, coordinated interregional planning for significant offshore wind development scenarios warrant investigation and understanding to ensure that resource plans are efficient. Coordinated planning with Duke and Dominion to integrate offshore wind resources in southern VA and northern NC can be expected to result in benefits to customers of both systems. Cost effective, collaborative plans should be encouraged for both the optimal wet and dry network designs to harvest and integrate offshore resources for coordinated transmission expansion developments in southern VA and northern NC.

The Southeast and Mid-Atlantic Regional Transformative Partnership for Offshore Wind Energy Resources (SMART-POWER) agreement by eastern seaboard governors was announced on November 2, 2020 and supported by the state of North Carolina. This collaborative effort has potential to result in even bigger and better solutions with regards to network expansion and cooperative transmission expansion, which provides even more value than a joint plan developed by Dominion and Duke. Although the challenges increase with expanded scope, the ability to integrate a more diverse set of offshore wind resources across a broader region should increase the effective capacity factor and transmission utilization rates for both wet and dry networks, which will lower costs to all consumers. To the extent that progress is made with SMART-POWER, assumptions regarding offshore wind development resources as well as transmission expansion plans to support effective integration need to be reflected in Duke's '21 IRP update.

CASPARY EXHIBIT 1



# Jay Caspary

**194 Tice Road, P O Box 460**
**Higden, AR 72067**
**jcaspary@gridstrategiesllc.com**
**501.951.3296**

**Experience**

- **Sept 2020 – present Grid Strategies LLC**
- **Vice President**
- **Leverage 40 years of utility and RTO experience to assist clients in realizing a clean energy future grid that is efficient, effective, secure and resilient.**

- **2001 - 2020 Southwest Power Pool**
- **Director – Research, Development & Tariff Services (RDTS)**
- **Manage research projects and funding priorities for SPP while providing strategic consulting for SPP executives and management**
- **Direct RDTS staff in support of programs and projects to support strategic objectives of SPP - Dynamic Line Rating pilot projects with AEP and Sunflower Electric, PMU deployment roadmapping, special studies like High Priority Incremental Load Study (HPILS), Value of Transmission, WAPA/Basin IS integration**
- **Direct all customer requested service studies including generation interconnections, transmission service and congestion hedging**
- **Co-lead for Technical Review Committee for DOE-funded, NREL-led Interconnections Seam Study**
- **Member of EPRI Grid Operations, Planning and Renewable Integration Leadership Team**
- **Steering Committee for TransGrid-X 2030 Symposium at Iowa State University**
- **U.S. Representative on CIGRE C1.35 and C1.44 evaluating merits of a global electric grid**

**2012 – 2013 Senior Policy Advisor – U. S. Department of Energy in Electricity Delivery and Energy Reliability (OE)**

- **Educate DOE and agency staff on grid operations and planning**
- **Serve on Grid Tech Team**
- **Recommend changes in research priorities and organizational structure of OE**
- **Member of WAPA Joint Outreach Team to facilitate grid modernization**

**Director – Transmission Development**

- **Led transmission expansion policy development within SPP and beyond, strategic and other benefit assessments for EHV transmission.**
- **Led inter-regional coordinated and collaborative planning studies, Eastern Interconnection Planning Collaborative (EIPC), WECC TEPPC, SWAT, SIRPP, etc.**

- **Represent SPP on the Technical Review Committees for the Eastern Wind Integration and Transmission Study (EWITS) sponsored by DOE/NREL, as well as Nebraska Power Association Wind Integration Study, and several ARRA funded projects for EPRI, et al.**
- **Chair EPRI Program 173: Enabling Transmission for Large Scale Renewables**
- **Direct activities of the Technical Studies & Modeling, Planning and Tariff Studies Sections of Engineering Department at SPP**
- **Direct development of SPP's EHV Overlay plan, as well as Wind Penetration Study**
- **Develop/Manage Engineer-In-Rotation program for all engineering groups at SPP**
- **Led implementation of Economic Upgrades within SPP, e.g., Westar's Wichita – Reno Co – Summit 345 kV and KETA's Spearville – Knoll – Axtell EHV projects**
- **Chair ISO/RTO Council Planning Committee**
- **Development and implementation of the SPP Transmission Expansion Plan (STEP)**
- **Develop process and template for economic transmission expansion planning**
- **Initiate and direct coordinated planning activities, e.g., ERCOT/SPP Joint Study**
- **Represent SPP on NERC Transmission Issues Subcommittee (TIS) and RAS**

