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January 18, 2018

Ms. Lynn Jarvis
Chief Clerk
North Carolina Utilities Commission
430 N. Salisbury Street
Raleigh, NC 27603

RE: ***North Carolina Clean Energy Business Alliance***
In the Matter of Petition for Approval of Competitive Procurement of Renewable Energy Program
NCUC Dockets E-2, Sub 1159 and E-7, Sub 1156
JOINT COMMENTS OF NORTH CAROLINA CLEAN ENERGY BUSINESS ALLIANCE AND NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

Dear Ms. Jarvis:

On behalf of the North Carolina Clean Energy Business Alliance ("NCCEBA") and North Carolina Sustainable Energy Association ("NCSEA"), we hereby submit Joint Comments of NCCEBA and NCSEA in the above referenced docket.

If you have any questions or comments regarding this filing, please do not hesitate to call me.

Thank you in advance for your assistance.

Very truly yours,

/s/Karen M. Kemerait

pbb

Enclosure

cc: Christopher J. Ayers, Esq.
Parties of Record

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1159
DOCKET NO. E-7, SUB 1156

In the Matter of: **Petition for Approval of Competitive Procurement of Renewable Energy Program**	**JOINT COMMENTS OF NORTH CAROLINA CLEAN ENERGY BUSINESS ALLIANCE AND NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION**

I. PROCEDURAL HISTORY

On July 27, 2017, Governor Cooper signed into law House Bill 589 (S.L. 2017-192). Part II of House Bill 589 enacted N.C. Gen. Stat. § 62-110.8, which required Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, "Duke Energy" or "Duke") to file for North Carolina Utilities Commission ("Commission") approval, on or before November 27, 2017, a program for the competitive procurement of energy and capacity from renewable energy facilities with the purpose of adding renewable energy to the State's generation portfolio in a manner that allows the State's electric public utilities to continue to reliably and cost-effectively serve customers' future energy needs ("CPRE Program" or the "Program"). N.C.G.S. § 62-110.8(b) provides that DEC and DEP may jointly or individually implement the requirements of the CPRE Program.

N.C.G.S. § 62-110.8(b) requires the Commission to adopt rules to implement the CPRE Program. On November 6, 2017, in Docket No. E-100, Sub 150, the Commission issued an Order adopting Commission Rule R8-71 to give full effect to the intent of the

General Assembly as expressed in the enactment of N.C.G.S. § 62-110.8. Commission Rule R8-71(c)(1) requires that DEC and DEP develop and seek Commission approval of guidelines for the implementation of the CPRE Program, and that DEC and DEP file the guidelines at the time DEC and DEP propose a CPRE Program. In accordance with N.C.G.S. § 62-110.8 and Commission Rule R8-71(c)(1), on November 27, 2017, DEC and DEP jointly filed a Petition for Approval of Competitive Procurement of Renewable Energy Program to Implement N.C. Gen. Stat. § 62-110.8 ("Petition"). Duke's Petition includes Initial CPRE Program Guidelines, Pro Forma Purchase Power Agreement ("Pro Forma PPA"), Initial CPRE Program Plan, and a 22-page pleading that provides information about those proposed CPRE documents.

On December 1, 2017, the Commission issued its Order Requiring Report and Allowing Comments on Proposed CPRE Program. In the Order, the Commission ordered that on or before January 5, 2018, parties may file comments addressing Duke Energy's Petition, including any recommended action that the Commission might take in response to Duke's Petition and related documents filed in this proceeding. On January 5, 2018, the Public Staff – North Carolina Utilities Commission filed a Motion for Extension of Time, requesting that the Commission extend the January 5 deadline to January 10, 2018. On January 5, 2018, the Commission issued its Order Granting Extensions of Time to allow the parties until January 10, 2018 to file comments.

On December 15, 2017, the Commission granted NCSEA's petition to intervene in these dockets, and on January 8, 2018, the Commission granted NCCEBA's petition to intervene.

In accordance with the Commission's Order, the North Carolina Clean Energy Business Alliance ("NCCEBA") and the North Carolina Sustainable Energy Association ("NCSEA") on behalf of themselves and their members submit the following comments addressing DEC's and DEP's Petition, Initial CPRE Program Guidelines, Pro Forma Purchase Power Agreement, and Initial CPRE Program Plan.

