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September 7, 2021

VIA Electronic Filing

Ms. Antonia Dunston, Interim Chief Clerk
North Carolina Utilities Commission
Dobbs Building
430 North Salisbury Street
Raleigh, North Carolina 27603

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

Dear Ms. Dunston:

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

Please do not hesitate to contact me should you have any questions. Thank you for your assistance with this matter.

Very truly yours,

/s/E. Brett Breitschwerdt

EBB:kjg

Enclosure

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 167

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:		
	)	**SEVENTH 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 ("Sub 167 Order"), and hereby respectfully provide this seventh 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 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 Sub 167 Order directed DEC and DEP to continue filing progress

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[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] 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 update the Commission and other interested parties on their progress in addressing the 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. The Companies continue to evaluate this issue with respect to designing more real-time as-available pricing options to better conform as-available pricing options to the intent of PURPA. The Companies are continuing discussions with the Public Staff and also plan to engage North Carolina Sustainable Energy Association ("NCSEA"), Southern Alliance for Clean Energy ("SACE"), and Carolinas Clean Energy Business Alliance ("CCEBA") in September on this issue.

- **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. The presentation shared with the stakeholder group at the August 19 meeting is attached as Attachment 1. The Companies plan to discuss the Companies' proposed CT cost calculation methodology in a follow up meeting in late September/early October.

- **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 Companies have continued discussions with the Public Staff on this issue and also 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 and plan to reengage to discuss the Companies' proposed PAF calculation methodology in a follow up meeting in late September/early October. The presentation shared with the stakeholder group at the August 19 meeting is included in Attachment 1.

- **<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 additionally engaged NCSEA, CCEBA, and SACE on this issue at the August 19 stakeholder meeting and plan to reengage to discuss the Companies' proposed methodology in a follow up meeting in late September/early October. The presentation shared with the stakeholder group at the August 19 meeting is included in <u>Attachment 1</u>.

- **<u>The Potential for QFs to Provide Ancillary Services and Appropriate Compensation</u>**

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, and they intend to have preliminary discussions with the Public Staff on this complex issue in the next 45 days. The Companies are also planning to engage with stakeholders in mid-September 2021 during the third Additional Issues stakeholder meeting on this topic.

- **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. A copy of the presentation shared with stakeholders at the September 2 meeting is attached as Attachment 2.

- **FERC's Order No. 872**

The Companies are continuing to review Order No. 872 and its impact on PURPA implementation in North Carolina. As they committed to do in their Continuance Motion, the Companies intend to develop their positions on Order No. 872's impact on PURPA implementation in North Carolina and to engage the Public Staff and other stakeholders on their positions in advance of their November 2021 filing.

Conclusion

As set forth above, the Companies continue to engage the Public Staff and stakeholders on the outstanding Sub 158 Additional Issues. The Companies also commit to engage with stakeholders on the Companies' positions with respect to the other Sub 158 Additional Issues in the September 2021 timeframe. The Companies will also continue to look for areas where consensus could be achieved with the Public Staff and the other stakeholders as they continue to develop their 2021 avoided cost filing.

Respectfully submitted, this the 7th day of September, 2021.

/s/E. Brett Breitschwerdt

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North Carolina 2021 Avoided Cost Stakeholder Meeting

August 19, 2021

Welcome and Ground Rules

- Level One Safety
- WebEx Instructions
  - Please mute microphones and video unless speaking or presenting
- We will take questions throughout the presentation and at the end of the meeting
  - Please use “raise your hand” function to ask questions
  - Will take questions in the order they were received
- Mailbox for questions and comments: ncavoidedcost@duke-energy.com

Agenda

Time	Description
9:00 – 9:05 AM	Welcome, Safety and Ground Rules (Terri Edwards)
9:05 – 9:20 AM	NC Avoided Cost Background; Scope and Goals for Stakeholder Meetings (Kendrick Fentress)
9:20 – 9:30 AM	Opening Comments (Glen Snider)
9:30 – 10:10 AM	Performance Adjustment Factor Metrics (Tom Davis)
10:10 – 10:40 AM	CT Capital Costs (Tom Davis)
10:40 – 10:50 AM	BREAK
10:50 – 11:35 AM	Substation Power Backflow (Brant Wertz)
11:35 AM – 11:45 AM	Additional Q&A/Comments; Closing Remarks

Background and Stakeholder Goals

October 30, 2020, NCUC Order Granting Continuance (Docket No. E-100, Sub 167):

- In providing an additional 365 days to address the Sub 158 Additional Issues, the Commission expects the Movants to make significant effort to address all of the Sub 158 Additional Issues, resolving these issues or otherwise achieving consensus with interested stakeholders before the commencement of the next biennial avoided cost proceeding.
- Additionally, the Commission expects and encourages 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.
- The Companies have reported on status of the Sub 158 Additional Issues in filings every 45 days at the Commission in Docket No. E-100, Sub 167.

Background and Stakeholder Goals

Sub 158 Issues:

- To cover today:
  - Cost increments and decrements to the publicly available combustion turbine (CT) cost estimates
  - Methodology for developing the performance adjustment factor (PAF)
  - Extent of backflow at substations
- To cover in future meetings:
  - Results of an independent technical review of the Astrapé Study on solar integration services charge (SISC) methodology
  - Other “Sub 158 Additional Issues,” as discussed in Duke’s 45-day updates in Docket No. E-100, Sub 167

Background and Stakeholder Goals

Anticipated general timeline:

- August – September:
  - August 19, 2021: Stakeholder Meeting on PAF, CT Costs and Substation Power Backflow
  - Early September 2021: Stakeholder meeting to communicate Technical Review Committee results of Astrape solar ancillary services study
  - Mid September: Stakeholder meetings on other Sub 158 additional issues
  - Late September: Follow Up Meeting on SISC TRC and Other Additional Issues
- November 1, 2021:
  - File application

North Carolina 2021 Avoided Cost Stakeholder Meeting

CT Capital Cost Review

August 19, 2021



Agenda

- Background / Review past NCUC Orders
- EIA Data and Assumptions
- Economies of Scale / Common Infrastructure
- Greenfield vs Brownfield Adjustments
- Conclusions

NCUC Docket No. E-100, Sub 140
2014 Avoided Cost Order

- Because the focus of the peaker **method is on a "hypothetical CT**," for the next phase of this proceeding, the Commission concludes that the utilities should use installed cost of CT per kW from publicly available industry sources, such as the EIA or PJM's cost of new entry studies or comparable data. Data on the installed cost of CT per kW taken from publicly available industry sources are to be tailored only to the extent clearly needed to adapt any such information to the Carolinas and Virginia. (Order on Inputs, at 48)

- It is appropriate to include economies of scale in the calculation of the installed cost of a CT. When constructing CT units, utilities are likely to construct up to four units at the same site. (Order on Inputs, at 9)

- It is inappropriate to include economies of scope in the calculation of the installed cost of a CT. When constructing CT units, utilities are unlikely to construct multiple units at the same time. (Order on Inputs, at 9)

- The hypothetical CT utilized by a utility for the purposes of determining avoided capacity rates should be based on the past operational history of the utility, as well as a reasonable expectation of the units the utility anticipates it will construct in the future. (Phase II Order, at 7)

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

- The Commission finds that the Utilities appropriately relied on publicly available industry sources for determining the installed per-kW cost of a CT and that their respective source information was tailored in a manner consistent with the guidance previously provided by the Commission.

- 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.