- **1981 – 2000 Illinois Power**

**Increasing levels of responsibility beginning with System Planning, and expanding expertise in Energy Supply, Regulatory Services, and Retail Marketing. Began career in Transmission Planning performing technical analyses as well as servicing at IP representative on the MAIN Engineering Committee, supporting Research & Development, negotiating and implementing the nation's first retail wheeling pilot program with industrial customers and transitioning interruptible customers to real time pricing tariffs, and then working with utilities and legislatures to get approval of retail choice in Illinois prior to developing and implementing marketing plans for commercial and industrial customers.**

**Education**

**University of Illinois** — **Bachelor of Science in Electrical Engineering with a Power Systems emphasis**

**Iowa State University** — **Course requirements for a Masters of Engineering**

**Memberships**

**2009 – Present Institute of Electrical and Electronics Engineers**
**2009 - Present Power and Energy Society**
**2016 – Present CIGRE**

**Awards**

**2011 UWIG Achievement Award for the advancement of transmission planning and markets in the SPP footprint, *Utility Wind Integration Group***

**2012 Technology Transfer Award for DOE Integration of Southwest Power Pool Wind by Southeast Utilities, *Electric Power Research Institute***

**2017 UVIG Service Award for 11 years of service to the UVIG Board of Directors, *Utility Variable-generation Integration Group***

**2019 Sullivan Alumni Association Hall of Fame Award, Sullivan Illinois**

## Service Activities

**2009 – 2012 NERC Integrating Variable Generation Task Force, Task 2.3 BA Services and Coordination Chair**

**2009 – 2020 Industry Advisory Board for Power Systems Engineering Research Center (PSERC) and GRid-connected Advanced Power Electronics Systems (GRAPES), including Chair for each organization**

**2009 – 2020 Member of Electric Power Research Institute Grid Planning & Operations Leadership Team**

**2016 – 2018 U. S. Department of Energy, Electricity Advisory Committee**

## Publications

**Wang, W., Ramasubramanian, D., Farantatos, E., Bowman, D., Scribner, H., Tanner, J., Cates, C., Caspary, J., and Gaikwad, A; *Evaluation of Inverter Based Resources Transient Stability Performance in Weak Areas in Southwest Power Pool's System Footprint*, CIGRE Session 48, 2020**

**Figueroa-Acevedo, A., Jahanbani-Ardakani, A., Nosair, H., Venkatraman, A., McCalley, J., Bloom, A., Osborn, D., Caspary, J., Okullo, J., Bakke, J., and Scribner, H., *Design and Valuation of High-Capacity HVDC Macrogrid Transmission for the Continental US*, IEEE Transactions on Power Systems, 2019**

**Bowman, D., McCann, R., Subramanian, D., Farantatos, E., Gaikwad, A., and Caspary, J., *SPP Grid Strength Study with High Inverter-Based Resource Penetration*, North American Power Symposium, 2019**

**Caspary, J., Bowman, D., Dial, K., Schoppe, R., Sharp, Z., Cates, C., Tanner, J., Ruiz, P. A, Li, X., and Tsuchida, T.B., *Application of Topology Optimization in Real-Time Opera*tions, CIGRE US National Committee 2019 Grid of the Future Symposium, 2019**

**McCalley, J., Caspary, J., Clack, C., Galli, W., Marquis, M., Osborn, D., Orths, A., Sharp, J., Silva, V., and Zeng, P., *Wide-Area Planning of Electric Infrastructure: Assessing Investment Options for Low-Carbon Futures*, IEEE Power and Energy Society Magazine, November/December 2017**.

**Caspary, J., McCalley, J., Stoltz, M., Bloom, A., Scribner, H., Novacheck, J., and Figueroa, A., *Eastern and Western Interconnections Seams Study Update*, CIGRE US National Committee 2017 Grid of the Future Symposium, 2017**

**Caspary, J., and Waldele, B., *Leveraging Technology: Maximizing Value in the Bulk Power Industry [In My View]*, IEEE Power and Energy Society Magazine, November/December 2016**

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