DEC / DEP Joint Exhibit 6

Clean and Redlined Copies of Notice of Commitment Form for QFs Eligible for Schedule PP

Docket No. E-100, Sub 175

NOTICE OF COMMITMENT TO SELL THE OUTPUT OF A SMALL QUALIFYING FACILITY ELIGIBLE FOR SCHEDULE PP TO Duke Energy Carolinas, LLC or Duke Energy Progress, LLC

This notice of commitment form establishes the procedure for a qualifying facility ("QF") with a nameplate capacity up to 1 MWAC that is requesting to establish a legally enforceable obligation ("LEO") and to commit to sell the output of a proposed QF generating facility pursuant to Duke Energy Carolinas, LLC's or Duke Energy Progress, LLC's (the "Company") Schedule PP (NC) and standard offer power purchase agreement and terms and conditions. QFs submitting this form after November 1, 2021, are committing to sell the full output of the generating facility to the Company pursuant to Schedule PP and the avoided cost rates and terms filed with Commission in Docket No. E-100, Sub 175, until such time as new rates are filed with the Commission in the next biennial avoided cost proceeding. Eligibility of QFs above 100 kW for Schedule PP shall be determined under N.C. Gen. Stat. § 62-156(b) (limiting eligibility to an aggregate 100 MW per Company) based upon the Effective Date of the LEO established under this Notice of Commitment form. Please note that a different form is required for QFs with a nameplate capacity greater than 1 MWAC seeking to commit to sell their output to the Company under a negotiated power purchase arrangement as provided for in N.C. Gen. Stat. § 62-156(c) and 18 C.F.R. 292.304(d)(2).

1. Delivery; Notices to Company. The QF shall deliver, via email, its executed Notice of Commitment to:

Duke Energy – Distributed Energy Technologies
Attn.: Wholesale Renewable Contract Manager
DERContracts@duke-energy.com

Any subsequent notice that a QF may be required to provide to Company pursuant to this Notice of Commitment shall be delivered to the same address.

2. Seller Information. The name, address, and contact information for Seller is:

Legal Name of Seller: ______________________________________

Contact Person: ________________________ Telephone: _________________________

Address: ______________________________ Email: _____________________________

3. Commitment to Sell. By execution and submittal of this binding legally enforceable obligation to sell and deliver the output of Seller's qualifying facility (the "Facility") for specified future delivery term of [2 years, 10 years] (the "Delivery Term"), Seller hereby commits to sell to the Company all of the electrical output of the Seller's Facility ("Notice of Commitment").

4. Certifications. By execution and submittal of this Notice of Commitment to sell the output of the Facility, Seller certifies as follows:

Eligibility for Schedule PP
Seller is a qualifying facility ("QF") with a maximum nameplate capacity of 1,000 kW and is eligible for the Company's Schedule PP.

Report of Proposed Construction (Rule R8-65)
Seller has filed a report of proposed construction for its ____ kW (net capacity ac) Facility with the North Carolina Utilities Commission ("NCUC") pursuant to NCUC Rule R8-65 ("Report of Proposed Construction") on [insert date] in Docket No. _______.

Application to Interconnect Generator to Company's System
Seller is requesting to become an Interconnection Customer of the Company, as that term is defined in the North Carolina Interconnection Procedures ("NCIP"), and has either submitted the NCIP Attachment 6 Interconnection Request Application Form for Certified Inverter-Based Generating Facilities No Larger Than 20 kW or has submitted the NCIP Attachment 2 Interconnection Request Application Form requesting a Maximum Generating Capacity less than or equal to 1 MWAC and the Company has notified the Seller-Interconnection Customer that its Interconnection Request is complete and the following queue number has been assigned [insert queue number].

Other Seller QFs within 1-10 miles
Seller is providing the QF self-certification or other documentation describing the location and nameplate capacity for all other QFs within one mile of the project and within 10 miles of the project, which are owned or controlled by the same developer, as well as identifying the capacity of the other affiliated QFs as well as their proximity to the Seller.

Site Control
Seller is providing reasonable evidence of site control for the entire contracting term.

Commercial Viability and Financial Commitment
Seller commits to provide upon the Company's request (i) a list of all acquired and outstanding QF permits, including a description of the status and timeline for acquisition of any outstanding permits; and (ii) reasonable evidence that the Seller is financially committed to constructing the QF and selling and delivering capacity and energy to the Company for term of the proposed contracting term.

5. Effective Date. This Notice of Commitment shall take effect on its "Submittal Date" as hereinafter defined. "Submittal Date" means (a) the receipted date of deposit of this Notice of Commitment with the U.S. Postal Service for certified mail delivery to the Company, (b) the receipted date of deposit of this Notice of Commitment with a third-party courier (e.g., Federal Express, United Parcel Service) for trackable delivery to the Company,

(c) the receipted date of hand delivery of this Notice of Commitment to the Company at the address set forth in paragraph 1, above, or (d) the date on which an electronic copy of this Notice of Commitment is sent via email to the Company if such email is sent during regular business hours (9:00 a.m. to 5:00 p.m.) on a business day (Monday through Friday excluding federal and state holidays). Emails sent after regular business hours or on days that are not business days shall be deemed submitted on the next business day.

6. LEO Date. By execution and submittal of this Notice of Commitment, and assuming that the certifications provided herein are accurate, Seller acknowledges that the legally enforceable obligation date ("LEO Date") for the Facility will be established as of the Submittal Date. The LEO Date will be used to determine Seller's eligibility for the rates, terms and conditions of the Company's currently effective Schedule PP.

7. Termination. This Notice of Commitment shall automatically terminate and be of no further force and effect upon: (i) execution of a PPA between Seller and Company or, (ii) if such Seller does not execute a PPA, sixty (60) days after Company's delivery of an "executable" PPA to the QF by the Company, that contains all information necessary for execution and which the Company has requested that the QF execute and return; provided however, that Seller shall not be required to execute a PPA any earlier than 30 days after receiving a Interconnection Agreement from Company. Seller's failure to execute a PPA prior to expiration of the Notice of Commitment period or termination, as identified above, shall result in termination of the LEO and the QF shall only be offered an as-available rate for a two-year period following expiration of the Notice of Commitment. Thereafter, the QF may elect to submit a new Notice of Commitment Form to establish a new LEO.

The undersigned is duly authorized to execute this Notice of Commitment for the Seller:

____

[Name]

____

[Title]

____

[Company]

____

[Date]

NOTICE OF COMMITMENT TO SELL THE OUTPUT OF A SMALL QUALIFYING FACILITY ELIGIBLE FOR SCHEDULE PP TO Duke Energy Carolinas, LLC or Duke Energy Progress, LLC

This notice of commitment form establishes the procedure for a qualifying facility ("QF") with a nameplate capacity up to 1 MWAC that is requesting to establish a legally enforceable obligation ("LEO") and to commit to sell the output of a proposed QF generating facility pursuant to Duke Energy Carolinas, LLC's or Duke Energy Progress, LLC's (the "Company") Schedule PP (NC) and standard offer power purchase agreement and terms and conditions. QFs submitting this form after November 1, ~~2020~~2021, are committing to sell the full output of the generating facility to the Company pursuant to Schedule PP and the avoided cost rates and terms filed with Commission in Docket No. E-100, Sub ~~167~~175, until such time as new rates are filed with the Commission in the next biennial avoided cost proceeding ~~(anticipated to be on November 1, 2021)~~. Eligibility of QFs above 100 kW for Schedule PP shall be determined under N.C. Gen. Stat. § 62-156(b) (limiting eligibility to an aggregate 100 MW per Company) based upon the Effective Date of the LEO established under this Notice of Commitment form. Please note that a different form is required for QFs with a nameplate capacity greater than 1 MWAC seeking to commit to sell their output to the Company under a negotiated power purchase arrangement as provided for in N.C. Gen. Stat. § 62-156(c) and 18 C.F.R. 292.304(d)(2).

1. Delivery; Notices to Company. The QF shall deliver, via ~~certified mail, courier, hand delivery or~~ email, its executed Notice of Commitment to:

Duke Energy – Distributed Energy Technologies
~~400 South Tryon Street~~
~~Mail Code: ST 14A~~
~~Charlotte, North Carolina 28202~~
Attn.: Wholesale Renewable Contract Manager
DERContracts@duke-energy.com

Any subsequent notice that a QF may be required to provide to Company pursuant to this Notice of Commitment shall be delivered to the same address ~~by one of the foregoing delivery methods~~.

2. Seller Information. The name, address, and contact information for Seller is:

Legal Name of Seller: ______________________________

Contact Person: ____________________ Telephone: ____________________

Address: ________________________ Email: ________________________

3. Commitment to Sell. By execution and submittal of this binding legally enforceable obligation to sell and deliver the output of Seller's qualifying facility (the "Facility") for specified future delivery term of [2 years, 10 years] (the "Delivery Term"), Seller hereby commits to sell to ~~Duke Energy Carolinas, LLC or Duke Energy Progress, LLC (the "~~Company~~")~~ all of the electrical output of the Seller's ~~qualifying facility (the "~~Facility ("Notice of Commitment").

4. Certifications. By execution and submittal of this ~~commitment~~Notice of Commitment to sell the output of the Facility ~~(the "Notice of Commitment")~~, Seller certifies as follows:

Eligibility for Schedule PP
Seller is a qualifying facility ("QF") with a maximum nameplate capacity of 1,000 kW and is eligible for the Company's Schedule PP.

Report of Proposed Construction (Rule R8-65)
Seller has filed a report of proposed construction for its ____ kW (net capacity ac) Facility with the North Carolina Utilities Commission ("NCUC") pursuant to NCUC Rule R8-65 ("Report of Proposed Construction") on [insert date] in Docket No. _______.

Application to Interconnect Generator to Company's System
Seller is requesting to become an Interconnection Customer of the Company, as that term is defined in the North Carolina Interconnection Procedures ("NCIP"), and has either submitted the NCIP Attachment 6 Interconnection Request Application Form for Certified Inverter-Based Generating Facilities No Larger Than 20 kW or has submitted the NCIP Attachment 2 Interconnection Request Application Form requesting ~~NCIP Section 3 Fast Track review~~a Maximum Generating Capacity less than or equal to 1 MWAC and the Company has notified the Seller-Interconnection Customer that its Interconnection Request is complete and the following queue number has been assigned [insert queue number].

Other Seller QFs within 1-10 miles
Seller is providing the QF self-certification or other documentation describing the location and nameplate capacity for all other QFs within one mile of the project and within 10 miles of the project, which are owned or controlled by the same developer, as well as identifying the capacity of the other affiliated QFs as well as their proximity to the Seller.

Site Control
Seller is providing reasonable evidence of site control for the entire contracting term.

Commercial Viability and Financial Commitment
Seller commits to provide upon the Company's request (i) a list of all acquired and outstanding QF permits, including a description of the status and timeline for acquisition of any outstanding permits; and (ii) reasonable evidence that the Seller is financially committed to constructing the QF and selling and delivering capacity and energy to the Company for term of the proposed contracting term.

5. Effective Date. This Notice of Commitment shall take effect on its "Submittal Date" as hereinafter defined. "Submittal Date" means (a) the receipted date of deposit of this Notice of Commitment with the U.S. Postal Service for certified mail delivery to the Company, (b) the receipted date of deposit of this Notice of Commitment with a third-party courier (e.g.,

Federal Express, United Parcel Service) for trackable delivery to the Company, (c) the receipted date of hand delivery of this Notice of Commitment to the Company at the address set forth in paragraph 1, above, or (d) the date on which an electronic copy of this Notice of Commitment is sent via email to the Company if such email is sent during regular business hours (9:00 a.m. to 5:00 p.m.) on a business day (Monday through Friday excluding federal and state holidays). Emails sent after regular business hours or on days that are not business days shall be deemed submitted on the next business day.

6. LEO Date. By execution and submittal of this Notice of Commitment, and assuming that the certifications provided herein are accurate, Seller acknowledges that the legally enforceable obligation date ("LEO Date") for the Facility will be established as of the Submittal Date. The LEO Date will be used to determine Seller's eligibility for the rates, terms and conditions of the Company's currently effective Schedule PP.

7. Termination. This Notice of Commitment shall automatically terminate and be of no further force and effect upon: (i) execution of a PPA between Seller and Company or, (ii) if such Seller does not execute a PPA, sixty (60) days after Company's delivery of an "executable" PPA to the QF by the Company, that contains all information necessary for execution and which the Company has requested that the QF execute and return; provided however, that Seller shall not be required to execute a PPA any earlier than 30 days after receiving a Interconnection Agreement from Company. Seller's failure to execute a PPA prior to expiration of the Notice of Commitment period or termination, as identified above, shall result in termination of the LEO and the QF shall only be offered an as-available rate for a two-year period following expiration of the Notice of Commitment. Thereafter, the QF may elect to submit a new Notice of Commitment Form to establish a new LEO.

The undersigned is duly authorized to execute this Notice of Commitment for the Seller:

____
[Name]

____
[Title]

____
[Company]

____
[Date]

DEC / DEP Joint Exhibit 7

Clean and Redlined Versions of DEC's and DEP's Notice of Commitment Form for QFs Larger than 1MW

Docket No. E-100, Sub 175

NOTICE OF COMMITMENT TO SELL THE OUTPUT OF A QUALIFYING FACILITY GREATER THAN 1MW$_{AC}$ TO Duke Energy Carolinas, LLC or Duke Energy Progress, LLC

(North Carolina)

This notice of commitment form establishes a binding legally enforceable obligation ("LEO") on behalf of a qualifying facility ("QF") with a nameplate capacity greater than 1 MW$_{AC}$, further described as "Seller" below, committing to sell and deliver the output of a proposed QF generating facility to Duke Energy Carolinas, LLC or Duke Energy Progress, LLC (the "Company") as provided for in N.C. Gen. Stat. § 62-156(b) and 18 C.F.R. 292.304(d)(3).

The QF shall deliver, via email, its executed Notice of Commitment to:

Duke Energy – Distributed Energy Technologies
Attn.: Wholesale Renewable Contract Manager
DERContracts@duke-energy.com

Any subsequent notice that a QF is required to provide to Company pursuant to this Notice of Commitment shall be delivered to the same email address specified above.

This form may also be used by a QF proposing to materially alter its generating facility to integrate an energy storage system and committing to sell the output of the modified generating facility to the Company. Please note that a different form is available for QFs with a nameplate capacity of 1 MW$_{AC}$ or less seeking to commit to sell their output to the Company under the currently available standard offer power purchase agreement and terms and conditions.

Seller Information. The name, address, and contact information for Seller is:

Legal Name of Seller: ____________________
Contact Person: ____________________ Telephone: ________________________
Address: ________________________ Email: ____________________________

By execution and submittal of this binding legally enforceable obligation to sell and deliver the output of the Facility for the Delivery Term (together will all completed Attachments hereto, the "Notice of Commitment"), Seller certifies as follows and is providing the following documentation to the Company:

1. Seller meets the requirements and has obtained certification from the Federal Energy Regulatory Commission ("FERC") to operate as a QF. Seller is providing documentation in Attachment A demonstrating the following:

   A. Seller has obtained self-certification of QF status filed with the FERC in Docket No. QF __________ (the "Facility"), or is otherwise providing documentation of having obtained QF status pursuant to the certification procedures set out in 18 C.F.R. 292.207; or,

B. If participating in the Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC Energy Storage System Retrofit Study Process, Seller is proposing to materially alter an existing QF to integrate an energy storage system to be fueled by the QF and has obtained certification of the modified QF in Docket No. QF __________ and has provided the new QF self-certification and written notice of the QF's commitment to construct the energy storage system to the North Carolina Utilities Commission ("Commission") in Docket No.__________ where the QF's Certificate of Public Convenience and Necessity was originally issued.

Seller shall also provide in Attachment A documentation for all other QFs located within one mile of the project or within 10 miles of the project, which are owned or controlled by the same developer, as well as identifying the capacity of the other affiliated QFs as well as their proximity to the Seller.

2. Seller's QF is currently operating or is proposed to be constructed and to interconnect to the Company's system at the location described in Attachment B (the "Project Site"). If Seller is not directly interconnected to the Company's System, Seller shall be responsible for making all necessary transmission arrangements with its interconnected electric utility to deliver its power to the Company pursuant to 18 C.F.R. 292.303(d).

3. Seller shall also provide in Attachment B all material information required for the Company to provide Seller an executable power purchase agreement within 30 days of the date of this notice of commitment. If information provided by Seller is not sufficient, the Company shall provide the Seller written notice providing an opportunity to cure such failure by the close of business on the tenth (10) business day following the posted date of such notice. The failure to provide the information requested within this period shall result in the Notice of Commitment being terminated pursuant to Section 8.

4. Commitment to Sell Power for Specified Future Delivery Term. Seller represents and hereby commits to commence delivery of its full electrical output to the Company for specified future delivery term of [2 years, 5 years] (the "Delivery Term") within 365 days of the Submittal Date (as defined below), except where the Seller is a new Interconnection Customer of the Company and its failure to begin delivery of power within 365 days is due to the time required for the Company to complete needed interconnection facilities or system upgrades by the in-service date specified in the Seller's interconnection request or in the interconnection agreement between the Seller and the Company, for which the Seller shall be given day-for-day extensions on its in-service date for any delays attributable to the in-service date of these interconnection facilities or system upgrades. By execution of this Form, Seller represents that the QF is commercially viable and financially committed to delivering its full electrical output to the Company for the specified Delivery Term and the Company can rely upon the QF's energy and capacity during the future Delivery Term for resource planning.

5. The documents attached hereto as Attachment C are provided to demonstrate Seller's commercial viability and financial commitment to sell and deliver power as of the Submittal Date for the future Delivery Term.

6. The mutually-binding legally enforceable obligation established by this Notice of Commitment shall take effect on its "Submittal Date" as hereinafter defined. "Submittal Date" means (a) the receipted date of deposit of this Notice of Commitment with the U.S. Postal Service for certified mail delivery to the Company, (b) the receipted date of deposit of this Notice of Commitment with a third-party courier (e.g., Federal Express, United Parcel Service) for trackable delivery to the Company, (c) the receipted date of hand delivery of this Notice of Commitment to the Company at the address set forth in paragraph 1, above, or (d) the date on which an electronic copy of this Notice of Commitment is sent via email to the Company if such email is sent during regular business hours (9:00 a.m. to 5:00 p.m.) on a business day (Monday through Friday excluding federal and state holidays). Emails sent after regular business hours or on days that are not business days shall be deemed submitted on the next business day.

7. LEO Date. By execution and submittal of this Notice of Commitment, Seller acknowledges that the date of the QF's binding legally enforceable obligation date to sell the Facility's full capacity and energy output to the Company ("LEO Date") will be the Submittal Date. Rates for purchases from the Seller's QF Facility will be based on the Company's avoided costs as of the LEO Date, calculated using data current as of the LEO Date.

8. Termination. This Notice of Commitment shall automatically terminate and be of no further force and effect in each of the following circumstances:

   a. Upon execution of a PPA between Seller and Company.

   b. If Seller terminates its Interconnection Request or is otherwise withdrawn from the interconnection queue.

   c. If Seller does not execute a PPA within 90 days after the Company delivers an executable PPA to the Seller that contains all information necessary for execution and which the Company has requested the Seller to execute and return; provided however, that Seller shall not be required to execute a PPA any earlier than 30 days after receiving a Facilities Study Agreement from Company. Notwithstanding the foregoing, if the PPA proposed by the Company becomes the subject of arbitration or complaint proceeding, the deadline for execution of the PPA shall be tolled upon the filing of the pleading commencing such proceeding and thereafter the deadline for execution of the PPA will be as directed by the Commission.

   d. If the Seller ceases to have control of the Project Site; ceases to be certified as a QF with FERC or ceases to be certificated by the Commission, if required, and any such deficiency has not been cured within ten (10) business days of written notice by the Company.

   e. Seller's failure to execute a PPA prior to expiration of the Notice of Commitment period, as identified in subsection 8.(c) above, shall result in termination of the LEO and the QF shall only be offered an as-available rate for a two-year period following expiration of the Notice of Commitment. Thereafter, the QF may elect to submit a new Notice of Commitment Form to establish a new LEO.

I swear or affirm, in my capacity as a duly-appointed officer of the Seller, that I have personal knowledge of the facts and information presented in this Notice of Commitment, I am competent to testify to those facts, and I have authority to make this binding legally enforceable obligation to the Company on behalf of Seller. I further swear or affirm that all of the statements and representations made in this Notice of Commitment are true and correct as of the date hereof. I further swear or affirm that Seller will comply will all requirements of this Notice of Commitment.

____
[Name]

____
[Title]

____
[Company]

____
[Date]

Attachment A to Notice of Commitment Form

[*Seller Information, QF Certification, and Affiliated QFs*]

1. Seller Information. The name, address, and contact information for Seller is:

Name: ___________________________ Telephone: ________________________

Address: _________________________ Email: ____________________________

2. Seller is providing its QF self-certification or other documentation of having obtained QF status pursuant to the certification procedures set out in 18 C.F.R. 292.207.

3. Seller is providing the QF self-certification or other documentation for all other QFs within one mile of the project and within 10 miles of the project, which are owned or controlled by the same developer, as well as identifying the capacity of the other affiliated QFs as well as their proximity to the Seller. Seller shall also provide a description of the organizational structure and chart of upstream developer, if applicable, and describe the affiliate relationship between Seller and other QFs within 10 miles of the project.

<u>Attachment B to Notice of Commitment Form</u>

[*Information Required to Complete PPA*]

The Company agrees to negotiate diligently and in good faith with Seller towards an executable power purchase agreement ("PPA"), and commits to provide Seller an executable PPA within 30 days of receipt of all project information reasonably required for the development of the PPA, including, but not limited to:

a. Facility Name and address of Project Site;
b. Description of Facility (include number, manufacturer and model of Facility generating units, and layout). Also, describe if storage is included;
c. Generation technology and other related technology applicable to the Facility;
d. Fuel type (s) and source (s);
e. Plans to obtain, or actual fuel and transportation agreements, if applicable;
f. Maximum design capacity AC and DC (MW), station service requirements, and net amount of power (kWh) to be delivered to the Company's electric system by the QF;
g. Site Map (include location and layout of the Facility, equipment, and other site details for the Project Site);
h. Delivery Point Diagram (include Delivery Point, metering, Facility substation)
i. 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 to deliver power to Company;
j. Quantity, firmness, and timing of daily and monthly power deliveries, including schedule of estimated Qualifying Facility electric output, in an 8,760-hour electronic spreadsheet format;
k. Ability, if any, of QF to respond to dispatch orders from the Company and, if applicable, whether solar QF plans to operate facility as a Controlled Solar Generator*;
l. Anticipated commencement date for delivery of electric output;
m. List of acquired and outstanding QF permits, including a description of the status and timeline for acquisition of any outstanding permits;
n. Interconnection Agreement status and estimated date for execution of Interconnection Agreement;
o. Estimated date for Financing Commitment*,
p. Estimated date for Final System Design* under Interconnection Agreement
q. Estimated date for Commencement Readiness Requirements* and
r. Proposed contracting term for the sale of electric output to the Company.

*Capitalized terms unless defined herein shall have the same meaning specified in the Companies' negotiated form of power purchase agreement for large QFs above 1MW accessible on [Duke website], unless otherwise specified herein.

<u>Attachment C to Notice of Commitment Form</u>

[*Information Required to Demonstrate Commercial Viability and Financial Commitment*]

Seller provides the following information in order to demonstrate commercial viability and financial commitment to sell and deliver power over the specified Delivery Term

1. Certificate of Public Convenience and Necessity; or Report of Proposed Construction.

   a. ____Seller has received a certificate of public convenience and necessity ("CPCN") for the construction of its _____ kW (net capacity$_{ac}$) Facility from the NCUC pursuant to North Carolina General Statute § 62-110.1 and NCUC Rule R8-64, which CPCN was granted by NCUC on [insert date] in Docket No. ____.

   b. _____ Seller is exempt from the CPCN requirements pursuant to North Carolina General Statute § 62-110.1(g) and has filed a report of proposed construction for its ____ kW (net capacity$_{ac}$) Facility with the NCUC pursuant to NCUC Rule R8-65 ("Report of Proposed Construction") on [insert date] in Docket No. ___.

   c. _____ Seller is proposing to co-locate an _____ kW (net capacity$_{ac}$) energy storage system at a generating facility that previously obtained a CPCN for the construction of a _____ kW (net capacity$_{ac}$) QF generating facility in Docket No. ____ and the QF has provided written notice to the NCUC of the planned energy storage addition to the QF.

2. Interconnection – Reasonable evidence that Seller is interconnected to the Company's system, has made transmission arrangements to deliver its power to the Company's system, or has requested to become an Interconnection Customer of the Company, as that term is defined in the North Carolina Interconnection Procedures ("NCIP"), and the Seller has met all applicable requirements to commence the interconnection study process under the Definitive Interconnection Study Process, including without limitation providing the Section 4.4.1 initial security requirement and has executed a Definitive Interconnection System Impact Study Agreement pursuant to NCIP Section 4.4.5.

3. Site Control – Reasonable evidence of site control for the entire contracting term

4. Project Development – Please provide a current status update on the development of the Facility, including anticipated timelines for:
   a. completion of key QF milestones specified in Attachment B,
   b. proof of payment of applicable permitting and other application fees
   c. the procurement of any long-lead time materials,
   d. execution of construction agreements or EPC contracts to construct the Facility,
   e. execution of third-party Transmission Agreements and other agreements or events necessary to achieve commercial operation of the facility within 365 days of the Submittal Date.

NOTICE OF COMMITMENT TO SELL THE OUTPUT OF A QUALIFYING FACILITY GREATER THAN 1MW$_{AC}$ TO Duke Energy Carolinas, LLC or Duke Energy Progress, LLC

~~Pursuant to the~~ (North Carolina ~~Utilities Commission's October 11, 2017 Order issued in Docket No. E-100, Sub 148, this~~)

This notice of commitment form establishes ~~the procedure for~~ a binding legally enforceable obligation ("LEO") on behalf of a qualifying facility ("QF") with a nameplate capacity greater than 1 MW$_{AC}$ ~~to establish a legally enforceable obligation ("LEO") and to commit~~, further described as "Seller" below, committing to sell and deliver the output of a proposed QF generating facility to Duke Energy Carolinas, LLC or Duke Energy Progress, LLC (the "Company") as provided for in N.C. Gen. Stat. § 62-156(b) and 18 C.F.R. 292.304(d)(~~2~~3). ~~Please note that a different form is available for QFs with a nameplate capacity of 1 MW$_{AC}$ or less seeking to commit to sell their output to the Company under the currently available standard offer power purchase agreement and terms and conditions.~~

~~1. Delivery; Notices to Company.~~ The QF shall deliver, via ~~certified mail, courier, hand delivery or~~ email, its executed Notice of Commitment to:

Duke Energy – Distributed Energy Technologies

~~400 South Tryon Street~~
~~Mail Code: ST 14A~~
~~Charlotte, North Carolina 28202~~
Attn.: Wholesale Renewable Contract Manager
DERContracts@duke-energy.com

Any subsequent notice that a QF is required to provide to Company pursuant to this Notice of Commitment shall be delivered to the same email address ~~by one of the foregoing delivery methods~~specified above.

This form may also be used by a QF proposing to materially alter its generating facility to integrate an energy storage system and committing to sell the output of the modified generating facility to the Company. Please note that a different form is available for QFs with a nameplate capacity of 1 MW$_{AC}$ or less seeking to commit to sell their output to the Company under the currently available standard offer power purchase agreement and terms and conditions.

~~2.~~ Seller Information. The name, address, and contact information for Seller is:

~~Name:~~ ______________________ ~~Telephone:~~ ______________________

~~Address:~~ ______________________ ~~Email:~~ ______________________

~~3. Commitment to Sell. Seller hereby commits to sell to the Company all of the electrical output of the Seller's QF described in Seller's self-certification of QF status filed with the Federal Energy Regulatory Commission in Docket No. QF________ (the "Facility").~~

Legal Name of Seller: ______________________
Contact Person: ____________________ Telephone: ______________________
Address: ____________________ Email: ______________________

~~4. Certifications.~~ By execution and submittal of this ~~commitment~~binding legally enforceable obligation to sell and deliver the output of the Facility ~~(~~for the Delivery Term (together will all completed Attachments hereto, the "Notice of Commitment"), Seller certifies as follows and is providing the following documentation to the Company:

~~(Select and complete the applicable certification(s) in Sections 4(A) and 4(B) below)~~

~~A. Certificate of Public Convenience and Necessity; or Report of Proposed Construction~~

~~i. _____ Seller has received a certificate of public convenience and necessity ("CPCN") for the construction of its _______kW (net capacity~~~~ac~~~~) Facility from the North Carolina Utilities Commission ("NCUC") pursuant to North Carolina General Statute § 62-110.1 and NCUC Rule R8-64, which CPCN was granted by NCUC on [insert date] in Docket No. __________.~~

~~ii. ________________________ Seller is exempt from the CPCN requirements pursuant to North Carolina General Statute § 62-110.1(g) and has filed a report of proposed construction for its __kW (net capacity~~~~ac~~~~) Facility with the NCUC pursuant to NCUC Rule R8-65 ("Report of Proposed Construction") on [insert date] in Docket No. ___.~~

~~B. Application to Interconnect QF Facility to Company's System~~

~~If Seller is requesting to become an Interconnection Customer of the Company, as that term is defined in the North Carolina Interconnection Procedures ("NCIP"), please indicate below whether the Seller has requested to interconnect the Facility under either: (i) the NCIP Section 3 ("Fast Track," as defined in NCIP Section 3.1); or (ii) NCIP Section 4 Full Study Process:~~

~~i. _____ Section 3 Fast Track:~~

~~a. Seller is eligible for interconnection under NCIP Section 3.1;~~

~~b. Seller has submitted the completed NCIP Attachment 1 Interconnection Request Application Form on [insert date] requesting Fast Track review;~~

~~c. The Company has accepted the Section 3 Interconnection Request as complete and provided the Interconnection Customer with queue number ______; and~~

~~d. Please select as applicable:~~

~~1. ______The Company has completed the Section 3 Fast Track study process and delivered a final Interconnection Agreement to Seller for execution; or~~

~~2. ______Seller was preliminarily determined a Project A or Project B by the Company under NCIP 1.8 and 105 days have~~

~~passed since Seller's interconnection request was submitted to the Company; or~~

~~3. ________Seller was preliminarily determined to be "On Hold" for System Impact Study under NCIP 1.8.3 and the Company has subsequently determined that Seller is now a Project B and at least 105 have passed since Seller became a Project B.~~

~~ii.~~ ____ ~~Section 4 Full Study:~~

~~a. Seller has submitted the completed NCIP Attachment 1 Interconnection Request Application Form on [insert date] requesting to interconnect under the NCIP Section 4 Study Process;~~

~~b. The Company has accepted the Section 4 Interconnection Request as complete and provided the Interconnection Customer with queue number _______; and~~

~~c. Please select as applicable~~

~~1. ________ Seller has executed and returned a System Impact Study Agreement to begin the Section 4 study process after being preliminarily determined a Project A or Project B by the Company under NCIP 1.8 and (i) Seller has received a System Impact Study Report or (ii) at least 105 days have passed since Seller's interconnection request was submitted to the Company; or~~

~~2. _________Seller was preliminarily determined to be "On Hold" for System Impact Study under NCIP 1.8.3 and the Company has determined that Seller is now a Project B and (i) Seller has received a System Impact Study Report or (ii) at least 105 have passed since Seller became a Project B.~~

1. Seller meets the requirements and has obtained certification from the Federal Energy Regulatory Commission ("FERC") to operate as a QF. Seller is providing documentation in Attachment A demonstrating the following:

   A. Seller has obtained self-certification of QF status filed with the FERC in Docket No. QF __________ (the "Facility"), or is otherwise providing documentation of having obtained QF status pursuant to the certification procedures set out in 18 C.F.R. 292.207; or,

   B. If participating in the Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC Energy Storage System Retrofit Study Process, Seller is proposing to materially alter an existing QF to integrate an energy storage system to be fueled by the QF and has obtained certification of the modified QF in Docket No. QF __________ and has provided the new QF self-certification and written notice of the QF's commitment to construct the energy storage system to the North Carolina Utilities Commission ("Commission") in Docket No.__________ where the QF's Certificate of Public Convenience and Necessity was originally issued.

