BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 175

In the Matter of:	)	
Biennial Determination of Avoided Cost	)	**JOINT INITIAL COMMENTS**
Rates for Electric Utility Purchases from	)	**OF CCEBA AND NCSEA**
Qualifying Facilities – 2021	)	
	)	

JOINT INITIAL COMMENTS OF CCEBA AND NCSEA

I. INTRODUCTION

Circumstances have changed significantly since the North Carolina Utilities Commission ("Commission") issued the April 15, 2020 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* in Docket E-100, Sub 158 ("Sub 158 Order"). The Sub 158 Order brought about a new paradigm in North Carolina qualified facility contracts. The Sub 158 Order approved the payment by qualified facility ("QF") owners for costs of the utility's ancillary services used to integrate the QF's solar generation onto the grid,[1] continued reliance on significant forward natural gas prices in establishing avoided energy costs,[2] and ongoing use of the peaker methodology in calculating avoided cost rates. The order also posed a series of questions for Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP") (DEC and DEP collectively "Duke"), Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina ("Dominion") (Duke and Dominion collectively the "Utilities"). Subsequently, in Docket No. E-100, Sub 167, the Utilities requested that the Commission extend the time for them

[1] Sub 158 Order, p. 95.
[2] *Id*. at 59.

to answer some of the issues laid out in the Sub 158 Order.[3] The Commission granted this request,[4] leading us to the current proceeding. However, in the meantime, another major change in North Carolina energy policy occurred.

On October 13, 2021, Governor Cooper signed into law House Bill 951[5] ("HB 951"), directing the Commission to take all reasonable steps to achieve a 70% reduction in Duke's carbon levels by the year 2030 and carbon neutrality by the year 2050. Pursuant to HB 951, the Commission is required to develop a plan ("Carbon Plan"), by December 31, 2022, to achieve these emission reductions, and to review the Carbon Plan every two years. On November 19, 2021, the Commission issued an Order in Docket No. E-100, Sub 179 initiating the process of developing a Carbon Plan.

Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Joint Initial Statement and Exhibits ("Joint Initial Statement") in this proceeding was filed on November 1, 2021, just weeks following the signing into law of HB 951. While it may have been understandable at the time, Duke did not consider the Carbon Plan in its Avoided Cost calculations even though this Commission's approval of a plan for compliance with the HB 951 mandates will materially change the mix of resources that will be built or procured over the avoided cost planning horizon.[6] As set forth below, the proposals made by Duke in its Joint Initial Statement do not reflect the reality of North Carolina electric

---

[3] *See, Duke Energy Carolinas, LLC, Duke Energy Progress, LLC's and Dominion Energy North Carolina's Notification of Intended Compliance with N.C. Gen. Stat. 62-156(b), Request for Continuance of Compliance with Certain 2020 Filing Requirements, and Request to Prospectively Modify Timing of Biennial Proceedings*, Docket No. E-100, Sub 167 (October 20, 2020).
[4] *Order Granting Continuance and Establishing Reporting Requirements*, Docket No. E-100, Sub 167 (October 30, 2020).
[5] S.L. 2021-165.
[6] *See*, Duke Response to NCSEA DR2-2 ("The assumptions for the Carbon Plan are still under development and not available as of this data request. The Companies did not rely upon the Carbon Plan in developing their avoided cost rates filed in this docket.").

generation market structures post HB 951 enactment. Specifically, the peaker method is highly unlikely to reflect the marginal unit being avoided in a state where, in less than eight years, generation must be 70% clean and 100% clean just two decades later. Reliance on assumptions related to the cost of a new CT unit or other cost assumptions related to carbon-emitting generation assets should be re-visited in light of HB 951 and the resulting Carbon Plan.

Moreover, the requirement to procure a majority of generation from non-carbon emitting sources, such as solar facilities, requires reevaluation of costs and fees currently being imposed on those resources. Duke's Solar Integration Services Charge ("SISC") (and Dominion's Re-Dispatch Charge) currently imposes costs on third-party clean energy providers despite the fact that once the Carbon Plan is finalized, these types of generation resources will and must be the norm, not the exception. To comply with its new clean energy mandate, Duke must plan and operate its system to optimally integrate very large quantities of interconnected clean energy resources. Helpfully, and as discussed below, these resources can provide valuable ancillary services for the North Carolina grid that will help facilitate their own integration and help support the stability of the grid. Those services need to be recognized in fact and encouraged economically to lower the system-wide costs of meeting North Carolina's clean-energy mandates.

II. SUPPORT FOR SACE'S INITIAL COMMENTS

Carolinas Clean Energy Business Association ("CCEBA") and North Carolina Sustainable Energy Association ("NCSEA") (CCEBA and NCSEA jointly the "Joint Commenters") have reviewed the Initial Comments of the Southern Alliance for Clean Energy ("SACE") in this docket and generally agree with and support the positions set forth in those comments. In particular, Joint Commenters agree with the following positions taken by SACE:

- State law requires system flexibility enhancements going forward;
- An aeroderivative gas turbine is the appropriate avoided capacity resource in the near term;
- Hydrogen-capable turbines and associated infrastructure upgrade costs should be used to calculate avoided capacity costs in the near future;
- Duke's natural gas commodity price forecast methodology should be revised;
- The updated Solar Integration Service Charge is flawed;
- QFs can provide positive ancillary services and should be compensated for doing so;
- Duke's avoided costs for non-carbon resources should be based on the cost of such resources assumed in the Carbon Plan;[7]
- Dominion should have utilized aeroderivative gas turbines in its avoided capacity calculations;
- Dominion's near-term natural gas price commodity forecast is reasonable; and
- Dominion's Re-Dispatch Charge has increased exponentially and appears to be in error.

Joint Commenters will not reiterate the points made by SACE, but offer additional support to the initial comments of SACE, as well as independent arguments, as set forth below.

III. ANCILLARY SERVICES

In its Sub 158 Order the Commission required Duke to assess:

> [W]hether a QF that can sufficiently demonstrate its ability, and contractually obligates itself to operate in a manner that provides positive ancillary service benefits at a lower cost than the utility's own conventional resources, should be appropriately compensated for those benefits, and an

[7] Joint Commenters support the concept of incorporating the requirements of HB 951 and the Carbon Plan into avoided cost rates, especially considering Governor Cooper's Executive Order 246 encouraging the Commission to include the social costs of carbon in the development of the Carbon Plan. As to the specifics of SACE's proposals, Joint Commenters reserve the opportunity to further review and provide reply comments.

identification of mechanisms to quantify the ancillary service benefits that such innovative QFs can provide.[8]

In its Joint Initial Statement, Duke concluded that after "investigating this complex issue" that "a QF selling 'must take' energy under PURPA cannot provide incremental positive ancillary services value under current system operations."[9] Duke listed a number of reasons why it believes this to be the case, including:

1. Duke does not have sufficient operational control over QFs;
2. The "must take" structure of existing QF power purchase agreements ("PPAs") is not compatible with QFs offering ancillary services; and
3. The peaker method already includes consideration of ancillary services.

Joint Commenters disagree with Duke's conclusions for the reasons listed below:

1. Duke's characterization of operational control of QFs is incomplete, and the changes required to facilitate the provision of ancillary services from QFs are easily attainable;
2. QFs already provide certain ancillary services to Duke without compensation, which is unjust and unreasonable.
3. QF operations and PPAs could be modified to incentivize the provision of valuable ancillary services;
4. The peaker method does not include the provision of, and compensation for, ancillary services;
5. Duke's assessment fails to address or consider the ability of new solar and solar + storage facilities to provide additional ancillary services.

As noted in item #5, the evaluation of solar and solar + storage's ability to provide ancillary services should not be limited to QFs with existing PPAs. Given the expected increase in solar and solar + storage capacity in the Duke balancing authorities in coming years, Duke should be planning for a system in which ancillary services can be and are provided by a broad range of resources, providing Duke's grid operators the ability to draw from geographically diverse resources to provide the ancillary services needed to maintain

[8] Sub 158 Order at 136 (Ordering Paragraph 24).
[9] Joint Initial Statement at 34.

reliability on a least-cost basis. This assessment should include technical, commercial, and operational requirements that will allow Duke to maximize the value of these resources and for the owners of those resources to be fairly compensated.

Because of the distinction between existing and new solar facilities, the discussion below first responds to Duke's assertions in the Joint Initial Statement related to existing QFs; it then discusses options and opportunities related to *new* solar and solar + storage facilities.

A. Duke's characterization of operational control of QFs is incomplete, and the changes required to facilitate the provision of ancillary services from QFs are easily attainable.

Duke states that "a fundamental aspect of [ancillary services] is that system operators must have control over the assets to dispatch them quickly as need arises…At this time, DEC and DEP system operators do not have such control over third-party QF resources."[10]

However, Duke significantly overstates the technical barriers to the provision of ancillary services by existing QFs. Existing QFs may already be equipped with automatic generation control ("AGC") capability that would allow them to currently, or with limited modification, provide ancillary services.[11] The extent of required modification would depend on the existing capabilities of the QF. QFs with advanced control capabilities would not require additional hardware, only a software modification to allow the existing hardware to perform additional functionality. QFs without advanced control capabilities could be evaluated to determine the feasibility of performing necessary upgrades to enable

[10] Joint Initial Statement at 35.

[11] Some existing QFs may have AGC capability but currently lack certain control technologies that would enable utilization of the AGC. Some newer QFs may also have both the AGC capability and the additional control technology required for the provision of numerous ancillary services.

such capabilities. Joint Commenters anticipate that upgrades to enable existing QFs to provide additional services could be made without substantial cost, and existing technical barriers to the provision of ancillary services are imminently solvable, provided that Duke is willing to engage with QFs to establish the necessary communication and data exchange. For existing QFs with many years of useful life remaining, and for new solar facilities expected to come online in coming years, the benefits that can be provided to the grid from the ability of these resources to provide ancillary services far outweigh the cost to facilitate their availability, and the Commission should require Duke to proactively work with stakeholders to pursue these efforts.

B. QFs already provide certain ancillary services to Duke without compensation, which is unjust and unreasonable.

Existing QFs are capable of providing voltage support, also known as reactive power. Reactive power, one type of ancillary service, is either generated or absorbed by electric generators to maintain a constant voltage level. Duke's Interconnection Agreement ("IA"), under the section entitled "Reactive Power", requires Interconnection Customers to "maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Utility has established different requirements that apply to all similarly situated generators in the control area on a comparable basis."[12] The IA further states:

> The Utility is required to pay the Interconnection Customer for reactive power that the Interconnection Customer provides or absorbs from the Generating Facility when the Utility requests the Interconnection Customer to operate its Generating Facility outside the range specified in Article 1.8.1 or outside the range established by the Utility that applies to all similarly situated generators in the control area. In addition, if the Utility pays its own

[12] Duke Interconnection Agreement, Section 1.8.1.

or affiliated generators for reactive power service within the specified range, it must also pay the Interconnection Customer.[13]

Simply by maintaining a composite power delivery at the prescribed power factor, QFs are providing a grid service, for which QFs are not currently compensated. The IA requires that if Duke pays its own or affiliated generators for reactive power within the specified range (i.e., 0.95 leading to 0.95 lagging), it must also pay the QF. The IA also requires that if Duke requests that the QF operate outside of the prescribed power factor, Duke must compensate the QF. Joint Commenters have submitted a data request to Duke regarding the extent to which Duke compensates its own generators for the provision of ancillary services, but as of the date of these comments Duke has not yet provided a response. To the extent Duke compensates its own or affiliated generators for the provision of reactive power, QFs providing such services must receive commensurate compensation. If Duke requests that a QF operate outside of the specified range, the QF must similarly be compensated.

It should be noted that Duke provides reactive power from its own renewable facilities in other jurisdictions. As discussed in comments filed by Duke in FERC's ongoing proposed rulemaking on reactive power compensation, Duke has advocated for a fixed compensation regime. Duke's interest in ancillary services stems from the fact that its "franchised utilities receive revenues for reactive power under [FERC] approved tariffs or rate schedules and reactive power compensation is an important component of consideration in our commercial renewables business."[14] Further, Duke supports a fixed compensation mechanism for reactive power that "provides a revenue stream for system

[13] Duke Interconnection Agreement, Section 1.8.2.
[14] Comments of Duke Energy Corporation, at 1, Federal Energy Regulatory Commission Docket No. RM22-2-000 (February 22, 2022) (attached as **Exhibit 1**).

cost recovery that reasonably matches the capability of the system, facilitates project financing, and is a key driver to the robust renewable build-out our nation is experiencing."[15] Regarding inverter-based resource ancillary services and degradation of VAR production, Duke pointed out the lack of degradation on the inverter elements (versus panels) and stressed that "generation owners must have a reasonable opportunity to recover the fixed costs related to their voltage support equipment, as well as the costs associated with making any repairs or upgrades that are needed over time."[16]

Joint Commenters support Duke Energy's recognition that inverter-based resources such as solar PV provide valuable ancillary services and should be compensated in a manner that encourages those services, facilitates project financing, and enables the robust renewable buildout that the nation is experiencing – and that North Carolina by law must undertake. Joint Commenters request that the Commission order further evaluation of the extent to which QFs are currently providing reactive power without compensation and whether and to what extent Duke compensates its own generators for the provision of reactive power.

C. <u>QF operations and PPAs could be modified to incentivize the provision of valuable ancillary services.</u>

As Duke correctly notes, QFs under existing standard offer PPAs cannot be forced to sell less than their full output.[17] However, QFs may agree to amend their PPAs, assuming they have reached agreement with Duke and the Commission has approved of the modification. For existing QFs, the operative question is whether the long-term value of

---

[15] *Id.* at 2 (emphasis added).
[16] *Id.* at 4.
[17] Joint Initial Statement at 36. Duke may only curtail QFs beyond minimum thresholds during a "system emergency." *See*, *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, p. 7, Docket No. E-100, Sub 148 (October 11, 2017).

these projects' ability to provide greater ancillary services can be identified and incorporated into commercial and contractual terms that will encourage QFs to modify their existing PPAs. While Joint Commenters believe it would be appropriate for stakeholders to further discuss and consider potential options for modifying existing PPAs, potential options include:

1. A QF could agree to modify its existing PPA if it was capable of providing, and receiving compensation for providing, ancillary services.
2. A QF could agree to change its existing PPA from a rate payable on a $/MWh basis to one payable on a $/MW basis to allow for full dispatchability.
3. A QF could agree to grant Duke full dispatchability during certain pre-established periods; if Duke determined that at certain times there was greater economic value of curtailing a QF, or operating a QF at lower output to allow for incremental ramping, then the QF could be compensated for its dispatchability during those times.

Alternatively, if the Commission determined it was more appropriate for a QF to receive compensation for the provision of ancillary services through a different mechanism – under the project's IA for example – such compensation could be accounted for outside of the QF's PPA.

These types of arrangements would require that existing QFs continue to receive the same or greater level of compensation as under their existing contracts. Joint Commenters would not anticipate (and it would not be reasonable to expect) a QF to make the commercial decision to enter into a modified PPA unless such change resulted in equal or greater revenue.[18] However, to the extent that the ancillary services provided by QFs provided economic benefit to Duke and the QF was fairly compensated for such benefit,

[18] Joint Commenters note that as a practical matter, most QFs are financed using a combination of debt and tax equity, which requires QFs to make payments on those obligations for varying periods of years. Even if a QF owner wanted to re-negotiate or amend its PPA, it would require the consent of the lender and/or tax equity provider. Those entities would be highly unlikely to provide such consent if the proposed PPA amendment resulted in decreased revenue or other terms less favorable to the QF than those in the existing PPA.

QFs should be given the option to modify existing PPAs to provide valuable ancillary services to the system.

Assuming contractual terms are reached, the operational barriers to having QFs provide a larger suite of ancillary services appear minimal, as discussed above. Most inverters installed in the past five years have AGC capability, and Joint Commenters understand that activating those functions requires modest investment, on the order of $10,000 per 5 MW QF. On the utilities' operational side, Duke has not shown why it could not make investments to fully utilize QF ancillary services, for example by modifying secure North American Electric Reliability Corporation ("NERC") reclosers to allow for AGC.

D. <u>The peaker method does not incorporate the provision of, and compensation for, ancillary services.</u>

In describing the incorporation of ancillary services into avoided cost rates, Duke states that "the value of positive ancillary services provided by a QF as part of the capacity and energy delivered to the utility, if any, is already incorporated into the calculation of the utility's full avoided cost rate."[19] Joint Commenters disagree that the existing peaker methodology includes ancillary services. While it might be possible to include the value of ancillary services provided by a QF in an avoided cost calculation, Duke's current avoided cost rates do not include such values. Avoided capacity costs under the peaker method are based on the projected cost to construct a simple-cycle combustion turbine ("CT"), including the fixed capital, financing and fixed operating costs associated with the construction and operation of the CT facility. Avoided energy costs under the peaker methodology represent an estimate of the variable operating costs that are avoided and

[19] Joint Initial Statement at 37.

would have otherwise been incurred by the utility but for the purchase from a QF. However, neither avoided energy nor avoided capacity costs under North Carolina's peaker methodology expressly include ancillary services.

In past avoided cost proceedings, the Commission has clearly stated that avoided cost rates do not include consideration of ancillary services. In its *Order Setting Avoided Cost Input Parameters*[20] the Commission stated "[o]nce all aspects of solar integration are more fully evaluated, the costs proposed to be included now by [Duke], those associated with ancillary services due to the intermittency of solar, may be offset completely or in part by some of the benefits that may be realized" but "it is premature for [Duke] to include integration costs and benefits associated with increasing levels of solar integration in their service territories in the calculation of their avoided cost rates."[21] The Commission reiterated that position in the Sub 158 Order.[22] Although the Commission ultimately included the SISC as a decrement to the avoided energy rate in the Sub 158 Order, no other consideration of ancillary service benefits is currently included in Duke's avoided cost rates, and Duke's assertion to the contrary is incorrect.

Because ancillary services are not currently included in avoided cost rates, there are two categories of ancillary services that should be considered: (1) ancillary services that QFs may be currently providing without compensation, and (2) ancillary services that QFs may be capable of providing for compensation. As described above, many QFs are already providing voltage support (or reactive power) to Duke without compensation, and solar and solar + storage facilities are capable of providing additional ancillary services and

[20] *Order Setting Avoided Cost Input Parameters*, Docket No. E-100, Sub 140 (December 31, 2014) ("Sub 140 Phase 1 Order").
[21] *Id.* at 60-61.
[22] Sub 158 Order, at 92.

providing grid operators new tools to balance and manage the grid. These services are not compensated via the existing avoided cost structure or other compensation mechanism, a result that is unjust in certain respects and unwise in others given North Carolina's mandate to transform its power grid to integrate much higher levels of zero carbon generation.

E. The Commission and stakeholders should evaluate how *new* solar and solar + storage facilities can provide, and be compensated for providing, ancillary services.

Duke's discussion of ancillary services in its Joint Initial Statement is limited to *existing* QFs. However, Duke and the Commission should also evaluate how new solar and solar + storage projects can provide, and be compensated for providing, ancillary services. The contractual limitations related to existing QFs discussed above would not apply to new solar and solar + storage facilities, and stakeholders would have greater flexibility to work collaboratively to devise a contract and commercial structure that achieved the goals of multiple stakeholders.

One challenge of considering ancillary services in a traditionally-regulated market like North Carolina is that, unlike in states with a Regional Transmission Organization ("RTO") or Independent System Operator ("ISO") and organized wholesale markets, no such market for ancillary services exists in North Carolina, and liquid market prices are therefore unavailable. As a result, it is somewhat more difficult to quantify ancillary services that are currently provided by Duke's generation fleet but that could instead be provided by a third party. Information regarding Duke's compensation for ancillary services provided to its own generators would assist in that analysis, but the Joint Commenters acknowledge that appropriate quantification of ancillary services provided by third-party generators will require additional consideration and analysis. However, the *ability* of new solar and solar + storage facilities to provide ancillary services and the benefits of doing so is well-documented.