2020 EIA (Sargent & Lundy) Capital Cost Study

Independent Statistics & Analysis
U.S. Energy Information Administration

Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies

February 2020

https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

2020 EIA (Sargent & Lundy) Capital Cost Study
Simple Cycle CT

- The Advanced CT ("ACT") Facility produces 237 MW of electricity using a single natural gas-fueled, F-class CT and associated electric generator. The CT is equipped with an inlet evaporative cooler to reduce the temperature of the turbine inlet air to increase summer output.
- Cost estimate assumes a greenfield installation
- Cost estimate includes dual fuel capability

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 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

Preliminary – For Stakeholder Discussion Purposes Only

EIA Capital Cost Update – February 2021

Table 2 shows a full listing of the overnight costs for each technology and electricity region, if the resource or technology is available to be built in the given region. The regional costs reflect the impact of locality adjustments, including one to address ambient air conditions for technologies that include a combustion turbine and one to adjust for additional costs associated with accessing remote wind resources. Temperature, humidity, and air pressure can affect the available capacity of a combustion turbine, and EIA's modeling addresses these possible effects through an additional cost multiplier by region. Unlike most other generation technologies where fuel can be transported to the plant, wind generators must be located in areas with the best wind resources. Sites that are located near existing transmission with access to a road network or are located on lower development cost lands are generally built up first, after which additional costs may be incurred to access sites with less favorable characteristics. EIA represents this possibility through a multiplier applied to the wind plant capital costs that increases as the best sites in a region are developed.

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

Economies of Scale / Common Infrastructure

- Examples of economies of scale common infrastructure costs include the following:

  - Land Acquisition
  - Clearing and Grubbing
  - Earthwork
  - Roads
  - Admin Building
  - Natural Gas M&R Station
  - Municipal water tie
  - Fire Header
  - Demin Tank
  - Lights/Security/Fencing

CT Capital Cost with Greenfield Economies of Scale Adjustments

CT Capital Cost with Greenfield Economy of Scale Adjustments
(For Illustration Purposes Only)

EIA Cost Basis		**Comments**
Nominal Rating (MW)	237	EIA Cost Update, February 2021, Table 1
Total Capital Cost ($/kW)	649	EIA Cost Update, February 2021, Table 2
Total Capital Cost, 2020$	$ 153,813,000	2020$
Total Capital Cost, 2021$	$ 157,658,325	Overnight cost escalated to 2021$ based on 2.5% inflation rate

Economies of Scale Adjustments		**Comments**
Total Common Infrastructure Cost (%)	10%	Assume 10% for illustration purposes. These component costs represent the cost of a one to four unit CT plant regardless of the number of units.
Total Common Infrastructure Cost per Unit (%)	2.5%	
Common Infrastructure Cost Adjustment (%)	-7.5%	
Common Infrastructure Cost Adjustment ($)	$ (11,824,374)	2021 $
Total Adjusted Capital Cost ($)	**$ 145,833,951**	**2021 $**
Total Adjusted Capital Cost ($/kW)	**615**	**2021 $/kW**

Source: EIA Cost and Performance Characteristics, February 2021
https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

CT Capital Cost with Brownfield Site Adjustments

CT Capital Cost with Brownfield Site Adjustments

(For Illustration Purposes Only)

		Comments
EIA Cost Basis		**Comments**
Nominal Rating (MW)	237	EIA Cost Update, February 2021, Table 1
Total Capital Cost ($/kW)	649	EIA Cost Update, February 2021, Table 2
Total Capital Cost, 2020$	$ 153,813,000	2020$
Total Capital Cost, 2021$	$ 157,658,325	Overnight cost escalated to 2021$ based on 2.5% inflation rate
Economies of Scale Adjustments		**Comments**
Total Infrastructure Cost (%)	10%	Assume 10% for illustration purposes
Total Infrastructure Adjustments ($)	$ (15,765,833)	2021 $
Total Adjusted Capital Cost ($)	**$ 141,892,493**	**2021 $**
Total Adjusted Capital Cost ($/kW)	**599**	**2021 $/kW**

Source: EIA Cost and Performance Characteristics, February 2021
https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

Conclusions

- The goal of developing avoided capacity costs is to strike a balance between using transparent, publicly-available data and tailoring that data to the Carolinas 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 applied to greenfield and brownfield sites
  - Greenfield economies of scale adjustments would spread the common infrastructure costs among 4 CT units
  - Brownfield site adjustments would credit the full amount of common infrastructure costs

- DEC and DEP do not currently have any greenfield projects in the transmission interconnection queue

- Applying cost increments/decrements to a brownfield site (or existing operating site) is consistent with the Companies' plans to construct new generation

Planned Methodological Approach

- Calculate 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 vs brownfield cost differential is relatively small
- The percentage adjustment to apply to the EIA data to reflect the economies of scale savings associated with constructing multiple units is under review
  - Stakeholders are encouraged to provide feedback and identify suggested data sources to assist in this effort

North Carolina 2021 Avoided Cost Stakeholder Meeting

Substation Power Backflow Review

August 19, 2021

Agenda

- Background on the inclusion of line losses in avoided cost
- NCUC Docket No. E-100 Sub 158 rulings on backflow analysis
- Additional backflow analysis performed
- Backflow criteria for elimination of line loss adder
- Conclusions

Consideration of Line Losses in Setting Avoided Costs

18 C.F.R. 292.304(e)(2)(iv):

(e) Factors affecting rates for purchases.

(2) . . . the following factors shall, to the extent practicable, be taken into account in determining rates for purchases from a qualifying facility:

(iv) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

N.C. Gen. Stat. § 62-156(c):

(c) Rates to be paid by electric public utilities to small power producers not eligible for the utility's standard contract . . . shall take into account factors related to the individual characteristics of the small power producer, as well as the factors identified in subdivisions (2) and (3) of subsection (b) of this section. . . .

Line Losses impact on Avoided Costs

Marginal Loss Factor

- Transmission and distribution losses are calculated based on each region's system to support a variety of regulatory requirements
- Based on these losses, a marginal loss factor is applied to each season or time period in the avoided cost tariff

Transmission vs Distribution Qualifying Facility (QF) Interconnections

- Transmission interconnections receive additional energy and capacity credit to account for avoided losses from generator step-up transformers (GSU)
- In addition to the avoided GSU losses, distribution interconnections also receive the energy and capacity credit for avoided losses from transmission lines, substation step down transformers (T/D)

Impact of Backflow on Line Losses

- The line losses used in the avoided cost tariff are system averages based on historical loads and do not reflect the impact of generation being concentrated at certain times of day or at certain substations.

DEC E-100, Sub 167 – Energy Credit Impact

E-100, Sub 167

REDACTED Exhibit 2
Page 1

DUKE ENERGY CAROLINAS, LLC
Energy Credits
Uncontrolled Solar Generation

Distribution
Based on 2021-2022 Costs (Variable Rate)
Cents per KWH

		DEC Summer Prem-Peak (Cents/KWH)	DEC Summer PM-Peak (Cents/KWH)	DEC Summer Off Peak (Cents/KWH)	DEC Winter Prem-Peak (Cents/KWH)	DEC Winter AM-Peak (Cents/KWH)	DEC Winter PM-Peak (Cents/KWH)	DEC Winter Off Peak (Cents/KWH)	DEC Shoulder Peak (Cents/KWH)	DEC Shoulder Off Peak (Cents/KWH)
1.	Avoided Energy Cost (Note 1)	3.48	2.74	2.54	3.76	0.73	3.12	2.75	2.17	2.67
2.	Working Capital Factor (Note 2)	1.015	1.015	1.015	1.015	1.015	1.015	1.015	1.015	1.015
3.	Marginal Loss Factor (Note 3)	1.040	1.037	1.020	1.034	1.028	1.028	1.022	1.021	1.016
4.	Unadjusted Energy Credits (L1*L2*L3)	3.67	2.88	2.63	3.95	0.77	3.26	2.86	2.25	2.75
5.	Integration Services Charge (Note 4)	-0.110	-0.110	-0.110	-0.110	-0.110	-0.110	-0.110	-0.110	-0.110
6.	Energy Credits (L4 + L5)	3.56	2.77	2.52	3.84	0.66	3.15	2.75	2.14	2.64

