BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 194

In the Matter of:	)	
Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities — 2023	)	**INITIAL COMMENTS OF NCSEA**

NOW COMES the North Carolina Sustainable Energy Association ("NCSEA"), pursuant to the Commission's August 7, 2023, *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing*, and the Commission's February 6, 2024, *Order Granting Extension of Time to File Comments*, and respectfully submits the following comments on the Joint Initial Statement and Proposed Standard Avoided Cost Rate Tariffs ("Joint Initial Statement"), filed by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, "Duke" or the "Companies"), on November 1, 2023.

I. INTRODUCTION

The establishment of standard offer avoided cost rates and standard power purchase agreements ("PPAs") for qualifying cogenerators and small power production facilities ("QF") have been an effective method to increase the capacity of solar megawatts ("MW") in North Carolina. In fact, according to the U.S. Energy Information Administration, 1,173 MW of North Carolina's 1,271 MW of all utility-scale solar capacity in 2015 were certified as QFs under the Public Utility Regulatory Policies Act of 1978 ("PURPA").[1] This

[1] *North Carolina has more PURPA-Qualifying Solar Facilities than any other State*, U.S. ENERGY INFO. ADMIN. (Aug. 23, 2016), https://www.eia.gov/todayinenergy/detail.php?id=27632.

represented the most solar energy procured through QFs in the nation. The state has had such success in procuring zero-carbon emitting resources like solar energy, that following the passage of HB 951, the Companies were able to report in its Initial Carbon Plan that the Companies have reduced carbon emissions associated with the entire Duke generation fleet in all jurisdictions by 40% of 2005 levels, and by 45% of 2005 levels within North Carolina electric generation facilities.[2] Certainly, many factors contribute to the Companies' ability to reduce carbon emissions from their electric generation fleet, but the contribution of electricity generated from solar resources, including QFs, is undeniable.[3] Absent PURPA, and other incentives to develop solar resources, Duke would not have had the luxury to boast significant progress towards its compliance with HB 951.

Qualifying facilities' role in continuing the advancement of achieving the HB 951 mandates will be significant. This is particularly true considering the Updated 2023 Fall Load Forecast filed in the biennial Carbon Plan IRP docket, E-100, Sub 190 ("Carbon Plan IRP"). On November 30, 2023, the Companies filed supplemental testimony in that docket announcing that "strong and unprecedented economic development in the Carolinas . . . has resulted in projected load growth across the Carolinas that substantially exceeds even the high load case included in the Companies' Carbon Plan IRP filing in August.[4] This announcement necessitated the Companies to file supplemental modeling portfolios and supporting analysis on January 31, 2024, to outline an additional resource

[2] *Carolinas Carbon Plan*, App'x A – Carbon Baseline & Accounting, Commission Dkt. No. E-100, Sub 179, 6 (May 16, 2022).

[3] *Carolinas Resource Plan*, Ch. 1 – Planning for a Changing Energy Landscape, Commission Dkt. No. E-100, Sub 190, 2 (Aug. 17, 2023) (acknowledging that approximately 1,000 solar facilities have been part of the orderly transition allowing the Companies to retire and replace significant capacity of carbon-emitting coal resources.).

[4] *Supplemental Testimony of Glen A. Snider*, Commission Dkt. No. E-100, Sub 190, 3–4 (Nov. 30, 2023).

generation mix to serve the Updated 2023 Fall Load Forecast. In Duke's supplemental portfolios and supporting analysis, the Companies project that "approximately 6.8 gigawatts ("GW") of new and diverse resource additions are required beyond the resources identified in Portfolio P3 Base in the Companies' Initial Plan in order to reliably meet the . . . increased energy demand reflected in the Updated 2023 Fall Load Forecast.[5] Further, the supplemental portfolios and supporting analysis specify an additional 700 MW of solar, for a total of 12.6 GW, and an additional 800 MW of battery energy storage, for a total of 5.1 GW, by 2035 to reliably serve its updated projected load.[6]

Figure 2: Incremental Resource Additions for Core Portfolios by 2035 and 2038[9]

By January 1 2035	Grid Edge	Coal Retirements	Solar	Battery	CT	CC	Onshore Wind	Pumped Storage Hydro	Advanced Nuclear	Offshore Wind
P3 Base	EE at least 1% of eligible retail sales IVVC growing to 96% DEC & 97% DEP circuits Winter DR & CPP	-6.2 GW	11.9 GW	4.3 GW	2.1 GW	4.1 GW	2.1 GW	1.7 GW	0.6 GW	0 GW
P3 Fall Base			12.6 GW	5.1 GW		6.8 GW		1.8 GW		2.4 GW
Difference		*0 GW*	*0.7 GW*	*0.8 GW*	*0 GW*	*2.7 GW*	*0 GW*	*0.2 GW*	*0 GW*	*2.4 GW*

By January 1 2038	Grid Edge	Coal Retirements	Solar	Battery	CT	CC	Onshore Wind	Pumped Storage Hydro	Advanced Nuclear	Offshore Wind
P3 Base	EE at least 1% of eligible retail sales IVVC growing to 96% DEC & 97% DEP circuits Winter DR & CPP	-8.4 GW	14.6 GW	6.0 GW	3.0 GW	4.1 GW	2.3 GW	1.7 GW	2.4 GW	0 GW
P3 Fall Base			17.5 GW	6.3 GW	2.1 GW	6.8 GW		1.8 GW	2.1 GW	2.4 GW
Difference		*0 GW*	*2.9 GW*	*0.3 GW*	*-0.9 GW*	*2.7 GW*	*0 GW*	*0.2 GW*	*-0.3 GW*	*2.4 GW*

Similarly, the Updated 2023 Fall Load Forecast caused changes to the Companies' Near-Term Actions Plan ("NTAP") in the Carbon Plan IRP. The updated near-term actions for procuring new solar and solar paired with storage resources represents an increased

[5] *Supplemental Planning Analysis*, Commission Dkt. No. E-100, Sub 190, 7, 38 (Jan. 31, 2024).

[6] *Supplemental Direct Testimony of Glen Snider, Michael Quinto, Thomas Beatty, & Ben Passty*, Commission Dkt. No. E-100, Sub 190, 19 (Jan. 31, 2024) (reproducing Figure SPA 1–2 to the Supp. Planning Analysis as Figure 2) [hereinafter, "Carbon Plan IRP Modeling Panel Supp. Testimony"].

procurement of 6,460 MW solar and 965 MW of paired storage through 2026.[7] The NTAP was also updated to convert 175 MW of planned stand-alone storage to paired storage.[8] The Companies continue to project solar resources as part of the least-cost achievement of HB 951 emission reduction mandates while providing safe and reliable service.

Not anticipated in the Companies' supplemental portfolios and supporting analysis is the retirement of any existing solar facilities over the course of its planning horizon. Specifically, significant amounts of contracted solar capacity are reaching the end of their initial QF PPA's term. Action is required to prevent this solar capacity from coming offline.[9] Given the challenges the Companies identified in the Carbon Plan IRP related to serving a significantly increased load forecast, it is in the public interest for the Companies to begin preparations to renew existing PPAs with QFs for a subsequent term to avoid "enlarging the challenge" of achieving HB 951's emission reduction mandates. Further, certain proposals, like discontinuing the predetermined Energy Storage System ("ESS"), in the Joint Initial Statement minimize the contributions of existing QFs as least-cost solutions in executing the NTAP. NCSEA's comments will address 1) the need to continue the predetermined ESS Retrofit Rates with reasonable adjustments to the program's framework, and 2) the need to conduct a new study that more accurately examines the ancillary benefits of solar and solar paired with storage, and other inverter-based resources ("IBR"). If accepted, these comments propose cost-effective methods to extend existing

[7] *Id.*, at 28

[8] *Id.*

[9] Prior to the enactment of N.C.G.S. § 2017-192 ("HB 589"), QFs that established a legally enforceable obligation *on or before* November 15, 2016, received a PPA term that lasted fifteen (15) years. Meaning, the last QF PPA executed prior to effective date in HB 589 will expire in 2031. However, QFs that established a legally enforceable obligation *after* November 15, 2016, received a PPA term of only ten (10) years. Accordingly, many—if not all—of the QF PPAs executed since the passage of HB 589 will reach their initial term even sooner.

QFs for an additional term and shrink the challenge of procuring zero-emitting resources to achieve the HB 951 emission reduction mandates.

II. COMMENTS

A. Support for the Continuation of the Predetermined Energy Storage System Retrofit Rates.

In the Joint Initial Statement, among its requests, the Companies propose to discontinue the "predetermined ESS Retrofit Rates after November 1, 2023."[10] In part, this proposal is in response to the Companies not receiving any ESS Retrofit project applications or Notice of Commitment Forms.[11] However, the lack of applications in the ESS Retrofit program is not due to a lack of interest from eligible QFs. Rather, the framework of the program combined with macroeconomic conditions beyond the control of eligible QFs—*e.g.*, the COVID-19 pandemic immediately followed by inflation and supply chain issues during the recovery—prevented eligible facilities from having the economic certainty and incentives to pursue this offering. Nevertheless, NCSEA agrees with the Companies' recommendation to discontinue the predetermined ESS Retrofit rates the Commission approved in the 2021 avoided cost proceeding, Docket No. E-100, Sub 175 ("2021 Sub 175 proceeding"). But, NCSEA recommends that the Commission order Duke to develop updated predetermined ESS rates for consideration in the 2025 avoided cost proceeding and recommends amending the current framework for the ESS Retrofit rates. NCSEA proposes amending the framework to offer the ESS Retrofit rates to QFs that renew their PPA for an additional term and agree to materially alter the existing facility

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[10] *Joint Initial Statement and Proposed Standard Avoided Cost Rate Tariffs*, Commission Dkt. No. E-100, Sub 194, 44 (Nov. 1, 2023) [hereinafter, "2023 Joint Initial Statement"].

[11] *Id.*

by co-locating a battery energy storage system. This will be in lieu of ESS Retrofit rates only becoming available for the remainder of the term of a QF's initial PPA. Such a framework would achieve maintaining current levels of solar capacity while opening a pathway to cost-effectively increasing the Companies' system storage capacity. Importantly, it will also provide the opportunity to review the efficacy and interest in such a program under more stable economic conditions.

Importantly, the Companies maintain they will continue to allow QFs that submit their Notice of Commitment Forms to materially alter their facility by installing an ESS after November 1, 2023, to be eligible for a negotiated rate calculated at the time the Notice of Commitment Form is submitted based on the most recent Commission-approved avoided cost methodology."[12] NCSEA acknowledges and appreciates the Companies maintaining this alternative path for QFs to permit and finance co-locating an ESS to their existing facilities. However, NCSEA also agrees with reply comments submitted by CCEBA in the 2018 avoided cost proceeding, Docket No. E-100, Sub 158 ("2018 Sub 158 proceeding") acknowledging that "the availability of standard ESS retrofit avoided cost rates will provide a more efficient means for QF owners to participate in an ESS retrofit process without being required to engage in the resource-intensive process of rate and PPA negotiation with Duke."[13] Maintaining this offering will be an important "stop-gap" in the interim, but such a project-by-project process may become untenable should the Commission find good cause to adopt NCSEA's proposed amended framework. Ultimately, it would be premature to discontinue any predetermined ESS Retrofit rates for

[12] *Id.*

[13] *Reply Comments of CCEBA*, Commission Dkt. No. E-100, Sub 158, 6 (Oct. 21, 2021).