In the Commission's 2019 proceeding implementing the competitive procurement of renewable energy ("CPRE") program, First Solar, Inc. ("First Solar") filed comments[23] discussing this topic and proposing a dispatchable PPA for use in the CPRE proceeding. The Commission ultimately determined in its 2019 order that adoption of the dispatchable PPA as proposed by First Solar was "premature at this time."[24] However, the First Solar Comments provide compelling examples of solar and solar + storage facilities providing grid services.[25] First Solar conducted extensive research on the technical capabilities, the operational benefits and the economic benefits of a dispatchable renewable structure, which allows a solar power plant to be dispatched flexibly by a system operator.[26] This dispatchability allows the utility's system operator to determine how to most efficiently operate the resource, including utilizing the resource to provide ancillary services. The First Solar Comments highlighted a case study demonstrating the expansion of dispatchable renewable energy procurement, a National Renewable Energy Laboratory ("NREL") study reporting on a 300-MW solar facility's ability to provide ancillary services, and a study of the economic impacts of dispatching solar in a flexible manner to allow for the provision of ancillary services.[27]

A Hawaiian Electric Companies ("HECO") study, "Proactive Solutions to Curtailment Risk: Identifying New Contract Structures for Utility-Scale Renewables,"

---

[23] *Comments of First Solar, Inc.*, Docket Nos. E-2, Sub 1159 & E-7, Sub 1156 (March 22, 2019) ("First Solar Comments"), attached as **Exhibit 2**.
[24] *Order Modifying and Accepting CPRE Plan*, p. 17, Docket Nos. E-2, Sub 1159 & E-7, Sub 1156 (July 2, 2019).
[25] First Solar Comments, p. 4.
[26] *Id.* at 2.
[27] *Id.* at 6.

evaluated contract solutions for utility-scale renewable assets to provide essential grid services to HECO while providing a financeable contracting mechanism.[28] HECO proposed a lump-sum payment, dispatchable renewable generation model, and subsequently filed eight executed PPAs with the Hawaii PUC in 2018, wherein HECO utilities had contracted for 262 MW of utility-scale solar with four hours of storage.[29]

A 2017 NREL study entitled "Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant" demonstrated in a real-world test that utility-scale solar plant equipped with advanced control technology can provide essential reliability services such as frequency control, voltage control, and ramping capability or flexible capacity.[30] That demonstration also showed that digitally-controlled inverters were able to respond more accurately than the most accurately dispatched thermal resources, outperforming the accuracy of fast-gas turbines by 42%.[31]

A study of the economic impacts of dispatching solar in a flexible manner, conducted by independent consultant Energy and Environmental Economics, Inc. and in conjunction with the Tampa Electric Company ("TECO"), showed that integrating utility-scale solar at higher penetration levels into a grid operator's dispatch stack would allow the operator to both commit fewer thermal units and operate the remaining thermal power units more efficiently.[32] The modeling demonstrated that allowing for up- and down-dispatch by the operator resulted in less actual curtailment of solar resources than would result under a solely curtailable operational model.[33] The TECO study also showed that

---

[28] *Id.* at 3-4. *See also*, *id.* at Appendix 2.
[29] *Id.* at 3.
[30] *Id.* at 6. *See also*, *id.* at Appendix 3.
[31] *Id.* at 6.
[32] *Id.* at 6-7. *See also*, *id.* at Appendix 4.
[33] *Id.* at 7.

changing operating parameters to make solar plants a dispatchable resource generated cost savings for the overall system.[34]

While Joint Commenters do not assert that a dispatchable PPA is the only way to allow a solar generator to provide ancillary services to the utility for compensation, a dispatchable PPA provides a viable mechanism by which generators outside of wholesale ancillary service markets can provide those services to the incumbent utility. Joint Commenters request that the Commission evaluate this and other contracting and compensation mechanisms that could allow solar and solar + storage facilities to provide these critical services and to be fairly compensated for doing so.

F. Joint Commenters request that the Commission order further evaluation of solar and solar + storage facilities' ability to provide ancillary services and the related contractual, commercial, and technical issues.

As discussed above, new and existing solar and solar + storage facilities in North Carolina have the potential to provide vital grid services to Duke. Given the substantial addition of renewable energy facilities anticipated in coming years as the Commission implements the decarbonization goals of HB 951, it is critical that all potential providers of ancillary services are enabled and sufficiently encouraged to provide these services. Increasing the dispatchability of these facilities will provide Duke greater operational control and flexibility and should result in substantial operational and economic efficiencies.

However, the lack of an existing market for ancillary services creates contractual, commercial, legal, and technical challenges that must be addressed in order to allow these significant benefits to be realized. The Joint Commenters therefore request that the

[34] *Id.* at 7.

Commission initiate a stakeholder process to further evaluate these issues in an effort to reach consensus on an approach to allowing both new and existing solar facilities to provide and be compensated for these important services.

G. Support for Ancillary Services Pilot

In discussions with other parties in this docket and others, Joint Commenters have discussed the potential for a pilot program to test the effectiveness of an ancillary services market in North Carolina. Such a pilot might not be dispositive of whether the market will be crowded with market participants and resulting in downward pressure on prices for services, but Joint Commenters believe that a pilot ancillary services market could prove cost-effectiveness and, potentially, dispel some of the concerns outlined by Duke in their Initial Comments. Further, as stated elsewhere, Duke's conclusions about market size and need for an ancillary services market ignore the likelihood of more generation resources, such as wind and solar, which will likely come online due to the carbon emission reduction mandate in HB 951. As such, Joint Commenters would support an ancillary services pilot program and requests the Commission open a docket to achieve that end.

IV. AVOIDED COST RATES

In light of the mandates of HB 951, it is highly unlikely that the costs that Duke avoids by purchasing QF power will be the capital and operating costs of a natural gas combustion turbine or combined cycle plant, as assumed in the peaker or proxy plant avoided cost methodology. In the new resource planning regime required by HB 951, this Commission is required to approve a resource plan for Duke that can be expected to include a mix of new resources, including significant volumes of solar and wind along with some natural gas and potentially other new technologies as they become available. This resource plan – the HB 951 Carbon Plan – will require a carefully constructed balance of resources to ensure that the HB 951 goals can be met at least cost while maintaining system reliability. Under this new regime, any new QF resources coming on line will necessarily replace resources of a similar type called for by the Carbon Plan. Otherwise, the modification of the resource mix would require complex remodeling to determine how a modification of the resource mix would affect carbon reduction, cost, and reliability, and potentially require reworking of the entire model and resource plan. As a result of these changes to North Carolina's energy future, the Joint Commenters believe that it would be prudent for the Commission and interested stakeholders to re-evaluate the peaker methodology given the development and implementation of the Carbon Plan.

V. GAS PRICE FORECASTS

To the extent that gas prices do continue to be an input to avoided cost calculations, Joint Commenters note that Duke's natural gas forecast used in the calculation of avoided energy rates and in IRP modeling has been contested in each of the avoided cost and IRP proceedings since 2014. Duke's preferred natural gas forecast methodology in those IRP proceedings uses ten years of forward market prices[35] followed by fundamental forecast data for the remainder of the planning period. Duke repeatedly argued for the use of this approach in both avoided cost and IRP proceedings. Numerous stakeholders have consistently opposed this approach, including the Joint Commenters, Public Staff, and SACE.

The Public Staff has previously taken the position that it is appropriate for Duke to use no more than five years of forward market data before transitioning to the Companies'

[35] In this proceeding, Duke has used the method ordered by the Commission in Docket Nos. E-100, Sub 148, E-100, Sub 158, and E-100, Sub 167, which required "no more than eight years" of forward contract natural gas prices before transitioning to fundamental forecast data." Joint Initial Statement at 25. As discussed below, Joint Commenters believe this method is still problematic.

fundamental forecast.[36] Further, Public Staff has stated that it has not identified any utilities other than DEC and DEP that rely wholly on forward prices for terms greater than six years. The Public Staff has also noted that Duke Energy Florida, Duke Energy Kentucky, and Duke Energy Indiana in their IRPs each rely wholly on market prices for the first five years, blend market and fundamental prices for the next five years, and switch to the fundamental forecast for the remainder of the planning period. The Public Staff further stated that Duke did not purchase ten-year forwards as a standard part of its fuel procurement practices, and its ability to purchase ten-year forwards on five occasions in the past three years should not be determinative as to whether the use of ten-year forwards is appropriate.[37] NCSEA has previously recommended that Duke use forward market prices for two years, with a transition in the next three years to the average of a set of recent fundamentals forecasts. Alternatively, NCSEA stated that it would not object to the use of forecast methodology used by Dominion – 18 months of forwards transitioning to a fundamentals forecast beginning at 36 months.[38]

SACE has previously stated that reliance on long-term forward pricing is inappropriate because future markets, which are highly responsive to short term and temporary trends, are not good indicators of long-term market trends. SACE has also noted that the lack of trading volume for NYMEX gas futures more than two to three years ahead prohibits prices from being robust forecasters of gas prices, and stated that long-term forecasts should not be based on short-term trends, but instead on more stable factors such

---

[36] *Initial Statement of the Public Staff*, pp. 21-28, Docket No. E-100, Sub 158 (February 13, 2019).
[37] *Id.*
[38] *Proposed Order of the North Carolina Clean Energy Business Alliance, the North Carolina Sustainable Energy Association, and the Southern Alliance for Clean Energy*, pp. 67-68, Docket No. E-100 Sub 158 (Sept. 4, 2019).

as resource base and expected production costs. SACE has therefore recommended that the Commission require Duke to rely on no more than two to three years of forward market price forecasts, before transitioning to a blended price forecast, and then a fundamental price forecast.[39]

In the 2020 Duke IRP proceeding, Joint Commenters presented the expert report of Kevin Lucas critiquing Duke's natural gas forecast methodology.[40] Mr. Lucas concluded that Duke's use of forward market forecasts, compared to a pricing forecast based more on fundamentals, provides less realistic and less reliable natural gas price projections for the mid-2020s through the mid-2030s. Mr. Lucas highlighted the volatility inherent in relying on forward market prices which, when used to establish IRP modeling – or in the present proceeding, avoided cost rates – can result in substantially different results within relatively short periods of time. Mr. Lucas recommended that Duke utilize eighteen months of forward market prices before transitioning to a blended fundamentals forecast, using at least two reputable sources, for the remainder of the planning period.[41]

The South Carolina Public Service Commission ("PSC") adopted Mr. Lucas's approach in considering the 2020 Duke IRPs. The PSC specifically found that Duke's natural gas forecast methodology was "flawed and results in generation mixes which do not represent the most reasonable and prudent means of meeting Duke's energy and capacity needs."[42] The PSC also concluded that "Duke's Natural Gas pricing forecasts rely

---

[39] *Initial Comments of the Southern Alliance for Clean Energy*, pp. 6-7, Docket No. E-100, Sub 158 (February 12, 2019).

[40] *Initial Comments of the North Carolina Sustainable Energy Association and the Carolinas Clean Energy Business Association on Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Integrated Resource Plans*, pp. 19-20, Docket No. E-100, Sub 165 (March 1, 2021). *Id.* at Exhibit 3, pp. 37-64 ("Lucas Report").

[41] Lucas Report at 55.

[42] South Carolina Public Service Commission Order 2021-447, p. 17, Docket Nos. 2019-224-E & 2019-225-E (June 28, 2021) ("SCPSC IRP Order").

too heavily on forward contract prices determined at a market low point and maintained for over 10 years in the forecast period. This methodology commits Duke to large-scale buildouts of natural gas generation assets, at the expense of renewables and storage, endangering Duke's internal commitment to net-zero generation by 2035."[43] The PSC instead ordered Duke to modify the 2020 IRP and in all future IRPs to "remodel its portfolios using natural gas pricing forecasts that rely on market prices for eighteen months before transitioning over eighteen months to the average of at least two fundamentals-based forecasts, as recommended by CCEBA Witness Lucas."[44]

In the Sub 148 Order the Commission noted at that time that it was "satisfied that at the present time the number of such transactions is sufficiently fewer to prevent the Commission from relying completely on this method for establishing energy prices in this case at this time and will continue to monitor the liquidity in the market in future avoided cost proceedings."[45] In the Sub 158 Order the Commission stated that although the parties opposed to Duke's use of eight years of forward market pricing had provided "substantial, competent, and material evidence and well-articulated arguments in support of their positions" the Commission was "not persuaded that a change in the fuel forecasting methodology approved in the 2016 Sub 148 Order is appropriate, at this time."[46]

This issue remains critically important not only for the present avoided cost proceeding, but also in the context of the development of the Carbon Plan under HB 951. The Commission has previously stated that it is appropriate for Duke to apply the same

[43] *Id.*
[44] *Id.* at 88.
[45] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 148, 77-78 (October 11, 2017) ("Sub 148 Order").
[46] Sub 158 Order at 59.

natural gas forecast methodology in its IRP proceeding that it uses to calculate avoided cost rates.[47] In this proceeding the Commission should require Duke to decrease its heavy reliance on illiquid and volatile natural gas prices, and Joint Commenters again urge the Commission to require Duke to use fewer years of forward market prices, with a transition to fundamental forecasts for the remainder of the applicable planning period. Although all of the alternative proposals summarized above would be more appropriate than Duke's proposed use of eight years of forward market prices, Joint Commenters recommend the Commission adopt the recommendation of Mr. Lucas, as presented in Docket No. E-100, Sub 165, that Duke utilize eighteen months of forward market prices before transitioning to a blended fundamentals forecast, using at least two reputable sources, for the remainder of the planning period.

VI. CONTRACTUAL TERMS

a. LEO Formation/Notice of Commitment

Joint Commenters are generally comfortable with Duke's proposed changes to its Notice of Commitment to Sell form for Qualifying Facilities larger than 1 MWac.[48] However, in Section 4 of the form, Duke requires the QF to represent that it will, subject to an exception discussed below, begin delivering the output of its facility to Duke no later than 365 days after the Notice of Commitment ("NOC") form Submittal Date. Given that Duke's expected time to complete interconnection studies and construct interconnection facilities is approximately four years, this requirement means that a QF (or potentially an existing QF requiring new interconnection study) would be unable to form a legally

[47] *Order Accepting Integrated Resource Plans, REPS and CPRE Program Plans with Conditions and Providing Further Direction for Future Planning*, p. 10, Docket No. E-100, Sub 165 (November 19, 2021).
[48] Joint Initial Statement, Exhs. 7 & 8.

enforceable obligation ("LEO"), execute a PPA and secure pricing until approximately three years into the interconnection study and construction process. That would create a totally unreasonable and untenable situation because QFs would have to incur substantial study costs and commit to and begin paying even greater interconnection facilities and network upgrade costs without having price certainty or an executed PPA. No QF has ever been financed or built under these circumstances and none would be in the future.

The exception proposed by Duke does not solve the problem. The exception provides the QF a day-for-day extension of the 365-day deadline for any days by which Duke's completion of the interconnection facilities and network upgrades exceeds the QF's requested interconnection date. Suppose a QF/interconnection customer submits an interconnection request on March 1, 2022, and, given Duke's expected study and construction timelines, requests an in-service date of March 1, 2026. As long as Duke completes its work by that date, the customer would not be eligible for any relief from the 365-day deadline and would have to submit is NOC form no earlier than March 1, 2025 (actually several months later than that because QFs, due to testing and inspection requirements, cannot typically begin delivering power until some months after Duke's interconnection work has been completed).

To comply with PURPA, a process for LEO formation must allow QFs to form LEOs and execute contracts at a reasonable point in the development process – a point at which price certainty is needed to allow the developer to justify major expenditures and secure financing. That point should be early in the interconnection study process before the QF faces the obligation to make major security postings and subject itself to significant withdrawal penalties if it exits the queue. The appropriate way to address this issue is for the NOC form to require the QF to represent that it will begin delivering the output of its facility to Duke within 90 days of Duke's completion of all required interconnection facilities and network upgrades. This is generally consistent with the deadline for achieving commercial operation included in Duke PPAs approved by this Commission for use in connection with the CPRE and Green Source Advantage programs and by the South Carolina PSC in connection with PURPA implementation. There is no rational reason why the deadline for a QF achieving commercial operation imposed by the LEO form should be any different.

If revised to accommodate Joint Commenters' concerns, paragraph 4 of the proposed NOC would read as follows:

> Commitment to Sell Power for Specified Future Delivery Term. If Seller is ~~an existing QF~~ an existing Interconnection Customer that has previously been placed in service and does not require additional interconnection study or the construction of new interconnection facilities or system upgrades, Seller represents and hereby commits to commence delivery of its full electrical output to the Company for specified future delivery term of [2 years, 5 years] (the "Delivery Term") within 365 days of the Submittal Date (as defined below). Where, ~~except where~~ the Seller is a new Interconnection Customer of the Company, or requires additional interconnection study, Seller represents and hereby commits to commence delivery of its full electrical output to the Company for a specified delivery term of [2 years, 5 years] within 90 days of the Company's written notice to the Interconnection Customer that the Company has completed all required interconnection facilities and system upgrades and the Company is ready to accept electricity from the Seller; provided that such date shall be extended day-for-day for any delays in the commencement of delivery not caused by Seller. ~~And its failure to begin delivery of power within 365 days is due to the time required for the Company to complete needed interconnection facilities or system upgrades by the in service date specified in the Seller's interconnection request or in the interconnection agreement between the Seller and the Company, for which the Seller shall be given day-for-day extensions on its in service date for any delays attributable to the in service date of these interconnection facilities or system upgrades.~~ By execution of this Form, Seller represents that the QF is commercially viable and financially committed to delivering its full electrical output to the Company

for the specified Delivery Term and the Company can rely upon the QF's energy and capacity during the future Delivery Term for resource planning.

VII. CONCLUSION

For the reasons set forth herein, Joint Commenters request that: (1) Duke be required to revise its natural gas forecast methodology in its avoided cost model and refile in this proceeding; (2) Duke revise the proposed Notice of Commitment form as shown herein; (3) the Commission authorize a stakeholder process and/or pilot program for compensation for ancillary services provide by qualified facilities and other non-utility owned generation facilities; (4) require Dominion to revise its Re-Dispatch charge as set forth herein; and (5) for any such further relief contemplated or outlined here and which the Commission sees fit.

Respectfully submitted this the 24th day of February 2022.

/s/ Benjamin W. Smith
Benjamin W. Smith
Associate General Counsel
NCSEA
N.C. State Bar No. 48344
4800 Six Forks Road
Suite 300
Raleigh, NC 27609
(919) 832-7601 Ext. 111
ben@energync.org

_/s/ John D. Burns
John D. Burns
General Counsel – CCEBA
N.C. State Bar No. 24152
811 Ninth Street
Ste 120-158
Durham, NC 27705
(919) 306-6906
counsel@carolinasceba.com

CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing document 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 24th day of February 2022.

/s/ Benjamin W. Smith
Benjamin W. Smith
Associate General Counsel
NCSEA
N.C. State Bar No. 48344
4800 Six Forks Road
Suite 300
Raleigh, NC 27609
(919) 832-7601 Ext. 111
ben@energync.org

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 175

In the Matter of:	)	
Biennial Determination of Avoided	)	**JOINT INITIAL COMMENTS OF**
Cost Rates for Electric Utility	)	**CCEBA AND NCSEA**
Purchases from Qualifying Facilities –	)	
2021	)	

EXHIBIT 1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERG REGULATORY COMMISSION

Reactive Power Capability Compensation	)	
	)	Docket No. RM22-2-000
	)	
	)	
	)	

COMMENTS OF
DUKE ENERGY CORPORATION

I. INTRODUCTION

Duke Energy Corporation ("Duke Energy") respectfully submits the following comments in response to the Notice of Inquiry ("NOI") issued by the Federal Energy Regulatory Commission ("FERC" or the "Commission") seeking comment on reactive power capability compensation, and in particular the industry's use of the method employed in *American Electric Power Service Corporation*[1] ("AEP Methodology") for developing reactive power rates.[2]

Duke Energy is a public utility holding company with franchised utility operations in the Midwest and Southeast and has a significant commercial renewables business. The Midwest franchised utilities include Duke Energy Ohio, Inc. ("DEO"), Duke Energy Kentucky, Inc.("DEK") and Duke Energy Indiana, LLC ("DEI"). DEO and DEK are members of PJM Interconnection, LLC ("PJM") and DEI is a member of the Midcontinent Independent System Operator, Inc. ("MISO"). The following Duke Energy franchised utility affiliates are located in the Southeast and are not members of RTOs/ISOs: Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, Inc. ("DEP") and Duke Energy Florida, Inc. ("DEF").

---

[1] *Am. Elec. Power Serv. Corp.*, Opinion No. 440, 88 FERC ¶ 61,141 (1999).
[2] *Reactive Power Capability Compensation*, Notice of Inquiry, 177 FERC ¶ 61,118 (2021) ("NOI").

Duke Energy's commercial renewables business is managed by Duke Energy Sustainable Solutions ("DESS"). DESS operates in 24 states and has invested more than $7.3 billion to grow its utility-scale wind and solar power businesses since 2007. As a leader in sustainable energy, DESS helps large enterprises reduce power costs, lower emissions, and increase resiliency, and provides wind, solar, resilient backup power, and energy services management. Across the United States, DESS owns or manages over 4,500 megawatts of utility scale solar, wind and battery storage projects.

Duke Energy appreciates the opportunity to provide comments to assist the Commission's understanding of the issues surrounding reactive power compensation for non-synchronous resources. Duke Energy's franchised utilities receive revenues for reactive power under Commission approved tariffs or rate schedules and reactive power compensation is an important component of consideration in our commercial renewables business.

While Duke Energy is supportive of the AEP Methodology, we believe guidance or adjustments should be made to the method to make it better suited for non-synchronous generation. Further, Duke Energy believes strongly that the Commission should grandfather utilities' existing Commission accepted reactive power cost of service tariffs, or rate schedules, if the Commission revises the reactive power compensation rules. In many cases, generation developers have secured funding for their projects expecting a revenue stream for reactive power that was developed using the Commission's current guidance on the AEP Methodology.

II. COMMENTS

Duke Energy supports the continued use of the AEP Methodology for determining the revenue requirement for reactive power rates, with modifications to account for non-synchronous resources, including solar and wind generation. The AEP Methodology has been used for many years by the industry as a reliable and straightforward method to recover costs associated with providing reactive power service, and a large number of utilities' reactive power rates have been approved at FERC using it. It would be disruptive to the industry to abandon this method, especially if existing rate schedules or tariffs are not grandfathered. The significant benefit of the AEP Methodology for wind and solar developers is that it is fixed, and not variable, which provides a revenue stream for system cost recovery that reasonably matches the capability of the system, facilitates project financing, and is a key driver to the robust renewable build-out our nation is experiencing.

However, Duke Energy supports the AEP Methodology being modified or "tweaked" to be a more streamlined and defined process, making it easier to develop cost support for reactive power filings. The AEP Methodology calculates a cost-of-service rate based on three components of a generation plant that support the production of reactive power: (1) the generator and its exciter; (2) accessory electric equipment that supports the operation of the generator-exciter; and (3) the remaining total production investment required to provide real power and operate the exciter. An allocator is used to distinguish the annual revenue requirement of the components between real and reactive power production. When the AEP Methodology was created and approved, the vast majority of generation was steam and the components referenced above were designed for synchronous resources, such as steam, and not for non-synchronous ones. Obviously, the generation components of synchronous resources are different from the components of non-synchronous ones and the AEP Methodology should account for the differences.