II. COMMENTS ON DUKE ENERGY'S PETITION FOR APPROVAL OF ITS CPRE PROGRAM

Duke Energy's filing of its proposed CPRE Program Guidelines, Pro Forma Purchase Power Agreement, and Initial CPRE Program Plan was accompanied by the Petition that introduced and explained those documents and discussed several ancillary issues. While most of NCCEBA and NCSEA's comments are presented in the following sections addressing each of those separate documents, the organizations have several comments on the Petition itself.

Pro Forma CPRE Power Purchase Agreement. At pages 6-7 of the Petition, Duke Energy explains that its proposed Pro Forma PPA is heavily based on bilateral purchase power agreements that DEC or DEP have previously negotiated with solar developers and on the basis of which solar projects have been financed and constructed. Duke therefore asserts that the terms and conditions of the Pro Forma PPA should be presumed to be commercially reasonable and therefore approved by the Commission. While Duke Energy's factual statements are correct, its presumption is not.

As an initial matter, the template that Duke Energy has used for negotiated PPAs over the past several years has never been reviewed and approved by this Commission. Such approval is statutorily required for the CPRE PPA and the Commission should take this opportunity to ensure that the PPA terms are commercially reasonable, fair to both parties, and do not allow Duke Energy to use its monopoly power to dictate burdensome terms to independent power producers. This is especially important in the context of a competitive solicitation program, where unnecessarily burdensome contract terms may require bidders to increase their pricing to compensate for the impact of such terms.

As discussed in detail in Section IV herein, despite the fact that projects have been financed based on the Duke Energy negotiated PPA template, a number of the terms and conditions contained therein are not commercially reasonable or otherwise present challenges for solar developers, and they should therefore be modified. Indeed, the financing of projects based on the negotiated PPA template has often required extensive negotiations with financing parties to persuade them to accept the PPA terms. NCCEBA and NCSEA urge the Commission to require Duke Energy to make their requested changes to the Pro Forma PPA, as detailed in Section IV, and the attached redline of the Pro Forma PPA, and thereby require Duke Energy to adopt a fair Pro Forma PPA for the CPRE Program. [1]

Recovery of Network Upgrade Costs Associated with Winning CPRE Projects through Base Rates. At pages 20-21 of the Petition, Duke Energy proposes that CPRE market participants develop proposals that include only the generating facility and interconnection facilities costs, and that the utilities separately seek to recover any Network Upgrade costs "through future adjustments to general cost of service to be reviewed and approved by the Commission in future general rate case proceedings." This is an important principle to the CPRE Program, and NCCEBA and NCSEA agree that

[1] Moreover, having a Commission-approved pro forma PPA for use outside the CPRE Program would be highly desirable, and is being actively discussed by stakeholders in connection with the follow-up proceedings to Docket No. E-100, Sub 148.

this is a sound approach and encourage the Commission to approve it. As noted by Duke Energy, this approach will facilitate both proposal submission and evaluation, and it should not adversely affect ratepayers since the upgrade costs will be included in the cost of delivered energy.

III. COMMENTS TO DEC'S AND DEP'S INITIAL CPRE PROGRAM GUIDELINES

The primary purposes of the CPRE Program Guidelines are to meet the requirements of N.C.G.S. § 62-110.8 that require Duke Energy to competitively procure 2,660 megawatts ("MW") of renewable energy and capacity in Duke Energy's service territories in a manner that allows Duke Energy to continue to reliably and cost-effectively serve customers' future energy needs, and to inform market participants of the terms and conditions of, and the process for participating in, the CPRE RFP Solicitation. *See* Commission Rule R8-71(c). To ensure that the CPRE Program Guidelines comply with N.C.G.S. § 62-110.8 and Commission Rule R8-71, NCCEBA and NCSEA provide the following comments addressing specific sections of DEC's and DEP's Initial CPRE Program Guidelines that do not comply with N.C.G.S. § 62-110.8 or Commission Rule R8-71.

<u>Section 1.3 ("Planned CPRE Allocation between DEC and DEP Service Territories")</u>. As required by Commission Rule R8-71, Duke has helpfully provided information about the timing of the entire 2,660 MW of competitive procurement and the planned allocation of that procurement between the DEC and DEP territories. However, Commission Rule R8-71(g) also requires that Duke Energy's CPRE Program Plan include "if designated by location, an explanation of how the electric public utility has

determined the locational allocation within its balancing authority area." Since Duke Energy has not provided any such locational designation specific to either DEC or DEP service territory in its CPRE Program Guidelines or initial CPRE Program Plan, it appears that Duke Energy does not intend to impose any such locational allocation in the initial tranche of CPRE competitive solicitation. Given that Duke Energy has failed to include any such locational allocation information in its November 27 CPRE Program Plan or Guidelines, Duke Energy should not be allowed to introduce such considerations into the Tranche 1 RFP Solicitation (and it is not clear that it intends to do so).

