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March 22, 2019

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

RE: **Joint Petition of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, for Approval of Competitive Procurement of Renewable Energy Program**
DOCKET NO. E-2, SUB 1159, DOCKET NO. E-7, SUB 1156

Dear Ms. Jarvis:

On behalf of the North Carolina Clean Energy Business Alliance ("NCCEBA"), we hereby submit **Comments of North Carolina Clean Energy Business Alliance** in the above-referenced dockets.

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
CC: All 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: Joint Petition of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, for Approval of Competitive Procurement of Renewable Energy Program	**COMMENTS OF NORTH CAROLINA CLEAN ENERGY BUSINESS ALLIANCE**

I. PROCEDURAL HISTORY

On February 21, 2018, the Commission issued an Order Modifying and Approving the Joint Competitive Procurement of Renewable Energy ("CPRE") Program for Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (together, "Duke").

On July 20, 2018, pursuant to Commission Rule R8-71(f)(2)(i), the Independent Administrator ("IA") of the CPRE Program transmitted to market participants the final documents to be used in the Tranche 1 CPRE RFP Solicitation. By that transmittal, the IA opened the Tranche 1 CPRE RFP Solicitation response period and established September 11, 2018 as the deadline for submission of proposals.

On July 30, 2018, in Docket No. E-100, Sub 101, Duke filed a Motion for Approval of CPRE-Related Modifications to the North Carolina Interconnection Procedures ("NCIP"). In the motion, Duke specifically requested approval of proposed new or modified Sections 1.7.1, 1.7.3, 4.3.4, and 4.3.9 of the NCIP, which establish a system impact grouping study process to more efficiently evaluate CPRE proposals within the current NCIP study process.

On September 5, 2018, in Docket No. E-100, Sub 157, Duke filed updates to its CPRE Program Plan, as part of its 2018 biennial integrated resource planning ("IRP") reports.

On October 5, 2018, in Docket Nos. E-100, Sub 101, E-2, Sub 1159, and E-7, Sub 1156, the Commission issued an *Order Approving Interim Modifications to North Carolina Interconnection Procedures for Tranche 1 of CPRE RFP*. Among other matters, the Commission states that it will consider several potential revisions to the CPRE rules and Duke's CPRE Program Plan for future tranches, including:

> 1) change the CPRE program plan to remove the ability of Duke to recover upgrade costs in base rates; 2) change the CPRE program plan to require an initial bid to contain all of the Interconnection Customer's costs; 3) revise the CPRE process to allow competitive bidders to refresh their bids based upon the assessment of grid upgrades identified in Step Two of the CPRE RFP bid evaluation process; and 4) explore options for Duke to more specifically direct generators to locations on the system that will not involve major network upgrades.

The IA, Duke, the Public Staff, NCCEBA, and other interested parties (collectively, "Stakeholders") attended meetings held on February 22, 2019 and March 6, 2019 to try to reach consensus about potential revisions to the CPRE rules and Duke's CPRE Program plan for Tranche 2 and later tranches.

On March 14, 2019, the IA filed a Report of the Independent Administrator – Tranche 2 Stakeholder Process ("IA Report"). The IA Report identifies issues in which consensus was reached among the Stakeholders and issues for which consensus was not reached.

II. COMMENTS

In accordance with the Commission's October 5, 2018 Order, the North Carolina Clean Energy Business Alliance ("NCCEBA") submits the following comments. The comments are in addition to or in response to information provided in the IA Report. NCCEBA is not providing specific comments regarding information in the IA Report for which NCCEBA is in complete agreement.

A. Duke should not be allowed to recover exorbitant liquidated damages from successful CPRE bidders who fail to perform or to require cash performance security for this excessive potential liability.

A standard provision in utility power purchase agreements ("PPAs") is a provision requiring the contracting party to pay liquidated damages to the utility if it fails to construct its facility (and/or to do so in a timely fashion). Such a provision has routinely been included in Duke PPAs prior to CPRE, along with the requirement that the contracting party post performance security for such liability. When Duke submitted the CPRE form PPA for the Commission's approval for Tranche 1, it represented that it is "virtually identical to, and substantially the same as" PPAs that Duke had previously entered into and that had been successfully financed by project developers. *See Duke's Petition for Approval of Competitive Procurement of Renewable Energy Program to Implement N.C. Gen. Stat. § 62-110.8,* p. 7. However, upon information and belief, without disclosing this fact to the Commission, Duke roughly quadrupled the amount of these liquidated damages from what it had previously required to 4% of PPA revenues over the life of the agreement. *See Section 20.5 (Commercial Operation Date Liquidated Damages), Tranche 1 PPA*. For a 65 MW project at $40/MWh, this amount would be approximately five million dollars, translating to $75,000 per megawatt (as compared to around $15,000 per megawatt for transmission-scale QF PPAs) -- an astronomical amount that bears no relationship to Duke's actual damages should the project not be constructed and thus constitutes an unlawful penalty. This liquidated damages amount should be reduced to the more reasonable level of 1% of PPA revenues in Tranche 2 and future tranches.