Duke Energy supports having direct reactive power cost factors determined for each individual piece of equipment of non-synchronous generation to be utilized in the AEP Methodology. Moreover, specific FERC accounts for certain types of non-synchronous energy resources (including wind and solar) would likely be helpful in reactive power rate filings and provide more certainty to the utilities and to FERC on how the costs are developed for the reactive power rate.[3]

If the Commission issues revisions or further guidance to the AEP Methodology, it must ensure that the utilities' whose tariffs or rate schedules have been accepted by FERC, for reactive power compensation, are grandfathered, and that these utilities are not required to update their reactive power tariff or rate schedule to incorporate any modified rate calculations. Developers have relied on the existing reactive power rate treatment using AEP Methodology, and obtained financing based on this methodology being in place. It would be unjust to change the rules in the middle of the game for generators that have relied on the AEP methodology being in place and Duke Energy supports the grandfathering of all pre-existing and FERC approved reactive power tariffs that have utilized the AEP Methodology

The Commission's NOI seeks comments on a resource's reactive power capability degrading over time, and how degradation should impact reactive power compensation. Duke Energy does not believe that the concept of VAR production degradation is necessarily applicable to intermittent resources. Degradation has not been observed on the most critical element in VAR production, the inverter. We have observed degradation in capability of modules over their lifetime; however, module degradation does not directly impact VAR production given the lack of degradation on the inverter element. Moreover, generation owners must have a reasonable opportunity to recover the fixed costs related to their voltage support equipment, as well as the costs associated with making any repairs or upgrades that are needed over time.

---

[3] FERC issued a NOI on January 19, 2021 seeking comments on the accounting and reporting of certain renewable energy generating assets and renewable credits and the ratemaking implications. *See Accounting and Reporting Treatment of Certain Renewable Energy Assets,* 174 FERC ¶ 61,032 (2021). FERC has not issued an order on the NOI. ("NOI on Renewable Accounting")

The Commission also seeks comments on whether the reports submitted by the Generator Owner to the Transmission Planner under NERC MOD-25-2 Reliability Standard accurately depict a resource's capability to provide reactive power. Duke Energy believes it would be problematic and inappropriate to use these reports in the determination of reactive power compensation. The NERC MOD-25-2 reports demonstrate the resource's capability for only the day when the testing was done, and the test results are impacted by system conditions at the time of testing. In other words, the NERC MOD-25-2 is merely a snapshot of the resource's capability at a certain point in time. The MOD 25-2 will vary by testing day due to a myriad of factors, including the temperature on the day of testing and by the dynamic nature of the transmission system which is constantly changing and will never be the same from day to day. For these reasons, Duke Energy does not believe NERC MOD-25-2 reporting should be tied to reactive power compensation.

III. COMMUNICATION

Duke Energy requests that all correspondence, communications, pleadings, and other documents related to this proceeding be addressed to:

Sheri May
Duke Energy Corporation
139 East 4th Street
Cincinnati, Ohio 45202
(513) 287-4340 (office)
(513) 404-8119 (cell)
Sheri.may@duke-energy.com

IV. CONCLUSION

Duke Energy respectfully requests that the Commission consider these initial comments in this proceeding.

Respectfully submitted,

/s/

Sheri May
Duke Energy Corporation
139 East Main Street
Cincinnati, Ohio 45202
(513) 287-4340
(513) 404-8119
Sheri.may@duke-energy.com

February 21, 2022

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 175

In the Matter of:	)	
Biennial Determination of Avoided	)	**JOINT INITIAL COMMENTS OF**
Cost Rates for Electric Utility	)	**CCEBA AND NCSEA**
Purchases from Qualifying Facilities –	)	
2021	)	

EXHIBIT 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH
DOCKET NO. E-2, SUB 1159
DOCKET NO. E-7, SUB 1156

In the Matter of Petition for Approval of Revisions to Generator Interconnection Standards	))))	COMMENTS OF FIRST SOLAR, INC.

NOW COMES First Solar, Inc. ("First Solar"), pursuant to the Order Requiring Interim CPRE Program Reports, Allowing Interim Implementation Of CPRE Program Plans, And Establishing Schedule For Filing Comments issued December 17, 2018, and the Commission's Order issued February 1, 2019, extending the time for parties to file comments on the Competitive Procurement of Renewable Energy ("CPRE") Program plans filed by Duke Energy Carolinas, LLC ("DEC"), and Duke Energy Progress, LLC ("DEP," together with DEC "Duke"), on September 1, 2018, in Docket No. E-100, Sub 157. By Order issued September 28, 2018, the Commission granted First Solar's Petition to Intervene in these dockets. Pursuant to those Orders, First Solar provides these comments regarding the CPRE Program plans proposed by Duke.

I. <u>INTRODUCTION</u>

First Solar is a photovoltaic ("PV") panel manufacturer and has sold over 17 gigawatts of PV panels worldwide. First Solar's manufacturing facilities are located in Ohio and Southeast Asia. First Solar employs over 1,200 people in the United States. First Solar has developed, financed, engineered, interconnected, constructed and currently operates many of the world's largest grid-connected solar power plants. First Solar has developed nearly five gigawatts of solar power plants in the United States. First Solar is the largest provider in the United States of operations and maintenance services for solar power plants. In so doing, First Solar gained significant experience with utility-scale solar plant procurement and contracting practices throughout the United States.

II. COMMENTS

First Solar files these comments to supplement the comments filed by the North Carolina Clean Energy Business Alliance ("NCCEBA") in these dockets. Specifically, First Solar files these comments to promote changes to the power purchase agreement ("PPA") to be used in future tranches of the CPRE Program to shift renewables procurement from a curtailment-focused, energy-only contracting model to a dispatchable, capacity-based product.

First Solar has conducted extensive research on the technical capabilities, the operational benefits and the economic benefits of a dispatchable renewable structure, which allows a solar power plant to be dispatched flexibly by a system operator. This shift in procurement will be consistent with the legislative intent of House Bill 589 and more cost effective for ratepayers, while also yielding operational benefits to Duke.

A. First Solar Proposes a Dispatchable PPA for Future CPRE Procurement.

First Solar proposes a capacity-based PPA structure by which market participants in the CPRE will bid fixed dollars per MW-month in response to future requests for proposals ("RFPs"). By leveraging a capacity payment, Duke will be able to treat a utility-scale solar asset as fully dispatchable, while at the same time creating revenue certainty for the facility developer. First Solar's proposed changes to the existing PPA are set forth in the attached Appendix 1. Because of the significant benefits for ratepayers, utilities and developers that result from a capacity approach to the PPA utilized for future tranches of the CPRE Program, First Solar urges the Commission to approve the changes outlined below and order them implemented.

This proposed PPA structure will allow Duke to flexibly dispatch solar assets alongside other generation assets based on optimal economic operations on a given day's forecasted insolation and customer demand. Under this revised framework, instead of delivered energy providing the key performance metric as is the case under the CPRE Tranche 1 PPA, renewable facilities will be required to meet dispatch availability and accuracy needs for Duke. Under this proposed PPA structure, Duke will still maintain contractual rights to one-hundred percent of the capacity, energy, stored energy and renewable energy credits from the renewable facility. These PPA changes are consistent with and advance the legislative intent of House Bill 589 that Duke maintain "rights to dispatch, operate, and control the solicited renewable energy facilities in the same manner as the utility's own generation resources."[1]

B. <u>Dispatchable Renewable Procurement is Expanding.</u>

This proposed change in PPA contracting structures for North Carolina is not without precedent in other markets. Solar developers are witnessing an evolution in renewables procurement to dispatchable models in bilateral markets where there is an increasing penetration of solar generation.

1. *Hawaiian Electric Companies Executed Seven Dispatchable PPAs for Utility-Scale Solar in 2018.*

Hawaiian Electric Companies ("HECO") are leading the way in the transition of renewables procurement to a dispatchable model. In procuring additional renewables, HECO sought to prospectively address operational challenges its utilities were

[1] N.C. Gen. Stat. § 62-110.8(b).

experiencing, namely significant curtailment of renewable resources contracted on an energy-only PPA model. In addition to the operational limitations of existing PPA structures, these challenges were caused, in part, by both a high penetration of behind-the-meter solar and an aging oil-fired generation fleet.

To develop a solution to address these operational challenges, HECO investigated contracting options in a study entitled "Proactive Solutions to Curtailment Risk – Identifying New Contract Structures for Utility-Scale Renewables," conducted by the Smart Electric Power Alliance and ScottMadden.[2] That study identified contract structures for renewable utility-scale assets that would balance curtailment risk and create the opportunity for renewable generation to provide essential grid services to HECO, while providing a financeable contracting mechanism.

Similar to the PPA revisions proposed by First Solar, HECO pursued a lump-sum-payment, dispatchable renewable generation model. To that end, HECO filed seven executed PPAs with the Hawaii Public Utilities Commission on December 31, 2018, wherein HECO utilities had contracted for procurement of a total of 262 MW of utility-scale solar with 4 hours of storage.[3]

---

[2] *See* Appendix 2.

[3] *See, for example*, Hawaii PUC Docket No. 2018-0430, *In the Matter of the Application of Hawai'l Electric Light Company, Inc. For Approval of Power Purchase Agreement for Renewable Dispatchable Generation with AES Waikoloa Solar, LLC*, https://dms.puc.hawaii.gov/dms/dockets?action=details&docketNumber=2018-0430. *See also* Docket No. 2018-0431 https://dms.puc.hawaii.gov/dms/dockets?action=details&docketNumber=2018-0431; Docket No. 2018-0432 https://dms.puc.hawaii.gov/dms/dockets?action=details&docketNumber=2018-0432; Docket No. 2018-0433 https://dms.puc.hawaii.gov/dms/dockets?action=details&docketNumber=2018-0433; Docket No. 2018-0434 https://dms.puc.hawaii.gov/dms/dockets?action=details&docketNumber=2018-0434;

2. NV Energy is Seeking Dispatchable Renewables in its Most Recent Procurement.

Likewise, in 2018 NV Energy ("NVE") released a renewable energy RFP that specifically sought dispatchable renewable resources. NVE's RFP requested bidders to address two distinct offer periods: (1) a full-requirements period and (2) a dispatchable period.[4]

For the full-requirements period, NVE proposes to purchase all energy capable of being produced by the renewable resource during the evening hours of June, July and August. For all other hours of the year, similar to the PPA revisions now proposed by First Solar, the utility will retain full dispatch rights as to the contracted renewable resources for the energy capable of being produced from the facilities.

C. <u>Flexible, Dispatchable Renewables Provide Technical Capabilities and Benefits.</u>

Dispatchable contracting structures for utility-scale solar facilities are possible due to advances in the technical capabilities of utility-scale solar control technology. These capabilities enable flexible, dispatchable solar while providing economic and operational benefits to ratepayers and utilities.

Utility-scale solar developers are increasingly including these technologies in their projects today. A survey by First Solar revealed that at least 920 MW of utility-scale solar projects in the southeastern United States have the technical capability to be dispatched by

---

Docket No. 2018-0435
https://dms.puc.hawaii.gov/dms/dockets?action=details&docketNumber=2018-0435; and Docket No. 2018-0436
https://dms.puc.hawaii.gov/dms/dockets?action=details&docketNumber=2018-0436.

[4] *See* NV Energy Fall 2018 Renewable Energy Request For Proposals Including Dispatchable Energy at pp. 13-14. https://www.nvenergy.com/about-nvenergy/doing-business-with-us/energy-supply-rfps/fall-2018-renewable-energy-rfp

a utility, if connected to communication infrastructure. Currently, at least 1,000 MW in California and 400 MW in Texas of utility-scale solar projects operate under automatic generation control signals.

First Solar has contributed to two studies that demonstrate the technical abilities of a utility-scale solar plant to be dispatched, as well as the economic and operational benefits that accrue from such arrangements.

1. *Utility-scale solar plants can provide essential reliability services.*

Conducted in collaboration with the National Renewable Energy Laboratory and the California Independent System Operator, First Solar participated in the development of a March 2017 study entitled "Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant."[5] The study demonstrated, in a real-world test, that a utility-scale solar plant equipped with advanced control technology, can provide essential reliability services such as frequency control, voltage control, and ramping capability or flexible capacity. That demonstration also showed that digitally-controlled inverters were able to respond more accurately than the most accurately dispatched thermal resources, outperforming the accuracy of fast-gas turbines by an average of 42%.

2. *Dispatching utility-scale solar can provide measurable system cost savings.*

In a study conducted by independent technical consultant Energy and Environmental Economics, Inc. in conjunction with the Tampa Electric Company ("TECO"), First Solar explored the economics of dispatching solar in a flexible manner.[6] In modeling fully dispatchable utility-scale solar projects on TECO's system, this study showed that

[5] *See* Appendix 3.
[6] *See* Appendix 4.

integrating utility-scale solar at higher penetration levels into a grid operator's dispatch stack would allow the operator to both commit fewer thermal power units and operate the remaining thermal power units more efficiently. The modeling demonstrated that allowing for up- and down-dispatch by the operator resulted in less actual curtailment of solar resources than would result under a solely curtailable operational model. This counter-intuitive outcome showed that curtailment is not an inevitable attribute of solar power plants; rather, the level of curtailment is a function of how solar power plants are operated.

In addition, the TECO study showed that changing operating parameters to make solar plants a dispatchable resource generated cost savings for the overall system. Said another way, while still economic under lower solar penetration scenarios, curtailment of solar resources resulted in less measurable system cost savings than would result from operating those resources to prioritize dispatch flexibility. Further, curtailed solar showed a decline in cost savings at higher solar penetration rates, whereas dispatchable solar showed an increase in cost savings at higher solar penetration rates.

D. <u>Flexible, Dispatchable Solar Can Provide Measurable Benefits to North Carolina.</u>

First Solar encourages the Commission to approve a change in the PPA to be used in contracting for future CPRE Program tranches, so that renewable resources are paid to provide capacity to meet overall system dispatch needs, rather than being paid to provide maximum energy output. This shift in the contracting structure will allow utilities like Duke to maximize cost savings while improving the responsiveness of the resource to meet grid needs. This new structure, which is already being used elsewhere, is consistent with the legislative intent of House Bill 589 and will provide increased value to ratepayers and increased operational benefits to the utility. In markets where utility-scale solar is becoming an increasingly significant share of the generation mix, prioritizing dispatchability under a capacity-based PPA structure allows for cost-effective procurement while also allowing operational flexibility to grid operators to provide reliable service to their customers. Adopting this structure in advance of reaching higher solar penetration will allow North Carolina to avoid potential curtailment and congestion issues that other regions have experienced as a result of a procurement model that prioritizes maximum energy production over dispatch flexibility. Unlike other regions, North Carolina will be able to take early and full advantage of the operational advantages offered by dispatchable inverter-based solar resources.

III. CONCLUSION

Based on the foregoing, First Solar requests that the Commission approve and order implementation of the changes recommended by NCCEBA and First Solar to the power purchase agreement to be used in future tranches of the CPRE Program, in order to shift renewables procurement model to a dispatchable, capacity-based product.

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

BURNS, DAY & PRESNELL, P.A.

By: ____________________
Daniel C. Higgins
P.O. Box 10867
Raleigh, North Carolina 27605
Telephone: (919) 782-1441
E-mail: dhiggins@bdppa.com
Attorneys for First Solar, Inc.

CERTIFICATE OF SERVICE

I hereby certify that a true and exact copy of the foregoing has been served on all counsel of record in this docket, by either depositing same in a depository of the United States Postal Service, first-class postage prepaid and mailed by the means specified below, or by electronic delivery.

This the 22nd day of March, 2018.

BURNS, DAY & PRESNELL, P.A.

Daniel C. Higgins
Post Office Box 10867
Raleigh, NC 27605
Tel: (919) 782-1441
Email: dhiggins@bdppa.com
Attorneys for First Solar, Inc.

DUKE NOTICE: THIS WORKING DRAFT DOES NOT CONSTITUTE A BINDING OFFER, SHALL NOT FORM THE BASIS FOR AN AGREEMENT BY ESTOPPEL OR OTHERWISE, AND IS CONDITIONED UPON BUYER'S RECEIPT OF ALL REQUIRED APPROVALS (INCLUDING MANAGEMENT, CREDIT AND LEGAL APPROVAL). ANY ACTIONS TAKEN BY A PARTY IN RELIANCE ON THE TERMS SET FORTH IN THIS WORKING DRAFT OR ON STATEMENTS MADE DURING NEGOTIATIONS PURSUANT TO THIS WORKING DRAFT SHALL BE AT THAT PARTY'S OWN RISK. UNTIL THIS AGREEMENT IS FULLY NEGOTIATED, APPROVED BY BUYER IN ITS SOLE DISCRETION, AND EXECUTED BY BOTH PARTIES, NO PARTY WILL HAVE ANY LEGAL OBLIGATION OR LIABILITY, WHETHER EXPRESSED OR IMPLIED, OR OTHERWISE ARISING IN ANY MANNER UNDER THIS DRAFT OR IN THE COURSE OF NEGOTIATIONS.

DUKE ENERGY PROGRESS

DUKE ENERGY

RENEWABLE POWER PURCHASE AGREEMENT

(CPRE Tranche 1)

Buyer: [Duke Energy Carolinas, LLC] [Duke Energy Progress, LLC]

Overnight Mail: 400 South Tryon Street
Mail Code: ST 14Q
Charlotte, North Carolina 28202
Regular Mail: PO Box 1006
Mail Code: ST 14Q
Charlotte, NC 28201-1006
Attn.: Contract Administrator
DERContracts@duke-energy.com

With Additional Notices of Events of Default
Or Potential Event of Default to:
Overnight Mail: 550 S. Tryon St.
Charlotte, North Carolina 28202
Regular Mail: P.O. Box 1321, DEC45
Charlotte, North Carolina 28201-1321
Attn.: VP Commercial Legal Support

Seller: ______________________
____
____
____
____

This Renewable Power Purchase Agreement, including Exhibits 1-~~10~~ 11 hereto, which are incorporated into and made part hereof (collectively, the "Agreement"), is made and entered into by and between [insert full legal name of Seller] (the "Seller") and [Duke Energy Carolinas, LLC] [Duke Energy Progress, LLC] (the "Buyer") under the terms specified herein. Buyer and Seller may be referred to individually as a "Party" and collectively as the "Parties." Notwithstanding anything set forth herein, neither this Agreement nor any transaction contemplated hereunder will be effective **unless and until both Parties have executed** and delivered this Agreement, and the later of such date shall be the "Effective Date" of this Agreement.

NOW THEREFORE, IN CONSIDERATION OF THE PROMISES AND MUTUAL COVENANTS SET FORTH HEREIN, FOR GOOD AND VALUABLE CONSIDERATION, THE SUFFICIENCY OF WHICH IS ACKNOWLEDGED, AND INTENDING TO BE BOUND HEREBY, THE PARTIES AGREE AS FOLLOWS:

1. **Definitions**

Unless defined in the body of the Agreement, any capitalized term herein shall have the meaning set forth below:

1.1. "AAA" is defined in Section 23.2.1.

1.2. "Abandon(s)" means the relinquishment of control or possession of the Facility and/or cessation of operations of or at the Facility by Seller. "Abandon" excludes cessation of generation to comply with Prudent Utility Practices, Permitted Excuse to Perform, or due to maintenance or repair of the Facility (including Maintenance Outages and Planned Outage), provided that such maintenance or repair activities are being performed in a Commercially Reasonable Manner and with Prudent Utility Practice.

1.3. "Account" means a Party's electronic account with the Tracking System.

1.4. "Act" means the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard, N.C. Gen. Stat. 62-133.8, including all rules promulgated by the Commission associated therewith, as each may be amended or modified from time-to-time, and any successor renewable energy standards, statutes, regulations, or rules.

1.5. "Affiliate" means, with respect to any entity, each entity that directly or indirectly controls, is controlled by, or is under common control with, such designated entity, with "control" meaning the possession, directly or indirectly, of the power to direct management and policies, or otherwise have control of an entity, whether through the ownership of voting securities or by contract or otherwise. Notwithstanding the foregoing, with respect to Buyer the term Affiliate does not include any subsidiaries or affiliates whose activities are subject to the oversight or regulation of any state commission(s) and/or federal energy regulatory commission.

1.6. "Agreement" is defined in the introductory paragraph hereof.

~~1.7. "Annual Payment Threshold" is defined in Section 8.9.~~

1.7. ~~1.8.~~ "Assignment" is defined in Section 24.1.

1.8. "Available Facility Energy" means, for any given period of time, the quantity of Energy from the Facility that Seller would have been capable of delivering at the Delivery Point for such period of time and will be calculated using the Solar Performance Modeling Program, as adjusted to reflect the Facility as built as of the Commercial Operation Date, and with inputs based on: (A) actual irradiance, spectral shift and ambient temperature determined by the meteorological stations located at the Facility for such period of time, (B) a degradation rate equal to [X%] per year, (C) actual snow or soiling losses for the Facility as measured by soiling stations at the Facility or, if no soiling stations are available, using a mutually agreed upon soiling loss assumption, (D) actual inverter availability for such period of time, and (E) any other adjustments necessary to accurately reflect the Facility's capability to produce and deliver energy at the Delivery Point based on actual conditions for such period of time.

1.9. "Back-Up Tapes" is defined in Section 16.3.

1.10. "Bankrupt" means, with respect to a Party or any Affiliate of such Party that is currently acting as its credit support provider, that such Party or Affiliate acting as credit support provider: (a) makes an assignment or any general arrangement for the benefit of creditors; (b) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy or similar law for the protection of creditors; (c) has such a petition filed against it as debtor and such petition is not stayed, withdrawn, or dismissed within thirty (30) Business Days of such filing; (d) seeks or has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets; (e) has a distress, execution, attachment, sequestration or other legal process levied, enforced or sued on or against all or substantially all of its assets; (f) is unable to pay its debts as they fall due or admits in writing of its inability to pay its debts generally as they become due; and/or (g) otherwise becomes bankrupt or insolvent (however evidenced).