QFs prior to determining the need for the Companies to maintain and expand its current generation fleet to meet the projected challenge in the Updated Fall 2023 Load Forecast.

1. The Current ESS Retrofit Framework did not Properly Incentivize the Deployment of ESS at Existing Solar QF Facilities.

The current ESS Retrofit framework allows QFs selling power to DEC and DEP to materially alter their facility to incorporate a co-located battery energy storage system and to amend their PPA to receive an ESS Retrofit rate for the remainder of the contract term.[14] In the 2018 Sub 158 proceeding, the Companies filed the ESS Retrofit Compliance Filing finalizing the eligibility criteria. The ESS Retrofit Compliance Filing reads:

> Eligibility for a New ESS retrofit avoided cost rate shall be limited to existing QFs that established either a legally enforceable obligation ("LEO") or entered into a PPA with the Companies under rates and terms approved by the Commission on or before November 15, 2016, and shall extend only for the term of the QF's PPA, whether currently existing or executed pursuant to an existing LEO established prior to November 15, 2016.[15]

Based on these criteria, the ESS Retrofit Compliance Filing determined that approximately 560 QF solar facilities above 1 MW, totaling 3,650 MW, are selling under PPAs and are eligible to retrofit their QF generator to integrate ESS.[16] As a result, according to the Companies, approximately 99% of QFs that have executed a PPA with the Companies have been eligible for the ESS Retrofit Rate.[17] The Companies, in the 2021 Sub 175 proceeding, subsequently published new ESS Retrofit avoided cost rates for PPAs with 2, 3, 4, 5, 6, 7,

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[14] *See 2023 Joint Initial Statement*, at 42.

[15] *ESS Retrofit Compliance Filing*, Attachment C, Commission Dkt. Nos. E-100, Sub 101; E-100, Sub 158, 1 of 3, (Sept. 29, 2021).

[16] *ESS Retrofit Compliance Filing*, at 5.

[17] *See 2023 Joint Initial Statement*, at 6 n. 18 (notifying the Commission that since November 15, 2016, the Companies have executed standard offer PPAs for nine QFs totaling 5.81 MW in the DEC service territory and ten QFs totaling 1.498 MW in the DEP service territory).

8, 9, and 10 years remaining in term.[18] The Commission approved the ESS Retrofit avoided cost rates in their November 22, 2022, *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*.[19]

The Commission, NCSEA, CCEBA (f/k/a "NCCEBA"), and SACE agreed that offering storage the term that remains on the PPA was reasonable at the time of its approval in the 2018 Sub 158 proceeding.[20] Today, the framework for ESS Retrofits ultimately proved unworkable and did not properly incentivize the co-location of ESS. First, "[t]he published New ESS retrofit avoided cost rate available to a retrofit ESS QF Interconnection Customer will correspond to the amount of time left on the QF Interconnection Customer's generation site's current PPA as of January 1, 2023."[21] Consequently, many QFs eligible for the ESS were unable to receive the more generous ESS Retrofit avoided cost rates for systems with more remaining years in the term of their PPA—particularly the most lucrative 10-year ESS Retrofit avoided cost rates.[22] As Duke explained, a QF that "signed a fifteen-year PPA in 2015 and is planning to retrofit an ESS at an existing generation site will receive an 8-year published New ESS Retrofit avoided cost rate."[23] To clarify, a QF

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[18] *Joint Initial Statement & Avoided Cost Rate Tariffs*, DEP & DEC Exhibits 12, Commission Dkt. No. E-100, Sub 175 (November 1, 2021) [hereinafter, "2021 Joint Initial Statement"].

[19] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Commission Dkt. No. E-100, Sub 175, 67–68 (Nov. 22, 2022) [hereinafter, "Sub 175 Nov. 22, 2022 Order"].

[20] *See Order Approving SISC Avoidance Requirements and Addressing Solar-Plus-Storage Qualifying Facility Installations*, Commission Dkt. Comm Nos. E-100, Sub 101; E-100, Sub 158, 10 (Aug. 17, 2021) [hereinafter, "Sub 158 Aug. 17, 2021 Order"].

[21] *ESS Retrofit Compliance Filing*, Attachment C, at 2 of 3.

[22] *See 2021 Joint Initial Statement*, DEP & DEC Exhibits 12 (outlining the New ESS Retrofit Avoided Cost Rates where QFs with more years in term remaining receive higher energy credits (¢/kwh) than many QFs with less years (*e.g.*, the DEC distribution 10-year ESS Retrofit energy credit is 3.66 ¢/kwh compared to the 5-year ESS Retrofit energy credit which is 3.32 ¢/kwh), and where QFs with more years in term remaining receive significantly higher capacity credits (*e.g.*, the DEC distribution 10-year ESS Retrofit winter capacity credit is 9.24 ¢/kwh compared to the 5-year ESS Retrofit winter capacity credit which is 4.95 ¢/kwh)).

[23] *ESS Retrofit Compliance Filing*, Attachment C, at 2 of 3.

that executed a PPA with the Companies just one year prior to the eligibility cutoff date of November 15, 2016, will only be able to take advantage of the 8-year ESS Retrofit avoided cost rate. A QF that signed a 15-year PPA in 2016, prior to the eligibility cutoff date of November 15, 2016, likely was only eligible for the 9-year ESS Retrofit avoided cost rate. Most QFs under the current framework were only eligible for the lesser-term, and less advantageous ESS Retrofit avoided cost rates. Duke even admitted that it would be a "rare case" that there would be a QF with more than 10 years remaining in its existing PPA to lock-in the 10-year term ESS Retrofit avoided cost rate.[24] It was a "rare case" because the current framework effectively precluded any QF from receiving the 10-year ESS Retrofit avoided cost rates.

Second, although the energy credits for the 2, 3, and 4-year ESS Retrofit avoided cost rates were greater than the 5-year energy credit, the rates were insufficient for a QF to justify the short payback period for its investment in an ESS. It is not economically viable for a QF with only a few years remaining on its initial PPA term to materially alter its facility with an ESS. A QF would not recover the full costs of such an investment. In fact, NCSEA previously commented to the Commission that "there is no reason to believe that any QF can finance an addition of storage device to its facility with only five years of price certainty."[25] Particularly, NCSEA Witness Norris testified that "a five-year avoided cost rate would 'undercut or fully eliminate the capacity value of the storage equipment and make it wholly unfinanceable."[26] The current framework effectively limited many QFs to

[24] *Id.*

[25] *Reply Comments by NCCEBA, NCSEA, & SACE*, Commission Dkt. No. E-100, Sub 158, 9 (Nov. 20, 2020).

[26] *Sub 158 Aug. 17, 2021 Order*, at 9–10.

the lesser energy and capacity credits, making the pursuit of ESS Retrofit avoided cost rates a risky proposition.

Moreover, under the current framework, there are only two outcomes for one of the approximately 560 QF solar facilities above 1 MW at the conclusion of their PPA's term should they materially alter their facility with an ESS. Either, 1) the QF renews its PPA with Duke for a subsequent term; or 2) the QF converts to a fixed, five-year term PURPA contract as it will not be eligible for the standard offer contract per N.C.G.S. § 62-156(b)–(c). Notably, both outcomes will not receive the ESS Retrofit avoided cost rates as those rates expire with the current PPA term.[27] And there is no guarantee a QF can pursue the first outcome. As outlined in the Companies' proposed Terms and Conditions for the Purchase of Electric Power, Duke has the option to renew the QF's PPA for a subsequent term. Subsection 7, "Contract Renewal," reads:

> This Agreement shall be subject to renewal for subsequent term(s) at the option of Company on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the Company's then avoided cost rates and other relevant factors, or (2) set by arbitration.[28]

Duke has discretion, and a gatekeeping role, as to how it wishes to treat existing QFs.[29] Transparency related to Duke's preferred outcome for expiring QF PPAs and/or how Duke plans to exercise its discretion in PPA renewal negotiations with QFs will help these

[27] This statement is also true for QFs that submit a Notice of Commitment Form after November 1, 2023, and receive negotiated rate ESS Retrofit avoided cost rate. Those rates will expire at the end of the current PPA term.

[28] *2023 Joint Initial Statement*, DEC and DEP Exhibits 4.

[29] NCSEA wishes to inform the Commission that each solar QF is unique and there exists extenuating circumstances for certain QFs that may lead to a third outcome—the decommissioning of the QF—if a timely resolution regarding PPA renewal is not reached with the Companies.

negotiations progress and instruct what the public interest requires—if anything. Regardless, under the current framework, even if a QF successfully negotiates a PPA renewal or converts to a PURPA contract and had committed to an ESS Retrofit, the QF's ESS will not be compensated an additional avoided cost rate for the benefits its material alteration. For the foregoing reasons, the current framework for predetermined ESS Retrofit avoided cost rates is no longer reasonable.

NCSEA's proposed amendments to the ESS Retrofit framework for predetermined ESS Retrofit avoided cost rates avoid the shortfalls of the current framework. Additionally, NCSEA's proposed amendments simplify the framework and are consistent with its past positions to create more certainty for QFs.[30] By limiting ESS Retrofit avoided cost rates to QFs that renew their PPA for a subsequent term, all QFs will be eligible for the 10-year energy and capacity credits. This is because the ESS Retrofit rates will initiate near the beginning of the subsequent PPA term after the interconnection of the ESS. This obviates the use of a cutoff date that disadvantages and unduly discriminates certain QFs over others. This amended framework also requires the development of only one set of rates (*i.e.*, the 10-year ESS Retrofit avoided cost rates), compared to the current framework which includes nine separate sets of rates. The proposed amended framework properly incentivizes QFs as it creates the price certainty to pursue the addition of an ESS, even at the latter stages of a QF's PPA term.

The proposed framework also increases certainty for Duke. As these rates are for retrofits to existing facilities, the Companies have increased certainty of the project

[30] *Sub 158 Aug. 17, 2021 Order*, at 9 ("10-year avoided cost rates would be needed to finance a facility with energy storage.").

interconnecting and thereby mitigating potential risks associated with the attrition of competitively procured new solar facilities.[31] NCSEA's proposed amendments to the framework provide certainty to QFs that their investments in ESS will be fully recovered and provides increased certainty to Duke that it can successfully interconnect additional storage to its system.

