STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1340
DOCKET NO. E-7, SUB 1310

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1340	)	
DOCKET NO. E-7, SUB 1310	)	
	)	COMMENTS OF THE PUBLIC STAFF
Duke Energy Progress, LLC,	)	ON THE PROPOSED 2024 SOLAR
and Duke Energy Carolinas, LLC,	)	PROCUREMENT
2024 Solar Procurement Pursuant to	)	
Initial Carbon Plan	)	

NOW COMES THE PUBLIC STAFF – North Carolina Utilities Commission (Public Staff), by and through its Executive Director, Christopher J. Ayers, and responds to the Commission’s February 8, 2024 Order Initiating Proceeding and Requesting Expedited Comments (Order). The Public Staff presents its initial comments on Duke Energy Progress, LLC (DEP), and Duke Energy Carolinas, LLC’s (DEC) (together, the Companies or Duke) proposed 2024 Solar Procurement Request For Proposals (RFP) design. The Order directs parties to file comments on three discrete issues: (1) Duke’s intent to eliminate the imputation of a shadow cost to Red Zone Expansion Plan (RZEP)-dependent proposals for purposes of evaluation and ranking; (2) Duke’s proposal to use a Resource Solicitation Cluster (RSC) for the 2024 RFP; and (3) Duke’s requested extension of time to file its 2024 Solar Procurement proposal.

Regarding the first matter, the Commission requested comments on whether and how imputing a “shadow cost” to RZEP-dependent proposals in the

2024 Solar Procurement RFP could (1) increase procurement costs for customers and result in non-IRP selected resources taking advantage of the RZEP in a way that provides fewer benefits for retail/native load customers; and (2) result in non-CPIRP-selected Interconnection Customers obtaining the benefit of the RZEP transmission capacity ahead of the 2024 Solar Procurement proposals.

The Public Staff believes the shadow costs[1] from the RZEP projects should not be imputed to 2024 Solar Procurement projects, as was done in the 2023 RFP. As noted in Duke's Motion,[2] these RZEP upgrades are classified as "contingent facilities" by the Carolinas Transmission Planning Collaborative (CTPC) and the costs will not be assigned to interconnection customers in the ongoing Definitive Interconnection System Impact Study (DISIS) clusters.

As background, the 2022 Solar Procurement[3] did not include the RZEP projects in the study baseline but did allocate costs of any upgrades triggered by projects located in the red zone in the bid process. In the Commission's Order Adopting Initial Carbon Plan and Providing Direction for Future Planning, it found that the 14 RZEP Projects would allow the interconnection of approximately 3,759 MW and determined that those RZEP Projects were necessary to achieve the

[1] In the 2023 RFP, the "shadow cost" was calculated as the cost of the RZEP upgrade multiplied by the ratio of the generator's impact on the RZEP upgrade to the capacity increase caused by the RZEP upgrade and was used to evaluate and rank the bids of projects that utilized an RZEP upgrade. Those projects, however, were not actually responsible for paying those upgrade costs.

[2] Duke's Motion to Open 2024 RFP Dockets, Grant Flexibility to Administer 2024 RFP Through a Resource Solicitation Cluster, and for Extension of Time to File 2024 RFP, filed February 5, 2024.

[3] Docket Nos. E-2, Sub 1297 and E-7, Sub 1268.

mandates of N.C. Gen. Stat. § 62-110.9 in a least cost manner and that the risk of those upgrades being underutilized is low.[4] The Commission also concluded that it was important that the 2023 Solar Procurement RFP[5] impute the appropriate percentage of the RZEP Project costs to solar projects that would have triggered an upgrade but for the proactive RZEP Projects for bid evaluation purposes.[6]

Initially, the Public Staff believed the concept of imputing a shadow cost for RZEP projects was a reasonable approach for determining the "best" utilization of new transmission resources (from a cost perspective) in a given cluster study, by factoring in both the proposed bid of the project and the all-in costs when considering transmission. The all-in cost of both an individual resource and its impact on the transmission system is an important holistic aspect of competitive bid evaluation and helps guide procurement to the most optimal selection of generation resources.