1.11. "Billing Meter" is defined in Section 10.

1.12. "Billing Period" is defined in Section 11.

1.13. "Business Day" means any day on which the Federal Reserve member banks in New York City are open for business. A Business Day shall run from 8:00 a.m. to 5:00 p.m. Eastern Prevailing Time.

1.14. "Buyer" shall have the meaning specified in the first paragraph of this Agreement

1.15. "Capacity" means and includes the electric generation capability and ability of the Facility and all associated characteristics and attributes, inclusive of the ability to contribute to peak system demands, as well as reserve requirements.

1.16. "Capacity Test" means the testing procedures, requirements and protocols set forth in Section 8.10 and Exhibit 11.

1.17. ~~1.16.~~ "Certificate" means the electronic instrument created and issued by the Tracking System.

1.18. ~~1.17.~~ "Change of Control" means a transaction or series of related transactions (by way of merger, consolidation, sale of stock or assets, or otherwise) with any person, entity or "group" (within the meaning of Section 13(d)(3) of the U.S. Securities Exchange Act of 1934) of persons pursuant to which such person, entity, or group would acquire (i) 50% or more of the voting interests in Seller or (ii) substantially all of the assets of Seller.

1.19. ~~1.18.~~ "Commercial Operation" means that the Facility is operational and placed into service such that all of the following have occurred and remain simultaneously true and accurate: (a) the Facility has been constructed, tested, and is fully capable of operating for the purpose of generating the Product and delivering as required herein; (b) the Facility has received written authorization from the Transmission Provider for interconnection and synchronization of the Facility with the System; (c) the Facility has obtained all Permits and Required Approvals; and (d) the Facility has met all requirements necessary for safely and reliably generating the Product and delivering the Product to Buyer in accordance with Prudent Utility Practice.

1.20. ~~1.19.~~ "Commercial Operation Date" means the date on which the Facility achieves or achieved Commercial Operation.

1.21. ~~1.20.~~ "Commercially Reasonable Manner" or "Commercially Reasonable" means, with respect to a given goal or requirement, the manner, efforts and resources a reasonable person in the position of the promisor would use, in the exercise of its reasonable business discretion and industry practice, so as to achieve that goal or requirement, which in no event shall be less than the level of efforts and resources standard in the industry for comparable companies with respect to comparable products. Factors used to determine whether a goal or requirement has been performed in a "Commercially Reasonable Manner" may include, but shall not be limited to, any specific factors or considerations identified in the Agreement as relevant to such goal or requirement.

1.22. ~~1.21.~~ "Commission" means the North Carolina Utilities Commission or any successor thereto.

1.23. ~~1.22.~~ "Contract Price" is defined in Section 4.5.

1.24. "Contract Capacity" means [XX] MW, subject to adjustment from time to time pursuant to Section 8.10.

1.25. ~~1.23.~~ "Contract Quantity" is defined in Section 4.3.

~~1.24. "Control Compensation" is defined in Section 8.9.1.~~

1.26. ~~1.25.~~ "Control Equipment" is defined in Section 8.7.

1.27. ~~1.26.~~ "Control Instruction" means any System Operator Instruction provided via the Control Equipment to dispatch, operate, and/or control the Facility in the same manner and/or for any reason as the System Operator may, in its sole discretion, dispatch, operate, and/or control Buyer's own generating resources and power purchase arrangements used to provide service to Buyer's native load customers.

1.28. ~~1.27.~~ "Costs" means, with respect to the Non-Defaulting Party, brokerage fees, commissions, and other similar third party transaction costs and expenses, and other costs and expenses reasonably incurred by such Party either in terminating any arrangement pursuant to which it has hedged its obligations or entering into new arrangements which replace the terminated transaction(s), and all reasonable attorneys' fees and other legal expenses incurred by the Non-Defaulting Party in connection with the termination.

1.29. ~~1.28.~~ "CPRE Program" means the Competitive Procurement of Renewable Energy Program instituted by Buyer pursuant to N.C. Gen. Stat. Section 62-110.8

1.30. ~~1.29.~~ "Credit Rating" means, with respect to any entity, the rating then assigned to such entity's unsecured, senior long-term debt obligations (not supported by third party credit enhancements) or if such entity does not have a rating for its senior unsecured long-term debt, then the rating then assigned to such entity as a corporate or issuer rating.

1.31. ~~1.30.~~ "Creditworthy" or "Creditworthiness" - means (i) a Person with an investment grade Credit Rating from two (2) of the three (3) Rating Agencies such that its senior unsecured debt (or issuer rating if such Person has no senior unsecured debt rating) is rated at least (A) BBB- by S&P, if rated by S&P, (B) Baa3 by Moody's, if rated by Moody's, and (C) BBB- by Fitch, if rated by Fitch, respectively, and (ii) has satisfactory and verifiable creditworthiness determined in Buyer's sole discretion.

1.32. ~~1.31.~~ "Defaulting Party" is defined in Section 19.

1.33. ~~1.32.~~ "Delivery Period" is defined in Section 4.1.

1.34. ~~1.33.~~ "Dispatch ~~Down" means any reduction or cessation of Energy generation by the Facility in response to an order or instruction by or direct action taken by the System Operator.~~ Accuracy Damages" is defined in Section 8.9.

1.35. "Dispatch Accuracy Rate" means, for each calendar year during the Delivery Period, the quotient of (a) the total Energy delivered from the Facility for such calendar year, divided by (b) the total Energy dispatched from the Facility by the Control Equipment for such calendar year; provided, however, that for any period of time for which the dispatch instructions did not comply with the Operating Characteristics, the Energy dispatched from the Facility for such period of time will be deemed to be equal to the Energy delivered from the Facility for such period of time.

1.36. "Dispatch Accuracy Rate Requirement" is defined in Section 8.9.

1.37. ~~1.34.~~ "Disputes" is defined in Section 23.1.

1.38. ~~1.35.~~ "Early Termination Date" is defined in Section 20.1.

1.39. ~~1.36.~~ "Delivery Point" means the point of interconnection between the Facility and the System on the high side (Buyer or Transmission Provider side) of the System.

1.40. ~~1.37.~~ "Effective Date" is defined in the introductory paragraph hereto.

1.41. ~~1.38.~~ "Emergency Condition" means, no matter the cause: (a) any urgent, abnormal, operationally unstable, dangerous, or public safety condition that is existing on the System or any portion thereof; (b) any urgent, abnormal, operationally unstable, dangerous, and/or public safety condition that is likely to result in any of the following: (i) loss or damage to the Facility or the System, (ii) disruption of generation by the Facility, (iii) disruption of service or stability on, to or of the System, or (iv) condition that may result in endangerment of human life or public safety; or (c) any circumstance that requires action by the System Operator to comply with standing NERC regulations or standards, including without limitation actions to respond to, prevent, limit, or manage loss or damage to the Facility, loss or damage to the System, disruption of generation by the Facility, disruption of service on the System, an abnormal condition on the System, and/or endangerment to human life or safety. An Emergency Condition will be an excuse to Seller's performance only if such condition is not due to Seller's negligence, willful misconduct, and/or Seller's failure to perform as required under this Agreement.

1.42. ~~1.39.~~ "Emergency Condition Instruction" means any System Operator Instruction relating to, due to, in response to, or to address an Emergency Condition.

1.43. ~~1.40.~~ "Energy" means three-phase, 60-cycle alternating current electric power and energy, expressed in either kWh or MWh, as the case may be.

1.44. ~~1.41.~~ "EPT" or "Eastern Prevailing Time" means the time in effect in the Eastern Time Zone of the United States of America, whether it be Eastern Standard Time or Eastern Daylight Savings Time.

~~1.42. "Estimation Methodology" is defined in Section 8.9.3.~~

1.45. ~~1.43.~~ "Event of Default" is defined in Section 19.

~~1.44. "Expected Annual Output" means the quantity of Energy identified in Exhibit 5 for each calendar year during the Delivery Period of the Facility.~~

1.46. ~~1.45.~~ "Facility" means Seller's [describe facility including renewable energy resource used] electric generating facility located in [_________] County, [_______________ [State], at ___________], as further identified in Exhibit 4.

1.47. ~~1.46.~~ "FERC" means the Federal Energy Regulatory Commission or any successor thereto.

1.48. ~~1.47.~~ "First COD Date" is defined in Section 20.5.

1.49. ~~1.48.~~ "Fitch" - means Fitch Ratings Ltd. or its successor.

1.50. ~~1.49.~~ "Force Majeure" is defined in Section 14.1.

1.51. ~~1.50.~~ "Force Majeure Instruction" means any System Operator Instruction relating to, due to, in response to, or to address a Force Majeure.

1.52. ~~1.51.~~ "GAAP" is defined in Section 9.1.

1.53. ~~1.52.~~ "Gains" means, with respect to the Non-Defaulting Party, an amount equal to the present value of the economic benefit to the Non-Defaulting Party, if any (exclusive of Costs), resulting from the termination of this Agreement for the remaining Term, determined in a Commercially Reasonable Manner. Factors used in determining the economic benefit may include, without limitation, reference to information available either internally or supplied by third parties, including without limitation, quotations (either firm or indicative) of relevant rates, prices, yields, yield curves, or other relevant market data, comparable transactions, settlement prices or market prices for comparable transactions, forward price curves, production by comparable facilities, expected and historical production, all calculated for the remaining Term of the Agreement for the Product (inclusive of all components).

1.54. ~~1.53.~~ "Governmental Authority" means any federal, state or local government, legislative body, court of competent jurisdiction, administrative agency or commission or other governmental or regulatory authority or instrumentality or authorized arbitral body, including, without limitation, the Commission.

1.55. ~~1.54.~~ "Guarantor" means any Creditworthy Person having the authority and agreeing to guarantee the Seller's obligations under this Agreement and is otherwise acceptable to Buyer in its sole discretion.

1.56. ~~1.55.~~ "Guaranty" means a parent company guaranty, in substantially the form set forth in Exhibit 6 attached hereto, provided by a Guarantor in favor of Buyer guaranteeing the obligations of Seller under this Agreement.

1.57. "Implied Energy Price" means the quotient of (a) the product of (i) the Contract Capacity, multiplied by (ii) the Contract Price, multiplied by (iii) the constant twelve (12), divided by (b) [insert the estimated average annual Available Facility Energy] MWh.

1.58. ~~1.56.~~ "Interconnection Agreement" means the separate interconnection and transmission service agreement (or agreements) to be negotiated and executed between Seller and the Transmission Provider concerning the interconnection of the Facility with the System, upgrade to the System to accommodate the Facility's interconnection with and operation in parallel with the System, and the requirements for transmission service.

1.59. ~~1.57.~~ "Interconnection Facilities and System Upgrades In-Service Date" shall be the later of the Requested Upgraded In-Service Date and Requested Facilities In-Service Date as specified in Appendix 4 (Milestones) of the Interconnection Agreement).

1.60. ~~1.58.~~ "Interconnection Instruction" means any order, action, signal, requirement, demand, and/or direction, howsoever provided or implemented by the System Operator due to, in response to, or to address any condition relating to any service and/or obligation occurring under the Interconnection Agreement.

1.61. ~~1.59.~~ "Interest Rate" means, for any date, the lesser of (a) the per annum rate of interest equal to the prime lending rate as may from time to time be published in *The Wall Street Journal* under "Money Rates" on such day (or if not published on such day on the most recent preceding day on which published), plus two percent (2%); and, (b) the maximum rate permitted by applicable law.

1.62. ~~1.60.~~ "kW" means kilowatt.

1.63. ~~1.61.~~ "kWh" means kilowatt-hour.

1.64. ~~1.62.~~ "Letter(s) of Credit" means one or more irrevocable standby letters of credit in the form of Exhibit 7 attached hereto, issued by a U.S. commercial bank or other financial institution reasonably acceptable to Buyer, which is not an Affiliate of Seller, which has and maintains a Credit Rating of at least A- from S&P and A3 from Moody's, for the Security Period, permitting Buyer to draw the entire amount if either such amount is owed or such Letter of Credit is not renewed or replaced at least thirty (30) Business Days prior to its stated expiration date, and is otherwise acceptable in all respects to Buyer in its sole discretion.

1.65. ~~1.63.~~ "Lien" means any mortgage, deed of trust, lien, pledge, charge, claim, security interest, easement, covenant, right of way, restriction, equity, or encumbrance of any nature whatsoever.

1.66. ~~1.64.~~ "Losses" means, with respect to the Non-Defaulting Party, an amount equal to the present value of the economic loss to the Non-Defaulting Party, if any (exclusive of Costs), resulting from the termination of this Agreement for the remaining Term, determined in a Commercially Reasonable Manner. Factors used in determining the economic loss or loss of economic benefit may include, without limitation, reference to information available either internally or supplied by third parties, including without limitation, quotations (either firm or indicative) of relevant rates, prices, yields, yield curves, or other relevant market data, comparable transactions, settlement prices or market prices for comparable transactions, forward price curves, production by comparable facilities, expected and historical production, all calculated for the remaining Term of the Agreement for the Product (inclusive of all components).

1.67. ~~1.65.~~ "Maintenance Outage" means the temporary operational removal of the Facility from service to perform work on specific components of the Facility, at a time when the Facility must be removed from service before the next Planned Outage in the interest of safety or the prevention of injury or damage to or undue wear and tear on the Facility or any component thereof.

1.68. ~~1.66.~~ "Milestone Deadline" means the deadline for Seller to achieve each Operational Milestone as set forth in Exhibit 3.

1.69. ~~1.67.~~ "Moody's" means Moody's Investors Service, Inc. or any successor-rating agency thereto.

1.70. ~~1.68.~~ "MW" means megawatt.

1.71. ~~1.69.~~ "MWh" means megawatt-hour.

1.72. ~~1.70.~~ "Nameplate Capacity Rating" means the installed temperature derated inverter nameplate AC capacity rating of the Facility set forth in Exhibit 4.

1.73. ~~1.71.~~ "NERC" means the North American Electric Reliability Corporation. For purposes of this Agreement, NERC includes any applicable regional entity with delegated authority from NERC, such as the SERC Reliability Corporation (SERC).

1.74. ~~1.72.~~ "New Renewable Energy Facility" is defined in the Act.

1.75. ~~1.73.~~ "Non-Defaulting Party" is defined in Section 20.

1.76. "Operating Characteristics" means the limitations on the dispatch of the Facility set forth in Exhibit 5 and the Energy Storage Protocol in Exhibit 10.

1.77. ~~1.74.~~ "Operational Milestone" means each operational event and result that Seller must achieve as set forth in the Operational Milestone Schedule, with such supporting documentation as may be requested by Buyer from time-to-time in its Commercially Reasonable discretion.

1.78. ~~1.75.~~ "Operational Milestone Schedule" means the schedule established in Exhibit 3 setting forth each Operational Milestone that Seller must fully complete by the Milestone Deadline.

1.79. ~~1.76.~~ "Party" or "Parties" is defined in the introductory paragraph hereto.

1.80. ~~1.77.~~ "Performance Assurance" means collateral in the form of either cash, Letter(s) of Credit or a Guaranty that is acceptable to Buyer in its sole discretion, in each case that meets the requirements set forth in this Agreement (including, without limitation, Section 5) provided by Seller to Buyer for the benefit of Buyer pursuant to this Agreement, as credit support, adequate assurances, and security to secure Seller's performance under this Agreement.

1.81. ~~1.78.~~ "Permit" means any permit, license, registration, filing, certificate of occupancy, certificate of public convenience and necessity, approval, variance or any authorization from or by any Governmental Authority and pursuant to any Requirements of Law.

1.82. ~~1.79.~~ "Permitted Excuse to Perform" means that Seller's obligation to generate~~,~~ and deliver, ~~and sell~~ and Buyer's obligation to receive ~~and purchase~~ is excused and no damages will be payable by either Party to the other Party, if and to the extent such failure is due solely to any of the following occurrences: (a) an Emergency Condition Instruction; (b) a Control Instruction; (c) an Interconnection Instruction; or, (d) a Force Majeure Instruction.

1.83. ~~1.80.~~ "Person" means any individual, entity, corporation, general or limited partnership, limited liability company, joint venture, estate, trust, association or other entity or Governmental Authority.

1.84. ~~1.81.~~ “Planned Outage” means the temporary operational removal of the Facility from service to perform work on specific components in accordance with a pre-planned operations schedule, such as for a planned annual overhaul, inspections, or testing of specific equipment of the Facility.

1.85. ~~1.82.~~ “Product” means the Capacity of the Facility, Energy generated by the Facility, and the RECs associated with the Energy generated by the Facility.

1.86. ~~1.83.~~ “Protected Information” is defined in Section 16.1

1.87. ~~1.84.~~ “Prudent Utility Practice” means those practices, methods, equipment, specifications, standards of safety, and performance, as the same may change from time to time, as are commonly used in the construction, interconnection, operation, and maintenance of electric power facilities, inclusive of delivery, transmission, and generation facilities and ancillaries, which in the exercise of good judgment and in light of the facts known at the time of the decision being made and activity being performed are considered: (i) good, safe, and prudent practices; (ii) are in accordance with generally accepted standards of safety, performance, dependability, efficiency, and economy in the United States; (iii) are in accordance with generally accepted standards of professional care, skill, diligence, and competence in the United States; and, (iv) are in compliance with applicable regulatory requirements and/or reliability standards. Prudent Utility Practices are not intended to be limited to the optimum practices, methods or acts to the exclusion of others, but rather are intended to include acceptable practices, methods and acts generally accepted in the energy generation and utility industry.

1.88. ~~1.85.~~ “PSC” means the Public Service Commission of South Carolina, or successor thereto.

1.89. ~~1.86.~~ “PURPA” means the Public Utility Regulatory Policies Act of 1978, as amended, and as such may be amended from time to time.

1.90. ~~1.87.~~ “PURPA Fuel Requirements” means the requirements set forth in 18 C.F.R. § 292.204 OR 205, as may be amended and/or restated.

1.91. ~~1.88.~~ “Qualifying Facility” means an electric generating facility that has been registered and certified by FERC as generator that qualifies for and meets the requirements set forth in PURPA, as it may be amended, and associated rules, regulations, orders.

1.92. ~~1.89.~~ “Rating Agency” or “Rating Agencies” - means the rating entities of S&P, Moody’s or Fitch.

1.93. ~~1.90.~~ “REA Reporting Rights” means the right of the reporting person or entity to report that it owns the Renewable Energy Attributes to any Governmental Authority or other party under any compliance, voluntary, trading, or reporting program, public or private and to any person, customers, or potential customers for, including without limitation, purposes of compliance, marketing, publicity, advertising, or otherwise.

1.94. ~~1.91.~~ “Regulatory Event” is defined in Section 15.1.

1.95. ~~1.92.~~ “Renewable Energy Attributes” means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation of Energy by the Facility, the use of such Energy, or such Energy’s displacement of conventional Energy generation, including any and all renewable or environmental characteristics and benefits of the Energy generated by the Facility. Renewable Energy Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride and other greenhouse gases (GHGs), ozone depleting substances, ozone, and non-methane volatile organic compounds that have been or may be determined by the United Nations Intergovernmental Panel on Climate Change (UNIPCC), by law, or otherwise by science or in the voluntary markets to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere; (3) any credit, allowance or instrument issued or issuable pursuant to a state implementation plan under regulations promulgated by the Environmental Protection Agency under the Clean Air Act and (4) the reporting rights to any of the foregoing, including, without limitation, REA Reporting Rights and any and all renewable and/or environmental characteristics and benefits of the Energy generated by the Facility. Renewable Energy Attributes do not include: (i) any Energy or Capacity of the Facility; (ii) investment tax credits, production tax credits, or other tax credits, cash grants in lieu of tax credits associated with the construction, ownership or operation of the Facility, or (iii) any adverse wildlife or environmental impacts.

1.96. ~~1.93.~~ "Renewable Energy Certificate(s)" or "REC(s)" means and, notwithstanding anything to the contrary set forth in the Act includes, all of the Renewable Energy Attributes and REA Reporting Rights associated with one (1) megawatt hour (MWh) of Energy generated by the Facility. The REC represents all title to and claim over all of the Renewable Energy Attributes and REA Reporting Rights associated with in any manner with the Energy generated by the Facility.

1.97. ~~1.94.~~ "Renewable Energy Resource" is defined in the Act.

1.98. ~~1.95.~~ "Required Approval" is defined in Section 6.

1.99. ~~1.96.~~ "Requirements of Law" means any federal, state, and local law, statute, regulation, rule, code, ordinance, resolution, order, writ, judgment, decree or Permit enacted, adopted, issued or promulgated by any Governmental Authority, including, without limitation, (i) the Act, (ii) those pertaining to the creation and delivery of the Product, (iii) those pertaining to electrical, building, zoning, occupational safety, health requirements or to pollution or protection of the environment, and (iv) principles of common law under which a person may be held liable for the release or discharge of any hazardous substance into the environment or any other environmental damage.

1.100. ~~1.97.~~ "Second COD Date" is defined in Section 20.5.1.

1.101. ~~1.98.~~ "Security Period" is defined in Section 5.6.

1.102. ~~1.99.~~ "Seller" shall have the meaning specified in the first paragraph of this Agreement.

1.103. "Solar Performance Modeling Program" means a commercially available computer modeling program that is generally accepted in the solar energy industry capable of modeling the expected Energy production of the Facility and other similar outputs. Solar Performance Modeling Program includes, but is not limited to, the PVSYST program and the Plant Predict program.

1.104. ~~1.100.~~ "S&P" means Standard & Poor's Ratings Services, Inc. or any successor-rating agency thereto.