Moreover, for a successful CPRE bidder to have to post performance security in this amount in the form of cash or a cash-collateralized letter of credit is a totally unreasonable requirement. Very few developers have the ability to come up with that amount of cash, especially if they receive multiple CPRE awards, and the requirement that they do so certainly increases the pricing of CPRE bids. The result is that the very largest developers who have the ability to avoid this posting requirement based on their creditworthiness have a significant advantage in the bidding process. And Duke self-build proposals, which are not subject to this requirement at all, have an even greater advantage. To address these problems, in addition to reducing the liquidated damages amount, the Commission should require that the form PPA be modified to allow for the use of a surety bond for this performance security. Surety bonds are a widely used and accepted form of performance security that can be provided much more easily and at a fraction of the cost to a cash posting.

B. <u>The CPRE Program Plan should continue to allow Duke to recover network upgrade costs in base rates.</u>

As noted in the IA Report, NCCEBA, along with the Stakeholders, agree that Duke should continue to be able to recover network upgrade costs[1] assigned to winning proposals in Tranche 2 and subsequent tranches. The current CPRE construct, as set forth in the RFP for Tranche 1, allows Duke to impute grid upgrade costs to bidding projects, but the successful bidder is not actually responsible for paying these costs. Rather, Duke incurs the grid upgrade costs, and has the ability to seek recovery of these costs in a future rate case. It is possible that network upgrade costs could be part of bids that win or are considered competitive in Tranche 2 and future tranches of CPRE, but it continues to be appropriate for Duke to recover grid upgrade costs for winning proposals in Tranche 2. By continuing to allow Duke to recover network upgrade costs in base rates, there will be no adverse impact to ratepayers, as CPRE bids, including the imputed grid upgrade costs for the project must be below the avoided cost cap established in House Bill 589. (This is actually a good deal for ratepayers since avoided costs do not necessarily include all of the interconnection costs of Duke's generating capacity.) In addition, since the generating capacity being added pursuant to CPRE was mandated by the General Assembly and is thus a fortiori in the public interest, any network upgrades required to accommodate that generation is also in the public interest and should be paid for by ratepayers, just as occurs with a utility self-built project outside of CPRE.

If Duke is not permitted to recover grid upgrade costs in base rates, the practical effect would be that CPRE bidders would increase the amount of their bids to cover the anticipated (but uncertain) cost of network upgrades. Since Duke is allowed to recover costs incurred in paying for CPRE projects, the network upgrades costs embedded in

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[1] Network upgrades and grid upgrades have the same meaning and are used interchangeably.

CPRE bids would be recovered from ratepayers. Thus, ratepayers would be indifferent between network upgrade costs being paid for by Duke in the first instance and rate-based and those costs being included in bids and recovered as part of higher CPRE cost recovery.

Not only will there be no adverse impact to ratepayers if Duke continues to be able to recover grid upgrade costs through base rates, but ratepayers might realize some benefit. Market participants will likely not know whether projects will have network upgrade costs when bids are submitted because many proposals will bid into Tranche 2 before the System Impact Study and Facilities Study have been completed. Market participants will likely consider unknown network upgrade costs to be a risk that should be factored into bid prices, which could increase the cost of projects bid into the Tranche 2 RFP Solicitation. By allowing Duke to recover the cost of network upgrades in base rates, market participants will not need to consider the risk of unknown costs, and will be able to provide their best offers in their proposals.

C. Competitive bidders should not be allowed to refresh their bids after assessment of grid upgrade costs in Step Two of the CPRE RFP bid evaluation process. Alternatively, if a refresh is allowed, all bidders should be able to participate.