2. *Economic Conditions, Including Inflation and Volatile Prices for Solar and Storage Components, Limited Enrollment in the ESS Retrofit Study Process.*

The parties performed extensive work to achieve consensus on an expedited study process for QFs committing to add an ESS to their facility. Originally, the first enrollment window for the ESS retrofit study was scheduled to open on May 28, 2020.[32] However, Duke and NCCEBA filed a motion to extend the timeline to the open the enrollment window as QFs could not "fully assess whether or not to enroll in the ESS Retrofit Study Process . . . until the appropriate avoided cost rates applicable to the energy storage element of an existing QF coupled with energy storage were established."[33] On May 27, 2020, the Commission suspended the enrollment window for the ESS Retrofit Study Process and directed the parties to engage in a stakeholder process that lasted a year and included multiple comment periods.[34] At the conclusion of that process, the Commission determined that "energy storage can provide benefits to ratepayers by enabling more dispatchable solar facilities, shifting energy from off-peak to on-peak hours, avoiding new

[31] *Carbon Plan IRP Modeling Panel Supp. Testimony*, at 28 (recognizing the increased solar procurement target is designed to address possible future attrition due to the ~24% average termination rate of solar PPA projects over the past five years of procurement.).

[32] *Sub 158 Aug. 17, 2021 Order*, at 3.

[33] *Id.*

[34] *Id.*

peaking capacity, and reducing solar intermittency."[35] However, the Commission also determined that the first enrollment window for Duke's ESS Retrofit Study Process could not occur until the Commission approved any necessary waivers of provisions to the NC Interconnection Procedures ("NCIP").[36] The Commission granted the requested waivers to the NCIP on May 12, 2022.[37]

To no fault of the Commission, Duke, the Public Staff, intervenors, or QFs, the current ESS Retrofit Rates framework was impacted by macroeconomic conditions that further disincentivized QFs from taking advantage of the ESS Retrofit avoided cost rates. Unfortunately, the enrollment windows for the ESS Retrofit Study Process overlapped with high inflation and interest rates. As can be seen in the chart below, illustrating the monthly inflation rate and Federal Reserve interest rate in the United States from January 2018 to September 2023, the country was experiencing peak inflation at the time the Commission granted the waivers to the NCIP.[38]

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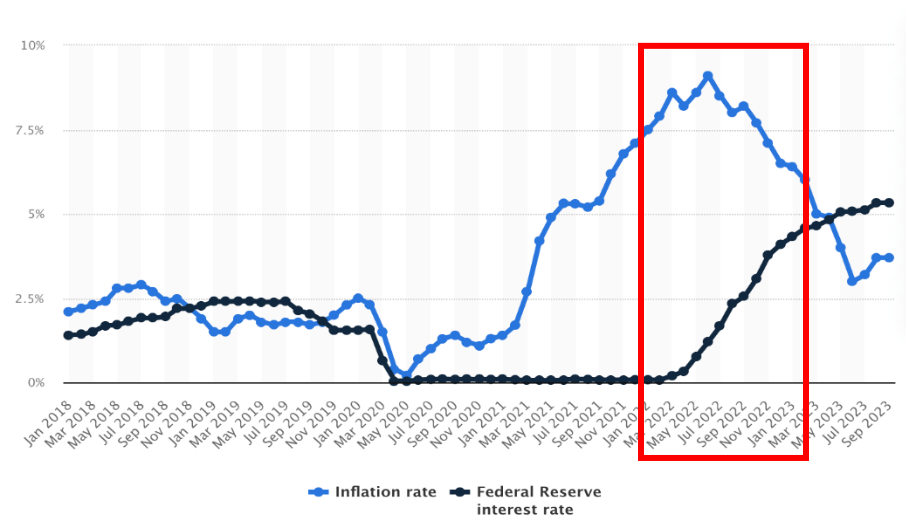
[35] *Id.*, at 10.

[36] *Id.*, at 4.

[37] *See Order Granting Waivers to Implement Energy Storage System Expedited Study Process and Approving Process to Establish Eligibility of Avoided Cost Rates for Retrofit Energy Storage Systems*, Commission Dkt. Nos. E-100, Sub 101; E-100, Sub 158 (May 12, 2022).

[38] *Inflation Rate & Federal Reserve Interest Rate Monthly in the U.S. from Jan. 2018 to Sept. 2023*, STATISTICA RESEARCH DEP'T (Nov. 6, 2023), https://www.statista.com/statistics/1312060/us-inflation-rate-federal-reserve-interest-rate-monthly/ (modified to denote the period between the opening of the ESS Retrofit Study Process enrollment window and Duke's January 23, 2023, Update Regarding the Expedited Study Process Available to ESS Retrofit Projects.).



Although inflation cooled following the opening of the enrollment window, the inflation rate remained high through the date the Companies filed its first update on the expedited study process. Further, the chart shows that during that period, the Federal Reserve was raising interest rates to control the rising inflation. The increasing interest rates, though successful in reducing inflation, were contemporaneously increasing the cost of capital—thereby also increasing the levelized cost of electricity for solar facilities and ESS. Accordingly, the year following the open enrollment window for the ESS Retrofit Study process was defined by higher costs. The combination of these two macroeconomic indicators affected the cost-effectiveness of installing an ESS at an eligible QF.

The National Renewable Energy Laboratory ("NREL") granularly illustrated the specific impacts to the costs of solar and storage components. As explained in the NREL report, "U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, with Minimum Sustainable Price Analysis: Q1 2022," the ongoing COVID-19 pandemic and other developments between Q1 2021 through Q1 2022 "contributed to unusually high—

and highly variable—PV and storage market costs and prices in Q1 2022."[39] These developments increased the prices for solar and storage components, constrained the supply chain to timely obtain the components, and tightened the labor market triggering higher labor costs to install the solar and storage systems.[40] To examine the impacts of the macroeconomic conditions on the costs for solar and ESS resources, NREL developed two benchmarks modeling the average capital costs for the resources. The Minimum Sustainable Price ("MSP") benchmark was designed "to capture the long-term cost impacts of technological evolution while muting the impacts of policy distortions and short-term market fluctuations."[41] While the Modeled Market Price ("MMP") benchmark accounts for the market conditions experienced during the analysis period, thereby identifying the short-term impacts of market and policy events.[42]

For solar, NREL's benchmarks showed the average cost for a 500 kW_{dc}, 1,000-V_{dc} commercial-scale, fixed-tilt, ground mounted system using driven-pile foundation system,[43] were 12% higher due to the market distortions afflicting the industry through Q1 2022. The MSP projected costs for a commercial-scale solar system at $1.71/$W_{dc}$ compared to the MMP which showed $1.94/$W_{dc}$.[44] For a lithium-ion, 4-hour standalone

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[39] VIGNESH RAMASAMY ET AL., *U.S. Solar Photovoltaic System & Energy Storage Cost Benchmarks, with Minimum Sustainable Price Analysis: Q1 2022*, NAT'L RENEWABLE ENERGY LAB., 2–3 (Sept. 2022), https://www.nrel.gov/docs/fy22osti/83586.pdf [hereinafter "NREL Q1 2022 Benchmark Report"].

[40] *Id.*, at 2–5.

[41] *Id.*, at 10.

[42] *Id.*

[43] *Id.*, at 22 (Acknowledging that the NREL benchmarks are not perfect matches to North Carolina QFs, the benchmark comparisons selected by NCSEA in the report were chosen because of their similarity to the systems that are eligible to be QFs under North Carolina law for illustrative purposes only. For example, NCSEA selected the benchmarks for "commercial scale-PV" because the 500 kW system modeled was more similar to a North Carolina QF than the NREL defined "utility scale-PV" which is a modeled baseline of 100 MW_{dc} system.).

[44] *Id.*, at 25–26.

commercial-scale storage system,[45] the MSP benchmarked the cost at $732,395 compared to the MMP benchmarked cost of $806,132—a 9% increase under the market distortions through Q1 2022. Last, for an ac-coupled, commercial-scale, solar-plus-storage system,[46] the MSP benchmarked the cost at $1.27 million and the MMP benchmarked the cost at $1.44 million.[47] Even though eligible QFs were only considering the costs of retrofitting the storage component to their existing facility, the NREL report demonstrates that the market distortions afflicting the industry raised costs for the entire solar and ESS industries. The higher costs caused by the market conditions through Q1 2022, did not provide QFs certainty that the ESS Retrofit avoided cost rates were sufficient to cover the costs of their investments. Therefore, the market conditions leading up to, and overlapping, the enrollment windows for the ESS Retrofit Study Process likely contributed the absence of enrollments.

However, the market distortions that hindered the economy are improving. As can be seen in the chart above, although it remains elevated, inflation has cooled in the United States and is far from its peak.[48] The Federal Reserve also announced it is now assessing when the appropriate time is to reduce the target range for the federal interest rate.[49] NCSEA has confidence that the described circumstances were extraordinary and their effects temporary. As a result, ESS prices should return to their historic trend of decreasing.

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[45] *Id.*, at 36 (assuming the battery size to be 300 kW_{dc}, 4-hour commercial standalone storage system because it is "an appropriate match to the representative 500 kW_{dc} benchmark commercial PV system.").

[46] *Id.*, at 39–40 (outlining the system parameters for combining the commercial-scale PV facility and the commercial-scale ESS.).

[47] *Id.*, at 40.

[48] *See supra.* note 38.

[49] *Federal Reserve Issues FOMC Statement*, FED. RESERVE (Jan. 31, 2024, 2:00 PM), http://federalreserve.gov/newsents/pressreleases/monetary20240131a.htm.

NCSEA believes it is in the public interest to adopt the amended framework and evaluate the efficacy and interest in an ESS Retrofit program under more stable economic conditions.

3. New Federal Tax Incentives for ESS, in Addition to ESS Retrofit Avoided Cost Rates, May Increase Participation in the Proposed Amended ESS Retrofit Framework.

In addition to the economy stabilizing and costs for solar and ESS facilities lowering, additional financial support for QFs interested in the ESS Retrofit program may arrive through the expansion of federal tax credits. The Inflation Reduction Act ("IRA") revised the investment tax credit, pursuant to 26 U.S.C. § 48("Section 48 ITC"), and created a new technology neutral tax credit, the Clean Electricity Investment Tax Credit, pursuant to 26 U.S.C. § 48E ("Section 48E CEITC"). Importantly, the IRA added energy storage technologies to the definition of "energy property," thereby making standalone energy storage systems eligible for the Section 48 ITC and the Section 48E CEITC.[50]

When parties to the 2018 Sub 158 proceeding were first contemplating avoided cost rates to incentivize the addition of an ESS to an existing QF, there were no other financial incentivizes available for energy storage. QFs looking to co-locate ESS at their existing facility could not take advantage of the federal 30% ITC. Per the IRS guidelines for the Section 48 ITC, ESS were only eligible for the ITC if they were co-located with a *new* solar generation system and the ESS took 75% from its total energy input from the solar facility—meaning the ESS was not mainly charging from the grid. This was called the Dual Use Rule. On November 22, 2023, the IRS provided guidance to interpreting the IRA's changes to the Section 48 ITC, stating, "[t]he Treasury Department and the IRS

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[50] *See* 26 U.S.C. § 48(c)(6) (applying the same definition for "energy storage technology" to 26 U.S.C. § 48E.).

recognize that the Dual Use Rule is no longer relevant to determining the eligibility of energy storage technology placed in service after December 31, 2022, because the IRA added energy storage technology as an energy property effective for property place in service after December 31, 2022."[51] However, the Section 48 ITC phases out by December 31, 2024, which means it is unlikely QFs looking to participated in the proposed amended ESS Retrofit framework will be able to take advantage of the Section 48 ITC.