1.105. ~~1.101.~~ "Station Power" means the Energy generated by the Facility and, whether metered or unmetered, used on-site to supply the Facility's auxiliary load and parasitic load and/or for powering the electric generation equipment. Station Power shall not include any Energy generated by the Facility and stored for later sale or delivery to the Buyer under this Agreement.

1.106. ~~1.102.~~ "System" means the transmission, distribution, and generation facilities that are owned, directed, managed, interconnected, controlled, or operated by Buyer and/or the Transmission Provider, including, without limitation, facilities to provide retail or wholesale service, substations, circuits, reinforcements, meters, extensions, or equipment associated with or connected to any interconnected facility or customer.

1.107. ~~1.103.~~ "System Operator" means the operators of the System that have the responsibilities for ensuring that the System as a whole or any part thereof operates safely, efficiently, and reliably, including without limitation the responsibilities to comply with any applicable operational or reliability requirements, the responsibilities to balance generation supply with customer load, the responsibilities to comply with any other regulatory obligation including least cost dispatch and System optimization, and the responsibilities to provide dispatch and curtailment instructions to generators supplying Energy to the System. The System Operator includes any person or entity delivering any such instructions or signals to Seller or taking any action relating to, due to, in response to, or to address such instructions.

1.108. ~~1.104.~~ "System Operator Instruction" for purposes of this Agreement means any order, action, signal, requirement, demand, dispatch decision, and/or direction, howsoever provided or implemented by the System Operator to operate, dispatch, control, manage, or otherwise operate the System in accordance with any applicable obligation and/or regulatory requirement, including, without limitation, those undertaken and implemented by the System Operator, in its sole discretion based on relevant System factors and dispatch considerations, including any and all ~~operating characteristics~~ Operating Characteristics, maintenance requirements, operational limitations, operational or dispatch planning, reliability (including standing NERC regulations or standards), safety, least cost dispatch, constraints, discharge, emissions limitations, compliance requirements, communications, resource ramp-up and ramp-down constraints and implementation, and any other System considerations~~, which may include, without limitation, any such instruction to: (i) interconnect, disconnect, integrate, operate in parallel, or synchronize with the System, (ii) increase, reduce, or cease generation output to comply with standing NERC regulations or standards or any other regulatory obligation applicable to the dispatch or operation of the System; (iii) respond to any transmission, distribution, or delivery limitations or interruptions; (iv) perform or cease performing any activity so as to operate in accordance with System limitations, including, without limitation, operational constraints that would require the System Operator to force offline or reduce generation output from reliability generators to accommodate generation by the Facility; and, (v) suspend, interrupt, dispatch, increase or decrease any operational and/or generation activity occurring on or into the System pursuant to Control Instructions, Emergency Condition Instructions, and Force Majeure Instructions. 1.104.1. For purposes of this Agreement, a System Operator Instruction shall not include any Interconnection Instruction~~.

1.109. ~~1.105.~~ "Taxes" means all taxes, fees, levies, licenses or charges imposed by any Governmental Authority, together with any interest and penalties thereon.

1.110. ~~1.106.~~ "Term" is defined in Section 3.1.

1.111. ~~1.107.~~ "Testing Period" is defined in Section 4.4.

1.112. "Theoretical Annual Output" means, for each full calendar year after the Commercial Operation Date, the quantity of Energy from the Facility that Seller would have been capable of delivering at the Delivery Point for the applicable calendar year with all inverters on-line and will be calculated using the Solar Performance Modeling Program, as adjusted to reflect the Facility as built as of the Commercial Operation Date, and with inputs based on: (A) actual irradiance, spectral shift and ambient temperature determined by the meteorological stations located at the Facility, (B) a degradation rate equal to [X%] per year, (C) actual snow or soiling losses for the Facility as measured by soiling stations at the Facility or, if no soiling stations are available, using a mutually agreed upon soiling loss assumption, and (D) any other adjustments necessary to accurately reflect the Facility's capability to produce and deliver energy at the Delivery Point assuming all inverters are on-line.

1.113. ~~1.108.~~ "Tracking System" means the verification system that accounts for the generation, sale, purchase, and/or retirement of renewable energy and credits, which will be the North Carolina Renewable Energy Tracking System, administered by the Commission pursuant to the Act.

1.114. ~~1.109.~~ "Transmission Provider" means the entity or division within [Duke Energy Carolinas, LLC] [Duke Energy Progress, LLC] that will provide interconnection and/or electric distribution or transmission service to enable delivery of Energy generated by the Facility to Buyer, and any such entity or division will include any successor or replacement thereto, including without limitation, a consolidated control area or a regional transmission organization.

1.115. ~~1.110.~~ "Vintage" means the moment when the MWh of Energy is generated by the Facility, and therefore, when the REC associated with that MWh of Energy is generated by the Facility.

2. Interpretation

2.1. Intent. Unless a different intention clearly appears, the following terms and phrases shall be interpreted as follows: (a) the singular includes the plural and vice versa; (b) the reference to any Person includes such Person's legal and/or permitted successors and assignees, and reference to a Person in a particular capacity excludes such Person in any other capacity or individually; (c) the reference to any gender includes the other gender and the neuter; (d) reference to any document, including this Agreement, refers to such document as it may be amended, amended and restated, modified, replaced or superseded from time to time in accordance with its terms, or any successor document(s) thereto; (e) reference to any section or exhibit means such section or exhibit of this Agreement unless otherwise indicated; (f) "hereunder", "hereof", "hereto", "herein", and words of similar import shall be deemed references to this Agreement as a whole and not to any particular section or other provision; (g) "including" (and with correlative meaning "include"), means "including without limitation" and when following any statement or term, is not to be construed as limiting the general statement or term to the specific items or matters set forth or to similar items or matters, but rather as permitting the general statement or term to refer to all other items or matters that could reasonably fall within its broadest possible scope; (h) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including"; (i) reference to any Requirements of Law refers to such Requirements of Law as it may be amended, modified, replaced or superseded from time to time, or any successor Requirements of Law thereto; and (j) all exhibits and attachments to this Agreement are hereby incorporated into this Agreement. Other terms used, but not defined in Section 1 or in the body of the Agreement, shall have meanings as commonly used in the English language and, where applicable, in the electric utility industry. Words not otherwise defined herein that have well known and generally accepted technical or trade meanings are used herein in accordance with such recognized meanings.

3. **Term and Termination**

3.1. Term. This Agreement shall be effective as of the Effective Date and shall remain in full force and effect until the [twentieth (20^{th})] anniversary of the Commercial Operation Date ("Term"), unless terminated earlier pursuant to the provisions of this Agreement.

3.2. Termination and Survival. This Agreement may be terminated earlier than the expiration of the Term as provided for herein. If this Agreement is terminated earlier than the expiration of the Term for any reason, including, without limitation, whether by its terms, mutual agreement, early termination, and/or event of default, such termination shall not relieve any Party of any obligation accrued or accruing prior to the effectiveness of such termination. Furthermore, any obligations, limitations, exclusions and duties which by their nature or the express terms of this Agreement extend beyond the expiration or termination of this Agreement, including, without limitation, provisions relating to compliance requirements, accounting, billing, billing adjustments, limitations or liabilities, dispute resolution, Performance Assurance, and any other provisions necessary to interpret or enforce the respective rights and obligations of the Parties hereunder, shall survive the expiration or early termination of this Agreement.

3.3. [FOR FACILITIES LOCATED IN SOUTH CAROLINA ONLY] Condition Precedent for Buyer. It is a condition to the continuing obligations of each Party under this Agreement that the Public Service Commission of South Carolina (the "PSC") shall have accepted this Agreement for filing with the PSC without any modification (unless such modification is acceptable to all the Parties), condition, suspension, or investigation. No later than twenty (20) Business Days after both Parties have executed this Agreement, Buyer will submit the Agreement for filing with the PSC. Seller agrees that Buyer will have sole discretion over all aspects of such submittal, including without limitation, the form and substance of the submittal, confidentiality, procedure, responding to any data requests, and providing any information to the PSC and the South Carolina Office of Regulatory Staff. Seller will not oppose or challenge the PSC's acceptance of this Agreement, and upon request by Buyer will promptly and fully support the PSC's acceptance of this Agreement without any modification, condition, suspension, or investigation. Buyer will make a good faith request that the PSC and the South Carolina Office of Regulatory Staff keep confidential the terms and conditions of this Agreement; *provided, however,* Seller agrees and acknowledges that information (including Protected Information) contained in this Agreement may become public by its submission to the PSC and the South Carolina Office of Regulatory Staff, and Seller hereby consents to any such disclosure, without any reservations and without any prior notice to Seller. If the PSC issues an order or any other directive to modify, condition, suspend, or investigate any aspect of this Agreement prior to its acceptance, then this Agreement will immediately terminate, and upon any such termination neither Party shall have any obligation, duty, or liability to the other Party under this Agreement. In the event of such termination, each Party will retain its respective rights under PURPA. Buyer will provide notice to Seller after Buyer has received written notice of the PSC's determination in regards to Buyer's request that the PSC accept the Agreement for filing, and if such written notice from the PSC accepts this Agreement without any modification, condition, suspension, or investigation then Buyer will notify Seller that the condition precedent under this Section 3.3 has been satisfied.

4. **Purchase and Sale Obligations**

4.1. Delivery Period. The "Delivery Period" for the Product to be generated by the Facility and sold by Seller to Buyer shall be for all hours starting at 12:00:01 AM EPT on the Commercial Operation Date through the end of the Term, unless this Agreement is terminated earlier pursuant to its terms and conditions.

4.2. Vintage. The RECs shall be of the same Vintage as the MWh of Energy generated by the Facility, and the RECs shall arise due to the generation of Energy by the Facility.

4.3. Contract Quantity. The "Contract Quantity" will be one hundred percent (100%) of the Capacity, output of Energy (including stored Energy), and associated RECs produced by the Facility, less that associated with Station Power.

4.3.1. Seller shall sell and deliver the Contract Quantity of the Product exclusively and solely to Buyer. Seller's failure to generate, sell, and deliver the Contract Quantity of the Product to Buyer will be excused with no damages payable to Buyer solely to the extent such failure is due to a Permitted Excuse to Perform.

4.3.2. Buyer shall have no obligation to receive~~, purchase, pay for,~~ or pay any damages associated with not receiving the Product due to a Permitted Excuse to Perform. Buyer shall have full and exclusive rights to the Product (inclusive of all components), and will be entitled to full and exclusive use of the Product (inclusive of all components) for its purposes and in its sole and exclusive discretion.

4.3.3. The estimated monthly and annual Available Facility Energy ~~production of the Facility~~ during the Delivery Period is set forth in Exhibit 1 hereto.

4.4. Testing Period. Prior to the Facility's Commercial Operation Date Seller may test the capability of the Facility to operate and generate the Product in accordance with this Agreement (such operational period, the "Testing Period"). Seller shall provide Buyer with written notice of a date certain on which Seller desires to initiate the Testing Period. Buyer will cooperate with Seller to enable the Facility to be dispatched at the levels required for Seller to complete all commissioning and testing requirements applicable to the Facility. After the Facility has achieved the Commercial Operation Date, the Buyer shall, expressly subject to the limitations set forth below, purchase the Product produced by the Facility during the Testing Period at the applicable Contract Price set forth in Exhibit 2, but expressly subject to the Buyer fully satisfying the following conditions: (i) the Testing Period shall not exceed sixty (60) days; (ii) the RECs shall meet all of the requirements set forth in this Agreement; and, (iii) Seller shall certify in writing to Buyer, and to Buyer's satisfaction, together with supporting details, that each unit of the Product (including the associated REC) to be sold and purchased during the Testing Period was generated in compliance with the requirements of this Agreement. To the extent Seller is unable to satisfy the foregoing requirements; the Buyer shall purchase the Energy generated by the Facility at the ~~rate for the~~ Test Energy ~~only component of the Product~~ Rate set forth in Exhibit 2.

4.5. Contract Price. The "Contract Price" for the Product shall be the price corresponding to the relevant portion of the Delivery Period as set forth in Exhibit 2.

4.6. Energy Delivery. Seller shall deliver the Contract Quantity of the Energy component of Product at the Delivery Point, and Seller shall be fully responsible for all costs, charges, expenses, and requirements associated with delivering the Energy to the Delivery Point. ~~Buyer will have no obligation to pay for any Energy not delivered to the Delivery Point.~~

4.7. REC Delivery. Seller shall deliver to Buyer's Account the Contract Quantity of the REC component of the Product in the form of Certificates. Seller agrees that in addition to representing the attributes and characteristics under the Tracking System's operating rules and requirements, the Certificate will also represent the REC, Renewable Energy Attributes, and REA Reporting Rights as defined in this Agreement. No later than fourteen (14) calendar days after the meter data is delivered to Seller's Account, Seller shall review the meter data and complete all acts necessary to create the Certificates in the Tracking System and shall transfer the Certificates into Buyer's Account. Each Party shall establish an

Account with the Tracking System for the creation, transfer, and/or receipt of the Certificates. Seller agrees to establish the Account for the Facility no later than fifteen (15) Business Days prior to the Commercial Operation Date.

4.8. Payment for Product. Buyer agrees to pay Seller for the Product generated and delivered in accordance with this Agreement by Seller to Buyer in accordance with the pricing set forth in Exhibit 2. Seller agrees that to the extent Buyer has already paid for the Product prior to Seller transferring the REC component of the Product in the manner noted above, Buyer shall have ownership of the REC component of the Product, and Seller shall hold the same in trust for Buyer until the transfer is completed as provided for herein. ~~Buyer shall not be obligated to pay for, and shall receive a full refund with respect to,~~ Seller shall refund Buyer [$XX/REC] for any RECs for which the Certificates are not delivered to Buyer's Account.

4.9. Transfer. In no event shall Seller procure or have the right to procure the Product or any component of the Product from any source other than the Facility for sale and delivery pursuant to this Agreement. Title to and risk of loss to the Product sold and delivered hereunder shall transfer from Seller to Buyer after completion of delivery at the Delivery Point and after completion of transfer of the REC component of the Product. Seller shall be responsible for any costs and charges imposed on or associated with the Product and the delivery of the Product at the Delivery Point and upon completion of transfer of the REC component. Buyer shall be responsible for any costs or charges imposed on or associated with the Product after the Delivery Point and after completion of transfer of the REC.

5. **Credit and Related Provisions**.

5.1. Pre-COD Performance Assurance Requirements. Subject to Section 5.3 below, no later than five (5) business days after the Effective Date, Seller shall provide and deliver to Buyer Performance Assurance in the amount of [*4% x total projected revenue under the Agreement during the Term as determined by Buyer in its reasonable discretion*], as such Performance Assurance may be adjusted pursuant to Section 20.5.1.

5.2. Post-COD Performance Assurance. Subject to Section 5.3 below, after the Facility achieves Commercial Operation, Seller shall provide Buyer with Performance Assurance in the amount of [*for each year during the Term the greater of (i) 2% x total projected revenue under the Agreement during the Term as determined by Buyer in its reasonable discretion and (ii) the overpayment to the Seller under the contract price relative to Buyer's actual avoided cost in the applicable year*] set forth in the below table corresponding to the applicable period during the Term of this Agreement. Seller may request and Buyer may, subject to Section 5.2, adjust the amount of such Performance Assurance within fifteen (15) Business Days of Seller's written request to coincide with the amount set forth in the below table. Seller's failure to provide the Performance Assurance and/or to maintain the Performance Assurance in the required amount and in full force and effect throughout the Term of this Agreement will be an Event of Default under this Agreement.

[*Insert* TABLE – Annual Performance Assurance]

5.3. Unsecured Credit For Creditworthy Sellers. If Seller, or its Guarantor as applicable, is Creditworthy and is not in default of any provisions under this Agreement or any Guaranty issued in support of this Agreement, the Seller shall be excused from the requirement to post Performance Assurance as required under Sections 5.1 and 5.2 above, as long as it remains Creditworthy. If at any time during the Term of this Agreement, Seller, or its Guarantor, ceases to be Creditworthy due to a change in its Credit Rating, then Seller will notify Buyer of such change in its credit status and shall provide Performance Assurance to Buyer in the amounts required under Section 5.1 or 5.2, as applicable, within five (5) Business Days after such change in its Credit Rating.

5.4. Financial Disclosures. Seller shall timely provide to Buyer financial information of Seller as follows: (i) within sixty (60) days after the end of each fiscal quarter of each fiscal year that this Agreement is effective, a copy of Seller's quarterly report containing unaudited consolidated financial statements for such fiscal quarter signed and verified by an authorized officer of Seller attesting to their accuracy; and, (ii) within 120 days after the end of each fiscal year that this Agreement is effective a copy of Seller's annual report containing audited consolidated financial statements for such fiscal year. The statements shall be prepared in accordance with generally accepted accounting principles or other procedures with which Seller is required to comply with under applicable law.

5.5. Netting. If an Event of Default has not occurred and a Party is required to pay an amount to the other Party under this Agreement, then such amounts shall be netted, and the Party owing the greater aggregate amount shall pay to the other Party any difference between the amounts owed. All outstanding obligations to make payment under this Agreement or any other agreement between the Parties may be netted, offset, set off, or recouped therefrom, and payment shall be owed as set forth above. Unless Buyer notifies Seller in writing (except in connection with a liquidation and termination) all amounts netted pursuant to this section shall not take into account or include any credit support, which may be in effect to secure Seller's performance under this Agreement. The netting set forth above, shall be without prejudice and in addition to any and all rights, liens, setoffs, recoupments, counterclaims and other remedies and defenses (to the extent not expressly herein waived or denied) that such Party has or to which such Party may be entitled arising from or out of this Agreement.

5.6. Set-off. In addition to any rights of set-off a Party may have as a matter of law or otherwise and subject to applicable law, upon the occurrence of an Event of Default, the Non-Defaulting Party shall have the right (but shall not be obligated to) without prior notice to the Defaulting Party or any other person to set-off any obligation of the Defaulting Party owed to the Non-Defaulting Party under this Agreement (whether or not matured, whether or not contingent and regardless of the currency, place of payment or booking office of the obligation) against any obligations of the Non-Defaulting Party owing to the Defaulting Party under this Agreement (whether or not matured, whether or not contingent and regardless of the currency, place of payment or booking office of the obligation). If any such obligation is unascertained, the Non-Defaulting Party may in a Commercially Reasonable Manner estimate that obligation and set-off in respect of the estimate, subject to the relevant Party providing an accounting and true-up to the other Party after the amount of the obligation is ascertained.

5.7. Performance Assurance Requirements. Seller shall ensure that the Performance Assurance in the required amount remains in full force, and effect, and outstanding, in the required amount, and for the duration required by this Agreement. All applicable Performance Assurance, as the amount thereof may be increased, decreased, and/or replenished pursuant to the terms of this Agreement, shall remain in full force, and effect, and outstanding for the benefit of Buyer until sixty (60) days following the later of: (a) the end of the Term or (b) the date on which Seller has fully satisfied all obligations to Buyer under this Agreement (the "Security Period"). If at any time any Performance Assurance fails to meet any of the requirements under this Agreement, Seller shall replace such Performance Assurance with alternative Performance Assurance that meets each of the requirements under this Agreement. Seller will be solely responsible for any and all costs incurred with providing and maintaining any Performance Assurance to the full amount required by this Agreement. If Seller fails to replace, renew, or otherwise maintain the required Performance Assurance as and when required by this Agreement, then Buyer: (a) shall be entitled to draw and retain hereunder the full amount of the Performance Assurance; (b) shall not be obligated to make any further payments to Seller until Seller shall have provided Buyer with the replacement Performance Assurance; and, (c) shall be entitled to give Seller notice of an Event of Default and pursue the termination rights and remedies provided for in this Agreement.

5.8. Grant of Security Interest. To secure its obligations and liabilities under this Agreement to Buyer, Seller hereby grants to Buyer a present and continuing first priority security interest in, and lien on (and right of netting and set-off against), and assignment of, all present and future Performance Assurance, including, without limitation, cash collateral and cash equivalent collateral and any and all proceeds resulting therefrom or the liquidation thereof, whether now or hereafter held by, on behalf of, or for the benefit of, Buyer; and, furthermore Seller agrees to take such actions as Buyer reasonably requires to perfect Buyer's first-priority security interest in, and lien on (and right of netting, recoupment, and set-off against), such Performance Assurance and any and all products and proceeds resulting therefrom or from the liquidation thereof, including without limitation proceeds of insurance. Upon or any time after the occurrence or deemed occurrence of an Event of Default or upon an Early Termination Date, Buyer (if it is the Non-Defaulting Party) may do any one or more of the following with respect to Seller (if it is the Defaulting Party): (i) exercise any of the rights and remedies of a secured party with respect to all Performance Assurance, including any such rights and remedies under law then in effect; (ii) exercise its rights of netting, recoupment, and set-off against any and all property of Seller in the possession of Buyer or its agent; (iii) draw on any outstanding applicable forms of Performance Assurance provided for the benefit of Buyer; and, (iv) liquidate all Performance Assurance then held by or for the benefit of Buyer free from any claim or right of any nature whatsoever of Seller, including any equity or right of purchase or redemption by Seller.

6. **Seller Compliance Requirements**.

6.1. Required Approvals. Seller shall at its sole cost and expense timely obtain, maintain, and comply with all Required Approvals during the Term of this Agreement. Without limiting the generality of the following, "Required Approvals" means all of the following:

6.1.1. Commission approval and certification that the Facility is registered and certified as a New Renewable Energy Facility for Buyer to use the Product, including, without limitation, for use to comply with the Act.

