Attachment DCC

DC-Coupled Storage

To be added as an Attachment to the Project Specific Addendum for PV+BESS Facilities that are DC-Coupled

ATTACHMENT DCC
DC-COUPLED STORAGE

This Attachment DCC (DC COUPLED STORAGE) sets forth the modifications to the Power Purchase Agreement for Renewable Dispatchable Generation (PV+BESS) for projects designed with a single Inverter System (as defined below) such that the PV System and BESS are "DC Coupled."

1. **Deletion of Defined Term. Definition of "PV System EAF Assessment Period" and "PV System Equivalent Availability Factor Performance Metric" will be deleted from the Schedule of Defined Terms.**

2. **Addition of New Defined Terms. The following will be added to the Schedule of Defined of Terms:**

   "Inverter System": The electric DC to AC and AC to DC power conversion equipment as more particularly described in Section 5 of Attachment A (Description of Generation, Conversion and Storage Facility).

   "Inverter System EAF Assessment Period": Shall mean, for purposes of calculating an Inverter System Equivalent Availability Factor, a rolling period of twelve (12) consecutive calendar months. At the end of each calendar month, the Inverter System EAF Assessment Period will roll forward to include the next calendar month and thus create a new PV System EAF Assessment Period. The initial "Inverter System EAF Assessment Period" shall consist of the 12 full calendar months of the initial Contract Year.

   "Inverter System Equivalent Availability Factor": Shall have the meaning set forth in Section 2.5(a) (Calculation of the Inverter System Equivalent Availability Factor) of the Agreement.

   "Inverter System Equivalent Availability Factor Performance Metric": Shall have the meaning set forth in Section 2.5(b) (Inverter System Equivalent Availability Factor Performance Metric and Liquidated Damages) of this Agreement.

3. **Revisions to Defined Term. The definition in the Scheduled of Defined Terms for the following is revised to read as follows:**

   "Facility": Seller's renewable electric energy facility that is the subject of this Agreement, including the PV System, Inverter System, the BESS, all Seller-Owned Interconnection Facilities and all other equipment, devices, associated appurtenances owned, controlled, operated and managed by Seller in connection with, or to facilitate, the production, generation, storage, transmission, delivery or furnishing by Seller of, electric energy to Company and required to interconnect with the Company System.

4. **Global Changes.**

   - **All references in the Agreement to "PV System EAF Assessment Period" will be changed to "Inverter System EAF Assessment Period."**

   - **All references in the Agreement to "PV System Equivalent Availability Factor" will be changed to "Inverter System Equivalent Availability Factor".**

- **All references in the Agreement to the "PV System Equivalent Availability Factor Performance Metric" will be changed to "Inverter System Equivalent Availability Factor Performance Metric".**

5. Agreement Section 2.4 is revised to read as follows:

2.4 Assurance of Capability of Facility to Deliver Net Energy Potential and Availability of BESS. In order to provide Company with reasonable assurance that, subject to the Renewable Resource Variability, the Facility's Net Energy Potential will be available for Company Dispatch: (i) the Inverter System Equivalent Availability Factor Performance Metric shall be used to evaluate the availability of the Inverter System for dispatch by Company; (ii) the GPR Performance Metric shall be used to evaluate the efficiency of the PV System; (iii) the BESS Capacity Performance Metric shall be used to confirm the capability of the BESS to discharge continuously for four (4) hours at BESS Contract Capacity (MW) or to discharge continuously for a total energy (MWh) equal to the BESS Contract Capacity (MWh) if the test is conducted at less than BESS Contract Capacity (MW); (iv) the BESS EAF Performance Metric shall be used to determine whether the BESS is meeting its expected availability; (v) the BESS EFOF Performance Metric shall be used to evaluate whether the BESS is experiencing excessive unplanned outages; and (vi) the RTE Performance Metric shall be used to evaluate the storage efficiency of the BESS. Whenever the PV System potential output is in excess of the Company Dispatch, the excess energy from the PV System shall be used to maximize the BESS State of Charge so long as this does not conflict with the operating parameters of the BESS set forth in Section 9(d) (Battery Energy Storage System) of Attachment B (Facility Owned by Subscriber Organization) to this Agreement. Seller shall design, operate and maintain the Facility in a manner consistent with the standard of care reasonably expected of an experienced owner/operator with the desire and financial resources necessary to design, operate and maintain the Facility to achieve the Performance Metrics. The foregoing is without limitation to Seller's other obligations under this Agreement, including the obligation to operate the Facility in accordance with Good Engineering and Operating Practices. The Performance Metrics are set forth in Section 2.5 (Inverter System Equivalent Availability Factor; Liquidated Damages; Termination Rights) through Section 2.11 (BESS Round Trip Efficiency Test; Liquidated Damages) of this Agreement and shall be interpreted consistent with the North American Electric Reliability Corporation Generating Availability Data System ("NERC GADS") Data Reporting Instructions.

6. Agreement Section 2.5 is revised to read as follows:

2.5 Inverter System Equivalent Availability Factor; Liquidated Damages; Termination Rights.

(a) Calculation of the Inverter System Equivalent Availability Factor. Following the end of each Inverter System EAF Assessment Period, the Inverter System Equivalent Availability Factor shall be calculated for such Inverter System EAF Assessment Period as follows:

$$\text{Inverter System Equivalent Availability Factor} = 100\% \times \frac{AH-EDH}{PH}$$

where:

Period Hours (PH) is the total number of hours in the Inverter System EAF Assessment Period counting twenty-four (24) hours per day. In a normal year, PH = 8,760 and in a leap year PH = 8,784 .

Available Hours (AH) is the number of hours that the Inverter System is not on Outage. It is the sum of all Service Hours (SH) + Reserve Shutdown Hours (RSH).

An "Inverter System Outage" exists whenever the entire Inverter System is not online producing electric energy and is not in a Reserve Shutdown state.

Inverter System Service Hours (SH) is the number of hours during the Inverter System EAF Assessment Period the Inverter System is online and producing or consuming electric energy to meet Company Dispatch and is not in RSH.

Inverter System Reserve Shutdown Hours (RSH) is the number of hours the Inverter System was available to the Company System but not converting electric energy or is offline at the Company's request for reasons other than Seller-Attributable Non-Generation or the measured plane of array irradiance is below the inverter manufacturer's minimum irradiance level for production. All hours between 7:00 pm and 6:00 am will be considered RSH. The Inverter System will be considered RSH in these hours, even if the system would otherwise be in an outage or derated state. For purposes of calculating the Inverter System Equivalent Availability Factor, any hours during which the Inverter System or any portion thereof is unavailable due to Force Majeure shall be deemed to be RSH for the calendar month in question. A BESS Outage or Derating can exist due to an Inverter System Outage or Derating during Inverter System Reserve Shutdown Hours and the effect of such Inverter System Outage or Derating on the BESS Availability shall be included when calculating the BESS Annual Equivalent Availability Factor in accordance with Attachment X (BESS Annual Equivalent Availability Factor).

An "Inverter System Derating" exists if the Inverter System is available for Company Dispatch, but at less than full potential output of the PV System for the given irradiance and BESS conditions, including deratings due to Seller-Attributable Non-Generation. For avoidance of doubt, if there is an Inverter System Outage there cannot also be an Inverter System Derating.