3. Marginal Loss Factor = 1 / (1 - % loss/100)

Based on marginal % losses of: Applies to:	Transmission Losses (Incl Step Up and Step down Transformer) Distribution level Interconnections	Step Up Transformer Losses Transmission level Interconnections
DEC Summer Prem-Peak	3.881%	0.149%
DEC Summer PM-Peak	3.544%	0.136%
DEC Summer OffPeak	1.999%	0.077%
DEC Winter Prem-Peak	3.255%	0.125%
DEC Winter AM-Peak	2.744%	0.106%
DEC Winter PM-Peak	2.754%	0.106%
DEC Winter OffPeak	2.115%	0.081%
DEC Shoulder Peak	2.058%	0.079%
DEC Shoulder OffPeak	1.530%	0.059%

DEC PPA - Capacity Credit Impact

E-100, Sub 167

REDACTED Exhibit 2
Page 6

DUKE ENERGY CAROLINAS, LLC
All Generation but Hydroelectric Generation without Storage
Capacity Cost for Determination
of Capacity Credits

(2020 $000s)

		Distribution		Transmission	
		CT Cost	FOM (6)	CT Cost	FOM (6)
1	Installed Combustion Turbine Cost (Note 1)	[redacted]			
2	Combustion Turbine Fixed Charge Rate (Note 2)	8.20%		8.20%	
3	Annual Combustion Turbine Carrying Cost (L1*L2)	[redacted]			
4	General Plant Factor (Note 4)	3.62%		3.62%	
5	Adjusted Annual Combustion Turbine Carrying Cost (L3 + (L3*L4)	[redacted]			
6	Combustion Turbine Fixed O&M Expenses	[redacted]			
7	Working Capital Factor (Note 4)		1.0361		1.0361
8	Subtotal (L5+(L6*L7))	[redacted]			
9	Performance Adjustment Factor (Note 5)	1.06	1.06	1.06	1.06
10	Marginal Loss Factor (Note 7)	1.0294	1.0294	1.0011	1.0011
11	Annual Capacity Cost (L8*L9*L10)	[redacted]			

7. Distribution:
   Based on marginal % loss of:
   On Peak 2.859% Loss factor = (1/(1 - On Peak loss%))
   Transmission:
   Step-Up Transformer Loss: 0.110% Loss factor = (1/(1 - Step up loss%))

NCUC Docket No. E-100, Sub 158

Sub 158 Order at Findings No. 13-15, pg. 9

13. Power backflow on substations in DENC's North Carolina service territory from solar generation on the distribution grid continues to increase such that avoided line loss benefits associated with distributed generation have been reduced or negated.

14. It is appropriate for DENC not to include a line loss adder in its standard offer avoided cost payments to solar QFs on its distribution network.

15. It is appropriate to require DEC and DEP to continue to include the line loss adjustments in their standard offer avoided energy calculations, to study the effects of distributed generation on power flows on their electric systems to determine if there is sufficient power backflow at their substations to justify eliminating the line loss adjustment from their standard offer avoided cost calculations filed in the next avoided cost proceeding, and to evaluate whether power committed to be sold and delivered by distribution-connected QFs not eligible for the standard offer is causing power backflow on the substation and whether the line loss adjustment is appropriate based upon the characteristics of the individual QF's power.

NCUC Docket No. E-100, Sub 158

Sub 158 Order at EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13 – 15, p. 34-36

“The Public Staff further recommends that in the next avoided cost proceeding the Commission require DEC and DEP to take into account the aggregate amount of renewable generation that will be, or is expected to be, interconnected by the end of the CPRE Program in their consideration of line loss impacts. Public Staff Initial Comments at 72-73.”

“The Commission also finds that it is appropriate for DEC and DEP to continue to incorporate the line loss factor in their standard offer avoided energy calculations at this time. With regard to Duke’s proposal to assess the individual characteristics of the QF that is not eligible for Schedule PP standard offer rates and to address the line loss adder as part of the PPA negotiation process, the Commission agrees with Duke that such an analysis is consistent with N.C.G.S. § 62-156(c) by taking into consideration the individual characteristics of the QF. Lastly, the Commission finds it appropriate to require the Utilities to continue to study the impact of distributed generation on power flows on their distribution circuits and to provide the results of those studies as a part of their initial filings in the next biennial avoided cost proceeding.”

Docket No. E-100, Sub 167

Bank Reverse Flow Analysis performed in 2020

From Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Joint Initial Statement and Exhibits Docket No. E-100, Sub 167, Pgs. 22-25

3. An avoided energy line loss adjustment continues to be appropriate for standard offer distribution-interconnected QFs

"Currently, in DEP, 100 out of 408 substation banks, or 24.5%, are backfeeding into the transmission system due to distribution-connected generation. The Companies' analysis further indicates that despite the high number of queued projects requesting to interconnect to the DEP distribution system in the near future, only about 132 out of 408 substations, or 32% of DEP's substations, are estimated to experience backfeed before the projects being addressed by this avoided cost proceeding start connecting."

"For DEC, the percentages of substation banks currently experiencing backfeed due to distribution-connected projects is significantly less – only 4.2%. Even accounting for the estimated impact of queued projects requesting to interconnect to the DEC distribution system, this number only grows to 7.7%."

Docket No. E-100, Sub 167

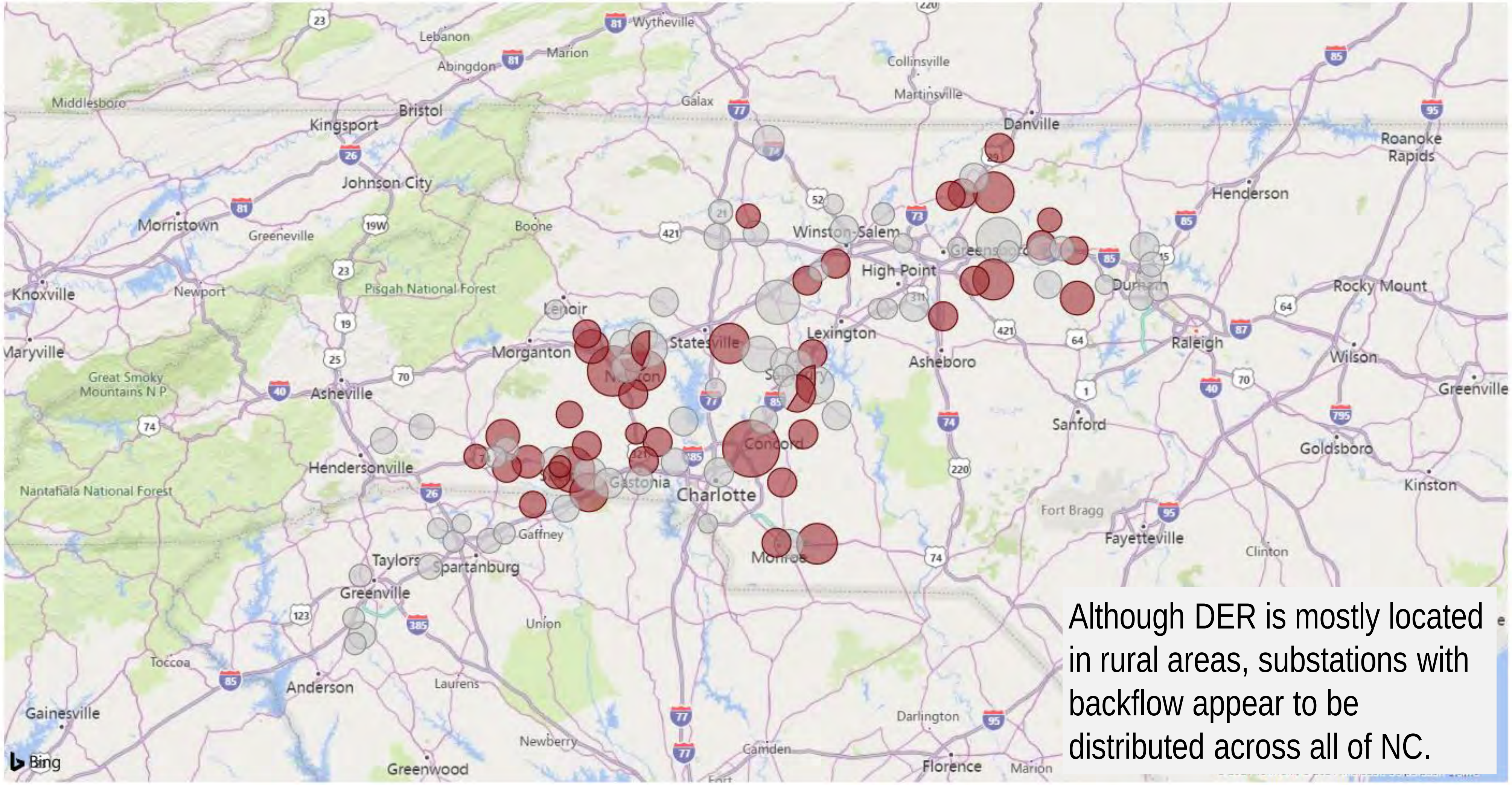
Bank Reverse Flow Analysis performed in 2020