6.1.2. All approvals and certifications that the Facility is a Qualifying Facility.

6.1.3. All Permits, authorizations, certifications, and/or approvals from any Governmental Authority and under any Requirements of Law, including, without limitation, from the Commission or FERC, for Seller to construct, build, own, operate, and maintain the Facility and sell and deliver the Product to Buyer.

6.2. Seller Covenants. Seller covenants to Buyer that it shall comply with all of the requirements of the Act and other Requirements of Law applicable to Seller, the Facility, and/or Seller's obligations under the Agreement. Without limiting the generality of the foregoing Seller represents and warrants to Buyer as of the Effective Date of this Agreement and throughout the Term of this Agreement that: (a) Seller has obtained an approved and valid report of proposed construction or certificate of public convenience and necessity for the Facility from the [Commission][PSC]; (b) Seller has submitted to the Transmission Provider and the Transmission Provider has accepted the completed interconnection request for the Facility; and (c) Seller has obtained all applicable certifications and/or approvals for the Facility from

FERC. Seller agrees and acknowledges that Buyer has entered into this Agreement in reliance upon the representations and warranties set forth in this section, and in the event of a breach or failure of or relating to any of the foregoing covenants and warranties, including without limitation for being false or misleading in any respect, then this Agreement will terminate upon Buyer providing Seller with thirty (30) day's written notice. Seller will indemnify and hold Buyer harmless for any breach or failure relating to any of the foregoing covenants and warranties, notwithstanding anything else to the contrary in this Agreement.

6.3. Seller Requirements. Seller agrees and acknowledges that the Act requires Buyer to make certain filings and/or submissions relating to Buyer's obligations under the Act. Within twenty (20) Business Days of a written request from Buyer, Seller agrees to provide Buyer with all information, documents, and affidavits from a duly authorized representative of Seller certifying that the Facility fully complies with PURPA, including without limitation, the PURPA Fuel Requirements and that the Facility and/or the Product complies with the Act and the requirements of the Tracking System. If Seller fails to promptly provide Buyer with such documentation, and Buyer is unable to use the Product for compliance in the calendar year that Buyer desires to use such Product for compliance purposes, then Seller shall be liable to Buyer for cover cost damages as set forth in Section 21.

7. **Seller's Facility Requirements.**

7.1. Seller Requirements. Seller covenants (except to the extent expressly set forth in this Agreement) that: the Facility shall be designed, constructed, operated, controlled, maintained, and tested at Seller's sole cost and expense; the Facility shall be designed, constructed, operated (inclusive, without limitation, of control, metering equipment, and personnel and staffing levels), controlled, maintained, and tested by Seller to perform as required by this Agreement and in compliance with all applicable Requirements of Law and Prudent Utility Practice; the Facility shall be capable of supplying the Product in a safe and reliable manner consistent with the requirements of each applicable Requirements of Law and Prudent Utility Practice; and, that all contracts, agreements, arrangements, and/or Permits (including, without limitation, those necessary or prudent for the construction, ownership and operation of the Facility, such as land use permits, site plan approvals, real property titles and easements, environmental compliance and authorizations, grading and building permits, and contracts and/or licenses to obtain the underlying fuel, install and operate the Facility, and deliver and sell the Product of the Facility) shall be timely obtained and maintained by Seller, at Seller's sole cost and expense. Seller shall be responsible for arranging and obtaining, at its sole risk and expense, any station service required by the Facility. Seller shall construct, interconnect, operate, and maintain the Facility in accordance with Prudent Utility Practice. Seller shall be responsible for all costs, charges, and expenses associated with generating, scheduling, and delivering the Energy to Buyer.

7.1.1. Notice Requirement. For each Operational Milestone, Seller shall deliver written notice to Buyer within five (5) Business Days of Seller having met such Operational Milestone. If Seller will be unable to timely meet any Operational Milestone, Seller shall also deliver written notice to Buyer informing Buyer that Seller will be unable to meet an Operational Milestone, but in any event Seller shall deliver notice to Buyer no later than five (5) Business Day after the due date of the Operational Milestone that Seller failed to achieve. Buyer shall have no obligation or liability to Seller for Buyer failing to advise Seller of any condition, damages, circumstances, infraction, fact, act, omission or disclosure discovered or not discovered by Buyer with respect to any Operational Milestone, the Facility, the System or any contractor.

7.2. Seller Responsibilities. Notwithstanding any provision of this Agreement to the contrary, the Seller agrees that: (a) Buyer shall have no responsibility whatsoever for any costs and/or

Taxes relating to the design, development, construction, maintenance, ownership, or operation of the Facility (including but not limited to any financing costs, and any costs and/or Taxes imposed by any Governmental Authority on or with respect to emissions from or relating to the Facility, and including but not limited to costs and/or Taxes related to any emissions allowances *inter alia* for oxides for sulfur dioxide or nitrogen, carbon dioxide, and mercury), all of which shall be entirely at Seller's sole cost and expense; and, (b) any risk as to the availability of production tax benefits, investment tax credits, grants or any other incentives relating to the design, development, construction, maintenance, ownership, or operation of the Facility shall be borne entirely by Seller.

7.2.1. No Exclusions. If any production or investment tax credit, grants, subsidy, or any other similar incentives or benefit relating, directly or indirectly, to the Facility is unavailable or becomes unavailable at any time during the Term of this Agreement, Seller agrees that such event or circumstance will not: (a) constitute a Force Majeure or Regulatory Event; (b) excuse or otherwise diminish Seller's obligations hereunder in any way; and, (c) give rise to any right by Seller to terminate or avoid performance under this Agreement. Seller agrees that it will solely and fully bear all risks, financial and otherwise throughout the Term, associated with Seller's or the Facility's eligibility to receive any such tax treatment or otherwise qualify for any preferential or accelerated depreciation, accounting, reporting, or tax treatment.

7.3. Transmission Provider. Seller agrees and acknowledges that the Interconnection Agreement is (and will be) a separate agreement (or agreements) between Seller and Transmission Provider, and will exclusively govern all requirements and obligations between Seller and Transmission Provider. Only the Interconnection Agreement will govern all obligations and liabilities set forth in the Interconnection Agreement, and Seller shall be solely and fully responsible for all costs and expenses for which Seller is responsible for under the Interconnection Agreement. Seller shall comply with all Interconnection Instructions.

7.3.1. Nothing in the Interconnection Agreement, nor any other agreement between Seller on the one hand and Transmission Provider on the other hand, nor any alleged event of default thereunder, shall affect, alter, or modify the Parties' rights, duties, obligation, and liabilities under this Agreement. This Agreement shall not be construed to create any rights between Seller and the Transmission Provider, and the terms of this Agreement are not (and will not) be binding upon the Transmission Provider. Seller agrees and acknowledges that Seller's performance under this Agreement depends on Seller's performance under the Interconnection Agreement, and Seller hereby grants Buyer the right and entitlement to obtain information from the Transmission Provider in regards to Seller's performance under the Interconnection Agreement.

7.4. System Operations. Seller agrees and acknowledges that the System Operator will be solely responsible for its functions, and that nothing in this Agreement will be construed to create any rights between Seller and the System Operator. Seller agrees that it is obligated to engage in interconnected operations with Buyer and the System, and Seller agrees to fully comply with all System Operator Instructions.

7.5. Insurance Obligations. Commencing with the initiation of construction activities of the Facility and continuing until the termination of this Agreement, and at no additional cost to Buyer, Seller shall maintain or cause to be maintained by contracted parties at the Facility, occurrence form insurance policies as follows: (a) Workers' Compensation in accordance with the statutory requirements of the state in which the Services are performed and Employer's Liability Insurance of not less than $500,000 each accident/employee/disease; (b) Commercial General Liability Insurance having a limit of at least $1,000,000 per occurrence/$2,000,000 in the aggregate for contractual liability, personal injury, bodily injury to or death of persons, and damage to property, premises and operations liability and explosion, collapse, and underground hazard coverage; (c) Commercial/Business Automobile Liability Insurance (including owned (if any), non-owned or hired autos) having a limit of at least $1,000,000 each accident for bodily injury, death, property damage and contractual liability; (d) Property Damage insurance on the Facility written on an all risk of loss basis; and, (e) if Seller will be handling or the Facility will have present environmentally regulated or hazardous materials, Pollution Legal Liability, including coverage for sudden/accidental occurrences for bodily injury, property damage, environmental damage, cleanup costs and defense with a minimum of $1,000,000 per occurrence (claims-made form acceptable with reporting requirements of at least one (1) year). All insurance policies provided and maintained by Seller or applicable party shall: (i) be underwritten by insurers which are rated A.M. Best "A- VII" or higher; (ii) specifically include Buyer as additional insured's, excluding, however, for Worker's Compensation/Employer's Liability and Property Damage insurance; (iii) be endorsed to provide, where permitted by law, waiver of any rights of subrogation against Buyer; and (iv) provide that such policies and additional insured provisions are primary and without right of contribution from any other insurance, self-insurance or coverage available to Buyer. Any deductibles or retentions shall be the sole responsibility of Seller or the applicable party. Seller's compliance with these provisions and the limits of insurance specified herein shall not constitute a limitation of Seller's liability pursuant to this Agreement. Any failure to comply with and these provisions shall not be deemed a waiver of any rights of Buyer under this Agreement or with respect to any insurance coverage required hereunder. Buyer at its sole discretion may request Seller to provide a copy of any or all of its required insurance policies, including endorsements in which Buyer is included as an additional insured for any claims filed relative to the Facility or this Agreement.

8. Facility Performance Requirements

8.1. Planned Outages. No later than fifteen (15) Business Days prior to the end of each year during the Term, Seller shall provide to Buyer a Planned Outage schedule for the upcoming year. Seller shall provide Buyer with reasonable advance notice of any material change in the Planned Outage schedule. Seller shall determine the number and extent of Planned Outages in a Commercially Reasonable Manner recognizing that it is the intent of the Parties to maximize ~~production of the~~ Available Facility Energy and to such extent Seller shall be excused from providing the Product during such Planned Outage(s). Unless both Parties expressly agree otherwise, any Planned Outage shall only occur during the months of March, April, May, September, October, or November.

8.2. Maintenance Outages. If Seller needs or desires to schedule a Maintenance Outage of the Facility, Seller shall notify Buyer, as far in advance as reasonable and practicable under the circumstances, of such proposed Maintenance Outage, and the Parties shall plan such outage to mutually accommodate the reasonable requirements of Seller and delivery expectations of Buyer. Notice of a proposed Maintenance Outage shall include the expected start date of the outage, the amount of output of the Facility that will not be available and the expected completion date of the outage. Buyer may request reasonable modifications in the schedule for the outage. Subject to its operational and maintenance needs, Seller shall comply with such requests to reschedule a Maintenance Outage. If rescheduled, Seller shall notify Buyer of any subsequent changes in the output that will not be available to Buyer and any changes in the Maintenance Outage completion date. As soon as practicable, any such notifications given orally shall be confirmed in writing.

8.3. Notice. Seller shall promptly provide to Buyer an oral report of all outages, Emergency Conditions, de-ratings, major limitations, or restrictions affecting the Facility, which report shall include the cause of such restriction, amount of generation from the Facility that will not be available because of such restriction, and the expected date that the Facility will return to normal operations. Seller shall update such report as necessary to advise Buyer of any material changed circumstances relating to the aforementioned restrictions. As soon as practicable, all oral reports shall be confirmed in writing. Seller shall promptly dispatch personnel to perform the necessary repairs or corrective action in an expeditious and safe manner in accordance with Prudent Utility Practice.

8.4. Performance. Seller shall act in a Commercially Reasonable Manner to maximize the ~~output of the~~ Available Facility Energy in a safe manner to generate the Product and to minimize the occurrence, extent, and duration of any event adversely affecting the available generation of the Product, in each case consistent with Prudent Utility Practice.

8.5. Output Requirement. Starting the first full calendar year after the Commercial Operation Date of the Facility, for each rolling two consecutive year period during the Delivery Period, Seller shall ~~deliver~~ make available to Buyer a cumulative volume of Available Facility Energy that is no less than ~~seventy~~ eighty-five percent (~~70~~ 85%) of the ~~Expected~~ Theoretical Annual Output ~~averaged over~~ for such two consecutive calendar ~~years on a rolling basis during the Delivery Period (the "Net Output~~ year period (the "Available Facility Energy Requirement"). Where a Permitted Excuse to Perform adversely affects ~~actual generation output of the~~ Available Facility Energy, the ~~Net Output~~ Available Facility Energy Requirement shall be reduced by the amount of Energy not ~~generated~~ available from the Facility for dispatch due to the Permitted Excuse to Perform; provided, however, Seller agrees that it must theordemonstrate to Buyer, in Buyer's Commercially Reasonable discretion, that the Available Facility~~'s generation output~~ Energy was actually reduced due to a Permitted Excuse to Perform. Buyer's sole remedy for Seller's failure to ~~deliver~~ meet the ~~Net Output~~ Available Facility Energy Requirement for any period of two consecutive calendar years shall be to receive a credit against the Contract Price for each month during the immediately following full calendar year. The foregoing monthly credit to Buyer shall be determined by (a) multiplying (i) the difference between the ~~Net Output Requirement and the actual~~ Available Facility Energy Requirement (as reduced for any applicable Permitted Excuses to Perform) and the cumulative Available Facility Energy (expressed in MWh) ~~delivered~~ made available by Seller ~~and received by Buyer~~ for dispatch during the applicable period by (ii) [*insert amount equal to* ~~50~~ [150%] of ~~Contract Price for~~ Implied Energy Price] and (b) then dividing the amount calculated by (a) above by twelve (12). If Seller fails to satisfy the ~~Net Output~~ Available Facility Energy Requirement for any two-year period, to determine compliance with the ~~Net Output~~ Available Facility Energy Requirement in the next rolling two-year period, then the amount of Available Facility Energy ~~generated~~ in the first year of such two-year rolling period will be deemed to be the higher of (i) ~~seventy~~ eighty-five percent (~~70~~ 85%) of the ~~Expected~~ Theoretical Annual Output for such year, or (ii) the actual amount of Available Facility Energy ~~generated by the Facility~~ in such year.

8.6. System Operator Instructions. Seller shall take all steps needed of it to implement and shall cooperate with Buyer in the implementation of all aspects of all System Operator Instructions. Seller shall immediately and fully comply with all System Operator Instructions, including without limitation all Control Instructions, Emergency Condition Instructions, and Force Majeure Instruction. Seller shall also immediately and fully comply with all Interconnection Instructions provided pursuant to the independent and separate

Interconnection Agreement with the Transmission Operator.

8.6.1. Seller hereby expressly agrees to and fully authorizes and grants to Buyer the right to fully control the Facility in any manner necessary to enable Buyer to directly take all actions required to implement or otherwise effectuate all System Operator Instructions, including Control Instructions, Emergency Condition Instructions, and Force Majeure Instructions. Except for ~~the payments provided by Buyer pursuant to Section 8.9 hereof~~ Buyer's obligation to pay the Contract Price for the Contract Capacity, Seller hereby releases and holds Buyer harmless from and against all harm to Seller or the Facility in any way arising from or relating to any direct or indirect control of the Facility by Buyer to implement or otherwise effectuate any System Operator Instructions except to the extent resulting from Buyer's negligence.

8.7. Control Equipment. To implement the control rights Seller has granted Buyer under Section 8.6, Seller shall design and construct the Facility to provide for Buyer and System Operation to have full or incremental and instantaneous control over the Facility to directly implement or otherwise effectuate any System Operator Instructions as currently or hereafter specified by Buyer, including installing automatic generation control with the current requirements further described in Exhibit 4 hereto ("Control Equipment"). Seller shall design the Facility to provide for the inclusion and operation of the Control Equipment and shall install and maintain the Control Equipment so that Buyer and System Operator shall have full or incremental instantaneous control over the Facility to take any action based in any manner to implement or otherwise effectuate any System Operator Instruction.

8.8. Control Instructions. The System Operator shall be entitled to and is hereby authorized to require the Facility to take or to directly take all actions to dispatch or otherwise control the generation output and operations of the Facility for any ~~Control Instruction. Except to the extent expressly set forth in Section 8.9, Seller shall not receive any compensation for any losses due to a Dispatch Down. Except as set forth in Section 8.9, all Seller losses for a Dispatch Down shall be borne solely and entirely by Seller, including, without limitation, for any losses arising due to the lost or reduced generation by the Facility, lost tax benefits, lost investment tax credits, grants or any other incentives or monetary opportunity relating to the design, development, generation from, construction, maintenance, ownership, or operation of the Facility.~~ System Operator Instructions, including Control Instructions, Emergency Condition Instructions, and Force Majeure Instructions.

8.9. ~~Limited Payments for Control Instruction Dispatch Down. During any calendar year during the Term hereof, Seller shall not receive any compensation from Buyer for any Dispatch Down until the Dispatch Down of Energy exceeds [first tranche ten (10)% for DEP] [first tranche five (5)% for DEC] of annual 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 "Annual Payment Threshold"). For any partial calendar year during the Term hereof, the Annual Payment Threshold shall be ratably prorated for the number of days in such partial calendar year.~~ Dispatch Accuracy Requirement. Starting the first full calendar year after the Commercial Operation Date of the Facility and for each full calendar year of the Delivery Period thereafter, Seller shall achieve a Dispatch Accuracy Rate of at least ninety percent (90%) ("Dispatch Accuracy Rate Requirement"). For each full calendar year after the Commercial Operation Date in which the Dispatch Accuracy Rate is less than the Dispatch Accuracy Rate Requirement, Seller will owe Buyer liquidated damages in the amount of (a) the Dispatch Accuracy Rate Requirement, minus the Dispatch Accuracy Rate for such calendar year, multiplied by (b) the total Available Facility Energy for such calendar year, multiplied by (c) the Implied Energy

Price ("Dispatch Accuracy Damages"). Buyer's sole remedy for Seller's failure to follow Control Instructions shall be to receive a credit in the amount of the Dispatch Accuracy Damages.

~~8.9.1. Control Compensation. In any calendar year, except as set forth in Section 8.10, after satisfaction of the Annual Payment Threshold, Seller shall receive compensation from Buyer for the Dispatch Down of Energy that the Facility would have generated but did not generate due to compliance with and implementation of Control Instructions, starting with the [insert amount specified in 8.9 + 1] MWh of Energy that is not so generated. Buyer shall calculate such amount payable to Seller by multiplying the Contract Price times the amount of Energy that could have been generated but was not generated due to compliance with and implementation of the Control Instruction ("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 of March commencing with the calendar year immediately following the first completed year of service and in each subsequent March invoice thereafter concluding with the calendar year immediately following the last completed year of service during the Term.~~

~~8.9.2. Limitations on Control Compensation. Buyer shall pay Seller a Control Compensation for the Dispatch Down of Energy if, and only if: (i) the Facility was generating 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; (ii) the actual cumulative reduction of Energy generation by the Facility due to the Dispatch Down exceeds the Annual Payment Threshold for the calendar year; and, (iii) 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 in excess of the Payment Threshold, and any and all other Seller losses or payments are expressly disclaimed and waived. For purposes of determining Control Compensation, the discharge of Energy from a Storage Resource shall not constitute the generation of Energy.~~

~~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.~~

8.10. ~~Emergency Condition and Force Majeure Instructions. Notwithstanding any~~

~~exceedance of the Annual Payment Threshold for any calendar year due to Control Instructions that the System Operator may provide or implement, the System Operator shall be entitled to and is hereby authorized to require the Facility to take or to directly take all actions to dispatch or otherwise control the generation output and operations of the Facility for Emergency Condition Instructions and Force Majeure Instructions. Except to the extent expressly set forth in Sections 8.10.1, Seller shall not receive any compensation for any losses due to a Dispatch Down for Emergency Condition Instructions or Force Majeure Instructions. Except as set forth in Section 8.10.1, all Seller losses for a Dispatch Down for Emergency Condition Instructions and Force Majeure Instructions shall be borne solely and entirely by Seller, including, without limitation, for any losses arising due to the lost or reduced generation by the Facility, production tax benefits, investment tax credits, grants or any other incentives or monetary opportunity relating to the design, development, construction, maintenance, ownership, or operation of the Facility.~~ Capacity Tests.

8.10.1. ~~In the event Seller proves that a Dispatch Down instruction issued by or action taken by the System Operator does not fall within the definition of an Emergency Condition Instruction or a Force Majeure Instruction and that the Facility actually reduced Energy production pursuant to such Dispatch Down instruction, then such Dispatch Down shall be administered as provided for in Section 8.9 hereof (*Limited Payments for Control Instruction Dispatch Down*).~~ If the Dispatch Accuracy Rate is less than the Dispatch Accuracy Rate Requirement for any full calendar year after the Commercial Operation Date, then Seller shall schedule and complete a Capacity Test within sixty (60) days following the end of such calendar year. Seller shall have the right to repeat the Capacity Test from time to time by providing Buyer at least three (3) days' prior notice of each repeated Capacity Test.

8.10.2. Subject to compliance with the site access requirements in Section 26.2, Buyer shall have the right to send one or more representative(s) to witness all Capacity Tests. Buyer shall be responsible for all costs, expenses and fees payable or reimbursable to its representative(s) witnessing any Capacity Test.

8.10.3. Following each Capacity Test, Seller shall submit a testing report to Buyer in accordance with Exhibit 11. If the actual capacity determined pursuant to a Capacity Test is less than the then-current Contract Capacity, then the actual capacity determined pursuant to such Capacity Test shall become the new Contract Capacity at the beginning of the day following the completion of the test for all purposes under this Agreement until a new Contract Capacity is determined pursuant to a subsequent Capacity Test.

8.11. Energy Storage. If the Facility is to be equipped with battery storage or other energy storage device (the "Storage Resource"), the Storage Resource shall be identified in Exhibit 4 attached to this Agreement, which shall be subject to Buyer's final approval. In all cases the Storage Resource must be charged solely by the Facility and the use of any Storage Resource shall be operated and equipped in accordance with the System Operator's Energy Storage Protocol, a copy of which is attached hereto as Exhibit 10, as may be modified from time to time by the System Operator (the "Energy Storage Protocol").