The IA Report incorrectly states that the Stakeholders are in agreement that market participants should be permitted to refresh bids if grid upgrade costs are assigned to projects. NCCEBA does not agree bids should be adjusted if there are grid upgrade costs. CPRE bidders should not be permitted to submit refreshed bid prices to account for the assessment of grid upgrades in the evaluation process. A refresh opportunity could frustrate the goal of the CPRE Program because it could create a disincentive for market participants to provide their best offers in their initial proposals. Also, allowing bids to be refreshed would complicate the evaluation process and lengthen the time required to complete the Step Two of the CPRE RFP bid evaluation process.

A better approach would be for CPRE bidders to provide in their initial bids an adjustment factor to automatically adjust their bid price if the estimated network upgrade differs from the bidder's estimate. In other words, if a bidder estimates a network upgrade of $2.0 million in its initial bid, but the cluster study identifies a required network upgrade equivalent to $5 million, the bidder would provide a method for the IA to covert the additional $3 million network upgrade into its bid price. This way, bids can be reasonably adjusted for network upgrades estimated through the cluster study process while avoiding the problematic issues with allowing the bidder to submit a wholly new bid price.

While NCCEBA opposes a refresh opportunity if network upgrades are triggered, if refreshing of bids is permitted, the refresh opportunity must be available to all proposals--not just projects assigned grid upgrade costs—to prevent any unfair advantage for refreshed bids. Market participants that adjust their bids could receive a competitive advantage to the detriment of bids not permitted to refresh their bids. An illustrative example of a possible unfair advantage for refreshed bids could involve a reduction in the cost of equipment of solar facilities after an initial bid is submitted. In that situation, the bidder with network upgrades assigned to its proposal could take advantage of the reduction of the equipment's cost by reducing the bid at the refresh opportunity, whereas other projects that do not trigger network upgrades would not have the same opportunity to improve their bid cost. Also, at the time that the refresh would be allowed, the IA would have determined the "clearing price" (the highest price to be paid in order to procure the requested megawatts), and a project with network upgrades would be given the opportunity to reduce its bid price, but a project without network upgrades would not be given the same opportunity. To prevent unfair advantage or "gaming" of the system, if some bidders are permitted to refresh their bids, all bidders must be allowed the opportunity to ensure a level field. In doing so, the Step Two evaluation process would be unduly cumbersome and complex because the IA would be required to perform repeat evaluations of all bids.

D. The CPRE Program Plan should not require the bid to contain all of the Interconnection Customer's interconnection facilities costs.

Unlike grid upgrade costs that can be recovered under Duke's base rates, winning CPRE bids should continue to be responsible for paying for all interconnection facilities costs, as required by the NCIP. However, there is no reason that CPRE bidders should be required to include interconnection facilities costs in a bid proposal. Since the market participant's bid price has to account for these costs, an estimate of those costs should play no role in the evaluation of bids. It appears that the IA may think it has the ability to disqualify bids where Duke's estimate of the interconnection costs exceeds the bidders estimate, but that factor is no different than the bidder's estimate of construction of material costs. It is the responsibility of the bidder to ensure that it can deliver the project at its bid price, accounting for all costs, including interconnection facilities. The bid bond, PPA liquidated damages, and performance security are the appropriate mechanisms for dealing with a bidder's failure to do so because it miscalculated its project economics.

E. Duke should be required to more specifically direct generators to locations on the system that will not involve major network upgrades.

NCCEBA requests that the Commission require Duke to provide, as expeditiously as possible, updated information for locations on Duke's system where major upgrades will not be required. A goal of the CPRE RFP Solicitation is to for Duke to competitively procure renewable energy facilities that are cost-effective, which means in locations, if possible, where substantial network upgrades are not required. For the market participants to submit the most cost-effective proposals, market participants must have up-to-date information about locations on Duke's grid where projects can be interconnected without requiring substantial network upgrades. Unless Duke furnishes this information, market participants will not be able to submit their most cost-effective projects. However, the guidance should not limit projects to specific areas, as any overly detailed instruction could drive up land prices for market participants and, consequently, result in higher bids.

F. Operational restrictions for energy storage should not be included in the Tranche 2 PPA.

Energy storage technologies – that are capable of capturing usable energy for use at another time – provide innovative and flexible solutions to serve energy needs and address existing and emerging challenges. Energy storage is a new and emerging technology in North Carolina with tremendous potential benefits to the state. It is important that the PPAs for CPRE do not contain problematic energy storage requirements that would act as a barrier to energy storage in CPRE.