In the event that Duke Energy intends to impose any locational allocation in the subsequent tranches of CPRE competitive solicitation, Duke should not be allowed to introduce such locational considerations without providing adequate notice to market participants through timely CPRE Plan updates. Ample notice of locational guidance is necessary for transparency, to allow for proper planning by the market participants, and to eliminate any unfair advantage for Duke Energy and its affiliates. As noted above, Duke Energy provided its targeted procurement of renewable energy facility capacity in DEC and DEP service territories in the four tranches, but did not include any more granular information designating the required or preferred locations of CPRE projects within Duke Energy's service territories. Appropriate locational information might include such considerations as the amount of renewable energy capacity allocated between North Carolina and South Carolina; specific locations or zones where projects must be sited; the amount of eligible capacity in such areas or zones; an allocation of eligible capacity between the distribution and transmission systems; and ineligible areas based on transmission and distribution limitations resulting from existing or approved renewable energy facilities in the area. If Duke does not provide notice to market participants of any locational designations through CPRE Plan updates, Duke should not be permitted to impose locational considerations in the subsequent tranches of the RFP Solicitations.

At present, Duke Energy has not committed to updating locational information frequently enough to allow the market participants to plan for projects to bid into the RFP Solicitation. For the market participants to submit the most cost-effective proposals, the market participants need up-to-date information about Duke's required or preferred locations so that they may propose facilities where needed. Duke Energy has committed to only updating the planned allocation between DEC and DEP service territories annually through subsequent CPRE Program Plan filings. Duke Energy should be required to provide any applicable locational guidance now for CPRE Tranches 2 and 3 and no later than in Duke Energy 2018 CPRE Program Plan Update for Tranche 4. Current and specific locational information will ensure that the CPRE RFP process functions as intended and will result in appropriate proposals that best meet Duke's requirements.

Section 2 ("CPRE Program RFP Solicitation Timeline"). Duke Energy has proposed a timeline for procuring the aggregate 2,660 MW of renewable energy facility capacity within 45 months of Commission approval of the CPRE Program. A portion of the timeline--Duke Energy's proposed contracting period for PPA agreements--is unnecessarily long. The contracting period for PPA agreements should be reduced from 90 to 30 days, as a 90-day period is not required to execute pro forma contracts that have already been approved by the Commission. Also, the date for issuance of the Tranche 4

RFP Solicitation should be accelerated by three months to July 2020. By shortening the contracting period for PPA agreements to 30 days and accelerating the issuance of the Tranche 4 RFP Solicitation, market participants will be able to begin construction of the renewable energy facilities in 2021. It is important that market participants be able to begin construction by December 31, 2021 so that they may qualify for the Solar Investment Tax Credit ("ITC"). Access to this tax credit will provide greater certainty for investment in the renewable energy facilities and will reduce costs for the market participants. The market participants will thus have the ability to submit more cost effective projects in the CPRE Solicitation, and those lower costs will benefit ratepayers.

Section 3.2 ("Market Participant Requirements").

In Market Participant Requirement 2, Duke Energy states that proposals must be for a single facility only and between 1 MW and 80 MW. However, Duke Energy notes that this requirement is for Tranche 1 only, and is subject to change in subsequent tranches based on the results of the Tranche 1 solicitation and changes in the market. Duke should not be permitted to change the requirement that proposals be between 1 MW and 80 MW. If the CPRE Program Guidelines allowed Duke Energy to change that requirement after Tranche 1, Duke Energy would have the ability to increase the minimum amount of capacity from 1 MW and reduce the maximum amount of capacity from 80 MW to the detriment of market participants. Any such change would adversely affect market participants that had submitted interconnection requests for projects that did not correspond with the changed capacity requirement (*e. g.,* an 80 MW project if Duke reduced the maximum amount of capacity to 75 MW), as those market participants would not be permitted to remain in the interconnection queue with upsized or downsized projects. Section 1.5 of the North Carolina Interconnection Procedures provides that an alteration to the size or output characteristics of the generating facility from its interconnection request submission constitutes a material modification that would result in withdrawal of the project from the interconnection queue. Furthermore, Duke Energy's Market Participant Requirement 2 is inconsistent with N.C.G.S. § 62-110.8(a) that dictates that renewable energy facilities that are eligible to participate in the CPRE Program may have a nameplate capacity rating of up to 80 MW.