9. Information Requirements

9.1. Accounting Information. Generally Accepted Accounting Principles ("GAAP") and SEC rules can require Buyer to evaluate various aspects of its economic relationship with Seller, e.g., whether or not Buyer must consolidate Seller's financial information. To evaluate if certain GAAP requirements are applicable, Buyer may need access to Seller's financial records and personnel in a timely manner. In the event that Buyer determines that consolidation or other incorporation of Seller's financial information is necessary under GAAP, Buyer shall require the following for each calendar quarter during the term of this Agreement, within 90 days after quarter end: (a) complete financial statements, including notes, for such quarter on a GAAP basis; and, (b) financial schedules underlying the financial statements. Seller shall grant Buyer access to records and personnel to enable Buyer's independent auditor to conduct financial audits (in accordance with GAAP standards) and internal control audits (in accordance with Section 404 of the Sarbanes-Oxley Act of 2002). Any information provided to Buyer pursuant to this section shall be considered confidential in accordance with the terms of this Agreement and shall only be disclosed, as required by GAAP, on an aggregate basis with other similar entities for which Buyer has power purchase agreements.

9.2. Facility Information. As of Effective Date and continuing for a period of three months after the Commercial Operation Date, Seller shall promptly provide to Buyer reports relating to the progress of the Facility's development and construction, financing, interconnection activities and performance under the Interconnection Agreement, testing, Seller's good faith estimate of the date for occurrence of the Commercial Operation Date, operational activities, and other information that Buyer may request in its Commercially Reasonable discretion to inform Buyer of Seller's performance under this Agreement. Within ten (10) days after the end of each calendar month until the Commercial Operation Date is achieved, Seller shall prepare and submit to Buyer a written status report which shall cover the previous calendar month, shall be prepared in a manner and format (hard copy or electronic) reasonably acceptable to Buyer and shall include (a) a detailed description of the progress of the Facility's construction, (b) a statement of any significant issues which remain unresolved and Seller's recommendations for resolving the same, (c) a summary of any significant events which are scheduled or expected to occur during the following thirty (30) days; and, (d) all additional information reasonably requested by Buyer. If Seller has reason to believe that the Facility is not likely to timely achieve any Milestone Deadline, including the Commercial Operation Date, Seller shall promptly provide written notice to Buyer with all relevant facts, and will provide Buyer with any other information Buyer may request from Seller in respects to such failure of Seller. Seller shall give written notice to Buyer no later than 30 days before Seller projects that the Facility will achieve Commercial Operation. Seller shall provide written notice to Buyer when the Commercial Operation Date has occurred. Following the Commercial Operation Date, Seller shall promptly provide to Buyer information requested by Buyer to verify any amounts of delivered Product, or to otherwise audit the Product delivered to Buyer. Seller shall, within ten (10) Business Days of electronic or written request provide Buyer with any other information germane to this Agreement and/or Seller's performance under and compliance with this Agreement, requested by Buyer in its Commercially Reasonable discretion.

9.3. Other Information. Seller shall provide to Buyer all information, instruments, documents, statements, certificates, and records relating to this Agreement and/or the Facility as requested by Buyer concerning any administrative, regulatory, compliance, or legal requirements determined by Buyer to fulfill any Requirements of Law, regulatory reporting requirements or otherwise relating to any request by any Governmental Authority. Seller will, at its own expense, provide Buyer with all information requested by Buyer to register, verify, or otherwise obtain Commission or any other third party recognition of the Product for use by Buyer, and at Buyer's request Seller shall register, verify, or otherwise validate or obtain Commission and/or any other third party recognition of the Product for use by Buyer.

9.3.1. Information Under the Act. Seller agrees and acknowledges that the Act requires Seller to make certain filings and/or submissions, including, without limitation, to maintain registration and certification of the Facility under the Act and to use the Product for compliance under the Act. Seller shall provide Buyer, for informational purposes only, a copy of any report, certification or filing that Seller submits to the Commission, within a reasonable time after making such submission, but in any event no later than five (5) Business Days after such submission. Notwithstanding anything to the contrary, Seller agrees and acknowledges that it shall be solely responsible for timely complying with all requirements under the Act.

9.4. Forecasts. Seller shall prepare and provide Buyer with the Facility's forecasted Available Facility Energy ~~production~~ by fuel type, if applicable. These non-binding forecasts of ~~production~~ Available Facility Energy will be determined and prepared in a Commercially Reasonable Manner with the intent of being as accurate as possible. Seller shall update a forecast any time information becomes available indicating a change in the forecast relative to the most previously provided forecast.

9.4.1. Year-Ahead Forecasts. Seller shall, by December 1 of each year during the Term (except for the last year of the Term), provide Buyer with a forecast of each month's average-day Available Facility Energy ~~production from the Facility~~, by hour, for the following calendar year. This forecast shall include an expected range of uncertainty based on historical operating experience. Seller shall update the forecast for each month at least five (5) Business Days before the first Business Day of such month.

9.4.2. Week-Ahead Forecasts. By 0800 EPT on the Friday preceding the immediately upcoming week of delivery, Seller shall provide Buyer with a daily forecast of ~~deliveries~~ Available Facility Energy for the upcoming week (Monday through Sunday). Seller shall update a forecast any time information becomes available indicating a change in the forecast of ~~generation~~ Available Facility Energy relative to the most previously provided forecast.

9.4.3. Day-Ahead Forecasts. By 0500 EPT on the calendar day immediately preceding the day of delivery, Seller shall provide Buyer with an hourly forecast of ~~deliveries~~ Available Facility Energy for each hour of the next seven (7) days. In the event that Seller has any information or other Commercially Reasonable basis to believe that the ~~production~~ Available Facility Energy from the Facility on any day will be materially lower or higher than what would otherwise be expected based on the forecasts provided, then Seller will inform Buyer of such circumstance by 0500 EPT on the preceding Business Day.

9.4.4. Communication. Seller shall communicate forecasts in a form, template, substance, and manner as requested by Buyer (e.g. Excel template), which form, template, substance, and manner may be modified by Buyer from time to time. Forecasts shall be transmitted by email (to be sent to: RenewableEnergyForecast@duke-energy.com) or by other media (e.g. website upload), as Buyer may instruct Seller from time to time. Requested forecast data may include but is not limited to, location, forecast timestamp, site capacity, a flag for actual or forecasted data, available site capacity, energy, reason for any capacity reduction, site plane of array (POA) irradiance, air pressure, and relative humidity for each hour of the next seven days.

9.4.5. History. Seller shall prepare and provide Buyer with the Facility's historical Energy production by fuel type, if applicable. The historical production will be determined and prepared by Seller in a Commercially Reasonable Manner with the intent of being as accurate as reasonably possible. Seller shall update any correction to the history any time information becomes available.

9.4.5.1. Daily History. By 0500 EPT on the Business Day immediately following the day of delivery, Seller shall provide Buyer with an hourly profile of deliveries for each hour of the previous seven days.

9.4.5.2. History Communication. Seller shall communicate history in a form, template, substance, and manner as requested by Buyer (e.g. Excel template), which form, template, substance, and manner may be modified by Buyer from time to time. The History shall be transmitted by email (to be sent to: RenewableEnergyForecast@duke-energy.com) or by other media (e.g. website upload), as Buyer may instruct Seller from time to time. Requested historical data may include but is not limited to, location, site capacity, a flag for actual or forecasted data, available site capacity, Available Facility Energy, energy generated, reason for any capacity reduction, site POA irradiance, air pressure, and relative humidity for each hour of the previous seven days.

10. **Metering**

10.1. Billing Meter. In the Interconnection Agreement between Seller and Transmission Provider, Seller shall arrange with the Transmission Provider to construct and install such meters and metering equipment as are necessary to measure the Energy delivered and received in accordance with the terms and conditions of this Agreement (the "Billing Meter"). Buyer shall provide to Seller the reasonable allowable accuracy limits relating to the performance of the Billing Meter, and Seller shall arrange with Transmission Provider to install and operate a Billing Meter that meets the allowable accuracy limits. Seller shall be responsible for paying the Transmission Provider for all costs relating to the Billing Meter, including, without limitation, its procurement, installation, operation, calibration, and maintenance. Seller shall ensure in its arrangement with the Transmission Provider for the Billing Meter to include communication equipment that enables Buyer to access and read the meter from a remote location. Seller hereby grants Buyer with rights to physically access the Billing Meter. Seller shall provide Buyer (at Seller's cost) with appropriate telephonic/electronic communication to allow Buyer to remotely read the meter. Seller may, at its own expense, install and maintain additional metering equipment for purposes of monitoring, recording or transmitting data relating to its sale of Energy from the Facility, so long as such equipment does not interfere with the Billing Meter. Seller shall arrange with the Transmission Provider to test the Billing Meter at regular intervals. Seller shall also arrange for either Party to have the right to request and obtain, at reasonable intervals and under reasonable circumstances, additional/special tests of the Billing Meter. The Party making such request for the test shall incur the costs associated with such test.

11. **Billing Period and Payment**

11.1. Billing Period. Subject to Seller authorizing Transmission Provider to provide Buyer with electronic access to the Billing Meter, Buyer shall read/obtain data from the Billing Meter at regular intervals, which shall be not less than twenty-seven (27) consecutive days and not more than thirty-three (33) consecutive days (each, a "Billing Period"). Within twenty-five (25) days after reading/obtaining data from the Billing Meter, Buyer shall provide Seller with an invoice detailing the amount of Product (Energy and an equal amount of RECs) delivered during the relevant Billing Period ~~and the associated~~ , any Dispatch Accuracy Damages for the relevant Billing Period, the Contract Capacity and Contract Price for the relevant Billing Period, the amount owed by Buyer to Seller for the Product which shall be calculated as the product of the Contract Capacity and Contract Price, and any other amounts due to or from Seller under this Agreement, subject to Seller cooperating with Buyer and providing Buyer with such information and/or data that Buyer may request to accurately prepare the invoice. Buyer shall pay Seller the invoiced amounts for each Billing Period, subject to Seller having transferred (or caused to be transferred) the REC

Certificates from Seller's Account to Buyer's Account in the Tracking System. Payment by Buyer shall be due by the later of thirty (30) days after the invoice date or fifteen (15) days after Buyer receives notification that the Seller has transferred the REC Certificates into Buyer's Account. If such amounts are not paid by the deadline, they shall accrue interest at the Interest Rate from the applicable due date until the date paid. Amounts not paid by such deadline shall accrue interest at the Interest Rate from the original due date until the date paid in accordance with this Agreement.

11.2. Meter Malfunction. In the event the Billing Meter fails to register accurately within the allowable accuracy limits as set forth above, then for purposes of preparing (or adjusting) any affected invoice Buyer shall adjust the amount of measured Energy for the period of time the Billing Meter was shown to be in error. If the time the Billing Meter became inaccurate can be determined, then the adjustment to the amount of measured Energy shall be made for the entire time from the time that the Billing Meter became inaccurate until the recalibration of the Billing Meter. If the time the Billing Meter became inaccurate cannot be determined, then the Billing Meter shall be deemed to have failed to register accurately for fifty percent (50%) of the time since the date of the last calibration of the Billing Meter.

11.3. Out-of-Service. If the Billing Meter is out of service, then for purposes of preparing any affected invoice, the Parties shall negotiate in good faith to determine an estimate of the amount of Energy delivered during the relevant Billing Period. Seller's meter (if any), may be used to establish such estimate, if both Parties agree. If, within twenty (20) days after the date that the Billing Meter is read as set forth above, the Parties have not reached agreement regarding an estimate of the amount of Energy delivered during the relevant Billing Period, then the amount of Energy delivered during the relevant Billing Period shall be determined using the ~~Estimation Methodology~~ Available Facility Energy and associated dispatch records.

11.4. Errors. If any overcharge or undercharge in any form whatsoever shall at any time be found for an invoice, and such invoice has been paid, the Party that has been paid the overcharge shall refund the amount of the overcharge to the other Party, and the Party that has been undercharged shall pay the amount of the undercharge to the other Party, within forty-five (45) days after final determination thereof; provided, however, that no retroactive adjustment shall be made for any overcharge or undercharge unless written notice of the same is provided to the other Party within a period of twelve (12) months from the date of the invoice in which such overcharge or undercharge was first included. Any such adjustments shall be made with interest calculated at the Interest Rate from the date that the undercharge or overcharge actually occurred.

11.5. Invoice/Payment Dispute. If a Party in good faith reasonably disputes the amount set forth in an invoice, charge, statement, or computation, or any adjustment thereto, such Party shall provide to the other Party a written explanation specifying in detail the basis for such dispute. The Party disputing the invoice, if it has not already done so, shall pay the undisputed portion of such amount no later than the applicable due date. If the Parties are thereafter unable to resolve the dispute through the exchange of additional documentation, then the Parties shall pursue resolution of such dispute according to the dispute resolution and remedy provisions set forth in the Agreement. Notwithstanding any other provision of this Agreement to the contrary, if any invoice, statement charge, or computation is found to be inaccurate, then a correction shall be made and payment (with applicable interest) shall be made in accordance with such correction; provided, however, no adjustment shall be made with respect to any invoice, statement, charge, computation or payment hereunder unless a Party provides written notice to the other Party questioning the accuracy thereof within twenty-four (24) months after the date of such invoice, statement, charge, computation, or payment.

12. **Audit Rights**

12.1. Process. Buyer shall have the right, at its sole expense and during normal business hours, without Seller requiring any compensation from Buyer, to examine and copy the records of Seller to verify the accuracy of any invoice, statement, charge or computation made hereunder or to otherwise verify Seller's performance under this Agreement, including, without limitation, verifying that the delivered Product complies with the Agreement.

12.2. Survival. All audit rights shall survive the expiration or termination of this Agreement for a period of twenty-four (24) months after the expiration or termination. Seller shall retain any and all documents (including, without limitation, paper, written, and electronic) and/or any other records relating to this Agreement and the Facility for a period of twenty-four (24) months after the termination or expiration of this Agreement.

13. **Taxes**

13.1. Seller. Seller shall be liable for and shall pay Buyer, or Seller shall reimburse Buyer if Buyer has paid or cause to be paid, all Taxes imposed by a Governmental Authority on or with respect to the Product delivered hereunder and arising prior its delivery to and at the Delivery Point (including ad valorem, franchise or income taxes which are related to the sale of the Product by Seller to Buyer and are, therefore, the responsibility of Seller). Seller shall indemnify, defend, and hold harmless Buyer from any liability for such Taxes, including related audit and litigation expenses.

13.2. Buyer. Buyer shall be liable for and shall pay Seller, or Buyer shall reimburse Seller if Seller has paid or caused to by paid, all Taxes imposed by a Governmental Authority on or with respect to the Product delivered hereunder and arising after the Delivery Point (other than ad valorem, franchise or income taxes which are related to the sale of the Product by Seller to Buyer and are, therefore, the responsibility of Seller). Buyer shall indemnify, defend, and hold harmless Seller from any liability for such Taxes, including related audit and litigation expenses.

13.3. Remittances. In the event Seller is required by any Requirements of Law to remit or pay Taxes that are Buyer's responsibility hereunder, Seller may request reimbursement of such payment from Buyer by sending Buyer an invoice, and Buyer shall include such reimbursement in the next monthly invoice and Buyer shall remit payment thereof. Conversely, if Buyer is required by any Requirements of Law to remit or pay Taxes that are Seller's responsibility hereunder; Buyer may deduct the amount of any such Taxes from the sums otherwise due to Seller under this Agreement. Any refunds or remittances associated with such Taxes shall be administered in accordance with Section 11.1.

13.4. Documentation. A Party, upon written request of the other Party, shall promptly provide a certificate of exemption or other reasonably satisfactory evidence of exemption if such Party is exempt from any Tax. Nothing herein shall obligate a Party to pay or be liable to pay any Taxes from which it is exempt pursuant to applicable law.

14. **Force Majeure**

14.1. Definition. "Force Majeure" means: (A) war, riots, floods, hurricanes, tornadoes, earthquakes, lightning, ice-storms, excessive winds, and other such extreme weather events and natural calamities; (B) explosions or fires arising from lightning or other natural causes unrelated to acts or omissions of the Party; (C) insurrection, rebellion, nationwide strikes; (D) an act of god or other such significant and material event or circumstance which prevents one Party from performing a material and significant obligations hereunder, which such event or circumstance was not anticipated as of the Effective Date, is not within the Commercially Reasonable control of, or the result of the negligence of such claiming Party, and which, by the exercise of Commercially Reasonable Efforts, the claiming Party is unable to overcome or avoid or cause to be avoided and, (E) delays in obtaining goods or services from any subcontractor or supplier caused solely by the occurrence of any of the events described in the immediately preceding subparts (A) through (D). The acts, events or conditions listed in subparts (A) through (E) above shall only be deemed a Force Majeure if and to the extent they actually and materially delay or prevent the performance of a Party's obligations under this Agreement and: (i) are beyond the reasonable control of the Party, (ii) are not the result of the willful misconduct or negligent act or omission of such Party (or any person over whom that Party has control), (iii) are not an act, event or condition that reasonably could have been anticipated, or the risk or consequence of which such Party has assumed under the Agreement; and, (iv) cannot be prevented, avoided, or otherwise overcome by the prompt exercise of Commercially Reasonable diligence by the Party (or any Person over whom that Party has control).

14.1.1. Notwithstanding anything to the contrary herein, Force Majeure will *not* include the following: (a) any strike or labor dispute of the employees of either Party or any subcontractor that is not part of a nationwide strike or labor dispute; (b) any difficulty in obtaining or maintaining sufficient, or appropriately skilled, personnel to perform the work in accordance with the requirements of this Agreement; (c) normal wear and tear or obsolescence of any equipment; (d) Buyer's inability to economically use or resell the Product delivered and purchased hereunder; (e) Seller's ability to sell the Product (or any component of the Product) at a more advantageous price; (f) loss by Seller of any contractual arrangement; (g) any Regulatory Event; (h) loss or failure of Seller's supply of the Product or inability to generate the Product that is not caused by an independent Force Majeure event; (i) the cost or availability or unavailability of fuel, solar energy, wind, or motive force, as applicable, to operate the Facility; (j) economic hardship, including, without limitation, lack of money or financing or Seller's inability to economically generate the Product or operate the Facility; (k) any breakdown or malfunction of Facility equipment (including any serial equipment defect) that is not directly caused by an independent event of Force Majeure; (l) the imposition upon Seller of costs or taxes allocated to Seller hereunder or Seller's failure to obtain or qualify for any tax incentive, preference, or credit; (m) delay or failure of Seller to obtain or perform any Permit; (n) any delay, alleged breach of contract, or failure under any other agreement or arrangement between Seller and another entity, including without limitation, an agent or sub-contractor of Seller (except as a direct result of an event of Force Majeure defined in 14.1(E)); (o) Seller's failure to obtain, or perform under, the Interconnection Agreement, or its other contracts and obligations to Transmission Provider; or (p) increased cost of electricity, steel, materials, equipment, labor, or transportation.

14.2. Event. If either Party is rendered unable by Force Majeure to carry out, in whole or in part, any material obligation hereunder, such Party shall provide notice and reasonably full details of the event to the other Party as soon as reasonably practicable after becoming aware of the occurrence of the event (but in no event later than three (3) Business Days of the initial occurrence of the event of Force Majeure). Such notice may be given orally but shall be confirmed in writing as soon as practicable thereafter (and in any event within ten (10) days of the initial occurrence of the event of Force Majeure); provided however, a reasonable delay in providing such notice shall not preclude a Party from claiming Force Majeure but only so long as such delay does not prejudice or adversely affect the other Party.

14.3. Effect. Subject to the terms and conditions of Section 14, for so long as the event of Force Majeure is continuing, the specific obligations of the Party that are demonstrably and specifically adversely affected by the Force Majeure event, shall be suspended to the extent and for the duration made necessary by the Force Majeure, will not be deemed to be an Event of Default, and performance and termination of this Agreement will be governed exclusively by this Section 14. Notwithstanding anything to the contrary in this Agreement, Force Majeure will *not* be applicable to and will *not* be available as an excuse to Seller's performance of the obligations set forth in Sections 19.3 through and including 19.24. Notwithstanding anything to the contrary in this Agreement, Force Majeure will not be available as an excuse to any delays or failures in Seller timely achieving Commercial Operations by the Commercial Operations Date, delays or failures for which shall be governed exclusively by Section 20.5.

14.4. Remedy. The Party claiming Force Majeure shall act in a Commercially Reasonable Manner to remedy the Force Majeure as soon as practicable and shall keep the other Party advised as to the continuance of the Force Majeure event. If a bona fide Force Majeure event persists for a continuous period of ninety (90) days, then the Party not claiming Force Majeure shall have the right, in its sole and unfettered discretion, to terminate this Agreement upon giving the other Party ten (10) Business Days advance written notice; *provided, however*, that where the Force Majeure event cannot be remedied within ninety (90) days and the claiming Party can demonstrate to the non-claiming Party its intention and ability to implement a Commercially Reasonable plan to remedy such Force Majeure event within an additional ninety days (90) days after the initial sixty (90) day period and the claiming Party uses Commercially Reasonable efforts to implement such plan, the non-claiming Party shall not have the right to terminate the Agreement until the expiration of such additional ninety (90) day period.

