Docket No. E-100, Sub 165

DUKE ENERGY PROGRESS

INTEGRATED RESOURCE PLAN

2020

ATTACHMENT II

DUKE ENERGY CAROLINAS & DUKE ENERGY PROGRESS COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY (CPRE) PROGRAM UPDATE

II

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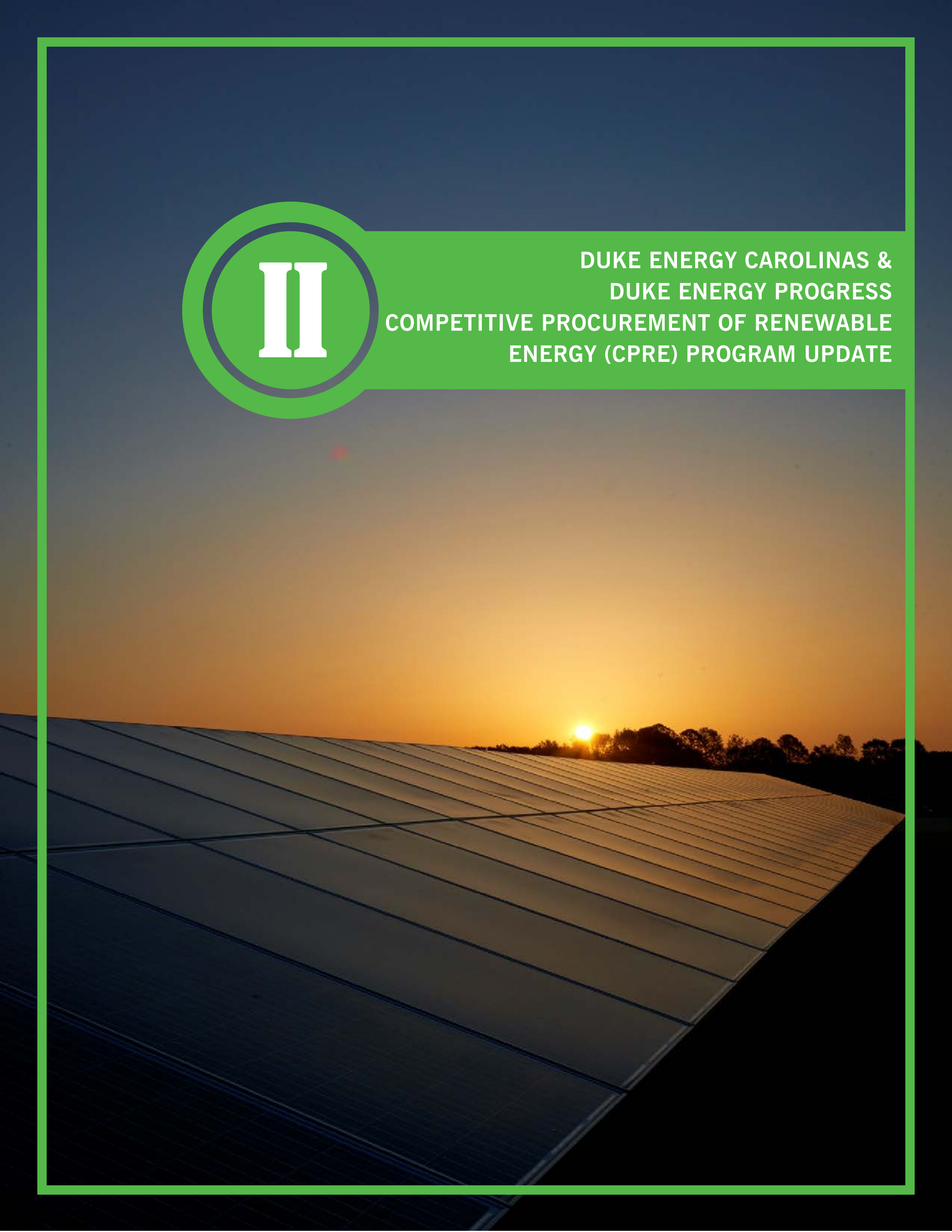


DUKE ENERGY CAROLINAS, LLC'S & DUKE ENERGY PROGRESS, LLC'S COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY (CPRE) PROGRAM PLAN UPDATE SEPTEMBER 1, 2020

INTRODUCTION

In accordance with North Carolina Utilities Commission ("NCUC" or the "Commission") Rule R8-71(g), Duke Energy Carolinas, LLC ("DEC"), and Duke Energy Progress, LLC ("DEP" and together with DEC, "Duke Energy" or "the Companies") provide this update to the Program Plan for the Companies' Competitive Procurement of Renewable Energy ("CPRE") Program ("Program").