Planned Market Participant Requirement 9.b needs to be revised as it is inconsistent with Commission Rule R8-71(l)(4). Duke Energy's Planned Bidder Requirement 9.b requires that both utility-owned and non-utility owned facilities must make available to the Independent Administrator ("IA") any revenue assumptions after the initial term; but Commission Rule R8-71(l)(4) requires that only utility-owned facilities must provide revenue assumptions after the initial term to the IA. Specifically, Commission Rule R8-71(l)(4) provides: "If the electric public utility's initial proposal includes assumptions about pricing after the initial term, such information shall be made available to the Independent Administrator and all participants." The reason for this distinction is that public utilities have much more extensive and sophisticated access to this type of information than market participants and would have an unfair competitive advantage as to market participants if not required to share this information (just as it is required to share other types of information that would give it an unfair competitive advantage). In contrast, there is not a comparable need to impose such a requirement on non-utility market participants, and doing so would unfairly require them to disclose proprietary information. Therefore, Planned Bidder Requirement 9.b must not require non-utility owned facilities to provide revenue assumptions after the initial term to the IA.

In regard to Planned Bidder Requirement 10, the Proposal Sponsor should be required to show experience developing facilities of the same renewable energy type (rather than technology).

The provision contained in Section 3.2 regarding deficient proposals should allow for a short "cure" period. The provision should be revised to state the following:

> In the event a proposal is determined by the IA to be deficient, the IA will provide written notice to the Proposal Sponsor of the deficiency and will allow the Proposal Sponsor five (5) days after receipt of written notice of the deficiency to cure the deficiency. There will be no opportunity afforded a Proposal Sponsor to refresh or revise its initial proposal on its own initiative. Fees submitted with a deficient proposal will not be returned with the exception of the proposal bond.

Furthermore, the provision that provides that Proposal Sponsors waive any recourse against Duke Energy and the IA for rejection of a bid or for failure to execute an Agreement for any reason should be deleted from Section 3.2. If Duke improperly eliminates a bid selected by the IA, the bidder would have the right to initiate a proceeding at the Commission to request appropriate recourse. The Commission's rules in no way eliminate or limit a bidder's ability to seek recourse against Duke Energy for improperly rejecting a bid or refusing to execute an Agreement with a bidder selected by the IA.

Section 3.3 ("Proposal Types"). Duke Energy has provided three proposal types (Power Purchase Agreement, Utility Self-developed Facilities, and Asset Acquisition). For the Asset Acquisition proposal type, Duke Energy has included partially developed renewable resource facilities (described as "Renewable Resource Asset Transfer"). The Renewable Resource Asset Transfer should be eliminated since partially developed facilities cannot be fairly priced and compared to other types of proposals as they will not have an EPC price quoted that can be evaluated. Indeed, it is impossible for a partially developed asset to be bid into a competitive solicitation because the developer does not have an all-in price for the output of its project. It is therefore hard to understand why Duke Energy would propose to include this project type in the CPRE program.

It appears that Duke Energy's objective with this proposal is to characterize partially developed projects that it acquires as Asset Acquisitions rather than Utility Self-developed, and thereby exclude such projects from the statutory 30% cap on Utility Self-developed projects that can be selected in the CPRE program. The logic of this characterization seems to be that since parties other than Duke Energy play some role in the development of these projects, and thus realize some financial benefit if they receive a CPRE award, the goal of the cap to diversify participation in the CPRE program is served. If that is the objective, a more straightforward and workable way to accomplish it would be to simply provide that partially developed projects do not count toward the 30% cap. However, the fact remains that Duke Energy (or its affiliates) will necessarily play a role in the development of these projects, and neither N.C.G.S. § 62-110.8 nor Commission Rule R8-71 allows for such exclusion.