When an RZEP project is designated as a contingent project, if a shadow price is not assigned, it creates a signal to developers that projects interconnecting to this line or designated area will see lower average interconnection costs and are more likely to be selected. If the selected portfolio of projects is highly concentrated around these RZEP projects, it may have the effect of quickly consuming the RZEP capacity while creating an uneven distribution of generation projects. This uneven distribution may, as loads increase and other electric generation facilities are

[4] Order at 116.

[5] Docket Nos. E-2, Sub 1317 and E-7, Sub 1290.

[6] Order at 118.

added to the system, result in the triggering of more substantial upgrades than would be required if the distribution of generation facilities was more even, while a larger distribution of projects would potentially provide other non-quantifiable benefits of a larger, more distributed area that would minimize the impacts of localized storms (e.g., rapid shadowing), as well as line outages that could cut off significant resource capacity in a concentrated area.

While the concept of a shadow cost was reasonable and served its intended purpose in the 2023 RSC, the Public Staff believes that the benefits of continuing the assignment of shadow costs, which attempt to account for long-term planning uncertainty and other non-quantifiable benefits, are now outweighed by the cost of each procurement portfolio due to the increasing procurement targets and load projections. Further, the assignment of a shadow cost risks distorting the economic ranking of projects in future RFPs. The Public Staff has always believed that any use of a shadow cost for RZEP projects could only be administered in the short term due to changing system conditions. As noted previously, as more generation and new load utilize the transmission system, the system power flows and topology will continually change, and this flux presents a challenge to the long-term reasonableness of any shadow cost.

For example, consider three hypothetical projects: A, B, and C, all seeking to interconnect to Duke's system, as shown in the below table. Assume that the RFP has procured the majority of the target capacity, and now must decide between executing a contract with Project A or B and that all other relevant evaluation factors (development risk, technology standards, etc.) are equal between Projects A and B. The Levelized Cost of Electricity (LCOE) represents the estimated cost that ratepayers will pay for the facility over the operational life. In this example, the RZEP upgrade shadow costs represent the estimated cost of RZEP upgrades that are already included in the study baseline because they have been accepted as contingent facilities by the CTPC, in a similar manner as a transmission upgrade designed for system reliability or load growth.[7]

Project	In RFP?	Consume RZEP Capacity?	LCOE	LCOE with RZEP Shadow Cost
A	Yes	Yes	$45	$65
B	Yes	No	$55	$55
C	No – in DISIS	Yes	$60	$60

Without the RZEP shadow costs, Project A is more competitive than project B and would likely be selected. However, Project B, which does not impact any RZEP projects, would be selected over Project A if RZEP shadow costs are considered, as it has a lower LCOE inclusive of the RZEP shadow costs. In the short term, this will result in higher procurement costs for customers (whether it is an asset transfer or purchased power), as they will be paying the higher LCOE for Project B.[8]

[7] The Public Staff differentiates allocating the costs of contingent facilities with the costs of new facilities. This example discusses contingent facilities. In all cases, if a project triggers a new upgrade, including an additional incremental upgrade to a contingent project, the costs of that incremental upgrade should be allocated to the project during bid evaluation.

[8] While the dollar figures are only illustrative, this is not a hypothetical situation; in the 2022 RFP, at least one project was not selected due to the imputed cost of RZEP upgrades.

Project C, which is not in the RFP and is interconnecting through DISIS, may represent a merchant plant, small power producer, or utility-owned project, and may or may not be needed to comply with the Carbon Plan. Despite consuming RZEP capacity, Project C is not assigned any of the RZEP shadow costs because projects within DISIS are not assigned the costs of contingent facilities included in the baseline.[9] Because it is not assigned RZEP shadow costs, this project may proceed to execute an interconnection agreement, claiming the RZEP transmission capacity that Project A was denied.[10]

In addition, the Public Staff notes that continuing to impute the shadow cost of the RZEP upgrades into the future, despite them being designated as "contingent facilities," would be unique in the Carolinas. To the best of the Public Staff's knowledge, for all other transmission upgrades, once a transmission project becomes part of the baseline (e.g., designated as a contingent facility), its costs are not allocated to any future generation projects that may utilize that transmission asset in future cluster studies.

