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October 22, 2021

VIA ELECTRONIC FILING

Ms. A. Shonta Dunston
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Eighth Joint 45-Day Progress Report
Docket No. E-100, Sub 167

Dear Ms. Dunston:

Enclosed for filing in the above-referenced docket is the Eighth Joint 45-Day Progress Report of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC.

If you have any questions, please do not hesitate to contact me.

Sincerely,

Kendrick C. Fentress

Kendrick C. Fentress

Enclosure

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Eighth Joint 45-Day Progress Report, in Docket No. E-100, Sub 167, has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, properly addressed to parties of record.

This the 22nd day of October, 2021.

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 167

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:		
	)	**EIGHTH JOINT 45-DAY**
Biennial Determination of Avoided Cost	)	**PROGRESS REPORT OF DUKE**
Rates for Electric Utility Purchasers from	)	**ENERGY CAROLINAS, LLC**
Qualifying Facilities – 2020	)	**AND DUKE ENERGY**
	)	**PROGRESS, LLC**

NOW COME Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies") by and through counsel, and pursuant to the *Order Granting Continuance and Establishing Reporting Requirements ("Reporting Order")*, issued by the North Carolina Utilities Commission ("NCUC" or "Commission") on October 30, 2020, and *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* issued on August 13, 2021 ("2020 Sub 167 Order"), and hereby respectfully provide this eighth 45-day report on their progress in addressing certain additional issues for the November 2021 avoided cost proceeding, Docket No. E-100, Sub 175. Specifically, the Reporting Order directed the Companies to file by December 7, 2020, and every 45 days thereafter, a proposal, including a timeline, of how the Companies intend to address each of the "Sub 158 Additional Issues," as discussed in the Reporting Order and further detailed herein. The Companies' progress report to the Commission on the Sub 158 Additional Issues is as follows:

Background

On August 13, 2020, the Commission issued an *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing*, which initiated the 2020 biennial proceeding for determining each utility's avoided costs with respect to rates for purchases from qualifying facilities pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") and the Federal Energy Regulatory Commission's ("FERC") regulations implementing those provisions, as well as North Carolina's PURPA implementation statute, N.C. Gen. Stat. § 62-156 ("Scheduling Order").

The Scheduling Order noted that the Commission's April 15, 2020 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* issued in Docket No. E-100, Sub 158 ("Sub 158 Order") set forth a number of additional issues to be addressed by the utilities in their initial November 1, 2020 filings in Docket No. E-100, Sub 167. These issues include:

- Real-time pricing tariffs;
- Cost increments and decrements to the publicly available combustion turbine cost estimates;
- The use of other reliability indices, specifically the Equivalent Unplanned Outage Rate ("EUOR") metric, to support development of the performance adjustment factor ("PAF");
- The extent of backflow at substations;
- The potential for qualifying facilities ("QFs") to provide ancillary services and appropriate compensation; and
- The results of an independent technical review of the Astrapé Study solar integration services charge ("SISC") methodology.

("Sub 158 Additional Issues")

On October 20, 2020, DEC, DEP, and Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina ("DENC") filed a Notification of Intended Compliance with N.C. Gen. Stat. § 62-156(b), Request for Continuance of Compliance with Certain 2020 Filing Requirements and Request to Prospectively Modify Timing of Biennial

Proceedings ("Continuance Motion"). In their Continuance Motion, the Companies and DENC noted FERC's issuance of Order No. 872 on July 16, 2020, as potentially identifying new avoided cost rate setting methodologies and addressing a number of issues that have the potential to impact the Companies', DENC's and the Commission's implementation of PURPA in North Carolina, once the amended regulations become effective December 31, 2020. The Companies proposed undertaking a critical and comprehensive analysis of the FERC's recently amended PURPA regulations to be able to more fully comment on them in an avoided cost filing.[1] Accordingly, the Companies and DENC requested, among other things, a continuance for addressing the Sub 158 Additional Issues until November 1, 2021. Through its Reporting Order, the Commission allowed the request and directed the Companies to file their plans to address the Sub 158 Additional Issues in the November 2021 avoided cost filing through an initial filing on December 7, 2020, and to thereafter provide updates on their progress on the Sub 158 Additional Issues at least every 45 days until the issues are fully addressed.

On August 13, 2021, the Commission issued the 2020 Sub 167 Order deciding all issues in the 2020 biennial avoided cost proceeding. Through that Order, the Commission found that DEC and DEP have complied with the requirements of the Reporting Order in filing 45-day updates detailing the Companies' progress addressing the Sub 158 Additional Issues to date.[2] The 2020 Sub 167 Order directed DEC and DEP to continue filing progress

[1] *See Order No. 872,* 172 FERC ¶ 61,041, *clarified in part*, *Order No. 872-A*, 173 FERC ¶ 61,158 (Nov. 19, 2020). Order No. 872's revisions to FERC's regulations implementing PURPA became effective December 31, 2020, which is 120 days after publication of the final rules in the Federal Register (85 FR 54638, published Sept. 2, 2020). *See* Order No. 872, at ¶ 753; PURPA then provides state regulatory authorities with one year to determine how to implement the new regulations for Utilities for which it has ratemaking authority. *See* 16 U.S.C. § 824a–3(f)(1).

[2] 2020 Sub 167 Order, at 58.

updates until the additional issues are fully addressed or until the filing of proposed rates and terms on November 1, 2021, in Docket No. E-100, Sub 175.

The Companies provide this final update to the Commission and other interested parties on their progress in addressing the Sub 158 Additional Issues, as follows:

Update on Activities to Address Sub 158 Additional Issues

- **Real-Time "As Available" Pricing Tariffs**

The Companies held an initial discussion with the Public Staff on June 16, 2021 to discuss the Commission's prior directives on this issue, to evaluate the new as-available rate options under Order No. 872, and to consider proposed options for creating more real-time as-available avoided energy cost pricing and rate options for QFs in North Carolina. On September 20, 2021, the Companies held a stakeholder meeting with the Public Staff, North Carolina Sustainable Energy Association ("NCSEA"), Southern Alliance for Clean Energy ("SACE"), Carolinas Clean Energy Business Alliance ("CCEBA") and other interested stakeholders on this issue. At the meeting, the Companies shared their proposal to use an increments and decrements marginal energy cost pricing methodology for calculating as-available rates. Under the Companies' proposal, as-available rates would be calculated based on actual marginal costs at the time of delivery rather than the current two-year fixed "variable energy rate" in Schedule PP. The presentation shared with the stakeholder group at the September 20 meeting is attached as Attachment 1.