<u>Section 3.5.1 ("Avoided Cost Rate")</u>. Duke Energy has proposed that the pre-solicitation information published by the IA will include DEC's and DEP's 20-year avoided cost rates using the peaker methodology that will be used to evaluate proposals in Tranche 1. In addition, Duke Energy has stated that for purposes of Tranche 1 CPRE

RFP Solicitation, it is planning to apply the peaker methodology to develop a generic large qualifying facility ("QF") avoided cost profile—consistent with the standard offer rates approved in Docket No. E-100, Sub 148, for small QFs up to 1 MW—and is not intending to take the specific capacity and energy supply characteristics of individual QF generating resources into account. NCCEBA and NCSEA are in agreement with these proposals, but would like to receive additional explanation from Duke Energy as to exactly how this will work in connection with the pricing and scoring of bids and how bids will be translated into a rate structure. Accordingly, NCCEBA and NCSEA request that Section 3.5.1 be modified to provide greater detail and clarity to address this issue.

In particular, based on past experience and good practice, NCCEBA and NCSEA expect that CPRE bidders will be asked to propose a single per MWh levelized cost of energy or PPA rate (or comparable revenue requirement), but that successful bidders will actually be compensated on a time-differentiated basis given the significant disparity in the value of on-peak and off-peak output. As mentioned above, it appears that Duke Energy intends to address this issue by developing a generic production profile that would be used for converting all successful bidders' pricing into a time differentiated rate schedule similar to those that have long been used in Duke Energy standard offer and negotiated PPAs. That approach is acceptable to NCCEBA and NCSEA. However, if that profile is different from the one most recently used to convert the Commission's time-differentiated standard offer tariff into a single all-in PPA price, the organizations would like to see that profile included in the guidelines and have an opportunity to comment on it. This is essential information required by bidders to allow them to bid a single all-in price per megawatt hour (or equivalent revenue requirement).

Another approach would be to have bidders bid a single price for off-peak energy and then provide that they would be paid for on-peak winter and summer production in the same proportion as those values relate to off-peak energy only pricing in the current standard offer tariff. By NCCEBA and NCSEA's calculation, in the current standard offer tariff, the price for on-peak summer generation is 141% of the price for off-peak energy, and the price for on-peak winter generation is 168%. Thus, under the proposal suggested above, a bidder whose energy only price was, for example, $40/MWh, would receive $56.40/MWh for summer on-peak delivery and $67.20/MWh for winter on-peak delivery. As with the prior approach, this would allow for an "apples-to-apples" comparison of bids while still appropriately compensating providers on a time-differentiated basis.

Section 3.5.2 ("Pro forma CPRE PPA"). As noted above, NCCEBA and NCSEA's detailed comments on Duke Energy's pro forma PPA are set forth in Section IV below and are reflected in the attached redline of the pro forma PPA. This section of the CPRE Program Guidelines is confusing with respect to what Duke Energy is proposing on the timing and approval of the initial pro forma PPA for use in Tranche 1 of the CPRE Program. NCCEBA and NCSEA believe that the pro forma PPA, which was required to be submitted with the CPRE Program Plan and Program Guidelines, must be approved by the Commission and should be reviewed and approved by the Commission as part of its review and approval of those documents. Waiting until 30 days before the Tranche 1 solicitation to finalize the pro forma PPA does not give market participants notice of the terms and conditions on which their proposals must be based or sufficient opportunity to object to unreasonable PPA terms and conditions. Nor is there any reason to delay review and finalization of the pro forma PPA since Duke Energy's proposal and other parties' responses are now before the Commission. Also, Duke should clarify that any modifications to the pro forma CPRE PPA for subsequent tranches must be submitted to the Commission for approval at the time that the CPRE Program Plan is updated annually (or sufficiently far in advance of the next solicitation to provide market participants adequate notice and opportunity to comment on such modifications). Finally, Duke Energy did not include MIPAs or EPC contracts in the CPRE Program Guidelines or CPRE Program Plan, and those contracts also need to be reviewed by market participants and approved by the Commission.

Section 3.5.3 ("Grid Locational Guidance"). Please see comments on Section 1.3 above.

Section 4.4 ("Grid Upgrade Evaluation"). NCCEBA and NCSEA support Duke Energy's proposal to conduct an expedited evaluation of the grid upgrades costs associated with all CPRE proposals.

NCCEBA and NCSEA have been working cooperatively with Duke Energy to determine whether changes are needed to the current interconnection procedures that would facilitate the CPRE Program and generally improve the interconnection process. NCCEBA and NCSEA believe that any changes to the interconnection procedures that could affect the CPRE Program should be carefully considered with input from interested parties. NCCEBA and NCSEA are waiting to receive Duke's most recent proposal on this subject. Once NCCEBA and NCSEA have received an updated proposal from Duke, NCCEBA and NCSEA intend to supplement this filing with comments addressing potential changes to the interconnection procedures that could affect the CPRE Program.