Seller shall also provide in Attachment A documentation for all other QFs located within one mile of the project or within 10 miles of the project, which are owned or controlled by the same developer, as well as identifying the capacity of the other affiliated QFs as well as their proximity to the Seller.

2. Seller's QF is currently operating or is proposed to be constructed and to interconnect to the Company's system at the location described in Attachment B (the "Project Site"). If Seller is not directly interconnected to the Company's System, Seller shall be responsible for making all necessary transmission arrangements with its interconnected electric utility to deliver its power to the Company pursuant to 18 C.F.R. 292.303(d).

3. Seller shall also provide in Attachment B all material information required for the Company to provide Seller an executable power purchase agreement within 30 days of the date of this notice of commitment. If information provided by Seller is not sufficient, the Company shall provide the Seller written notice providing an opportunity to cure such failure by the close of business on the tenth (10) business day following the posted date of such notice. The failure to provide the information requested within this period shall result in the Notice of Commitment being terminated pursuant to Section 8.

4. Commitment to Sell Power for Specified Future Delivery Term. Seller represents and hereby commits to commence delivery of its full electrical output to the Company for specified future delivery term of [2 years, 5 years] (the "Delivery Term") within 365 days of the Submittal Date (as defined below), except where the Seller is a new Interconnection Customer of the Company and its failure to begin delivery of power within 365 days is due to the time required for the Company to complete needed interconnection facilities or system upgrades by the in-service date specified in the Seller's interconnection request or in the interconnection agreement between the Seller and the Company, for which the Seller shall be given day-for-day extensions on its in-service date for any delays attributable to the in-service date of these interconnection

facilities or system upgrades. By execution of this Form, Seller represents that the QF is commercially viable and financially committed to delivering its full electrical output to the Company for the specified Delivery Term and the Company can rely upon the QF's energy and capacity during the future Delivery Term for resource planning.

5. The documents attached hereto as Attachment C are provided to demonstrate Seller's commercial viability and financial commitment to sell and deliver power as of the Submittal Date for the future Delivery Term.

6. ~~5. Effective Date. This~~The mutually-binding legally enforceable obligation established by this Notice of Commitment shall take effect on its "Submittal Date" as hereinafter defined. "Submittal Date" means (a) the receipted date of deposit of this Notice of Commitment with the U.S. Postal Service for certified mail delivery to the Company, (b) the receipted date of deposit of this Notice of Commitment with a third-party courier (e.g., Federal Express, United Parcel Service) for trackable delivery to the Company, (c) the receipted date of hand delivery of this Notice of Commitment to the Company at the address set forth in paragraph 1, above, or (d) the date on which an electronic copy of this Notice of Commitment is sent via email to the Company if such email is sent during regular business hours (9:00 a.m. to 5:00 p.m.) on a business day (Monday through Friday excluding federal and state holidays). Emails sent after regular business hours or on days that are not business days shall be deemed submitted on the next business day.

7. ~~6.~~ LEO Date. By execution and submittal of this Notice of Commitment, ~~and assuming that the certifications provided herein are accurate,~~ Seller acknowledges that the date of the QF's binding legally enforceable obligation date to sell the Facility's full capacity and energy output to the Company ("LEO Date") ~~for Seller's QF Facility~~ will be ~~determined as of~~ the Submittal Date ~~or such later date as may be established by the NCUC~~. Rates for purchases from the Seller's QF Facility will be based on the Company's avoided costs as of the LEO Date, calculated using data current as of the LEO Date.

8. ~~7.~~ Termination. This Notice of Commitment shall automatically terminate and be of no further force and effect in each of the following circumstances:

a. Upon execution of a PPA between Seller and Company.

b. If Seller terminates its Interconnection Request or is otherwise withdrawn from the interconnection queue.

c. ~~b.~~ If Seller does not execute a PPA within ~~six months (as such period may be extended by mutual agreement of Seller and Company)~~90 days after the Company~~'s submittal of the~~ delivers an executable PPA to the ~~QF,~~Seller that contains all information necessary for execution and which the Company has requested the Seller to execute and return; provided~~,~~ however, that ~~if Seller is an Interconnection Customer of the Company and no interconnection agreement for the Facility has been tendered to Seller prior to the expiration of such deadline, the deadline for execution of the PPA~~Seller shall not be ~~automatically extended until the date that is five days after the date that the final Interconnection~~required to execute a PPA any earlier than 30 days after receiving a Facilities Study Agreement ~~is tendered to the Seller~~from Company. Notwithstanding the foregoing, if the PPA proposed by the Company becomes the subject of arbitration or complaint proceeding, the ~~six month~~ deadline for execution of the PPA shall be tolled upon the filing of the pleading commencing such proceeding and thereafter the deadline for execution of the PPA will be as directed by the ~~NCUC~~Commission.

d. If the Seller ceases to have control of the Project Site; ceases to be certified as a QF with FERC or ceases to be certificated by the Commission, if required, and any such deficiency has not been cured within ten (10) business days of written notice by the Company.

e. ~~c.~~ Seller's failure to execute a PPA prior to expiration of the Notice of Commitment period, as identified in subsection ~~7~~8.(~~b~~c) above, shall result in termination of the LEO and the QF shall only be offered an as-available rate for a two-year period following expiration of the Notice of Commitment. Thereafter, the QF may elect to submit a new Notice of Commitment Form to establish a new LEO.

~~The undersigned is duly authorized to execute this Notice of Commitment for the Seller:~~

I swear or affirm, in my capacity as a duly-appointed officer of the Seller, that I have personal knowledge of the facts and information presented in this Notice of Commitment, I am competent to testify to those facts, and I have authority to make this binding legally enforceable obligation to the Company on behalf of Seller. I further swear or affirm that all of the statements and representations made in this Notice of Commitment are true and correct as of the date hereof. I further swear or affirm that Seller will comply will all requirements of this Notice of Commitment.

____
[Name]

____
[Title]

____
[Company]

____
[Date]

Attachment A to Notice of Commitment Form

[*Seller Information, QF Certification, and Affiliated QFs*]

1. Seller Information. The name, address, and contact information for Seller is:

Name: ____________	Telephone: ____________
Address: ____________	Email: ____________

2. Seller is providing its QF self-certification or other documentation of having obtained QF status pursuant to the certification procedures set out in 18 C.F.R. 292.207.

3. Seller is providing the QF self-certification or other documentation for all other QFs within one mile of the project and within 10 miles of the project, which are owned or controlled by the same developer, as well as identifying the capacity of the other affiliated QFs as well as their proximity to the Seller. Seller shall also provide a description of the organizational structure and chart of upstream developer, if applicable, and describe the affiliate relationship between Seller and other QFs within 10 miles of the project.

Attachment B to Notice of Commitment Form

[*Information Required to Complete PPA*]

The Company agrees to negotiate diligently and in good faith with Seller towards an executable power purchase agreement ("PPA"), and commits to provide Seller an executable PPA within 30 days of receipt of all project information reasonably required for the development of the PPA, including, but not limited to:

a. Facility Name and address of Project Site;
b. Description of Facility (include number, manufacturer and model of Facility generating units, and layout). Also, describe if storage is included;
c. Generation technology and other related technology applicable to the Facility;
d. Fuel type (s) and source (s);
e. Plans to obtain, or actual fuel and transportation agreements, if applicable;
f. Maximum design capacity AC and DC (MW), station service requirements, and net amount of power (kWh) to be delivered to the Company's electric system by the QF;
g. Site Map (include location and layout of the Facility, equipment, and other site details for the Project Site);
h. Delivery Point Diagram (include Delivery Point, metering, Facility substation)
i. 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 to deliver power to Company;
j. Quantity, firmness, and timing of daily and monthly power deliveries, including schedule of estimated Qualifying Facility electric output, in an 8,760-hour electronic spreadsheet format;
k. Ability, if any, of QF to respond to dispatch orders from the Company and, if applicable, whether solar QF plans to operate facility as a Controlled Solar Generator*;
l. Anticipated commencement date for delivery of electric output;
m. List of acquired and outstanding QF permits, including a description of the status and timeline for acquisition of any outstanding permits;
n. Interconnection Agreement status and estimated date for execution of Interconnection Agreement;
o. Estimated date for Financing Commitment*,
p. Estimated date for Final System Design* under Interconnection Agreement
q. Estimated date for Commencement Readiness Requirements* and
r. Proposed contracting term for the sale of electric output to the Company.

*Capitalized terms unless defined herein shall have the same meaning specified in the Companies' negotiated form of power purchase agreement for large QFs above 1MW accessible on [Duke website], unless otherwise specified herein.

Attachment C to Notice of Commitment Form

[*Information Required to Demonstrate Commercial Viability and Financial Commitment*]

Seller provides the following information in order to demonstrate commercial viability and financial commitment to sell and deliver power over the specified Delivery Term

1. Certificate of Public Convenience and Necessity; or Report of Proposed Construction.

   a. ____Seller has received a certificate of public convenience and necessity ("CPCN") for the construction of its _____ kW (net capacity$_{ac}$) Facility from the NCUC pursuant to North Carolina General Statute § 62-110.1 and NCUC Rule R8-64, which CPCN was granted by NCUC on [insert date] in Docket No. ____.

   b. ____ Seller is exempt from the CPCN requirements pursuant to North Carolina General Statute § 62-110.1(g) and has filed a report of proposed construction for its _____ kW (net capacity$_{ac}$) Facility with the NCUC pursuant to NCUC Rule R8-65 ("Report of Proposed Construction") on [insert date] in Docket No. ___.

   c. ______Seller is proposing to co-locate an _____ kW (net capacity$_{ac}$) energy storage system at a generating facility that previously obtained a CPCN for the construction of a _____ kW (net capacity$_{ac}$) QF generating facility in Docket No. ____ and the QF has provided written notice to the NCUC of the planned energy storage addition to the QF.

2. Interconnection – Reasonable evidence that Seller is interconnected to the Company's system, has made transmission arrangements to deliver its power to the Company's system, or has requested to become an Interconnection Customer of the Company, as that term is defined in the North Carolina Interconnection Procedures ("NCIP"), and the Seller has met all applicable requirements to commence the interconnection study process under the Definitive Interconnection Study Process, including without limitation providing the Section 4.4.1 initial security requirement and has executed a Definitive Interconnection System Impact Study Agreement pursuant to NCIP Section 4.4.5.
3. Site Control – Reasonable evidence of site control for the entire contracting term
4. Project Development – Please provide a current status update on the development of the Facility, including anticipated timelines for:
   a. completion of key QF milestones specified in Attachment B,
   b. proof of payment of applicable permitting and other application fees
   c. the procurement of any long-lead time materials,
   d. execution of construction agreements or EPC contracts to construct the Facility,
   e. execution of third-party Transmission Agreements and other agreements or events necessary to achieve commercial operation of the facility within 365 days of the Submittal Date.

DEC / DEP Joint Public Redacted Exhibit 8

Additional Technical Support for Inputs to Avoided Capacity and Avoided Energy Rate Calculations

Docket No. E-100, Sub 175

NC Avoided Cost Filing (Docket No. E-100, Sub 175)
DEC/DEP Joint Exhibit 8 – Technical Support
Avoided Capacity and Energy Inputs and Rate Design

This Exhibit provides additional detail on the following topics:

I. DEC and DEP First Year of Undesignated Capacity Need Update

As presented in Chapter 13 of the DEC's and DEP's 2020 IRPs, the Companies generally assess their respective first year of undesignated capacity need as part of the biennial integrated resource planning ("IRP") process as well as through annual updates to their IRPs. The Companies last filed their identified first resource needs with the Commission in September 2020 as part of their 2020 IRPs. Because the Commission's June 29, 2021 Order in Docket No. E-100, Sub 165 waived the Companies' obligation to file 2021 IRP updates under Rule R8-60(h)(2), the Companies have not filed any updated assessment of DEC's or DEP's respective first year of undesignated capacity need in 2021. For purposes of this 2021 avoided cost filing, the Companies provide the following support for their respective first resource need for use in calculating their avoided capacity costs.

Methodology Used to Determine First Year of Undesignated Capacity Need

The Companies' expected load growth, planned unit retirements, and expiring purchase power contracts contribute to the need for new generation resources. The resources used to meet the load requirements and a reasonable reserve margin fall into two categories: Designated and Undesignated.

Designated resources include resources:

- with contracts for which PPAs are already signed;
- that are in service or currently under construction;
- that have been granted a CPCN or CECPCN;
- are a result of normal work included in the Companies' planning budget;
- are conservation programs such as EE and DSM; and
- that are renewable resources required to meet mandated requirements in NC and SC (NC REPS, NC HB589, SC Act 62, NC HB951, etc.).

Undesignated resources include:

- purchase power contracts that have not yet been executed;
- projects not yet approved by NCUC or PSCSC;
- projects not included in the Companies' planning budget; and
- projected resources in the IRP that do not have a CPCN or CECPCN granted

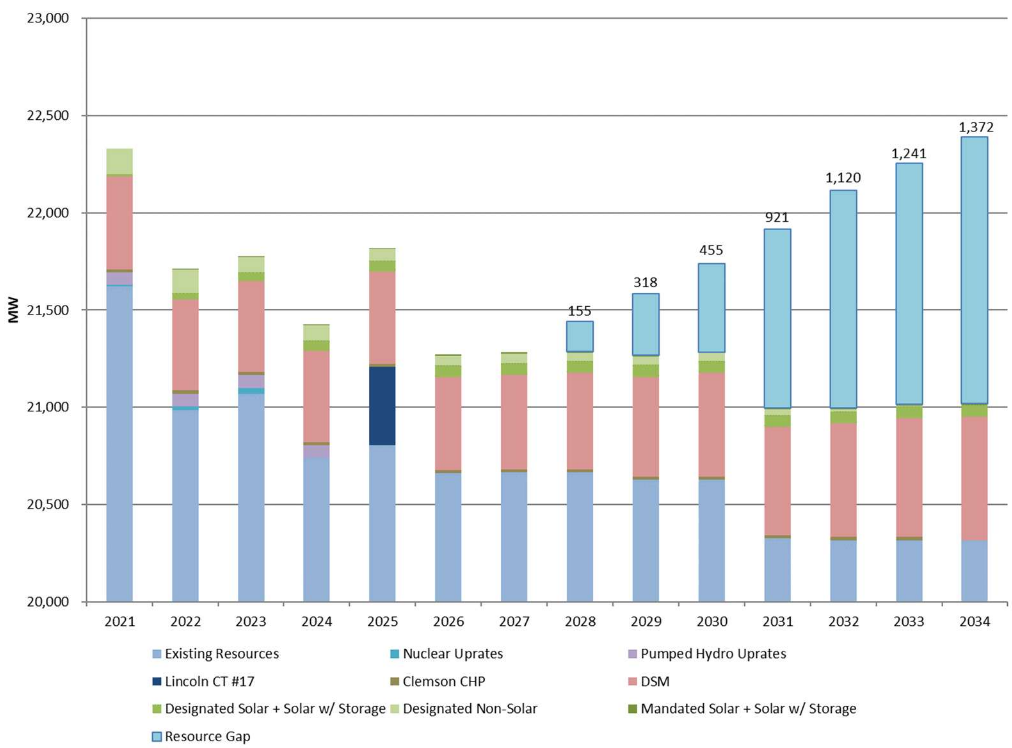
DEC First Undesignated Resource Need

Only DEC's designated resources are considered when determining the first resource need for purposes of the development of standard offer avoided capacity rates. Consistent with most recently filed 2020 IRP, the designated resources utilized to calculate the first year of resource need for DEC remain the same, with one notable exception for DEC.

In September of 2020, DEC's IVVC program was not yet approved by the Commission and, as such, was not included as a designated resource in the Company's 2020 IRP. In the March 31, 2021 Order in Docket No. E-7, Sub 1214, however, the Commission approved aspects of the Companies' Grid Improvement Plan, including the IVVC program. Accordingly, projects under the IVVC program are now considered designated, rather than undesignated, resources, and have been factored into DEC's future resource need determination.

The figure below demonstrates that DEC's first year of undesignated capacity need arises in 2028.

Load Resource Balance for DEC First Need



In DEC's 2020 IRP, the first undesignated capacity resource need was determined to be in 2026. The two-year delay to 2028 reflects the addition of approximately 175 MW of new designated resources from DEC's IVVC projects.

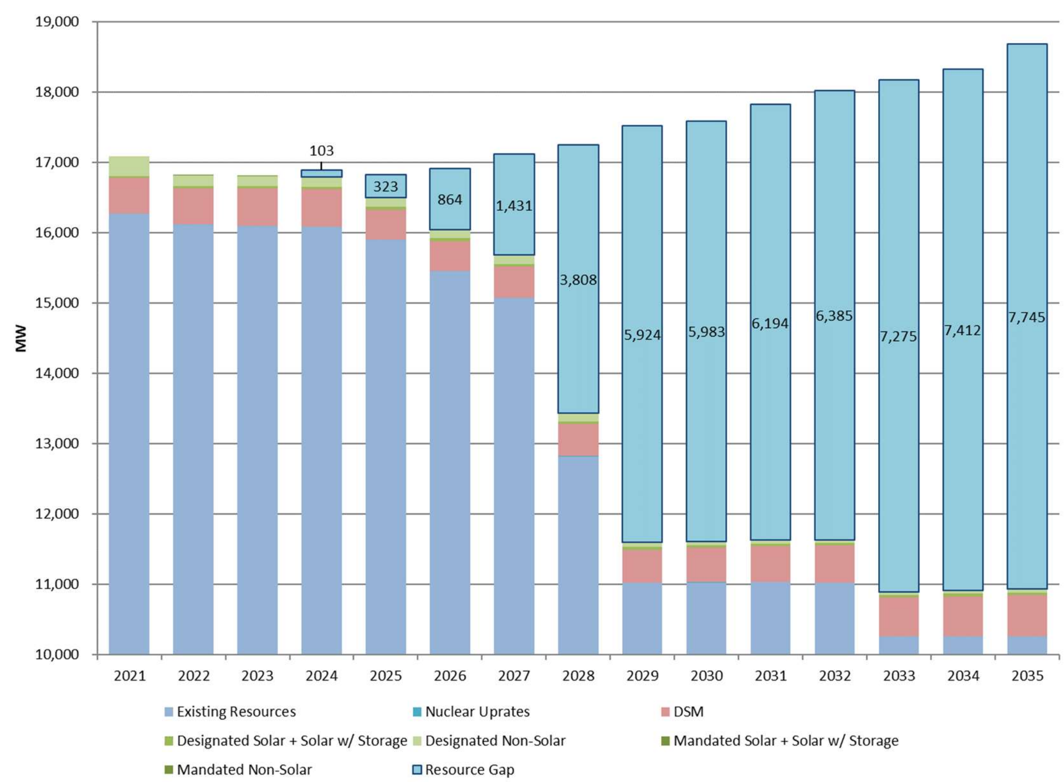
DEP First Undesignated Resource Need

Only DEP's designated resources are considered when determining the first resource need for purposes of the development of standard offer avoided capacity rates. Consistent with most recently filed IRP, the designated resources utilized to calculate the first year of resource need for DEP remain the same with no adjustments.

DEP's first year of resource need calculation contains the same designated resources as utilized in the 2020 IRP. While the Commission's March 31, 2021 Order in Docket No. E-2, Sub 1146 approved DEP's deployment of IVVC projects after the filing of the 2020 IRP, the addition of IVVC projects to the list of designated resources did not have the same impact to DEP's first undesignated resource need as it did for DEC. This is because DEP already had a distribution system demand response ("DSDR") program in place which was included as a designated resource. This DSDR program is expected to be replaced with the newly approved IVVC project, and there is no expected change in capacity between the two projects. Accordingly, there has been no change in DEP's first undesignated capacity need as compared to the need identified in DEP's 2020 IRP.

The figure below demonstrates that the first year of DEP's undesignated capacity need arises in 2024.

Load Resource Balance for DEP First Need



DEP's first year of need in 2024 remains the same as identified in the 2020 IRP.

II. <u>CT Capital Cost</u>

The Companies use the greenfield economies of scale methodology to calculate the CT Capital Costs. This methodology assesses the avoided capacity cost by taking the U.S. Energy Information Administration's ("EIA") most current published overnight cost of a CT unit and applying a percentage decrement to reflect the economies of scale associated with a four-unit CT site in the Carolinas.[1] This Exhibit provides supporting information for the standardized and repeatable methodology, which has been developed by the Companies and Dominion[2] and accepted by the Public Staff for purposes of developing the avoided CT cost.

The table below shows the EIA data that reflects the cost to construct a single unit at a greenfield site ($665/kW). The Companies and Dominion independently developed estimates for the common infrastructure costs for a four-unit greenfield site. After adjusting for the carrying costs associated with the economies of scale adjustment,[3] the Companies' estimate resulted in a 6.7% decrement to the EIA data and the Dominion estimate resulted in a 7.5% decrement to the EIA data. The average of the two estimates is 7.1%. Because the infrastructure cost estimates were very similar between the Companies and Dominion, the Companies recommended using the average of the two estimates (7.1%) and rounding down the result to 7.0%. The Public Staff found this 7.0% decrement to the EIA data to be a reasonable adjustment to reflect the economies of scale associated with constructing four CT units at a greenfield site. A 7.0% decrement to the EIA data results in an overnight capital cost of $619/kW (2021$), which DEC and DEP are using to develop their avoided capacity rates in the Sub 175 docket.

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[1] *See* U.S. Energy Information Administration, Cost and Performance Characteristic of New Generating Technologies, *Annual Energy Outlook 2021* at Table 2 (p. 3) (February 2021), *available at* https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf (last visited Oct. 18, 2021).

[2] The Companies developed this methodology collaboratively with input from Dominion Energy North Carolina ("Dominion") and understand that Dominion is using a consistent greenfield economies of scale methodology to develop their avoided CT capital cost.

[3] Ordering Paragraph 6, p.54 of NCUC Sub 140 Phase II Order: That DEC, DEP, and DNCP shall recalculate the installed costs of a CT excluding economies of scope and taking into account any carrying costs associated with the economies of scale.

CT Capital Cost with Economies of Scale Adjustments[4]

(2021 $MM unless otherwise noted)

			Comments
EIA Cost Basis			
Nominal Rating (MW)		237	EIA Annual Energy Outlook 2021, Table 1
Total Capital Cost (2020 $/kW)		649	EIA Annual Energy Outlook 2021, Table 2
Total Capital Cost (2021 $/kW)		665	Assumes 2.5% inflation rate
Total Capital Cost (2021$)		157.7	Reflects cost to construct a single unit at a greenfield site
Infrastructure Economies of Scale Adjustments			
Natural Gas M&R Station	$	3.2	Based on February 2020 EIA Capital Cost Report
Electrical Interconnect	$	0.6	Based on February 2020 EIA Capital Cost Report
Land acquisition	$	0.6	Based on February 2020 EIA Capital Cost Report
Civil	$	1.9	Based on internal estimates
Water: Muni. Tie and Demin. Tank	$	1.1	Based on internal estimates
Fire Header	$	2.5	Based on internal estimates
Admin Building/Security	$	3.6	Based on internal estimates
Subtotal	**$**	**13.4**	
Contingency (10%)	$	1.3	Based on February 2020 EIA Capital Cost Report
Total Common Infrastructure Cost	**$**	**14.8**	
Total Common Infrastructure Cost per Unit	$	3.7	
Common Infrastructure Cost Adjustment	**$**	**(11.1)**	
Total Adjusted Capital Cost excl Carry Cost ($)	**$**	**146.6**	Reflects economies of scale for constructing 4 CTs at a greenfield site excl carry cost adjustment
Total Adjusted Capital Cost excl Carry Cost ($/kW)	**$**	**619**	Reflects economies of scale for constructing 4 CTs at a greenfield site excl carry cost adjustment
Economies of Scale Carrying Cost Adjustment			
Carrying Cost Adj ($/kW)	$	2.0	
Total Adj Capital Cost incl Carry Cost Adj ($/kW)	**$**	**621**	Reflects economies of scale for constructing 4 CTs at a greenfield site incl carry cost adjustment
Calculated % Adjustment to EIA CT Cost			
Duke		6.7%	
Dominion		7.5%	
Avg of Duke and Dominion		7.1%	
Modeled CT Cost			
EIA Total Capital Cost (2021 $/kW)	$	665	
Modeled % Adjustment		7.0%	
Total Adjusted Capital Cost (2021 $/kW)	**$**	**619**	

[4] U.S. Energy Info. Admin., EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2021, *available at* https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

III. <u>CT Fixed Operations and Maintenance Cost</u>

To calculate the fixed operations and maintenance ("FOM") costs of a CT unit, the Companies use EIA FOM data for a single-unit greenfield site and apply internal estimates to adjust the cost to reflect the economies for a four-unit CT site.[5]

REDACTED

EIA Single Unit Greenfield Site		
FOM ($/kW-Yr, 2020$)	7.04	EIA Annual Energy Outlook 2021, Table 1
FOM ($/kW-Yr, 2021$)	7.22	Assume 2.5% Inflation Rate
Capacity Rating (MW)	237	EIA Annual Energy Outlook 2021, Table 1
FOM (2021 MM$)	1.7	

Internal Estimates	
1st Unit (2021 MM$)	[redacted]
Next Unit (2021 MM$)	
4 Unit Site (2021 MM$)	

	(2021 $/kW-Yr)	
	1 Unit	**4 Units**
EIA	7.2	$\boxed{3.8}$
Internal Estimates	[redacted]	

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

[5] U.S. Energy Info. Admin, EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2021, Table 1, p. 2, *available at* https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

IV. Avoided Capacity Rate Design

The Public Staff and the Companies agreed in the Commission-approved Sub 158 Rate Design Stipulation to utilize the Companies' seasonal and hourly allocations of capacity payments based upon the loss of load risk identified in the Astrapé 2018 Solar Capacity Value Study. Astrapé completed a new resource adequacy study in 2020, and the Companies have used the loss of load risk identified in this more recent study for updating the avoided capacity rate design in Sub 175.[6]

DEC

Capacity Payment Period Definitions

The loss of load risk table below for DEC shows that loss of load risk occurs primarily during winter AM hours for the months of December-March with some loss of load risk occurring during summer PM hours for the months of July and August. The DEC capacity payment hours have been redefined as shown below:

DEC Capacity Payment Period Definitions

	Dec-Mar	Jul-Aug
AM	HE 6-10	N/A
PM	N/A	HE 18-21

Seasonal Allocation Factor

The loss of load risk table shows a seasonal allocation of 96% Winter and 4% Summer for DEC.

DEC Seasonal Allocation

Winter	Summer
96%	4%

[6] The 2020 Resource Adequacy Studies were filed with the Commission as Exhibit III to the 2020 IRPs in Docket No. E-100, Sub 165.

DEC 17% Reserve Margin (2020 Resource Adequacy Study)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	Winter	Summer
1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.2%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.0%
5	1.0%	0.5%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%	0.0%
6	4.4%	1.5%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.6%	0.0%
7	16.6%	5.7%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	23.6%	0.0%
8	32.8%	7.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.6%	43.3%	0.0%
9	15.6%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	16.6%	0.0%
10	4.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.4%	0.0%
11	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
13	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
17	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
18	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
19	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%
20	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%
21	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%
22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
23	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
24	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	74.9%	16.6%	1.8%	0.0%	0.0%	0.0%	1.0%	2.6%	0.0%	0.0%	0.0%	3.1%	96.4%	3.6%

DEP

Capacity Payment Period Definitions

The loss of load risk table below for DEP shows that loss of load risk occurs exclusively during winter AM hours for the months of December-March. The DEP capacity payment hours have been redefined as shown below:

DEP Capacity Payment Period Definitions

	Dec-Mar
AM	HE 5-9

Seasonal Allocation Factor

The seasonal allocation for DEP shows that 100% of the loss of load risk occurs during the winter.

DEP Seasonal Allocation

Winter	Summer
100%	0%

DEP 17% Reserve Margin (2020 Resource Adequacy Study)

	Month													
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Winter**	**Summer**
1	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%
2	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	0.0%
3	0.6%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	1.0%	0.0%
4	1.7%	0.8%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	2.8%	0.0%
5	6.3%	3.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	10.1%	0.0%
6	11.4%	6.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	18.7%	0.0%
7	16.4%	9.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.4%	27.9%	0.0%
8	20.0%	9.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	31.0%	0.0%
9	6.2%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.0%	0.0%
10	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	0.0%
11	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%
12	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
13	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
17	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
18	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
19	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
20	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
21	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%
22	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%
23	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.0%
24	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%
	64.0%	**30.0%**	**0.4%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**5.6%**	**100.0%**	**0.0%**

V. Performance Adjustment Factor ("PAF")

The Companies, Public Staff and Dominion reached a consensus to adopt the Equivalent Unplanned Outage Factor ("EUOF") metric for developing the PAF. Similar to the Equivalent Unplanned Outage Rate ("EUOR") metric, which the Commission directed the Companies to consider, the EUOF metric includes the impact of maintenance outages which can also occur during peak demand periods and appropriately excludes planned outages from the calculation. The Companies compiled five years (2016-2020) of Generating Availability Data System ("GADS") data, calculated EUOF for the entire generation fleet (excluding Company-owned solar resources)[7] and included the months consistent with the capacity payment period definitions.

EUOF equals the sum of all Unplanned Outage Hours plus Equivalent Unplanned Derated Hours divided by Period Hours. "Unplanned" hours include forced and maintenance outage hours. The system weighted EUOF is calculated using the following formula established by the North American Electric Reliability Corporation ("NERC"):[8]

Weighted Equivalent Unplanned Outage Factor – WEUOF

$$WEUOF = \frac{\Sigma\,[(UOH + EUDH) \times NMC]}{\Sigma\,(PH \times NMC)} \times 100\%$$

$$WEUOF = \frac{\Sigma\,[(MOH + FOH + EFDH + EMDH) \times NMC]}{\Sigma\,(PH \times NMC)} \times 100\%$$

As noted above, the EUOF metric allows the Companies to align calculation of the PAF with the actual period in which the Companies pay for capacity. In the past, the Companies have used the Equivalent Availability ("EA") metric, which required calculation of the PAF based only on the critical peak season months of January-February and July-August. Inclusion of additional months would introduce periods with planned outages that would artificially decrease the EA and increase the PAF. Thus, use of the EA metric did not allow alignment between the EA calculation and the actual capacity payment period definitions which included the additional months of December and March. The EUOF metric is not impacted by planned outages, which allowed alignment of the EUOF calculation with the actual capacity payment period definitions. For DEC, this includes the winter months of December-March and summer months of July-August. To align with DEP's

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[7] Because solar generation is not part of the mandatory GADS reporting requirements at this time, the system weighted EUOF calculation is based on the performance of the entire generation fleet excluding Company-owned solar resources. If GADS data was available and Company-owned solar resources were included in the calculation, it would likely have a negligible impact on the system weighted EUOF or resulting PAF since total Company-owned solar is approximately 200 MW (combined for DEC and DEP) compared to total Company-owned generation of approximately 38,000 MW (combined for DEC and DEP).

[8] North Am. Electric Reliability Corporation, Generating Availability Data System: Data Reporting Instructions, Appendix F, at F-17-F-18 (Jan. 2021), *available at* https://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/Appendix_F_Equations_2021_DRI.pdf.

actual capacity payment period, the DEP data was based only on the winter months of December-March and does not include any summer months.

Based upon these calculations and the agreed-upon methodology, DEC's and DEP's respective system weighted EUOF during this timeframe averages approximately 4%, which results in a PAF of 1.04 for both DEC and DEP as provided below.