- **Cost Increments and Decrements to the Publicly Available Combustion Turbine Cost Estimates**

The Companies held an initial discussion with the Public Staff on April 6, 2021 to discuss the Commission's prior directives on this issue, and proposed options for potential increments and decrements to combustion turbine cost estimates that should be considered in developing avoided capacity rates under the peaker methodology. The Companies and the Public Staff held additional discussions on the proposed CT cost calculation methodology on June 17, 2021. On August 19, 2021, the Companies held a stakeholder meeting with NCSEA, SACE, and CCEBA, as well as the Public Staff to discuss this issue. Finally, the Companies and DENC jointly discussed their proposed CT cost calculation methodology with the Public Staff on October 12, 2021, and the Public Staff has confirmed that it supports the Companies' use of publicly available data with regional and state-specific adjustments, but reserves the right to review and comment upon those adjustments during the proceeding. A copy of the presentation shared at the October 12 meeting is attached as Attachment 2.[3]

- **The Use of Other Reliability Indices to Support Development of the PAF**

In its Sub 158 Order, the Commission concluded that the PAF calculations proposed by the Companies in their November 1, 2018 Joint Initial Statement were consistent with the Commission's October 11, 2017 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* in Docket No. E-100, Sub 148 and appropriate for purposes of that proceeding. The Commission, however, also accepted the Public Staff's recommendation to consider other reliability metrics, specifically the EUOR. Accordingly, the Commission directed the Companies and the Public Staff to address the appropriateness of using EUOR as an alternative to the Equivalent Availability ("EA") method. The Companies held an initial discussion with the Public Staff on March 11, 2021 to discuss the Commission's prior directives on this issue, and proposed options for developing the PAF for use in the upcoming 2021 avoided cost proceeding. The

[3] Figures presented in this presentation were preliminary as of October 12, 2021 and are subject to finalization by DENC and the Companies.

Companies have continued discussions with the Public Staff on this issue and engaged with both the Public Staff and DENC regarding the benefits of alignment of the PAF reliability metric between the utilities. The Companies additionally engaged NCSEA, CCEBA, and SACE on this issue at the August 19 stakeholder meeting. On October 11, 2021, the Companies met with the Public Staff to discuss a number of issues related to their planned November 1, 2021 avoided cost filing. As part of that meeting, the Companies again discussed the PAF calculation methodology. Following the meeting, the Public Staff indicated that it supports the Companies' proposal regarding PAF calculation methodology.

- **<u>The Extent of Backflow at Substations</u>**

The Companies addressed this issue in their Joint Initial Statement filed in this docket on November 2, 2020, at pages 23-25, as well as in their Reply Comments filed March 5, 2021, at pages 14-15. As addressed in the Companies' Reply Comments, the Companies plan to further analyze the geographical concentrations of back-feeding substations on their systems and whether an updated rate design with and without a line loss adder based on the amount of back-feeding at a substation would be appropriate in order to provide appropriate market-based signals to QFs regarding the value of the energy at the selected location. The Companies met with the Public Staff on June 23, 2021, to discuss the issue of line losses and geographical concentration of back-feeding substations on their systems. The Companies engaged NCSEA, CCEBA, and SACE on this issue at the August 19 stakeholder meeting. Finally, the Companies revisited their analysis of substation backflow at the October 11 meeting with the Public Staff. The Companies proposed to maintain the line loss adder for standard offer-eligible distribution-connected QFs contracting under Schedule PP, but to address backflow at QFs greater than 1 MW on a case-by-case basis. The Public Staff indicated that it has no objection to the general proposal but stated that it plans to further investigate the proposal through discovery and comments.

- **The Potential for QFs to Provide Ancillary Services and Appropriate Compensation**

The Companies previously addressed the complexity of this issue, in part, in the Joint Report that they filed with DENC on the Storage Retrofit Stakeholder Meetings in Docket No. E-100, Sub 158 on September 16, 2020 ("Stakeholder Report"). In that Stakeholder Report, the Companies cited regulation and balance ancillary services for offsetting solar volatility as the only quantified ancillary service eligible for payment in North Carolina. These two ancillary services were quantified for purposes of quantifying solar integration costs only after a contentious and lengthy proceeding in Docket No. E-100, Sub 158. To date, no QFs have demonstrated their ability to avoid imposing increased ancillary costs by operating as controlled solar generators. Therefore, the Companies continue to contend that this complex issue requires additional technical, legal, and regulatory review. Primarily, with respect to the potential of QFs providing ancillary services, the Companies will continue to consider how to hold their customers harmless from costs incurred by the Companies from the addition of intermittent QFs and any potential provision of ancillary services from QFs. The Companies had preliminary discussions of this issue with the Public Staff in the context of the recent Storage Retrofit Stakeholder Meetings. In addition, the Companies discussed this issue with the Public Staff, NCSEA, CCEBA, SACE, and other stakeholders at the September 20 stakeholder meeting. As addressed in that presentation, the Companies are not aware of any vertically-integrated electric utility that is relying upon QFs to provide positive ancillary services and, furthermore, believe that the full avoided cost rates paid to QFs in North Carolina already compensate QFs for any ancillary services benefits associated with capacity and energy that the QF delivers to DEC or DEP and that the Companies purchase at avoided costs. Accordingly, DEP is not planning to present any proposals to obtain ancillary services from third-party QFs in its Joint Initial Statement. A copy of the presentation shared at the September 20 stakeholder meeting is attached as Attachment 3.

- **The Results of an Independent Technical Review of the Astrapé Study SISC Methodology**

As discussed in prior Reports, the Companies completed formation of the SISC independent technical review committee ("TRC") in early March 2021. Technical experts from the Pacific Northwest National Laboratory, the National Renewable Energy Laboratory, and Lawrence Berkeley National Laboratory participated in the TRC as "Technical Leads" for the purpose of supporting an in-depth technical review of the SISC study methodology and modeling. Representatives from the Public Staff and the South Carolina Office of Regulatory Staff ("SC ORS") also participated in the TRC as "regulatory observers." The Brattle Group ("Brattle") acted as the TRC Principal consultant. Brattle independently coordinated the TRC meetings with the Technical Leads and regulatory observers and authored the TRC report for the Companies to incorporate into their 2021 avoided cost filings in North Carolina and South Carolina.

Draft integration charge results were calculated by Astrapé Consulting, LLC and first presented at the May 21 TRC meeting. Further iterations were completed based on comments and feedback from the TRC, and the last iteration of SISC results were presented by Astrapé at the July 16 meeting. The TRC has concluded that its SISC review is complete and Brattle released the final TRC report on August 31. The Companies coordinated a presentation by the TRC to interested stakeholders on September 2 to describe the results of the SISC independent technical review, as summarized in the TRC's report. The Companies revisited their updated SISC analysis at the October 11 meeting with the Public Staff, and the Public Staff stated that it agreed with the TRC Report's findings and recommendations and supports the updated SISC methodology presented in the updated Astrapé Consulting report.

- **<u>FERC's Order No. 872</u>**

The Companies are continuing to review Order No. 872 and its impact on PURPA implementation in North Carolina. At the September 20, 2021 stakeholder meeting, the Companies addressed their planned implementation of Order No. 872. Specifically, the Companies explained that they recognize potential benefits of Order No. 872's new rate setting options to ensure accuracy of avoided cost rates and mitigate over-payment risk for customers but are not proposing significant changes to methodology/framework for setting long-term avoided cost rates for either Standard Offer or Large QFs. The Companies are proposing to update the Schedule PP as-available rates consistent with new Order No. 872 guidance and also plan to incorporate the new commercial viability and financial commitment requirements to establish a legally enforceable obligation as part of updating the Notice of Commitment form. A copy of the presentation shared at the September 20 stakeholder meeting is attached as <u>Attachment 4</u>.