Equivalent Derated Hours (EDH) is the sum of ESADH, EPDH, and EUDH. For deratings due to inverter unavailability, the equivalent full outage hour(s) are calculated by multiplying the actual duration of the derating (hours) by the number of inverters in the Inverter System unavailable and dividing by the total number of inverters in the Inverter System. For deratings, that do not impact the availability of an entire inverter or set of entire inverters, the equivalent full outage hour(s) are calculated by multiplying the actual duration of the derating (hours) by the size of the derating (in MW) divided by the Contract Capacity.

Equivalent Seller-Attributable Derated Hours (ESADH): A Seller-Attributable Derating occurs when there is an Inverter System Derating, due to Seller-Attributable Non-Generation or deratings by Company pursuant to Section 8.3 (Company Rights of Dispatch). Each individual derating is transformed into equivalent full outage hour(s). These equivalent hour(s) are then summed.

Equivalent Planned Derated Hours (EPDH) includes Planned Deratings (PD) and Maintenance Deratings (D4). A Planned Derating is when the Inverter System experiences a derating scheduled well in advance and for a predetermined duration. A Maintenance Derating is a derating that can be deferred beyond the end of the next weekend (Sunday at midnight or before Sunday turns into Monday) but requires a reduction in capacity before the next Planned Derating (PD). Each individual derating is transformed into equivalent full outage hour(s). These equivalent hour(s) are then summed.

Equivalent Unplanned Derated Hours (EUDH): An Unplanned Derating (Forced Derating) occurs when the Inverter System experiences a derating that requires a reduction in availability before the end of the nearest following weekend. Each individual Unplanned Deration is transformed into equivalent full outage hour(s). These equivalent hour(s) are then summed.

EXAMPLE: The following is an example of an Inverter System Equivalent Availability Factor calculation and is included for illustrative purposes only. Assume the following:

- Inverter System has 10 inverters and the Facility has a Contract Capacity of 30 MWs.

- Inverter System EAF Assessment Period = first 12 full calendar months following the Commercial Operations Date (non-leap year).

- Inverter System was online and producing electric energy for 4,000 hours and was available but not producing electric energy due to lack of sufficient irradiance and BESS SOC for production for 500 hours.

- 3 Inverters were offline for 100 hours due to a Planned Derating.

- 2 Inverters were offline for 50 hours due to an Unplanned Derating.

- The Inverter System had a 3 MW derating for 100 hours due to Subscriber Organization-Attributable Non-Generation.

The Inverter System Equivalent Availability Factor would be calculated as follows:

$$PH = 8{,}760 \ hours \ in \ 12 \ calendar \ months$$

$$SH = 4{,}000 \ hours$$

$$RSH = 500 \ hours + (11 \ hours/day \ x \ 365 \ days) = 4{,}515 \ hours$$

$$AH = SH + RSH = 4{,}000 \ hours + 4{,}515 \ hours = 8{,}515 \ hours$$

$$ESADH = 100 \ hours \ x \left(\frac{3 \ MW}{30 \ MW}\right) = 10 \ hours$$

$$EPDH = 100 \ hours \ x \left(\frac{3 \ inverters}{10 \ inverters}\right) = 30 \ hours$$

$$EUDH = 50 \ hours \ x \left(\frac{2 \ inverters}{10 \ inverters}\right) = 10 \ hours$$

$$EDH = ESADH + EPDH + EUDH = 10 \ hours + 30 \ hours + 10 \ hours = 50 \ hours$$

$$EAF = 100\% \times \frac{8{,}515 - 50}{8{,}760} = 96.6\%$$

(b) Inverter System Equivalent Availability Factor Performance Metric and Liquidated Damages. For each Inverter System EAF Assessment Period, a Inverter System Equivalent Availability Factor shall be calculated as provided in accordance with Section 2.5(a) (Calculation of Inverter System Equivalent Availability Factor) to this Agreement. In the event the Inverter System Equivalent Availability Factor is less than 98**%** (the "Inverter System Equivalent Availability Factor Performance Metric") for any Inverter System EAF Assessment Period, Seller shall be subject to liquidated damages as set forth in this Section 2.5(b) (Inverter System Equivalent Availability Factor Performance Metric and Liquidated Damages). For avoidance of doubt, because the Inverter System Equivalent Availability Factor is calculated over a Inverter System EAF Assessment Period of 12 calendar months, the first month for which liquidated damages would be calculated under this Section 2.5(b) (Inverter System Equivalent Availability Factor Performance Metric and Liquidated Damages) would be the last calendar month of the initial Contract Year. If the Inverter System Equivalent Availability Factor for a Inverter System EAF Assessment Period is less than the Inverter System Equivalent Availability Factor Performance Metric, Seller shall pay, in accordance with Section 2.12. (Payment of Liquidated Damages for Failure to Achieve Performance Metrics; Limitation on Liquidated Damages), and Company shall accept, as liquidated damages for Seller's failure to achieve the Inverter System Equivalent Availability Factor Performance Metric for such Inverter System EAF Assessment Period, an amount calculated in accordance with the following formula:

Inverter System Equivalent Availability Factor	Amount of Liquidated Damages Per Calendar Month
97.9% and below	For each one-tenth of one percent (0.001) by which the Inverter System Equivalent Availability Factor for such Inverter System EAF Assessment Period falls below the Inverter System Equivalent Availability Factor Performance Metric, an amount equal to 0.001917 of the Applicable Period Lump Sum Payment for the last calendar month of such Inverter System EAF Assessment Period.

For purposes of determining liquidated damages under the preceding formula, the amount by which the Inverter System Equivalent Availability Factor for the Inverter System EAF Assessment Period in question falls below the applicable threshold shall be rounded to the nearest one-tenth of one percent (0.001). Each Party agrees and acknowledges that (i) the damages that Company would incur if the Seller fails to achieve the Inverter System Equivalent Availability Factor Performance Metric for a Inverter System EAF Assessment Period would be difficult or impossible to calculate with certainty and (ii) the aforesaid liquidated damages are an appropriate approximation of such damages.

EXAMPLE: The following is an example calculation of liquidated damages for the Inverter System Equivalent Availability Factor Performance Metric and is included for illustrative purposes only. Assume the monthly Lump Sum Payment is $1,000,000 and the Inverter System Equivalent Availability Factor is 96.6% as calculated in the example in Section 2.5(a) (Calculation of the Inverter System Equivalent Availability Factor) above.

The liquidated damages would be calculated as follows:

Applicable Period Lump Sum Payment = $1,000,000

$1,000,000 x .001917 = $1,917

98.0% - 96.6% = 1.4%

1.4%/0.1% = 14

$1,917 x 14 = $26,838

(c) Inverter System Equivalent Availability Factor Termination Rights. The Parties acknowledge that, although the intent of the liquidated damages payable under Section 2.5(b) (Inverter System Equivalent Availability Factor Performance Metric and Liquidated Damages) is to compensate Company for the damages that Company would incur if the Subscriber Organization fails to achieve the Inverter System Equivalent Availability Factor Performance Metric for a Inverter System EAF Assessment Period, such liquidated damages are not intended to compensate Company for the damages that Company would incur if a pattern of underperformance establishes a reasonable expectation that the Inverter System is likely to continue to substantially underperform the Inverter System Equivalent Availability Factor Performance Metric. Accordingly, and without limitation to Company's rights under said Section 2.6(b) (Inverter System Equivalent Availability Factor Performance Metric and Liquidated Damages) for those Inverter System EAF Assessment Periods during which the Seller failed to achieve the Inverter System Equivalent Availability Factor Performance Metric, the failure of the Facility to achieve a Inverter System Equivalent Availability Factor of not less than **84%** for each of three consecutive Contract Years shall constitute an Event of Default under the Agreement for which Company shall have the rights (including but not limited to the termination rights) set forth in Section 15. (Events of Default) and Section 16. (Damages in the Event of Termination by Company) of the Agreement.