Bank Reverse Flow Calculations					Capacity Factor Assumption	
Updated: 5/27/2020					0.2	
Based on 2019 data sourced from ISOP Data System (PI, FMS) and DET Datamart						
	Banks Analyzed	**Reverse Flow Banks due to DER**	**% of Banks**	**Reverse Flow Energy [MWh]**	**Estimated DER Generation [MWh]**	**% of DER Output that is Reverse Flowing (estimated)**
DEC	1041	44	4.23%	49,749	1,288,124	3.862%
DEP	408	100	24.51%	361,958	2,985,280	12.125%
Added: 10/23/2020						
Estimated based on a ratio of median bank load vs generation. Assumes all distribution queue generation connects.						
	Banks Analyzed	**Reverse Flow Banks due to DER**	**% of Banks**			
DEC	1041	80	7.68%			
DEP	408	132	32.35%			

Geographical Concentrations - DEC

DEC Substation Banks with Backflow due to DER (bubble size indicates MW Capacity of DER)

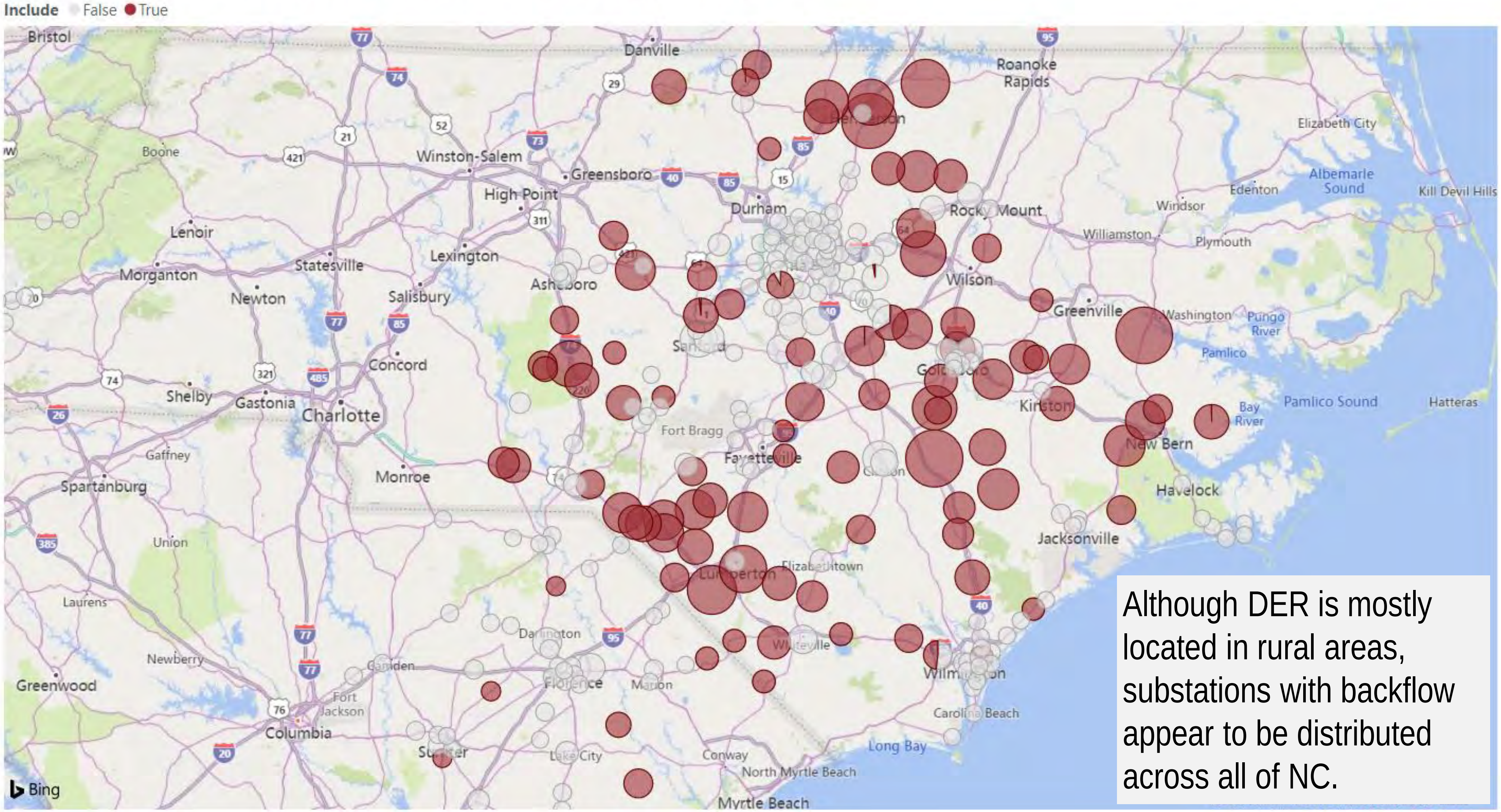
Include ● False ● True



Although DER is mostly located in rural areas, substations with backflow appear to be distributed across all of NC.

Geographical Concentrations - DEP

DEP Substation Banks with Backflow due to DER (bubble size indicates MW Capacity of DER)



Although DER is mostly located in rural areas, substations with backflow appear to be distributed across all of NC.