<u>Other Issues On Which the Companies Are Seeking Consensus Prior to the November 1, 2021 Avoided Cost Filing</u>

In addition to the Sub 158 Additional Issues, the Companies have also made efforts to engage with the Public Staff on a number of additional issues that have been contested in prior avoided cost proceedings in an attempt to reach consensus in advance of their

November 1, 2021 Avoided Cost filing.[4] Notable issues discussed included the appropriateness of continuing the natural gas price forecasting methodology and avoided fuel hedging adjustment methodology adopted by the Commission in calculating avoided energy rates, updating first year of capacity need, and capacity and energy rate design issues, including the treatment of start costs in production modeling.[5] Each of these issues was discussed at the Companies' October 11 meeting with the Public Staff. As a result of these discussions, the Companies and the Public Staff have agreed to support the Companies' continued use of forward natural gas prices for eight years before using fundamental forecast data for the remainder of the planning period in calculating avoided energy rates, consistent with the Commission-approved methodology in the 2020 Sub 167, 2018 Sub 158 and 2016 Sub 148 proceedings. With respect to inclusion of an avoided fuel hedging adjustment in calculating avoided energy rates, the Companies and the Public Staff agreed that it would be appropriate for the Companies to calculate an avoided fuel hedge value using a methodology consistent with the methodology that the Commission approved for DENC in the 2020 Sub 167 proceeding and prior 2018 Sub 158 proceeding. The Public Staff stated that the Companies' capacity and energy rate designs and first year of capacity need require additional investigation and that the Public Staff plans to address these issues in comments to be filed in the proceeding. Regarding the treatment of start and shutdown costs in avoided energy modeling, in a meeting with the Public Staff on October 19, 2021, the Companies committed to adhering to the modeling approach utilized in the approved 2018 Sub 158 and 2020 Sub 167 avoided energy rates, in which start and shutdown costs

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[4] *Reporting Order*, at 3 ("[E]ncourag[ing] the Movants and interested parties to use this additional time to reach consensus to the maximum extent possible on all of the issues to be presented to the Commission in the November 1, 2021 filing.")

[5] See the Commission's *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities,* filed on August 13, 2021, in Docket No. E-100, Sub 167, at 40.

were allocated for the duration of each unit's run time, rather than in the hour in which they occur. This methodology results in intuitive and appropriate avoided energy price signals.

Conclusion

As set forth above, the Companies have engaged in robust discussion with the Public Staff and stakeholders on the outstanding Sub 158 Additional Issues as well as a number of additional issues in an attempt to reach consensus on as many issues as possible before their November 1, 2021 Avoided Cost Filing. In addition to the stakeholder meetings discussed above, the Companies held a final stakeholder meeting on October 5, 2021 that was led by stakeholders, offering them a platform in which to raise issues and discuss concerns with the Companies' proposed approach to addressing each of the Sub 158 Additional Issues. The significant efforts by the Companies, Public Staff, and Intervenors to engage with each other over the past year have resulted in minimization of the contested issues that must be litigated by the Commission in the Sub 175 proceeding.

Respectfully submitted, this the 22nd day of October, 2021.

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ATTACHMENT 1

DUKE ENERGY®

As-Available Avoided Energy Rate Discussion

September 20, 2021

Agenda

- Background on PURPA Purchase Obligation
  - PURPA implementation options under FERC Order No. 872 for “LEO Contracts”
  - Options for “as available” energy-only rate for QFs who do not commit their full production to Duke
- NC “As Available” Rate Policy
- New As Available Rate Proposal

Background

FERC PURPA Regulations Set Framework for Utilities to make “Purchases ‘as available’ or pursuant to a legally enforceable obligation.” 18 C.F.R. 292.304(d)(1)-(2)

(1) Each qualifying facility shall have the option either:

(i) To provide energy ***as the qualifying facility determines such energy to be available for such purchases***, in which case the rates for such purchases shall be based on the electric utility's avoided cost for energy ***calculated at the time of delivery***; or

(ii) To provide energy or capacity ***pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term***, in which case the rates for such purchases shall, except as provided in paragraph (d)(2) of this section, be based on either:

(A) The avoided costs calculated at the time of delivery; or

(B) The avoided costs calculated at the time the obligation is incurred.

(iii) The rate for delivery of energy calculated at the time the obligation is incurred may be based on estimates of the present value of the stream of revenue flows of future locational marginal prices, or Competitive Prices during the anticipated period of delivery.

(2) Notwithstanding paragraph (d)(1)(ii)(B) of this section, a state regulatory authority or nonregulated electric utility may require that rates for purchases of energy from a qualifying facility pursuant to a legally enforceable obligation ***vary through the life of the obligation and be set at the electric utility's avoided cost for energy calculated at the time of delivery***.

FERC Order 872 Policy Goals

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FERC Provides Flexibility for Using Market Pricing and Real-Time Energy Rate under LEO Option

- *Policy Rationale*: Need for "re-balancing" of risk allocation between QFs and customers
  - "[C]ontrary to the Commission's expectation in 1980, there have been numerous instances where overestimates and underestimates of energy avoided costs used in fixed energy rate contracts have not balanced out... Giving states the ability to require energy rates in QF contracts to vary based on the purchasing utility's avoided cost of energy at the time of delivery ensures that QF rates do not exceed the avoided cost rate cap imposed by PURPA." Order No. 872, at ¶ 723.

- *Policy Rationale*: Recognition that energy market pricing at time of delivery is more accurate than administratively-determined projections of avoided costs
  - "Using transparent market prices to establish as-available avoided cost rates also allows QFs, utilities, and the states to avoid the expenditure of the time and resources involved in litigating administratively-set avoided cost rates, and allows those rates to automatically adjust—up and down—as avoided costs change." Order No. 872, at ¶ 31.

FERC Order 872 Policy Solution

Flexibility for Using Market Pricing and Real-Time Energy Rate

- 18 C.F.R. 292.304(d)(1)(iii): "The rate for delivery of energy calculated at the time the obligation is incurred may be based on estimates of the present value of the stream of revenue flows of future locational marginal prices, or Competitive Prices during the anticipated period of delivery."
- 18 C.F.R. 292.304(d)(2): "Notwithstanding paragraph (d)(1)(ii)(B) of this section [providing for rates to be calculated at the time the obligation is incurred], a state regulatory authority . . . may require that rates for purchases of energy from a qualifying facility pursuant to a legally enforceable obligation vary through the life of the obligation, and be set at the electric utility's avoided cost for energy calculated at the time of delivery."