7. **Cross references elsewhere in the Agreement to Section 2.5 and its Subsections. All Cross-References elsewhere in the Agreement to any of Section 2.5, Section 2.5(a), Section 2.5(b) and Section 2.5(c) are corrected to reflect the revised captions for those Sections as set forth above.**

8. **Agreement Section 2.6 is revised to read as follows:**

2.6 Measured Performance Ratio; Liquidated Damages; Termination Rights

(a) Calculation of Measured Performance Ratio.

(i) The Measured Performance Ratio ("MPR") represents the PV System's measured power output compared to its theoretical DC power output as adjusted for the plane of array irradiance and weather conditions measured at the Site. The net PV System output in MW will be measured at such points mutually agreed to by the Parties on the Facility's single-line diagram attached hereto as Attachment E (Single-Line Drawing and Interface Block Diagram).

(ii) Following the end of each MPR Assessment Period, the MPR shall be calculated for such MPR Assessment Period (using the previous 12 months of data) as follows:

$$MPR_{corr} = \frac{\sum_i P_{AC\_i} + \sum_i P_{DC\_i}}{\sum_i \left[P_{DC_{STC}}\left(\frac{G_{POA_i}}{G_{STC}}\right)\left(1 - \frac{\delta}{100}\left(T_{cell\_typ\_avg} - T_{cell\_i}\right)\right)\right]}$$

Where:

i = each 15-minute interval during the MPR Assessment Period where the conditions set forth in Section 2.6(a)(iii) are met.

P_{AC_i} is the active power output of the PV System measured at the POI averaged over time period i (MW)

P_{DC_i} is the measured power output of the PV System measured at the input to the BESS charging system averaged over time period i (MW)

G_{STC} = plane of array irradiance at the standard condition of 1,000 W/m^2

$P_{DC_{STC}}$ is the DC rated capacity of the PV System at the standard test conditions of 1,000 W/m^2 and 25°C (MW), (i.e., the DC power rating of the PV panels at standard test conditions multiplied by the number of PV panels in the Facility);

G_{POA_i} is the measured plane of array irradiance averaged over time period i (W/m^2);

T_{cell_i} = cell temperature computed from measured meteorological data averaged over time period i using the equation provided below. (°C)

$T_{cell\_typ\_avg}$ = annual average irradiance-weighted cell temperature computed from one year of weather data using the GPR Performance Metric weather file and the equation below. (°C) Calculated once per GPR Performance Metric.

δ = temperature coefficient for power (%/°C, negative in sign) that corresponds to the installed photovoltaic modules

$$T_{cell\_typ\_avg} = \frac{\sum_j \left[G_{POA\_typ\_j} \times T_{cell\_typ\_j}\right]}{\sum_j G_{POA\_typ\_j}}$$

Where:

j = each hour of the year in the GPR Performance Metric weather file (hours 1-8760)

$G_{POA\_typ\_j}$ = Plane of array irradiance for each hour of the year determined from the GPR Performance Metric weather file and tracker orientation. This irradiance is zero (0) when the sun is not up. (W/m^2)

$T_{cell\_typ\_j}$ = calculated cell operating temperature for each hour of the year. Computed using the equation for T_{cell_i} below but using the GPR Performance Metric weather file for the weather variables in the equation.

$$T_{cell\_i} = G_{POA_i} \times e^{(a + b \times WS_i)} + T_{a\_i} + \left(\frac{G_{POA_i}}{G_{STC}} \times dT_{cond}\right)$$

Where:

T_{a_i} = the measured ambient temperature averaged over time period i [°C]

WS_i = the measured wind speed corrected to a measurement height of 10 meters (using the anemometer height and proper Hellmann coefficient) averaged over time period i [m/s]

a = empirical constant reflecting the increase of module temperature with sunlight as presented in Table 2 below.

b = empirical constant reflecting the effect of wind speed on the module temperature as presented in Table 2 below [s/m]

e = Euler's constant and the base for the natural logarithm.

dT_{cond} = conduction temperature coefficient from module to cell as presented in Table 2 below.

Table 2. Empirical Convective Heat Transfer Coefficients Module Type	**Mount**	a	b	dT_{cond}
Glass/cell/glass	Open rack	-3.47	-0.0594	3
Glass/cell/glass	Close-roof mount	-2.98	-0.0471	1
Glass/cell/polymer sheet	Open rack	-3.56	-0.0750	3
Glass/cell/polymer sheet	Insulated back	-2.81	-0.0455	0
Polymer/thin-film/steel	Open rack	-3.58	-0.1130	3

(iii) The time periods used in the foregoing calculation shall be only periods during which, for the entire 15-minute interval, the PV System output is allowed to convert all irradiance to gross power (whether directed to the BESS or POI) and the measured plane of array irradiance is not less than 600 W/m^2 . Data points that will be excluded from the calculation of the MPR are limited to data points where: (A) the G_{POA} is below 600 W/m^2, (B) G_{POA} above the maximum threshold, (C) the Inverter System is in Reserve Shutdown, (D) when the Inverter System has a Planned or Unplanned Derating, (E) the PV System was not allowed to convert the full gross DC output to energy to deliver to the BESS and/or POI, due to Company Dispatch being less than the PV System potential at the measured irradiance and the BESS reaching its maximum State of Charge, (F) there is an Inverter System Outage, (G) the BESS is discharging, or (H) there is Force Majeure affecting the PV System or Inverter System. The aforementioned 15-minute intervals are fixed intervals that commence, in sequence, at the top of each hour and at 15, 30 and 45 minutes past the hour. At the end of each month, Subscriber Organization shall provide Company a report that lists all hours when such excluded data points occur (from the Facility's SCADA system as necessary) to validate the exclusion of any data points from the calculation set forth in Section 2.6(a)(ii) above. This information shall be validated on a monthly basis.

(iv) MPR Test. In the event that the set of operational data points under Section 2.6(a)(iii) that is available for any month to calculate the MPR cannot be validated to Company's reasonable satisfaction or in the event there were not at least 16 such data points during such month that could be used to calculate the MPR, the Company shall have the right to perform a test ("MPR Test") to collect the data points for such month to be used to calculate the MPR in lieu of the use of operational data for such month. The Company shall retain sole discretion as to when to conduct the MPR Test and the MPR Test may be conducted at any point during the month following the month for which Company was either unable to validate the set of operational data points for such month or there were not at least 16 data points available during such month, provided that Company will provide Seller three (3) Business Days' notice prior to conducting the MPR Test. The MPR Test shall have a minimum duration of four (4) hours and shall run until at least 16 data points are collected that meet the criteria set forth in Section 2.6(a)(iii), subject to the limitation set forth in the last sentence of this Section 2.6(a)(iv). To the extent possible, the Company shall schedule the MPR Test for a period where the Inverter System and BESS are fully available and weather conditions are expected to be optimum allowing the PV System to generate at full capacity for the duration of the MPR Test (if possible). However, if Company chooses a period where some of the Facility inverter(s) and/or BESS are unavailable, $P_{DC_{STC}}$ shall be adjusted to account for any reduction in capability to accept energy from the PV System due to the unavailable inverter(s) and/or BESS.