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WEUOF

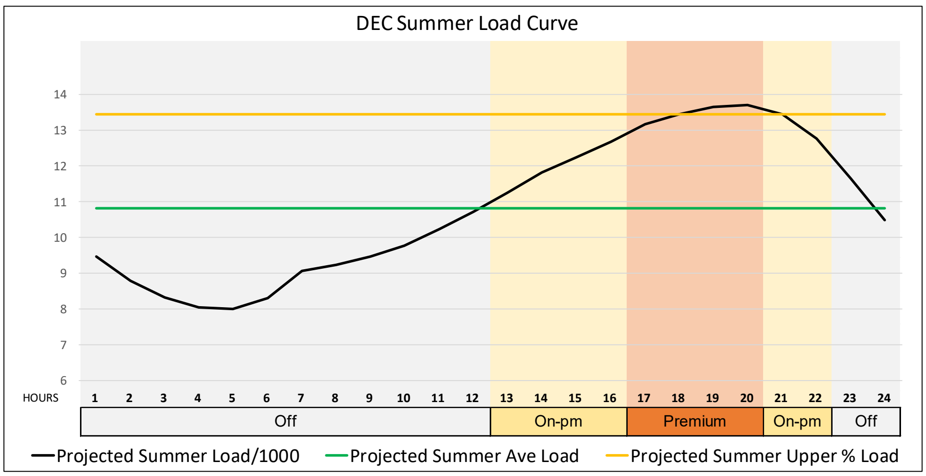
DEC	Jan	Feb	Mar	Jul	Aug	Dec	Total	
2016	[redacted]							
2017	[redacted]							
2018	[redacted]							
2019	[redacted]							
2020	[redacted]							PAF = 1/(1-WEUOF)
Average 2016-2020	[redacted]						4.0%	1.04

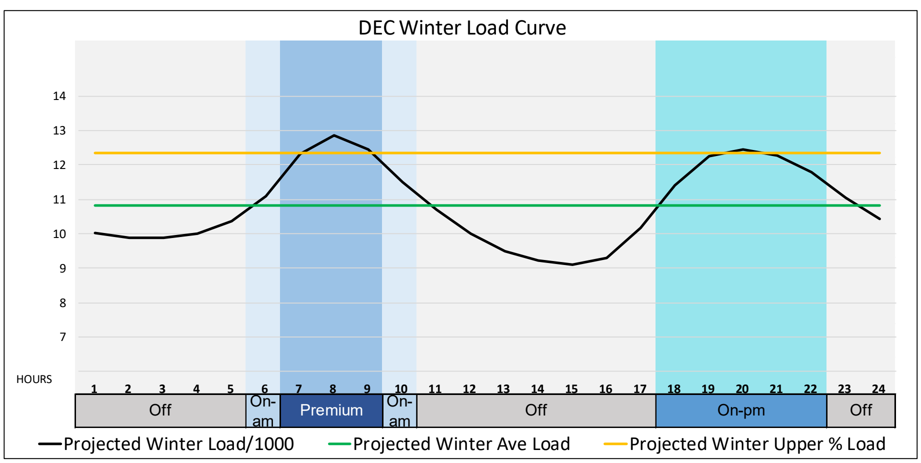
WEUOF

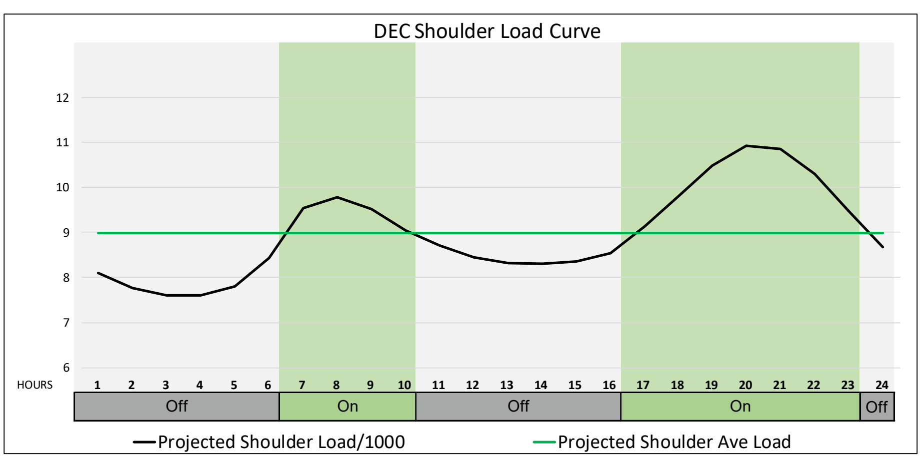
DEP	Jan	Feb	Mar	Dec	Total	
2016	[redacted]					
2017	[redacted]					
2018	[redacted]					
2019	[redacted]					
2020	[redacted]					PAF = 1/(1-WEUOF)
Average 2016-2020	[redacted]				3.9%	1.04

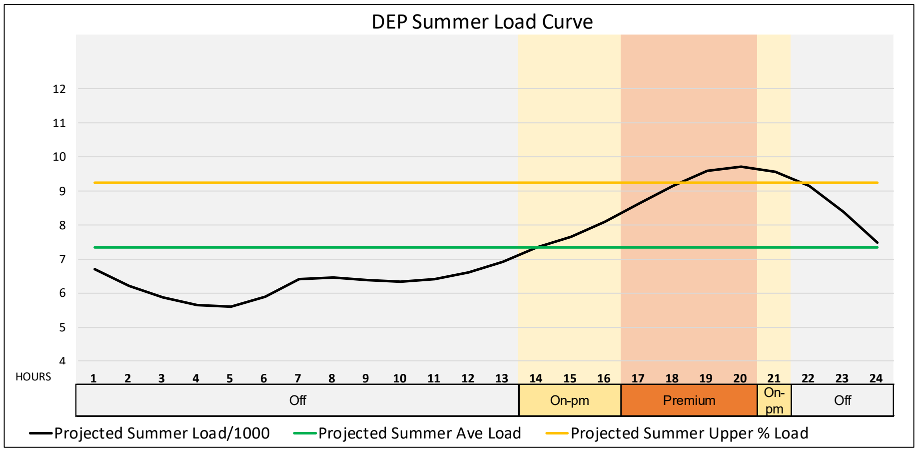
VI. Avoided Energy Rate Design

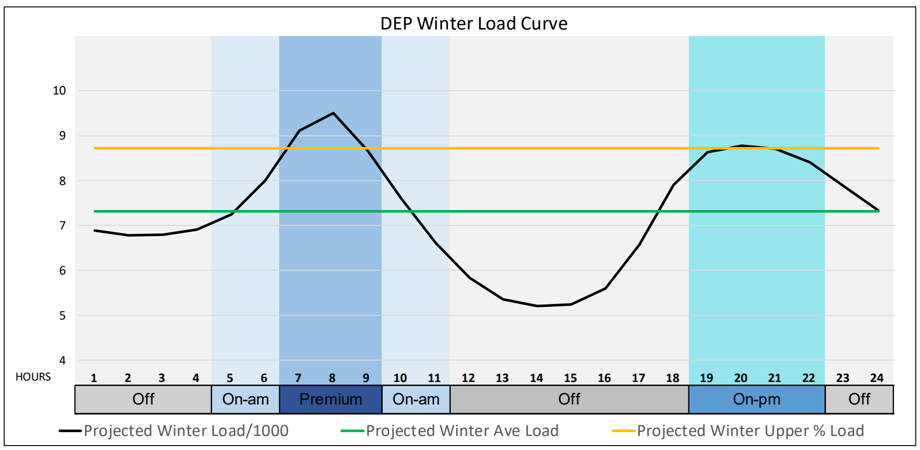
The following graphs are intended to provide a visual comparison of on-peak and premium peak hours by season based on DEC's and DEP's projected loads as compared to currently approved energy price periods. The legend shows color-shaded blocks which represent the current energy period definitions and color-coded graph lines which show the projected hourly load net of renewable energy supply. The hours where the net loads (black line) are above the season average (green line) are considered as potential on-peak or premium peak hours, and those above the upper-percentile level (gold line) guide the selection of the premium peak hours.

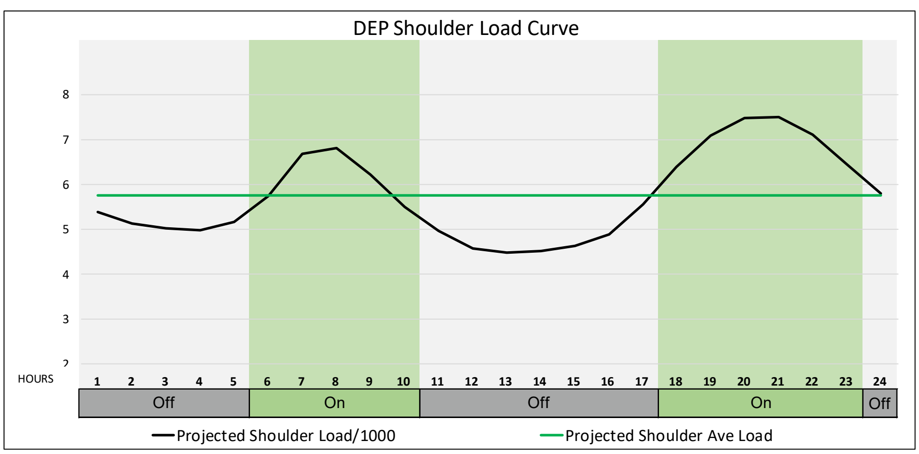












Looking at the graphs, the hour definitions for both DEC and DEP continue to be reasonable for use in the 2021 filing. Analysis of trends will be ongoing to determine if enough evidence exists to warrant a shift in hourly definitions in future filings.

VII. DEC and DEP Avoided Energy and Capacity Pricing Periods

As compared to the pricing periods approved by the Commission in Docket No. E-100, Sub 167, the Companies' proposed energy price blocks remain the same, while their proposed capacity price blocks have shifted and are no longer identical as demonstrated by the two new 2021 charts below.

Energy Pricing Periods (2021 to 2020 Comparison)

<table>
<tr><th colspan="25">DEC Energy Independent Price Blocks (2021 and 2020)</th></tr>
<tr><td></td><td colspan="3">Summer Premium Peak</td><td colspan="3">Summer On-Peak</td><td colspan="2">Summer Off-Peak</td><td colspan="3">Winter Premium Peak</td><td colspan="3">Winter On-Peak (AM)</td><td colspan="3">Winter On-Peak (PM)</td><td colspan="2">Winter Off-Peak</td><td colspan="3">Shoulder On-Peak</td><td colspan="2">Shoulder Off-Peak</td></tr>
<tr><td>Hour Ending</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>13</td><td>14</td><td>15</td><td>16</td><td>17</td><td>18</td><td>19</td><td>20</td><td>21</td><td>22</td><td>23</td><td>24</td></tr>
<tr><td>Summer (Jun - Sep)</td><td colspan="12">Off</td><td colspan="4">On</td><td colspan="4">Premium</td><td colspan="2">On</td><td colspan="2">Off</td></tr>
<tr><td>Winter (Dec - Feb)</td><td colspan="5">Off</td><td>On</td><td colspan="3">Premium</td><td>On</td><td colspan="7">Off</td><td colspan="5">On (PM)</td><td colspan="2">Off</td></tr>
<tr><td>Shoulder (Remaining)</td><td colspan="6">Off</td><td colspan="4">On</td><td colspan="6">Off</td><td colspan="7">On</td><td>Off</td></tr>
</table>

<table>
<tr><th colspan="25">DEP Energy Independent Price Blocks (2021 and 2020)</th></tr>
<tr><td></td><td colspan="3">Summer Premium Peak</td><td colspan="3">Summer On-Peak</td><td colspan="2">Summer Off-Peak</td><td colspan="3">Winter Premium Peak</td><td colspan="3">Winter On-Peak (AM)</td><td colspan="3">Winter On-Peak (PM)</td><td colspan="2">Winter Off-Peak</td><td colspan="3">Shoulder On-Peak</td><td colspan="2">Shoulder Off-Peak</td></tr>
<tr><td>Hour Ending</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>13</td><td>14</td><td>15</td><td>16</td><td>17</td><td>18</td><td>19</td><td>20</td><td>21</td><td>22</td><td>23</td><td>24</td></tr>
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<tr><td>Winter (Dec - Feb)</td><td colspan="4">Off</td><td colspan="2">On</td><td colspan="3">Premium</td><td colspan="2">On</td><td colspan="7">Off</td><td colspan="4">On (PM)</td><td colspan="2">Off</td></tr>
<tr><td>Shoulder (Remaining)</td><td colspan="5">Off</td><td colspan="5">On</td><td colspan="7">Off</td><td colspan="6">On</td><td>Off</td></tr>
</table>

Capacity Pricing Periods (2021 to 2020 Comparison)

<table>
<tr><th colspan="25">DEC Capacity Independent Price Blocks (2021)</th></tr>
<tr><td>Hour Ending</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>13</td><td>14</td><td>15</td><td>16</td><td>17</td><td>18</td><td>19</td><td>20</td><td>21</td><td>22</td><td>23</td><td>24</td></tr>
<tr><td>Summer (Jul - Aug)</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td colspan="4">Summer</td><td></td><td></td><td></td></tr>
<tr><td>Winter (Dec - Mar)</td><td></td><td></td><td></td><td></td><td></td><td colspan="5">Winter</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

<table>
<tr><th colspan="25">DEP Capacity Independent Price Blocks (2021)</th></tr>
<tr><td>Hour Ending</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>13</td><td>14</td><td>15</td><td>16</td><td>17</td><td>18</td><td>19</td><td>20</td><td>21</td><td>22</td><td>23</td><td>24</td></tr>
<tr><td>Summer (Jul - Aug)</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Winter (Dec - Mar)</td><td></td><td></td><td></td><td></td><td colspan="5">Winter</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

<table>
<tr><th colspan="25">DEC and DEP Capacity Independent Price Blocks (2020)</th></tr>
<tr><td>Hour Ending</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>13</td><td>14</td><td>15</td><td>16</td><td>17</td><td>18</td><td>19</td><td>20</td><td>21</td><td>22</td><td>23</td><td>24</td></tr>
<tr><td>Summer (Jul - Aug)</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td colspan="4">Summer (PM)</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Winter (Dec - Mar)</td><td></td><td></td><td></td><td></td><td></td><td></td><td colspan="3">Winter (AM)</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td colspan="3">Winter (PM)</td><td></td><td></td><td></td></tr>
</table>

VIII. Avoided Fuel Hedge Value

For the energy rates that the Companies are proposing in this proceeding, and consistent with prior proceedings and the Public Staff's recommendation,[9] the Companies have used the Black-Scholes option pricing method to determine the fuel hedging benefits. Consistent with this approach, the Companies entered the current Henry Hub gas pricing data into the option pricing model, resulting in a call option value of approximately $0.5121/MMBtu and a put option value of $0.5086/MMBtu. The net option price, or difference between the call and put option values, of $0.0035/MMBtu represents the estimated fuel price hedging benefit. Multiplying the $0.0035/MMBtu by a gas combined-cycle plant heat rate of 7 MMBtu/MWh results in a fuel price hedging value of $0.02/MWh, which is assumed constant for all years of the Schedule PP contract. The Black-Sholes Model inputs and results are shown below.

REDACTED

Fuel Hedge Value - Black-Scholes Model

As of Date: 10/7/2021

Forward Month	NYMEX Henry Hub Gas[1]	Gas Vol[2]	Interest Rate[2]	Expiry[3]	Time to Expiry	Call Option[4]	Put Option[4]	Call-Put Spread	Assumed Gas Heat Rate[5]	Hedge Value ($/MWh)
Jun-22	3.869	[redacted]		5/28/2022	0.6384	$ 0.5121	$ 0.5086	$ 0.0035	7	$ 0.02

Assumptions:

[1]Nymex Henry Hub Gas price sourced from NYMEX as of 10/7/21 for June 2022 contract

[2]Gas volatility curve and interest rate curve as of 10/7/21 for June 2022 contract sourced from internal and confidential CXL database used as a source of record for commodities, and trading positions

[3]Assumed June 2022 contract expires 3 days before the end of the month

[4]Call and put options valuated via Black Scholes calculator (European option)

[5]Assumed average combined cycle gas heat rate of 7 MMBtu/MWh

[9] *See* Initial Statement of the Public Staff, Docket E-100, Sub 140 at 36 (Filed Jun. 22, 2015).

IX. Start Cost Modeling

Pursuant to the Commission's directive in the *2020 Sub 167 Order*, the Companies have modified their start cost modeling to resolve unintended impacts on the avoided energy pricing periods.[10] In the PROSYM production cost model, representative planned maintenance and other operations and maintenance ("O&M") costs are allocated to unit operation such that they are attributed to the phase of operation that generates the cost, including starting up or shutting down (cycling), per MWh of operation and per Hour of operation. O&M costs are modeled in this manner to optimize the projected maintenance cost and to give an accurate projection of operation. However, this modeling can have unintended consequences in calculating the avoided energy costs for different pricing periods. Adding the no-cost 100 MW base load QF purchase to the change case can cause units to start in a later hour. For example, if a start is delayed from a peak hour to a premium peak hour, the change case cost is increased in the premium peak hour, resulting in a lower delta avoided cost between the base case and change case in that hour. To solve this issue for avoided cost purposes, the start-up and shut-down costs are distributed over the anticipated operation and added to the per MWh and per Hour cost components. Total O&M costs, including start costs, are captured in this approach while providing intuitive and appropriate avoided energy price signals. This methodology is consistent with the modeling approach utilized in the approved 2018 Sub 158 and 2020 Sub 167 avoided energy rates, and the Public Staff has indicated that it supports the Companies' approach to this calculation.

[10] *2020 Sub 167 Order,* at 7.

DEC / DEP Joint Exhibit 9

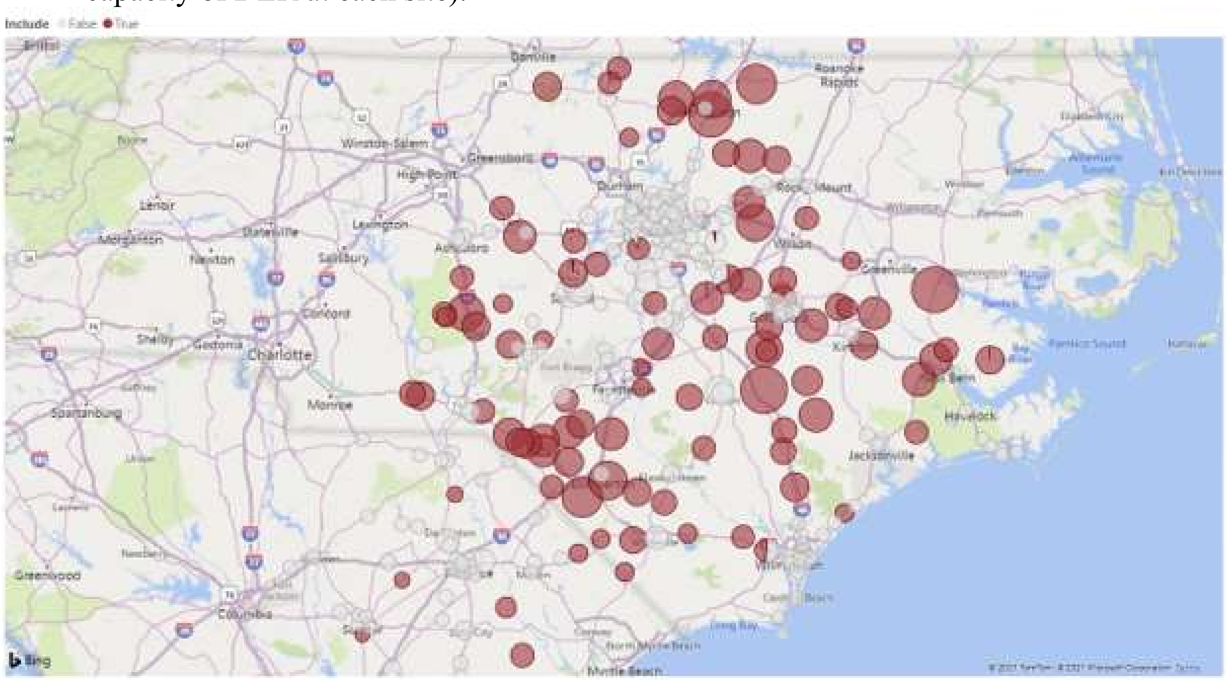
Geographical Location of Substations with Backflow

Docket No. E-100, Sub 175

NC Avoided Cost Filing (Docket No. E-100, Sub 175)
DEC/DEP Joint Exhibit 9
Geographical Locations of Substations with Backflow in North and South Carolina

I. DEC Substation Banks with Backflow Due to Distributed Energy Resources ("DER") (bubble size indicates the megawatts ("MW") of capacity of DER at each site).

II. DEP Substation Banks with Backflow Due to DER (bubble size indicates the MW of capacity of DER at each site).



DEC / DEP Joint Exhibit 10

Technical Review Committee's Review of Duke Energy's SISC, prepared by The Brattle Group, on behalf of the SISC TRC

Docket No. E-100, Sub 175

Technical Review Committee's Review of Duke Energy's Solar Integration Service Charge (SISC)

PREPARED BY

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Johannes Pfeifenberger
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On behalf of the

SISC Technical Review Committee

PREPARED FOR

Duke Energy Carolinas and
Duke Energy Progress

AUGUST 31, 2021

Brattle

NOTICE

- This report by the named authors and the Technical Review Committee (TRC) was prepared for Duke Energy Carolinas and Duke Energy Progress, in accordance with The Brattle Group's engagement terms. It is intended to be read and used as a whole and not in parts.
- The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.
- There are no third party beneficiaries with respect to this report, and The Brattle Group does not accept any liability to any third party in respect of the contents of this report or any actions taken or decisions made as a consequence of the information set forth herein.

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I. Overview of the Technical Review Committee (TRC) Process

On April 15, 2020, the North Carolina Utilities Commission ("NCUC") issued a final Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, directing Duke to organize and coordinate an independent technical review of the "Duke Energy Carolinas and Duke Energy Progress Solar Integration Service Charge Study" to be undertaken by Astrapé Consulting in 2021 (referred to herein as the "Astrapé Study"). The purpose of the Astrapé Study is to analyze and quantify the costs of the ancillary service impact associated with integrating existing and future solar generation on both the DEC and DEP systems. This solar integration cost is then applied by Duke as Solar Integration Service Charge ("SISC") to intermittent solar generation facilities requesting to sell power to Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") (jointly "the Companies").

The NCUC Order specifically stated that:

> . . . the Commission directs Duke to assemble a technical review committee to provide a review of the Astrapé Study. The technical review committee shall be comprised of individuals, not otherwise affiliated with Duke or any of its affiliates or organizations in which Duke is a member, who have technical expertise, knowledge, and experience related to the integration of solar generation as well as the development of complex research, development, and modeling. The committee should include personnel employed by the National Laboratories with relevant experience and expertise. The purpose of the work with a technical review committee is to provide an in-depth review of the study methodology and the model used for system simulations. The technical review committee should provide specific comments or feedback to Duke in the form of a report, which report is to be included in the initial filing made in Duke's 2020 biennial avoided cost proceeding.

Pursuant to NCUC guidance provided in Docket E-100, Sub 158, the TRC "should include personnel employed by the National Laboratories with relevant experience and expertise." The Companies have thus retained the following individuals from National Laboratories as members of the TRC ("TRC Technical Leads"):

- 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, Lawrence Berkeley National Laboratory (LBNL)

The Public Service Commission of South Carolina ("PSCSC") similarly directed Duke to undertake "an independent technical review of the underlying modeling, inputs, and assumptions of the Integration Services Charge prior to the next avoided cost proceeding" (PSCSC Order No. 2019-881-A, at 31, 121). Duke agreed with certain interveners to complete the independent technical review in a Partial Settlement Agreement filed with the PSCSC on October 21, 2019, in Docket Nos. 2019-184-E and 2019-185-E. That Partial Settlement Agreement, which was approved by the SCPSC in Order No. 2019-881-A, provided, in pertinent part, that:

> The Astrapé Study used to calculate the SISC presents novel and complex issues that warrant further consideration. Duke shall submit the study methodology and inputs to an independent technical review and include the results of that review and any revisions in its initial filing in the next avoided cost proceeding. To the maximum extent practicable the independent review of the study methodology shall take into consideration the South Carolina Integration Study called for by S.C. Code Ann. § 58- 37-60. This process shall be subject to Commission oversight and comment from interested stakeholders.[1]

The Companies, with input from the NC Public Staff and SC Office of Regulatory Staff ("ORS"), have retained The Brattle Group ("Brattle") as the TRC Principal Consultant to coordinate the TRC meetings, incorporate feedback from the TRC Technical Leads, and author the TRC Report for the Companies to incorporate into their 2021 regulatory filings.

The Brattle Group has substantial expertise in understanding the intra-hour impacts of renewable energy and the impacts of its associated intermittency on a regulated electric utility's system operations. Additionally, through various past consulting engagements, Brattle has demonstrated experience in collaborating with various entities in the development and presentation of technical studies related to renewable energy integration.

The NC Public Staff and the SC ORS have designated the following individuals to participate in the TRC as "regulatory observers" subject to substitution if needed:

- NC Public Staff Primary Regulatory Observer: Jeff Thomas

[1] S.C. Code Ann. § 58- 37-60 provides in pertinent part that "[t]he commission and the Office of Regulatory Staff are authorized to initiate an independent study to evaluate the integration of renewable energy and emerging energy technologies into the electric grid for the public interest. An integration study conducted pursuant to this section shall evaluate what is required for electrical utilities to integrate increased levels of renewable energy and emerging energy technologies while maintaining economic, reliable, and safe operation of the electricity grid in a manner consistent with the public interest. Studies shall be based on the balancing areas of each electrical utility." At this time, no South Carolina Integration Study has commenced.

- NC Public Staff Alternate Regulatory Observer: Dustin Metz
- SC Office of Regulatory Staff Observer: Robert Lawyer
- SC Office of Regulatory Staff Observer: O'Neil Morgan

Starting in March 2021, Brattle consultants (the "TRC Principal") have coordinated regular meetings of the TRC and Astrapé to review the SISC study methodology and modeling assumptions with the Technical Leads, participation by the Regulatory Observers (as available), and Duke technical staff (as needed to address the specific questions raised by the TRC). During these meetings, Astrapé consultants have presented the proposed SISC study methodology and initial draft results to the TRC and the Regulatory Observers for review in biweekly meetings.

In our role as the TRC Principal, we (the named Brattle consultants) have now compiled this TRC Report for the Companies, who will then present the TRC's findings to stakeholders. This TRC Report will also be included in the Companies' South Carolina Act 62 PURPA filing.

II. Public Stakeholder Meeting and Comments

On March 19, 2021, also hosted a public stakeholder meeting to introduce the TRC, discuss plans for completing the scope of study required by the NCUC and PSCSC, and solicit any comments for consideration by Astrapé and the TRC to inform the ongoing study. The presentation slides used for this meeting are attached as Appendix A.

The public comments received in response to the March 19 stakeholder meeting—submitted on March 30 by the Southern Environmental Law Center (SELC) on behalf of Southern Alliance for Clean Energy, North Carolina Sustainable Energy Association, and the Carolinas Clean Energy Business Association—are attached as Appendix B. These comments have been reviewed by the TRC and reflected in the refined SISC study methodology as applied by Astrapé in the current SISC study effort (as reflected the next section of this report).

III. The TRC Review of the SISC Study Methodology

During the TRC meetings, conducted from early March 2021 through the beginning of July 2021, the TRC members discussed several methodological and modeling questions with the Astrapé team. The Astrapé team implemented the recommendations from the TRC, which are reflected in the preliminary report published by Astrapé. In making its recommendations, the TRC also considered the comments provided by the SELC, many of which aligned with the TRC's perspective and have been incorporated in Astrapé final modeling effort.

This section of this TRC Report summarizes the main topics discussed by the TRC during its meetings with Astrapé, provides the TRC's recommendations on each topic, and discusses how Astrapé incorporated the recommendations. The topics include:

A. **Modeling the DEC and DEP Joint Dispatch Agreement (JDA):** The JDA between DEC and DEP allows for joint unit commitment and dispatch between the two utilities (subject to certain limitations). The TRC believes that the JDA allows the two utilities to provide load following reserves at a lower cost than under strictly separate ("islanded") balancing area operation. The TRC recommended that Astrapé model a case that reflects the JDA, and the results of that case were included in the preliminary report ("the Astrapé Report").

B. **The Proposed Southeast Energy Exchange Market (SEEM):** The TRC discussed the possibility of modeling Duke's membership in the proposed SEEM, which would entail modeling some intra-hour imports and exports from Duke's two utilities with the neighboring utilities that plan to join SEEM. In the end, the TRC recommended not modeling the SEEM in this iteration of the SISC estimate, but that it should be considered for the future as operational experience in the SEEM becomes available.

C. **Representation of Solar Volatility and Geographic Diversity:** The TRC and Astrapé discussed the methodology used to model solar profiles, including improvements Astrapé made since their previous effort to estimate the SISC to incorporate the geographic diversity of solar resources. The TRC finds that Astrapé's currently modeling approach to capture solar volatility, including the benefit of decreased volatility due to geographic diversity as more solar resources come online, is a significant improvement compared to their methodology in the 2018 study.

D. **The Level of Solar Curtailments:** The TRC raised questions about the fact that Astrapé assumes no cost for curtailing solar in the model, and recommended that Astrapé conduct a sensitivity that imposes a cost for curtailments to observe how this would change the estimated SISC. The results of that sensitivity suggest that imposing a cost on curtailments does not materially change the SISC, or the overall level of curtailments. The sensitivity results also documented that only a small portion of the simulated curtailments relate to flexibility limits.

E. **Operational Flexibility of Duke Generation Resources:** The TRC explored whether the modeled operational flexibility of some of Duke's combustion turbine (CT) resources and their pumped storage hydro facilities accurately reflected constraints on those resources. The TRC discussed the topic with subject matter experts at Duke. The TRC concluded that, while some of Duke's CTs and pumped storage facilities are less flexible than similar resources owned by other utilities, the modeling assumptions reflect the current operational restrictions on these generation resources.

F. **The Addition of Flexible Generation Resources to Duke's Fleet:** The TRC observed that Duke may be able to provide the load following necessary to integrate new solar at a lower cost by investing in or contracting for additional flexible resources. The TRC, working with Astrapé, conducted a back-of-the-envelope estimate to compare how much it would cost to provide the same level of load following reserves determined by SERVM with new battery resources. The TRC found that under the solar penetration levels studied in Tranche 2 it is unlikely that building new battery storage resources would be cheaper than providing load following with Duke's current generation fleet. However, the TRC recommends that the Commissions should continue the discussion regarding Duke's investment in new flexible resources in the context of Duke's resource planning efforts, especially as solar penetration levels increase beyond those modeled in Tranche 2 and as the cost of new flexible resources change over time.

G. **Methodology for Modeling the Addition of Load Following Reserves:** Astrapé implemented a new methodology for determining how load following reserves are added by the model to accommodate new solar. The new methodology is more targeted to specific times of day (compared to an all-hours approach used in the 2018 SISC study), which reduces the amount of load following and the cost needed to integrate new solar. The TRC finds that the new approach is an improvement compared to the 2018 study, results in a lower solar integration cost, and better represents the actual solar integration cost.

H. **Benchmarking the Estimated Cost of Reserves:** The TRC compared the estimated cost of load following reserves with similar reserve products in PJM. The estimated cost of load following for DEC and DEP are higher than they are in PJM, which is expected and reasonable given the size of Duke's footprint relative to PJM and given the relative inflexibility of Duke's generation resources.

I. **Consideration of Comments from the SELC:** The TRC reviewed and discussed all the comments submitted by the SELC, many of which aligned with the TRC's own view on how to improve the estimate of the SISC. Where the TRC agreed with comments from SELC, it recommended that Astrapé implement those changes in its model.

J. **Interpretation of Solar Tranches:** The TRC reviewed the modeling assumptions for the three Tranches of solar penetration studied by Astrapé. Tranche 1 represents a level of solar penetration slightly lower than the currently planned solar additions in DEC and DEP and Tranche 2 models a level of solar that is slightly higher than the currently planned solar additions. Tranche 3 analyzes much higher levels of solar penetration than expected during the time when the SISC estimated in this proceeding will be in effect. The TRC recommends that the Commissions not rely on the results of Tranche 3 in setting the SISC in the current proceeding.