As Available Updates Under FERC Order 872

FERC Authorizes States to Implement Energy Rates that Reflect "As Available" Avoided Costs

- FERC established new "competitive price" concept in regulations (18 C.F.R. 292.304(b)(7)) for pricing as-available QF energy sales to electric utilities located outside a market. *See 18 C.F.R. 292.304(b)(7).*

- FERC also granted state regulatory authorities "**flexibility to require that energy rates** (but not capacity rates) in QF power sales contracts and other LEOs **vary** in accordance with changes in the purchasing electric utility's **as available avoided costs at the time the energy is delivered**." (172 FERC ¶ 61,041 at P 44.) See 18 C.F.R. 292.304(d)(2).

Duke's Position Regarding FERC Order 872

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- New additional guidance from FERC 872 could inform changes to the current rate constructs, which rely on fixed rates for energy and capacity with various terms - 2, 5 and 10 year contracts/rates.

- At this time, Duke does not plan to propose changes the rate structure for 2, 5 or 10 year rates for QFs that commit to sell their full output to Duke (have a LEO).

- At this time, Duke believes the HB589 rate requirements strike a good balance between the interests of customers and QF developers for new QF contracts.
  – Almost all new Projects are competitively sourced or driven by a customer program

- Duke will continue to monitor how the market evolves and may propose changes in the future.

NC As Available Rate Policy

Background - NCUC Docket No. E-100, Sub 100

- **In 2005, NCUC reaffirms policy of using two-year energy rate as as-available avoided cost pricing:**
  - The exact method of determining the "as available" rate is not specified in the FERC regulations implementing Section 210 of PURPA. In discussing this purchase requirement, the FERC stated that PURPA did not intend a "minute-by-minute" determination of avoided cost. The FERC further stated that "the rates for purchases [on an as-available basis] are to be based on the purchasing utility's avoided costs estimated at the time of delivery, " but did not specify when that estimate should be made." Sub 101 Order, at 44.
  - NCUC reaffirmed its long-standing policy of using the <u>two year "variable" energy rate (which is actually fixed and not truly variable)</u> as the appropriate as-available rate as providing "the advantages of predictability and certainty for the QFs and ease of administration for the utilities." *Id.*

North Carolina As Available Rates

- NCUC directed Duke to “evaluate and, if found to be appropriate, offer an RTP-based avoided cost tariff as an optional alternative to their Schedule PP”.
  - “RTP” or “Real time price” can mean a variety of things; e.g. for “RTP” retail C&I rates are published day-ahead, not in true real time.
  - This request implies an interest in reducing forecasting error to hold customers harmless.
- The current As Available rate does not require a commitment by the QF to sell all its energy to the utility.
- The fixed 2 year rate for As Available energy has the unintended effect of providing a free fixed price put option to the QF.
- As Larger QFs roll off their existing contracts, more QFs may take advantage of this to the detriment of customers.

New "As Available" Framework

- Fixing a rate ahead of time will usually result in an over- or under- payment by Duke compared to the actual costs avoided when the energy is produced.
- Ex post analysis is optimal for holding customers harmless.
- Current Inc/Dec pricing methodology seems to meet the requirements for an As Available rate.
  - Performed ex post
  - Currently used for transmission and wholesale imbalance billing.

New “As Available” Framework

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- Why use ex post rates?
  - To better protect customers
  - To reflect the costs actually avoided
  - To eliminate the free put option for QFs to play against the wholesale market
- Ex post rates would provide fair compensation to QFs for the energy provided, in accordance with PURPA.
- QFs could still commit to sell all energy under a two-year fixed rate contract if they prefer that.
- This As Available proposal is consistent with FERC Order 872.

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ATTACHMENT 2

Dominion Energy

DUKE ENERGY

CT Capital Cost Review – Public Staff

October 12, 2021

Discussion Topics

- NCUC Sub 158 Order
- EIA Data and Assumptions
- Common Infrastructure Economies of Scale
- CT Capital Cost with Greenfield Economies of Scale Adjustments
- Economies of Scale Carrying Costs
- Conclusions
- Proposed Methodological Approach

NCUC Docket No. E-100, Sub 158
2018 Avoided Cost Order

- The Public Staff notes that the Utilities have retired, and plan to retire over the next 10 years, significant natural gas and coal generation that may lead to the availability of several brownfield sites for potential future use for both baseload and peaking needs that may "represent potential value to customers that is not reflected in the costs of a greenfield site."

- It is appropriate to require DEC, DEP, and DENC to include in their initial statements to be filed in the 2020 biennial avoided cost proceeding an evaluation and application of cost increments and decrements to the publicly available CT cost estimates, including the use of brownfield sites, existing infrastructure, decrements for electrical and natural gas connections, and other balance of plant items, to the extent it is likely that this existing infrastructure will be used to meet future capacity additions by the utility.

EIA Capital Cost Update – February 2021

Independent Statistics & Analysis
U.S. Energy Information Administration

February 2021

Cost and Performance Characteristics of New Generating Technologies, *Annual Energy Outlook 2021*

https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

EIA Capital Cost for a Simple Cycle CT

- The EIA Advanced CT produces 237 MW of electricity using a **single natural gas-fueled, F-class CT** and associated electric generator
- EIA cost estimate assumes a **greenfield installation**
- EIA cost estimate does not reflect economies of scale associated with constructing 4 CTs at a greenfield site

EIA Capital Cost Update – February 2021

Table 1. Cost and performance characteristics of new central station electricity generating technologies

Technology	First available year[1]	Size (MW)	Lead time (years)	Base overnight cost[2] (2020 $/kW)	Techno-logical optimism factor[3]	Total overnight cost[4,5] (2020 $/kW)	Variable O&M[6] (2020 $/MWh)	Fixed O&M (2020$/ kW-yr)	Heat rate[7] (Btu/kWh)
Ultra-supercritical coal (USC)	2024	650	4	3,672	1.00	3,672	4.52	40.79	8,638
USC with 30% carbon capture and sequestration (CCS)	2024	650	4	4,550	1.01	4,595	7.11	54.57	9,751
USC with 90% CCS	2024	650	4	5,861	1.02	5,978	11.03	59.85	12,507
Combined-cycle—single shaft	2023	418	3	1,082	1.00	1,082	2.56	14.17	6,431
Combined-cycle—multi shaft	2023	1,083	3	957	1.00	957	1.88	12.26	6,370
Combined-cycle with 90% CCS	2023	377	3	2,471	1.04	2,570	5.87	27.74	7,124
Internal combustion engine	2022	21	2	1,813	1.00	1,813	5.72	35.34	8,295
Combustion turbine—aeroderivative[8]	2022	105	2	1,169	1.00	1,169	4.72	16.38	9,124
Combustion turbine—industrial frame	2022	237	2	709	1.00	709	4.52	7.04	9,905

EIA Capital Cost Update – February 2021

Table 2. Total overnight capital costs of new electricity generating technologies by region

2020 dollars per kilowatt

Technology	14 SRCA
Ultra-supercritical coal (USC)	3,533
USC with 30% CCS	4,454
USC with 90% CCS	5,852
CC—single shaft	993
CC—multi shaft	872
CC with 90% CCS	2,424
Internal combustion engine	1,776
CT—aeroderivative	1,071
CT— industrial frame	649