(v) For each MPR Assessment Period that includes one or more months for which a MPR Test was performed, the data points collected during said MPR Test for such month(s) shall be used together with the data points for months for which an MPR Test was not conducted to calculate the MPR for the MPR Assessment Period in question using the formula set forth in Section 2.6(a)(ii) above. The result of the calculation based on the MPR Test shall be the MPR for the MPR Assessment Period in question.

(vi) EXAMPLE: The following is an example of a Measured Performance Ratio calculation and is included for illustrative purposes only. Assume the following:

- Facility with 120,000 panels with a standard test condition rating of 300 W
- P_{DCSTC}= 120,000 X 300 W = 36 MW
- For illustrative purposes only, 4 hours of data which met the criteria specified in Section 2.6(a)(iii) have been recorded over the MPR Assessment Period. It should be noted that all available operational data that meets the criteria specified in Section 2.6(a)(iii) shall be included in the actual calculation:

Time Period	Average Measured Plane of Array Irradiance (W/m^2)	Average Measured Active Power at POI (MW)	Average Measured DC Power at BESS Charging Input (MW)	Average Measured Ambient Temperature (^oC)	10 Meter Elevation Average Measured Wind Speed (m/s)

1	690	16	0	27	3
2	850	2	21	26	8
…	…	…	…	…	…
i	750	19	1	29	7

$$MPR_{corr} = \frac{\sum_i P_{AC\_i} + \sum_i P_{DC\_i}}{\sum_i \left[P_{DC_{STC}} \left(\frac{G_{POA_i}}{G_{STC}}\right)\left(1 - \frac{\delta}{100}\left(T_{cell\_typ\_avg} - T_{cell\_i}\right)\right)\right]}$$

where:

$$T_{cell\_i} = G_{POA_i} \times e^{(a+b\times WS_i)} + T_{a\_i} + \left(\frac{G_{POA_i}}{G_{STC}} \times dT_{cond}\right)$$

Assuming:

The temperature coefficient (δ) of the installed modules is -0.4%/ºC

The average irradiance-weighted cell temperature ($T_{cell\_typ\_avg}$) has been calculated as 28ºC

The installed modules are a glass/cell/polymer sheet module type using an open rack mount. (a = -3.56; b = -0.0750; dT_{cond} = 3)

$\sum_i P_{AC\_i}$ = 16 MW + 11 MW + … + 19 MW = **255MW**

$\sum_i P_{DC\_i}$ = 0 MW + 22 MW + … + 10 MW = **50 MW**

$\sum_i \left[P_{DC_{STC}} \left(\frac{G_{POA_i}}{G_{STC}}\right)\left(1 - \frac{}{100}\left(T_{cell\_type\_avg} - T_{cell\_i}\right)\right)\right]$ = 36 MW × [(690/1000)x(1–(0.4/100)x(28-((690)x $e^{(-3.56-0.075\times3)}$+27)+((690/1000)x3)))+

(850/1000)x(1–(0.4/100)x(28–((850x $e^{(-3.56-0.075\times8)}$+26)+((850x3)))+

… +

(750/1000)x(1–(0.4/100)x(28-((750)x $e^{(-3.56-0.075\times7)}$+29+((750)x3)))]

= **374.76 MW**

MPR = (255+50) MW/ 374.76 MW = **0.814**

9. Section 3.iv of Attachment J (Company Payments for Energy, Dispatchability and Availability of BESS) is revised to read as follows:

(iv)

- Under the Company's previous forms of as-available power purchase agreements for renewable energy, the independent power producer was compensated for the production and delivery of electrical energy and assumed the risk of non-payment for events such as Force Majeure that prevented such production and delivery. Although under the Agreement most or all of Seller's compensation will be in the form of a Lump Sum Payment rather than for the production and delivery of electrical energy, it is not the intent of the Parties that Seller should be entitled to unrestricted compensation in circumstances in which an independent power producer would not have been able to earn compensation under the Company's prior form of power purchase agreements (i.e., if the Facility or any portion thereof is unable to produce and deliver electric energy). Although the liquidated damages that are payable if the Inverter System Equivalent Availability Factor fails to satisfy the Inverter System Equivalent Availability Factor Performance Metric address this issue in certain of the circumstances when the Inverter System or a portion thereof is unable to generate electric energy, the Inverter System Equivalent Availability Factor does not account for events of Force Majeure because Force Majeure hours are deemed to be Reserve Shutdown Hours for purposes of calculating the Inverter System Equivalent Availability Factor under Section 2.5(a) (Calculation of the Inverter System Equivalent Availability Factor) of the Agreement. Furthermore, in the case of the PV System, the liquidated damages that are payable if the MPR fails to satisfy the GPR Performance Metric addresses this issue in certain of the circumstances when the PV System or a portion thereof is unable to generate electric energy while inverters are available, the MPR does not account for events of Force Majeure because periods containing such events are excluded from the calculation under Section 2.6(a) (Calculation of Measured Performance Ratio) of the Agreement. Similarly, in the case of the BESS, although the liquidated damages that are payable if the BESS Annual Equivalent Availability Factor fails to satisfy the BESS EAF Performance Metric addresses this issue in certain of the circumstances when the BESS or a portion thereof is unavailable to respond to Company Dispatch, the BESS Annual Equivalent Availability Factor does not account for events of Force Majeure because Force Majeure are deemed to be Reserve Shutdown Hours for purposes of calculating the BESS Annual Equivalent Availability Factor under Attachment X (BESS Annual Equivalent Availability Factor) to the Agreement.

- Accordingly, and without limitation to the generality of the foregoing provisions of Section 3 (Calculation of Lump Sum Payment) of this Attachment B (Company Payments for Energy, Dispatchability and Availability of BESS), the monthly Lump Sum Payment shall be adjusted downward pro rata for each hour or portion thereof during the calendar month in question that the Facility or a portion thereof was not available to generate energy or respond to Company Dispatch because of a Force Majeure condition (i) affecting the Facility or any portion thereof or (ii) that otherwise delays or prevents the Seller from making the Facility or a portion thereof generate energy and make it available for Company Dispatch.

- In the case of a BESS Force Majeure, such downward adjustment in the Lump Sum Payment shall be limited to the BESS Allocated Portion of the Lump Sum Payment. Further, during any periods in which there is a Force Majeure affecting both (i) the PV System or Inverter System, and (ii) the BESS, the Lump Sum Payment shall only be adjusted for the effect of the Force Majeure on the PV System or Inverter System.

- The hours the Facility is affected by a Force Majeure are converted to equivalent full outage hours by multiplying the actual duration of the event (hours) by (i) the size of the reduction in MWs or number of devices, divided by (ii) the Contract Capacity if the size of the reduction is in MWs or the total number of devices in the affected system if the size of the reduction is a device count. These equivalent hour(s) are then summed. The summation of equivalent full outage hours is then divided by the months total period hours (number of days in the month x 24hrs/day) to determine the pro-rated factor the Lump Sum Payment will be adjusted by. To avoid any concern of double counting in this calculation any concurrent Force Majeure affecting both the PV System and Inverter System will only consider the more significantly affected system in this calculation; if the affect is equal the equivalent full outage hours from just one of the systems will be included in the calculation. For all non-concurrent Force Majeure, the equivalent full outage hours of the non-concurrent event shall be included in the summation of equivalent full outage hours for calculating the pro-rated effect on the Lump Sum Payment.