The remainder of this section provides a more in-depth review each of these topics, including details of the TRC's recommendations.

A. Modeling the DEC and DEP Joint Dispatch Agreement

After the merger of Duke and Progress, the combined company implemented the JDA between DEC and DEP to provide generation at a lower cost for customers of both utilities. Under the JDA, Duke performs a joint unit commitment and minute-by-minute energy dispatch subject to transmission availability between the two utilities. The JDA allows lower fuel and operational costs for both utilities. Although each BA must have sufficient capacity to meet their respective planning reserves and operating reserves, the transfer of economic energy between the two BAAs allows for lower-cost load following, than would be achieved under separate unit commitment and dispatch.

In its previous estimate of the SISC, Astrapé modeled independent unit commitment and dispatch for the DEC and DEP generation resources. The previous Astrapé study also assumed that there was no transmission interconnection between the two utilities and no exchange of economic energy for the purpose of intra-hour load following. Similar assumptions are reflected in the "islanded" cases presented in the Astrapé Report in this estimate of the SISC.

To reflect the operation of the JDA, the TRC requested that Astrapé simulate a scenario for the current study where DEC and DEP areas perform joint unit commitment and minute-by-minute dispatch subject to applicable transmission limitations. Astrapé and the TRC discussed the operation of the JDA with subject matter experts at Duke to ensure that the model reflects the true operation of the JDA as best as possible. In the combined case, resources in DEC and DEP are jointly committed and dispatched, but the BA's must satisfy their individual operating reserve requirements, and the model respects the transmission constraint between DEC and DEP. The Astrapé Report presents the results of this case as the "combined" case.

The TRC recommended modeling the combined case because it better reflects Duke's current operations than the islanded cases.

B. The Proposed Southeast Energy Exchange Market (SEEM)

Within the last year, Duke and several other utilities in the Southeast region have proposed creating the Southeast Energy Exchange Market (SEEM). As proposed, the SEEM will facilitate 15 minute trading between Duke and its neighbors, such as TVA and Southern Company, without the need for paying transmission wheeling fees between the areas. In the SEEM, schedules would be locked in five to ten minutes before the 15 minute trading period, implying that the SEEM could respond on a 20 to 25 minute basis to help balance solar volatility between SEEM members. As of the writing of this report, that proposed market rules are still in front of FERC for approval and the SEEM has not begun operation.

The TRC decided that it is premature at this point to include potential effects of the SEEM in the estimate of the SISC. This recommendation was made because the design, implementation, and actual operations of SEEM are still uncertain, making any modeling assumptions used to represent the SEEM at least partially speculative. The TRC made this recommendation in light of the fact that the proposed start date for the SEEM is January 2022, which is during the time period when the currently estimate of the SISC is likely to be in effect. However, the effects of the SEEM can be considered in the next estimation of the SISC after the exchange is implemented and operational experience has been gained.

In addition, the TRC is not certain that the SEEM will be helpful in balancing solar volatility given the 20 to 25 minute lead time needed to lock in schedules prior to real-time operation. The TRC raises the question of how much solar uncertainty is resolved 20 to 25 minutes before real-time. There is some evidence from studies done in other jurisdictions related to wind volatility that even a 30-minute prior to real-time update to schedules can reduce integration costs.[2] However, that study is almost 10 years old, is from a different region of the country, and does not address solar volatility, which has different characteristics then wind. This uncertainty is another reason why the TRC recommends waiting until the SEEM has been in operation for some time before it is represented in the modeling done to estimate the SISC.

The TRC recommends including SEEM in next update of the SISC when more is known about SEEM operations and there is historical data on SEEM intra-hour energy trades.

[2] See the 2012 Bonneville Power Administration Study accessed here: https://www.bpa.gov/Finance/RateCases/InactiveRateCases/BP12/Final%20Proposal/BP-12-FS-BPA-05.pdf

C. Representation of Solar Volatility and Geographic Diversity

The TRC reviewed the methodology utilized by Astrapé in the SERVM model to capture solar profiles in line with historical volatility. The hourly solar profiles used in the model come from the National Renewable Energy Laboratory's (NREL) National Solar Radiation Database for the last 39 years for each county in Duke's service territory.[3] On top of the hourly profiles, Astrapé adds 5-minute volatility to represent real-time solar output. The 5-minute volatility is determined from historical data.

Unlike in their previous estimation of the SISC, Astrapé accounted in this study for the decline in unitized volatility of Duke's aggregate solar portfolio due to the addition of new solar resources. The decline in solar volatility as a decreasing function of solar capacity is due to the increasing geographical diversity of Duke's solar resources, as new facilities come online in different parts of the Carolinas. The Astrapé team analyzed the decline of aggregate solar volatility by observing the historical 5-minute volatility of solar for DEC, DEP, and the combined DEC-DEP footprint. This provided three historical data points of 5-minute solar volatility as a function of installed solar capacity. The Astrapé team fitted a curve to the 95th percentile in solar volatility at those three levels of solar deployment, and then extrapolating that trend to greater levels of solar deployment.[4]

The TRC raised several questions during the discussion with the Astrapé team. First, the TRC pointed out that it will be more difficult to forecast solar volatility on certain types of days (e.g., partially cloudy days), and asked how day-ahead forecasts are generated in SERVM. The Astrapé team explained that the model compares the realized output for the day in question and compares it to other days with similar profiles. Next, the model randomly samples those similar days to use as a forecast (e.g., if a day's realized solar output is highly variable, corresponding to a partially cloudy day the model will select a profile from a similarly cloudy day).

In addition to the difficulty in forecasting solar volatility on a day-ahead basis, the TRC commented that intra-hour solar volatility would be larger on a day that is partially cloudy. The Astrapé team responded that the model accounts for this implicitly by sampling volatility profiles as a function of hourly solar production, so an hour with 50% of nameplate output will stochastically draw its volatility profile from a historic hour that also has approximately 50% nameplate output.

The TRC discussed the inclusion of behind-the-meter solar in the historical data used to determine the intra-hour volatility of solar. The Astrapé team indicated that the historical solar data is from SCADA and does not include behind-the-meter solar, so ramps in solar generation could actually be larger than

[3] Carden, K., Wintermantel, N., and Patel, P., "Duke Energy Carolinas and Duke Energy Progress Solar Integration Service Charge (SISC) Study," Preliminary Draft, p. 23.

[4] *Id.*, pp. 27-28

modeled. The modeling effort may thus underestimate the integration cost of new solar resources. Behind-the-meter solar is included in the historical load data and affects the load volatility, but increased adoption of behind-the-meter adoption is not modeled, implying that the load volatility is fixed during the forecast period.

The TRC finds that Astrapé has significantly improved the modeling of solar volatility, including the benefits from a decline in volatility as new solar resources come online in DEC's and DEP's service territories.

D. The Level of Solar Curtailments

The TRC raised questions about the level of solar curtailments observed in the results, and regarding how curtailments effect the integration cost of new solar resources. The TRC noted that solar curtailments reached very high levels in the "island" case, where DEC and DEP perform independent unit commitment and dispatch, and cannot trade with each other. For example, in the island case, solar curtailment in DEP ranges from 6.8% in Tranche 1 to 14.1% in Tranche 2.[5] In the combined case, which reflects the JDA, curtailment levels are significantly lower and range from 0.3% in Tranche 1 to 3.0% in Tranche 2 for the combined DEC and DEP footprint.[6]

The Astrapé model does not include a penalty for solar curtailment, though curtailing solar does impose an increase in fuel costs in the model as fossil generation replaces curtailed solar. The lack of penalty for curtailments is consistent with state regulations for PURPA contracts. Even during non-emergency conditions, Duke does not pay a penalty for curtailments unless curtailed energy over the year is greater than 5% of expected annual output in DEC and 10% expected annual output in DEP for North Carolina; and 5% of expected annual output in South Carolina.

The TRC, in discussion with Astrapé, noted that the high levels of curtailments estimated in the simulations might actually reduce the SISC. This is because only a small fraction of the simulated curtailments relate to intra-hour load following needs. This also means that the model can use curtailments as load following reserve, and the ability to curtail solar without a penalty may make them a low-cost way to provide the additional load following reserves needed to integrate new solar resources. This is consistent with a recent study on solar integration costs in Arizona, which found that integration costs increased when solar curtailments were reduced by applying a penalty.[7]

5 *Id.,* p. 48

6 *Id.,* p. 53

7 See https://www.osti.gov/biblio/1164898/

To explore the impact of solar curtailments on integration costs, the TRC requested that Astrapé conduct a sensitivity that includes an economic penalty for curtailing solar resources. The results of that sensitivity demonstrated that curtailments and the estimated SISC remain relatively the same even with the penalty on curtailments included in the model. In fact, the SISC increases by a small amount given the penalty, which confirms that curtailments reduce overall integration costs.[8]

The TRC finds the treatment of curtailments in the model is conservative in terms of its impact on the SISC and is consistent with policy related to PURPA contracts.

E. Operational Flexibility of Duke Generation Resources

The TRC reviewed the modeling assumptions used to represent the operational parameters of DEC's and DEP's conventional generation fleet, including max output, min output, minimum downtime, minimum uptime, 10 minute ramping capability, and startup time. This review led the TRC to raise questions about the modeling assumptions used for two particular resource types: combustion turbines (CTs) and pumped storage hydro resources. The modeling assumptions used to represent these two resource types indicated that the resources were less flexible than TRC members expected. In light of the fact that CTs and pumped storage hydro are typically ideal resources for providing load following, the TRC requested additional information from Duke on the operational characteristics of these resources.

The TRC noted that a number of block-loaded CTs (e.g., Lincoln and Mill Creek) are modeled without any flexibility, meaning the minimum output on the units is equal to maximum output. Duke confirmed that these units cannot be put on Automatic Generation Control (AGC) because of air permit restrictions. Upon further review, the TRC concluded that the lack of ramping capability for these CTs might not have substantial impact on the SISC, as the units are relatively small capacity that can be committed in less than an hour. In fact, the SERVM model is able to commit or de-commit the CTs unit-by-unit to help ramp up generation as solar production declines. Astrapé confirmed that the CTs can be used this way by SERVM, as the model has the ability to start and shutdown units intra-hour even though commitment is determined only on an hourly basis.

The TRC requested a detailed explanation of the capabilities of Duke's Bad Creek and Jocassee pumped storage hydro units. The modeling assumptions suggested that both resources have a very narrow window between minimum generation and maximum generation. Duke provided the following operational information about pumped storage:

8 This sensitivity was conducted before the final version of the model and results were completed. Given the results, the TRC did not recommend that this assumption be applied to the final version of the model.

- When in generation mode, the Bad Creek units can operate between 320-420 MW, and the Jocassee units can operate between 170-195 MW.
- When in pumping mode, the units have no ramping capability because they are single-speed motors (fixed load).
- The units are often in pumping mode during periods of peak solar generation, to utilize the low variable cost energy provided by solar resources. Therefore, the pumped storage units are typically not available to provide load following in the hours when solar volatility is most severe.

The TRC discussed with the Duke the feasibility of upgrading the pumps to variable frequency drive, which would enable them to provide more flexibility. Duke indicated that the company has considered that in the past, but that the new machines did not fit within the existing physical structure. Given that an upgrade to the two pumped storage hydro resources is currently not planned, the TRC concluded that the resources should be modeled based on the existing operational capabilities.

TRC concludes that the CT and pumped storage units in DEC and DEP are less flexible than in other systems. However, barring potentially expensive upgrades to the units, their limited flexibility appears to reflect legitimate constraints on their operation and are correctly represented in the simulations to estimate the SISC.

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

The TRC observed that as the total estimated integration cost grows large enough—particularly under Tranches 2 and 3—it may be less expensive to provide the necessary load following reserves by investing in or contracting for new flexible resources, such as battery storage. The current assumption in the Astrapé study is that all load following reserves will be supplied through the operation of Duke's current generation fleet, implying increased fuel and operating expenses to provide the load following needed to integrate the new solar. The TRC suggested that it may be possible to provide the same level of load following reserves at a lower cost by having additional battery storage resources on the system.

For example, the Astrapé study found that the annual integration cost in the combined case under Tranche 2 is \$24.3 million per year.[9] The TRC and Astrapé conducted a back-of-the-envelope calculation to test whether new batteries could provide the needed load following at a lower cost. This would require enough battery capacity to cover the maximum increase in load following reserves for any hour

[9] Carden, K., Wintermantel, N., and Patel, P., "Duke Energy Carolinas and Duke Energy Progress Solar Integration Service Charge (SISC) Study," Preliminary Draft, p.51.

estimated by Astrapé's modeling. Astrapé estimated that the maximum load following would be 472 MW, implying that the system would require 472 MW of 1-hour battery resources to provide the same result as modeled by Astrapé.[10] Lazard's 2020 Levelized Cost of Storage Analysis estimates a range of costs for 1-hour in-front-of-the-meter battery resources of $55-$87/kW-year.[11] Applying those numbers to the estimated 472 MW of needed batteries produces a cost estimate of $26.9 million per year to $41.1 million per year. Therefore, the TRC found that it is unlikely that new battery resources could provide the same integration at a lower cost than Duke's existing resource fleet, based on the Tranche 2 level of solar penetration.

However, the TRC recognizes that the cost of battery storage has been declining in recent years and the level of solar penetration on Duke's system continues to climb, and will likely be above the levels analyzed in Tranche 2 within the time horizon used for integrated resource planning. Moreover, the TRC recognizes that battery storage resources provide additional benefits to Duke customers through inter-hourly energy arbitrage opportunities, and that battery resources may imply additional costs not accounted for in the estimate conducted by the TRC. Therefore, the TRC raises the issue for the Commissions to consider during Duke's future resource planning processes.

The TRC finds that it is unlikely that battery storage alone would provide a cost effective integration solution based on the solar penetration levels studied under Tranche 2. However, the TRC raises this question for the Commissions to consider during Duke's future resource planning efforts if they were to determine that is appropriate.

G. Methodology for Modeling the Addition of Load Following Reserves

In the current Astrapé study, additions of load following reserves additions made only to maintain the intra-hour reliability level that the Duke systems are able to achieve in the absence of solar generation. This is a less stringent criterion than the absolute level of loss of load events (LOLE) that was used in the 2018 study. In addition, the current study increases load following reserves on a monthly basis and only during the hours of the day when solar-related flexibility violations are likely to occur each month. This is a different approach than that employed I the 2018 study, which increased reserve requirements by the same amount for all hours of the year. Maintaining no-solar reliability levels and targeting the load following reserves additions to the months and time of day when needed reduces integration costs.

[10] The results from SERVM in the Astrapé study provide an average realized increase in load following needed to integrate new solar over the entire year (204 MW), but not the maximum increase in load following needed for this calculation. Therefore, we use the ratio of the maximum targeted increase in load following (1,047 MW) to the average targeted increase (452 MW) to scale up the average realized increase. See Figures 16 and 21 in the Astrapé Report for the targeted load following amounts. The resulting estimate is as follows: (1,047/452)*204 = 472.

[11] See Lazard's Levelized Cost of Storage Analysis, Version 6.0, accessed at https://www.lazard.com/perspective/lcoe2020

The TRC noted that the reserve levels might be adjusted further depending on each the day's volatility forecast. For example, required reserves could be higher on partially-cloudy days when volatility is the greatest. However, this forecast-based approach is still in the research stages and, thus, not standard practice among system operators. It is consequently not necessary to include it in this study of the SISC.

The TRC finds Astrapé's approach to be reasonable, representing a significant improvement over the 2018 study and consistent with how most system operators determine their load following requirements.

H. Benchmarking the Estimated Cost of Reserves

To benchmark and validate the results of the Astrapé model, the TRC compared the implied cost of load following reserves from the simulation to the cost of reserves in PJM, the neighboring organized RTO market. The TRC determined the implied price of Duke load following reserves based on (1) the simulated increase in ancillary service costs: the ancillary service cost impact ($/MWh) multiplied by the renewable generation (MWh); divided by (2) the additional load following MWh needed to integrate the renewable energy. The TRC and Astrapé found that the implied cost of load following reserves from the simulation is $17.25/MWh to$20.45/MWh in the combined case for Tranche 1 and Tranche 2, respectively.

Publicly available data from the PJM market indicates that the cost of regulation reserves was $13.55/MWh in 2020, $16.27/MWh in 2019.[12] Therefore, the estimated prices in Duke's service territory are slightly higher than in the PJM. However, the higher cost of reserves for DEC and DEP than PJM is expected, due to the much smaller footprint relative to PJM and the more limited flexibility of Duke's generation fleet. Therefore the TRC finds that the estimated cost of load following reserves is within the expected range.

The TRC finds that the estimated cost of additional load following reserves is reasonable given the size of DEC's and DEP's footprint relative to PJM and given the relative inflexibility of Duke's generation fleet (specifically the CTs that are block loaded and the narrow operating range of the two pumped storage resources).

[12] Monitoring Analytics, Independent Market Monitor for PJM, "2020 State of the Market Report for PJM," Section 10, p. 464, accessed here: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020-som-pjm-sec10.pdf. The Regulation Ancillary Services product in PJM is not an exact benchmark for the 10-minute load following reserves modeled in the Astrapé study, because the PJM Regulation product requires 5-minute response. However, there is no exactly comparable product in PJM's market, as there is no market in PJM for load following reserve similar to the load following deployed by Duke. The 5-minute Regulation product in PJM is likely more expensive than a hypothetical 10-minute product in PJM that would be more directly comparable to the 10-minute load following reserves used in the study.

I. Consideration of Southern Environmental Law Center Comments

The TRC considered all the topics raised by the SELC, several of which align with the TRC's own views on how to improve the estimation of the SISC. The list of topics raised by the SELC and the TRC recommendations for each are:

1. **The flexibility balancing requirement should be based on NERC standards, not historical 5-minute flexibility violations.**

   The model is set up to replicate the historical operation of Duke's system. The methodology matches simulated 5-minute flexibility violations in the added solar cases with 5-minute violations in the no solar case, which is calibrated to match the historical 60-minute ramping capability of the DEC and DEP systems. The TRC found that this is a significant improvement over the approach used in the previous Astrapé study. The previous approach determined the additional load following reserves necessary to maintain 0.10 expected flexibility violations per year ($LOLE_{FLEX}$). The new approach adds load following reserves as needed, and lets the model calculate the flexibility violations. The additional load following will free the capacity of units on AGC to provide system regulation and avoid violations of NERC standards. Astrapé iterates the simulation by reducing or adding more load following reserves to match historical 5-minute flexibility violations. Therefore, this new approach calculates the cost of integrating solar resources due to the need for additional load following reserves to maintain the historical 5-minute flexibility violations.

   It is possible that historical operations have resulted in higher reliability than is necessary to avoid NERC violations, creating a "cushion" of added reliability that could be lost without violating NERC standards. The TRC did not study if such a reliability cushion exists, because the TRC believes it is out of scope for this study. One may make an argument that Duke has historically over-provided reliability compared to what is necessary to achieve the NERC standards, and that it may be possible for Duke to provide less reliability and lower system costs while maintaining NERC standards. The TRC did not study what optimal operation would look like, as that is a separate issue from estimating the SISC.

   Moreover, adjusting the modeling assumptions to reduce the level of reliability to exactly the amount needed to avoid NERC standards implies eliminating any potential reliability cushion that has historically been provided to customers and giving all the benefit of eliminating that cushion entirely to solar resources.

   The TRC and Astrapé discussed additional modeling considerations related to this topic:

- The model has perfect foresight 5 minutes ahead. Therefore, the number of 5-minute flexibility violations found by the model is less than what would occur in reality, implying that the estimate of integration costs in conservative in this.
- The TRC raised technical concerns about how to fully model the NERC BAAL standards without modeling the frequency on the entire Eastern Interconnection. Modeling the entire interconnection would require a much larger modeling effort than was provided for in this study, with uncertain additional benefits from the added modeling effort.
- Astrapé provided information on the length of flexibility violations (5-min vs. 10-min) to inform whether having the model match historical 10-min flexibility violations, instead of 5-min violations, would significantly alter the results. The addition of solar resources increases the share of longer flexibility violations, which implies the integration costs would be higher if the modeling was forced to match historical 10-minute flexibility violations. Therefore, the approach used by Astrapé results in a lower SISC relative to using a longer flexibility violation.

2. Non-spinning reserves should be allowed to provide load following.

Astrapé's model allows non-spinning reserves to provide load following, including the quick start resources.

3. Account for aggregation benefits and reduced variability and uncertainty as more solar resources come online.

The TRC finds that Astrapé has made several adjustments for this study relative to the 2018 study to better capture solar variability, as well as adjustments to capture some of the aggregation benefits and reduced variability/uncertainty as new solar resources. See discussion in Section III.C.

4. Validate the model results against historical reserve data.

The TRC discussed this suggestion and concluded that historical data likely does not provide a good comparison to the model results for the estimate of the future SISC. Historical data would be based on lower solar penetration and different system conditions (e.g., fuel prices, coal retirements, water conditions, load levels, etc.) that will affect the quantity and cost of load following reserves historically held by Duke.

5. Incorporate the SEEM.

The TRC recommended not including a representation of the SEEM in the model for this iteration of the estimation of the SISC, as the final market structure has not been approved and implemented. In addition, it is unclear how much the SEEM will help provided lower-cost load following reserves, given the requirement to lock in schedules 20 to 25 minutes ahead of real-time. The TRC suggests that the Commissions should consider this for future updates of the SISC. See discussion Section III.B

6. Model DEP and DEC with unified commitment and dispatch.

The TRC recommended that Astrapé conduct a sensitivity that includes the JDA. The results of that sensitivity are presented in the Astrapé Report as the "combined case." The TRC finds that the combined case better represents actual operation of DEC and DEP with the JDA relative to the islanded case. The TRC recommends that the Commissions consider those results when setting the SISC. See discussion Section III.A

7. **The high cost of conventional generator inflexibility.**
The TRC requested additional information from Duke to confirm the modeling assumptions related to the operational flexibility of Duke's CTs and its pumped storage hydro resources. The TRC finds that these resources are relatively inflexible compared to similar resources in other parts of the country, but the modeling assumptions represent legitimate operating restrictions on Duke's system. See discussion Section III.F

J. Interpretation of Solar Tranches

The Astrapé study estimates the SISC for a wide range of potential solar penetration. Tranche 1 represents a level of solar penetration that is slightly less than the currently planned solar additions in DEC and DEP. Tranche 2 models a level of solar that is slightly higher than the currently planned solar additions. Lastly, Tranche 3 analyzes much higher levels of solar penetration than expected during the time when the SISC estimated in this study will be implemented. By the time solar penetration reaches the levels analyzed in Tranche 3, DEC's and DEP's conventional resource mix will likely be considerably different, which means that the cost of integrating solar will be significantly different than Tranch 3 estimates.

Given the level of solar development analyzed in each Tranche, the TRC found the Commissions do not consider the results of Tranche 3 in determining the current SISC. The TRC recommended that the Tranche 3 results be placed in an appendix of the Astrapé Report and only be relied upon for illustrative purposes, as the estimates are unlikely to reflect the cost of solar integration during the time when this SISC will be in place. Moreover, the composition of the Duke generation fleet will likely change before the levels of solar penetration studied in Tranche 3 on the DEC or DEP systems are achieved, which would result in different integration costs than determined for Tranche 3 in this study.

The TRC recommends that the Commissions do not rely on the results of Tranche 3 in setting the SISC in the current proceeding.

IV. TRC Conclusions and Recommendations

The TRC engaged with Astrapé to understand the modeling approach employed to estimate the SISC, and the underlying assumptions. Where appropriate the TRC asked for information from subject matter experts at Duke to inform discussions regarding the modeling assumptions. During this process, the TRC made two recommendations to the modeling approach, both of which were adopted by Astrapé for this iteration of the estimate of the SISC:

- The TRC recommended modeling the JDA between DEC and DEP to better reflects Duke's current operations and any reduction in the integration costs provided by the joint unit commitment and dispatch that occurs under the JDA. Astrapé modeled a sensitivity that includes the JDA and included those results in their report, as the "combined case."
- The TRC recommended not modeling the proposed SEEM in this estimate of the SISC. The TRC recommends including it in the model for subsequent updates to the SISC when more is known about SEEM operations and there is historical data on SEEM energy trades.

In addition to the two specific recommendations related to the modeling approach and scope, the TRC reached several conclusions related to the study approach that may be informative for the Commissions in their review of the estimated SISC:

- The TRC finds that the Astrapé made significant improvements in the study methodology and assumptions since the previous SISC study:
  - Astrapé applied a new approach to determine how many load following reserves are necessary to integrate new solar resources. The new approach calibrated the modeled 60-minute ramping capability (ramping capability is provided by operating reserves) with historical ramping capabilities in the no solar case.[13] The modeled 60-minute ramping capability resulted in a specific number of 5-minute flexibility violations for the no solar case. The cases with added solar are simulated to match the number of 5-minute flexibility violations to the number of violations in the no solar case. The TRC found that this is a significant improvement over the approach used in the previous Astrapé study. The previous approach determined how many additional load following reserves are needed to maintain 0.10 expected flexibility violations per year ($LOLE_{FLEX}$) due to the new solar resources. The new approach adds load following reserves in a targeted manner and the model calculates the flexibility violations. The simulation is then iterated with adjustments to the added load following reserve amounts to match historical 5-minute flexibility violations.

[13] Carden, K., Wintermantel, N., and Patel, P., "Duke Energy Carolinas and Duke Energy Progress Solar Integration Service Charge (SISC) Study," Preliminary Draft, p. 35.

- Astrapé implemented a new approach for reflecting solar volatility, including the benefits due to the geographic diversity of new solar resources coming online in Duke's service territories. The new approach accounts for the diversity between solar production profiles in different counties throughout the Carolinas, which capture the fact that new solar facilities will come online in different locations.
- Astrapé implemented a targeted approach to only add additional load following reserves in hours when they are most likely needed (i.e., whenever volatility is the highest). This is an improvement over the previous study, which added load following reserves in all hours. The targeted approach reduces the overall estimated integration cost.

The TRC agrees with both improvements, and believes the improvements better represent actual system conditions and operations. In both instances, the improved approach will likely reduce the overall integration cost of new solar and result in a lower SISC.

- TRC concludes that the CT and pumped storage resources owned by DEC and DEP are less flexible than similar resources owned by other utilities. However, barring upgrades to the units, the modeling assumptions used to represent their flexibility appear to reflect legitimate constraints on their operation. The TRC believes that the addition of more flexible resources to Duke's generation will likely reduce the integration cost of solar. However, the TRC determined that this question is out of scope for Astrapé's estimate of the near-term SISC.
- The TRC finds Astrapé's treatment of curtailments to be conservative in terms of impact on the SISC. The ability to freely curtail solar to manage flexibility issues on the system, lowers the integration cost of new solar resources and leads to a reduced SISC. The TRC asked Astrapé to run a sensitivity with an economic curtailment penalty, and the results of that sensitivity confirmed that the penalty slightly increases the SISC. Although overall system costs may be higher with additional solar curtailments, due to the increase in fuel costs needed to replace curtailed solar production. The TRC discussed this issue with subject matter experts at Duke, and confirmed that no penalty on curtailments is consistent with PURPA contract rules and historical system operation.
- The TRC finds that the estimated cost of reserves is reasonable given the size of DEC's and DEP's footprint relative to PJM (the competitive market the TRC benchmarked against), and given the relative inflexibility of Duke's generation fleet.
- The TRC recommended that the results for Tranche 3 of Astrapé's study be reported in an appendix as likely does not reflect current or near-term solar integration costs for DEC and DEP. The TRC advises that the Commission consider both the Tranche 1 and Tranche 2 results in setting the SISC, potentially interpolating between the two results to set the current SISC.

Appendix A: March 19, 2021 Stakeholder Meeting Presentation

Technical Review Committee for the Solar Integration Service Charge (SISC)

PRESENTED BY

Stephanie Ross

Hannes Pfeifenberger

MARCH 19, 2021

Brattle

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

Stephanie Ross
Associate, Boston

Technical Leads on the TRC

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 – Research Scientist, Electricity Markets and Policy Group at Lawrence Berkeley National Lab (LBNL)

Regulatory Observers on the TRC

- 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.

TRC Work Plan

Conduct independent technical review of the methodology and assumptions used byAstrapé to develop the SISC, with substantial input from technical experts and regulatory observers

- Provide technical review of the SISC analysis' inputs, methodology, and outputs
  - Review input assumptions. For example:
    - Intra-hour renewable generation uncertainty
    - Changes since the 2020 Duke IRP, particularly early generation retirements (e.g., Allen Unit 3 which will be retired nine months early on March 31, 2021)
  - Review methodology. For example:
    - Compare Astrapé's approach with similar methodologies developed by the National Labs
    - Ensure consistency with changes in market fundamentals (e.g., natural gas prices, wholesale power markets, Southeast Energy Exchange Market (SEEM))
  - Review results
- Provide input and feedback to Astrapé throughout the review process so that it can be incorporated into the analysis in a timely manner
- Prepare TRC report with input from technical experts and regulatory observers

Timeline

March – June 2021

- TRC will meet bi-weekly through June 25, 2021
  - TRC Kickoff Meeting: March 2, 2021
  - TRC Meeting #2: March 12, 2021
  - TRC Meeting #3: March 26, 2021
  - Bi-weekly meetings thereafter

Milestones

- March – Astrapé develops draft set of results by end of March / early April to TRC
- April – TRC reviews results and provides feedback
- May – Astrapé performs any additional analysis to finalize study
- June – TRC finalizes recommendations and Brattle compiles final report

Revised SISCs for DEC/DEP will be included in both states' 2021 Avoided Cost filings

- July 2021: South Carolina – Filed with the Companies' Avoided Cost proceeding
- November 2021: North Carolina – Filed with the Companies' Avoided Cost proceeding.

Questions and Comments?

Duke has opened a channel for written comments to inform the TRC's review of the SISC

- sisctrc@outlook.com
- All comments due by April 2, 2021

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- Electric Transmission
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- Electrification & Growth Opportunities
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- Finance and Ratemaking
- Gas/Electric Coordination
- Market Design
- Natural Gas & Petroleum
- Nuclear
- Renewable & Alternative Energy

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- Antitrust/Competition
- Bankruptcy & Restructuring
- Big Data & Document Analytics
- Commercial Damages
- Environmental Litigation & Regulation
- Intellectual Property
- International Arbitration
- International Trade
- Labor & Employment
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- Product Liability
- Securities & Finance
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Appendix B: Southern Environmental Law Center Comments

SOUTHERN ENVIRONMENTAL LAW CENTER

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March 31, 2020

Via Email

Solar Integration Services Charge (SISC)
Technical Review Committee (TRC)
sisctrc@outlook.com

Ravi Mujumdar, Lead Planning Analyst
Duke Energy
Carolinas Integrated Resource Planning
ravi.mujumdar@duke-energy.com

Re: Comments for SISC TRC

Dear Members of the TRC and Mr. Mujumdar,

On behalf of the Southern Alliance for Clean Energy, North Carolina Sustainable Energy Association, and the Carolinas Clean Energy Business Association we submit the attached comments for the TRC prepared by Brendan Kirby, P.E.

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

Sincerely,

/s/ Nick Jimenez
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SISC TRC Concerns

Brendan Kirby P.E. 31 March 2021

Flexibility Balancing Requirement Should Be Based on Mandatory NERC Reliability Rules

Duke first presented its proposed Solar Integration Services Charge ("SISC") in the North Carolina Utilities Commission ("NCUC") 2018 avoided cost proceeding (Docket No. E-100 Sub 158) and later filed the SISC in the South Carolina Public Service Commission ("PSCSC") 2019 avoided cost proceedings (Docket Nos. 2019-185-E and 2019-186-E). In those proceedings I submitted testimony and an accompanying report evaluating Duke's proposed SISC and appeared before the NCUC and PSCSC during evidentiary hearings on the SISC.[1] The partially updated methodology described in the March 19, 2021 Astrape "Ancillary Service Impact Study to Calculate Solar Integration Services Charge (SISC)" presentation is an improvement over the methodology presented in the November 11, 2018 "Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study" report but there are still significant concerns that we hope the TRC will carefully consider.