Common Infrastructure Economies of Scale

- Examples of common infrastructure economies of scale include:
  - Land Acquisition
  - Clearing and Grubbing
  - Earthwork
  - Roads
  - Municipal Water Tie
  - Natural Gas M&R Station
  - Electrical Interconnect
  - Fire Header
  - Demin Tank
  - Admin Building
  - Lights/Security/Fencing

- Common infrastructure cost adjustments can be applied to greenfield and brownfield sites
  - Greenfield economies of scale adjustments would spread the common infrastructure costs among 4 CT units
  - Brownfield site adjustments may credit the full amount of common infrastructure costs

CT Capital Cost with Greenfield Economies of Scale Adjustments

EIA Cost Basis	DUKE	DOMINION
Nominal Rating (MW)	237	237
Total Capital Cost (2020 $/kW)	649	649
Total Capital Cost (2021 $/kW)	665	665
Total Capital Cost (2021$)	**$ 157,658,325**	**$ 157,658,325**
Infrastructure Economies of Scale Adjustments	**2021$**	**2021$**
[redacted]	[redacted]	[redacted]
Contingency (10%)	$ 1,342,000	$ 1,484,000
Total Common Infrastructure Cost	**$ 14,765,000**	**$ 16,326,000**
Total Common Infrastructure Cost per Unit	$ 3,691,000	$ 4,081,500
Common Infrastructure Cost Adjustment	**$ (11,074,000)**	**$ (12,244,500)**
Total Adjusted Capital Cost ($)	**$ 146,584,000**	**$ 145,414,000**
Total Adjusted Capital Cost ($/kW)	**$ 618**	**$ 614**
% Adjustment (Excluding Carrying Cost Adj)	**-7.0%**	**-7.8%**

*Based on February 2020 EIA Capital Cost Report

Carrying Costs Associated with Economies of Scale Adjustments

With regard to economies of scale, when recalculating the installed costs of a CT, the Utilities shall take note of the affidavit of Ben Johnson, filed on behalf of NCSEA, stating that adjustments to include **economies of scale should be computed net of the additional carrying costs (capital costs, property taxes, etc.) that would be incurred by acquiring a larger parcel of land, clearing and preparing a larger site, building additional roads, and constructing larger buildings and structures prior to the time when they are needed for the additional units. The Commission finds merit in this argument.** The Utilities should continue to provide detail as to the economies of scale being achieved and the specific components of the EPC contract or balance of plant to which the efficiencies are being applied, while also taking into account any carrying costs associated with the economies of scale. NCUC Docket No. E-100, Sub 140 (Phase II Order, at 22)

Economies of Scale Carrying Costs - Dominion

Total Common Infrastructure Cost	**$ 16,326,000**
Total Common Facility Cost per Unit	$ 4,081,500
Common Facility Cost Adjustment	**$ (12,244,500)**

Scenario 1: No carrying costs associated with economies of scale adjustments
Scenario 2: 2 units constructed in year 1 and 2 units constructed in year 2
Scenario 3: 4 units constructed over a 4 year period

	DOM
Discount Rate	[redacted]
AFUDC rate	

Scenario 2: 2 units in year 1 and 2 units in year 2

	CTs	Carry Cost
Year 1	2	$ 500,351
Year 2	4	$ -
Year 3	4	$ -
Year 4	4	$ -
Year 5	4	$ -
NPV		$ 469,990
Plant MW		237
$/kW		$ 2.0

	DOM
Discount Rate	[redacted]
AFUDC rate	

Scenario 3: 4 units over a 4 year period

	CTs	Carry Cost
Year 1	1	$ 750,527
Year 2	2	$ 512,860
Year 3	3	$ 262,841
Year 4	4	$ -
Year 5	4	$ -
NPV		$ 1,375,330
Plant MW		237
$/kW		$ 5.8

CT Capital Cost with Greenfield Economies of Scale Adjustments

Economies of Scale Carrying Cost Adjustment	Duke	Dominion	Average
Scenario 1: No carrying cost associated with economies of scale adjustments			
Carrying Cost Adj ($/kW)	N/A	N/A	**N/A**
Total Overnight Cost incl Carry Cost Adj ($/kW)	$ 618	$ 614	**616**
% Adjustment	**-7.0%**	**-7.8%**	**-7.4%**
Scenario 2: 2 Units constructed in year 1 and 2 units constructed in year 2			
Carrying Cost Adj ($/kW)	$ 2.0	$ 2.0	**2.0**
Total Overnight Cost incl Carry Cost Adj ($/kW)	$ 621	$ 616	**618**
% Adjustment	**-6.7%**	**-7.5%**	**-7.1%**
Scenario 3: 4 Units constructed over a 4 year period			
Carrying Cost Adj ($/kW)	$ 6.0	$ 5.8	**5.9**
Total Overnight Cost incl Carry Cost Adj ($/kW)	$ 624	$ 619	**$ 622**
% Adjustment	**-6.1%**	**-6.9%**	**-6.5%**

Conclusions

- The goal of developing avoided capacity costs is to strike a balance between using transparent, publicly-available data and tailoring that data to avoid an overpayment risk to customers

- The EIA data reflects the cost to build a single CT at a greenfield installation and does not capture economies of scale associated with constructing multiple units at a site

- Common infrastructure cost adjustments can be similarly applied to greenfield and brownfield sites
  - Greenfield economies of scale adjustments would spread the common infrastructure costs among 4 CT units
  - Brownfield site adjustments may credit the full amount of common infrastructure costs

- Most of the resource needs in the Companies' IRPs are driven by coal and heavy oil unit retirements presenting opportunities to construct new generation at brownfield sites

- The Companies expect that a brownfield site could offer higher cost savings than greenfield economies of scale adjustments although the level of savings may be very site specific

- Duke and Dominion independent estimates of common infrastructure costs for a 4 CT greenfield site produced very similar results
  - Reasonable to use the average of the two estimates
  - Carrying costs associated with economies of scale adjustments are relatively small

Proposed Methodological Approach

- Calculate the avoided capacity cost based on the use of greenfield economies of scale adjustments
  - Consistent with currently approved avoided capital cost methodology
  - Brownfield costs can vary by site
  - Greenfield approach is conservative to the benefit of QFs as it results in a smaller economies of scale adjustment
- Use CT capital cost data published by EIA as the starting point for calculating the avoided capacity cost
- Apply a 7.0% decrement to the EIA data to reflect the economies of scale for constructing 4 CTs at a greenfield site
- The proposed approach results in an overnight cost of $619/kW (2021$) for use in the 2021 avoided cost filing

ATTACHMENT 3

Avoided Cost: Qualifying Facilities and Ancillary Services in the PURPA framework

September 20, 2021

NCUC Sub 158 Order

Ordering Paragraph 24:

“24. That Duke shall include in its initial filings in the next biennial avoided cost proceeding an evaluation of whether a QF that can sufficiently demonstrate its ability, and contractually obligates itself, to operate in a manner that provides positive ancillary service benefits at a lower cost than the utility’s own conventional resources, should be appropriately compensated for those benefits, and an identification of mechanisms to quantify the ancillary service benefits that such innovative QFs can provide”

Agenda

- Overview of ancillary services
- Operational, technical and economic factors when QFs provide ancillaries
- Legal precedent and background

Purpose of Ancillary Services

- The power system is designed to tolerate some swings in frequency and energy before action must be taken to balance the system. Ancillary services are needed to preserve reliable power system operations and for NERC reliability standard compliance.
- It is normal for the frequency to move around simply from load causing imbalances between resources and demand, but during certain times, intermittent generators are contributing to these imbalances more significantly than load. There can also be sudden events that cause dramatic frequency changes.
- Ancillary Services are essentially the ability to change the energy output to keep the system within those tolerance bands and, when needed, to rebalance the system and/or respond to disruptive events. All BA's in the Eastern Interconnection provide ancillary services.
- In order to provide most of these services, system operators must have control over the assets used.
- Ancillary services are a key part of operating the bulk electric system, but not a "large" part of our system (both cost-wise and MW-wise).
- Historically, the controllable units built to serve load can also provide ancillary services.