However, the CEITC goes into effect January 1, 2025, and expires at the later of December 31, 2032, or the calendar year the Secretary determines that the annual carbon emissions from electricity generation are 75% lower than 2022 levels.[52] As each of the QFs eligible for an ESS Retrofit Rate have PPAs scheduled to expire by 2031, all facilities seeking to renew their PPA for an additional term likely will be eligible for the CEITC. Additional guidance from the Treasury Department and IRS will be needed though. The IRA also introduced the phrase "energy project," which is defined as a project consisting of one or more energy properties that are part of a single project."[53] For example, an energy project could be an onshore wind farm with a battery storage system on contiguous sites or identified in the same master construction plans or permits. Currently, the guidance provided by the IRS is silent regarding a scenario where of an energy property is added to another, existing energy property (*i.e.*, an existing solar QF materially altering its system with an ESS) to create an energy project, and whether the CEITC will be available to the added energy property (*i.e.*, the ESS). However, given the efficiencies of co-locating an

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[51] Definition of Energy Property and Rules Applicable to the Energy Credit, 88 Fed. Reg. 82203 (Nov. 22, 2023) (to be codified at 26 C.F.R. pt. 1).

[52] *Id.* § 48E(e) (adopting, by reference, the definition of "Credit Phase-Out" and "applicable year" established in 26 U.S.C. § 45Y(d)).

[53] 26 U.S.C. § 48(a)(9).

ESS with a solar generation facility, the federal agencies may produce guidance advising on this scenario. The guidance for the Section 48E CEITC is required to be issued no later than January 1, 2025.[54] It would be imprudent to end any predetermined ESS Retrofit avoided cost rates prior to learning the full scope of the financing opportunities for such a material alteration.

B. Support for an Updated Study on the Ancillary Services and Potential Benefits of Solar Paired with Storage.

In the 2021 Sub 175 proceeding *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, the Commission directed Duke "to conduct a preliminary investigatory study of the operating characteristics of IBRs at certain of its own IBR facilities to understand which ancillary services each resource or combination of resources can provide."[55] While requiring Duke to file a report on this study, the Commission also directed Duke Energy to "address the potential benefits, if any, to customers, of QFs providing ancillary services and whether a pilot program would be worthwhile."[56] Duke Energy duly filed its Inverter-Based Resource Report ("IBR Report") on Aug. 1, 2023. **Exhibit 1**.[57]

While NCSEA commends Duke Energy for the rapid and timely production of the IBR Report, the limitations imposed by the compressed timeline undermine any conclusions that can be made. The IBRs tested include two standalone solar facilities (40MW_{ac} and 54.6 MW_{ac}) and one standalone storage facility (8.8MW_{ac}, 1-hour

[54] *See* 26 U.S.C. § 48E(i).

[55] *Sub 175 Nov. 22, 2022 Order*, at 45.

[56] *Id.*, at 46.

[57] *Inverter Based Resources Testing Report*, Commission Dkt. No. E-100, Sub 175 (Aug. 1, 2023).

duration).[58] No paired solar and storage facility, and only one storage configuration, was tested. While Duke Energy's Active Power Testing for the solar facilities did include morning and afternoon times, these were only done for one day (May 12, 2023). Similarly, the Reactive Power Testing was only done over a 2-day period in mid-May (May 23–24, 2023), and the storage facility was only tested for a limited period on June 16, 2023.[59]

With such limitations imposed on the tests, the IBR Report represents merely a snapshot in time of the potential for some types of IBRs to provide ancillary services—more study is needed to determine the actual ancillary services that IBRs can provide. Within the IBR Report, Duke Energy states that:

> additional testing with different, larger Duke-owned IBR resource types (standalone batteries and solar plus storage) could allow for design of the testing with plans to record more parameters for post testing data analytics to thoroughly evaluate the capabilities of IBRs to provide certain ancillary services. Additional testing would also allow for assessing the costs for the testing and the IBR design/modifications needed to provide the ancillary service.[60].

The Commission should require Duke to conduct further testing on the ability of IBRs to provide ancillary services. In designing such future testing, to maximize the applicability of the conclusions from the resulting report, the Commission should require Duke to conduct stakeholder engagement concerning the types of equipment Duke intends to test and the design(s) of the testing Duke intends to carry out.

[58] Exhibit 1, at 3.

[59] *Id.*

[60] *Id.*, at 17.

Further, the availability and capability of different types of technologies continue to evolve rapidly—particularly with battery storage.[61] As such, the Commission should consider making such studies cyclical within the biennial avoided cost proceedings in anticipation of the deployment of ever more advanced technologies. This would allow North Carolina to take a more prospective, intentional approach to the integration of new technologies, rather than determining what value they may, or may not, provide after already being deployed at scale.

In the IBR Report, Duke Energy states that it believes that further study is needed before determining if a pilot is worthwhile.[62] However, the IBR Report did identify one ancillary service that IBRs are already providing and are expected to continue to provide—reactive power management/voltage support. NCSEA noted that these services were being provided to Duke Energy without compensation in the previous avoided cost proceeding,[63] the IBR Report has now confirmed that assertion. The IBR Report notes that this service is based on locational needs.[64] Considering location-specific constraints prevalent throughout certain parts of Duke's balancing authority, such as the Red Zones,[65] NCSEA believes that the time is ripe for a pilot program to determine the actual reactive power management/voltage support IBRs would provide if appropriately compensated for such

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[61] *See, e.g.*, *The Future of Battery Technology*, S&P GLOBAL (last visited Feb. 20, 2024), https://www.spglobal.com/esg/s1/topic/the-future-of-battery-technology.html ("New battery technology breakthrough is happening rapidly. Advanced new batteries are currently being developed, with some already on the market. The latest generation of grid scale storage batteries have a higher capacity, a higher efficiency, and are longer-lasting.").

[62] Exhibit 1, at 17.

[63] *Sub 175 Nov. 22, 2022 Order*, at 43.

[64] Exhibit 1, at 17.

[65] *See Order Adopting Initial Carbon Plan and Providing Direction for Future Planning*, Commission Dkt. No. E-100, Sub 179, 112–19, 122–23 (Dec. 30, 2022) (discussing Duke Energy's Red-Zone Transmission Expansion Plan projects).

service. Also, because Duke is already going through the process of identifying key areas of congestion across its balancing areas, identifying a set of IBRs near a location where they would be likely to provide ancillary services should not be difficult.[66]

Finally, before the Commission considers canceling the predetermined ESS Retrofit avoided cost rates, the potential benefits that such facilities could provide the grid should at least be studied.

III. CONCLUSION

For the reasons set forth herein, NCSEA respectfully requests that the Commission consider these initial comments in this proceeding.

Respectfully submitted this 21st day of February, 2024.

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[66] *See Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice*, Commission Dkt. No. E-7, Sub 1214, 24–26, 131–32 (Mar. 31, 2021) (discussing settlement terms between NCSEA, NCJC et al., and Duke Energy Carolinas); *see Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice*, Commission Dkt. No. E-2, Sub 1219, 25–27, 133–34 (Apr. 16, 2021) (discussing settlement terms between NCSEA, NCJC et al., and Duke Energy Progress).

IBR TESTING REPORT

ACTIVE AND REACTIVE POWER TESTING OF THE ELM CITY AND MONROE SOLAR INVERTER-BASED RESOURCES (IBR) WAS CONDUCTED OVER SEVERAL DAYS. ADDITIONALLY, TESTING OF THE ASHEVILLE ROCK HILL BATTERY RESPONSE TO ACTIVE POWER SETPOINT CONTROL WAS CONDUCTED. THIS REPORT PROVIDES AN OVERVIEW OF THE RESULTS FROM THOSE TESTS AND RESULTING RECOMMENDATIONS

DUKE ENERGY®

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Executive Summary

Site Information

The sites used for the active and reactive power testing were the Elm City and Monroe solar facilities. Both sites are owned and operated by Duke Energy and each site is located within a different Balancing Authority (BA) in the Carolinas region. Active power testing was conducted with the Asheville Rock Hill battery site in the CPLW Balancing Authority Area of the Duke Energy Progress BA.

Inverter-Based Resources Tested

Standalone Solar

- Elm City Solar (40 MWac)
- Monroe Solar (54.6 MWac)

Standalone Battery Storage

- Asheville Rock Hill Battery (8.8 MWac; 1-hr)

Test Dates and Times

The following dates and times were chosen for the testing:

Active Power Testing

- Friday, May 12, 2023, at 9:00 am - Solar
- Friday, May 12, 2023, at 12:00 pm - Solar
- Friday, June 16, 2023, at 11:30 am - Battery

Reactive Power Testing

- Tuesday, May 23, 2023, from 10:00 am – 5:00 pm – Solar
- Wednesday, May 24, 2023, from 10:00 am – 5:00 pm - Solar

Satellite Views of Cloud Cover for Active Power Testing

Weather for the Elm City active power test was partly cloudy during the morning test with mostly clear skies during the afternoon test. Monroe saw mostly cloudy skies during the morning active power test with some clearing during the afternoon test. Figure 1 and Figure 2 reflect the satellite cloud cover for the Elm City Solar and Monroe Solar sites near the time of the morning and afternoon testing.