Example 1: if a Facility has ten inverter(s) and, during the month of May (which has 31 calendar days or 744 calendar hours), one inverter is not available to respond to Company Dispatch for a period of 360 hours due to a Force Majeure condition as aforesaid, the monetary amount of the resulting downward adjustment to the monthly Lump Sum Payment for the month of May would be calculated as follows:

- Monetary Amount of Downward Adjustment = (MLSP x 1/10) x 360/744

Example 2: if a Facility has ten inverter(s) and 10 MW of PV panels, and during the month of May (which has 744 period hours) an event or events of Force Majeure cause one inverter to not be available to respond to Company Dispatch for a period of 360 hours, and 2 MW of PV panels to be unavailable for 120 hours, 60 hours of which occurred concurrently with the Inverter System as aforesaid, the monetary amount of the resulting downward adjustment to the monthly Lump Sum Payment for the month of May would be calculated as follows:

First, determine what adjustment factor to use during the concurrent Force Majeure:

PV System Concurrent FM factor = 2/10

Inverter System Concurrent FM factor = 1/10

Since the PV System Concurrent FM Factor is greater than the Inverter System Concurrent FM Factor it is used during the concurrent FM time:

Monetary Amount of Downward Adjustment

$$= \text{MLSP}\,\frac{\left(1/10 \times (360 - 60)\right) + \left(2/10 \times (120 - 60)\right)}{31 * 24}$$

where**:**

MLSP = The monthly Lump Sum Payment that would be payable for such month but for the downward adjustment.

Example 3: if a Facility has forty BESS modules and, during the month of June (which has 720 period hours), one BESS module is not available to respond to Company Dispatch for a period of 240 hours due to a Force Majeure condition as aforesaid, the monetary amount of the resulting downward adjustment to the monthly Lump Sum Payment for the month of June would be calculated as follows:

Monetary Amount of Downward Adjustment	= (BLSP x 1/40) x 240/720

where:

BLSP = The BESS Allocated Portion of the Lump Sum Payment that would be payable for such month but for the downward adjustment.

For purposes of determining the monetary amount of the foregoing downward adjustment, the product obtained by multiplying a monetary value by a fraction shall be rounded to the nearest cent.

10. Section 1 (Monthly Report) of Attachment T (Monthly Reporting and Dispute Resolution By Independent AF Evaluator) is revised to read as follows:

1. Monthly Report. Commencing with the month during which the Commercial Operations Date is achieved, and for each calendar month thereafter during the Term, Seller shall provide to Company a Monthly Report in Excel, Lotus or such other format as Company may require, which Monthly Report shall include (i) the data for the calendar month in question populated into the form of "Inverter System & PV System Monthly Report" below, (ii) the data for the BESS Measurement Period ending with the calendar month in question populated into the form of "BESS Measurement Period Report" below, and (iii) Seller's calculations of the Performance Metrics and any liquidated damages assessments for the each Performance Metric Period ending with such calendar month as set forth below. Seller shall deliver such Monthly Report to Company by the fifth (5^{th}) Business Day following the close of the calendar month in question. Seller shall deliver the Monthly Report electronically to the address provided by the Company. Company shall have the right to verify all data set forth in the Monthly Report by inspecting measurement instruments and reviewing Facility operating records. Upon Company's request, Seller shall promptly provide to Company any additional data and supporting documentation necessary for Company to audit and verify any matters in the Monthly Report.

Inverter System & PV System Monthly Report
NAME OF IPP FACILITY: [Facility Name]
MONTHLY REPORT PERIOD: [Month Day, Year] to [Month Day, Year]

Enter the information for each Force Majeure event effecting the Inverter System and/or the PV System during the reporting period. Dates and times should be entered to the nearest minute. Duration and equivalent hours should be rounded to 2 decimal places. When using MWs for item (D) below, Contract Capacity is to be provided for (E); and when using number of devices for item (D), total number of devices is to be provided for (E).

Date/Time Start (A)	Date/Time End (B)	Duration (hrs) (C) = (B-A)	Size of effect in MW or Number of devices system that are offline (D)	Contract Capacity or Total number of devices in the effected system (E)	Equivalent Hours (hrs) (C x D)/E

…					

Calendar hours in the reporting period: _______________

Total equivalent hours for the reporting period (from above, with proper accounting for any simultaneous events): _______________

Omit any periods where Force Majeure was the sole cause of the Outage or Deration in the reporting areas below as those periods will be counted in their entirety as RSH per Section 2.5 (Inverter System Annual Equivalent Availability Factor) of this Agreement.

.

Enter the information for each Outage during the reporting period. Dates and times should be entered to the nearest minute. Duration should be rounded to 2 decimal places.

Date/Time Start (A)	Date/Time End (B)	Duration (hrs) (B-A)
…		

Calendar hours in the reporting period: _______________

Total Outage hours for the reporting period (from above): _______________

Available Hours (AH) in the reporting period: _______________

AH from the last eleven (11) reporting periods: _______________

AH for the last twelve (12) reporting periods: _______________

Date/Time Start (A)	Date/Time End (B)	Duration (hrs) (C) = (B-A)	Size of derating (MW) or Number of Inverters (D)	Contract Capacity or Total number of Inverters in the Inverter system (E)	Equivalent Hours (hrs) (C x D)/E

…					

Total Equivalent Seller-Attributable Derated hours (ESADH) for the reporting period: ________________

ESADH from the last eleven (11) reporting periods: ________________

ESADH for the last twelve (12) reporting periods: ________________

Enter the information for each Seller-Attributable Derating events during the reporting period. Dates and times should be entered to the nearest minute. Duration and equivalent hours should be rounded to 2 decimal places. When using MWs for item (D) below, Contract Capacity is to be provided for (E); and when using number of inverters for item (D), total number of inverters is to be provided for (E).

Enter the information for each Planned Derating event during the reporting period. Dates and times should be entered to the nearest minute. Duration and equivalent hours should be rounded to 2 decimal places. When using MWs for item (D) below, Contract Capacity is to be provided for (E); and when using number of inverters for item (D), total number of inverters is to be provided for (E).

Date/Time Start (A)	Date/Time End (B)	Duration (hrs) (C) = (B-A)	Size of derating (MW) or Number of Inverters (D)	Contract Capacity or Total number of Inverters in the Inverter system (E)	Equivalent Hours (hrs) (C x D)/E
…					

Total equivalent planned derated hours (EPDH) for the reporting period: ________________

EPDH from the last eleven (11) reporting periods: ________________

EPDH for the last twelve (12) reporting periods: ________________

Enter the information for each Unplanned Derating event during the reporting period. Dates and times should be entered to the nearest minute. Duration and equivalent hours should be rounded to 2 decimal places. When using MWs for item (D) below, Contract Capacity is to be provided for (E); and when using number of inverters for item (D), total number of inverters is to be provided for (E).

Date/Time Start (A)	Date/Time End (B)	Duration (hrs) (C) = (B-A)	Size of derating (MW) or Number of Inverters (D)	Contract Capacity or Total number of Inverters in the Inverter system (E)	Equivalent Hours (hrs) (C x D)/E
…					

Total equivalent unplanned derated hours (EUDH) for the reporting period: _______________

EUDH for the last eleven (11) reporting periods: _______________

EUDH for the last twelve (12) reporting periods: _______________

Period Hours (PH) is : _______ (8760 hours if no 29th day in February in the last twelve months; otherwise 8784 hours)

Enter the Available Hours, ESADH, EPDH, and EUDH for the last twelve (12) reporting periods as calculated above.