The CPRE Program is being implemented pursuant to N.C. Gen. Stat. § 62-110.8, as enacted by North Carolina Session Law 2017-192 ("HB 589"). This updated Program Plan presents the Companies' current plans for implementing the CPRE Program.

The Companies' CPRE Compliance Reports (mostly recently filed in Docket No. E-7, Sub 1231 for DEC and Docket No. E-2, Sub 1254 for DEP) detail the outcome and status of the Companies' ongoing actions to comply with the requirements of G.S. 62-110.8 for the applicable reporting periods. In summary, the final results from Tranche 1 and the initial results from Tranche 2 have been successful, procuring approximately 1,210 MW of resources at prices below administratively-established avoided costs.

1. CPRE COMPLIANCE PLAN

1.1. IMPLEMENTATION OF AGGREGATE CPRE PROGRAM REQUIREMENTS

Under N.C. Gen. Stat. § 62-110.8(a), the Companies are responsible for procuring renewable energy and capacity through a competitive procurement program in a manner that allows the Companies to continue to reliably and cost-effectively serve customers' future energy needs. The Companies are required to procure energy and capacity from renewable energy facilities in the aggregate amount of 2,660 MW ("Initial Targeted Amount"), which amount is subject to adjustments as described in more detail below. The CPRE requests for proposals ("RFPs") must be reasonably allocated over a term of 45 months beginning with the Commission approval of the CPRE Program on February 21, 2018.

Renewable energy facilities eligible to participate in the CPRE RFPs include those facilities that use renewable energy resources identified in N.C. Gen. Stat. § 62-133.8(a)(8) but are limited to a nameplate capacity rating of 80 MW or less that are placed in service after the date of the electric public utility's initial competitive procurement. The renewable energy facilities to be developed or acquired by the Companies or procured from a third party through a power purchase agreement under the CPRE Program must also deliver to the Companies all of the environmental and renewable attributes associated with the power.

The Companies can satisfy the CPRE Program requirements through any of the following:

> (i) Renewable energy facilities to be acquired from third parties and subsequently owned and operated by the Companies;
> (ii) Self-developed renewable energy facilities to be constructed, owned, and operated by the Companies up to a 30% cap identified in N.C. Gen. Stat. § 62-110.8(b)(4)[1]; or
> (iii) The purchase of renewable energy, capacity, and environmental and renewable attributes from renewable energy facilities owned and operated by third parties that commit to allow the Companies rights to dispatch, operate, and control the solicited renewable energy facilities in the same manner as the Companies' own generating resources.

Per N.C. Gen. Stat. § 62-110.8(b), electric public utilities may jointly or individually implement these aggregate competitive procurement requirements. The Companies plan to continue to jointly implement the CPRE Program.

1.2. PROJECTED UNCONTROLLED RENEWABLE ENERGY GENERATING CAPACITY

N.C. Gen. Stat. § 62-110.8(b)(1) provides that if prior to the end of the initial 45-month competitive procurement period (November 2021), the Companies have executed PPAs and interconnection agreements for renewable energy and capacity within their Balancing Authorities ("BAs") that are not subject to economic dispatch or curtailment and were not procured pursuant to N.C. Gen. Stat. § 62-159.2 ("Transition MW Projects") having an aggregate capacity in excess of 3,500 MW, the Commission shall reduce the competitive procurement aggregate amount by the amount of such exceedance. If the aggregate capacity of such Transition MW Projects is less than 3,500 MW at the

[1] The Companies voluntarily agree to recognize both Self-developed Proposals, as well as third-party PPA Proposals offered by any Duke Energy affiliate bid into the CPRE RFP Solicitation(s), as being subject to the 30% cap.

end of the initial 45-month competitive procurement period, the Commission shall require the Companies to conduct an additional competitive procurement in the amount of such deficit.

As of July 2020, there is approximately 4,480 MW of resources that qualify as Transition MW (comprised of 4,200 MW of solar capacity and 280 MW of-non-solar capacity). And the Companies expect that a substantial additional amount of resources will qualify as Transition MW by the end of the initial 45-month CPRE period in accordance with N.C. Gen. Stat. § 62-110.8(b)(1). Therefore, at a minimum, the CPRE procurement target will be reduced by 800 MW and the Companies' current projections show that the Transition MW may ultimately exceed 3,500 MW by as much as 1,850 MW and possibly more depending on the extent to which SC Act 62 and Interconnection Queue reform facilitate additional interconnections by the end of the 45-month CPRE period.

