Refining the Net Excess Energy Credit to Improve Its Accuracy

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NEEC Background and Proposed NEECs

The NEEC refers to the compensation rate for monthly net excess generation under the Companies' respective Residential Solar Choice and Non-Residential Solar Choice Riders, designated Riders RSC and NSC. The same rate is used for the NEEC in both Rider RSC and Rider NSC. The rates themselves equivalent to the annualized avoided cost rates for uncontrolled solar generation interconnected to the distribution system over a five-year time horizon.[1] The present NEEC rates are set at 3.35 cents/kWh for DEC[2] and 3.40 cents/kWh for DEP.[3] The Companies propose to update those rates to 4.40 cents/kWh for DEC[4] and 3.90 cents/kWh for DEP.[5]

These comments recommend several refinements to the calculation of the NEEC to ensure that it properly values electricity exported to the grid by net metered generation. These comments on the calculation of the NEEC are limited to this specific aspect of the Companies' updated avoided cost filings rather than the parameters for establishing avoided cost rates that are more generally applicable to qualifying facilities ("QFs").

NEEC Calculation Term

In its August 2023 Order adopting the NEEC rates, the Commission approved the use of a 5-year time horizon of avoided costs for the annualized NEEC calculation, but stated an openness to further discussion of the issue.[6] The five-year time horizon was based on the recommendations of the Public Staff that the NEEC rate use a longer time horizon than what the Companies had initially proposed (2 years) since net metering generation is incorporated within the Companies' integrated resource plan ("IRP") modeling as a reduction in load, but that a 10-year term "may be too long, as there is no contractual obligation for the net metered facility to operate for that term".[7]

The August 2023 Order also noted that the North Carolina Solar Energy Association ("NCSEA") recommended a longer 10-year term because there was no basis for assuming that a net metered facility would not operate for longer than five years, most solar equipment manufacturer warranties are good for at least 10 years, and net metering customers have a strong incentive to operate their systems longer than 10 years (i.e., continued bill savings to

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[1] *See* DEC and DEP Updated Exhibits 11.

[2] DEC Rider RSC, effective January 1, 2024. https://www.duke-energy.com/-/media/pdfs/for-your-home/rates/electric-nc/ncriderrsc.pdf?rev=6708db0bd6e84039b1f3208a219e7c2e.

[3] DEP Rider RSC, effective October 1, 2023. https://www.duke-energy.com/-/media/pdfs/for-your-home/rates/dep-nc/leaf-no-668-rider-nsc-ry1.pdf?rev=f42cbbd08aab43938b0f927c6533f88a.

[4] DEC Updated Exhibit 11.

[5] DEP Updated Exhibit 11.

[6] NCUC Docket No. E-100, Sub 175. Order Establishing Net Excess Energy Credit for NEM Tariff. August 3, 2023. p. 4.

[7] *Ibid*., pp. 2-3.

recoup the initial investment).[8] The August 2023 Order contained little discussion of why Commission reached the conclusion that the use of a 5-year time horizon for calculating the avoided cost rates used in the NEEC was reasonable in light of the different recommendations made by the Public Staff and NCSEA. In particular, the August 2023 Order did not address the Public Staff's implicit assumption that there is some question as to whether a typical net metered solar system will, on average, operate for only 5 years.

We recommend that the Commission reconsider its determination that the NEEC should use a 5-year levelized avoided cost rate and instead use a rate based on a period of 10 years or longer for two reasons. First, the Public Staff's apparent concerns about the time period over which a net metered solar system can reasonably be expected to operate, and deliver value, are unfounded and in conflict with the assumptions that the Companies' use in developing the load forecast that underpins its 2023 North Carolina Carbon Plan and Integrated Resource Plan ("2023 CPIRP"). A net metered solar system, regardless of the whether it is subject to a contractual obligation, can reasonably be expected to operate for at least 20 years. This reality is reflected in the customer-sited solar forecast that the Companies' incorporated into their 2023 CPIRP, which appears to assume that a new system installed in 2023 will continue to operate through 2050.[9] That is, the Companies' calculations of expected energy and capacity from customer-sited solar systems contain no apparent adjustments or modifications for system attrition over time. Therefore, the Companies' load forecast, and the ultimate outputs from its modeling, implicitly reflect customer-sited solar facilities continuing to operate over long-term time horizon well beyond 5 years.