AH (A)	ESADH (B)	EPDH (C)	EUDH (D)	Inverter System Annual Equivalent Availability Factor 100% x (A – B – C - D)/PH

Enter the following properties for the facility's PV panels that are used in the calculation of the Measured Performance Ratio. Refer to Section 2.5(a) (Calculation of Inverter System Equivalent Availability Factor) and Section 2.6(a) (Calculation of Measured Performance Ratio) of the Agreement for the definitions of terms.

DC rated capacity of the system at standard test conditions ($P_{DC_{STC}}$): _______________

Temperature coefficient of power in %/°C(δ): _______________

Temperature empirical constant (a): _______________

Wind speed empirical constant (b): _______________

Conduction temperature coefficient (dT_{cond}): _______________

Annual average irradiance-weighted cell temperature ($T_{cell\_typ\_avg}$) ______________

For the reporting period, provide 15-minute interval averaged site data for the following measurements in .csv format. The data set should include an indication of whether each interval is included or excluded in the calculation of the Measured Performance Ratio and the reason for exclusion (refer to Section 2.6(a) (Calculation of Measured Performance Ratio) of the Agreement for data requirements and defined terms).

Measured data:

- P_{AC_i} is the active power output of the PV System measured at the POI averaged over time period i (MW)
- P_{DC_i} is the measured DC power output of the PV System measured at the DC input to the BESS charging system averaged over time period i (MW)
- G_{POA_i} is the measured plane of array irradiance averaged over time period i (W/m^2);
- T_{a_i}= the measured ambient temperature averaged over time period i [°C]
- WS_i= the measured wind speed corrected to a measurement height of 10 meters (using the anemometer height and proper Hellmann coefficient) averaged over time period i [m/s]

Calculated data:

- Computed cell temperature (T_{cell_i})

Using the data provided above, enter the calculated values for Measured Performance Ratio rounded to the third decimal place (0.001).

Measured Performance Ratio for the reporting period: ______________

Measured Performance Ratio for this reporting period and the previous eleven (11) reporting periods: ______________

Enter the Applicable Contract Year and calculated Degradation Factor for the reporting period. Refer to Section 2.6(c) (GPR Performance Metric and Liquidated Damages) of the Agreement for how these should be calculated.

Applicable Contract Year: ______________

Degradation Factor: ______________

BESS Measurement Period Report
NAME OF IPP FACILITY: [Facility Name]
BESS MEASUREMENT PERIOD: [Month Day, Year] to [Month Day, Year

Enter the applicable information to demonstrate satisfaction of the BESS Capacity Performance Metric during the reporting period. This can be from either the most recent BESS Capacity Test performed during the period or taken from operational data reflecting the net output of the BESS.

Date/Time Start	Date/Time End	Total MWh delivered to the POI (A)	BESS Contract Capacity (MWh) (B)	BESS Capacity Ratio 100% x (A/B)

Enter the applicable information to demonstrate satisfaction of the BESS RTE Performance Metric during the reporting period. This can either be from the most recent BESS RTE Test performed during the period or taken from operational data reflecting the charging/discharging of the BESS.

Date/Time Start	Date/Time End	Total MWh delivered to the POI (A)	Charging Energy (MWh) (B)	BESS RTE Ratio 100% x (A/B)

Enter the information for each Force Majeure event effecting the BESS during the reporting period. Dates and times should be entered to the nearest minute. Duration, size of reduction, BESS Contract Capacity (MW), and equivalent hours should be rounded to 1 decimal place. When using MWs for item (D) below, BESS Contract Capacity is to be provided for (E); and when using number of inverters for item (D), total number of inverters is to be provided for (E).

Date/Time Start (A)	Date/Time End (B)	Duration (hrs) (C) = (B-A)	Size of Reduction (MW) or Number of BESS Modules Affected (D)	BESS Contract Capacity (MW) or Total Number of BESS Modules (E)	Equivalent Hours (hrs) (C x D)/E
…					

Calendar hours in the reporting period: ___________________

Total equivalent hours for the reporting period (from above, with proper accounting for any simultaneous events): ________________

Please provide the following BESS availability information even in months containing Force Majeure. Omit any periods where Force Majeure was the sole cause of the Outage or Deration in the reporting areas below as those periods will be counted in their entirety as RSH per Attachment X (BESS Annual Equivalent Availability Factor) of this Agreement.

Enter the information for each BESS Outage during the reporting period. Dates and times should be entered to the nearest minute. Duration should be rounded to 1 decimal place.

Date/Time Start (A)	Date/Time End (B)	Duration (hrs) (B-A)
…		

Calendar hours in the reporting period: ______________

Total Outage hours for the reporting period (from above): ______________

Available Hours (AH) in the reporting period: ______________

AH from the last three (3) reporting periods: ______________

AH for the last four (4) reporting periods: ______________

Enter the information for each BESS Planned Derating event during the reporting period. Dates and times should be entered to the nearest minute. Duration, size of reduction, BESS Contract Capacity (MW), and equivalent hours should be rounded to 1 decimal place.

Date/Time Start (A)	Date/Time End (B)	Duration (hrs) (C) = (B-A)	Size of Reduction (MW) (D)	BESS Contract Capacity (MW) (E)	Equivalent Hours (hrs) (C x D)/E
…					

Total equivalent planned derated hours (EPDH) for the reporting period: ____________

EPDH from the last three (3) reporting periods: ____________

EPDH for the last four (4) reporting periods: ____________

Enter the information for each BESS Unplanned Derating event during the reporting period. Dates and times should be entered to the nearest minute. Duration, size of reduction, BESS Contract Capacity (MW), and equivalent hours should be rounded to 1 decimal place.

Date/Time Start (A)	Date/Time End (B)	Duration (hrs) (C) = (B-A)	Size of Reduction (MW) (D)	BESS Contract Capacity (MW) (E)	Equivalent Hours (hrs) (C x D)/E
…					

Total equivalent unplanned derated hours (EUDH) for the reporting period: _____________

EUDH for the last three (3) reporting periods: _____________

EUDH for the last four (4) reporting periods: _____________

Period Hours (PH) is : _______ (8760 hours if no 29^{th} day in February in that last twelve months; otherwise 8784 hours).

Enter the Available Hours, EPDH, EUDH, and Period Hours for the last four (4) reporting periods as calculated above.

AH (A)	EPDH (B)	EUDH (C)	BESS Annual Equivalent Availability Factor 100% x (A – B – C)/PH

Enter the information for each Unplanned (Forced) Outage during the reporting period. Dates and times should be entered to the nearest minute. Duration should be rounded to 1 decimal place.

Date/Time Start (A)	Date/Time End (B)	Duration (hrs) (B-A)
…		

Total Forced Outage Hours (FOH) for the reporting period (from above): ______________

FOH from the last three (3) reporting periods: ______________

FOH for the last four (4) reporting periods: ______________

Enter the FOH and EUDH for the last four (4) reporting periods as calculated above.

FOH (A)	EUDH (B)	BESS Annual Equivalent Forced Outage Factor 100% x (A + B)/8760

If the BESS Measurement Period for which this report has been prepared contains a month with a BESS Force Majeure event, please indicate the proper 12-month period used to calculate the BESS Annual Equivalent Availability Factor for this report.