The fundamental concern is with both studies' focus on 5-minute ramping "flexibility violations". Astrape's slide 5 defines "Flexibility Violations" as the "Number of events where generators modeled in SERVM could not meet the next 5-minute net load." There is no mandatory NERC reliability rule requirement for a BA's generators to "meet the next 5-minute net load". Balancing requirements under normal, non-contingency[2], conditions are established in NERC's BAL-001-2 – Real Power Balancing Control Performance standard with its two reliability metrics: Control Performance Standard 1 (CPS1) and the Balancing Authority ACE[3] Limit (BAAL). Neither of these require balancing every 5 minutes. A brief summary of the BAL-001-2 balancing requirements is provided at the end of these comments but NERC allows 30 minutes to restore an imbalance under normal conditions, and only requires imbalances that are hurting interconnection frequency to be mitigated at all. In developing the mandatory BAL standards NERC found that excessive balancing beyond what is required by CPS1 and BAAL does not improve power system reliability.

Duke's current proposal to base the SISC on calculating the added following reserves that would be needed to maintain the same level of balancing with additional solar generation as was historically

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[1] My testimony and report in NCUC Docket No. E-100 Sub 158 was filed on June 21, 2019 and is available at http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=afafa2e6-c755-4521-ae8e-16a9cbf90424. My testimony and report in PSCSC Docket Nos. 2019-185-E and 2019-186-E were filed on September 11, 2019 (Direct Testimony) and October 11, 2019 (Surrebuttal Testimony) and are available at http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=afafa2e6-c755-4521-ae8e-16a9cbf90424 and https://dms.psc.sc.gov/Attachments/Matter/71de8985-f38b-4e6d-bdab-f0b7607d704b.

[2] Balancing requirements during contingencies are established in NERC's BAL-002 – Disturbance Control Standard (DCS) which requires balancing within 15 minutes but which also allows for the use of contingency reserves to restore the balance.

[3] Area Control Error

required without solar generation is an improvement over the 2018 proposal, which calculated the reserves required to meet an arbitrary balancing requirement of 0.10 $LOLE_{FLEX}$ Events Per Year (Astrape slide 11). Still, neither calculation is based on meeting NERC reliability requirements.

The concern with applying a 5-minute balancing requirement is that it does not reflect the reliability requirements that actually apply to the utility. A purely hypothetical example may help to illustrate why this is a concern. Suppose a utility had a perfectly flat load. It would have no variability and no ramping requirements. It would have zero ramping shortfalls in one hundred years, let alone ten years. The utility's exemplary historic pre-solar following performance would not be based on holding sufficient reserves to meet NERC mandatory reliability requirements but instead would be an artifact of the utility's load characteristics. It would not make sense to add reserves sufficient to maintain a perfectly flat net-load when solar (or any other variable load or generator) was added. Instead, it would make sense to determine what reserves were needed to meet NERC mandatory reliability standards.

DEC and DEP do not have perfectly flat loads, so the hypothetical example is not perfectly applicable. Still, the concept is valid. Sufficient reserves should be added to maintain mandatory reliability performance. Excessive reserves beyond that amount impose unnecessary costs without improving reliability.

Not All Imbalances Are Equal

Simply counting imbalances with an LOLE metric is overly simplistic – as would be allowing 30-minute imbalances every hour just because they would not technically violate NERC mandatory reliability standards. Five- to 10-minute imbalances every hour would not threaten reliability. Similarly, 20-minute imbalances that occurred once a week or once a month would not be a reliability concern. Imbalance limits should reflect the imbalance frequency and duration. A suggested set of imbalance limits are: imbalances of 15 minutes or less are not limited, Imbalances longer than 15 minutes but no longer than 20 minutes are allowed once a week, Imbalances longer than 20 minutes but no longer than 25 minutes are allowed once a year.

Requiring All Following Reserves to be Spinning Reserves Is Inappropriate

Duke is requiring all SISC following reserves to be spinning reserves ("Load Following Up/Down Reserves – identical to spinning reserves", Astrape slide 7) provided by on-line generation operating at less than maximum capacity. This is not appropriate. Spinning reserves are typically much more expensive than non-spinning reserves provided by fast-start generation or demand side management or storage. It seems likely that modeling will show that small fluctuations are more common than large fluctuations. For events that happen hourly, spinning reserves are appropriate. For events which happen once a week or a few times a year, non-spinning reserves are probably much more appropriate. NERC mandatory balancing requirements provide ample time for fast-start generators, demand side management, and storage to respond to these more infrequent events.

Additional battery storage should also be considered to determine if it would be a lower cost option for supplying any needed additional following reserves. Fast battery response is an ideal resource for following reserves where extended response duration is not required. Batteries can typically be installed quickly, within the time frame required for implementing the SISC.

Updated Solar Volatility

The SISC is being calculated for higher penetrations of solar generation than currently exist. Astrape slide 7 states that the analysis will: "Update solar volatility based on most recent data – Include diversity benefit at higher solar tranches; Extrapolated from historical data." Fortunately, Duke now has operating data and experience with a larger solar fleet than when they first calculated a SISC. It is critical that the "Extrapolation from historical data" recognize the diversity benefits of aggregating larger amounts of solar generation. The extrapolation should not be linear but should instead reflect aggregation benefits that reduce the per-unit variability and uncertainty as solar penetration increases. Further, Duke should now have multiple historical data years of high penetrations of solar and should be able to compare costs actually caused by solar intermittency including specifically the associated costs built into the SISC against what the Astrape model shows. Essentially, the Astrape model, at this point, should be validated against historical data.

SEEM

Duke and regional utilities have filed with FERC to establish the Southeast Energy Exchange Market (SEEM) that will facilitate 15-minute energy trading. SEEM should assist balancing solar variability both by providing a fast regional outlet for excess solar generation (reducing solar curtailment) and a fast supply for solar shortfalls (reducing required reserves). It is a valid point that a filed SISC cannot be based on a regional energy exchange market that does not yet exist, but it is also a valid point that a pre-SEEM SISC will be immediately invalid once SEEM is operational. While doing the modeling necessary to establish the pre-SEEM SISC it seems prudent to include SEEM sensitivity analysis. Including preliminary SEEM results would inform the Commissions and stakeholders of potential SEEM benefits.

Modeling DEP & DEC as Separate BAs

It would also be informative to model the benefits of joint DEC and DEP dispatch on the SISC. The Two BAs could capture the aggregation benefits of operating with a single combined ACE for compliance with NERC BAL-001-02 while still operating independently otherwise. The savings for all rate payers, not just SISC customers, may justify the effort. It would be good to know.

The High Cost of Conventional Generator Inflexibility

While being more applicable to cost allocation/causation than to cost calculation, the inflexibility of Duke's conventional generators is a major concern because it results in an increased calculated SISC with Astrape and Duke's analysis method. Higher minimum loads, slower ramp rates, longer startup times, and higher cycling costs all increase the costs attributed to integrating solar generation by this analysis method. Arguably, the SISC could be allocated to conventional generators as an inflexibility integration charge. At a minimum, the methodology should consider allocating costs associated with the inflexibility of any new conventional generators to those generators rather than to solar generators. Similarly, existing conventional generators should be allocated inflexibility costs to the same extent that existing solar generators are assessed a SISC.

Applicable Mandatory NERC Balancing Requirements

NERC's reliability standard BAL-001-2 – Real Power Balancing Control Performance establishes two reliability metrics that apply during normal (non-contingency) operations: Control Performance Standard 1 (CPS1) and the Balancing Authority ACE Limit (BAAL).

CPS1 Reliability and Balancing Requirement

CPS1 limits the annual average 1-minute area control error deviations. ACE deviations result from difference between a BA's total instantaneous generation (plus scheduled imports) and total instantaneous load (plus scheduled exports) (plus the BA's instantaneous frequency support obligation).[4] While 100% compliance is required, this metric may be a bit deceptive. The CPS1 metric runs between 0% and 200%, meaning continuous perfect balancing would result in a CPS1 score of 200%, not 100%. Therefore, 100% compliance does not mean compliance during every minute. The CPS1 requirement is reflected in the following formula:

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \leq \epsilon_1^2$$

This formula is simpler than it at first appears. It says that the annual average of the instantaneous ACE values, times the instantaneous ΔF [frequency deviation from the scheduled frequency (usually 60 Hz)], must be less than 0.000324.[5] It is the multiplication of ACE times ΔF that makes balancing operations easier (and analysis harder). During times when frequency is exactly equal to 60 Hz then there is no CPS1 limit on ACE. When frequency is exactly equal to 60 Hz then ΔF is zero, which is multiplied by ACE and the result remains zero no matter how large ACE is. Physically this means that the BA can be far out of balance with no penalty when frequency is exactly 60 Hz. This makes sense for reliability because, if frequency is exactly equal to 60 Hz (ΔF is zero) the overall interconnection is not experiencing an overall imbalance and an individual BA's imbalance is not a reliability threat.

Further, not all imbalances are bad. If frequency is below 60 Hz (ΔF is negative) and the BA is over-generating (excess solar, for example) then the BA's imbalance is supporting reliability by reducing the interconnection's overall imbalance and helping to push frequency back up to 60 Hz. CPS1 calculation credits the BA for that help. The excess generation is a reliability benefit and there is no requirement to reduce ACE. Conversely, if frequency is above 60 Hz (ΔF is positive) and the BA is under-generating (excess load or solar is suddenly reduced, for example) the BA is again helping overall power system reliability by reducing the interconnection's overall imbalance and helping to push frequency back down to 60 Hz, and CPS1 again credits the BA.

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[4] Because BA load cannot be measured directly it is determined indirectly by measuring the BA's generation and interconnection flows (imports and exports). NERC defines ACE as "The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias[.]" Reliability Standards for the Bulk Electric Systems of North America, NERC (updated July 3, 2018).

[5] ϵ_1 for the Eastern Interconnection is 0.018 Hz (Reliability Standards for the Bulk Electric Systems of North America, updated July 3, 2018) ϵ_1^2 is 0.000324.

Given that short-term, unexpected solar variability within the Duke service territories is unlikely to be related to frequency variations in the 720,000 MW Eastern Interconnection, CPS1 does not require correction of imbalances about half of the time. This significantly reduces the balancing reserves that Duke must have available and reduces the times Duke must exercise those reserves.

BAAL Reliability and Balancing Requirement

Like CPS1, the Balancing Authority ACE Limit (BAAL) does not require perfect compliance. In fact, BAAL only limits ACE deviations that exceed 30 consecutive minutes. Further, like CPS1, BAAL only limits ACE deviations that hurt interconnection frequency. That is, over-generation is not limited when interconnection frequency is below 60 Hz and under-generation is not limited when interconnection frequency is above 60 Hz. BAAL limits are specific to each BA and depend on the actual interconnection system frequency at each time interval. As shown below, ACE limits are lax when frequency is close to 60 Hz and get progressively tighter as frequency deviates farther from 60 Hz.

Again, given that short-term, unexpected solar variability within the Duke service territories is unlikely to be related to frequency variations in the very large Eastern Interconnection, BAAL does not require correction of imbalances about half of the time.

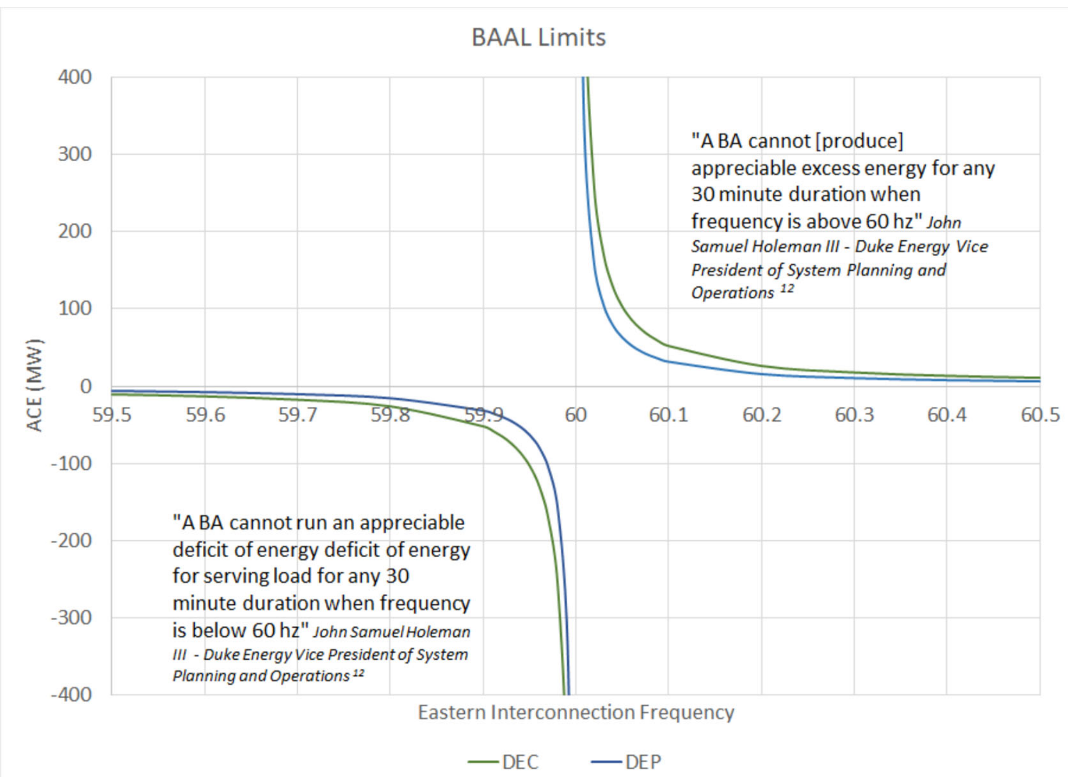

Figure 1 BAAL allows 30 minutes to restore balance.

DEC / DEP Joint Exhibit 11

DEC's and DEP's 2021
Solar Integration Service Charge Study
prepared by Astrapé Consulting

Docket No. E-100, Sub 175

ASTRAPÉ CONSULTING
innovation in electric system planning

Duke Energy Carolinas and Duke Energy Progress Solar Integration Service Charge (SISC) Study

10/22/2021

PREPARED FOR

Duke Energy

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Acknowledgement

We acknowledge the valuable contributions of many individuals to this report and to the underlying analysis, including peer review and input offered by the Duke Energy staff. We especially would like to acknowledge the analytical, technical, and conceptual contributions of the Technical Review Committee (TRC) comprised of Johannes Pfeifenberger, John Tsoukalis, and Stephanie Ross of The Brattle Group, technical experts Gregory Brinkman from the National Renewable Energy Laboratory (NREL) , Nader Samaan from the Pacific Northwest National Laboratory (PNNL) , and Andrew Mills from the Lawrence Berkeley National Laboratory (LBNL), and regulatory observers from the North Carolina Public Staff (NC-PS) and, South Carolina Office of Regulatory Staff (SC-ORS).

Contents

Executive Summary

The Solar Integration Service Charge (SISC) Study is the second SISC Study performed by Astrapé Consulting for Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) referred to herein as the Companies. The first study was conducted in 2018. As part of this second study, the Companies, with input from the North Carolina Public Staff (NCPS) and South Carolina Office of Regulatory Staff (ORS), retained The Brattle Group ("Brattle") as Technical Review Committee (TRC) Principal consultant. Brattle coordinated TRC meetings to review the findings in this report, incorporated feedback from the TRC Technical Leads, and will separately author a TRC report for the Companies to incorporate in their 2021 regulatory filings. In addition to Brattle, the TRC consisted of regulatory observers from the NCPS, ORS, and technical leads from the national labs mentioned on page 2. The TRC provided significant feedback and recommendations during a bi-weekly review process which commenced in March 2021 and concluded in July of 2021. These were reflected in the Study as discussed throughout this report.

As DEC and DEP continue to add solar to their systems, understanding the impact the solar fleet has on real time operations is important. Due to the intermittent nature of solar resources and the requirement to meet real time load on a minute-to-minute basis, online dispatchable resources need to have enough flexibility to ramp up and down to accommodate unexpected movements in solar output. Not only can solar drop off quickly but it can also ramp up quickly. Unexpected movement in either direction causes system ramping needs. When solar output drops off quickly, reliability can be an issue if other generators are not able to ramp up fast enough to replace the lost solar energy. When solar ramps up quickly, if other generators are not able to ramp down to match the solar output change, some solar generation may need to be curtailed. At low solar penetrations, the unexpected changes in solar output can be cost effectively accommodated by increasing upward ancillary service[1] targets within the existing conventional fleet. Increasing ancillary service targets forces the system to commit more generating resources which allows generators to dispatch at lower levels giving them more capability to ramp up. There is a cost to this increase in ancillary services because generators are operated less efficiently when they are dispatched at lower levels. Generators may also start more frequently which also increases costs. As solar penetrations continue to rise, carrying additional ancillary services to mitigate solar uncertainty with the conventional fleet becomes more expensive. This Study analyzes multiple solar penetration levels and quantifies the cost of utilizing the existing fleet to reliably integrate the additional solar generation.

For this Study, the Strategic Energy and Risk Valuation Model (SERVM) was utilized because it not only performs intra-hour simulations which include full commitment and dispatch logic, but also because its commitment and dispatch decisions can be performed against uncertain net load forecasts. This uncertainty results in flexibility excursions defined as an event where the online generation fleet is not able to ramp fast enough to match upward net load perturbations. These flexibility excursions are not expected to represent firm load shed events, but rather are simply a measure of the fleet's ability to follow net load changes given a particular set of operating guidelines. At each solar penetration level, simulations were performed assuming the same ancillary service inputs that are used in SERVM simulations with zero solar capacity. The number of flexibility excursions were recorded from those simulations. Next, total flexibility excursions with solar generation were calibrated to the same level as in the zero solar simulations by increasing ancillary services in the form of load following reserves. The goal of the Study is to maintain the same ability to follow net load as demonstrated in the no solar base case in any solar

[1] Ancillary services are defined in further detail in the Input Section of the Report but for purposes of this Study, load following, which is represented by 10-minute system ramping capability, was used to resolve flexibility gaps.

penetration level analyzed. Finally, system costs were compared between operating with the zero-solar baseline ancillary services (lower cost, but more flexibility excursions) to operating with the higher-solar load following requirements (higher cost but achieves the same level of flexibility excursions that existed before the solar was added). The difference in cost is allocated to the solar energy and represents the Solar Integration Services Charge (SISC). The SISC was estimated for both an "island case," which assumes DEC and DEP need to follow their respective loads with their own resources and a "combined case", which approximates the joint dispatch agreement under which DEC and DEP are currently operating as recommended by the TRC.

Two levels of solar penetrations were modeled for both DEC and DEP as shown in Table ES-1. The solar penetration scenarios reflect a range of solar capacity that would cover the Companies' expectations over the next 3-5 years consistent with the 2024 Study year. Calculating the SISC for these levels provides the Companies with a SISC value as a function of solar penetration to be used in setting the SISC. The Appendix includes a third (even higher) tranche of solar generation, which was simulated but is not relevant to the current effort of setting the SISC due to solar capacity levels modeled that exceed the levels DEC and DEP will reach in the next several years.

Table ES-1. DEC and DEP Solar Penetrations Analyzed

	DEC MW	DEP MW
Tranche 1	976	2,908
Tranche 2	2,431	4,019

Table ES-2 shows the results of the island cases for both DEC and DEP which were used to determine the load following requirements for each Company. As solar generation is added, net load volatility increases, causing flexibility excursions to increase. To reduce the excursions, additional load following is added across the day, which is discussed in detail later in the report. SERVM then commits to the higher load following target which causes an increase in costs. For DEC, the results show that as solar increases from 0 MW to 967 MW, on average 12 MW of additional load following across the daytime hours is required to maintain the same number of excursions that occurred in the 0 MW solar scenario. When tranche 2 is added to the analysis, which includes 2,431 MW, 46 MW of additional load following on average across daytime hours is required compared to the 0 MW solar case. Similar patterns are seen in DEP, as shown in Table ES-3. Tranche 1, which assumes 2,908 MW of solar capacity, requires 95 MW of additional load following on average across daytime hours. Tranche 2 which, assumes 4,019 MW of solar capacity, requires 157 MW of additional load following on average across daytime hours.

Table ES-2. DEC Island Results

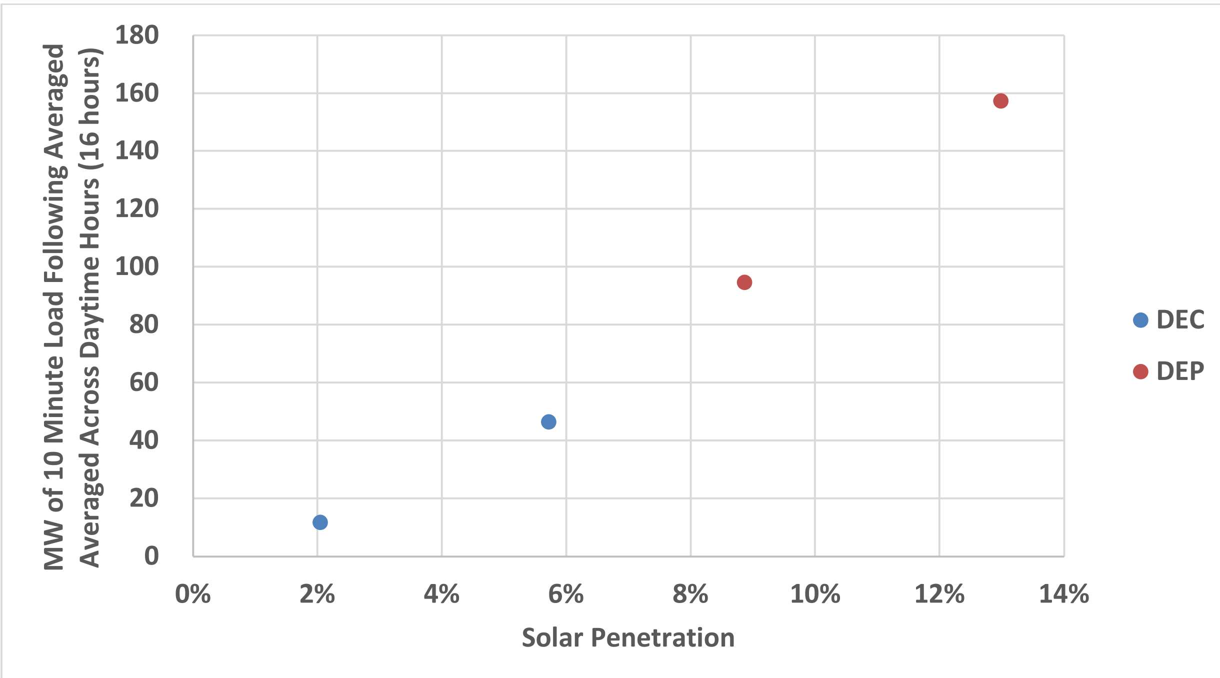
	DEC No Solar	DEC Tranche 1	DEC Tranche 2
Total Solar (MW)	0	967	2,431
Flexibility Violations (Events Per Year)	2.6	2.6	2.6
Realized 10-Minute Load Following Reserves (Average MW Over Daytime Hours Assuming 16 Hours) (MWh)	0	12	46

Table ES-3. DEP Island Results

	DEP No Solar	DEP Tranche 1	DEP Tranche 2
Total Solar (MW)	0	2,908	4,019
Flexibility Violations (Events Per Year)	0.6	0.6	0.6
Realized 10-Minute Load Following Reserves (Average MW Over Daytime Hours Assuming 16 Hours) (MWh)	0	95	157

Figure ES-1 shows the load following increase as a function of solar penetration for both DEC and DEP.

Figure ES-1. Quantified Required Increase in Load Following Reserves as a Percentage of Solar Penetration



As requested by the TRC, the Study simulated the Joint Dispatch Agreement (JDA) between the DEC and DEP balancing areas to determine the SISC.[2] The combined JDA results reflect modeling the DEC and DEP balancing areas simultaneously with transmission capability between them.

In these simulations, the realized load following additions determined in the island case with separate balancing areas were targeted for the combined case except now economic transfers can be made on a 5-minute basis. These economic transfers reduce system costs and in turn reduce integration costs. In

[2] The island SISC costs were also calculated and are shown in the body of the report.

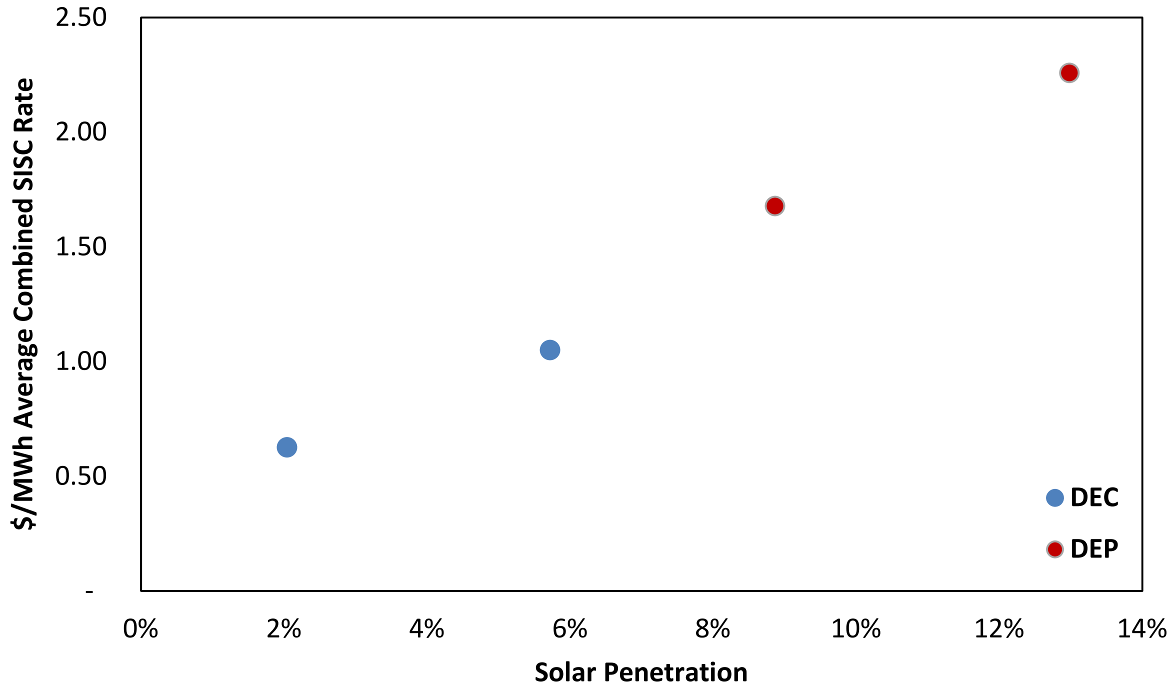
discussions with the Companies' operators, this method is potentially optimistic because SERVM has perfect foresight within the 5-minute time step to dispatch generation in both zones to perfectly minimize system production costs, whereas the JDA may be subject to more uncertainty and less dispatch flexibility. The results are shown in the following table. As expected, there are savings versus the island scenario as discussed in the body of the report. These benefits then have to be allocated to each Companies' integration cost. Astrapé along with the TRC and the Companies determined it was most appropriate to allocate the benefit based on the rated cost of load following (in $/MWh) from the combined analysis compared to the island results. Table ES-4 shows the load following cost rate as well as the average and incremental SISC rates based on the JDA simulations. The load following cost rate is the total production cost increase divided by the additional 10-minute load following reserves that are increased. The SISC rates for both DEC and DEP are lower in the combined case than in the island cases.

Table ES-4. Combined Results with Load Following Cost Allocation

	DEC Tranche 1	DEP Tranche 1	Combined Tranche 1	DEC Tranche 2	DEP Tranche 2	Combined Tranche 2
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
Combined (JDA Modeled) 10-Minute Load Following Cost Rate ($/MWh)	17.25	17.25	17.25	20.45	20.45	20.45
Average SISC with Combined (JDA Modeled) Load Following Rates ($/MWh)	0.63	1.68	1.42	1.05	2.26	1.79
Incremental SISC with Combined (JDA Modeled) Load Following Rates ($/MWh)	0.63	1.68	1.42	1.29	3.51	2.26

Figure ES-2 shows the average SISC for both tranches by Company for the combined cases.

Figure ES-2. Average Combined SISC Rates for Tranche 1 and 2



These SISC average and incremental rates across these tranches provide the Companies with information to determine a rate to be used in its avoided cost filing. There are average and incremental rates across a wide range of solar penetrations. The rates are highly correlated with the solar penetration as seen in Figure ES-2 so SISC rates for any penetration level can be deduced from the analysis.

Key Changes to Study Methodology from 2018 Study

Working with the TRC, incorporating feedback from the 2018 Study, and applying lessons learned from other renewable integration studies performed by Astrapé, the Study incorporated a number of key changes to its methodology. First, since the industry does not have a standard for modeled flexibility excursions, the targeted flexibility excursions for this study was changed to the number of flexibility excursions from the pre-solar case for each of the Companies. In the 2018 Study, flexibility excursions were targeted to 0.1 events per year.[3] Since the pre-solar case was setup to mimic the Companies' standard operating practices, maintaining the base case flexibility excursions in each solar penetration scenario is appropriate. While these varied by Company, they were higher than the value from the 2018 Study. Second, the 2018 Study added flat blocks of operating reserves to eliminate flexibility excursions. While additional overnight operating reserve targets isn't expected to significantly affect commitment[4], the study recognizes that the introduction of solar does not change the volatility of net load in non-solar hours, and so changes in operating reserve targets should only be added across the daytime hours to manage solar volatility and ramps. Finally, the recommended SISC is based on the production cost savings from the combined commitment and dispatch of the DEC and DEP systems. In this study, the rated cost of load following from the combined case is used to calculate the individual Company's SISC, reducing costs from the scenario where each Company is simulated as an island.

The following sections of this report provide greater detail regarding the SISC study framework, model inputs, simulation methodology, and study results.

[3] In the 2018 Study these were referred to as LOLE FLEX events. Recognizing that these events do not correspond to load shed, they are now referred to as flexibility excursions.

[4] Unit constraints typically result in having excess reserves overnight.