Second, the NEEC rate itself will be updated every 2 years in the biannual avoided cost update cycle rather than being locked-in for a longer period of time. Consequently, there is no danger that the NEEC will become outdated or stale, which is the concern that is often expressed with the establishment of long-term avoided cost rates. Rather, the NEEC will be responsive to changed system conditions and avoided cost values on a 2-year cycle even if the rate itself is calculated based on a longer time horizon.

Accordingly, we recommend that the NEEC calculation use a minimum term of 10 years consistent with the term offered under standard offer QF contracts, and that consideration be given to using a longer term (e.g., 20 or 25 years) that is more consistent with the typical lifetime of a customer-sited solar facility.

<u>Line Losses</u>

The Companies' NEEC calculations include gross-ups for line losses varied by the avoided cost pricing periods using the same amounts applied for distribution-interconnected QFs.[10] The Companies' workpapers indicate that line losses are calculated for the categories of: (a)

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[8] *Ibid.,* pp. 3-4.

[9] NCUC Docket No. E-100, Sub 190. Response to Public Staff 3-17, Attachments. The Attachment includes hard-coded values for "degraded" capacity and energy generation, but we believe that this is in reference to panel degradation rather than system inoperability.

[10] Companies' response to SACE 1-3, Worksheet entitled "SACE-1-3_Calc_Confidential.xlsx."

generator step-up, (b) transmission line, and (c) transmission/distribution transformation.[11] Of note, the loss factors do not include a category for distribution line losses. This is appropriate for in front of the meter QFs that export substantial quantities of energy to the distribution grid since that electricity would serve demand at locations remote from the generation facility. However, the same is not true for net metered systems, whose exports are likely to serve loads in close proximity to the system (e.g., a residential net metering customer's next door neighbor) and therefore incur minimal distribution line losses. Accordingly, it is appropriate for the NEEC calculation to incorporate a distribution line loss factor in addition to the line loss factors used for distribution-connected QFs.[12]

Avoided Transmission and Distribution Costs

In the August 2023 Order establishing the parameters for the NEEC, the Commission determined that it would be "appropriate to revisit the appropriate NEEC and whether avoided T&D and carbon costs should be included in the calculation of the NEEC in future avoided cost proceedings."[13] The Companies' avoided cost filings in this docket did not address the inclusion of either an avoided transmission or avoided distribution cost component within the NEEC, and it seems likely that they will continue to ignore the topic unless the Commission initiates a further investigation.

To be clear, we do not recommend that the Commission "speculate" on the matter of avoidable T&D costs. However, we also observe that: (a) a sound analytical methodology should alleviate such concerns, and (b) there is precedent in other jurisdictions with the inclusion of avoided T&D costs in both analytical studies and the establishment of compensation rates for distributed solar projects. The examples of avoided T&D costs being incorporated into specific rates include, but are not necessarily limited to, the following:

- California: The California Public Utilities Commission ("CPUC") so-called Avoided Cost Calculator ("CA ACC") tool calculates hourly avoided cost values for distributed energy resources ("DERs") over a 30-year time horizon.[14] The CA ACC was historically used primarily for long-term cost-effectiveness evaluations, but in December 2022 the CPUC adopted a net billing tariff under which compensation for exports from customer-sited solar facilities are based primarily on CA ACC rates.[15]

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[11] See for example the Companies' response to AGO 1-7, Attachment entitled "DEC-Losses-Energy-All-Summer-2023-Confidential", in tab labeled "Loss Factors-Energy Summary all".

[12] For clarity, the loss factor could reasonably exclude variable distribution transformer losses because net metering exports would in most cases travel through the distribution transformer in order to reach an end load.

[13] NCUC Docket No. E-100, Sub 175. Order Establishing Net Excess Energy Credit for NEM Tariff. August 3, 2023. p. 4.