Morning Test

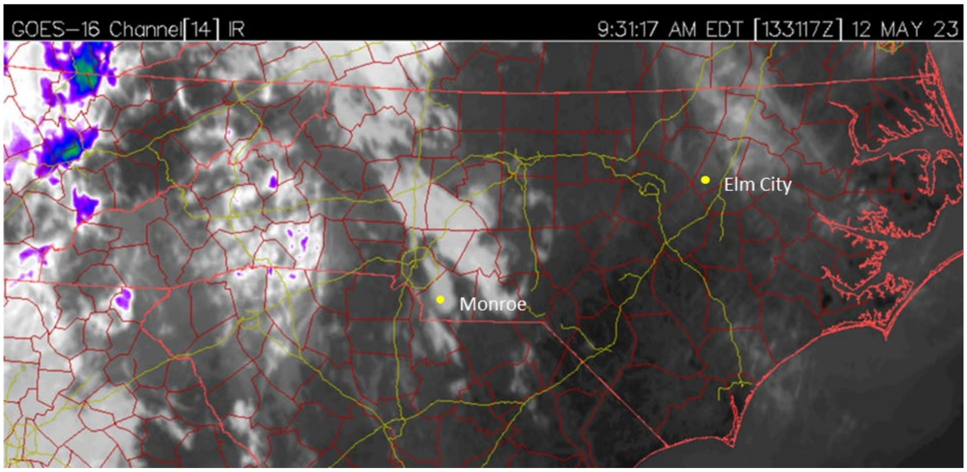

Figure 1 Cloud Cover During Morning Test

Afternoon Test

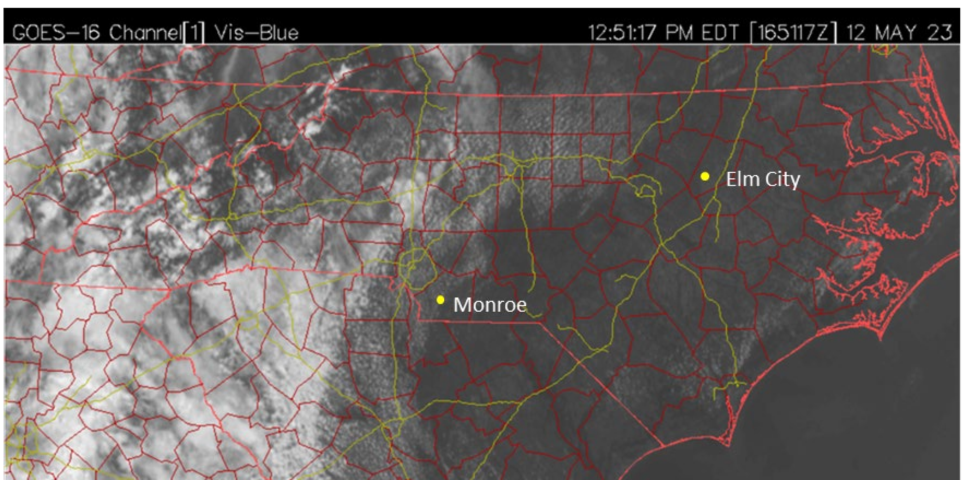

Figure 2 Cloud Cover During Afternoon Test

Introduction

NCUC Docket No. E-100, Sub 175 directed Duke Energy to conduct a preliminary investigatory study of the operating characteristics of IBRs at certain of its own IBR facilities to understand which ancillary services each resource, or combination of resources, can provide. The NCUC Order directed Duke Energy to file a report, on or before August 1, 2023, addressing the potential benefits, if any, to customers of QFs providing ancillary services and whether a pilot program would be worthwhile.

Duke Energy tested the operating characteristics of IBRs at both its Elm City (40 MWac) and Monroe (54.6 MWac) standalone solar facilities and at its Asheville Rock Hill (8.8 MWac; 1-hr) standalone battery storage facility. Elm City is connected to a 115kV transmission facility within the DEP BA, while Monroe is connected to a 100kV transmission facility within the DEC BA. The Asheville Rock Hill battery is connected to a 23kV express feeder out of the Asheville Rock Hill substation in the CPLW Balancing Authority Area (BAA) of the DEP BA.

Test Plan Layout

The test plan for the Duke Energy owned and operated resources involved both active and reactive power testing using setpoint control issued from the Regulated Renewable Operations Center (RROC) or the Distributed Generation Operations Center (DGOC). Test objectives were to determine how the resource would follow an active power setpoint, how it would respond to varying levels of reactive power injections, and how active and reactive power injections interplay with the controller logic and inverter capabilities. Each test occurred on different days where solar energy supported the test objectives.

Active Power Test

Active power testing was designed to create an offset between the actual yield and the estimated yield that would support frequency regulation at varying output levels and characteristics. This was accomplished by manually changing the active power setpoint in the Power Plant Controller (PPC) approximately every 10 seconds to create a ten (10) MW reduction of the actual output from the estimate. Estimated output for the facility is calculated using a model that takes inputs such as irradiance measured at the site, the number of inverters in service, and ambient and back-panel temperatures.

As part of this test, the active power setpoint was additionally offset to mimic frequency regulation by changing the setpoint to respond to deviations in the Area Control Error (ACE) for the respective BAA. ACE is a measure of the deviation of actual tie-line power flows with scheduled tie-line flows and a frequency bias contribution that represents the BA contribution of active power to assist with balancing resources and demand and regulating frequency on the Eastern Interconnection in compliance with NERC Reliability Standard requirements. The active power setpoint was either reduced or increased if ACE went above the high ACE regulation deadband or below the ACE deadband respectively. The ACE regulation deadband used for this test was fifty (50) MW.

Reactive Power Test

Reactive power testing was designed to move the resource's reactive power from zero (0) Megavolt-Amperes Reactive (Mvar) to full reactive absorption in small intervals by switching the resource to var control mode and changing the reactive power setpoint. Once at full reactive power absorption, the active power was then curtailed to determine if the resource could maintain its reactive power at lower active power outputs. The test would also show the sites ability to impact voltage in the local area as the reactive power was modified.

Elm City's voltage schedule is set to operate between 114kV and 119kV with a target of 115kV for every hour of the day. Monroe's voltage schedule is set to operate between 101.7kV and 106.5kV with a target that varies between 103.7kV and 105kV based on the day of the week and time of day.

Voltage support for a standalone battery system will be completed for a transmission-connected facility once available. Coordination would need to be assured between the Asheville Rock Hill battery site and substation voltage regulation devices, other feeders at the substation, and the voltage regulation schemes from the Distribution Management System (DMS) prior to conducting a reactive power test with the Asheville Rock hill battery. For this reason, Duke Energy did not test the voltage regulation capabilities of the Asheville Rock Hill battery resource.

Battery Regulation Test

The Greensmith Energy Management System (GEMS) was used to send setpoints to the Asheville Rock Hill BESS controller every 1-minute from zero (0) active power output to P_{min}, back to zero (0), then to P_{max} and back to zero (0). The facility is normally performing a droop-based frequency response operation if the controller senses a frequency deviation beyond the deadband.

Elm City Testing

Elm City is a standalone solar facility with an active power output interconnection limit of 40 MWac. The facility uses an Emerson/Ovation Power Plant Controller (PPC). It has been set up with a reactive power output limit at 95% power factor at its full interconnection output results in a Mvar limit of ±13.15 Mvar. Elm City is also assigned a voltage schedule in which it is to operate while producing active power into the transmission system.

Active Power Test Parameters

The active power setpoint test of the Elm City Solar facility was started just after 9:15 am, Friday, May 12, 2023. Active power test parameters were to generate a setpoint that reduced the active power output of the facility by ten (10) MWs from the facility's estimated capability based on current facility parameters and weather conditions. The setpoint was additionally offset to mimic frequency regulation by responding to deviations in the CPLE BAA ACE. Implementation of the setpoint within the PPC was done by manually entering the newly calculated setpoint approximately every 10 seconds into the facility's PPC. Setpoint calculation subtracted 10 MWs from the estimated yield calculation and would increase or decrease the result in response to a decrease or increase in ACE in proportion to Elm City's regulation response.

At the start of the test the facility was generating 22.1 MW with output increasing as the sun continued to rise. At 9:15 am, the Regulated Renewable Operating Center (RROC) made the first setpoint change from forty (40) MWs to the calculated 12.4 MW and kept changing the value every 10 seconds for the next 17 minutes to follow each new setpoint result. Results of the test are seen in Figure 3 below.

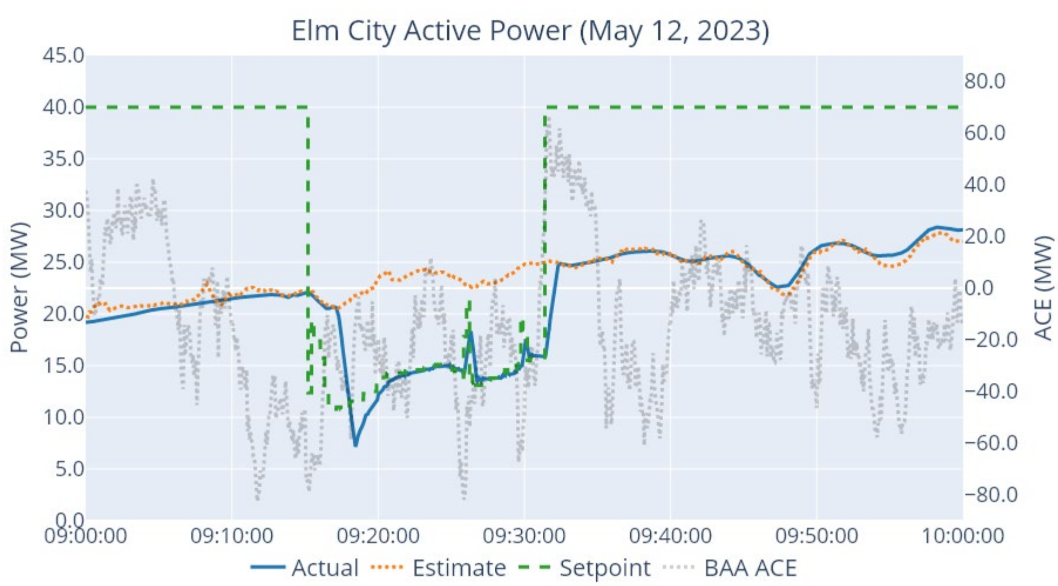

Figure 3 Elm City First Active Power Test - Site-Level Results

It took the PPC just over one (1) minute to start responding, but it then followed the setpoint relatively closely for the duration of the test. This delay was attributed to the starting setpoint being at the

Interconnection Agreement Limit (40 MW) and having to adjust down to the initial setpoint at approximately 12 MW. Also, the effects of the controller time delay and ramp limit are reflected in the response. At 09:24 and 09:29, the CPLE ACE went below the deadband causing the setpoint to increase proportionate with its allocation in response. As discussed above, initial response to the setpoint change was delayed until the PPC was able to overcome the difference between the original setpoint and the adjusted setpoint at the beginning of the test. Once the controller adjusted to this difference, the PPC followed the setpoint with a tight response.

Inverter-level response shows variability between the individual inverters that can be seen with the site-level aggregate active power injection when the facility is not being actively controlled. This variability is due to the size of the respective facilities and weather variations across their footprint along with variations between the inverters and panels themselves. As reflected in Figure 4, the variability mostly reduces once the inverters are controlled to an output below their full capability based on current irradiance.