Error! Reference source not found. identifies the total amount of MW that currently qualify as Transition MW (see "Current Transition MW" row). In addition, Figure 1 includes a projection of potential additional Transition MW (see "Potential Additional MW"). The projected range is based on applying a materialization factor to the projects that have an established LEO to sell to the Companies. This includes projects from certain settlement agreements that enabled certain projects to retain the rights to previously established LEO's from older avoided cost dockets. This increase in the number of MW that have reached settlement agreements is the primary cause of the significant increase in the projected total number of Transition MWs.

As previously noted, a project must have executed a PPA and an Interconnection Agreement prior to the end of the CPRE Procurement Period in order to qualify as a Transition MW. Note that some percentage of these potential Transition MW may not be counted as Transition MW due to interconnection timing but may ultimately still be constructed after the initial 45-month competitive procurement period (November 2021).

FIGURE 1

POTENTIAL ADDITIONAL TRANSITION MW'S

Consolidated Transition Summary	DEP	DEC	Total
Solar Connected	2,636	711	3,348
Non-Solar Connected	139	138	277
Additional Solar with a PPA/IA	451	405	855
Current Transition MW	**3,226**	**1,254**	**4,480**
Potential Transition MW*	215 to 715	50 to 150	265 to 865
Total	**~ 3,440 to 3,940**	**~ 1,300 to 1,400**	**~ 4,740 to 5,340**

*Includes projects with a signed PPA, but no IA as well as projects with a LEO but no PPA. The upper end of the range is based on Duke's estimates of materialization rates for these projects. Lower end of range is a more conservative view of materialization rates and intended to bound potential outcomes.

Note that the Companies' projections for CPRE procurement do not currently assume that there will be any re-allocation of capacity to the CPRE program for unsubscribed MW under G.S. 62-159.2 (Renewable Energy Procurement for Major Military Installations, Public Universities and Other Large Customers).

1.3. TRANCHE 1 RFP RESULTS

TRANCHE 1:

The contracting period for Tranche 1 concluded on July 8, 2019. Below is a summary of results for DEC and DEP:

600 MW DEC REQUEST

- 58 proposals ranging from 7 to 80 MW-AC totaling 2,733 MW
    - Median proposal was 50 MW
- All proposals were solar, 3 included storage
- 1,416 MW proposed in NC, 1,317 MW in SC
- 10 projects were contracted totaling 435 MW

- 9 in NC totaling 415 MW; 1 in SC totaling 20 MW
- 2 projects included energy storage
- 2 DEC utility-owned projects selected (94 MW) and 3 Duke affiliate (Duke Energy Renewables "DER") projects selected (95 MW)
- Average all in delivered price ~$38.86; estimated savings versus avoided cost of $213.24million over 20-year term

80 MW DEP REQUEST

- 20 proposals ranging from 7 to 80 MW-AC totaling 1,231 MW
  - Median proposal was 75 MW
- All proposals were solar, 1 included storage
- 617 MW proposed in NC, 614 MW in SC
- 2 projects were contracted totaling 87 MW
  - 1 in NC totaling 80 MW; 1 in SC totaling 7 MW
  - Average all in delivered price ~$38.31; estimated savings versus avoided cost of $33.17 million over 20-year term

TRANCHE 2:

Tranche 2 evaluations were completed and winning proposals were notified on July 17, 2020. The 90-day contracting period will conclude on October 15, 2020. Preliminary results of Tranche 2 for DEC and DEP are as follows:

600 MW DEC REQUEST

- 37 proposals ranging from 15 – 80 MW-AC, totaling 1,853.7 MW
  - Median proposal was 50 MW
- All proposals were solar, 3 included storage
- 1,051 MW proposed in NC, 802.7 MW in SC
- 11 projects have been selected as winners (contracts to be executed by Oct. 15)
  - 9 in NC totaling 514 MW, 2 in SC totaling 100 MW

80 MW DEP REQUEST

- 6 proposals ranging from 56 – 80 MW-AC, totaling 440.9 MW
    - Median proposal was 75 MW
- All proposals were solar, 1 included storage
- 366 MW proposed in NC, 74.9 proposed in SC
- 1 project has been selected as a winner (contract to be executed by Oct. 15).