In summary, if the RZEP upgrades are designed to proactively resolve congestion that is exacerbated by large amounts of generation concentrated in areas of the transmission system, while enabling the interconnection of new

[9] This is due to the rules governing interconnection. For state jurisdictional projects, the North Carolina Interconnection Procedures define Network Upgrades as "additions, modifications, and upgrades" to the transmission system beyond the Base Case. For FERC jurisdictional projects, the Large Generator Interconnection Procedures similarly establishes a Base Case and defines Network Upgrades as "modifications or additions" to the transmission system.

[10] This is not a hypothetical situation. In the 2022 DISIS, there were several projects that were not in the 2022 Solar Procurement RFP but which benefited from RZEP upgrades, although the extent to which these projects utilized the RZEP upgrades is not known.

generation resources in service of the Carbon Plan, it no longer appears appropriate to penalize projects attempting to utilize that interconnection capacity, unless there is evidence that the lack of RZEP cost allocation is leading to a disorderly utilization of the transmission system. There are confounding factors as one considers multiple annual RFP cycles and system changes in the interim; for example, a project rejected today may be able to bid in future RFPs at a lower overall price while potentially avoiding significant impacts to the transmission system within a given cluster study. However, in total, the Public Staff believes continuing to allocate RZEP costs for contingent facilities may be overly complex given the dynamics of increasing procurement targets, transition of the energy system, and load growth. The Public Staff acknowledges the possibility that continuation of the imputation of a shadow cost may result in higher procurement costs that are not offset by lower transmission upgrade costs. To the extent that discontinuing the allocation of shadow costs results in a disorderly utilization of the transmission system, the Commission could revisit what factors, including shadow costs, should be included in the RFP evaluation process.

Regarding the second issue, the Public Staff supports the use of an RSC for the 2024 Solar Procurement RFP. This process was beneficial in the 2023 RFP, in that the use of an RSC appears to have led to less volatility in the 2023 DISIS cluster.[11] While it is still early to declare the 2023 RFP a success, early signs are promising, and the Public Staff believes it would be premature to require the 2024 RFP to participate in the 2024 DISIS cluster. In addition, it may not be possible to finalize the 2024 RFP and receive Commission approval of the RFP and associated documents prior to the closing of the 2024 DISIS enrollment period. If this were to occur, 2024 RFP projects would not be able to begin the interconnection study process until mid-2025.

Finally, the Public Staff agrees that more time is needed to develop the 2024 RFP. While the 2024 RFP will be largely similar to the 2023 RFP, there are still matters that must be addressed through a stakeholder process. For example, given the extraordinary volumes of solar likely to be sought in the 2024 and 2025 RFPs, stakeholders have been discussing methods to reduce the likelihood of projects withdrawing after executing a contract (PPA or asset acquisition), as was seen in the Competitive Procurement of Renewable Energy (CPRE) program. Addressing this issue may require further detailed discussions on how to reduce the time between contract execution and commercial operation, or potential indices that might be used to adjust bid prices up or down should material changes in the market emerge after contract execution. These discussions are ongoing and could benefit from additional time.

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[11] For example, the 2022 DISIS, which included the 2022 Solar Procurement, had to conduct a Phase 3 restudy, due to the significant volume that withdrew after the Phase 2 study results were released. The 2023 DISIS is less likely to require a Phase 3 restudy, as the 5,900 MW of solar and solar plus storage projects that bid into the 2023 RFP will not affect the 2023 DISIS cluster when losing projects withdraw. Moreover, in the 2023 RSC, the losing projects withdraw prior to the Phase 2 study, making the need for a Phase 3 restudy unlikely as well.

However, the Public Staff also notes that it is imperative that Duke, stakeholders, and the Public Staff reach agreement on the parameters of the 2024 RFP as soon as possible. The 2023 CPIRP Update, filed January 31, 2024, emphasizes the need for swift and decisive action to procure resources necessary to meet the carbon reduction targets in N.C.G.S. § 62-110.9. Any significant delay to the orderly procurement of solar and solar plus storage resources puts compliance at risk.

Respectfully submitted, this the 15th day of February 2024.

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CERTIFICATE OF SERVICE

I certify that a copy of these Initial Comments of the Public Staff has been served on all parties of record or their attorneys, or both, in accordance with Commission Rule R1-39, by United States Mail, first class or better; by hand delivery; or by means of facsimile or electronic delivery upon agreement of the receiving party.

This the 15th day of February, 2024.

Electronically submitted
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