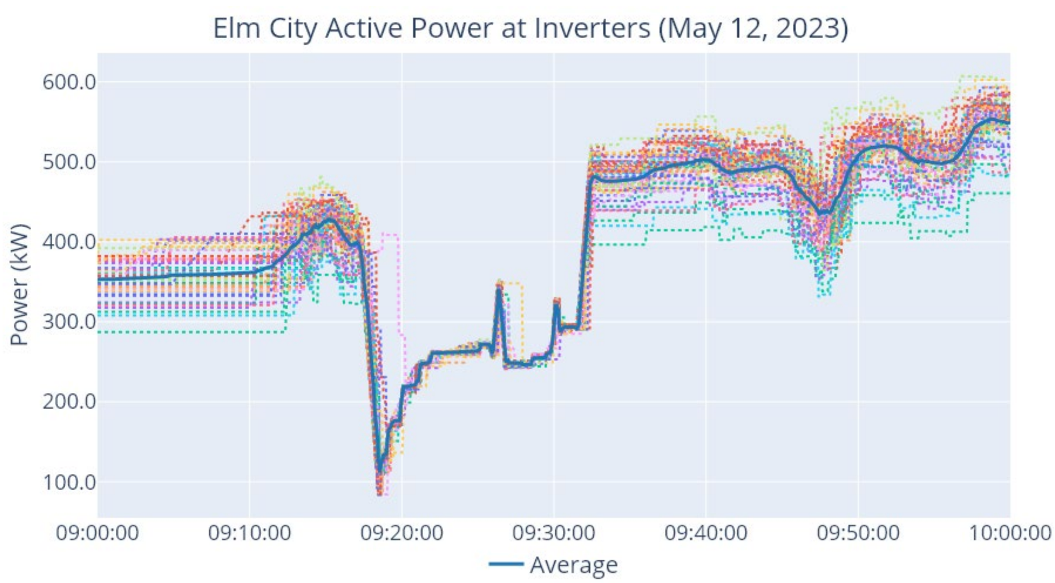

Figure 4 Elm City First Active Power Test - Inverter-Level Results

The second active power control test started at 12:32 with the site at full output as shown in Figure 5. During this test, the setpoint stayed mostly flat at 30 MWs, 10 MWs offset below the site's estimated yield except for small increases in response to ACE going slightly below the lower deadband. Implementation response at the start of the test window had less of a delay than the earlier test as the difference between the initial setpoint and the new setpoint was smaller.

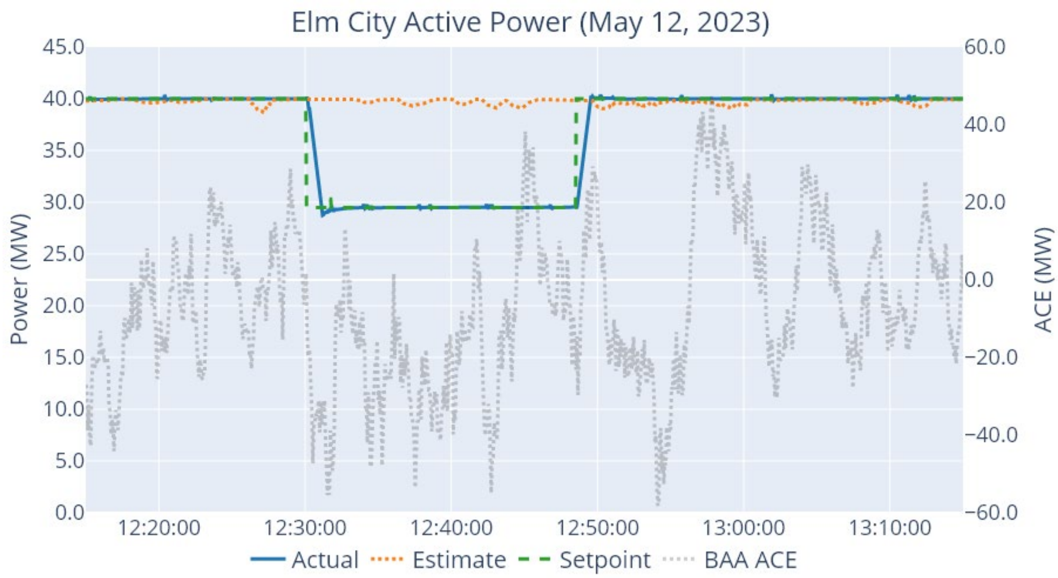

Figure 5 Elm City Second Active Power Test - Site-Level Results

Inverter-level response for the second active power test saw slightly less variability during the active power control window, but a much larger spread outside the test window. Figure 6 shows that some inverters were not able to reach the average yield, with the largest deficiency close to 20% lower than the average. All inverters reached the same active power output during the curtailment window. This larger deviation in inverter output points to the issue being proportional and most likely related to variations in panel and inverter capabilities.

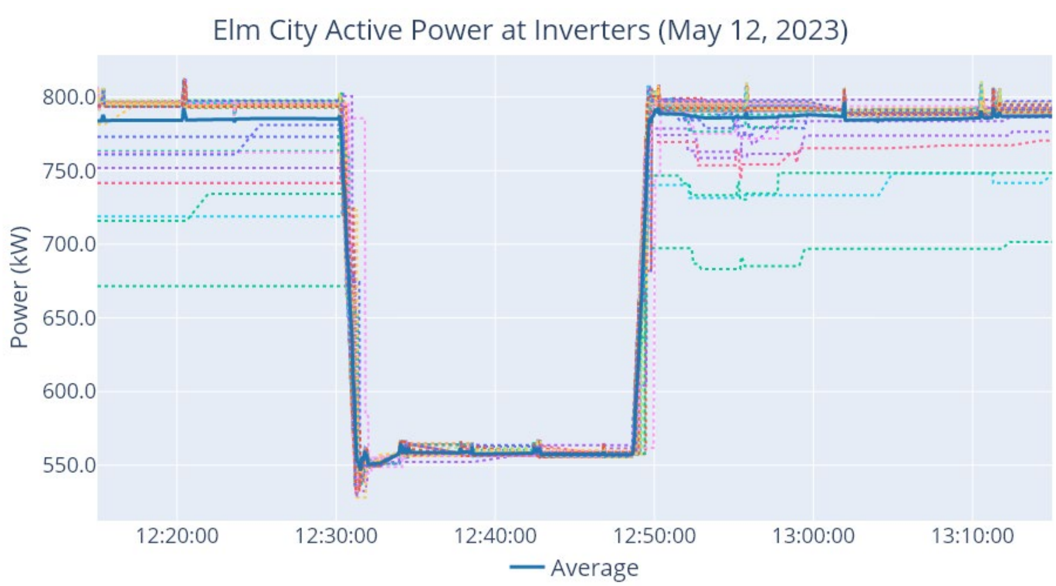

Figure 6 Elm City Second Active Power Test - Inverter-Level Results

Reactive Power Test

The Elm City reactive power test occurred in two (2) parts. The first part of the test was to manually modify the site reactive power output from zero (0) Mvar to full reactive power absorption, and the second was to determine the impact to the reactive power injections when the site active power output was reduced.

Site reactive power was increased from around 10 Mvar leading (absorbing) to zero (0) Mvar for the start of the test. Then the reactive power setpoint was stepped from zero (0) Mvar to 13 Mvar leading in increments of just over 3.1 Mvar. Site reactive power output followed the reactive power setpoint taking almost 2 minute to settle into the new setpoint value after each reactive power setpoint change.

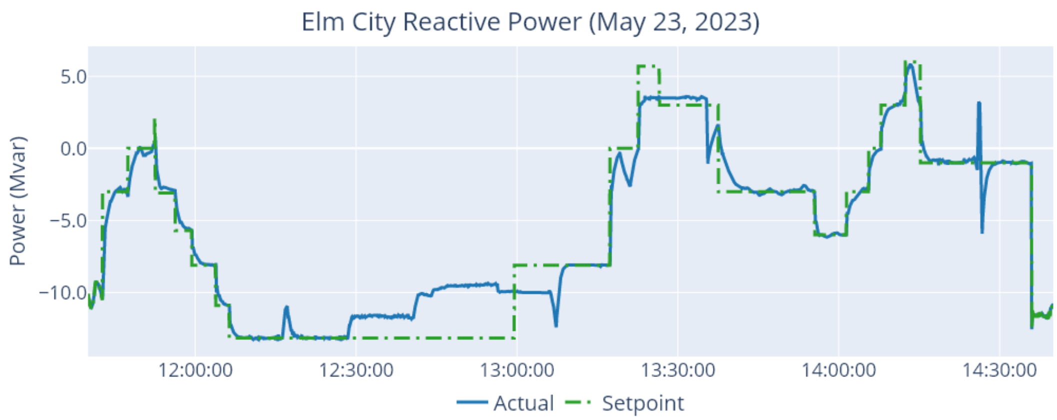

Figure 7 Elm City Reactive Power Response - Site Level

Inverter temperatures during this test rose proportionately until active power began to reduce, remaining in tolerance of the site engineering parameters.

At 13.1 Mvar leading, the site's active power was reduced from full output of 40 MW in 10 MW increments to determine if the site could maintain the level of Mvar absorption. After stepping active power output to 20 MW, reactive power absorption was reduced by approximately 1.5 Mvar. An additional 2.1 Mvar reduction occurred when the active power was reduced to 4 MW. After 20 minutes at 4 MW output, the site was returned to normal active power output.

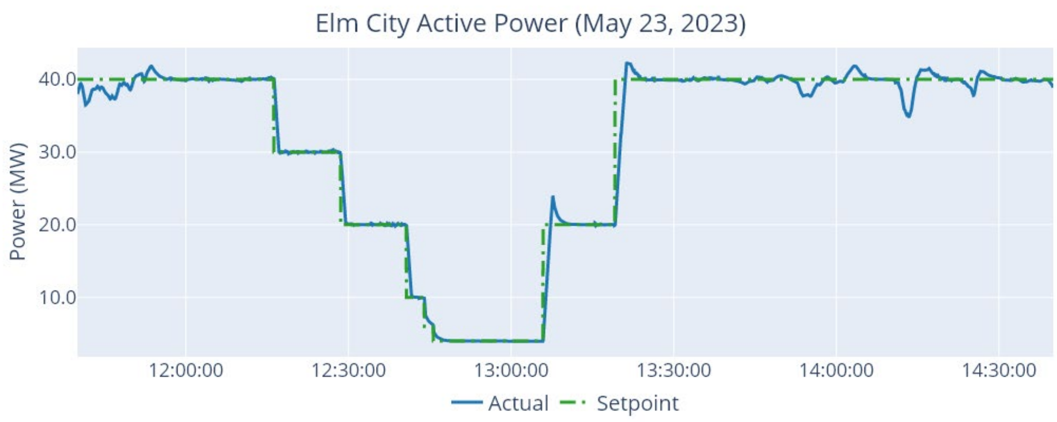

Figure 8 Elm City Active Power Response at Full Reactive Power Absorption

During this reactive power test, voltage trended down within its voltage range about 0.5 kV as expected when reactive power trended down. Bus voltage increased to approximately 1.5 kV as the reactive power moved from 13.1 Mvar leading to 3.5 Mvar lagging. The voltage increase was larger than would have occurred because a capacitor bank was energized in the region just after 12:52.