11. Attachment W (BESS TESTS) is revised to read as follows:

ATTACHMENT W
BESS TESTS

Prior to achieving Commercial Operations, and in each BESS Measurement Period, unless waived by Company, Seller shall demonstrate that the BESS satisfies the (1) BESS Capacity Performance Metric, and (2) the RTE Performance Metric, each as defined and further described below.

BESS Capacity Performance Metric

- The BESS Capacity Performance Metric reflecting the net output of the BESS from the Point of Interconnection can be demonstrated either through (i) operational data or (ii) a scheduled formal BESS Capacity Test.
- The "BESS Capacity Performance Metric" shall be deemed to be satisfied where the BESS Capacity Ratio is not less than **100%** for an applicable BESS Measurement Period. The "BESS Capacity Ratio" shall be the number, expressed as a percentage, equal to the total "Discharge Energy" (MWh discharge) delivered to the Point of Interconnection to bring the BESS from (i) its maximum State of Charge or (ii) 100% State of Charge to a 0% State of Charge, divided by the BESS Contract Capacity.
- A "BESS Capacity Test" is when the Company coordinates Company Dispatch to demonstrate the BESS maintains the power output required to follow the dispatch signal provided by the Company through a control setpoint, as measured at the Point of Interconnection, and is able to continuously discharge energy to the Point of Interconnection according to Company Dispatch to bring the BESS from (i) its maximum State of Charge or (ii) 100% State of Charge to a 0% State of Charge.
- The BESS Capacity Test can only be performed when the BESS is at the lower of: (i) its maximum State of Charge or (ii) 100% State of Charge prior to the start of the BESS Capacity Test and during the BESS Capacity Test, Company Dispatch allows for continuous discharge of the BESS to 0% State of Charge with energy delivered to the Point of Interconnection.

RTE Performance Metric.

- The "RTE Performance Metric" is set forth in the Project Specific Addendum. The RTE Performance Metric reflecting the charging/discharging of the BESS can be demonstrated either through (i) operational data or (ii) a scheduled formal RTE Test.

- Demonstration of the RTE Performance Metric requires measurement of "Charging Energy" (MWh charge) at the BESS charging input to bring the BESS from a 0% State of Charge to a 100% State of Charge from the PV System or grid according to Company Dispatch, followed by measurement at the Point of Interconnection of the "Discharge Energy" (MWh discharge) delivered to the grid to bring the BESS to a 0% State of Charge according to Company Dispatch. The exact point of measurement for Charging Energy will be mutually agreed to by the Parties on the Facility's single-line diagram attached to the Agreement as Attachment E (Single-Line Drawing and Interface Block Diagram). For the purposes of evaluating satisfaction of the RTE Performance Metric, the "RTE Ratio" shall be the number, expressed as a percentage, equal to the total Discharge Energy delivered to the Point of Interconnection during the BESS Capacity Test, divided by the Charging Energy measured at the BESS charging input.

- The formula for the RTE Ratio is as follows: RTE Ratio = 100% x (MWh discharge)/(MWh charge)

- The RTE Performance Metric will be deemed to have been "passed" or "satisfied" to the extent the RTE Ratio is not less than the RTE Performance Metric set forth in Section 2.11(a) (RTE Test and Liquidated Damages) of the Agreement.

- An "RTE Test" is when the Company coordinates Company Dispatch to demonstrate the charging/discharging requisite to satisfy the RTE Performance Metric.

- The RTE Test may be conducted concurrently with a BESS Capacity Test.

- For purposes of the RTE Test, the charging cycle shall begin when the BESS is at a 0% State of Charge prior to a (i) 100% discharge cycle or (ii) BESS Capacity Test if being conducted concurrently and the Charging Energy is the amount of energy, as measured at the BESS DC charging input, that brings the BESS to a 100% State of Charge.

BESS Test Procedures

- After Commercial Operations, Seller shall demonstrate satisfaction of the BESS Capacity Performance Metric by reference to the operational data reflecting the net output of the BESS from the Point of Interconnection, or by conducting a scheduled formal BESS Capacity Test during such BESS Measurement Period. Once Seller demonstrates satisfaction of the BESS Capacity Performance Metric through either operational data or a scheduled formal BESS Capacity Test (100% discharge cycle), the BESS shall be deemed to have met the BESS Capacity Performance Metric and satisfied ("passed") the BESS Capacity Test for the applicable BESS Measurement Period.

- After Commercial Operations, Seller shall demonstrate satisfaction of the RTE Performance Metric by reference to the operational data reflecting the charging/discharging of the BESS, or by conducting a scheduled formal RTE Test during such BESS Measurement Period. Once Seller demonstrates satisfaction of the RTE Performance Metric through either operational data or a scheduled formal RTE Test (100% charge/discharge cycle), the BESS shall be deemed to have met the RTE Performance Metric and satisfied ("passed") the RTE Test for the applicable BESS Measurement Period.

- Any BESS Capacity Test or RTE Test (each a "BESS Test" and collectively, the "BESS Tests") scheduled in lieu of being demonstrated by reference to operational data as provided below shall be performed at a time reasonably requested by Company in its sole discretion.

- Seller shall be permitted up to a total of three (3) BESS Tests (100% discharge cycles) within a BESS Measurement Period to demonstrate satisfaction of the BESS Capacity Performance Metric and the RTE Performance Metric for such BESS Measurement Period, unless additional such tests are authorized by Company. If upon completion of the first BESS Test, Seller does not "pass" either the BESS Capacity Test or the RTE Test, Company shall attempt to notice up to two (2) additional BESS Tests within a BESS Measurement Period, for Subscriber Organization to further demonstrate its performance. If a scheduled formal BESS Test is requested by Seller, Company shall attempt to schedule a formal BESS Test and Company shall provide notice to Seller no less than three (3) Business Days prior to conducting such scheduled formal BESS Test.

- If, during a BESS Measurement Period, Seller fails to pass a BESS Capacity Test, the BESS shall nevertheless be deemed to have satisfied the BESS Capacity Performance Metric for the applicable BESS Measurement Period if (i) Company failed to notice up to three BESS Capacity Tests in order for Seller to further demonstrate the BESS' performance during such BESS Measurement Period, or (ii) Seller was unable to perform at least two (2) such noticed BESS Capacity Tests during such BESS Measurement Period due to (a) conditions on the Company System other than Seller-Attributable Non-Generation or (b) an act or omission by Company. If Seller-Attributable Non-Generation is the cause for the inability to demonstrate the BESS Capacity Performance Metric, the BESS Capacity Ratio used to assess liquidated damages shall be the highest demonstrated in operational data or the most recently completed test during the applicable BESS Measurement Period.

- If, during a BESS Measurement Period, Seller does not demonstrate satisfaction of the BESS Capacity Performance Metric through operational data or a BESS Capacity Test, assessment of Liquidated Damages will be based on the last of the BESS Capacity Tests performed.

- If, during a BESS Measurement Period, Seller fails to pass an RTE Test, the BESS shall nevertheless be deemed to have satisfied the RTE Performance Metric for the applicable BESS Measurement Period if (i) Company failed to notice up to three RTE Tests in order for Seller to further demonstrate the BESS' performance during such BESS Measurement Period, or (ii) Seller was unable to perform at least two (2) such noticed RTE Tests during such BESS Measurement Period due to (a) conditions on the Company System other than Seller-Attributable Non-Generation or (b) an act or omission by Company. If Seller-Attributable Non-Generation is the cause for not adequately demonstrating the RTE Performance Metric, the RTE Ratio used to assess liquidated damages shall be the highest demonstrated in operational data or the most recently completed test during the applicable BESS Measurement Period.