Preliminary – For Stakeholder Discussion Purposes Only

Introduce 50% Backflow Criteria

Line loss benefits despite backflow

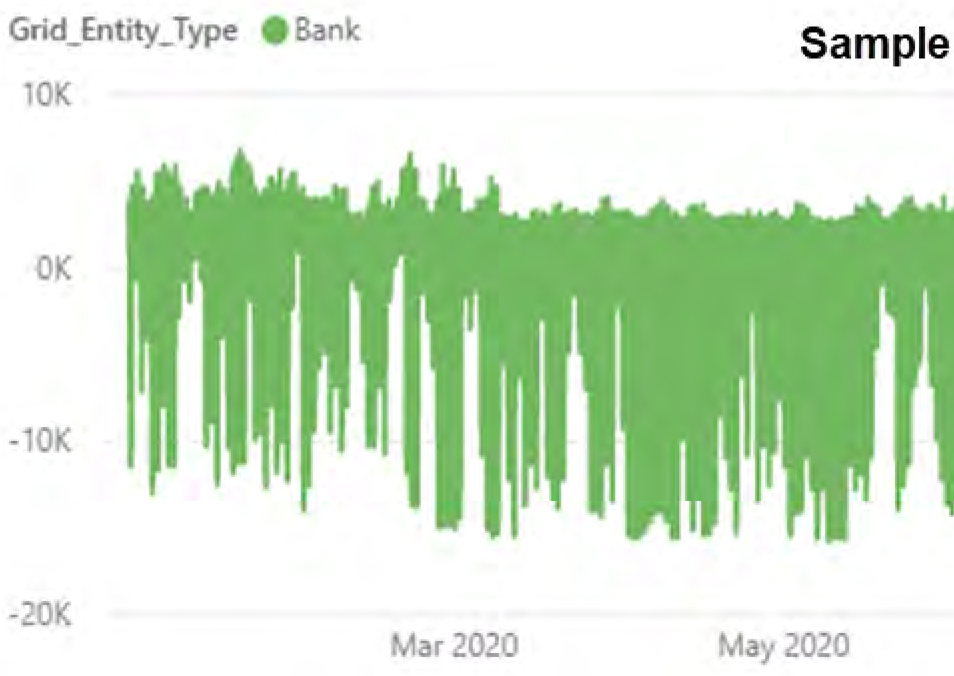
Although backflow starts to offset the line loss benefits of distribution-connected generation, recent results from DG cost of service study work with NC State suggests that significant backflow is required before you would expect to see an increase in marginal losses (“DG Cost of Service: Sample Case Studies”, pg. 41) .

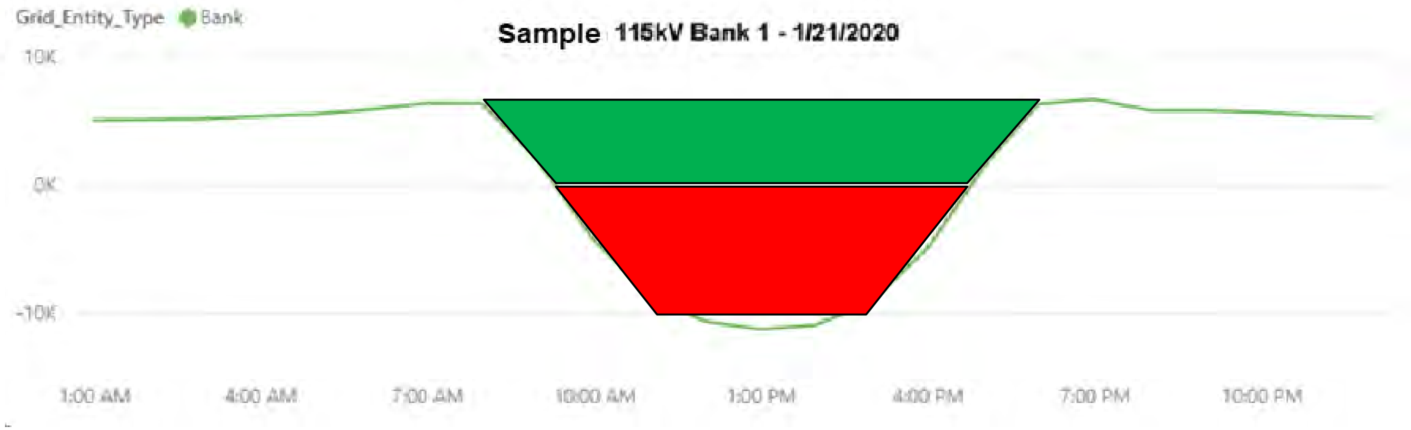
50% Backflow Criteria

To calculate the point in which the next MW of generation would cause a negative marginal loss impact would require detailed gross and net load information. This data is not currently available to reliably perform this calculation so instead the 50% backflow criteria is provided as a proxy for when additional generation on that substation bank would cause more backflow than it would offset load. This is calculated based on a ratio of the annual backflow energy divided by an estimate of the DER annual generation.

$$\frac{\sum Substation\ Backflow}{Capacity\ Factor\ \%\ x\ DER\ Capacity\ x\ 8760} \geq 50\%$$

Example of 50% DER Backflow





For all of 2020, 50% of the DER energy output offsets load and 50% backflows into the transmission system. Any additional DER would increase backflows while only offsetting a small amount of load.

Impact of 50% Backflow Criteria

Substation banks that currently meet 50% criteria:

- 4 banks in DEP
- 2 banks in DEC

Impact of 1 MW standard offer QF's

- Only 4 banks were identified that could go from below 50% to above 50% backflow due to the addition of 1 MW of generation. 3 of those banks have reached their ONAN limit per the Method of Service Guidelines and therefore no additional QF's can receive an interconnection agreement.
- Therefore, DEC and DEP will continue to offer the line loss adder as part of the standard-offer PPA

Impact of Negotiated PPA QF's

- No distribution-connected projects have signed negotiated PPA's under Sub 158 rates
- Distribution-connected QF's not expected to play a large role in future renewables growth
- However, a single QF can have a capacity up to 20 MW and still interconnect to distribution and would likely cause significant backflow to the transmission system

Elimination of Line Loss Adder - Criteria

Criteria:

- QF is not eligible for standard offer
- QF is interconnecting to distribution
- QF does not have an existing IA
- One of the criteria below:
  - The substation bank that serves the distribution point-of-interconnect has DER backflow >=50%
  - The addition of the QF would cause DER backflow to become >=50%

Rate Impact:

- If criteria is met, the QF would receive the transmission rates that exclude marginal loss factors for capacity and energy
- These avoided energy rates are approximately 3% less than the rates for a QF interconnecting to distribution

Conclusions

- DEC and DEP are both experiencing increasing levels of backflow into the transmission system due to DER.
- The percentage of banks with backflow is still much lower than what Dominion Energy North Carolina has experienced. Also, distributed generation in DEC and DEP is not as geographically concentrated as in DENC.
- Some backflow into the transmission system is not likely to offset the line loss benefits of DER but there is a point in which additional generation will start to increase substation losses
- The impact of 1 MW standard offer QF's is not likely to have a large impact on backflow in the near-term so there are currently no plans to change the line loss adder criteria in the standard offer PPA.
- A QF with a negotiated PPA (> 1 MW), could backflow a significant amount of energy into the transmission system and, when the 50% criteria is met, will receive the transmission rate without the line loss factor.

DUKE ENERGY®

Duke Energy Carolinas / Duke Energy Progress

Solar Integration Services Charge Technical Review Committee
Stakeholder Information Outreach Session





DUKE ENERGY®

BUILDING A ***SMARTER*** ENERGY FUTURE®

September 2, 2021

Safety Moment / Friendly Reminders / Opening Remarks

- Safety Moment

- Friendly Reminders
  - Everyone is muted
  - Please use the Raise your Hand function in WebEx if you have a question, we will call on you
  - Participants may also submit questions throughout this meeting via the chat feature
    - Please use the chat feature for any technical issues

BUILDING A SMARTER ENERGY FUTURE℠

- Glen Snider, Director, Carolinas IRP & Analytics
  - Opening Remarks
    - As we will discuss in more detail today, both the SC Commission and the NC Commission have directed Duke to undertake, organize, and coordinate a Technical Review Committee (TRC) to review the modeling, inputs and assumptions of the Solar Integration Services Charge (SISC).
    - We will describe how, with input from both the NC Public Staff and SC−ORS, Duke assembled the TRC consistently with the directives of the NC and SC Commission Orders.