Main Types of Ancillary Services

- **Spinning Reserves** includes on-line generation that can either increase or decrease output relative to its current generation output upon system operator direction to respond to imbalances on the system. This spinning reserve can also respond to significant events on the Eastern Interconnection to arrest frequency decline (aka Primary Frequency Response).
- **Regulating Reserves** (aka AGC Response), is a subset of Spinning Reserves, which includes Secondary Frequency Response and Regulation Response *are used to manage the active power volatility of a BA's load and generation resources.* To provide regulating reserves, an asset must be reliable, must be integrated into the generation dispatch model, and must respond to Automatic Generation Control (AGC) signals that are used to continuously balance energy supply with demand in order to maintain Scheduled Frequency. No third party resources provide Regulating Reserves in DEC or DEP today.
- **Contingency Reserves**: Firm capacity resources that can respond in 15 min to meet the Balancing Authority's requirement to respond to a Balancing Contingency Event (disturbance control event). The majority of contingency reserves are Duke-owned, controlled, and on a ready-state off-line. NCEMC Anson generation can provide contingency reserves if the units are off-line and available.
- **Black start (sometimes considered an ancillary service)**: When the grid goes dark, there must be resources that have the ability to energize the grid and bring other resources back online. Requires high energy content and to be ready at all times (e.g. in a full state of charge, for batteries).

How Ancillary Services Are Provided

- The utility runs a marginal cost economic dispatch every minute which produces the economic basepoint (a generation setpoint for that next minute) for each dispatchable unit.
- Adjustments are made to the economic basepoints continually as regulation response in which an algorithm proportionally allocates the regulation response required based on Area Control Error (ACE) deviations.
- Regulation response is a brief deviation from economic dispatch basepoint to get back within ACE tolerances.
- The units providing regulation response must be on AGC.
- The baseline planning number is currently 230 MW of regulating reserve of AGC response capability. DEC and DEP have approximately 1.3 GW of off-line Contingency Reserve to meet the 950 MW daily requirement in DEC and DEP. Most Contingency Reserves are offline.

The complexity of managing a future system with hundreds of small resources providing regulation response is vast, and operators must be prepared to make manual adjustments to these resources at any time. The more resources providing regulation response, the more complex the modeling and dispatch becomes.

Operational, Technical, and Economic Aspects

Operational Aspects of Ancillaries

"…sufficiently demonstrate its ability… to operate in a manner that provides positive ancillary service benefits…"

- Providing ancillary services is not "plug and play".
- The challenge is not so much what the facility is capable of doing on its own or how quickly it can ramp up/down, but modeling and dispatching the resource in concert with all other resources on AGC in the BA to collectively respond to the immediate needs of the grid.
- Ramping or otherwise changing export is only beneficial to the grid when it is responding in a coordinated and controlled fashion that is in synchrony with all of the other generators in the BA.
- Expanding the BA's modeling and dispatch optimization to include myriad third party resources is a fundamental change in how the grid is operated. It will require a significant financial and technical investment in telecommunications, modeling, studies, and ancillary engineering support, including increases in ongoing operations and maintenance.

Commercial Practicality of QFs providing Ancillaries

"… and contractually obligates itself …"

- QFs are paid based on delivered energy and capacity, so they are incentivized to produce as much as possible to maximize revenue.
- Providing ancillary services would require a resource to be operated below maximum output.
  - Being operated to provide ancillaries will cannibalize energy and capacity revenue.
  - Storage attached to the Generator may capture some of the forgone energy but today the economics are not favorable.
- From what we see with the SISC, the ancillary services values quantified today are far below the foregone energy and capacity values.

Cost Implications

*"… at a **lower cost** than the utility's own conventional resources…"*

- Under PURPA, the utility's calculation of full avoided cost of avoided generation necessarily includes the provision of ancillaries, which means that customers will not benefit from the QF's provision of ancillaries at some incremental cost above full avoided cost.
- In order to use third party resources for ancillaries, significant investment will be required to accommodate the new modelling, engineering support, communications, etc. to move to a system that relies on many small facilities for ancillaries instead of fewer, larger facilities. That will likely dramatically reduce the benefit of distributed ancillaries.
- There is a limited need for regulating reserves, as demonstrated by PJM's prices for these services plummeting when the market was quickly saturated.
- "[M]ost ISOs only require 100-400 MW of the product in any given hour. Even PJM — the largest wholesale market in the world at roughly 170 GW of peak demand — only requires 800 MW of regulation, compared to 3,900 MW of BESS that is currently either online or in the interconnection queue." (New battery storage on shaky ground in ancillary service markets | Utility Dive)

Legal Precedent and Background

Avoided Costs Include Ancillary Services

18 C.F.R. 292.101(b)(6):

(6) ***Avoided costs*** means the **incremental costs** to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

16 U.S.C. 824a-3(d):

(d)"Incremental cost of alternative electric energy" defined [--] For purposes of this section, the term "incremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.

FERC clarifies that energy sold under PURPA "includes capacity, energy and ancillary services."

See Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. by Pub. Utils., 123 FERC ¶ 61,055, n. 869, 2008 FERC LEXIS 788, (April 21, 2008).

Current Situation for QF Ancillaries

- We are not aware of any State using small renewable producers to provide ancillary services under PURPA
- Certain Organized Markets do pay for Ancillary Services from Resources who allow the Operator to control them.
  - Recent market prices for Ancillaries have fallen as Operators refine their pricing models.
  - To the best of our knowledge, none of these resources are QFs.
- Customers pay for Ancillaries through a combination of Capacity costs (fixed and variable) and Energy Costs (primarily Fuel).
- Under PURPA, QFs are already fully compensated for the avoided Energy (Fuel and purchased power) and Capacity (fixed and variable) Costs of the Peaker so no additional compensation is warranted.
- FERC has clarified that ancillary services are already incorporated into the calculation of full avoided costs.

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Order 872 Implementation
Legally Enforceable Obligation
Standards Discussion

September 20, 2021

Introduction

1. FERC Order 872 Background
2. New Options for Setting Avoided Cost Rates
3. LEO Standard
4. Guidance from Other States
5. Duke Energy Implementation Proposal

FERC Order 872 - Background

Order No. 872 issued after first significant rulemaking impacting PURPA avoided cost rate-setting since FERC issued Order No. 69 in 1980.