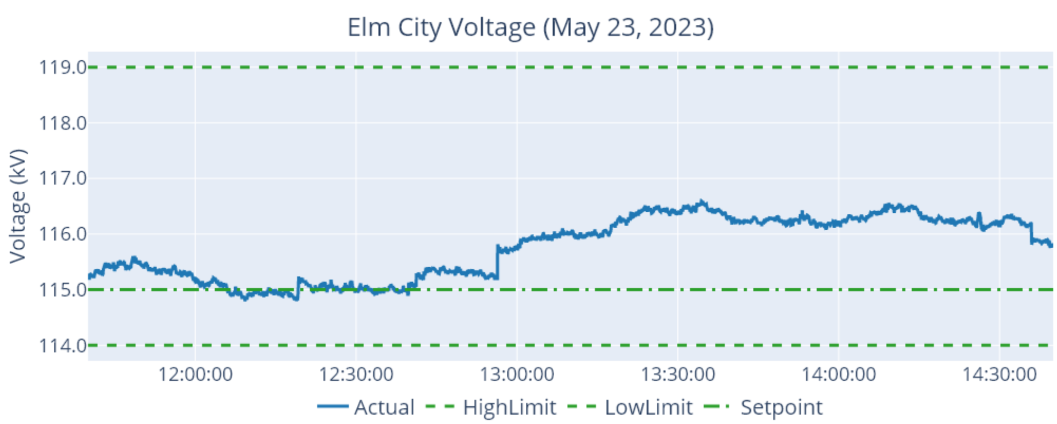

Figure 9 Elm City Voltage During Reactive Power Test

Monroe Testing

Monroe is a standalone solar facility with an active power output interconnection limit of 54.6 MWac and uses a Rockwell PPC. It has been set up with a reactive power output limits at 93% leading and 97% lagging power factor at its full interconnection output resulting a Mvar limit of +21.6/-13.7 Mvar. Monroe is also assigned a voltage schedule in which it is to operate while producing active power into the transmission system. Additionally, Monroe's voltage schedule target adjusts based on the day of the week and time of day to meet system needs as Monroe is connected at 100kV.

Active Power Setpoint Test

The active power setpoint test of the Monroe Solar facility was started just after 9:50 am, Friday, May 12, 2023. The setpoint was additionally offset to mimic frequency regulation by responding to deviations in the DUK BAA's ACE. Implementation of the setpoint was done by manually entering the newly calculated setpoint approximately every 10 seconds into the facility's PPC (PPC). Setpoint calculation subtracted 10 MWs from the estimated yield calculation and would increase or decrease the result in response to a decrease or increase in ACE in proportion to Monroe's regulation response.

At the start of the test the facility was generating 19.0 MW with output increasing as the sun continued to rise and cloud cover moved through the area. At 9:50 am, someone from the Regulated Renewable Operating Center (RROC) made the first setpoint change from forty (54) MWs to the calculated 5.4 MW and kept changing the value every 10 seconds for the next 20 minutes to follow each new setpoint result. Results of the test are seen in Figure 10 below.

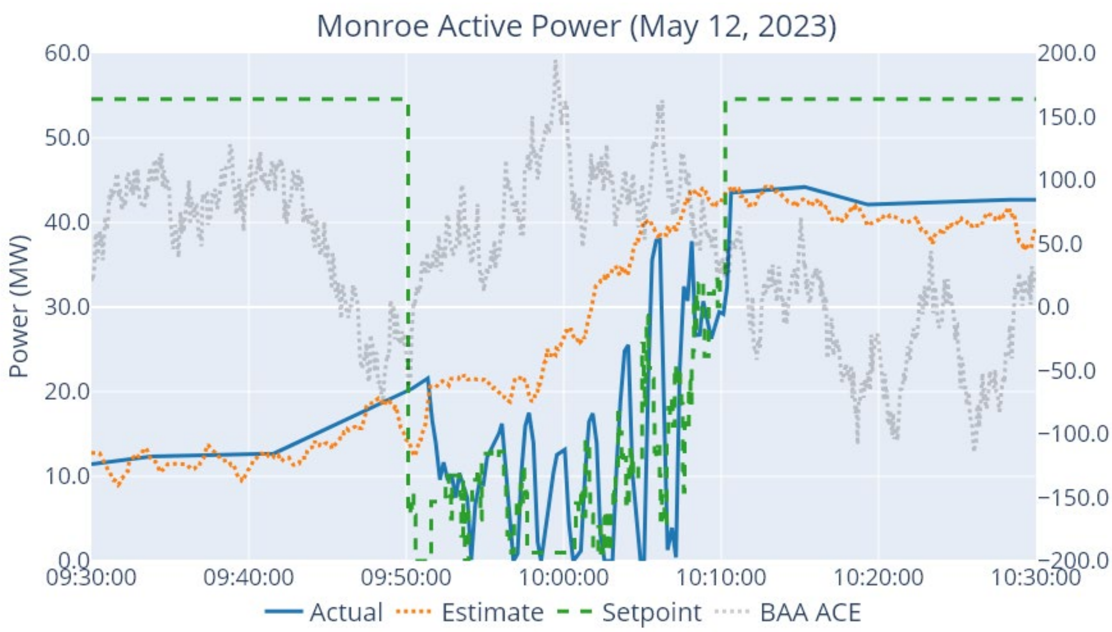

Figure 10 Monroe First Active Power Test - Site-Level Results

Like with the Elm City test, it also took this control over a minute to start responding. From 9:54 through the end of the end of the test window, ACE continually exceeded the upper deadband resulting in the setpoint changing to accommodate regulation response needs. The Monroe controller had some control response lag creating some delay in following the control setpoint. Variability of the weather along with this time delay with the plant controller increased the need for additional regulation response from other conventional resources during this test.

Also like with Elm City, individual inverters had different active power response injections due to the size of the site over many acres and the construction and performance variations between the different inverters and their associated panels. Once the site setpoint was reduced below the actual capability, all inverters maintained the same active power injection but for the small windows where the setpoint was close to the resource output capability. Inverter-level results can be seen in Figure 11.

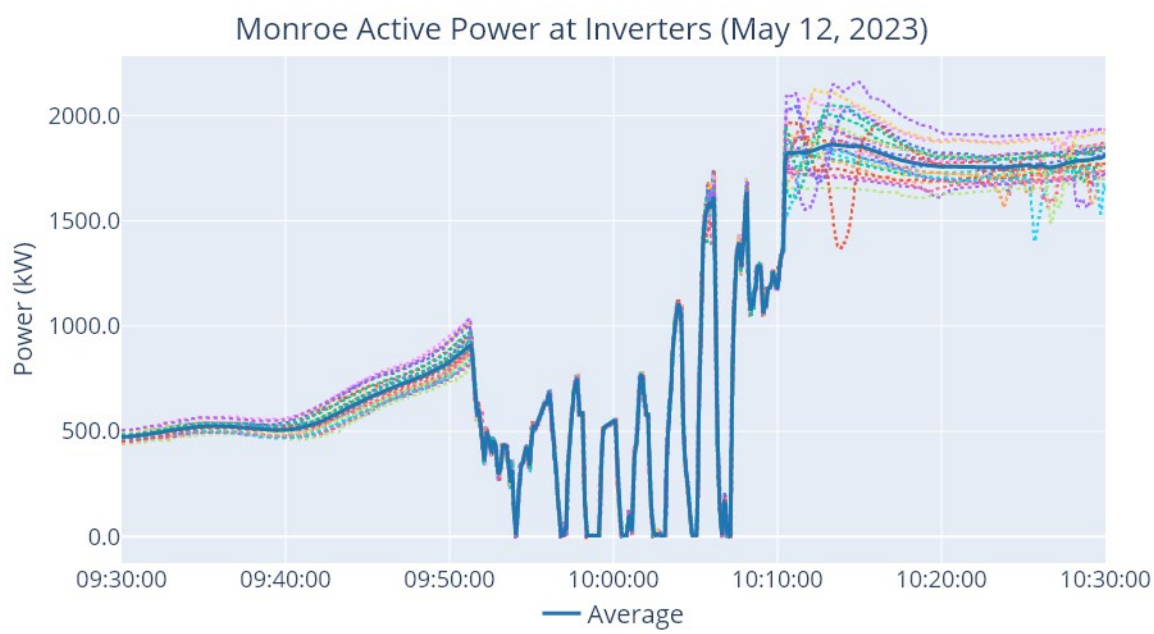

Figure 11 Monroe First Active Power Test - Inverter-Level Results

The second active power control test started at 12:00 with the site almost at full output as reflected with Figure 12. During this test, as with the morning test, the setpoint moved around as it tried to provide frequency regulation and in response to variations in cloud cover. Initially, the 10 MW setpoint was reduced due to ACE exceeding the upper deadband. At this point, the facility began to experience obscuration causing the setpoint to fall further to maintain the 10 MW offset, as frequency regulation was not needed. As the site capability continued to decline, ACE moved beyond the lower limit causing the setpoint to increase to provide regulation response. The variation in site capability due to intermittent cloud cover, coupled with frequency regulation needs continued for the remainder of the test.

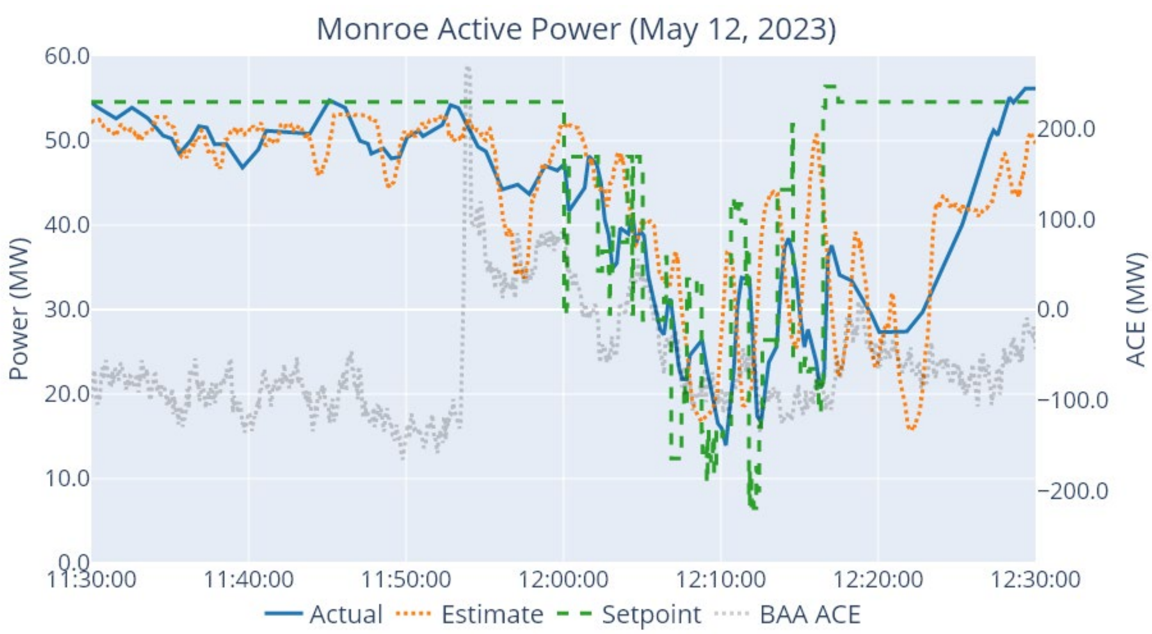

Figure 12 Monroe Second Active Power Test - Site-Level Results

Inverter-level response for the second active power test saw significant variability both during and outside the active power control window. It can be seen in Figure 13 that output between inverters varied significantly as well as response characteristics. Many of the inverters saw variations as large as 70%. This larger variation was predominantly related to variations in cloud cover.