TRC Principal Consultant: The Brattle Group

The Companies, with input from the NC Public Staff and SC Office of Regulatory Staff (“ORS”), retained The Brattle Group (“Brattle”) as TRC Principal consultant who coordinated the TRC meetings, facilitated review of the study methodology and the model used for system simulations, incorporated feedback from the TRC Technical Leads, and authored the TRC report for the Companies to incorporate into their 2021 regulatory filings.

- Hannes Pfeifenberger, Principal
- John Tsoukalis, Principal
- Stephanie Ross, Associate

Brattle

Technical Review Committee Report for Duke's Solar Integration Service Charge (SISC)

PRESENTED BY

Hannes Pfeifenberger

John Tsoukalis

On behalf of the

SISC Technical Review Committee

SEPTEMBER 2, 2021

Agenda

- **Review of TRC Process**
- **Summary of Issues Considered and Recommendations made by the TRC**
- **TRC Overview of Preliminary Astrapé Results**
- **Questions and Comments**

About the Brattle team

The Brattle team assists electric utilities, independent system operators, generation and transmission developers, electricity customers, regulators, and policymakers with planning, regulatory, and market design challenges in the electricity industry. Relevant experience also includes addressing renewable integration challenges, power system simulations, applications of the SERVM simulation tool, and collaborations with national labs.

Hannes Pfeifenberger
Principal, Boston

John Tsoukalis
Principal, Washington DC

Stephanie Ross
Associate, Boston

TRC Members

In addition to the Brattle team, three technical leads from the National Labs with relevant experience and expertise are serving on the TRC:

- Nader Samaan – Chief Engineer and Team Lead (Grid Analytics), Electricity Security Group at Pacific Northwest National Laboratory (PNNL)

- Gregory Brinkman – Researcher V-Model Engineering and Member, Grid Systems Group in the Strategic Energy Analysis Center at National Renewable Energy Laboratory (NREL)

- Andrew Mills – Staff Scientist, Electricity Markets and Policy Group at Lawrence Berkeley National Lab (LBNL)

Regulatory Observers Participating in TRC Meetings

- Observers from the NC Public Staff:
  - Jeff Thomas (primary)
  - Dustin Metz (alternate)
- Observers from the SC Office of Regulatory Staff:
  - Robert Lawyer
  - O'Neil Morgan
  - Gretchen Pool

- The participation of the NC Public Staff and SC ORS Regulatory Observers is designed to encourage **open dialogue and ensure the transparent nature** of the TRC review process.

- The positions or perspectives raised by the Regulatory Observers in those discussions do not, however, limit the ability of those agencies to ultimately agree or disagree with the findings of the TRC or to take positions in later proceedings that do not align with the TRC's findings and recommendations.

Overview of Work Conducted by the TRC

The TRC met twice a month with Astrapé to conduct an independent review of the methodology and assumptions used to develop the SISC

- Input was provided by the regulatory observers, and where appropriate, by Duke subject-matter experts
  - For example, Duke staff assisted in the review of system operations under the joint dispatch agreement, the operating characteristics of Duke's generation, and solar curtailment rules under PURPA contracts
- The TRC requested sensitivities and additional analyses from Astrapé to inform their review of the estimated SISC
- The TRC made recommendations to Astrapé to modify their methodology and assumptions
  - For example, the TRC requested modeling of the Joint Dispatch Agreement (JDA) between DEC and DEP
- The TRC reviewed stakeholder comments and made recommendations based on their review
  - The only set of comments received were provided by the Southern Environmental Law Center (SELC)
- The Brattle team prepared the TRC report with input from the technical experts, and considering comments by stakeholders and regulatory observers during the TRC meetings

Agenda

- Review of TRC Process
- **Summary of Issues Considered and Recommendations made by the TRC**
- TRC Overview of Preliminary Astrapé Results
- Questions and Comments

1. The Joint Dispatch Agreement (JDA)

The TRC recommended Astrapé model the JDA, and believes this better represents system operation and the cost of integrating solar resources

- The JDA allows Duke to conducted joint unit commitment and dispatch for all generation resources in DEC and DEP (while retaining individual BAA obligations for DEC and DEP)
- The TRC discussed the operation of the JDA with Duke subject matter experts
  - Based on those conversations, the TRC recommended Astrapé model the JDA in a combined DEC-DEP sensitivity
  - The TRC understands that Duke is required to hold operating and load following reserves independently for the DEC and DEP BAAs, and the Astrapé modeling reflects that constraint
  - The JDA nevertheless allows for lower cost provision of load following reserves than islanded operation
- The TRC finds that modeling the JDA is an improvement on the original study methodology, and recommends that the Commissions refer to Astrapé JDA case results in setting the SISC

2. The Proposed Southeast Energy Exchange Market (SEEM)

The TRC did not recommend that the SEEM be modeled in this estimate of the SISC, but should be included in future estimates

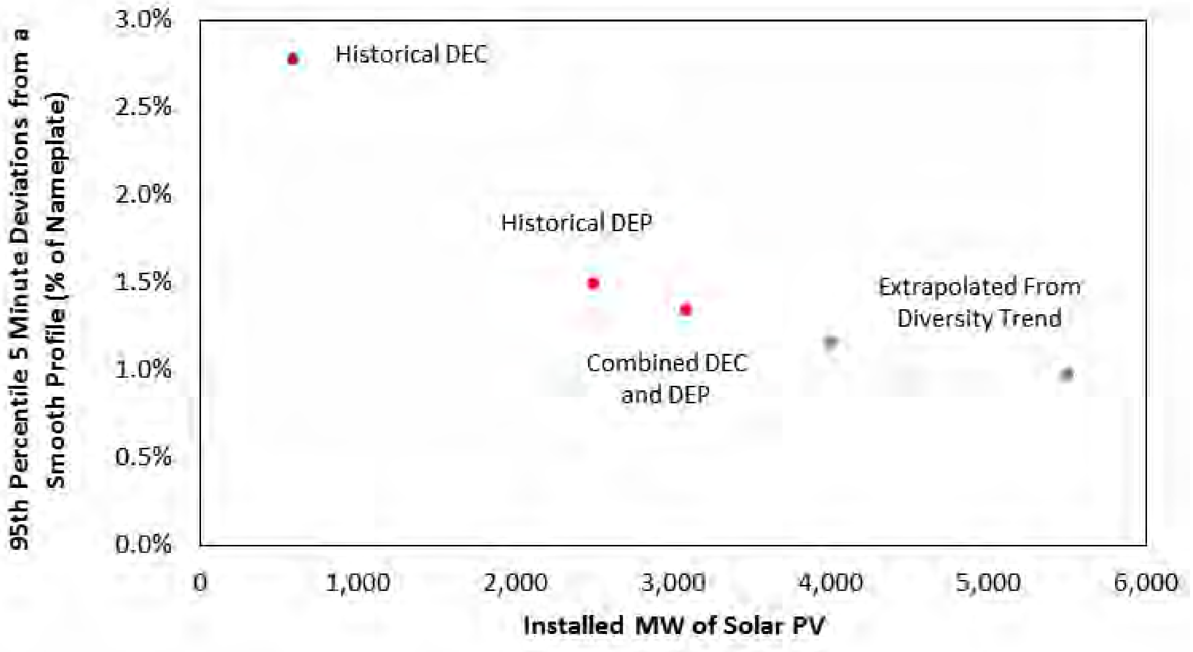
- The proposed SEEM will allow for 15 minute trading of energy between Duke and its neighbors
  - The TRC discussed the proposed market design with Duke subject matter experts.
  - The TRC understands that trades will need to be locked in 5-10 minutes prior to the 15 minute trading period, implying that the SEEM could respond on a 20-25 minute basis to help balance solar volatility.
    - The TRC debated, but did not ask Astrapé to analyze, whether the SEEM would actually reduce the cost of integrating solar due to the 20-25 minute time lag between locking in trades and real-time
- The proposed market rules for the SEEM have yet to be approved by FERC, which leaves uncertainty regarding the market design.
- Based on this uncertainty, the TRC does <u>not</u> recommend that the SEEM be modeled at this time
  - Once SEEM market rules are finalized and there is an operational history with the SEEM, it should be included in simulations to derive SCIC estimates