I. Study Framework

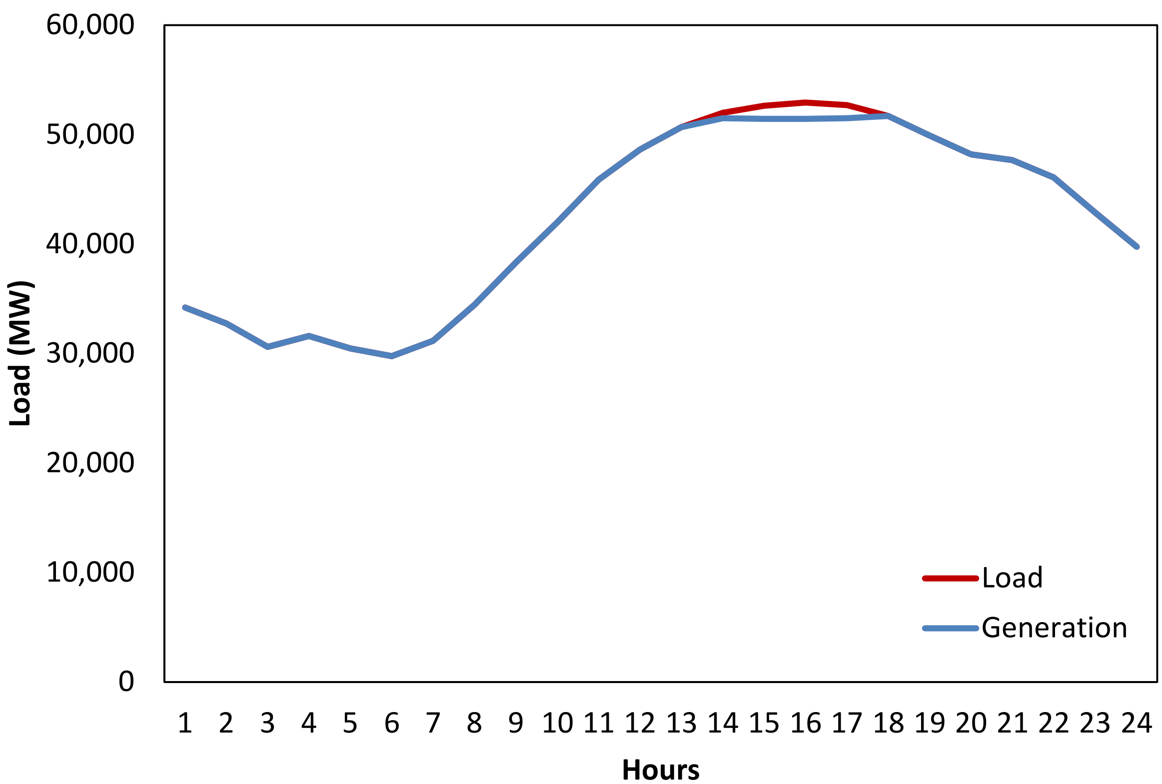
The economic effects of adding significant solar generation to a fleet are generally analyzed in a production cost simulation model. These models perform a commitment and dispatch of the conventional fleet against the gross load minus the expected renewable generation. Comparing the economic results from simulations with significant solar against simulations with more conventional resources allows planners to assess the economic implications of these additions. However, these analyses typically commit and dispatch resources with an exact representation of the load and solar patterns. This perfect knowledge aspect of the simulations overstates the value of resources like solar because they have significant inherent uncertainty. This Study incorporates the inherent uncertainty and forces the production cost model to make decisions without perfect knowledge of the load, solar, or conventional generator availability. In this framework, the objective function of the commitment and dispatch is still to minimize cost.

The enforcement of reliability requirements in simulation tools with perfect foresight is generally through a reserve margin constraint; each year is required to have adequate capacity to meet a particular reserve margin requirement. These types of simulations are unlikely to recognize reliability events partly because of their perfect foresight framework, but also because they use simplified generator outage logic. The outages at any discrete hour in the simulations typically represent average outages. In actual practice, reliability events are driven by coincident generator outages much larger in magnitude than the average. In the simulations performed for this Study, the SERVM model incorporates both load and solar uncertainty, as well as generator outage variability. In this framework, testing the capability of the conventional fleet to integrate solar resources is more reflective of actual conditions.

The inability to match generation and net load driven by solar output variability and volatility is different from capacity shortfall events analyzed in a typical resource adequacy analysis. They are events that could have been addressed by operating the existing conventional fleet differently. If solar output in a hypothetical system were to drop unexpectedly by 1,000 MW in a 5-minute period, only resources that are online or synched to the grid with the appropriate operating flexibility would be able to help alleviate the loss of the solar energy. So, for this analysis, the model differentiates events by their cause. Inputs are optimized such that events driven by a lack of capacity and events driven by a lack of flexibility achieve specific targets at minimum cost.

(1) Loss of Load Expectation (LOLE): number of days per year with loss of load due to capacity shortages. Figure 1 shows an example of a capacity shortfall which typically occurs across the peak of a day.

Figure 1. LOLE Example



(2) Flexibility Excursions: number of days per year the system cannot meet a known 5-minute net load ramp due to system flexibility shortfalls. In other words, there was enough capacity installed but not

enough flexibility to meet the net load ramps, or startup times prevented a unit from coming online fast enough to meet the unanticipated ramps. The vast majority of the flexibility excursions occur in less than one hour.

Reliability targets for capacity shortfalls have been defined by the industry for decades. The most common standard is “one day in 10 years” LOLE, or 0.1 LOLE. To meet this standard, plans must be in place to have adequate capacity such that firm load is expected to be shed one or fewer times in a 10-year period. Reliability targets for operational reliability are covered by the North American Electric Reliability Corporation (NERC) Balancing Standards. The Control Performance Standards (CPS) dictate the responsibilities for Balancing Areas (BA) to maintain frequency targets by matching generation and load.

Understanding how the increase in solar generation will affect the ability of a BA to meet the CPS1 and the Balancing Authority Area Control Error Limit (BAAL) would be ideal. However, simulating violations of these standards is not possible. While the simulations performed in SERVM do not measure the NERC Balancing Standards, the flexibility excursions (times when a 5-minute known net load could not be met by the system’s generation fleet) are correlated with the ability to balance load and generation. In SERVM, instead of replicating the second-to-second Area Control Error (ACE) deviations, net load and generation are balanced every 5 minutes. The committed resources are dispatched every 5 minutes to meet the unexpected movement in net load. In other words, the net load with uncertainty is frozen every 5 minutes and generators are tested to see if they are able to meet both load and minimum ancillary service requirements. Any periods in which generation is not able to meet load but there is sufficient installed capacity on the system are recorded as flexibility excursions. While there are operational reliability standards provided by NERC that provide some guidance in planning for flexibility needs, there is not a standard for flexibility excursions as measured by SERVM or in other solar integration modeling practices. Absent a standard, this Study assumes that maintaining the same level of flexibility excursions as solar penetration increases is an appropriate objective. The DEC and DEP systems were simulated with current loads and resources until operating reserves in the no solar case were similar to historical operating reserves. Running the system like this produces a number of flexibility excursions which would become the target that would be maintained after solar is added.

For each renewable penetration level analyzed, changes were made to the level of load following targeted to maintain the same number of flexibility excursions per year as seen in the base case with no solar. With more ramping capability provided by the increase in load following reserves, the unexpected drops in solar output are not as likely to create flexibility excursions. However, this creates a change in operating cost that has an impact on system costs. Comparing the total production costs assuming the same ancillary services targets used before the solar was added to the final, mitigated case production costs calculated using higher load following targets, which brings flexibility excursions back to the no solar case, determines the SISC on the system.

The more solar resources that are added, the more challenging and more expensive it becomes to carry the necessary additional ancillary services. In some hours, all conventional generation resources are dispatched near their minimum generation level in order to provide the targeted operating reserves, and yet the total generation is still above the load. This situation results in solar curtailment. The model assumes that any overgeneration can be used as load following and since incremental overgeneration is correlated with incremental solar penetration, higher curtailment is actually associated with lower SISC in this Study. Given existing solar contracts, this treatment is potentially optimistic in that curtailment may not be able to be used as flexibly as typical load following capability, and the real world system may be committed and dispatched less optimally to avoid some curtailment that is shown in the model results.

II. Model Inputs and Setup

The following sections include a discussion on the major modeling inputs included in the SISC Study. The majority of inputs are consistent with 2020 Resource Adequacy Studies completed for DEC and DEP. The model was simulated on 5-minute time intervals versus hourly intervals to capture the flexibility requirements of the system given imperfect knowledge around load, solar, and generating units. Simulating at 5-minute intervals requires additional information on generating resources and volatility distributions on load and solar as discussed in the following sections.

The utilities are modeled as islands for the SISC Study because each balancing area is responsible for its own NERC Compliance. However, given the joint dispatch agreements in place, the TRC requested a sensitivity that was performed to understand the benefits of dispatching DEC and DEP as combined systems, which is discussed later in the results. For resource adequacy, neighbor assistance capacity plays a significant role in the results. Weather diversity and generator outage diversity are benefits available to DEC and DEP regardless of the type of capacity neighboring regions build. Also, it is required to capture this assistance to achieve the one day in ten-year standard which equates to an LOLE of 0.1 events per year as outlined in the 2020 Resource Adequacy Studies. To achieve approximately 0.1 LOLE in this study, additional resources at costs above a gas CT were included in both DEC and DEP systems to mimic outside purchases.

A. Load Forecasts and Load Shapes

Load Forecasts and Shape Modeling

Table 1 displays the modeled seasonal peak forecast net of energy efficiency programs and behind the meter solar for 2024 for both DEC and DEP.

Table 1. 2024 Peak Load Forecast

	DEC	DEP East	DEP West	Coincident DEP
2020 Summer	18,456 MW	12,227 MW	879 MW	13,042 MW
2020 Winter	17,976 MW	13,390 MW	1,175 MW	14,431 MW

To model the effects of weather uncertainty, thirty-nine historical weather years (1980 - 2018) were developed to reflect the impact of weather on load. Based on the last five years of historical weather and load[5], a neural network program was used to develop relationships between weather observations and load. The historical weather consisted of hourly temperatures from five weather stations across the DEP service territory. The weather stations included Raleigh, NC, Wilmington, NC, Fayetteville, NC, Asheville, NC, and Columbia, SC. Other inputs into the neural net model consisted of hour of week, eight hour rolling average temperatures, twenty-four hour rolling average temperatures, and forty-eight hour rolling average temperatures. Different weather to load relationships were built for the summer, winter, and shoulder seasons. These relationships were then applied to the last thirty-nine years of weather to develop thirty-nine synthetic load shapes for 2024. Equal probabilities were given to each of the thirty-nine load shapes in the simulation. The synthetic load shapes were scaled to align the normal summer and winter peaks to the Companies' projected thirty-year weather normal load forecast for 2024.

[5] The historical load included January 2014 through September 2019.

Figures 2 to 5 below show the results of the weather load modeling by displaying the peak load variance for both the summer and winter seasons for each of the Companies. The y-axis represents the percentage deviation from the average peak. Thus, the bars represent the variance in projected peak loads for 2024 based on weather experienced during the historic weather years. The highest summer temperatures typically are only a few degrees above the expected highest temperature and therefore do not produce as much peak load variation as the winter. Based on the neural net modeling, the figures show that DEC and DEP summer peak loads can be 6-7% higher than the forecast due to weather alone, while winter peak can be about 18% higher than the forecast for DEC and more than 21% higher than the forecast for DEP in an extreme year.

Figure 2. DEC Winter Peak Weather Variability

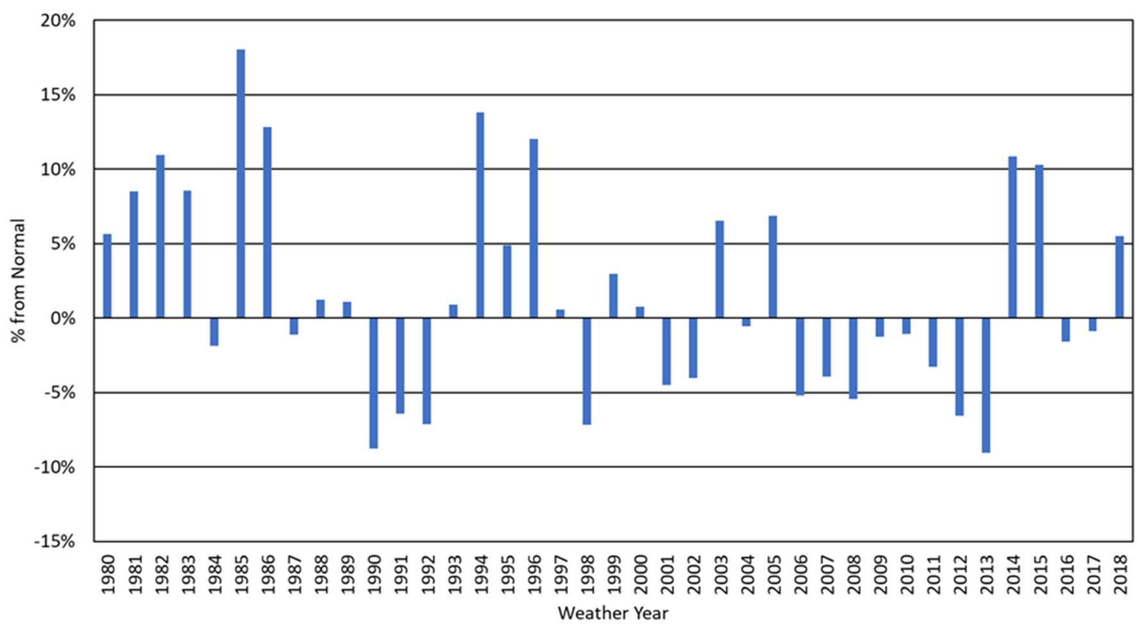


Figure 3. DEP Winter Peak Weather Variability

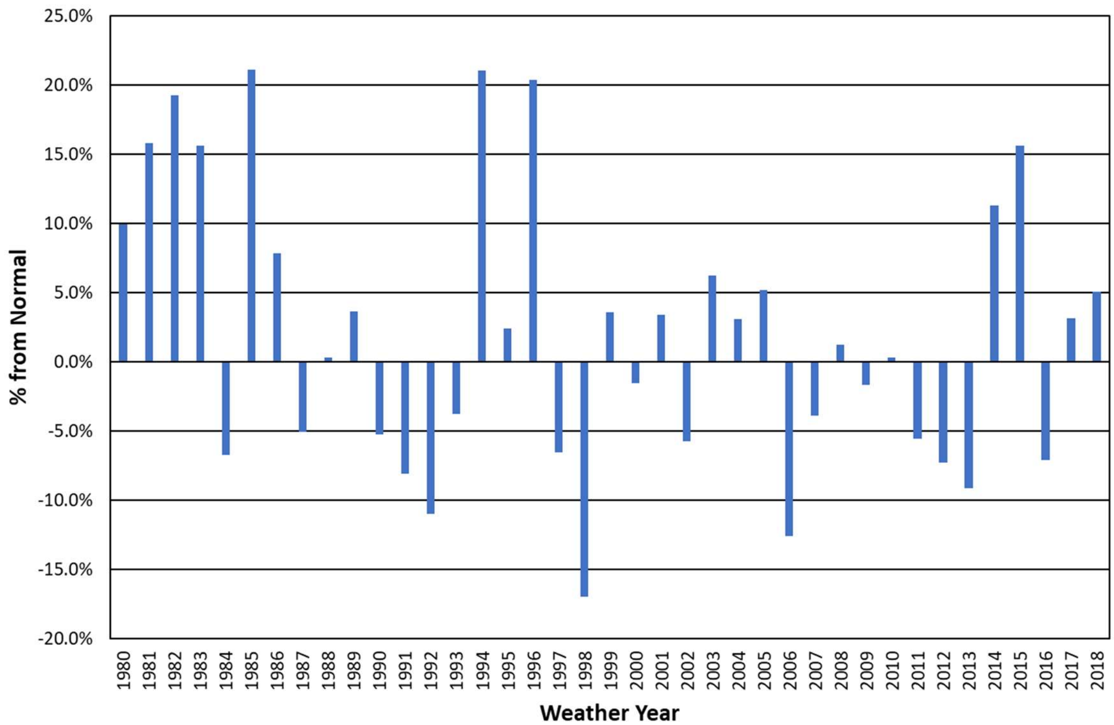


Figure 4. DEC Summer Peak Weather Variability

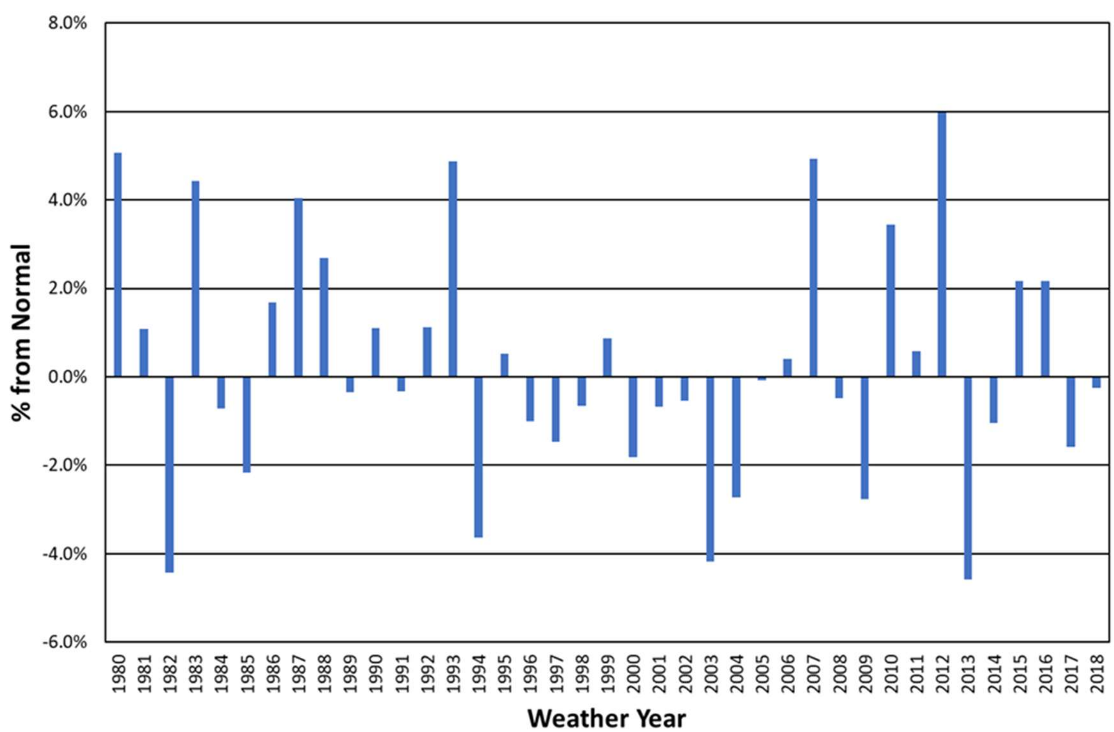
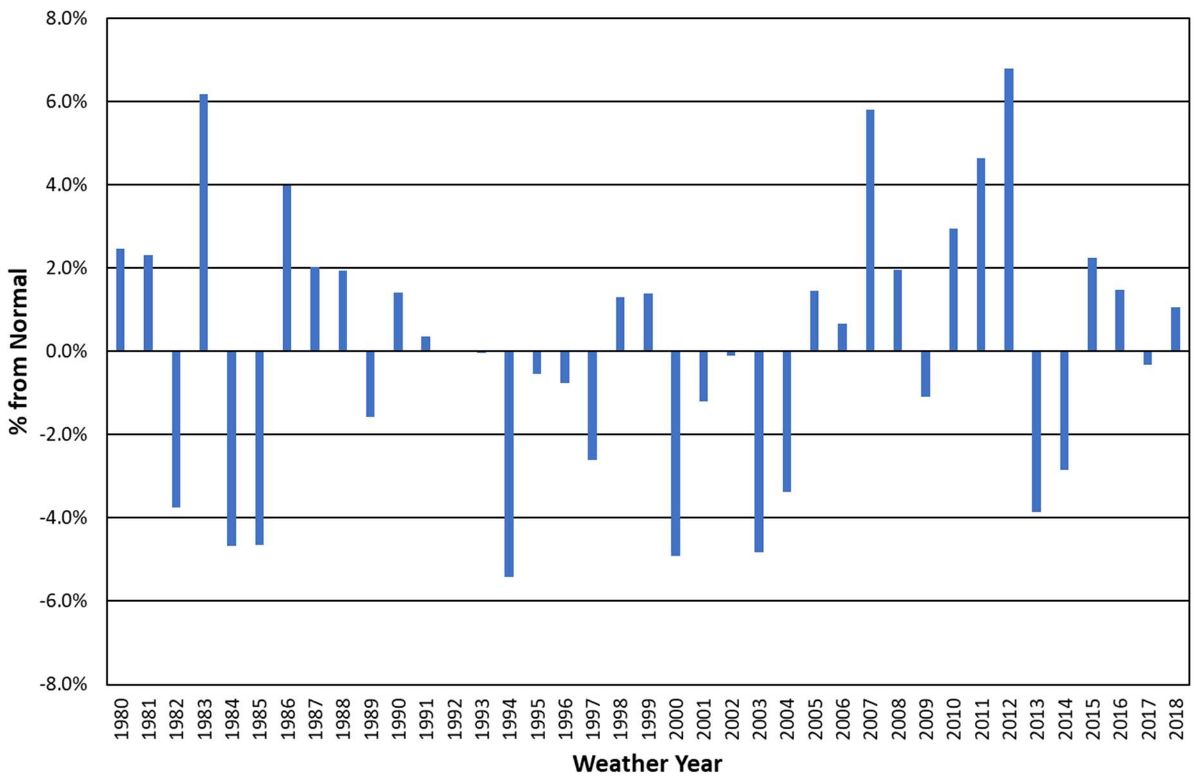


Figure 5. DEP Summer Peak Weather Variability



Economic Load Forecast Error

The same economic load forecast error multipliers used in the 2020 Resource Adequacy were used for this study. Because these assumptions are included in the base case and the change case, they have minimal impact on the results of the SISC Study. The economic load forecast error multipliers were developed to isolate the economic uncertainty that the Companies have in their four-year ahead load forecasts. Four years is an approximation for the amount of time it takes to build a new resource or otherwise significantly change resource plans. To estimate the economic load forecast error, the difference between Congressional Budget Office (CBO) Gross Domestic Product (GDP) forecasts four years ahead and actual data was fit to a distribution which weighted over-forecasting more heavily than under-forecasting load. Because electric load grows at a slower rate than GDP, a 40% multiplier was applied to the raw CBO forecast error distribution. Table 2 shows the economic load forecast multipliers and associated probabilities. As an illustration, 25% of the time, it is expected that load will be over-forecasted by 2.7% four years out. Within the simulations, when DEP over-forecasts load, the external regions also over-forecast load. The SERVM model utilized each of the thirty-nine weather years and applied each of these five load forecast error points to create 195 different load scenarios. Each weather year was given an equal probability of occurrence.

Table 2. Load Forecast Error

Load Forecast Error Multipliers	Probability (%)
0.958	10.0%
0.973	25.0%
1.00	40.0%
1.02	15.0%
1.031	10.0%

B. Solar Shape Modeling

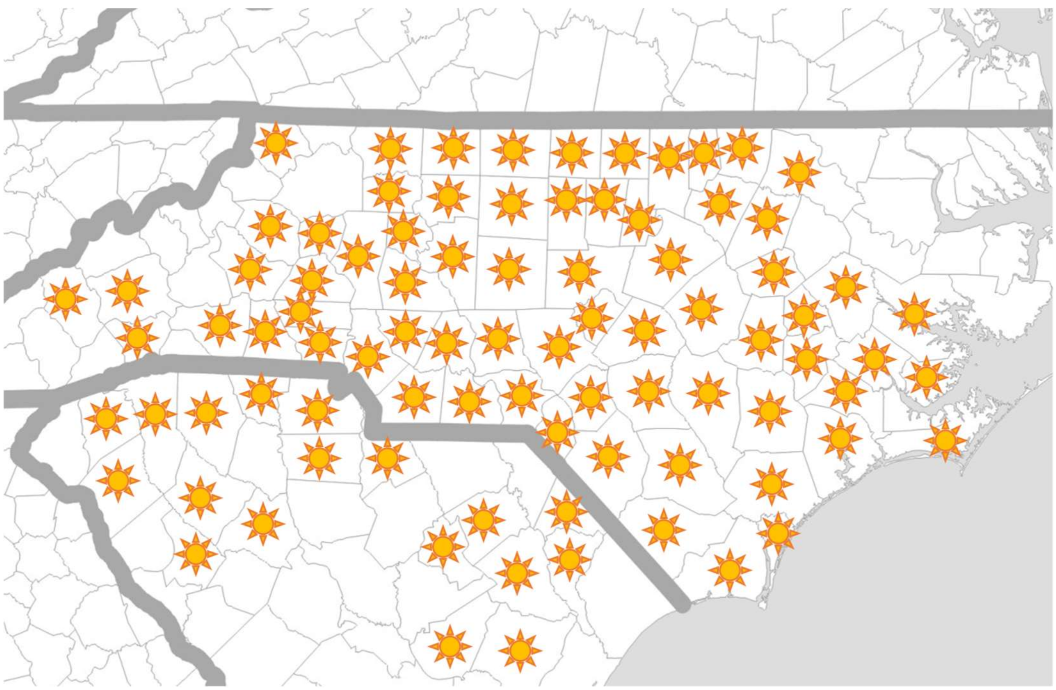
Table 3 shows the solar capacity levels that were analyzed. The solar penetration scenarios included two solar tranches which represents the expected amount of solar capacity that will be seen over the next 3-5 years which is consistent with the 2024 study year. A third higher tranche was also analyzed but since it is not used for purposes of setting the SISC charge it was only included in the Appendix for informational purposes.

Table 3. Solar Capacity Penetration Levels

	DEC MW	DEP MW
Tranche 1	976	2,908
Tranche 2	2,431	4,019

Similar to load shapes, the solar units were simulated with thirty-nine solar shapes representing thirty-nine years of weather. The solar shapes were developed by Astrapé from data downloaded from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB) Data Viewer. The data was then input into NREL's System Advisor Model (SAM) for each year and county to generate hourly profiles for both fixed and tracking solar profiles. Figure 6 shows the county locations that were used which is represented with a wide geographical area across both DEC and DEP balancing areas.

Figure 6. Solar Profile Locations



The differing solar tranches were developed based on the Base Case for the 2020 Resource Adequacy Study, shown in Table 4. In order to decrease up or down capacity from these total levels, the future solar category was increased or decreased to achieve specific levels. For DEC Tranche 1, all of the future solar and a portion of CPRE Tranche 1 had to be removed since only 967 MW of solar was being modeled for that scenario.

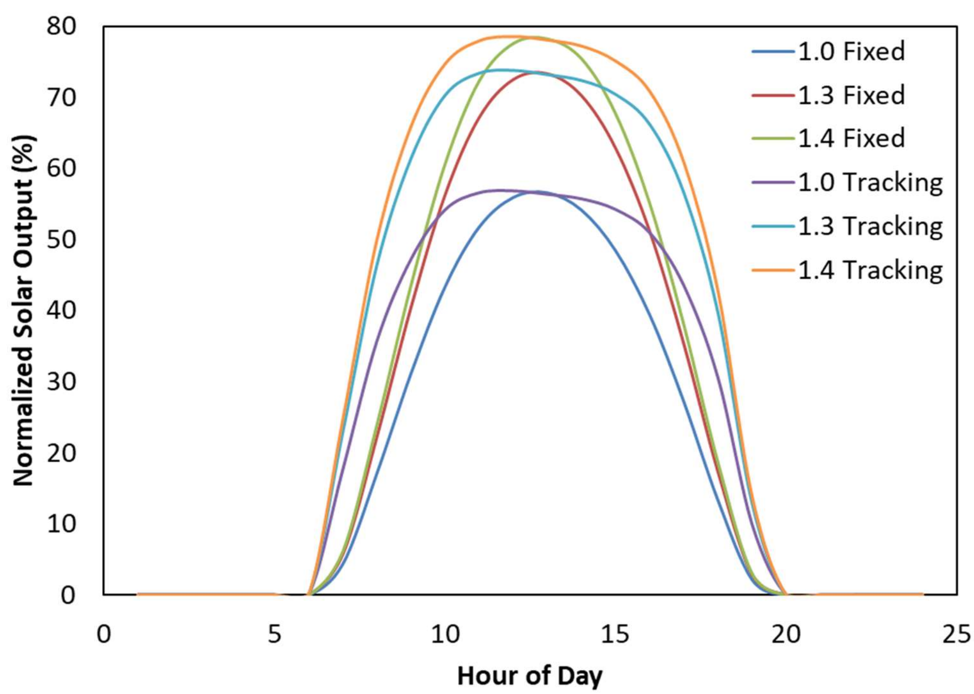
Table 4. Solar Capacity by Tranche

Unit Type	DEC Capacity (MW)	DEP Capacity (MW)
Utility Owned-Fixed	85	141
Transition-Fixed	660	2,432
CPRE Tranche 1 Fixed 40%/Tracking 60%	465	86
Future Solar Fixed 40%/Tracking 60%	1,368	1,448
Total	**2,578**	**4,107**

*Utility owned-fixed and future has a 1.4 inverter loading ratio; Transition and CPRE assumed a 1.3 inverter loading ratio

Figure 7 shows August average profiles for different inverter loading ratios for both fixed and tracking technologies. While the hourly shapes are important, it is the intra hour volatility that is discussed in the next section that drives the SISC.

Figure 7. Average August Output for Different Inverter Loading Ratios



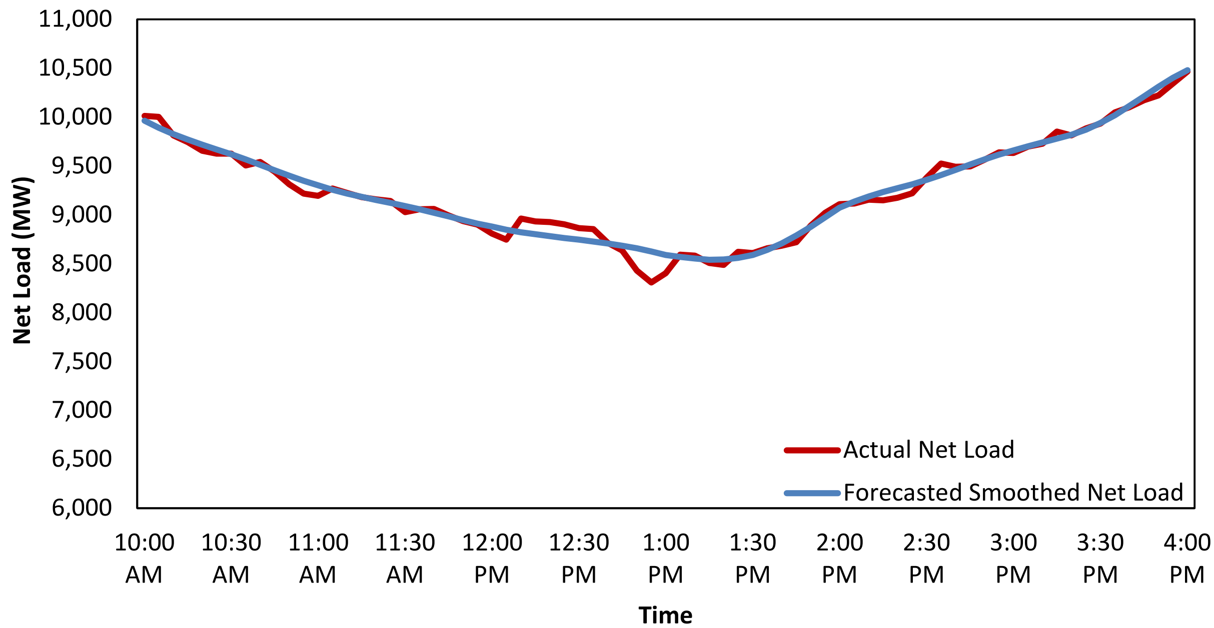
C. Load and Solar Volatility

For purposes of understanding the economic and reliability impacts of net load uncertainty, SERVM captures the implications of unpredictable intra-hour volatility. To develop data to be used in the SERVM simulations, Astrapé used 1 year of historical five-minute data for load and solar. Within the simulations, SERVM commits to the expected net load and then has to react to intra hour volatility as seen in history which may include ramping units suddenly or starting quick start units.

Intra-Hour Forecast Error and Volatility

Within each hour, load and solar can move unexpectedly due to both natural variation and forecast error. SERVM attempts to replicate this uncertainty, and the conventional resources must be dispatched to meet the changing net load patterns. SERVM replicates this by taking the smooth hour to hour load and solar profiles and developing volatility around them based on historical volatility. An example of the volatile net load pattern compared to a smooth intra-hour ramp is shown in Figure 8. The model commits to the smooth blue line over this 6-hour period but is forced to meet the red line on a 5-minute basis with the units already online or with units that have quick start capability. As intermittent resources increase, the volatility around the smooth, expected blue line increases requiring the system to be more flexible on a minute-to-minute basis. The solution to resolve the system's inability to meet load on a minute-to-minute basis is to increase operating reserves or add more flexibility to the system which both result in additional costs.

Figure 8. Volatile Net Load vs. Smoothed Net Load



The load volatility is shown in Table 5 below and is the same volatility used in the previous SISC Study performed in 2018. The 5-minute variability in load is quite low ranging mostly between +/-1% on a normalized basis. The load volatility is included in the base case and the change cases. With no intermittent resources on the system, this is the net load volatility assumed in the modeling.