- June 16, 2016 – FERC held Technical Conference on PURPA implementation.
- September 19, 2019 – Notice of Proposed Rulemaking issued.
- July 16, 2020 – Order No. 872 Issued Establishing Updated FERC Regulations Implementing PURPA.
- November 19, 2020 – Order No. 872-A Issued Providing Certain Clarifications and Affirming Decision in Order No. 872.
- Appeals of Order No. 872 pending in 9th Circuit Court of Appeals. Currently in briefing stage.

New Options for Setting Avoided Cost Rates

- Grants states flexibility to set variable energy rates (but *not* variable capacity rates) in QF contracts, such that rates paid to QFs will vary according to changes in the utility's avoided costs. 18 C.F.R. § 292.304(d)(1)(i);
- For utilities located in RTOs/competitive wholesale markets, grants states flexibility to set as-available energy rates with a rebuttable presumption that the locational marginal price (LMP) in those markets represents avoided cost. 18 C.F. R. § 292.304(b)(6);
- Outside of competitive wholesale market, grants states flexibility to set as-available energy rates at "competitive prices" from liquid market hubs or calculated from a formula based on natural gas price indices and heat rates for Combined Cycle. 18 C.F.R. § 292.304(b)(7);
- Grants states additional flexibility to establish fixed rates using present value projections of LMP/Competitive Price energy price revenues during the term of a QF's contract. 18 C.F.R. § 292.304(d)(1)(iii); and
- Allows states to set energy rates and procure needed QF capacity using transparent and non-discriminatory competitive solicitations to set avoided costs. 18 C.F.R § 292.304(b)(8).

Duke Energy Implementation Proposal

- Order No. 872 provides flexibility and optionality in setting/structuring avoided cost rates to reduce overpayment risk of long-term fixed price PPAs at administratively determined avoided costs.
- New rate options would need be reconciled with NC's PURPA implementation framework under N.C. Gen. Stat. § 62-156.
- At this time, Duke is not proposing significant changes to methodology/framework for setting long-term avoided cost rates for either Standard Offer or Large QFs.
- Duke recognizes potential benefits of Order No. 872's new rate setting options to ensure accuracy of avoided cost rates and mitigate over-payment risk for customers and will continue to evaluate these options in the future.
- Duke is proposing to update as-available rates consistent with new Order No. 872 guidance.

LEO Standard

LEO Standard:

- 18 C.F.R. 292.304(d)(3): "***Obtaining a legally enforceable obligation.*** A qualifying facility must demonstrate **commercial viability** and **financial commitment** to construct its facility pursuant to **criteria determined by the state regulatory authority** or nonregulated electric utility as a prerequisite to a qualifying facility obtaining a legally enforceable obligation. Such criteria must be **objective and reasonable**."
- States have flexibility to determine what constitutes commercial viability and financial commitment, but the criteria used must be "objective and reasonable." Order 872, ¶ 684.
- FERC highlighted that a utility must be able to rely on a LEO commitment for **resource planning** purposes:
  - "[R]equiring a showing of commercial viability and financial commitment, based on objective and reasonable criteria, will ensure that **no electric utility obligation is triggered** for those QF projects that **are not sufficiently advanced** in their development, and therefore, for which it would be **unreasonable** for a utility to include in its **resource planning**." *Id.*

FERC Order 872 – LEO Standard

Examples of factors FERC identified that states could consider to determine commercial viability and/or financial commitment:

- Taking meaningful steps to obtain site control adequate to commence construction of the project at the proposed location;
- Filing an interconnection application with the appropriate entity;
- Submitting all applications, including filing fees, to obtain all necessary local permitting and zoning approvals. Order 872, ¶ 685.

FERC Order 872- LEO Standard

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Factors considered must be within the control of the QF.

- States may require QFs to apply for required permits, but LEO cannot be dependent on issuance of such permits. Order 872, ¶ 685.

Examples of factors FERC suggested states should not require for a QF to demonstrate commercial viability or financial commitment:

- Obtaining financing. *Id.* ¶ 687;
- Executing a PPA. *Id.*;
- Completion of a system impact, interconnection, or transmission feasibility study. *Id.* ¶ 694.

FERC Order 872 – Rebuttable Presumption of Separate Sites

- Affiliated QFs within 1 mile of each other are considered to be at the same site. 18 C.F.R. § 292.204(a)(2).
- Affiliated QFs located 10 miles or more from each other are considered to be separate sites. 18 C.F.R. § 292.204(a)(2)(B).
- Affiliated QFs located more than 1 mile, but less than ten miles from each other are rebuttably presumed to be at separate sites. 18 C.F.R. § 292.204(a)(2)(C).
  - **Challenging the rebuttable presumption**
    - Interested persons or entities may challenge a QF certification by "specify[ing] facts that make a prima facie demonstration that the facility described in the certification . . . or recertification . . . does not satisfy the requirements for QF status." *Id.* at 263.
    - Any protest must be "adequately supported" by "supporting documents, contracts, or affidavits, as appropriate." *Id.* "General allegations or unsupported assertions will not provide a basis for denial of certification or recertification." *Id.*

Guidance from Other States

- There is limited guidance from other states as utilities commissions are just beginning to consider implementation of Order 872 requirements.
- To date, Duke is aware that the Michigan Public Service Commission has entered a final order implementing the LEO provisions of FERC Order 872.
  - Non-contractual LEO process recently contested in Michigan, *Greenwood Solar, LLC v DTE Electric Co,* Order *pp. 53-54* Case No. U-20156 (Sept. 26, 2020), *aff'd per curium* by Michigan Court of Appeals December 17, 2020 (Docket No. 351223).
    - ” [I]nherent in the formation of an LEO is a ***binding commitment by both sides to the agreement*** or obligation-- the obligation by the utility to purchase the power and the obligation by the QF to provide energy and capacity upon which the utility and its customers can rely. . . necessary for a QF to fully understand and commit to its obligations. This is necessary to strike the right balance between access for QFs on the one hand and system reliability and certainty in utility planning and procurement to protect ratepayers on the other hand.”

Guidance from Other States - Michigan

Michigan PSC identified general criteria utilities could use to evaluate whether a LEO has formed under Order 872:

- Documentation of having obtained ***QF status from FERC*** pursuant to certification procedures in 18 C.F.R. 292.207;
- Submission of an ***interconnection*** application and proof of payment of applicable fees;
- Demonstration of meaningful steps to obtain ***site control*** adequate to commence construction of the project at the proposed location;
- Submission of all ***applications, including filing fees***, to obtain all necessary local ***permitting and zoning*** approvals;
- Documentation of proximity to other affiliated projects within 1 mile/10 miles;

In the Matter, on the Commission's Own Motion to Examine the Changes to the Regulations Implementing the Public Utility Regulatory Policies Act, Dkt. No. U-20905, 2021 Mich. PSC LEXIS 165 (Jul. 2, 2021).