3. Solar Volatility and the Benefit of Geographic Diversity

The TRC found Astrapé appropriately accounts for the geographic diversity of new solar and the declining per MW volatility as installed solar MW increase

- Astrapé plotted the declining relationship between solar volatility and installed capacity based on the recent historical volatility of Duke's solar resources
  - Observed three data points: DEC, DEP, and combined
- The extrapolated trend from historical data is used to model solar volatility at higher levels of installed solar capacity
- The TRC finds that this approach is a significant improvement over the 2018 study and includes the benefit of declining per-unit volatility as new solar resources come online

Solar Capacity vs. Volatility from Astrapé Study



4. Solar Curtailments

The TRC finds not including an penalty for solar curtailments aligns with system operation and is conservative with respect to the SISC

- The TRC observed that simulated solar curtailments in the model are significant (14% in DEP under Tranche 2 in the Island Case)
  - The JDA Case only saw solar curtailments of 3% under Tranche 2 in the combined DEC-DEP system
  - Note: only a small portion of the curtailments are due to intra-hour load following constraints
- The TRC asked Astrapé to conduct a sensitivity with an economic penalty for solar curtailments
  - The economic penalty did not reduce curtailments significantly and resulted in a slightly higher SISC, indicating that solar curtailments provide relatively low-cost supply of load following reserves
  - Higher curtailments are likely to result in higher overall system costs, even though they lower the SISC
- The regulatory observers and Duke subject matter experts indicated that Astrapé's approach (no penalty for curtailments) is more consistent with PURPA contracts in the Carolinas
- Based on the results of the sensitivity, the TRC did not recommend any change to Astrapé's approach

5. The Operational Flexibility of Duke Generation Resources

The TRC investigated the modeling assumptions related to resource flexibility and concluded that they accurately reflect actual operating constraints

- The TRC observed that the modeled operating characteristics for some of Duke's CTs and their pumped storage resources seems relatively inflexible compared to similar resources owned by other utilities
  - DEC pumped storage resources (Jocassee and Bad Creek) must have all units operating in the same direction (e.g., pumping or generating), the units all have a single pumping capacity (i.e., no flexibility when pumping), and limited difference between min and max generation when generating:
    - Bad Creek units 1-4 can generate between 320 and 420 MW
    - Jocassee units 1-4 can generate between 170 and 195 MW
  - DEC Lincoln and Mill Creek CTs are completely block-loaded (i.e., operate only at max gen)
- The TRC met with subject matter experts at Duke to discuss the operational capabilities of these resources and found that the modeling assumptions accurately reflect unit constraints
  - Investments to upgrade the pumped storage resources would be necessary to increase their flexibility
  - The CTs are relatively small, allowing for some flexibility by committing them individually within the hour

6. The Addition of Flexible Generation Resources to Duke's Fleet

The TRC found that the load following needed (under Tranche 2) for integration likely cannot be provided at a lower cost with new flexible resources

- For Tranche 2, Astrapé estimates solar integration costs in the JDA Case of **$24.3 million/year**
  - The *average* additional load following reserves needed for integration are 204 MW
  - The *maximum* load following needed is more likely to be around 470 MW
- Industry studies suggest new 1-hour battery storage can be added for $55-$87/kW-year
  - Therefore, building or contracting 470 MW of 1-hour batteries would cost **$26.9 to $41.1 million/year**
- At higher levels of solar penetration, new flexible resources may be more cost effective than using Duke's convention resources to provide the needed load following
- New battery resources would provide other benefits to Duke customers; if taken together all the benefits may justify the cost of new batteries
- The TRC concluded that the Commissions can decide to analyze adding additional flexible resources through Duke's resource planning processes

7. Methodology for Modeling Addition of Load Following Reserves

Astrapé improved the methodology for adding load following reserves by adding varying levels of reserves and only in hours with solar production

- In the 2018 study, the model added fixed blocks of reserves in all hours to eliminate flexibility violations
  - This resulted in more reserves than needed (especially in non-solar hours), causing higher estimated solar integration costs
- The current methodology adds load following reserves only in solar production hours and only in amounts necessary until flexibility violations return to the level observed in the no solar case
- The TRC finds that the new approach represents a significant improvement over the previous approach, and is consistent with how other system operators hold the additional load following needed to integrate solar

8. Benchmarking the Estimated Cost of Reserves

The TRC found that the estimated cost of load following reserves is reasonable based on the characteristics of Duke's system

- The TRC benchmarked the estimated cost of load following reserves against reserve prices in PJM
  - The estimated cost of intra-hour load following from the Astrapé model in the JDA Case is $17.25/MWh (Tranche 1) and $20.45/MWh (Tranche 2)
  - The cost of 5-minute regulation reserves in PJM was $13.55/MWh in 2020 and $16.27/MWh in 2019
    - The comparison to 5-minute regulation in PJM is not a perfect comparison, as the load following reserve in the model is a 10-minute product.
- The higher cost of load following for the Duke system is expected given the smaller size of the footprint and the relative low flexibility of some of Duke's generation fleet
- The TRC concluded that the estimated cost of load following reserves was reasonable compared to the neighboring market region (PJM).

9. Suggestions from the SELC

The TRC reviewed and discussed all the conceptual suggestions submitted by SELC; some aligned with the TRC's view and were implemented

- Many of SELC's suggestions aligned with the TRC's view and were implemented by Astrapé:
  - **Account for the JDA:** The TRC recommended this change and it was implemented by Astrapé
    - The JDA Case modeled by Astrapé produces a lower estimated SISC charge for DEC and DEP
  - **Allow Non-Spin Reserves to Provide Load Following:** This was already reflected in the Astrapé approach
  - **Account for Aggregation Benefits at Higher Solar Levels:** Astrapé made several adjustments since the 2018 study that account for the benefit of reduced volatility due to the diversity of a larger solar portfolio
  - **Address the High Cost of Conventional Generator Inflexibility:** The TRC reviewed assumptions on conventional resources and concluded that they are accurate, though some of Duke's resources are less flexible than expected
    - The TRC observed that the estimated integration costs may be large enough to support investment in new flexible resources at higher future levels of solar penetration (e.g., Tranche 3)
    - The SELC recommended that inflexible conventional resource pay an inflexibility charge; the TRC found that this would not be a common approach and is a topic for the Commissions to address

9. Suggestions from the SELC (cont'd)

- Some of SELC's suggestions were not implemented in the study:
  - **Model NERC Standards:** The TRC did not recommend Astrapé model the NERC standards, for several reasons:
    - The approach used by Astrapé is a significant improvement over the 2018 study, and is likely conservative given the perfect 5-minute foresight used in the model (actual solar ramps would be larger than modeled)
    - Modeling the NERC standards would require a model of the entire Eastern Interconnection; given the limitations of this study scope the TRC did not recommend implementing this change
    - The TRC questioned if it is appropriate to model NERC standards if Duke's historical operation was more conservative (i.e., provided higher reliability than required). Modeling lower reliability than historically achieved (even if complying with NERC standards) would shift benefits from customers (who benefit from higher reliability) to solar resources
  - **Account for the Proposed SEEM:** The TRC did not recommend Astrapé model the SEEM
    - The TRC recommends that the SEEM be modeled in future estimates of the SISC, once the market design in approved and there is some operational history in the SEEM
  - **Validate the Results Against Historical Reserve Levels:** The TRC discussed this as a potential benchmark, but found that comparing against historical reserve levels held by Duke may not be informative
    - Historical data would be based on lower solar penetration and different system conditions than represented in the model (e.g., fuel costs, coal retirements, water conditions, etc.)