The 12 projects selected in Tranche 2 have an estimated savings versus avoided cost of $103 million over the 20-year contract term. There were no Duke Energy self-developed projects selected as finalists and no finalist projects include energy storage.

1.4. PLANNED RFP SOLICITATIONS

As discussed in section 1.2, the ultimate amount of MW that will satisfy the statutory criteria of a Transition MW is unknown at this time. Based on the amount of MW that have already met the criteria for Transition MW and the Companies projection of a range of potential additional Transition MW (as show in Figure 1 above), the range for total Transition MW is ~4,740 to ~5,340.

Therefore, on the most conservative side of the Companies' projections, the total number of Transition MW would be 4,740, meaning that N.C. Gen. Stat. § 62-110.8(b)(1) would require the CPRE procurement target to be reduced to 1,420 MW. Assuming that all winning projects from Tranche 2 ultimately execute a PPA, the total MW procured through CPRE to date will be 1,211 MW. Thus, under the most conservative projection, there is only approximately 209 MW remaining to be procured through CPRE.

At the far end of the Companies' projections, the total number of Transition MWs could be as high as 5,340 MW, meaning that N.C. Gen. Stat. § 62-110.8(b)(1) would require the CPRE procurement target to be reduced to only 820 MW, in which case the Companies would actually be in an over-procured position.

Given the substantial uncertainty regarding whether any further CPRE procurement will be needed and, if so, how much, the Companies do not believe that it would be appropriate to make a firm decision at this time regarding the timing of or procurement target for Tranche 3.

However, the Companies also recognize that such uncertainty is challenging for market participants and, if additional MWs are required to be procured through Tranche 3, the Companies recognize the benefit of an earlier procurement to provide the greatest potential for leveraging the maximum amount of ITC.

Therefore, the Companies intend to seek stakeholder feedback via the IA website for input regarding how to approach Tranche 3. It might be possible to open Tranche 3 as originally scheduled in late 2020 but with undetermined capacity procurement targets (which procurement target could ultimately be 0 MW). Alternatively, the opening of Tranche 3 could be delayed until the procurement targets are established with a higher degree of certainty.

After receiving such feedback, the Companies will petition the Commission for approval of any proposed plan and confirmation of the appropriate adjustment to the CPRE targeted procurement amount. Note that the Companies interpret N.C. Gen. Stat. § 62-110.8(a) to require that CPRE procurements need only be commenced prior to the end of the initial 45-month competitive procurement period (November 2021) and not completed.

1.5. ALLOCATIONS OF RESOURCES

As prescribed by N.C. Gen. Stat. § 62-110.8(c), the Companies have the authority to determine the location and allocated amount of each CPRE RFP, as well as the CPRE Total Obligation to be procured within their respective service territories taking into consideration:

(i) the State's desire to foster diversification of siting of renewable energy resources throughout the State;

(ii) the efficiency and reliability impacts of siting of additional renewable energy facilities in each public utility's service territory; and

(iii) the potential for increased delivered cost to a public utility's customers as a result of siting additional renewable energy facilities in a public utility's service territory, including additional costs of ancillary services that may be imposed due to the operational or locational characteristics of a specific renewable energy resource technology, such as non-dispatchability, unreliability of availability, and creation or exacerbation of system congestion that may increase redispatch costs.

The Companies are currently planning to allocate and procure the CPRE Program Total Obligation through the Tranche 1-3 CPRE RFP Solicitations, discussed above, by soliciting the amounts of

Renewable Energy Resource capacity shown in **Error! Reference source not found.**. The total solicitation is impacted by the amount of Transition MWs. The calculation of potential additional Transition MWs is dynamic and uncertain so Figure 2 shows a range of potential solicitations for Tranche 3.

FIGURE 2

PLANNED CPRE SOLICITATION TARGETS BY TRANCHE

	DEC (APPROXIMATE MW)	DEP (APPROXIMATE MW)
Tranche 1 – under contract	435	86
Tranche 2 - selected	614	75
Tranche 3	0 - 571*	0 – 80*
Total	1049 – 1620	161 - 241

*If all potential additional Transition MWs materialize then Tranche 3 may not be necessary. The upper end of the range represents a low materialization estimate for potential additional transition MWs

This allocation reflects the same consideration that informed the Companies' initial allocation of MW as described in the Companies' initial Program Plan. The Companies' system operational experience integrating additional renewable energy resource capacity into the DEC and DEP BAs and distribution and transmission system operations, will inform the manner in which future CPRE Program Plans propose to allocate the remaining CPRE Program Procurement between the DEC and DEP service territories. As a result, the planned CPRE solicitation targets for DEC and DEP shown in Figure 2 are subject to change.