Unfortunately, energy storage requirements and operational restrictions were added to the Tranche I PPA without the benefit of any stakeholder input that should have been required to address this new and important technology. NCCEBA was sufficiently concerned about the addition of the energy storage protocol that was unilaterally included in the Tranche I PPA (without any market participant input or Commission oversight) that NCCEBA filed a motion with the Commission on May 25, 2018. In the motion, NCCEBA advised that the requirements were unreasonable, unnecessary, extremely onerous, and would likely render storage projects unfinanceable. (The specific problems with these requirements are discussed in detail below.) Results of the Tranche 1 RFP Solicitation have borne out NCCEBA's concern: the energy storage protocol was in fact unreasonable and prevented the vast majority of market participants from including energy storage in their proposals. The IA's Second Status Report filed with the Commission on December 21, 2018 detailed participation in Tranche 1 of CPRE. The facts presented by the IA demonstrate that the storage requirements were in fact a barrier to market participants bidding energy storage in the Tranche 1 RFP Solicitation. The IA reported that there were 58 proposals in DEC territory for Tranche 1, but only three of which were storage proposals. For DEP territory, there were 20 proposals, but only one of which was a storage proposal.

For the Tranche 2 RFP Solicitation, there is an opportunity to correct the problems with the energy storage requirements in the Tranche 1 PPA so that there might be more energy storage proposals submitted in response to the Tranche 2 RFP. Specifically, there should be no operational restrictions on energy storage in the Tranche 2 PPA– unless Duke demonstrates that the restrictions are required to maintain grid reliability, a stakeholder process is conducted to address Duke's proposed restrictions, and the Commission determines that the restrictions are in fact necessary for grid reliability. If unreasonable energy storage requirements are not removed from the Tranche 2 PPA, there will again be limited – or no – energy storage proposals in the Tranche 2 RFP. Ensuring that energy storage can be included in bids in the Tranche 2 RFP will provide benefits to Duke, the ratepayers, and market participants.

The energy storage protocol in Exhibit 10 of the Tranche I PPA contains numerous problematic operational limitations, including ramp rate restrictions, scheduling limitations, and undefined additional restrictions that could be imposed in the future. NCCEBA believes that those restrictions may not be necessary for grid reliability on Duke's system. Energy storage requirements 6 and 7 provide that ramp rates for energy storage shall not exceed 5% of the facility's nameplate capacity on a per-minute basis while the facility is not generating, and no more than 1% while the facility is generating. Duke should be required to present technical justification for why it is necessary to impose ramp rate restrictions. Any ramp rate limitation reduces the ability of a battery to discharge during time periods in which its output is most valuable, and thus reduces the potential revenue that a battery can generate. Even in the scenario of a DC-coupled battery limited to the use case of bulk discharge windows during on-peak hours, a 5% per minute ramp rate limitation (as a portion of nameplate capacity) means that a battery would have to forfeit 20 minutes of full output opportunity during the on-peak window, which may be only 120 minutes total (and perhaps less in the future with even more granular on-peak periods). As such, this restriction is antithetical to the Commission's desire to see more granular on-peak periods, undermines the ability of storage technologies to provide full value to ratepayers, and will reduce the amount of storage that is ultimately installed.

More broadly, it is worth recalling that one of the primary attributes of batteries is their ability to ramp quickly. The majority of use applications for grid-connected batteries in the United States is for fast-response ancillary services. For example, the primary purpose of PJM's technology-neutral Reg D fast response frequency signal was to take advantage of more fast-ramping resources, which batteries were best positioned to provide (and resulted in up to 300 MWac of batteries installed in PJM territory). While it may be the case that DC-coupled batteries under CPRE may not be applied for such a use case immediately, it would be unreasonable to prematurely restrict the ability of these batteries to provide such fast-response services in the future.

A ramp rate restriction would also minimize the ability of batteries to "firm" the production profile of solar facilities throughout the day and to thus <u>reduce</u> the "fast ramping" that occurs during intermittent cloud coverage. In other words, "fast [down] ramping" occurs on a daily basis with solar facilities across North Carolina during intermittent cloud coverage, and batteries could offer one solution. However, batteries would be prevented from doing so with a ramp rate restriction.

Also, energy storage requirement 8 contains ambiguous scheduling limitations. DC-coupled batteries under the present DEC and DEP rate structure will provide the most value to ratepayers through discharge during on-peak periods, and in limited cases during other hours studied under the System Impact Study (*e.g.*, on a weekend day with no on-peak period). This is how markets work: price signals indicate when a product or service is most valuable. If Duke currently anticipates that it will seek to prevent the discharge of batteries during well-defined, Commission-approved on-peak periods, Duke should provide justification for why and when it anticipates such a scenario. Duke has provided no such justification.