10. Interpretation of Tranches Modeled by Astrapé

The TRC recommends that the Commissions not consider the Tranche 3 results when establishing the SISC

- The solar generation levels modeled in Tranche 1 and 2 are consistent with recent resource plans for solar development in DEC and DEP
  - Tranche 3 models significantly more solar penetration than contained by Duke's recent resource plans
  - Tranche 3 is illustrative of potential future integration needs, but is largely speculative at this point
    - Duke's conventional resource mix will likely change before reaching the solar penetration levels modeled in Tranche 3, which will alter the integration cost

	Installed Solar Capacity (MW)	
	DEC	DEP
Tranche 1	967	2,908
Tranche 2	2,431	4,019
(Tranche 3*	3,931	5,519)

** Tranche 3 models solar penetration levels beyond current plans; it is included for illustrative purposes only*

Agenda

- Review of TRC Process
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- **TRC Overview of Preliminary Astrapé Results**
- Questions and Comments

Overview of Preliminary Astrapé Results

Astrapé's preliminary results show a range of integration charges from $0.63/MWh to $2.41/MWh, depending on the solar penetration and utility

Preliminary Estimated SISC from Astrapé Study ($/MWh)

	Island Case		Combined Case	
	DEC	DEP	DEC	DEP
Tranche 1	$1.00	$2.01	$0.63	$1.68
Tranche 2	$1.43	$2.41	$1.05	$2.26

- The Combined Case illustrates the savings from the JDA between DEC and DEP
- A draft Astrapé report was circulated to participants, which includes details of the modeling approach and a complete set of results
  - A final report will be filed with the Commissions

Overview of Preliminary Astrapé Results:
Summary of Cases

- Astrapé estimated the SISC under three levels of solar penetration (all compared to a *no solar case*)

	Installed Solar Capacity (MW)	
	DEC	**DEP**
Tranche 1	967	2,908
Tranche 2	2,431	4,019
(Tranche 3*	3,931	5,519)

** Tranche 3 models solar penetration levels beyond current plans; it is included for illustrative purposes only*

- Astrapé simulated two cases:
  - The ***island case*** that conducted unit commitment and dispatch independently for DEC and DEP; and
  - The ***combined case*** that reflects the Joint Dispatch Agreement (JDA), allowing for joint unit commitment and dispatch between two companies
    - Recognizing individual BAA obligations, such as operating reserves

Overview of Preliminary Astrapé Results:
Annual Solar Integration Costs

Total annual integration costs decline (relative to the Island case) when the JDA is considered:

- From **$13.3 million/year** to **$10.7 million/year** under Tranche 1
- From **$27.6 million/year** to **$24.3 million/year** under Tranche 2

Summary of Results from Astrapé Study

		Tranche 1			Tranche 2		
		DEC	DEP	Combined	DEC	DEP	Combined
	Solar Capacity (MW)	967	2,908	3,875	2,431	4,019	6,450
	Solar Generation (MWh)	1,887,513	5,677,206	7,564,719	5,279,071	8,312,634	13,591,705
Island Case	10-min LF Reserves During Solar Hours (Island Case)	12	95	106	46	157	204
Island Case	Island Case Integration Costs ($)	$1,886,777	$11,422,833	$13,309,610	$7,555,552	$20,015,360	$27,570,912
Island Case	Island Case Average SISC ($/MWh)	$1.00	$2.01	$1.76	$1.43	$2.41	$2.03
JDA Case	10-min LF Reserves Cost in JDA Case ($/MWh)	$17.25	$17.25	$17.25	$20.45	$20.45	$20.45
JDA Case	JDA Case Integration Costs ($)	$3,174,863	$7,542,222	$10,717,085	$9,645,181	$14,691,557	$24,336,737
JDA Case	JDA Case Average SISC ($/MWh)	$0.63	$1.68	$1.42	$1.05	$2.26	$1.79
JDA Case	JDA Case Incremental SISC ($/MWh)	n/a	n/a	n/a	$1.29	$3.51	$2.26

Overview of Preliminary Astrapé Results:
SISC Estimates

SISC estimates also decline (relative to the Island case) when the JDA is considered

- From **$1/MWh** to **$0.63/MWh** (for DEC) and **$2.01/MWh** to **$1.68/MWh** (for DEP) under Tranche 1
- From **$1.43/MWh** to **$1.05/MWh** (for DEC) and **$2.41/MWh** to **$2.26/MWh** (for DEP) under Tranche 2

Summary of Results from Astrapé Study

		Tranche 1			Tranche 2		
		DEC	DEP	Combined	DEC	DEP	Combined
	Solar Capacity (MW)	967	2,908	3,875	2,431	4,019	6,450
	Solar Generation (MWh)	1,887,513	5,677,206	7,564,719	5,279,071	8,312,634	13,591,705
Island Case	10-min LF Reserves During Solar Hours (Island Case)	12	95	106	46	157	204
Island Case	Island Case Integration Costs ($)	$1,886,777	$11,422,833	$13,309,610	$7,555,552	$20,015,360	$27,570,912
Island Case	Island Case Average SISC ($/MWh)	$1.00	$2.01	$1.76	$1.43	$2.41	$2.03
JDA Case	10-min LF Reserves Cost in JDA Case ($/MWh)	$17.25	$17.25	$17.25	$20.45	$20.45	$20.45
JDA Case	JDA Case Integration Costs ($)	$3,174,863	$7,542,222	$10,717,085	$9,645,181	$14,691,557	$24,336,737
JDA Case	JDA Case Average SISC ($/MWh)	$0.63	$1.68	$1.42	$1.05	$2.26	$1.79
JDA Case	JDA Case Incremental SISC ($/MWh)	n/a	n/a	n/a	$1.29	$3.51	$2.26

Questions or Comments?

Our Practices and Industries

ENERGY & UTILITIES

- Competition & Market Manipulation
- Distributed Energy Resources
- Electric Transmission
- Electricity Market Modeling & Resource Planning
- Electrification & Growth Opportunities
- Energy Litigation
- Energy Storage
- Environmental Policy, Planning and Compliance
- Finance and Ratemaking
- Gas/Electric Coordination
- Market Design
- Natural Gas & Petroleum
- Nuclear
- Renewable & Alternative Energy

LITIGATION

- Accounting
- Analysis of Market Manipulation
- Antitrust/Competition
- Bankruptcy & Restructuring
- Big Data & Document Analytics
- Commercial Damages
- Environmental Litigation & Regulation
- Intellectual Property
- International Arbitration
- International Trade
- Labor & Employment
- Mergers & Acquisitions Litigation
- Product Liability
- Securities & Finance
- Tax Controversy & Transfer Pricing
- Valuation
- White Collar Investigations & Litigation

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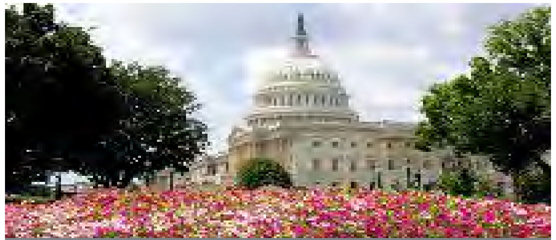
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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Seventh Joint 45-Day Progress Report of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*, as filed in Docket No. E-100, Sub 167, was served via electronic delivery or mailed, first-class, postage prepaid, upon all parties of record.

This, the 7th day of September, 2021.

/s/E. Brett Breitschwerdt

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