The Companies took into consideration the following factors prescribed by N.C. Gen. Stat. § 62-110.8(c) when establishing the allocation of MWs to DEC and DEP:

(i) FOSTERING DIVERSIFICATION OF SITING OF ADDITIONAL RENEWABLE ENERGY RESOURCES[2]

The Companies' primary objective is to procure cost-effective renewable energy resource facilities that allow DEC and DEP to reliably dispatch, operate, and control the facilities in the same manner as utility-owned generating resources, while diversifying the siting of renewable energy facilities across the Companies' BAs. The CPRE Program recognizes the State's desire to foster diversification of additional renewable energy facilities and to more effectively integrate additional utility-scale solar and other resources into the Companies' system operations. The Companies have developed the CPRE Program Plan allocations to meet the goals of diversifying the locations and avoiding inefficient or unreliable over-concentration of additional renewable energy facilities, and improving planning for the siting of additional facilities across the Companies' BAs and within their respective service territories throughout North Carolina and South Carolina.

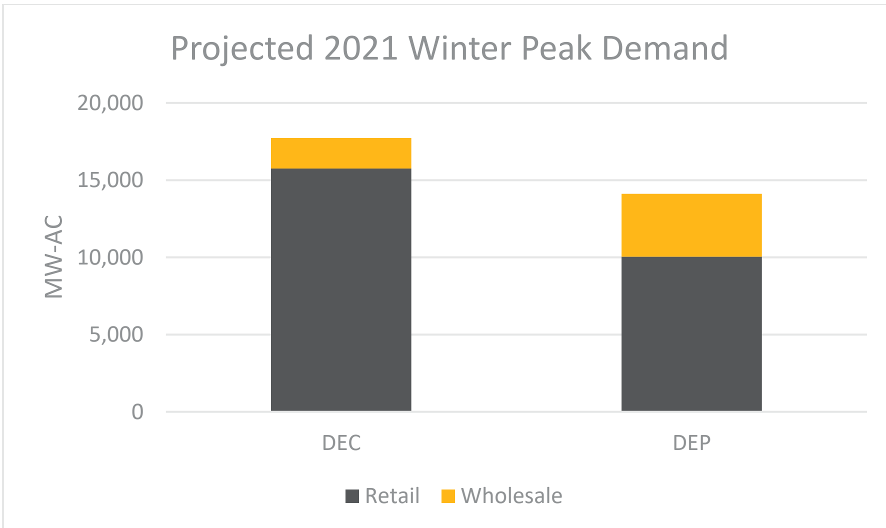
ADDING CPRE UTILITY-SCALE SOLAR IN DEC WILL FOSTER IMPROVED DIVERSIFICATION AS EXISTING UTILITY-SCALE SOLAR IS CONCENTRATED IN DEP

DEP is a smaller BA than DEC. The 2021 projected winter peak load for DEC is approximately 17,700 MW in comparison to the DEP projected winter peak load of approximately 14,100 MW, as seen in Figure 3.

[2] All Proposals bid into the Tranche 1 CPRE RFP Solicitation were utility-scale solar generating facilities. The Companies have primarily analyzed the need for additional diversification of siting for utility-scale solar resources. The Companies may consider the need to analyze diversification of siting of other renewable energy resource technologies in future CPRE Program Plans, depending on interest from other technologies in the Tranche 2 CPRE RFP Solicitation.