- If, during a BESS Measurement Period, Seller does not demonstrate satisfaction of the RTE Performance Metric through operational data or RTE Tests, assessment of liquidated damages will be based on the last of the RTE Tests performed.

- Company will conduct any necessary BESS Test(s) through Company Dispatch. Company shall have the right to attend, observe and receive the results of all BESS Tests. Seller shall provide to Company the results of each BESS Test (including time stamped graphs of system performance based in operational data or test data) no later than ten (10) Business Days after any BESS Test.

12. Attachment X (BESS Annual Equivalent Availability Factor) is revised to read as follow:

ATTACHMENT X
BESS ANNUAL EQUIVALENT AVAILABILITY FACTOR

To the extent the Commercial Operations Date occurs on a date other than the first day of a BESS Measurement Period, the period between the Commercial Operations Date and the first day of the next BESS Measurement Period if any, shall be ignored for purposes of this BESS Availability Factor.

For the purposes of calculating the BESS Annual Equivalent Availability Factor for the first three (3) full BESS Measurement Periods in the first Contract Year, the calculation will assume that the BESS is one hundred percent (100%) available for the remaining hours of the Contract Year. If an Inverter System Outage or Derating exists as set forth in Section 2.5(a) (Calculation of the Inverter System Equivalent Availability Factor) of the Agreement, those hours will be excluded in the BESS Annual Equivalent Availability Factor, except Inverter System Outages or Deratings that effect BESS availability but which occur during Inverter System Reserve Shutdown Hours as set forth in this Attachment X (Bess Annual Equivalent Availability Factor).

"BESS Annual Equivalent Availability Factor" shall be calculated as follows:

$$\text{BESS Annual Equivalent Availability Factor} = 100\% \times \frac{AH-EPDH-EUDH}{PH}$$

Where:

PH is period hours (8760 hours; except leap year is 8784).

Available Hours (AH) is the number of hours that the BESS is not on Outage. It is sum of all Service Hours (SH) + Reserve Shutdown Hours (RSH).

A "BESS Outage" exists whenever the entire BESS is offline and unable to charge or discharge electric energy and is not in Reserve Shutdown state.

If the Inverter System is in Reserve Shutdown but would have otherwise been on Outage the Inverter System Outage is counted as a BESS Outage during that period due to its effect on the BESS Availability.

Service Hours (SH) is the number of hours during the applicable BESS Measurement Period and the immediately preceding three (3) full BESS Measurement Periods the BESS is online and (i) charging from the PV System or Company System, or (ii) discharging electric energy to the Company System.

Reserve Shutdown Hours (RSH) is the number of hours during the applicable BESS Measurement Period and the immediately preceding three (3) full BESS Measurement Periods the BESS is available but not charging or discharging electric energy or is offline at the Company's request for reasons other than Seller-Attributable Non-Generation or there is an Inverter System Outage or Derating as set forth in Section 2.5(a) (Calculation of Inverter System Equivalent Availability Factor) of this Agreement. For purposes of calculating the BESS Annual Equivalent Availability Factor, any hours during which the BESS or any portion of the BESS is unavailable due to Force Majeure shall be deemed to be Reserve Shutdown Hours for the calendar month in question.

A "BESS Derating" exists when the BESS is available but at less than BESS Contract Capacity (MW). For the avoidance of doubt, if there is a BESS Outage occurring there cannot also be a BESS Derating. If the Inverter System is in Reserve Shutdown but would have otherwise had a derating the Inverter System Derating is counted as a BESS Derating during that period due to its effect on the BESS availability.

EPDH is the equivalent planned derated hours, including Planned Deratings (PD) and Maintenance Deratings (D4). A Planned Derating is when the BESS experiences a derating scheduled well in advance and for a predetermined duration. A Maintenance Derating is a derating that can be deferred beyond the end of the next weekend (Sunday at midnight or before Sunday turns into Monday) but requires a reduction in capacity before the next Planned Derating (PD). Each individual derating is transformed into equivalent full outage hour(s) by multiplying the actual duration of the derating (hours) by (i) the size of the reduction (MW) divided by (ii) BESS Contract Capacity (MW). These equivalent hour(s) are then summed for the applicable BESS Measurement Period and the immediately preceding three (3) full BESS Measurement Periods. If the Inverter System is experiencing a Planned Derating as set forth in Section 2.5(a) (Calculation of Inverter System Equivalent Availability Factor) any BESS Planned Derating during the Inverter System Planned Derating is excluded from the BESS EPDH calculation.

EUDH is the equivalent unplanned derated hours. An Unplanned Derating (Forced Derating) occurs when the BESS experiences a derating that requires a reduction in availability before the end of the nearest following weekend. Unplanned Deratings include those due to Seller-Attributable Non-Generation effecting BESS availability, but which occur during Inverter System Reserve Shutdown Hours. Each individual Unplanned Derating is transformed into equivalent full outage hour(s) by multiplying the actual duration of the derating (hours) by (i) the size of the reduction (MW) divided by (ii) the BESS Contract Capacity. These equivalent hour(s) are then summed for the applicable BESS Measurement Period and the immediately preceding three (3) full BESS Measurement Periods. If the Inverter System is experiencing an Unplanned Derating as set forth in Section 2.5(a) (Calculation of Inverter System Equivalent Availability Factor) any BESS Unplanned Derating during the Inverter System Unplanned Derating is excluded from the BESS EUDH calculation.

The following examples are provided as illustrative examples only:

Example A: The BESS was continuously available, with no Planned or Unplanned (Forced) Deratings during the applicable BESS Measurement Period and in the immediately preceding three (3) full BESS Measurement Periods. In this case AH = 8760, EPDH and EUDH = 0 hours

$$\text{BESS EAF} = 100\% \times \frac{8{,}760-0}{8{,}760} = 100\%$$

Example B: During the applicable BESS Measurement Period and the immediately preceding three (3) full BESS Measurement Periods. The BESS was online and charging from the PV System or discharging electric energy to the Company System for 8,400 hours and was available but not discharging electric energy due to lack of stored energy (i.e., not Seller-Attributable Non-Generation) for 226 hours. The BESS experienced a Planned Derating of 7.2 MWs for 100 hours for maintenance that was scheduled a month in advance. The BESS also experienced an Unplanned Derating of 6.2 MWs for 100 hours as the derating could not be deferred to beyond the nearest following weekend.

The Inverter System experienced a 4 MW Unplanned Derating for 35 hours not during RSH (i.e., an Inverter System Derating, as set forth in Section 2.5(a) (Calculation of Inverter System Equivalent Factor) of this Agreement. The BESS Contract Capacity (MW) is 10 MW.

Inverter System Derating = (35 hours x 4MW/10MW) = 14 hours

PH = 8,760 hours in 12 calendar months

SH = 8,400 hours

RSH = 226 hours + 14 hours

AH = SH + RSH = 8,400 hours + 226 hours = 8,640 hours

EPDH = 100 hours x 7.2MW/10MW = 72 hours

EUDH = 100 hours x 6.2MW/10MW = 62 hours (Unplanned Derating (Forced Derating))

BESS EAF = $100\% \times \frac{8{,}640-72-62}{8{,}760} = 97.1\%$