Guidance from Other States - Michigan

DTE Electric Company Proposal

- Proposes a case-specific “holistic and critical evaluation of the relevant facts and circumstances to each project” to assess commercial viability and financial commitment. “A simple checklist of criteria is insufficient.”

- While acknowledging that a utility may not require final execution of a PPA to establish a LEO, argues that “the level of QF commitment to the Company through a LEO <u>must be as binding and reliable as a PPA</u>.”

In the Matter, on the Commission’s Own Motion, Establishing the Method and Avoided Cost Calculation for DTE Electric Company to Fully Comply with the Public Utilities Regulatory Policy Act of 1978, 16 USC 2601 et seq., Case No. U-18091, Direct Testimony of A.F. Crozier, Direct Testimony of David Blinkley (Apr. 5, 2021).

Guidance from Other States - Michigan

DTE Electric Proposal for Establishing Commercial Viability and Financial Commitment

– To achieve certainty for long-term planning, DTE proposes a "minimum list of criteria," including:

- Identification of expected avoided costs;
- Proof of QF certification with FERC;
- Forecasted capacity and energy production profile for the proposed term, including the amount the QF is committed to provide and scheduled commercial operation date;
- Demonstration of capability to secure land rights for the proposed project for the requested term of the contract;
- List of all required permits and approvals necessary to develop and operate the facility for the term of the requested PPA, along with proof of submitted permits (including filing fees) from jurisdictions with authority (municipality, MDEQ, etc.) required to construct and operate the proposed QF
- Paid for and completed Distribution Study
- Proof of fuel security/Cogeneration host details
- Substantial evidence of consideration for environmental/wildlife factors (if applicable)
- Substantial evidence of consideration for local zoning, ordinances and community engagement (if applicable)
- Creditworthiness

Duke Energy LEO Implementation Proposal

- Specific to new LEO standard, updates to Notice of Commitment Form and contracting process are needed to align both with Order No. 872 and new Queue Reform process.
- Duke continues to try to manage risk of "speculative LEOs" where QF is not actually committing itself to sell and deliver power and can walk away from LEO.
- Goal of LEO process should be to facilitate efficient path to contracting for QF, while balancing need for binding "PPA-like" obligation to promote system reliability and certainty in utility planning and procurement.
- For new QFs, LEO can be used to demonstrate readiness in DISIS Cluster process, so want assurances of meaningful commitment to proceed to PPA execution if project is proceeding as a "ready project" in queue

Proposed Updates to Large QF (> 1 MW_{AC}) Notice of Commitment Form

- To demonstrate commercial viability and financial commitment, Duke proposes to require a QF to provide the following information in connection with the large QF NOC Form:
  - Interconnection:
    - Reasonable evidence that the QF is (1) interconnected to the Company's system; (2) has made transmission arrangements to deliver power to the Company's system; and/or (3) has requested to become an Interconnection Customer of the Company.
    - Reasonable evidence that the QF has met all applicable requirements to commence the interconnection study process, including providing the Section 4.4.1 initial security requirement and execution of a Definitive Interconnection System Impact Study Agreement.
  - Site Control:
    - Reasonable evidence of site control for the entire contracting term.
    - Proof of filing of all necessary permitting and zoning applications, including payment of associated fees.

Proposed Updates to Large QF (> 1 MW_{AC}) Notice of Commitment Form

- Evidence of commercial viability and financial commitment (cont.):
  - <u>CPCN</u>
  - <u>Project Development</u>: Anticipated timelines for completion of key milestones, including:
    - ➢ Licenses, permits, and other necessary approvals;
    - ➢ Funding of QF's development and operations;
    - ➢ Facility engineering and drawings;
    - ➢ Significant equipment purchases;
    - ➢ Procurement of long lead time materials;
    - ➢ Construction agreement(s);
    - ➢ Signing of third-party Transmission Agreements, where applicable.

- To address risk of stale rates, **<u>new QFs under development</u>** must represent that they will either (1) achieve COD and commence delivery of full electrical output to the Company **<u>within 365 days</u>** of the Submittal Date or (2) **<u>accept Liquidated Damages</u>** similar to Large QF PPA if fail to deliver in future.

- Existing Interconnected QFs must commit to deliver power **<u>within 365 days of current PPA expiry/new term</u>**.

Proposed Updates to Large QF (> 1 MW_{AC}) Notice of Commitment Form

- Duke further proposes some limited updates to conditions that would result in termination of the NOC Form and corresponding LEO. In addition to the termination conditions in the NOC Form approved in Docket No. E-100, Sub 148, Duke proposes that the NOC Form and LEO would automatically terminate:
  - If the Seller terminates its Interconnection Request or is otherwise withdrawn from the interconnection queue;
  - If the Seller does not execute a PPA within 90 days after the Company delivers an executable PPA. This period may be extended by mutual agreement of the Seller and the Company for a period not to exceed 365 days.
    - Note: The NOC Form approved in E-100, Sub 148 required execution of a PPA within 6 months of PPA delivery.
  - If the Seller ceases to maintain control of the Project Site or is no longer certified as a QF with FERC. In either circumstance, the NOC Form allows the seller 10 business days to cure the deficiency upon receipt of written deficiency notice from the Company.

Proposed Updates to Large QF (> 1 MW_{AC}) Notice of Commitment Form

Information needed to prepare an executable PPA

- Duke proposes expressly requiring a QF to provide the following information, all of which is needed to prepare a PPA:
  - Facility Name and address;
  - Description of Facility (number, manufacturer and model of Facility generating units) including generation technology and whether storage included;
  - Fuel type(s) and source(s);
  - Proposed contracting term for the sale of electric output to the Company
  - Maximum design capacity AC and DC (MW), and estimate monthly production (Mwh);
  - Proposed site location and electrical interconnection point;
  - Where QF is or will be interconnected to an electrical system other than the Company's, plans to obtain, or actual electricity transmission agreements with the interconnected system;

Proposed Updates to Large QF (> 1 MW_{AC}) Notice of Commitment Form

Information required for PPA (cont.)

- Anticipated commencement date for delivery of electric output;
- List of acquired and outstanding QF permits, including a description of the status and timeline for acquisition of any outstanding permits; and
- Interconnection agreement status.

Duke will commit to providing an executable PPA within 30 days of receiving this information, effectively aligning the PPA execution date (absent mutually agreed-upon extension) after Phase 1 results if an QF interconnection customer uses a NOC Form/LEO to establish Phase 1 readiness in DISIS Cluster Study

Proposed Updates to Large QF (> 1 MW_{AC}) Notice of Commitment Form

- To confirm whether QFs are independent sites, Duke proposes requiring that the QF provide documentation for all QFs located within 1 mile and 10 miles of the project that are owned or controlled by the same developer, including by:
  - Identifying the capacity of other affiliated QFs;
  - Identifying the proximity of other QFs to the Seller;
  - Demonstrating that Seller has obtained self-certification of the other affiliated QFs;
  - Describing the organization structure and chart of upstream developer, if applicable; and
  - Describing the affiliate relationship between the Seller and other QFs within 10 miles of the project.

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