FIGURE 3

2021 PROJECTED PEAK LOAD BY BA



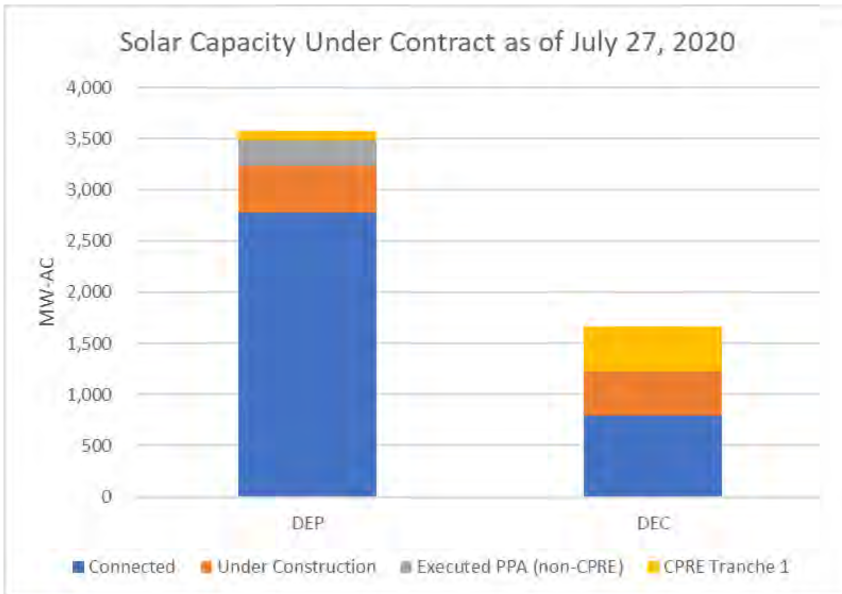
While DEP is a smaller BA, the Companies have experienced a significantly greater concentration of utility-scale solar development in DEP compared to DEC. As of July 27, 2020, the Companies are contractually obligated to purchase from third-party owners approximately 4,496 MW of solar under REPS and legacy PURPA contracts, in addition to approximately 225 MW of utility-owned solar, and approximately 521 MW from CPRE Tranche 1 contracts. As shown in **Error! Reference source not found.**, this utility-scale solar growth has been especially significant in DEP, where approximately 75% of the total non-CPRE MWs under contract are located.

If the total solar energy capacity in DEC and DEP were to be spread across the service territories based on their respective utilities' peak load, the DEC service territory should have approximately 60% of the solar energy capacity rather than its current ~20%.

To achieve the goals of diversifying the siting of renewable energy facilities throughout the Companies' service territories in a manner that promotes efficiency, reliability, and mitigates cost impact on the Companies' customers, the Companies' planned total CPRE Program procurement allocation (provided in **Error! Reference source not found.**), seeks proposals primarily in the DEC service territory in North Carolina and South Carolina. If the Transition MWs proceed as expected and the CPRE targets are met with primarily or all solar capacity, the resulting composition is a more balanced split of solar capacity between DEC and DEP.

FIGURE 4

SOLAR CAPACITY UNDER CONTRACT AS OF JULY 27, 2020



(ii) SYSTEM OPERATIONS AND RELIABILITY IMPACTS

In developing the proposed allocation of CPRE Program resources between the DEP and DEC service territories, the Companies also considered the operational efficiency and reliability impacts of siting additional renewable energy facilities within the DEC and DEP BAs. The highly concentrated levels of uncontrolled legacy PURPA contract solar that are currently installed, under construction, and under contract to be installed in the DEP BA has caused the Companies to primarily allocate the planned CPRE Program procurement towards the larger DEC BA, where significantly less utility-scale solar is installed today. The Companies' planned CPRE Program allocation between the DEC and DEP BAs is also supported by the growing levels of operationally excess energy and increasingly steep ramping requirements in the DEP BA.

INDEPENDENT BA SYSTEM OPERATIONS BASICS

DEP and DEC are each independent BAs responsible for maintaining compliance with North American Electric Reliability Corporation ("NERC") reliability standards to ensure reliable operations on their systems, as well as managing power flows between their systems and other utility systems. DEP and DEC must independently control their respective network resources to meet system loads and maintain compliance with reliability regulations within their separate BAs. Each BA must independently comply with NERC's mandatory Reliability Standards on a unified basis across the entire BA that encompasses territory in both North Carolina and South Carolina.

DEP's and DEC's system operators independently plan and operate each BA's generating resources to reliably meet increasing and decreasing intra-day and day-ahead system loads within reliability and generating unit availability and operating limits. These reliability requirements place the burden on the DEP and DEC BAs to balance generation resources (including new dispatchable CPRE renewable energy facilities), unscheduled energy injections (existing QF and renewable energy contracts), and load demand in real-time, all of which is essential to providing reliable firm native load service. To meet this objective, DEP and DEC must independently plan for and maintain a "Security Constrained Unit Commitment" of baseload and load-following assets, regulation resources, operating reserves, and spinning reserves, working together to ensure real-time frequency support and balancing.

The Companies' baseload[3] and must-run regulation units[4] represent the foundational resources necessary to meet load requirements, provide reliability, and meet mandatory NERC Reliability Standards. In the aggregate, the operationally constrained minimum reliable output of these generators represents the Lowest Reliability Operating Level ("LROL") of the BA's Security Constrained Unit Commitment. These essential generating resources cannot be de-committed in real time nor on an intra-day basis, because they must run within specified engineering levels and provide essential frequency and regulation support to the BA, and because they are needed to meet upcoming peak demands, such as the evening peak demands and next day peak demands. The LROL represents the

[3] The Companies' baseload units are firm native load generating resources such as nuclear, coal, and large natural gas combined cycle units that form the foundation of reliable service to meet the core system demand.