Table 5. Load Volatility

Normalized Divergence (%)	Probability (%)
-2.2	0.000
-2	0.007
-1.8	0.007
-1.6	0.007
-1.4	0.016
-1.2	0.058
-1	0.205
-0.8	0.624
-0.6	1.578
-0.4	6.886
-0.2	42.055
0	39.243
0.2	6.500
0.4	1.590
0.6	0.591
0.8	0.361
1	0.170
1.2	0.066
1.4	0.009
1.6	0.003
1.8	0.001
2	0.024
2.2	0.000

The intra hour volatility of solar is higher than intra hour load volatility and is based on data from June 2019 through October 2020. The 5-minute data was analyzed and days with anomalies or missing recordings were removed from the dataset. For this reason, the dataset range was longer than one year. The historical data was aggregated at the DEC level and the DEP level. The historical DEC data represented 586 MW of existing solar capacity and the DEP level represented approximately 2,495 MW of existing solar capacity. Knowing that solar capacity is only going to increase in both service territories, it is difficult to predict the volatility of future portfolios. In both DEC and DEP, the majority of the historical data is made up of smaller-sized units while new solar resources are expected to be larger. So, while it is expected there will be additional diversity among the solar fleet, the fact that larger units are coming on may dampen the diversity benefit. Based on feedback from stakeholders and the TRC, the raw historical data volatility was utilized and then extrapolated out based on the diversity benefit trend seen in the historical data. Three levels were developed from the historical data including the 586 MW from the DEC historical data, 2,495 MW from the DEP historical data, and 2,900 MW from the combined dataset. The volatility declines with additional solar, and this dataset was trended out to 5,500 MW of solar as shown in Figure 9. The figure measures the 95TH percentile of the 5-minute solar deviation as a percentage of nameplate capacity. This measure declines as solar penetration increases.

Figure 9. Declining Volatility as a Function of Solar Capacity

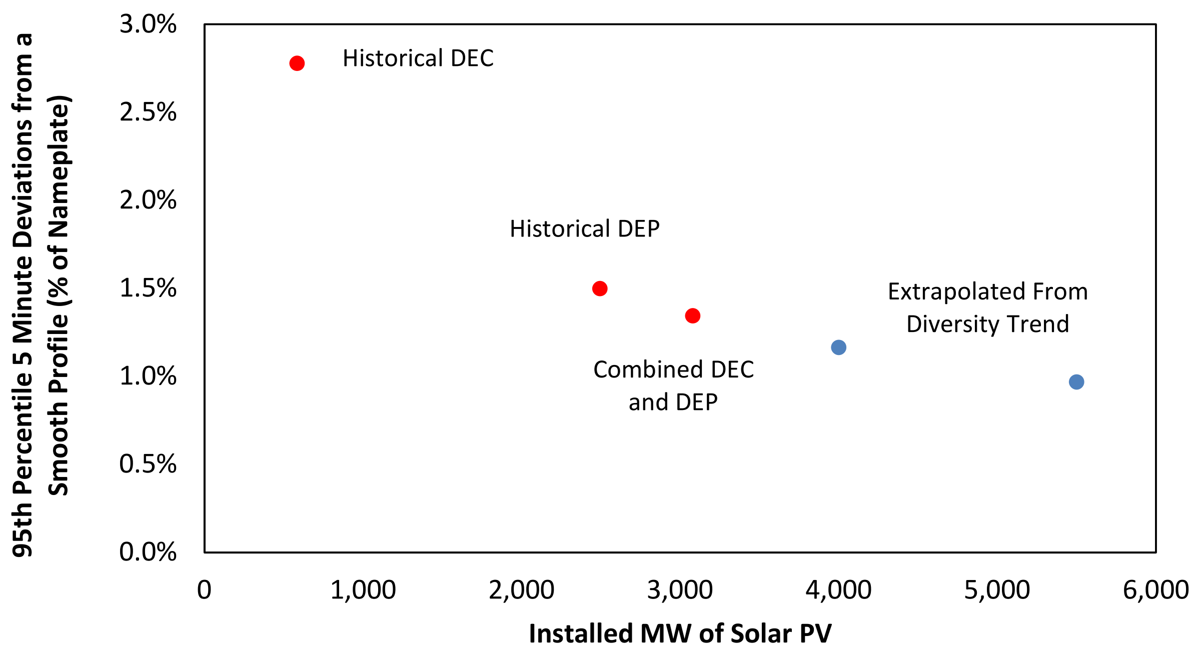


Table 5 shows the probability at different 5-minute divergence levels across the 5 solar penetrations in the previous Figure. The table shows a steady decline in unitized volatility due to diversity benefits of larger portfolios.

Table 5. DEC Base Solar Volatility - 500 MW

Solar Capacity Level MW	586	2,495	3,081	4,000	5,500
5 Minute Normalized Divergence	Probability %	Probability %	Probability %	Probability %	Probability %
-14%	0.00%	0.00%	0.00%	0.00%	0.00%
-13%	0.01%	0.00%	0.00%	0.00%	0.00%
-12%	0.01%	0.00%	0.00%	0.00%	0.00%
-11%	0.03%	0.00%	0.00%	0.00%	0.00%
-10%	0.05%	0.00%	0.00%	0.00%	0.00%
-9%	0.10%	0.00%	0.00%	0.00%	0.00%
-8%	0.19%	0.01%	0.00%	0.00%	0.00%
-7%	0.32%	0.02%	0.01%	0.00%	0.00%
-6%	0.59%	0.06%	0.03%	0.01%	0.00%
-5%	1.09%	0.21%	0.12%	0.05%	0.02%
-4%	1.91%	0.65%	0.46%	0.29%	0.11%
-3%	3.43%	1.90%	1.58%	1.14%	0.72%
-2%	6.31%	5.53%	5.24%	4.69%	3.81%
-1%	14.07%	19.74%	20.66%	21.92%	23.45%
0%	57.78%	63.39%	64.39%	65.60%	67.18%
1%	6.28%	5.76%	5.42%	4.88%	3.96%
2%	3.51%	1.91%	1.52%	1.12%	0.63%
3%	2.04%	0.58%	0.41%	0.23%	0.10%
4%	1.06%	0.18%	0.11%	0.05%	0.01%
5%	0.59%	0.05%	0.02%	0.01%	0.00%
6%	0.31%	0.02%	0.01%	0.00%	0.00%
7%	0.14%	0.00%	0.00%	0.00%	0.00%
8%	0.09%	0.00%	0.00%	0.00%	0.00%
9%	0.04%	0.00%	0.00%	0.00%	0.00%
10%	0.02%	0.00%	0.00%	0.00%	0.00%
11%	0.01%	0.00%	0.00%	0.00%	0.00%
12%	0.01%	0.00%	0.00%	0.00%	0.00%
13%	0.00%	0.00%	0.00%	0.00%	0.00%
14%	0.00%	0.00%	0.00%	0.00%	0.00%

D. Conventional Thermal Resources

Conventional thermal resources owned by the Companies and purchased as Purchase Power Agreements were modeled consistent with the 2024 study year. These resources are economically committed and dispatched to load on a 5-minute basis. Similar to the resource adequacy study, the capacities of the units are defined as a function of temperature in the simulations allowing for higher capacities in the winter compared to the summer. SERVM dispatches resources on a 5-minute basis respecting all unit constraints including startup times, ramp rates, minimum up times, minimum down times, and shutdown times. All thermal resources are allowed to serve regulation, spinning, and load following reserves as long as the minimum capacity level is less than the maximum capacity.

The unit outage data for the thermal fleet in both Companies was based on historical Generating Availability Data System (GADS) data and is consistent with the 2020 Resource Adequacy Study. Unlike typical production cost models, SERVM does not use an Equivalent Forced Outage Rate (EFOR) for each unit as an input. Instead, historical (GADS) data events are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. Units without historical data use history from similar units. The events are entered using the following variables:

Full Outage Modeling
Time-to-Repair Hours
Time-to-Fail Hours

Partial Outage Modeling
Partial Outage Time-to-Repair Hours
Partial Outage Derate Percentage
Partial Outage Time-to-Fail Hours

Maintenance Outages
Maintenance Outage Rate - % of time in a month that the unit will be on maintenance outage. SERVM uses this percentage and schedules the maintenance outages during off peak periods.

Planned Outages
The actual schedule for 2019 was used.

To illustrate the outage logic, assume that the historical GADS data reported that a generator had 15 full outage events and 30 partial outage events. The Time-to-Repair and Time-to-Fail between each event is calculated from the GADS data and their respective inputs are the distributions used by SERVM. Because there may be seasonal variances in EFOR, the data is broken up into seasons based on history which contain Time-to-Repair and Time-to-Fail inputs for summer, off peak, and winter. Further, assume the generator is online in hour 1 of the simulation. SERVM will randomly draw a Time-to-Fail value from the distribution provided for both full outages and partial outages. The unit will run for that amount of time before failing. A partial outage will be triggered first if the selected Time-to-Fail value is lower than the selected full outage Time-to-Fail value. Next, the model will draw a Time-to-Repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. The full outage counters and partial outage counters run in parallel. This more detailed modeling is important to capture the tails of the distribution that a simple convolution method would not capture. Planned maintenance events are modeled separately and dates are entered in the model representing a typical year.

E. Hydro, Pump Storage Modeling, and Battery Modeling

The hydro portfolios in DEC and DEP are modeled in segments that include Run of River (ROR) and Scheduled (Peak Shaving). The Run of River segment is dispatched as base load capacity providing its designated capacity every hour of the year. The scheduled hydro is used for shaving the daily net peak load but also includes minimum flow requirements. By modeling the hydro resources in these two segments, the model captures the appropriate amount of capacity dispatched during peak periods and is consistent with the 2020 Resource Adequacy Study.

In addition to conventional hydro, DEC owns and operates a pump-storage fleet. The total capacity included was 2,460 MW. (1) Bad Creek at a 1,680 MW summer/winter rating and (2) Jocassee at a 780 MW summer/winter rating. These resources are modeled with reservoir capacity, pumping efficiency, pumping capacity, generating capacity, and forced outage rates. SERVM uses excess capacity to economically fill up the reservoirs to ensure the generating capacity is available during peak conditions. While the pumped-storage units have fast ramping capability, the range from minimum to maximum for generating is fairly low providing minimal intra hour load following benefit for solar integration. The resources offer single speed pumping which doesn't allow for ramping capability during pumping. The pump storage fleet does assist in hourly energy balances which reduces curtailment significantly for DEC. Table 6 provides the characteristics of the pump-storage fleet.

Table 6. Pump Storage Resources

DEC Pump Storage Unit	Gen Capacity (MW)	Gen Capacity Min (MW)	Pumping Capacity (MW)	Pumping Min Capacity (MW)	Pond Capacity (MWh)	Equivalent Storage Hours (Hours)	Ramp Rate (MW/min)
Bad Creek_1	420	320	369	369	8,257	15	40
Bad Creek_2	420	320	369	369	8,257	15	40
Bad Creek_3	420	320	369	369	8,257	15	40
Bad Creek_4	420	320	369	369	8,257	15	40
Jocassee_1	195	170	205	205	14,385	27	40
Jocassee_2	195	170	205	205	14,385	27	40
Jocassee_3	195	170	205	205	14,385	27	40
Jocassee_4	195	170	205	205	14,385	27	40

The SISC Study maintained the same level of standalone battery for both DEC and DEP that was projected in the 2020 Resource Adequacy Study for DEC and DEP for the study year 2024. This results in 100 MW of standalone battery capacity in DEC and 81 MW in DEP. The batteries are allowed to be used for economic arbitrage and serve ancillary services to avoid flexibility based on their state of charge and output capability. There were no constraints modeled on the battery flexibility or number of cycles.

F. Demand Response Modeling

Demand Response programs are modeled as resources in the simulations. They are modeled with specific contract limits including hours per year, days per week, and hours per day constraints consistent with the 2020 Resource Adequacy Study. For 2024, DEC assumed 1,122 MW of Demand Response in the summer and 442 MW in the winter. DEP assumed 1,001 MW of summer capacity and 461 MW of winter capacity.

G. Study Topology

As discussed previously, the Companies were modeled as islands for this analysis because each balancing area is responsible for its own NERC requirements. By modeling in this manner, the required operating reserves and flexibility requirements are calculated for each of the Companies. The TRC also requested the analysis be performed assuming the Joint Dispatch Agreement (JDA) between DEC and DEP was utilized. Astrapé accommodated this request and in this scenario, each BA still holds its own operating reserves, but economic exchanges are allowed to reduce the costs of the additional load following requirements. The results sections show the results as an island and a combined DEC and DEP case.

H. Ancillary Services

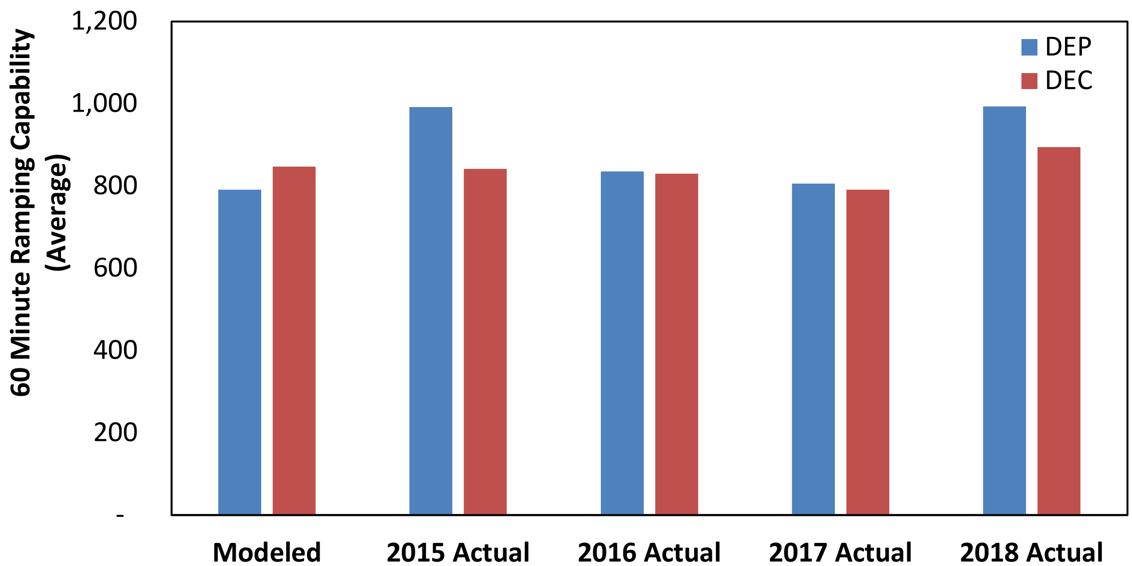
Ancillary service targets are input into SERVM. SERVM commits resources to meet energy needs plus ancillary service requirements. These ancillary services are needed for uncertain movement in net load or sudden loss of generators during the simulations. Within SERVM, these include regulation up and down, spinning reserves, load following reserves, and quick start reserves. Table 7 shows the definition of ancillary service for each study. Spinning reserves and load following up reserves are identical and represent the sum of the 10-minute ramping capability of each unit on the system. To maintain operational flexibility as solar resources are added, the load following up reserves are increased until the flexibility excursions seen in the "no solar" case are met. The load following up reserves represent an increase in ramping capability of the fleet meaning that more resources are turned on so that they can be operated further away from their maximum capacity level allowing for more ramping capability.

Table 7. Ancillary Services

Ancillary Service	Definition
Regulation Down Requirement	10 Minute Product served by units with AGC capability
Regulation Up Requirement	10 Minute Product served by units with AGC capability
Spinning Reserves Requirement	10 Min Product served by units who have minimum load less than maximum load
Load Following Down Reserves	10 Min Product served by units who have minimum load less than maximum load
Load Following Up Reserves	10 Min Product served by units who have minimum load less than maximum load
Quick Start Reserves Requirement	Served by units who are offline and have quick start capability

To ensure the operating reserves were at reasonable levels for the "no solar" case, Astrapé compared the realized 60-minute ramping capability in the model to historical dispatch data during the 2015-2018 time period. This comparison is shown in Figure 10. While this comparison would never be expected to be exact due to differences in weather, loads, resource mix, fuel prices, and generator performance among other things it does show that the modeled levels are not unreasonable as a starting point to determine flexibility excursions in the no solar scenario. Non spinning reserves are available in all cases and SERVM uses those to mitigate flexibility excursions.

Figure 10. No Solar 60 Minute Ramping Capability Comparison



I. Flexibility Excursion

A flexibility excursion is calculated by the model as any day where resources could not meet load but there was additional installed capacity on the system. These flexibility excursions are not expected to represent firm load shed events, but rather are simply a measure of the fleet's ability to follow net load changes given a particular set of operating guidelines. This is distinguished from a firm load shed event which is due to insufficient resources when operators are required to begin rolling blackouts.

III. Simulation Methodology

Since these flexibility excursions are low probability events, a large number of scenarios must be considered to accurately project these events. For this Study, SERVM utilized 39 years of historical weather and load shapes, 5 points of economic load growth forecast error, and 10 iterations of unit outage draws for each scenario to represent the full distribution of realistic scenarios. The number of yearly simulation cases equals 39 weather years * 5 load forecast errors * 10 unit outage iterations = 1,950 total iterations for each level of solar penetration simulated. Weather years and solar profiles were each given equal probability while the load forecast error multipliers were given their associated probabilities as reported in the input section of the report. This set of cases was simulated for each of the solar penetration levels in Table 8.

Table 8. Solar Penetration Levels

Tranche	DEC Incremental MW	DEC Cumulative MW	DEP Incremental MW	DEP Cumulative MW
No Solar	0	0	0	0
Tranche 1	967	967	2,908	2,950
Tranche 2	1,464	2,431	1,111	4,019

For each case, and ultimately each iteration, SERVM commits and dispatches resources to meet load and ancillary service requirements on a 5-minute basis. As discussed in the load and renewable uncertainty sections, SERVM does not have perfect knowledge of the load or renewable resource output as it determines its commitment. SERVM begins with a week-ahead commitment, and as the prompt hour approaches the model is allowed to make adjustments to its commitment as units fail and more certainty around net load is gained. Ultimately, SERVM forces the system to react to these uncertainties while maintaining all unit constraints such as ramp rates, startup times, and min-up and min-down times. During each iteration, flexibility excursions and total costs are calculated where:

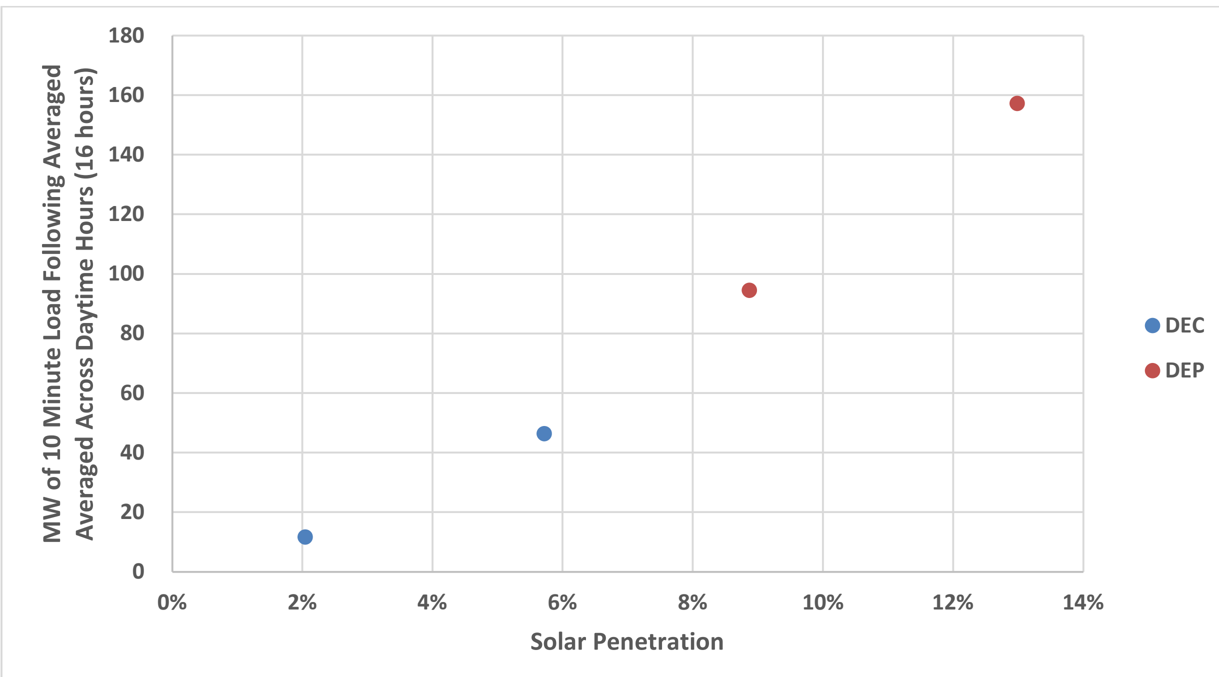
$$\text{Total Costs} = \text{Fuel Costs} + \text{O\&M Costs} + \text{Startup Costs}$$

These flexibility excursions and cost components are calculated for each of the 1,950 iterations and weighted based on probability to calculate an expected total cost for each study simulated. As the systems are simulated from 0 MW of solar to several thousand MWs of solar, the net load volatility increases causing flexibility excursions to increase. In order to reduce these events down to the level that was seen in the no solar case, additional ancillary services (load following up reserves) are simulated in the model so the system can handle the larger net load volatilities. Renewable curtailment is also captured in the model, and it is noted that curtailment is used as load following in the model. If renewable curtailment was avoided with some type of curtailment penalty in the solar cases before and after load following additions, the load following costs would actually rise because the model fully uses curtailment as load following. The model also uses quick start resources in all scenarios modeled.

IV. Load Following Requirements

In response to stakeholders and the TRC, the Study added load following across the day to manage the solar ramps and volatility and targeted additions based on when the flexibility excursions were occurring. Figure 11 shows the quantified required increase in operating reserves for Tranche 1 and 2 for both DEC and DEP as a percentage of solar penetration. The additions are correlated to solar penetration as additional solar increases the load following reserves requirement.

Figure 11. Quantified Required Increase in Operating Reserves as a Percentage of Solar Penetration



Figures 12-14 show heat maps of the flexibility excursions on a 12x24 basis for the DEC no solar case, DEC Tranche 1, and DEC Tranche 2 cases. In the no solar case, any flexibility excursions are during high load periods when operating reserves have a tendency to be lower.

Figure 12. DEC No Solar Case: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.09%	0.02%	0.04%	0.02%	0.00%	0.00%	0.06%	0.00%	0.05%	0.03%	0.02%	0.05%
2	0.32%	0.06%	0.01%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.26%
3	0.20%	0.04%	0.01%	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.06%	0.20%
4	0.22%	0.21%	0.33%	0.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.05%	0.52%
5	0.28%	0.42%	0.08%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.05%	0.30%
6	0.84%	0.56%	0.51%	0.03%	0.00%	0.00%	0.00%	0.00%	0.01%	0.02%	0.12%	0.46%
7	3.42%	1.71%	0.94%	0.19%	0.01%	0.01%	0.01%	0.02%	0.29%	0.12%	0.35%	0.79%
8	1.29%	0.83%	0.67%	0.48%	0.02%	0.01%	0.12%	0.10%	0.05%	0.20%	0.74%	1.80%
9	0.61%	0.53%	0.40%	0.08%	0.03%	0.08%	0.13%	0.03%	0.09%	0.16%	0.32%	1.66%
10	0.40%	0.26%	0.24%	0.11%	0.14%	0.62%	0.64%	0.43%	0.10%	0.07%	0.13%	0.25%
11	0.05%	0.04%	0.38%	0.04%	0.04%	0.53%	0.60%	0.78%	0.21%	0.02%	0.25%	0.12%
12	1.09%	0.03%	0.07%	0.14%	0.02%	0.26%	0.80%	0.37%	0.08%	0.05%	0.03%	0.01%
13	0.35%	0.01%	0.08%	0.03%	0.07%	0.44%	0.33%	0.27%	0.13%	0.07%	0.11%	0.04%
14	0.00%	0.02%	0.05%	0.08%	0.19%	0.48%	2.35%	1.37%	0.22%	0.15%	0.09%	0.08%
15	0.04%	0.00%	0.18%	0.06%	0.50%	2.87%	5.55%	4.39%	0.88%	0.29%	0.23%	0.02%
16	0.17%	0.02%	0.14%	0.49%	1.04%	2.25%	3.75%	1.78%	1.54%	0.62%	0.07%	0.02%
17	0.46%	0.07%	0.11%	0.77%	1.35%	1.01%	2.14%	1.56%	1.60%	0.74%	0.13%	0.13%
18	1.12%	0.20%	0.14%	0.73%	0.56%	0.57%	0.60%	0.43%	1.13%	0.55%	0.18%	0.24%
19	0.29%	0.29%	0.30%	0.56%	0.53%	0.37%	0.57%	0.41%	0.59%	0.48%	0.28%	0.47%
20	0.49%	0.40%	0.42%	0.35%	0.18%	0.12%	0.50%	0.15%	0.13%	0.36%	0.28%	0.75%
21	0.18%	0.11%	0.19%	0.20%	0.02%	0.03%	0.10%	0.00%	0.16%	0.14%	0.14%	0.34%
22	0.05%	0.05%	0.10%	0.03%	0.00%	0.17%	0.02%	0.01%	0.03%	0.48%	0.15%	0.09%
23	0.05%	0.02%	0.05%	0.09%	0.16%	0.00%	0.06%	0.12%	0.01%	0.94%	0.01%	0.06%
24	0.01%	0.02%	0.02%	0.05%	0.02%	0.00%	0.31%	0.24%	0.14%	0.66%	0.01%	0.10%

As solar is added, the flexibility excursions move towards later in the afternoon or during solar ramp up periods as shown in Figures 13 and 14.

Figure 13. DEC Tranche 1 Solar: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions Before Load Following Is Added

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.42%	0.09%	0.01%	0.01%	0.07%	0.00%	0.08%	0.07%	0.11%	0.07%	0.02%	0.16%
2	0.26%	0.13%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.03%	0.29%
3	0.08%	0.02%	0.02%	0.00%	0.00%	0.00%	0.01%	0.01%	0.00%	0.00%	0.03%	0.12%
4	0.18%	0.23%	0.13%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.06%	0.26%
5	0.53%	0.49%	0.21%	0.00%	0.12%	0.00%	0.00%	0.00%	0.00%	0.00%	0.09%	0.32%
6	1.25%	0.89%	0.90%	0.06%	0.00%	0.03%	0.00%	0.00%	0.02%	0.08%	0.20%	0.61%
7	2.50%	1.76%	0.81%	0.25%	0.04%	0.02%	0.01%	0.04%	0.00%	0.20%	0.49%	0.84%
8	1.49%	0.87%	0.57%	0.17%	0.09%	0.07%	0.10%	0.11%	0.07%	0.21%	0.77%	1.38%
9	0.65%	0.29%	0.32%	0.21%	0.04%	0.15%	0.36%	0.08%	0.05%	0.12%	0.23%	0.44%
10	0.35%	0.10%	0.19%	0.10%	0.17%	0.39%	0.53%	0.43%	0.07%	0.10%	0.08%	0.25%
11	0.07%	0.01%	0.31%	0.06%	0.16%	0.44%	0.56%	0.52%	0.21%	0.07%	0.08%	0.04%
12	0.06%	0.01%	0.11%	0.06%	0.07%	0.38%	0.89%	0.54%	0.15%	0.09%	0.10%	0.00%
13	0.03%	0.04%	0.09%	0.20%	0.25%	0.20%	0.35%	0.72%	0.27%	0.02%	0.07%	0.10%
14	0.02%	0.01%	0.11%	0.08%	0.22%	0.26%	1.79%	0.42%	0.27%	0.19%	0.14%	0.03%
15	0.08%	0.00%	0.05%	0.09%	0.27%	1.13%	2.35%	2.39%	0.25%	0.41%	0.14%	0.07%
16	0.06%	0.04%	0.11%	0.26%	0.58%	1.65%	4.41%	2.82%	0.95%	0.66%	0.41%	0.14%
17	0.74%	0.29%	0.24%	0.68%	1.27%	1.76%	3.56%	2.01%	2.35%	1.49%	0.31%	0.31%
18	0.34%	0.33%	0.39%	0.90%	1.73%	1.11%	1.18%	1.14%	1.32%	0.69%	0.24%	0.49%
19	0.40%	0.25%	0.51%	0.71%	1.16%	0.90%	0.79%	0.49%	0.90%	0.46%	0.32%	0.35%
20	1.32%	0.46%	0.47%	0.33%	0.51%	0.10%	0.15%	0.23%	0.28%	0.30%	0.35%	0.63%
21	0.48%	0.16%	0.35%	0.11%	0.09%	0.06%	0.09%	0.04%	0.02%	0.07%	0.42%	0.47%
22	0.37%	0.24%	0.12%	0.09%	0.01%	0.00%	0.03%	0.00%	0.00%	0.07%	0.07%	0.09%
23	0.07%	0.01%	0.04%	0.00%	0.00%	0.00%	0.02%	0.00%	0.00%	0.02%	0.00%	0.11%
24	1.01%	0.00%	0.08%	0.04%	0.00%	0.06%	0.07%	0.15%	0.08%	0.02%	0.05%	0.02%

Figure 14. DEC Tranche 2 Solar: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions Before Load Following Is Added

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.13%	0.01%	0.00%	0.02%	0.03%	0.00%	0.10%	0.03%	0.07%	0.08%	0.00%	0.04%
2	0.14%	0.02%	0.00%	0.01%	0.00%	0.00%	0.00%	0.02%	0.05%	0.01%	0.01%	0.06%
3	0.26%	0.00%	0.01%	0.11%	0.00%	0.00%	0.00%	0.00%	0.10%	0.00%	0.00%	0.03%
4	0.17%	0.10%	0.07%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.04%	0.14%
5	0.17%	0.27%	0.16%	0.06%	0.03%	0.00%	0.00%	0.01%	0.00%	0.02%	0.04%	0.26%
6	0.74%	0.74%	0.78%	0.63%	0.51%	0.03%	0.01%	0.00%	0.06%	0.49%	0.31%	0.49%
7	2.02%	1.14%	1.26%	0.41%	0.12%	0.22%	0.11%	0.13%	0.24%	0.56%	0.44%	0.59%
8	1.31%	0.51%	0.16%	0.14%	0.05%	0.05%	0.09%	0.24%	0.09%	0.05%	0.31%	0.85%
9	0.13%	0.09%	0.22%	0.05%	0.10%	0.22%	0.16%	0.25%	0.06%	0.04%	0.09%	0.10%
10	0.01%	0.06%	0.05%	0.07%	0.07%	0.17%	0.42%	0.35%	0.21%	0.10%	0.11%	0.11%
11	0.08%	0.01%	0.27%	0.07%	0.19%	0.23%	0.40%	0.52%	0.25%	0.08%	0.08%	0.05%
12	0.02%	0.02%	0.08%	0.12%	0.11%	0.35%	0.44%	0.45%	0.24%	0.09%	0.05%	0.03%
13	0.02%	0.02%	0.07%	0.09%	0.20%	0.23%	0.30%	0.39%	0.19%	0.22%	0.08%	0.01%
14	0.02%	0.00%	0.02%	0.10%	0.32%	0.29%	0.32%	0.42%	0.18%	0.17%	0.05%	0.02%
15	0.03%	0.01%	0.05%	0.28%	0.44%	0.30%	0.41%	0.94%	0.27%	0.17%	0.11%	0.06%
16	0.13%	0.01%	0.16%	0.38%	0.46%	0.43%	0.73%	0.86%	0.54%	0.45%	0.45%	0.08%
17	3.81%	0.44%	0.36%	0.82%	1.38%	1.09%	1.48%	1.78%	1.33%	4.98%	2.97%	2.06%
18	0.89%	0.65%	2.74%	4.30%	2.06%	1.68%	1.58%	2.23%	3.50%	1.33%	0.08%	0.51%
19	0.30%	0.25%	0.24%	2.04%	2.64%	2.15%	1.80%	2.13%	0.92%	0.30%	0.13%	0.28%
20	0.25%	0.16%	0.25%	0.15%	0.43%	0.41%	0.31%	0.21%	0.26%	0.17%	0.15%	0.36%
21	0.17%	0.15%	0.08%	0.07%	0.12%	0.05%	0.04%	0.06%	0.08%	0.03%	0.14%	0.23%
22	0.02%	0.04%	0.19%	0.08%	0.01%	0.01%	0.04%	0.02%	0.00%	0.03%	0.04%	0.02%
23	0.04%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.03%	0.02%
24	0.02%	0.01%	0.03%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%	0.02%

Figures 15-16 show the load following targets input into the model to lower the amount of flexibility excursions until they are at the same level as the no solar case. While these are the targets for the commitment, the realized incremental reserves are output as reported previously in Figure 11. Because the modeling can take advantage of periods where there are excess reserves due to commitment constraints on resources, the realized additional load following will always be less than the change in targets. In other words, there are periods where the target was increased but the system is already providing ample reserves on some of those days, so the incremental realized reserves reported in the results are less than these target input changes. These targets were adjusted upward in an iterative process by analyzing when the flexibility excursions were occurring and were increased until the number of events approached the number of events in the no solar case.