[14] *See* the 2022 Distributed Energy Resources Avoided Cost Calculator Documentation (Version 1b, September 15, 2022), available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2022-acc-documentation-v1b-updated.pdf

[15] CPUC. Docket No. R.20-08-020. Decision Revising Net Energy Metering Tariff and Subtariffs (D.22-12-056). December 15, 2022. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K043/500043682.PDF

- Utah: In October 2020 the Utah Public Service Commission ("UT PSC") adopted a net billing tariff for customers of Rocky Mountain Power under which exports from customer-sited solar systems are compensated at a value-based rate that includes avoided transmission and distribution components derived from marginal costs applied to representative export profile.[16]
- Minnesota: Minnesota's Value of Solar ("VOS") rate, which was used to establish bill credit rates for community solar subscriptions from 2017-2023,[17] utilized a 25-year levelized avoided cost rate including both transmission and distribution components.[18]
- Kentucky: Kentucky's net metering successor design ("NMS II) establishes an export credit rate for the "dollar value" of excess customer generation that includes transmission and distribution components based on a 25-year levelized rate applied to expected deferrable future investments.[19]

It is important that the parameters for such further consideration be established now even if specific rates are not adopted in order to ensure that the requisite information is available for review in future proceedings. Our comments below recommend a methodological framework in broad terms that could be implemented either in the current proceeding if the necessary data can be assembled, or in a subsequent update if it cannot.[20]

Avoided Transmission Costs

It is well-established that the combination of load growth and the evolution of the Companies' fleet of available generation resources (either owned by the Companies or third parties) will create a need for new transmission development and the incurrence of incremental transmission costs. The Companies' CPIRP incorporates consideration of the costs associated with transmission upgrades, shown below in Figure 1 for the P3 portfolio as identified in the Companies' August 17, 2023 CPIRP filing.[21]

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[16] UT PSC. Docket No. 17-035-61. Order issued October 30, 2020. https://pscdocs.utah.gov/electric/17docs/1703561/3161911703561o10-30-2020.pdf

[17] 2023 HF 2310 mandated the use of a different methodology for establishing bill credit rates for new community solar facilities enrolled in the program starting January 1, 2024. *See* Minnesota 2023 Session Law No. 60. Enacted May 24, 2023. https://www.revisor.mn.gov/bills/bill.php?b=house&f=HF2310&ssn=0&y=2023

[18] Minnesota Public Utilities Commission. Docket No. E-002/M-13-867. Order Approving Value of Solar Rate for Xcel's Solar Garden Program, Clarifying Program Parameters, and Requiring Further Filings. September 6, 2016. https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={01EC193B-0588-4371-B601-F0E0AA9D4D2D}&documentTitle=20169-124627-01

[19] Kentucky Public Service Commission. Case No. 2020-00174. Order issued May 14, 2021. https://psc.ky.gov/pscscf/2020%20Cases/2020-00174//20210514_PSC_ORDER.pdf

[20] Our recommended methodological framework is informed by, but not identical to, the examples noted in California, Utah, Minnesota, and Kentucky.

[21] NCUC Docket No. E-100, Sub 190. Verified Petition For Approval of 2023-2024 Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas LLC and Duke Energy Progress LLC. Appendix L, p. 39. August 17, 2023.

Figure 1: Forecasted CPIRP Transmission Costs

Table L-9: Portfolio P3 Base Transmission Upgrade Cost Estimate ($M)

Transmission Area	2030	2035
DEC	$1,489	$5,397
DEP	$1,323	$3,378

The interconnected character of the transmission system, factors and uncertainties involved, and typically "lumpy" nature of transmission investment generally makes the evaluation of avoidable investments somewhat challenging. However, for the purposes of the NEEC, we believe that a reasonable estimate can be arrived by examining how the Companies' forecasts of transmission costs under its preferred portfolio would change under the sensitivities that were evaluated for the low, base, and high forecasts of customer-sited solar generation. Such an evaluation would identify the incremental transmission costs associated with varying levels of growth in customer sited solar for which the differences reflect the marginal transmission costs associated with more (or less) customer-sited solar generation.

The differences in capital investment costs can be readily translated into differences in the present value of revenue requirements for the different scenarios, which can then be translated into an avoided cost rate by dividing that amount by the differences in customer-sited solar energy generation in each scenario. Such an approach would implicitly incorporate consideration of the variety of factors that influence transmission planning and investment according to the best available information on Companies expect to evolve their system over the course of the coming years and on which they heavily rely for investment decisions.