Additionally, energy storage requirement 9 provides Duke with the unfettered right to add additional (and undefined) operating restrictions. This is particularly concerning because "operating restrictions" is a highly expansive and vague term that is not defined in the PPA. This restriction represents the most commercially unreasonable provision in the proposed protocol and will very likely prevent all or most storage systems from being financed, unless there is more specificity about those vague additional "operating restrictions".

G. CPRE bids should continue to be required to meet an in-service date eligibility requirement, and unlike what occurred in Tranche 1, that eligibility requirement should be enforced.

The Tranche 1 RFP appropriately included as an eligibility requirement for participation that a bidder be capable of placing its project in service by January 1, 2021. This type of deadline is common in energy and other types of competitive procurements as a way to ensure that facilities are brought online in the timeframe expected. House Bill 589 includes a timeline for expeditious procurement; thus, Tranche 2 should continue to include a similar in-service date eligibility requirement. (The fact that multiple tranches are contemplated over a period of years provides a market opportunity for projects less advanced in the development process.) Thus, Tranche 2 should include a similar in-service date eligibility requirement.

In addition, any such eligibility requirement should actually be enforced. The IA made only a cursory and inadequate evaluation of Tranche 1 bidders' ability to meet the January 1, 2021 in-service date, with the result, on information and belief, that many projects were included in the Tranche 1 competitive tier that have no possibility of complying with this requirement. This not only eviscerates the intention of the requirement but also delays the date by which legislatively mandated renewable generation resources will be brought on line. It also denies bidders who are actually able to meet that deadline the competitive advantage they should enjoy, thereby contradicting the market signal established by the RFP.

H. The curtailment provisions in the Tranche I PPA should be revised in the Tranche 2 PPA.

A major objective of the CPRE program established by House Bill 589 was to give Duke the ability, which it does not have under PURPA, to freely curtail third-party renewable generation resources, just as it can with its own generation facilities. The corollary of this right, which is essential to any party (including Duke) being able to finance and construct a generation facility is that project revenues have to be certain regardless of how much curtailment occurs. Despite this fact, in Tranche 1 the Commission approved, over NCCEBA's objection, a form PPA that, for no coherent reason, allowed uncompensated curtailment of up to 5% in DEC territory and 10% in DEP territory. In addition to serving no logical purpose and being inconsistent with the fundamental approach of House Bill 589, these provisions (contained in Section 8.9 of the Tranche 1 PPA) are problematic because the curtailment will result in higher bid prices to cover the cost of an unknown amount of unpaid curtailment. As the CPRE

Program is intended to enable Duke to procure renewable energy facilities at the lowest cost, the 5% and 10% curtailment amounts 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. Thus, the pricing that is offered in CPRE bids will have to be increased to meet a return criteria, since it assumes that only 90-95% of the energy output will be paid for. In other words, in the current construct of the Tranche 1 PPA, ratepayers will pay for the cost of maximum curtailment whether it is used or not, which means that ratepayers will pay for something they will not receive.

To solve this problem, Section 8.9.1 of the Tranche 2 PPA should state that the Seller shall be compensated at the PPA price for the curtailed energy that the facility would have generated but did not generate due to curtailment instructions. (Please see the red-line markup of Section 8.9 of the Tranche I PPA attached hereto as Exhibit A.) This option creates an incentive for Duke to optimize its system to efficiently accommodate more generation from the resources that are procured under CPRE. This is a key benefit of this curtailment approach since the legislature has indicated through enactment of House Bill 589 that its intent is for the state and the ratepayers to benefit from more low-cost renewable energy production. This solution is beneficial because it creates revenue certainty that will result in lower bid prices for the benefit of ratepayers, and ratepayers will not be paying for something that they do not receive. Importantly, the solar facility will then be treated the same way as a utility-owned asset, and it will be dispatched economically.

I. Duke's Build Transfer Agreement, Engineering, Procurement, and Construction Agreement, and Asset Purchase Agreement should be reviewed and approved by the Commission.