Figure 15. DEC Tranche 1: Final Incremental Load Following Targets (MW)

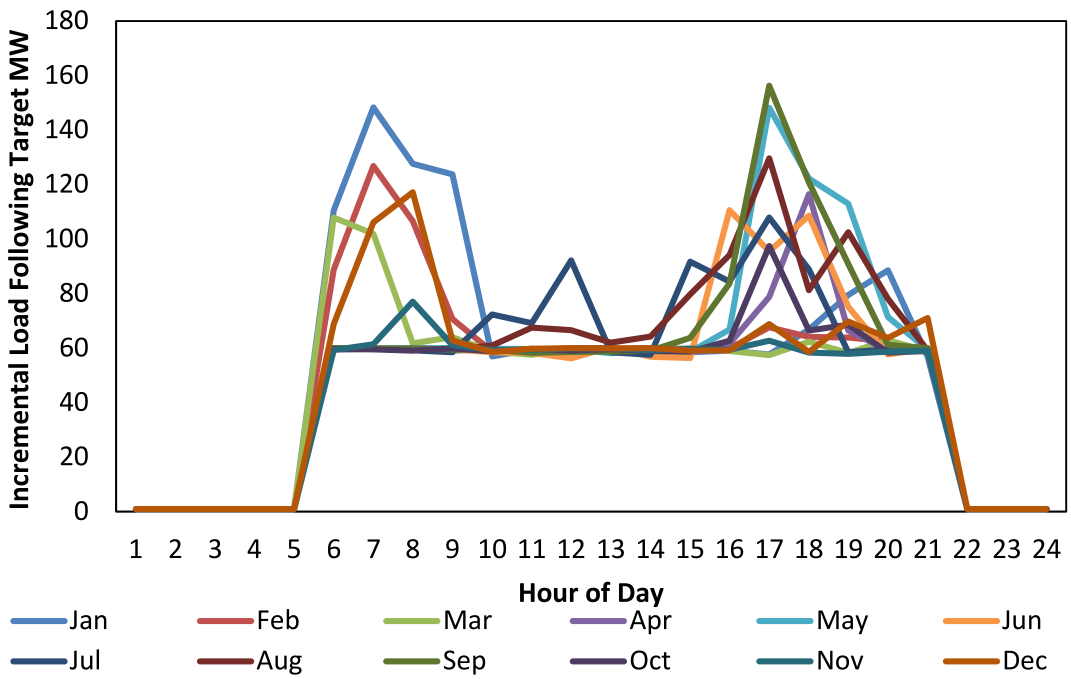
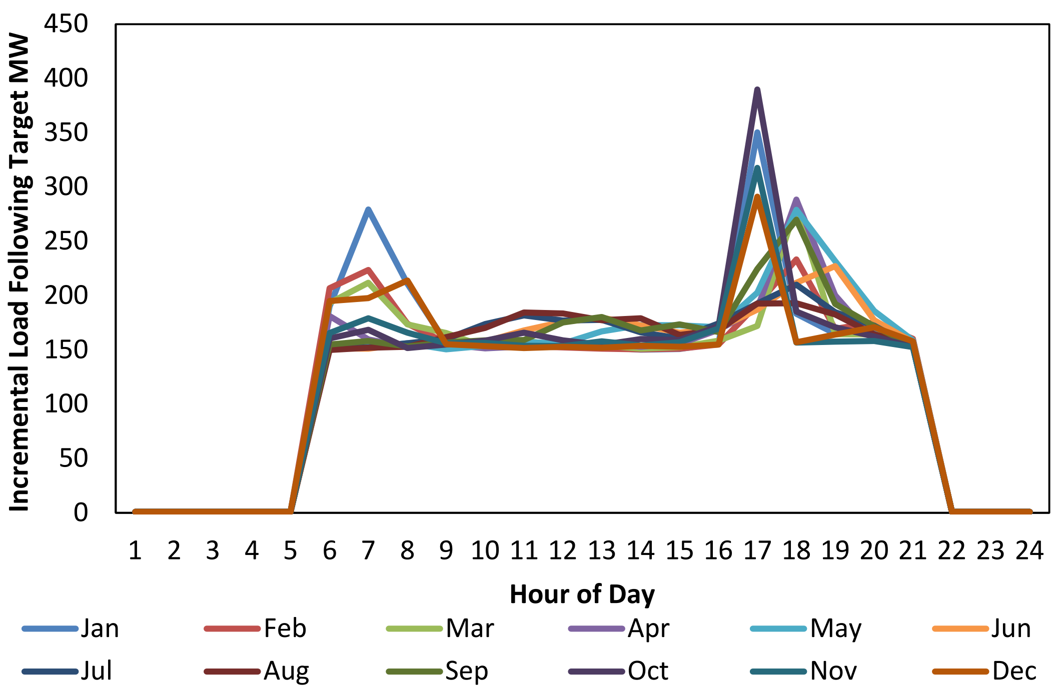


Figure 16. DEC Tranche 2: Final Incremental Load Following Targets (MW)



The same figures are shown for DEP in Figures 17-21 below.

Figure 17. DEP No Solar Case: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	0.00%	0.00%	0.08%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%
3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%
4	0.21%	0.03%	0.06%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.10%
5	0.11%	0.15%	0.18%	0.26%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.18%	0.75%
6	2.30%	1.92%	0.69%	0.04%	0.30%	0.00%	0.00%	0.00%	0.00%	0.12%	1.35%	1.40%
7	1.45%	3.23%	1.00%	0.37%	0.00%	0.00%	0.00%	0.00%	2.69%	0.00%	1.92%	1.99%
8	4.78%	2.98%	1.19%	0.12%	0.00%	0.00%	0.21%	0.22%	0.00%	0.10%	0.60%	1.45%
9	3.33%	0.88%	0.14%	0.00%	0.00%	0.93%	0.63%	0.11%	0.09%	0.00%	0.05%	0.14%
10	0.29%	0.07%	0.00%	0.00%	0.10%	0.14%	0.23%	0.07%	0.02%	0.01%	0.00%	0.10%
11	0.29%	0.00%	0.00%	0.00%	0.01%	0.29%	0.48%	0.28%	0.00%	0.04%	0.00%	0.00%
12	0.00%	0.00%	0.00%	0.00%	0.05%	0.11%	0.19%	0.03%	0.02%	0.00%	0.00%	0.00%
13	0.00%	0.00%	0.01%	0.00%	0.02%	0.13%	0.16%	0.21%	0.17%	0.00%	0.00%	0.00%
14	0.00%	0.00%	0.00%	0.00%	0.33%	0.29%	0.18%	0.40%	0.56%	0.16%	0.00%	0.00%
15	0.00%	0.00%	0.00%	0.47%	0.55%	1.17%	0.68%	1.72%	1.28%	0.67%	0.00%	0.00%
16	0.00%	0.00%	0.00%	0.41%	1.23%	1.09%	0.81%	1.84%	3.19%	1.33%	0.00%	0.00%
17	0.00%	0.00%	0.24%	0.97%	1.61%	1.49%	1.10%	1.52%	3.14%	0.97%	0.00%	0.00%
18	0.00%	0.00%	0.11%	0.39%	3.91%	1.09%	1.03%	1.15%	2.16%	1.16%	0.07%	0.00%
19	0.33%	0.42%	0.05%	0.21%	0.47%	0.08%	0.11%	0.37%	0.97%	0.21%	2.18%	0.07%
20	0.17%	0.71%	0.95%	3.69%	0.01%	0.00%	0.14%	0.00%	0.04%	0.07%	0.07%	0.46%
21	0.56%	0.24%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.06%	0.46%
22	0.01%	0.00%	0.00%	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%
23	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Figure 18. DEP Tranche 1 Solar: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions Before Load Following Is Added

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%
2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	0.09%	0.02%	0.14%	0.15%	0.05%	0.00%	0.00%	0.00%	0.00%	0.02%	0.02%	0.03%
6	0.09%	0.68%	1.93%	3.32%	2.86%	0.00%	0.00%	0.00%	0.14%	0.20%	2.64%	0.32%
7	0.13%	0.14%	0.74%	0.17%	0.01%	0.01%	0.00%	0.00%	0.01%	0.82%	3.59%	0.15%
8	0.18%	0.06%	0.02%	0.01%	0.00%	0.00%	0.02%	0.00%	0.00%	0.00%	0.09%	0.14%
9	0.09%	0.00%	0.02%	0.01%	0.01%	0.00%	0.01%	0.01%	0.00%	0.02%	0.03%	0.04%
10	0.00%	0.00%	0.01%	0.02%	0.00%	0.01%	0.03%	0.02%	0.00%	0.00%	0.00%	0.02%
11	0.00%	0.00%	0.01%	0.01%	0.06%	0.06%	0.05%	0.08%	0.03%	0.00%	0.01%	0.00%
12	0.00%	0.01%	0.02%	0.05%	0.02%	0.08%	0.02%	0.02%	0.05%	0.08%	0.01%	0.00%
13	0.00%	0.00%	0.02%	0.08%	0.11%	0.08%	0.03%	0.05%	0.07%	0.07%	0.00%	0.01%
14	0.01%	0.00%	0.07%	0.35%	0.54%	0.08%	0.05%	0.10%	0.12%	0.14%	0.11%	0.01%
15	0.01%	0.07%	0.26%	0.86%	0.99%	0.32%	0.12%	0.07%	0.31%	0.63%	0.84%	0.10%
16	0.18%	0.19%	0.99%	2.21%	1.81%	0.27%	0.12%	0.12%	0.68%	2.08%	6.59%	1.39%
17	0.63%	1.75%	4.08%	3.87%	3.16%	0.76%	0.59%	0.97%	1.77%	3.59%	1.63%	0.75%
18	0.01%	0.70%	2.02%	4.89%	2.98%	1.43%	1.80%	2.74%	3.43%	1.01%	0.01%	0.00%
19	0.01%	0.02%	0.00%	0.67%	4.38%	2.61%	2.35%	1.70%	0.04%	0.01%	0.01%	0.01%
20	0.03%	0.03%	0.01%	0.00%	0.01%	0.01%	0.01%	0.02%	0.00%	0.00%	0.03%	0.03%
21	0.00%	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.03%
22	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%
23	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Figure 19. DEP Tranche 2 Solar: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions Before Load Following Is Added

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	0.01%	0.02%	0.04%	0.14%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.12%	0.04%
6	0.05%	0.15%	0.77%	2.15%	1.04%	0.02%	0.00%	0.01%	0.08%	0.07%	1.38%	0.17%
7	0.05%	0.08%	0.46%	0.04%	0.00%	0.00%	0.01%	0.00%	0.00%	0.17%	1.92%	0.08%
8	0.11%	0.02%	0.02%	0.02%	0.02%	0.00%	0.00%	0.01%	0.00%	0.02%	0.11%	0.09%
9	0.01%	0.01%	0.04%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.04%	0.04%	0.01%
10	0.01%	0.00%	0.02%	0.03%	0.00%	0.01%	0.02%	0.04%	0.00%	0.03%	0.06%	0.05%
11	0.00%	0.00%	0.00%	0.01%	0.02%	0.06%	0.07%	0.06%	0.05%	0.02%	0.01%	0.01%
12	0.00%	0.01%	0.01%	0.02%	0.13%	0.16%	0.08%	0.13%	0.10%	0.10%	0.02%	0.01%
13	0.00%	0.00%	0.00%	0.12%	0.24%	0.26%	0.12%	0.17%	0.13%	0.04%	0.03%	0.01%
14	0.00%	0.01%	0.09%	0.18%	0.46%	0.39%	0.15%	0.24%	0.24%	0.25%	0.25%	0.01%
15	0.03%	0.01%	0.28%	0.47%	1.05%	0.52%	0.20%	0.29%	0.71%	0.67%	0.48%	0.10%
16	0.12%	0.17%	0.89%	1.28%	1.85%	0.95%	0.23%	0.43%	1.21%	1.80%	3.09%	1.88%
17	3.09%	2.43%	3.65%	2.28%	2.24%	0.63%	0.49%	0.71%	1.34%	5.34%	4.11%	1.63%
18	0.10%	1.31%	3.65%	4.70%	2.81%	1.58%	1.81%	2.63%	3.83%	1.59%	0.00%	0.00%
19	0.00%	0.02%	0.00%	2.00%	4.15%	2.54%	2.63%	3.38%	0.03%	0.00%	0.00%	0.04%
20	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%
21	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%
22	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
23	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Figure 20. DEP Tranche 1: Final Incremental Load Following Targets

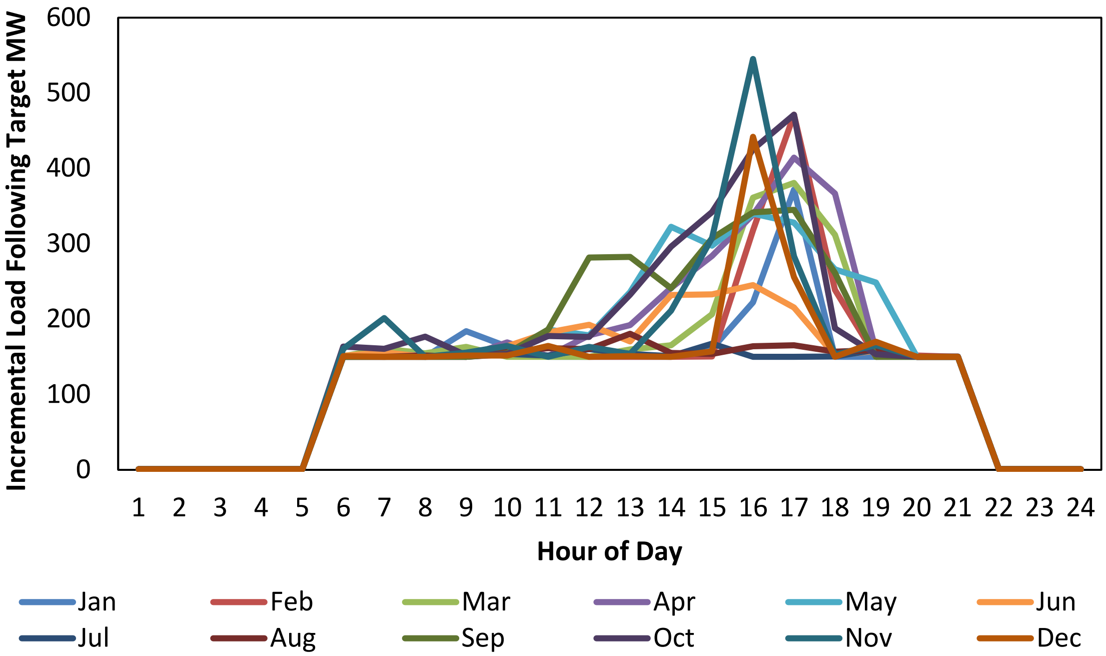
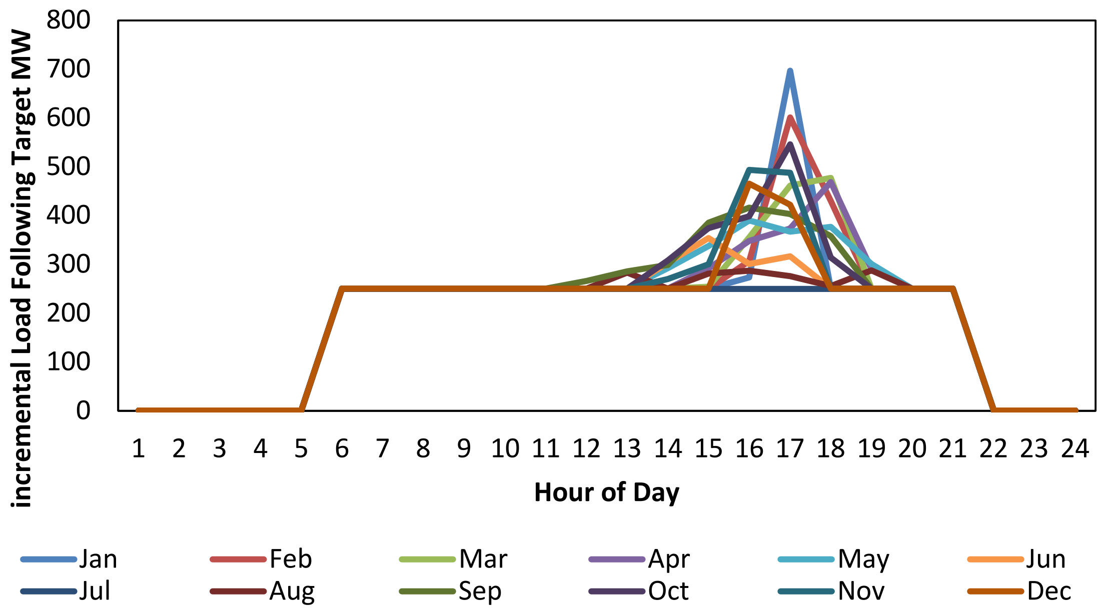


Figure 21. DEP Tranche 2: Final Incremental Load Following Targets for Commitment



IV. Island Results

Tables 9 and 10 shows the results of the island cases for both DEC and DEP. As solar generation is added, net load volatility increases causing flexibility excursions to increase if nothing is done to mitigate them. To reduce the excursions, additional load following as presented in the previous sections are added into the model. This higher load following target which causes an increase in costs. For DEC, the results show that as solar increases from 0 MW to 967 MW, 12 MW on average across daytime hours of additional load following is required to maintain the same number of excursions that occurred in the 0 MW solar scenario. The increase in load following also increases renewable curtailment slightly by 2,338 MWh. The total costs of the additional load following across the incremental 967 MW of solar generation is calculated as $1.00 /MWh. As tranche 2 is added to the analysis, which includes 2,431 MW, 46 MW of additional load following on average across daytime hours is required compared to the 0 MW solar case. The total costs of the additional load following for the incremental tranche 2 solar is $1.67/MWh while the total average cost of the additional load following for tranche 2 solar is $1.43/MWh. The incremental cost represents the cost of the solar capacity between Tranche 1 and Tranche 2. A minimal amount of additional renewable curtailment is seen in DEC largely due to the pump storage resources which assist in managing hourly imbalances. Similar patterns are seen in the DEP Table 10. Tranche 1 which assumes 2,908 MW of solar requires 95 MW of additional load following on average across daytime hours which results in $2.01/MWh. Tranche 2 which assumes 4,019 MW of solar capacity requires 157 MW of additional load following on average across daytime hours which results in a total cost of load following of $2.41/MWh. The incremental cost of Tranche 2 is $3.26/MWh. For DEP, the curtailment is higher because it does not have access to the same pump storage seen in DEC. Curtailment puts downward pressure on the SISC because it serves as free load following.

Table 9. DEC Island Results

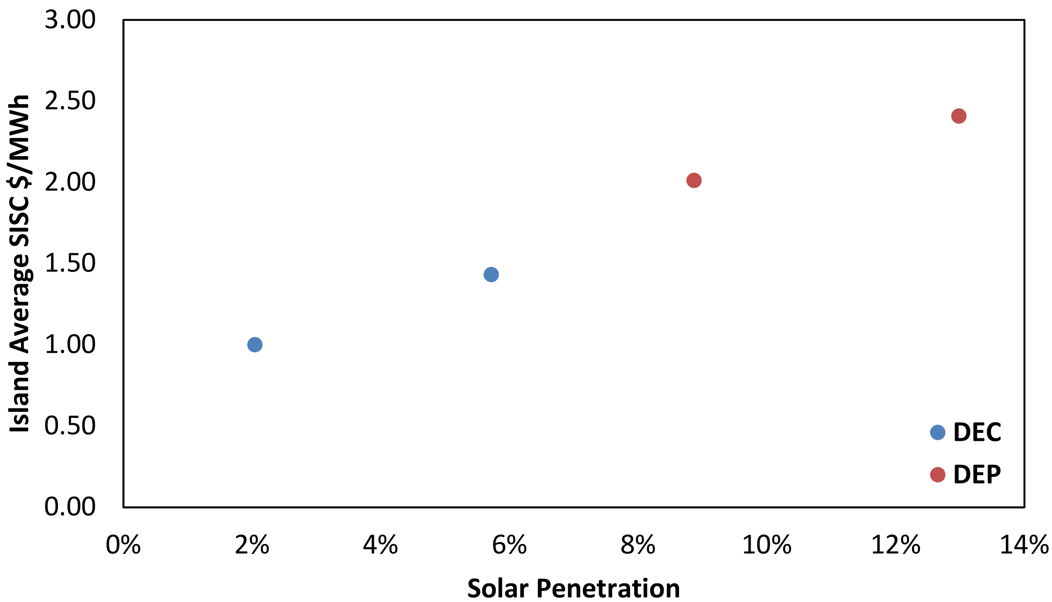
	DEC No Solar	DEC Tranche 1	DEC Tranche 2
Total Solar (MW)	0	967	2,431
Flexibility Violations (Events Per Year)	2.6	2.6	2.6
Average SISC ($/MWh)	0	1.00	1.43
Incremental SISC ($/MWh)	0	1.00	1.67
Realized 10-Minute Load Following Reserves (Average MW Over Solar Hours Assuming 16 Hours) (MW)	0	12	46
Additional Curtailment Due to Solar and Load Following (MWh)	0	2,338	43,003
Additional Curtailment Only Due to Additional Load Following (MWh)	0	227	6,882
Solar Generation (MWh)	0	1,887,495	5,279,075
Percentage of Solar Generation Curtailed (%)	0	0.12%	0.80%
Percentage of Solar Generation Curtailed Due to Additional Load Following (%)	0	0.01%	0.13%

Table 10. DEP Island Results

	DEP No Solar	DEP Tranche 1	DEP Tranche 2
Total Solar (MW)	0	2,908	4,019
Flexibility Violations (Events Per Year)	0.6	0.6	0.6
Average SISC ($/MWh)	0	2.01	2.41
Incremental SISC ($/MWh)	0	2.01	3.26
Realized 10-Minute Load Following Reserves (Average MW Over Solar Hours Assuming 16 Hours) (MW)	0	95	157
Additional Curtailment Due to Solar and Load Following (MWh)	0	392,280	1,187,332
Additional Curtailment Only Due to Additional Load Following (MWh)	0	27,072	94,271
Solar Generation (MWh)	0	5,677,218	8,312,633
Percentage of Solar Generation Curtailed (%)	0	6.8%	14.1%
Percentage of Solar Generation Curtailed Due to Additional Load Following (%)	0	0.5%	1.1%

Figure 22 shows the island average SISC as a function of solar penetration for both DEC and DEP.

Figure 22. Average SISC as a function of Solar Penetration



V. Combined (JDA Modeled) Results

The combined (JDA Modeled) results model the two DEC and DEP balancing areas with transmission capability between them. Table 11 shows the DEC to DEP E and DEC to DEP W transmission capability, which is consistent with the 2020 Resource Adequacy Study.

Table 11. Import and Export Capability

Source	Sink	Winter Capability MW	Summer Capability MW
DEC	DEP E	1,373	1,373
DEC	DEP W	341	341
DEP E	DEC	2,600	1,900
DEP W	DEC	155	155

In these simulations, the realized load following additions determined in the island case were targeted for the combined case except now economic transfers can be made on a 5-minute basis. These economic transfers reduce system costs and in turn reduce integration costs. In discussions with the Companies' operators, this method is potentially optimistic because SERVM has perfect foresight within the 5-minute time step to dispatch generation in both zones to perfectly minimize system production costs, whereas the JDA may be subject to more uncertainty and less dispatch flexibility.

The results are shown below in Table 12 for both Tranche 1 and 2. As expected, the total costs to increase the load following across the two systems decreases. For Tranche 1 the total costs decrease from 13.3 million dollars to 10.7 million dollars. This benefit is then allocated across the Companies to develop a lower SISC rate for each Company. Astrapé along with the TRC and the Companies determined it was most appropriate to allocate the benefit based on the rated cost of load following (in $/MWh) from the combined analysis. The load following cost is the total production cost increase divided by the additional

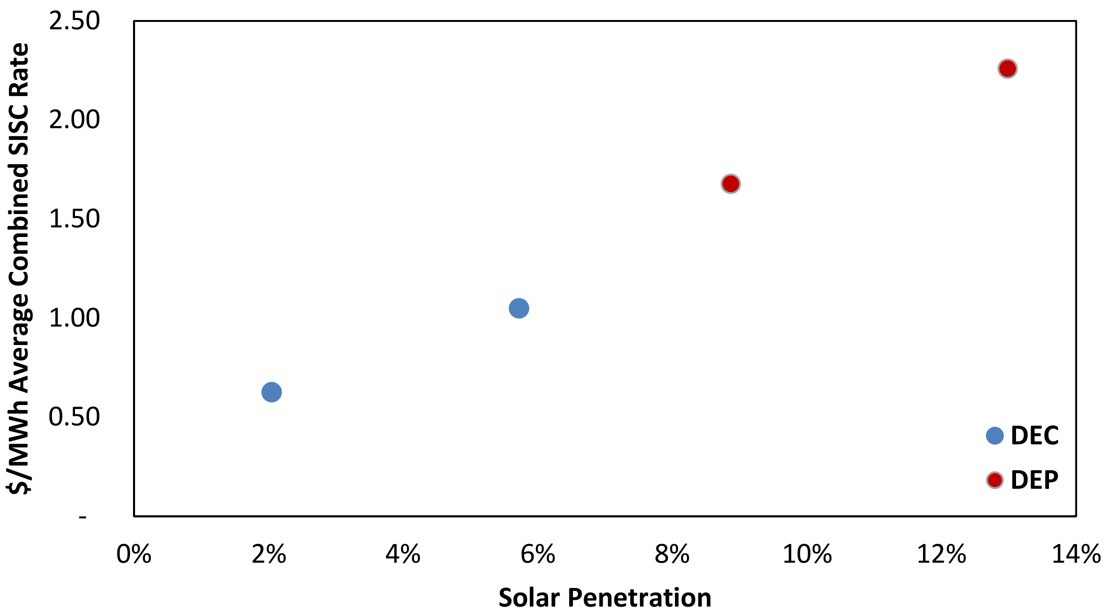
10-minute load following reserves that are increased. This results in average and incremental SISC values assuming the benefit of the JDA as expressed at the bottom of Table 12.

Table 12. Combined (JDA Modeled) Results with Load Following Cost Allocation

	DEC Tranche 1	DEP Tranche 1	Combined Tranche 1	DEC Tranche 2	DEP Tranche 2	Combined Tranche 2
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 10-Minute Load Following Reserves Needed (Average Over Daily 16 Hours) (MW)	12	95	106	46	157	204
Island 10 Min Load Following Cost Rate ($/MWh)	27.45	20.67	21.42	27.85	21.79	23.17
Island Integration Costs ($)	1,886,777	11,422,833	13,309,610	7,555,552	20,015,360	27,570,912
Average Island SISC ($/MWh)	1.00	2.01	1.76	1.43	2.41	2.03
Combined (JDA Modeled) 10-Minute Load Following Cost Rate ($/MWh)	17.25	17.25	17.25	20.45	20.45	20.45
Combined (JDA Modeled) Integration Costs ($)	3,174,863	7,542,222	10,717,085	9,645,181	14,691,557	24,336,737
Average SISC with Combined (JDA Modeled) Load Following Rates ($/MWh)	0.63	1.68	1.42	1.05	2.26	1.79
Incremental SISC with Combined (JDA Modeled) Load Following Rates ($/MWh)	0.63	1.68	1.42	1.29	3.51	2.26

Figure 23 shows the average SISC for both tranches for the Combined Cases as a function of solar penetration.

Figure 23. Average Combined SISC Rates for Tranche 1 and 2



Lastly Table 13 shows the curtailment in the combined JDA case at the different solar levels. The table breaks up the curtailment into total curtailment from the no solar cases and into a category showing what portion of that curtailment occurred due solely to the load following increase. In the combined (JDA Modeled) case the overall solar curtailment is 0.3% for Tranche 1 and 3% for Tranche 2. Overall, low levels of curtailment take place in the Combined (JDA Modeled) case.

Table 13. Combined (JDA Modeled) Curtailment

	Tranche 1	Tranche 2
Renewable Capacity (MW)	3,875	6,450
Solar Penetration (%)	4.8%	8.7%
Renewable (MWh)	7,564,719	13,591,705
Additional Curtailment from No Solar Case (MWh)	25,333	407,012
Additional Curtailment from No Solar Case (% of Total Solar Gen)	0.3%	3.0%
Portion of Additional Curtailment Only Due to Additional Load Following (MWh)	1,215	38,471
Portion of Additional Curtailment Only Due to Additional Load Following (% of Total Solar Gen)	0.02%	0.3%

VI. Summary

The Study results show the impact solar has on the DEC and DEP systems. As more solar is added, additional ancillary services in the form of load following are required to meet load in real time. This Study simulated both the DEC and DEP systems to determine the amount of load following that was needed to maintain the same level of flexibility excursions the system experienced before the solar was added. Then, the costs of the load following were calculated to determine SISC. This was conducted as an island for both DEC and DEP as well as a combined analysis assuming the JDA was used to economically produce the load following requirements. These inputs, methods, and results have been reviewed by the TRC as discussed in the TRC Report. The values in the Study provide information for the Companies to propose a SISC for its Avoided Cost Filing.

VI. Appendix

While having no impact on the rates being set in the Companies Avoided Cost filing, a third tranche was also simulated representing 3,931 MW in DEC and 5,519 MW in DEP. The results for the island and combined case are shown in Table A.1 for informational purposes. The DEC analysis shows that the cost of ramping needs begins to increase exponentially. By the time this penetration of solar is on the system, it is likely there will be a significantly different resource mix which may assist in the ramping needs and reduce the integration costs. Similar to the first two tranches, the combined JDA analysis for Tranche 3 brings these values down significantly.

Table A.1. Tranche 3 Results

	DEC Tranche 3	DEP Tranche 3
Total Solar (MW)	3,931	5,519
Flexibility Violations (Events Per Year)	2.6	0.6
Average SISC ($/MWh)	7.03	2.70
Incremental SISC ($/MWh)	15.44	3.32
Realized 10 Min Load Following Reserves (Average MW Over Solar Hours Assuming 16 Hours) (MW)	147	233
Additional Curtailment Due to Solar and Load Following (MWh)	444,474	2,932,656
Additional Curtailment Only Due to Additional Load Following (MWh)	230,458	206,563
Solar Generation (MWh)	8,878,524	11,872,220
Percentage of Solar Generation Curtailed (%)	5.01%	24.7%
Percentage of Solar Generation Curtailed Due to Additional Load Following (%)	2.60%	1.7%
Combined (JDA Modeled) Tranche 3 Average SISC ($/MWh)	2.36	2.70