Section 7 ("CPRE Standards of Conduct"). This section references Duke Energy's Evaluation Team supporting the IA's Step 1 evaluation and ranking process and evaluating proposals in Step 2 of the evaluation process. This portion of Section 7 is in conflict with Commission Rule 8-71(f)(3), as the rule makes it clear that Duke Energy's role is limited to providing information to the IA to develop the methodology and the cost of network upgrades, and does not involve independently evaluating proposals. Thus, this section needs to be revised to remove references to Duke's evaluation of proposals.

III. COMMENTS TO DUKE ENERGY'S PRO FORMA PURCHASE POWER AGREEMENT

NCCEBA and NCSEA request that the following amendments to the proposed Agreement to Purchase Output of the [Name] Solar Facility, and those set forth in the attached redline, be made.

Most Significant Amendments

Section 8.5 Output Requirement.

Section 8.5 contains a 70% Net Output Requirement with damages owed by Seller to Buyer for failure to satisfy this requirement for two consecutive years. These damages are in the form of a monthly credit to the Contract Price in the immediately following year equal to one-twelfth of the difference between the Net Output Requirement and the actual energy delivered multiplied by a percentage of the contract price. Duke Energy has inserted a placeholder value of 50% for this purpose, but that figure is excessive and should be reduced to 25%.

Sections 8.6 – 8.10 – Curtailment and Control Rights.

Sections 8.6 and 8.8 should include a sentence that requires Buyer to conduct all curtailment and dispatch actions in a non-discriminatory fashion.

Section 8.6.1 should delete the sentence: "Except for the payments provided by Buyer pursuant to Section 8.9 hereof, Seller hereby releases and holds Buyer harmless from and against all harm to Seller or the Facility in any way arising from or relating to any direct or indirect control of the Facility to implement or otherwise effectuate any System Operator Instructions."

Section 8.9 Limited Payment for Control Instruction Dispatch Down allows for a certain amount of unpaid curtailment, up to 5% in DEC and 10% in DEP, plus compensation for curtailment beyond those limits. NCCEBA and NCSEA do not agree that there should be different standards for curtailment in DEP than DEC and that the limits should be minimized. Moreover, this provision will result in higher ratepayer costs with no additional benefit. By allowing a certain percentage of unpaid curtailment, financial backers of projects will require the financial models to be run assuming that maximum curtailment takes place. So the pricing that is offered will be increased to meet a return criteria, since it assumes only 90-95% of the energy output is paid for. In other words, in the current construct, ratepayers will pay for the cost of maximum curtailment whether it is used or not, and ratepayers will be paying for something they are not getting.

Below are two alternative ways to handle this situation that provide more certainty for bidders, allow for maximum flexibility in curtailment, and result in lower costs for ratepayers.

In the first proposal, the solar farm is treated similarly to a rate-based utility asset with an annual revenue requirement, except a) the revenue amount is competitively bid through the RFP; and b) there is an annual "true up" to ensure payment is based on actual performance.

i. Once a project is selected based on the established selection criteria, the bid is converted to an annual revenue requirement using the developer's bid price and annual production estimate.

ii. The developer is paid a monthly fee based on that annual revenue requirement, regardless of curtailment amount. (Note: This is similar to the utility cost recovery model).

iii. At the end of each year (or quarter), the project's actual production including curtailed energy is compared to the production estimate used to calculate the annual payment, and any over-payment or under-payment is "trued up" by adjusting the next payment down or up.

This proposal creates revenue certainty that will drive down bid prices and save ratepayers money. In addition, ratepayers will not be paying for something that they do not receive. The solar facility will be treated the same way as a utility owned asset and be dispatched economically.

In the second proposal, curtailment is treated as a service and the project is paid a curtailment service fee equal to the PPA rate.

i. Project bids in a PPA rate as normal.

ii. When a project is curtailed, it is not paid for energy not delivered but is instead paid a curtailment service fee equal to the per-kWh PPA rate at the time of curtailment.

This proposal creates revenue certainty that will drive down bid prices and save ratepayers money. In addition, ratepayers will not be paying for something that they do not receive. The facility will be paid for a needed service and not for energy that is not delivered. Curtailment is not limited and the facility will be dispatched economically.