The Build Transfer Agreement ("BT Agreement"), Engineering, Procurement, and Construction Agreement ("EPC Agreement"), and Asset Purchase Agreement ("APA") contain terms and conditions that affect substantial rights of the market participants, and as such, require careful consideration by the Commission and the market participants. These agreements were unilaterally submitted by Duke in Tranche 1, and have never been reviewed by the IA, the Public Staff, or the Commission. We note that N.C.G.S. § 62-110.8(b)(3) contemplates that CPRE agreements be approved by the Commission.[2] While this section of the law was not well drafted and could be read to refer only to the pro forma PPAs, there is no reason to infer that the General Assembly wanted the Commission to approve one type of contract to be utilized in the CPRE program but not others. In any case, the Commission clearly has the authority to require that all program documents be submitted for its approval, and did exactly that in adopting Rule R8-71(c). That rule requires each utility to submit to the Commission for approval as part of its program guidelines "[p]ro forma contract(s) to be utilized in the CPRE Program." In light of the fact that these agreements are complex and severely flawed agreements and have received no review whatsoever, the Commission should not permit these agreements to be utilized in Tranche 2 of the CPRE Program until the Commission has approved them after comment by the Public Staff and intervenors.

[2] N.C.G.S. § 62-110.8(b)(3) provides: "Each public utility shall submit to the Commission for approval and make publicly available at 30 days prior to each competitive procurement solicitation a pro forma contract to be utilized for the purpose of informing market participants of terms and conditions of the competitive procurement."

III. CONCLUSION

NCCEBA respectfully requests that the Commission consider the issues raised in NCCEBA's Comments.

Respectfully submitted, this the 22nd day of March, 2019.

/s/ Karen M. Kemerait
Karen M. Kemerait
434 Fayetteville Street, Suite 2800
Raleigh, NC 27601
Telephone: (919) 755-8741
Attorney for: North Carolina
Clean Energy Business Alliance

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 22nd day of March, 2019.

/s/ Karen M. Kemerait
Karen M. Kemerait
434 Fayetteville Street, Suite 2800
Raleigh, NC 27601
Telephone: (919) 755-8741
Attorney for: North Carolina
Clean Energy Business Alliance

EXHIBIT

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8.9. Payments for Control Instruction Dispatch Down. For any calendar month during the Term hereof, Seller shall receive compensation from Buyer for any expected output stated in whole MWhs of Energy that the Facility would have generated but did not generate due to compliance with and implementation of Control Instructions (such quantity, the "Curtailed Energy").

8.9.1. Control Compensation. Except as set forth in Section 8.10, Seller shall receive compensation from Buyer for Curtailed Energy that the Facility would have generated but did not generate due to compliance with and implementation of Control Instructions. Buyer shall calculate such amount payable to Seller by multiplying the Contract Price times the amount of the Curtailed Energy ("Control Compensation"). The Control Compensation shall be determined using the Estimation Methodology set forth in Section 8.9.3. The Control Compensation shall be included in the invoice for the month immediately following the month in which Control Instructions resulted in Curtailed Energy.

8.9.2. Limitations on Control Compensation. Buyer shall pay Seller a Control Compensation for the Curtailed Energy if, and only if: (i) the Facility was generating or would have been generating (absent the Control Instruction) Energy at the time of the Control Instruction and meteorological and Facility operating conditions were such that the Facility would have actually reduced produced Energy at the time of the Dispatch Down instruction; and, (ii) the Dispatch Down was due to a System Operator Instruction that was a Control Instruction, but not due to an Emergency Condition Instruction, Force Majeure Instruction, or Interconnection Instruction. The Control Compensation shall be Seller's sole and exclusive payment and remedy for compliance with the Control Instructions, and any and all other Seller losses or payments are expressly disclaimed and waived.

8.9.3. Estimation Methodology. Buyer shall determine in a Commercially Reasonable Manner the quantity of Energy that could not be generated due to compliance with and implementation of the Dispatch Down instruction(s) based on: (i) The power plant controller output data points specified in Exhibit 9 attached hereto, which Seller shall provide to Buyer, on a real time basis, during the Term of this Agreement; (ii) the duration of the Dispatch Down; (iii) the amount of the generating capability of the Facility that is curtailed by the applicable Dispatch Down (e.g. 10% generation capability is curtailed); (iv) the solar exposure, irradiance, and meteorological circumstances actually recorded at the Facility during the Dispatch Down period; and (v) the Facility design, performance capability, and historic performance (the "Estimation Methodology"). Seller shall be responsible for installing and maintaining all equipment necessary to provide Buyer with the power plant controller output data points specified in Exhibit 9 on a real time basis. In the event that the real time data specified in 8.9.3(i) is unavailable historical production data required under Section 9.4.5 shall be used in its place.

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