We recommend that the time horizon used for the comparison be aligned with the time horizon that we recommend for calculating the NEEC more generally, a minimum of 10 years. Given that the Companies' CPIRP frequently presents portfolio level data using a time horizon through 2035 (e.g., Figure 1), the period through 2035 could be reasonable for this purpose although a longer time horizon merits consideration given the typical useful operational life of a customer-sited solar system and the fact that the Companies' customer-sited solar forecasts extend through 2050.

With respect to the specific comparison of customer-sited solar deployment scenarios, we recommend that the calculation use an average of the low-to-base and base-to-high scenarios because there is no clear reason why one scenario is more accurate or likely than the other. Using an average would also likely result in lower volatility in the avoided transmission cost rate in future updates in the event that there are significant differences between the two metrics. Again, as we discussed above regarding the term of the NEEC calculation, the avoided transmission cost value would still be updated on a biennial basis, allowing it to change in response to evolving system conditions and investment needs.

Avoided Distribution Costs
There are two primary inputs that are necessary to construct a calculation of avoided distribution systems, as follows:

1. An accepted figure for marginal distribution costs, typically stated in terms of $/kW unit costs.
2. An acceptable methodology for determining the effectiveness of a given resource at contributing to reduced distribution loads, which can be referred to as the *effective capacity* and is typically denominated as a percentage (%).

The Companies' avoided generation capacity cost calculations for uncontrolled solar generation utilize these basic inputs, applying marginal generation capacity costs across the time windows when capacity is needed and calculating avoided cost rates based on the coincidence of a solar production shape with those time periods.

A Commission-accepted figure for marginal distribution costs has already been established for use in evaluating the cost-effectiveness of the Companies' EE/DSM filings, which were used by the Companies in their marginal cost study evaluating the proposed residential Solar Choice tariffs.[22] What remains is a further evaluation of the relative coincidence of customer-sited solar generation with the distribution peaks that cause the need for additional distribution system investments. Our understanding of the Commission's discussion of avoidable T&D costs in its August 2023 Order establishing the current NEEC methodology is that the Commission has lingering concerns on the matter of the effectiveness of customer-sited solar at reducing distribution loads.

In order to address those concerns, we recommend that the effective capacity determination be made using analyzing the timing of circuit-level peaks throughout the year varied by month and time of day as a starting point for further discussion.[23] The end result of such an analysis would be the assignment of a weight for each hour of a 12 month X 24 hour representation of those peaks, to which a solar generation profile can then be applied. This hourly mapping process could be accomplished using the count, or number, of distribution circuits that have historically peaked during a given hour, or be weighted accordingly to the load served by an individual circuit.

For instance, if there are 1,000 circuits for which data is available on the time of the circuit peak and 10 of those circuits peak during a given hour (e.g., the hour ending 5 PM in August), that

[22] NCUC Docket No. E-100, Sub 180. Public Staff Initial Comments. March 29, 2022.
[23] This basic hourly mapping methodology is similar to how the CA ACC addresses distribution avoided costs, although the CA ACC incorporates additional complexities, such as locational marginal costs and an 8760-hour multi-year framework that uses weather normalized forecasted distribution peaks and other adjustments necessitated by an 8760 hour allocation regime. For further details, see the 2022 Distributed Energy Resources Avoided Cost Calculator Documentation (Version 1b, September 15, 2022), available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2022-acc-documentation-v1b-updated.pdf

hour would receive a 1% weight in the calculation of effective solar capacity. The hourly weight for each hour of a 12 month X 24 hour peak profile is then multiplied by a representative solar capacity factor for those hours and the hourly results summed to produce an overall solar effective capacity factor that represents the alignment of solar production with distribution peaks.

This basic methodological framework could be further refined if sufficient data is available to do so, including but not limited to in the following ways:

- Using multiple years of distribution peak data.
- Using forecasted distribution peak data rather than historic data.
- Developing a further weighting factor based on the capacity of net metered systems on individual distribution circuits.

As alluded to above, establishing a durable methodology would benefit from additional discussion that addresses details such as data needs and data availability and potential refinements to the framework described above that could be deployed initially, or phased in over time. We look forward to engaging in such discussions in this and subsequent avoided cost proceedings.