[4] Must-run regulation and regulation reserves resources are generating resources that must run to provide load balancing regulation and frequency regulation support to maintain reliability by supporting system frequency to the required target of 60 Hz in compliance with mandatory NERC Reliability Standards.

level on the BA at which continued energy injections into the BA above the BA's load causes the BA to have operationally excess energy.[5]

As has been discussed in recent avoided cost and IRP filings and in the initial CPRE plan filed in November, 2017, integration of additional solar is increasingly causing operationally excess energy and extreme ramping events in DEP. Further increases of solar generation in the DEP BA will continue to increase the risk of future potential NERC noncompliance and associated reliability risks, unless DEP has adequate dispatch control rights to proactively plan and dispatch generation resources on its system. Continued addition of solar generation in the DEP BA will exacerbate existing reliability challenges and increase the potential future risks of NERC noncompliance. The DEP BA's growing experience managing operationally excess energy and increasingly steep ramping requirements as additional unscheduled and uncontrolled solar generation comes online will also increase the likelihood of emergency curtailment in DEP. DEC currently is better positioned to accommodate additional solar resources without creating routine instances of operationally excess energy. However, DEC will also eventually face similar issues with operationally excess energy and ramping as additional solar generation is added to the system. This further strengthens the importance of the additional contractual curtailment rights available to DEC and DEP for the CPRE facilities.

(iii) POTENTIAL FOR INCREASED DELIVERED COST; ANCILLARY SERVICES

The Companies have evolved and will continue to evolve the modeling necessary to quantify the increased delivered costs and additional ancillary services needed to maintain NERC Balancing Authority compliance due to siting additional renewable energy facilities in DEC or DEP. Based on the prior two factors discussed, the vast majority of the MW's to be procured through CPRE have been allocated to DEC, however this third factor may influence future decisions to further adjust this allocation.

[5] The Companies testified to the importance of managing system operations to maintain the LROL of the BA's Security Constrained Unit Commitment in the 2016 avoided cost proceeding. *See In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016*, Pre-filed Direct Testimony of John S. Holeman, III, at 7-8, 12-13 Docket No E-100, Sub 148 (filed February 21, 2017).

ALLOCATION OF RESOURCES

In summary, the growing concentration of legacy PURPA solar facilities installed in the DEP BA, associated operational challenges and reliability risks on the DEP system and growing risks of uncompensated system emergency curtailments in DEP, and projections of DEP's and DEC's respective ability to reliably accommodate additional solar energy have informed the Companies' decision to allocate CPRE development primarily in the DEC service territory. The Companies anticipate that the designated allocation of CPRE Program capacity may evolve over the CPRE Procurement Period, and the Companies intend to meet the CPRE Program requirements in a manner that ensures continued reliable electric service to customers while procuring cost-effective renewable energy resource capacity located within the DEC and DEP service territories. The Companies will update the planned allocation, if it is determined that changes are appropriate, through subsequent CPRE Program Plan filings.

1.6. LOCATIONAL DESIGNATION

For purposes of the Tranche 1 CPRE RFP Solicitation, the Companies published Grid Locational Guidance information to the Independent Administrator's website on May 10, 2018 and also held a webinar open to all registrants to review and discuss these materials and answer questions from potential market participants and other interested parties. The Grid Locational Guidance was updated at conclusion of Tranche 1 and published to the Independent Administrator's website August 6, 2019 in advance of a webinar discussion on August 7, 2019. This guidance was intended to provide market participants with information on areas that have known transmission and distribution limitations as a result of the amount of existing or approved renewable energy facilities in the area. The goal of providing this grid locational guidance is to minimize the need for costly network upgrades to integrate CPRE renewable energy facilities and to provide information to market participants for use when planning development activities for the proposals submitted into the Tranche 2 CPRE RFP. The grid locational guidance information consists of a map and a table of circuits and substations that have known or increasing constraints.

The Companies continue to evaluate how to provide further updates to this guidance to provide potential participants in CPRE as much information as possible to enable the most cost effective proposals to be bid into the RFP.

2. CPRE TRANCHE 1 RFP DOCUMENT AND PRO FORMA PPA

The Tranche 1 RFP constitute the Companies' Program Guidelines for the completed solicitation.