Section 19 and Exhibit 3 – Events of Default and Operational Milestone Schedule.

Section 19 Events of Default should be amended in several areas to allow a reasonable cure period and to make it clear that there is a materiality threshold, especially since the termination rights in Section 20.1 have no materiality threshold. The following are suggested amendments:

Section 19.5 creates an event of default if Seller does not deliver written notice to Buyer within one (1) Business Day of reaching an Operational Milestone or failing to reach an Operational Milestone under Section 7.1.1. The notice provision should be extended to five (5) Business Days in Section 7.1.1. Moreover, there should be a cure provision added to this section.

Section 19.8 creates an event of default for failing to fully and timely complete an Operational Milestone. This section should provide that failure to achieve an Operational Milestone does not constitute an event of default if it would not cause the Seller to fail to achieve timely COD or include a reasonable cure provision.

Section 19.11 creates an event of default if the Seller Abandons the Facility for fifteen (15) consecutive days. The time period should be extended to thirty (30) days.

Section 19.13 allows failures to maintain the Facility's registration as a New Renewable Energy Facility to be cured within five (5) Business Days. This time period should be extended to thirty (30) days.

Section 19.17 creates an event of default if Seller fails to promptly and fully comply with a System Operator Instruction. This section needs a materiality threshold and a cure period.

Section 19.18 creates an event of default for failure to provide, replenish, renew, or replace a Performance Assurance or otherwise fully comply with the requirements of the Agreement, with a cure period of two (2) Business Days. This section should only apply to a Performance Assurance or credit related provision and should provide five (5) Business Days for the cure.

Section 19.26 provides a general cure period of twenty (20) days for events of default without specific cure periods. This time period should be extended to thirty (30) days.

Exhibit C creates Operational Milestones with deadlines that if not met become events of default under Section 19.8. In addition to providing a cure period, as suggested above, Seller should be held harmless for delays caused by Buyer and that can be remedied before the Commercial Operation Date.

<u>Sections 20.5 – Commercial Operation Date Liquidated Damages</u>.

Section 20.5 fails to include an excusable delay provision. It is not commercially reasonable to subject a Seller to large liquidated damages and potential termination of the PPA due to events beyond the Seller's control, specifically including interconnection and other delays caused by the Buyer. In addition, the liquidated damages provisions greatly exceed actual and consequential damages. This section should be amended to provide for a daily liquidated damages provision that more closely estimates the Buyer's actual damages. A more reasonable amount would be 4% x total projected revenue under the Agreement during the first year of the Term as determined by Buyer in its reasonable discretion divided by 180.

Sections 24.1 and 24.3 Assignment/Lender Protections.

Section 24.1 allows the Buyer to freely assign the PPA and the PPA allows for collateral assignment; but is silent on any lender protections *(e.g.,* notices of default and extended cure period), and expressly states that collateral assignment does not create any rights for the lender. These terms are not commercially reasonable and greatly complicate project financing. Similarly, Section 1.7 of Exhibit 3 provides that the Financing Milestone Commitment not require an estoppel or consent to the collateral assignment of the PPA from Buyer. Section 1.7 of Exhibit 3 should be removed because estoppels and consents to collateral assignment are common in financings of solar facilities.

Additional Suggested Amendments to the Proposed Agreement to Purchase Output of the [Name] Solar Facility

Definitions.

Section 1.10 defines Bankrupt. This definition should delete the inclusion of credit support provider. This is especially concerning, since being Bankrupt is an event of default under Section 19.23.

Section 3.3 South Carolina Public Service Commission Approval.

Section 3.3 provides that the Agreement is subject to review and approval of the Public Service Commission of South Carolina (PSC) for Facilities located in South Carolina. This section contains a termination provision upon certain actions of the PSC. This section should also allow for acceptance of the PSC's modifications, if Buyer and Seller agree. And, language should be added that that "Buyer will not challenge or oppose the PSC's acceptance of the Agreement." In the event that the Agreement is terminated, a sentence should be added that "in the event of such termination, each Party will retain its respective rights under PURPA."

Section 5 Credit and Related Provisions.

Section 5.1 creates an additional pre-COD Performance Assurance requirement. This requirement should only be based on the projected revenue during the first year of the Term.

Section 5.3 creates options for further assurances. These options are not necessary.

Sections 5.5 and 5.6 create the requirement of netting and set offs of amounts owed under "any other agreement" with the Seller in the event of default. This language should be deleted.