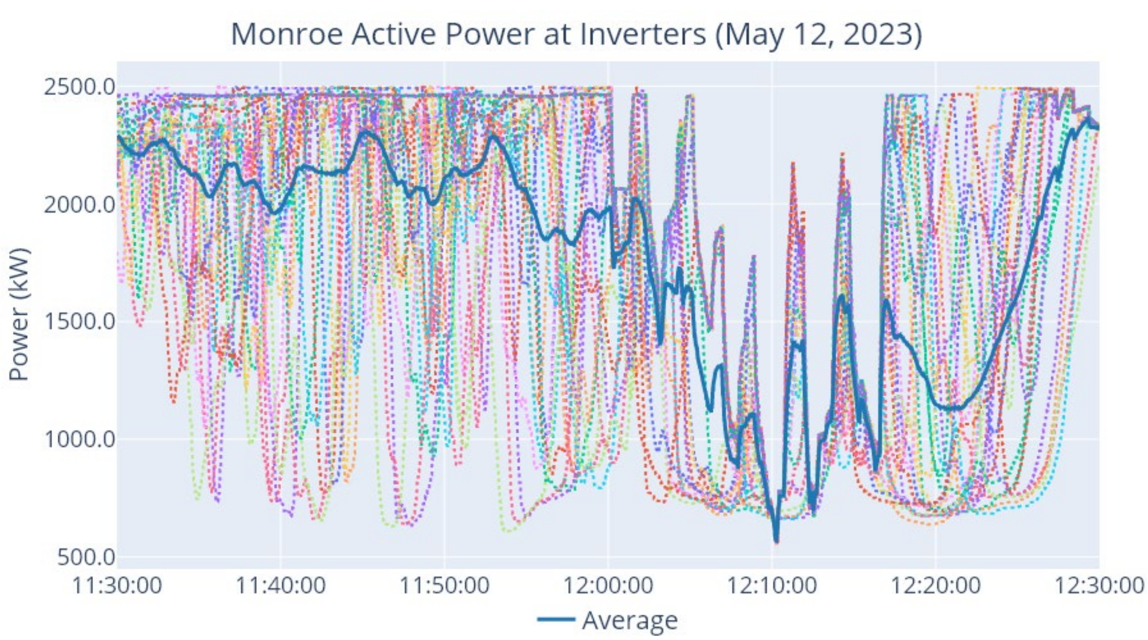

Figure 13 Monroe Second Active Power Test - Inverter-Level Results

Reactive Power Setpoint Test

On May 24, 2023, Duke Energy started to test the reactive power capabilities of the Monroe Solar site like the Elm City reactive power testing. However, the reactive power response was not properly following the manual setpoint signals being sent from RROC to the controller, so the testing was cancelled

The capability of the reactive power, Q-controller for the Monroe Solar facility was observed with PI data on May 28, 2023, to ensure the controller was still properly responding with Mvar injection/absorption for local voltage support. Figure 14 reflects this observation and concludes the Q-controller was operating properly for providing voltage support.

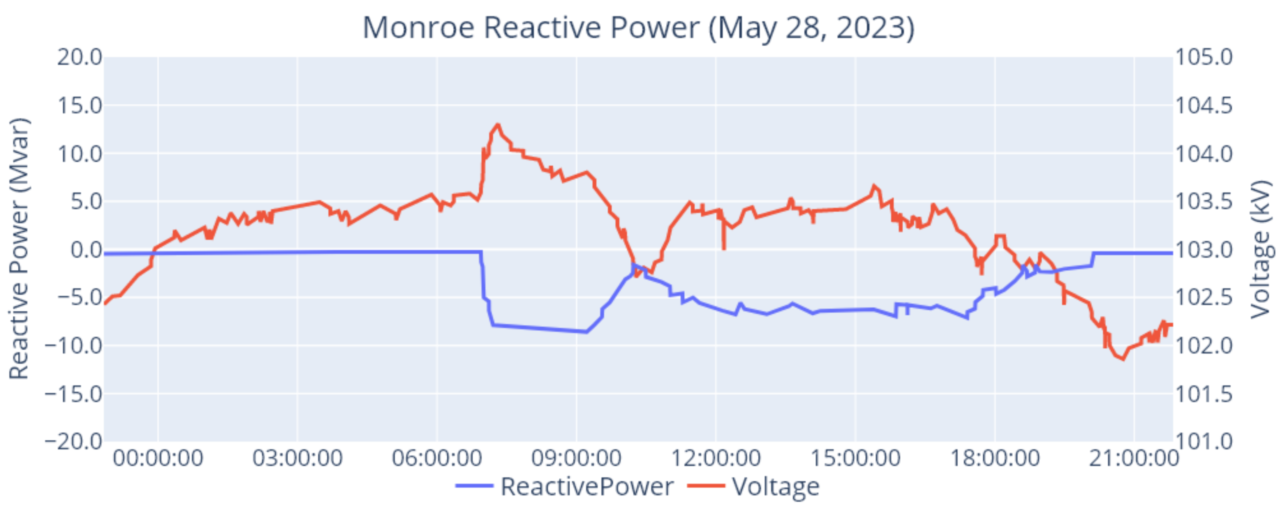

Figure 14 PI Data Reflecting Verification of Monroe Q-Controller Performance (+) Mvar = Absorbing

Asheville Rock Hill Test

During this test, the BESS active power setpoint was changed from zero (0) MW to -6.4 MW, then back to zero (0) MW, then 6.4 MW and back to zero (0) MW. These setpoint changes were implemented on 0.5 MW steps for the duration of the test. There was a control signal latency of 45 seconds identified from the time of the setpoint change to the time the response was measured. The results of this test are reflected in Figure 15.

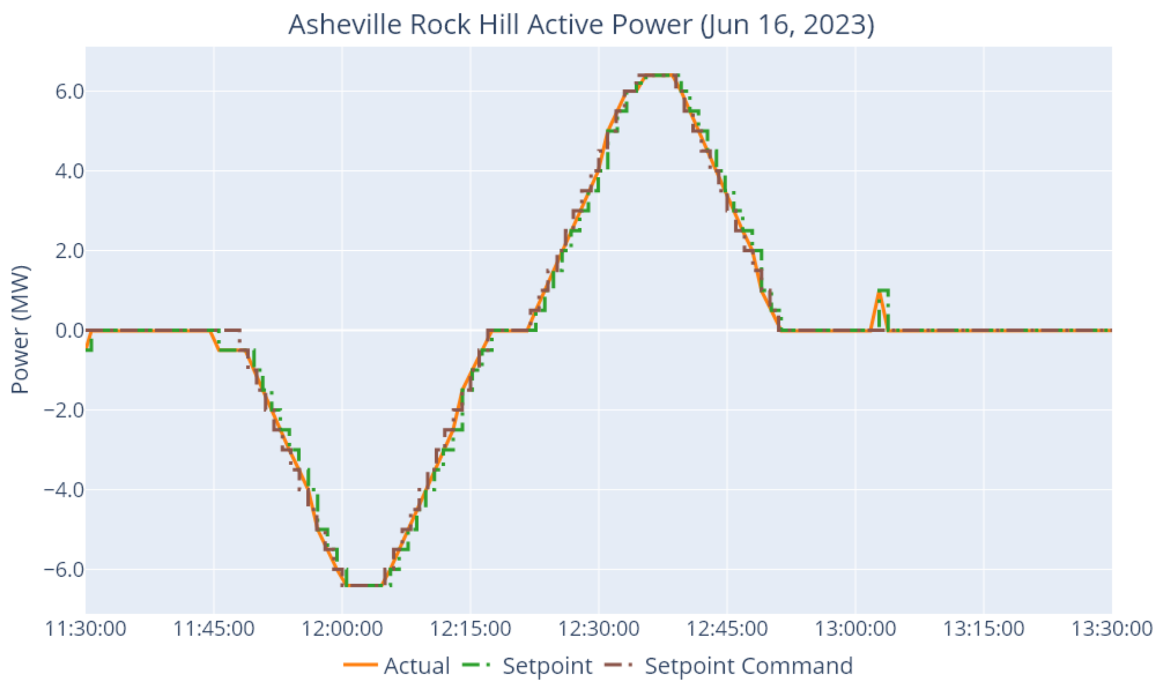

Figure 15 Asheville Rock Hill Active Power Response to Setpoint Control

Conclusions

1. While some IBRs are suitable for providing regulation, maintaining a regulation range with standalone solar on partly cloudy to mostly cloudy days is infeasible. Based on the Monroe Solar active power testing, trying to maintain the 10 MW regulation range during the intermittency created by cloud cover created the need for more regulation from conventional resources.
2. With respect to controllers, the Elm City Solar controller appeared to perform better than the Monroe Solar controller. It was observed that suboptimal control tuning can lead to a poor control system response. Parameters for IBR controls need to be tuned, verified, and tested to ensure the proper response and dampening. This control functionality comes at a cost for the testing itself, control system tuning engineers, telecommunications improvements, etc.
3. This testing highlights the importance of commissioning and monitoring of IBRs with respect to control system stability and capability to provide acceptable active power management and voltage support.
4. Reactive power management/voltage support is a service based on locational needs. This service has been provided successfully by transmission connected solar following a voltage schedule within power factor limits for several years now and will continue to be utilized from transmission-connected IBRs in the future to some degree as the locational need is determined by Transmission Planners.

Recommendations

Based on the short timeline (January – June 2023) to design and conduct the testing , additional testing with different, larger Duke-owned IBR resource types (standalone batteries and solar plus storage) could allow for design of the testing with plans to record more parameters for post testing data analytics to thoroughly evaluate the capabilities of IBRs to provide certain ancillary services. Additional testing would also allow for assessing the costs for the testing and the IBR design/modifications needed to provide the ancillary service. Duke Energy believes that further study and testing of different Duke-owned IBR resource types such as standalone batteries and solar plus storage, (resource types that will be significant in the future resource mix), will help determine whether a pilot program would be worthwhile.

This testing further illustrates that the industry must move forward with implementing enhanced commissioning and monitoring requirements for IBRs. And where monitoring reveals subpar performance, additional testing will be conducted, and recommended solutions will be provided.

CERTIFICATE OF SERVICE

I hereby certify that a copy of *Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Inverter Based Resources Testing Report* filed in Docket No. E-100, Sub 175 was served electronically or via U.S. mail, first class postage prepaid, upon all parties of records.

This the 1st day of August, 2023.

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CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service lists have been served true and accurate copies of the foregoing 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 21st day of February, 2024.

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