COMMENTS ON STAKEHOLDER ENGAGEMENT REGARDING THE PRO FORMA PPA

Consistent with the directive in the NCUC's order approving the CPRE Program in February 2018 in Docket Nos. E-2, Sub 1159 and E-7, Sub 1156, the Companies have substantially revised the PPA based on feedback received through two formal comment periods and continued to engage with stakeholders to determine if consensus can be reached on additional revisions to the PPA. More specifically, based on comments filed by stakeholders in Docket Nos. E-2, Sub 1159 and E-7, Sub 1156, the Companies made significant revisions to the November 2017 version of the Pro forma PPA before publishing this on May 11 as a pre-solicitation document for Tranche 1 of the RFP. Market Participants and other interested parties then had a second opportunity to review the Pro Forma PPA (along with other draft solicitation documents). These comments were provided via the IA website. The Companies and the IA evaluated all of the comments received on the draft documents, including the Pro forma PPA and proceeded to make further, significant revisions to the Pro forma PPA before publishing the final PPA to be used in the Tranche 1 solicitation on June 8, 2018. The IA detailed the results of the comment period in their report which was completed on June 20, 2018 and posted to the website on June 21, 2018. In this report, the IA finds that the Companies gave full consideration to each observation and the IA agreed with the changes that the Companies elected to make to the PPA. On June 25, 2018 the Commission approved the final Pro forma PPA for use in Tranche 1 of the CPRE program.

The Companies held an additional stakeholder meeting regarding the PPA on August 7, 2018 via webinar. Approximately 50 participants called in to the webinar. The Companies presented a summary of the process that led to the Commission approval of the Tranche 1 PPA and summarized key changes made during the course of this process in response to comments and suggestions made by stakeholders. The Companies then opened the floor to questions from the webinar participants. Several of these questions were unrelated to the PPA and these individuals were directed to use the message board and Q&A process on the IA website. The comments on the PPA itself were very limited. The Companies provided responses to these comments on the call and reiterated the commitment to take these comments into consideration during the drafting of the Tranche 2 PPA document.

3. CPRE TRANCHE 2 RFP DOCUMENT AND PRO FORMA PPA

The Tranche 2 RFP document and pro-forma PPA were posted to the IA website in draft form on October 15, 2019 and as final documents on February 7, 2020 (RFP) and March 3, 2020 (PPA). These documents are available at: https://decprerfp2019.accionpower.com. The Companies made minor revisions to the Tranche 2 documents from the Tranche 1 versions in response to stakeholder feedback. Primarily, the Tranche 2 documents implement the solar integration service charge credit consistent with the directive in the NCUC's order approving pro forma PPA on January 24, 2020.

COMMENTS ON STAKEHOLDER ENGAGEMENT REGARDING THE PRO FORMA PPA

Pursuant to the NCUC Order Modifying and Accepting CPRE Program Plan on July 2, 2019, the pre-solicitation process for Tranche 2 allowed for comment opportunity with stakeholders that was supervised by the Independent Administrator. The Commission order required monthly stakeholder meetings to address any issues not specifically addressed in the order and to reach consensus on Tranche 2 documents. The schedule for these meetings is provided as Figure 5.

FIGURE 5

TRANCHE 2 STAKEHOLDER MEETING SCHEDULE

DATE	TOPIC(S)
August 7, 2019	Review of IA's final Tranche 1 Report Grid Locational Guidance Discussion concerning PPA Storage Protocols
September 12, 2019	PPA Terms and Conditions Grouping Study Base Case
October 10, 2019	General RFP Structure Asset Acquisition Discussion
November 13, 2019	Bidding Questions Tranche 2 Schedule
February 6, 2020	SISC Implementation T&D Evaluation

4. OTHER PROGRAM PLAN UPDATES

ENERGY STORAGE

Recognizing the improving cost effectiveness of energy storage technologies and planned future adoption by the Companies and consideration by other utilities in recent competitive generation procurements, the Companies' made the determination that Renewable plus Storage Proposals—if thoughtfully integrated into the Companies' system operations—should be accepted for consideration in the CPRE RFP. For this reason, the Companies' Tranche 1 RFP and pro forma Tranche 1 PPA enabled market participants the option to offer Renewable plus Storage Proposals. Storage was included in 4 bids in Tranche 1 and 2 of these bids were ultimately awarded contracts.

Storage was included in 4 bids in Tranche 2 but no storage proposals were selected as finalists.

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