Section 5.7 requires that Performance Assurances remain in effect for one hundred and fifty (150 days beyond the later of the end of the term of the Agreement and Seller's performance. Should a post-COD Performance requirement be retained, this period should be reduced to thirty (30) days.

Section 6 Seller Compliance Requirements.

Section 6.2 sets forth Seller's covenants to Buyer and allows Buyer to terminate the Agreement upon five (5) Business Days written notice of any breach or failure relating to the covenants or warranties. This time period should be extended to thirty (30) days to allow for a potential cure or a remedy of a non-material failure.

Section 6.3 includes a provision that would give Seller both cover costs and reimbursement for the purchase of a product that does not comply with Buyer's obligations under the Act. The last sentence requiring reimbursement should be deleted to avoid double recovery.

Section 7.3 Transmission Provider.

Section 7.3 addresses the interconnection agreement between Buyer and Seller. This section should add a provision that Seller should not be responsible if Buyer delays Seller's performance and such delay caused by Buyer shall not trigger liquidated damages or an event of default.

Section 14.4 Remedy for Force Majeure.

This section gives the Parties the ability to terminate the Agreement if a Force Majeure event occurs for ninety (90) days, with the option of purchasing an additional ninety (90) days to cure for liquidated damages. This section should provide the additional ninety (90) days to cure without the requirement of liquidated damages if there is a commercially reasonable effort to remedy the effects of the force majeure event.

Sections 21.2 and 21.3 Cover Costs.

Sections 21.2 and 21.3 include cover costs at two (2) times the Contract Price. This amount should be reduced to the Contract Price. These sections also should include a cure period.

Section 24. 1 Assignment

This section should include language regarding an assignment by Buyer to a successor that does not believe is financially secure.

Section 24. 2 Pledge

This section should include additional language regarding financing parties rights.

Section 26.6 Limitation of Duty to Buy.

Section 26.6 waives Seller's (any affiliate and/or successor of Seller) rights to sell the output of the Facility to Buyer during the Term the Agreement would have been in effect, if the Agreement is terminated due to a default by Seller. This section, which would abrogate Seller's rights under PURPA, should be replaced by a section that prohibits Seller during the remainder of the PPA term from seeking to sell future output of the Facility to Buyer at price that is higher than the Contract Price.

IV. COMMENTS TO DEC'S AND DEP'S INITIAL CPRE PROGRAM PLAN

NCCEBA and NCSEA provide the following comments addressing specific sections of DEC's and DEP's Initial CPRE Program Plan that do not comply with N.C.G.S. § 62-110.8 or Commission Rule R8-71.

Section 2.3 ("Planned RFP Solicitations"). As previously noted in comments to Section 2 of the CPRE Program Guidelines, Duke Energy's proposed contracting period for PPAs should be shortened from 90 days to 30 days, and the date for issuance of the Tranche 4 RFP Solicitation should be moved up to July 2020.

Section 2.4 ("Allocations of Resources"). The first paragraph of this section should be revised to add the following highlighted information:

> 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 Solicitation, 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 of siting of additional renewable energy facilities in each public utility's 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 nondispatchability, unreliability of availability, and creation or exacerbation of system congestion that may increase redispatch costs.
>
> **In addition, the Companies should take into consideration that utility-scale solar PV systems can provide essentially ancillary services to the grid related to different forms of active and reactive power controls, such as automatic generation control, ramp rate control, voltage regulation, and frequency control. Such services are to be considered when evaluating a project's cost-effectiveness and value to ratepayers.**

Section 2.5 ("Locational Designation").

As previously noted in comments to Section 1.3 of the CPRE Program Guidelines, Duke Energy should be required to provide any locational guidance to market participants sufficiently far in advance of a CPRE RFP Solicitation to allow all participants to develop proposals that comply with such guidance on a level playing field with Duke Energy and its affiliates. To meet that test, any applicable locational guidance needs to be provided now for CPRE Tranches 2 and 3 and no later than in the Duke Energy 2018 CPRE Program Plan Update for Tranche 4.

CONCLUSION

NCCEBA and NCSEA respectfully request that the Commission consider the issues raised in the Joint Comments and the revisions and amendments to DEC's and DEP's Initial CPRE Program Guidelines, Pro Forma Purchase Power Agreement, and Initial CPRE Program Plan.

Respectfully submitted, this the 10th day of January, 2018.

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CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing Comments by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

This the 10th day of January, 2018.

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