14.5. Termination. Unless otherwise agreed upon by the Parties in writing and in each Party's sole discretion, upon the expiration of the periods set forth above in Sections 14.4, this Agreement may be terminated without any further notice and further opportunity to cure any non-performance. Upon termination becoming effective pursuant to a Force Majeure under Section 14, neither Party will have any liability to the other Party or recourse against the other Party, other than for amounts arising prior to termination. Notwithstanding the claimed existence of a Force Majeure event or any other provisions of this Agreement, nothing herein shall relieve any Party from exercising any right or remedy provided under this Agreement with respect to any liability or obligation of the other Party that is not excused or suspended by the Force Majeure event, including, without limitation, the right to liquidate and early terminate the Agreement for any Event of Default not excused by the Force Majeure event. Nothing herein shall be construed so as to obligate any Party to settle any strike, work stoppage or other labor dispute or disturbance or to make significant capital expenditures, except in the sole discretion of the Party experiencing such difficulty.

15. **Change in Law**

15.1. Regulatory Event. A "Regulatory Event" means one or more of the following events:

15.1.1. Illegality. After the Effective Date, due to the adoption of, or change in, any applicable Requirements of Law or in the interpretation thereof by any Governmental Authority with competent jurisdiction, it becomes unlawful for a Party to perform any material obligation under this Agreement.

15.1.2. Adverse Government Action. After the Effective Date, there occurs any adverse material change in any applicable Requirements of Law (including material change regarding a Party's obligation to sell, deliver, purchase, or receive the Product) and any such occurrence renders illegal or unenforceable any material performance or requirement under this Agreement.

15.2. Process. Upon the occurrence of a Regulatory Event the Party affected by the Regulatory Event may notify the other Party in writing of the occurrence of a Regulatory Event, together with details and explanation supporting the occurrence of a Regulatory Event. Upon receipt of such notice, the Parties agree to undertake, during the thirty (30) days immediately following receipt of the notice, to negotiate such modifications to reform this Agreement to remedy the Regulatory Event and attempt to give effect to the original intention of the Parties. Upon the expiration of the 30-day period, if the Parties are unable to agree upon modifications to the Agreement that are acceptable to each Party, in each Party's sole discretion, then either Party shall have the right, in such Party's sole discretion, to terminate this Agreement with a 30-day advance written notice.

16. **Confidentiality**

16.1. Protected Information. Except as otherwise set forth in this Agreement, neither Party shall, without the other Party's prior written consent, disclose any term of this Agreement or any information relating to this Agreement, or any discussion or documents exchanged between the Parties in connection with this Agreement (such information, the "Protected Information") to any third person (other than the Party's employees, affiliates, counsel, and accountants, and current and prospective lenders and investors in the Facility if Buyer is given at least ten (10) Business Days advance written notice of such disclosure and to whom such disclosure is being made, who have a need to know such information, have agreed to keep such terms confidential for the Term, and for whom the Party shall be liable in the event of a breach of such confidentiality obligation), at any time during the Term or for five (5) years after the expiration or early termination of this Agreement. Each Party shall be entitled to all remedies available at law or in equity (including but not limited to specific performance and/or injunctive relief,) to enforce, or seek relief in connection with, this confidentiality obligation. Notwithstanding any other provision of this Agreement, a violation of any confidentiality obligations shall be an Event of Default hereunder, and any claim related to or arising out of any confidentiality obligations herein may be brought directly in any state or federal court of competent jurisdiction in [DEP - Wake County, North Carolina] [DEC - Mecklenburg County, North Carolina], in accordance with Section 26.5 of this Agreement, and shall not be subject to dispute resolution or arbitration pursuant to Section 23 of this Agreement.

16.2. Non-Confidential Information. Protected Information does not include information: (i) that is or becomes available to the public other than by disclosure of receiving Party in breach of this Agreement; (ii) known to receiving Party prior to its disclosure; (iii) available to receiving Party from a third party who is not bound to keep such information confidential; or, (iv) independently developed by the receiving Party without reliance upon the Protected Information. Notwithstanding anything to the contrary herein, in no event will Protected Information include the concept of constructing or providing energy from a power plant, using any specific fuel source, in any specific location.

16.3. Return of Confidential Information. Upon request of disclosing Party, receiving Party shall either (i) return the Protected Information, including all copies, or (ii) destroy the Protected Information, including all copies, and present written assurances of the destruction to disclosing Party. Notwithstanding the foregoing, both Parties acknowledge that Protected Information transferred and maintained electronically (including e-mails) may be automatically archived and stored by Receiving Party on electronic devices, magnetic tape, or other media for the purpose of restoring data in the event of a system failure (collectively, "Back-Up Tapes"). Notwithstanding the terms of this Agreement, in no event shall Receiving Party be required to destroy Protected Information stored on Back-Up Tapes; provided, however, any Protected Information not returned or destroyed pursuant to this Section shall be kept confidential for the duration of its existence. Furthermore, the receiving party may retain one (1) copy of such Protected Information in receiving Party's files solely for audit and compliance purposes for the duration of its existence; provided, however, such Protected Information shall be kept confidential for the duration of its existence in accordance with the terms of this Agreement.

16.4. Required Disclosures. Notwithstanding the confidentiality requirements set forth herein, a Party may, subject to the limitations set forth herein, disclose Protected Information to comply with the Act, request of any Governmental Authority, applicable Requirements of Law, or any exchange, control area or System operator rule, in response to a court order, or in connection with any court or regulatory proceeding. Such disclosure shall not terminate the obligations of confidentiality unless the Protected Information falls within one of the exclusions of this Agreement. To the extent the disclosure of Protected Information is requested or compelled as set forth above, the receiving Party agrees to give disclosing Party reasonable notice of any discovery request or order, subpoena, or other legal process requiring disclosure of any Confidential Information. Such notice by the receiving Party shall give disclosing Party an opportunity, at disclosing Party's discretion and sole cost, to seek a protective order or similar relief, and the receiving Party shall not oppose such request or relief. If such protective order or other appropriate remedy is not sought and obtained within at least thirty (30) days of receiving Party's notice, receiving Party shall disclose only that portion of the Protected Information that is required or necessary in the opinion of receiving Party's legal counsel; provided, however, receiving Party shall use reasonable efforts to obtain assurances that confidential treatment will be accorded to any Confidential Information so disclosed.

16.5. Regulatory Disclosures by Buyer. This Section 16.5 will apply notwithstanding anything to the contrary in this Agreement. Seller acknowledges that Buyer is regulated by various regulatory and market monitoring entities. Buyer is permitted, in its sole discretion, to disclose or to retain and not destroy (in case of a future disclosure need as determined by Buyer in its sole discretion) any information (including Protected Information) to any regulatory commission (inclusive of the NCUC, SCPSC, FERC), NERC, market monitor, office of regulatory staff, and/or public staff, or any other regulator or legislative body without providing prior notice to the Seller or consent from the Seller, using Buyer's business judgment and the appropriate level of confidentiality Buyer seeks for any such disclosures or retentions in its sole discretion. In the event of the establishment of any docket or proceeding before any regulatory commission, public service commission, public utility commission, or other agency, tribunal, or court having jurisdiction over Buyer, the Protected Information shall automatically be governed solely by the rules and procedures governing such docket or proceeding to the extent such rules or procedures are additional to, different from, or inconsistent with this Agreement. In regulatory proceedings in all state and federal jurisdictions in which Buyer does business, Buyer will from time-to-time be required to produce Protected Information, and Buyer may do so without prior notice to Seller or consent from Seller, using Buyer's business judgment, and the appropriate level of confidentiality Buyer seeks for such disclosures in its sole discretion. When a request for disclosure of information, including Protected Information, is made to Buyer, Buyer may disclose the information, including Protected Information, without prior notice to the Seller or consent from the Seller, using Buyer's business judgment and the appropriate level of confidentiality Duke seeks for such disclosures in its sole discretion. Seller further acknowledges that Buyer is required by law or regulation to report certain information that could embody Protected Information from time-to-time, and Buyer may from time-to-time make such reports, without providing prior notice to Seller or consent from Seller, using Buyer's business judgment and the appropriate level of confidentiality Buyer seeks for such disclosures in its sole discretion.

17. **Mutual Representations and Warranties**

17.1. As of the Effective Date and throughout the Term, each Party represents and warrants to the other Party that:

17.1.1. It is duly organized, validly existing and in good standing under the Requirements of Law of the jurisdiction of its organization or formation and has all requisite power and authority to execute and enter into this Agreement;

17.1.2. It has all authorizations under the Requirements of Law (including but not limited to the Required Approvals), necessary for it to legally perform its obligations and consummate the transactions contemplated hereunder or will obtain such authorizations in a timely manner prior to the time that performance by such Party becomes due;

17.1.3. The execution, delivery, and performance of this Agreement will not conflict with or violate any Requirements of Law or any contract, agreement or arrangement to which it is a party or by which it is otherwise bound;

17.1.4. This Agreement constitutes a legal, valid, and binding obligation of such Party enforceable against it in accordance with its terms, and such Party has all rights necessary to perform its obligations to the other Party in accordance with the terms and conditions of this Agreement;

17.1.5. It is acting for its own account, has made its own independent decision to enter into this Agreement and as to whether or not this Agreement is appropriate or proper for it based upon its own judgment, is not relying upon the representations, advice or recommendations of the other Party in so doing, is capable of assessing the merits of this Agreement, and understands and accepts the terms, conditions, and risks of this Agreement for fair consideration on an arm's length basis;

17.1.6. No Event of Default or event which with notice or lapse of time, or both, would become an Event of Default, has occurred with respect to such Party, and that such Party is not Bankrupt and there are no proceedings pending or being contemplated by it, or to its knowledge, threatened against it which would result in it being or becoming Bankrupt;

17.1.7. There is no pending, or to its knowledge, threatened legal proceeding at law or equity against it or any Affiliate, that materially adversely affects its ability to perform its obligations under this Agreement;

17.1.8. It is a "forward contract merchant" and this Agreement constitutes a "forward contract" as such terms are defined in the United States Bankruptcy Code;

17.1.9. It is an "eligible commercial entity" within the Commodity Exchange Act;

17.1.10. It is an "eligible contract participant" within the Commodity Exchange Act; and;

17.1.11. Each person who executes this Agreement on behalf of such Party has full and complete authority to do so, and that such Party will be bound by such execution.

18. **Seller Representations and Warranties to Buyer**

18.1. For all Product and every aspect thereof, Seller represents, warrants, and reaffirms to Buyer as a continuing warranty and representation that:

18.1.1. No Product (including any REC) has been, or will be, sold, retired, claimed, represented as part of any electricity output, use, or sale, or otherwise used to satisfy any renewable energy, efficiency, emissions, and/or offset obligation under the Act, or under any voluntary or mandatory standard, marketplace, or jurisdiction, or otherwise;

18.1.2. All Product (including every REC) will meet the specifications and requirements in this Agreement, including without limitation, compliance with the Act;

18.1.3. Each unit of the Product will be and was generated during the applicable Vintage;

18.1.4. Seller has provided and conveyed and will provide and convey to Buyer all Capacity rights associated with the Facility and all Energy produced by the Facility;

18.1.5. Seller has provided and conveyed and will provide and convey to Buyer all Renewable Energy Attributes and REA Reporting Rights associated with all Energy generated by the Facility as part of the Product being delivered to Buyer;

18.1.6. Seller holds all the rights to all the Product from the Facility, Seller has the right to sell the Product to Buyer, and Seller agrees to convey and does convey to Buyer all rights and good title to the Product free and clear of any Liens, encumbrances, or title defects;

18.1.7. Seller has not and will not double sell, double claim or any manner otherwise double count the Product (including, without limitation, any Capacity of the Facility or any REC, Renewable Energy Attributes, or REA Reporting Rights) in any manner (including, for example, by issuing a press release or otherwise claiming that Seller is creating any environmental benefit, using a renewable energy source, or selling renewable energy (in each case inclusive of thermal energy) to any person other than exclusively to and for the benefit of Buyer);Seller will not claim to for itself any of the Renewable Energy Attributes, “green energy”, ”clean energy”, “carbon-free energy” or other rights sold to Buyer, in any public communication concerning the output of the Facility, the Facility or the RECs;

18.1.8. Seller shall at all times be fully compliant with the requirements of the Federal Trade Commission’s “Green Guides,” 77 F.R. 62122, 16 C.F.R. Part 260, as amended or restated, and;

18.1.9. Seller has not and will not in any manner interfere with, encumber or otherwise impede Buyer’s use, transfer, and sale of any Product.

19. **Events of Default**

19.1. An “Event of Default” means with respect to the non-performing Party (such Party, the “Defaulting Party”), the occurrence of any one or more of the following, each of which, individually, shall constitute a separate Event of Default:

19.2. The failure to make, when due, any payment required pursuant to this Agreement if such failure is not remedied within ten (10) Business Days after the Defaulting Party’s receipt of written notice; *provided, however*, a Party will have two (2) Business Days to remedy any failure to make payment required under Section 21;

19.3. Any covenant or warranty made by Seller under Section 6.2 (Seller Covenant) is false or misleading in any respect when made or when deemed made or repeated.

19.4. Any representation or warranty made by a Party under Section 17 and elsewhere in this Agreement (except Section 18 which is a separate Event of Default) is false or misleading in any material respect when made or when deemed made or repeated;

19.5. Seller fails to comply with Section 7.1.1 and such failure is not remedied within three Business Days after Seller's receipt of written notice from Buyer.

19.6. Any representation or warranty made by Seller under Section 18 (Seller Representations and Warranties to Buyer) is false or misleading in any respect when made or when deemed made or repeated;

19.7. If Seller prior to the Commercial Operation Date ceases construction of the Facility for more than thirty (30) consecutive days;

19.8. Seller fails to fully and timely achieve any of the Operational Milestone Schedule events (other than the Commercial Operation Date that is governed exclusively by Section 19.9 and 20.5); *provided, however,* that such failure shall not be deemed an Event of Default if Seller can make a Commercially Reasonable demonstration to Buyer, in Buyers Commercially Reasonable discretion, that in spite of missing the Milestone Deadline the Facility will achieve Commercial Operation by the Commercial Operation Date as it may be extended pursuant to the terms of Section 20.5.

19.9. Seller fails to achieve Commercial Operation by the Commercial Operation Date, as it may be extended pursuant Section 20.5;

19.10. The actual Nameplate Capacity Rating of the Facility is higher than the Nameplate Capacity Rating set forth in Exhibit 4, or is lower than the Nameplate Capacity Rating by more than five (5) percent of the Nameplate Capacity Rating set forth in Exhibit 4.

19.11. Seller Abandons the Facility for more than thirty (30) consecutive days;

19.12. Seller fails to obtain or maintain the Facility's registration or certification as a Qualifying Facility under PURPA.

19.13. Seller fails to obtain or maintain the Facility's registration as a New Renewable Energy Facility, and such failure is not cured within thirty (30) days.

19.14. Seller fails to fully comply with the PURPA Fuel Requirements.

19.15. Seller delivers or attempts to deliver to Buyer any Product (or any component thereof) that was not generated by the Facility.

19.16. Seller delivers or attempts to deliver any Product (or component thereof) to any entity or person other than to the Buyer.

19.17. Seller fails to promptly and fully comply with a System Operator Instruction.

19.18. Seller fails to provide, replenish, renew, or replace the Performance Assurance and/or otherwise fails to fully comply with the credit related requirements of this Agreement, including without limitation, Section 5, and any such failure is not cured within five (5) Business Days.

19.19. Seller fails to fully meet all the insurance requirements set forth in Section 7.5, and such failure is not cured within five (5) Business Days.

19.20. Seller fails to fully comply with all of the confidentiality obligations set forth in Section 16.

19.21. Seller consolidates or amalgamates with, or merges with or into, or transfers all or substantially all of its assets to, another entity and: (i) at the time of such consolidation, amalgamation, merger or transfer, the resulting, surviving or transferee entity fails to assume all the obligations of Seller under this Agreement to which it or its predecessor was a party by operation of law or pursuant to an agreement reasonably satisfactory to the other Party; or (ii) the creditworthiness of the party or the resulting, surviving, transferee or successor entity is weaker than that of Seller prior to such action; or (iii) the benefits of any guaranty fail to extend to the performance by such resulting, surviving, transferee or successor entity of its obligations under this Agreement

19.22. An assignment by or Change of Control with respect to Seller, other than in compliance with Section 24;

19.23. A Party becomes Bankrupt;

19.24. Seller transfers or assigns or otherwise conveys any of its rights or obligations under this Agreement to another Person in violation of the terms and conditions of this Agreement;

19.25. Seller violates the publicity obligations set forth in Section 26.10;

19.26. If the Facility is equipped with a Storage Resource: (i) Seller's failure to materially comply with the Energy Storage Protocol as required under this Agreement and such failure is not remedied within three Business Days after Seller's receipt of written notice from Buyer, or (ii) if Seller fails to materially comply with any Energy Storage Protocol on more than three (3) occasions over the Term of this Agreement; *provided however,* that any such failure shall not be counted against the cumulative limit if Seller can make a Commercially Reasonable demonstration to Buyer that Seller's failure to materially comply with the Energy Storage Protocol was beyond Seller's reasonable control and not the result of Seller's intentional misconduct or gross negligence; and

19.27. Except to the extent constituting a separate Event of Default (in which case the provisions applicable to that separate Event of Default shall apply) the failure to perform any material covenant or obligation set forth in this Agreement, if such failure is not remedied within thirty (30) days after the Defaulting Party's receipt of written notice.

20. **Early Termination.**

20.1. Early Termination Date. If an Event of Default with respect to a Defaulting Party has occurred and is continuing, then the other Party (such Party, the "Non-Defaulting Party") shall have the right, in its sole discretion and upon written notice to the Defaulting Party, to pursue any or all of the following remedies: (a) withhold payments due to the Defaulting Party under this Agreement; (b) suspend performance under this Agreement; and/or (c) designate a day (which day shall be no earlier than the day such notice is effective and shall be no later than twenty (20) days after the delivery of such notice is effective) as an early termination date to accelerate all amounts owing between the Parties, liquidate, net, recoup, set-off, and early terminate this Agreement and any other agreement between the Parties (such day, the "Early Termination Date").

20.2. Effectiveness of Default and Remedies. Where an Event of Default is specified herein and is governed by a system of law which does not permit termination to take place upon or after the occurrence of the relevant Event of Default in accordance with the terms of this Agreement an Event of Default and Early Termination Date shall be deemed to have occurred immediately upon any such event and no prior written notice shall be required. All of the remedies and provisions set forth in this section shall be without prejudice to any other right of the Non-Defaulting Party to accelerate amounts owed, net, recoup, setoff, liquidate, and early terminate this Agreement.

20.3. Net Settlement Amount. If the Non-Defaulting Party establishes an Early Termination Date, then the Non-Defaulting Party shall calculate its Gains or Losses and Costs resulting from the termination as of the Early Termination Date, in a Commercially Reasonable Manner. The Non-Defaulting Party shall aggregate such Gains or Losses and Costs with respect to the liquidation of the termination and any other amounts due under this Agreement and any other agreement between the Parties into a single net amount expressed in U.S. dollars (the "Net Settlement Amount"). The Non-Defaulting Party shall then notify the Defaulting Party of the Net Settlement Amount. The Defaulting Party shall pay the Non-Defaulting Party the full amount of the Net Settlement Amount within two (2) Business Days of delivery to the Defaulting Party of the notice of the Net Settlement Amount that the Defaulting Party is liable for.

20.4. Payment. Any Net Settlement Amount will only be due and payable only to the Non-Defaulting Party from and by the Defaulting Party. If the Non-Defaulting Party's aggregate Gains exceed its aggregate Losses and Costs, if any, resulting from the termination of this Agreement, the Net Settlement Amount will be deemed to be zero and no payment will be due or payable. The Non-Defaulting Party shall under no circumstances be required to account for or otherwise credit or pay the Defaulting Party for economic benefits accruing to the Non-Defaulting Party as a result of the Defaulting Party's default. The Non-Defaulting Party shall be entitled to recover any Net Settlement Amount by netting or set-off or to otherwise pursue recovery of damages. Additionally, Buyer will be entitled to recover any Net Settlement Amount by drawing upon any Performance Assurance or by netting or set-off, or to otherwise pursue recovery of damages. Any calculation and payment of the Net Settlement Amount will be independent of and in addition to Seller's obligation to reimburse Buyer for overpayments pursuant to Section 20.6.

20.5. Commercial Operation Date Liquidated Damages.

20.5.1. Failure to Achieve First COD Date. Notwithstanding anything to the contrary in this Agreement, to the extent an Event of Default occurs due to Seller's failure to timely achieve the Commercial Operation Date as set forth in Exhibit 3 (the "First COD Date"), then this Agreement shall terminate and Seller shall be liable to Buyer for liquidated damages in the amount of [*4% x total projected revenue under the Agreement during the Term as determined by Buyer in its reasonable discretion __________ U.S. dollars ($_________)*] (the "Default Liquidated Damages") which shall be due and payable by Seller within five (5) Business Days after the First COD Date; provided however, if no later than twenty (20) Business Days prior to the First COD Date Seller notifies Buyer in writing that Seller will be unable to achieve Commercial Operation by the First COD Date and Seller also notifies Buyer in writing that Seller desires to continue performance under this Agreement, then this Agreement shall remain in full force and effect and upon payment of liquidated damages to Buyer in the amount of [25% of the Default Liquidated Damages] (the "Initial Liquidated Damages") within five (5) Business Days after the First COD Date, Seller shall have up to an additional one hundred eighty (180) days from the First COD Date to achieve Commercial Operation (such extended date, the "Second COD Date").

20.5.2. Second COD Date. If Seller achieves Commercial Operation on or before the Second COD Date Seller shall pay Buyer additional liquidated damages, within five (5) Business Days of achieving the Second COD Date, in the amount of [75% of the Default Liquidated Damages divided by 180] [U.S. _____________dollars ($_______________)] per day (the "Per Diem Liquidated Damages") for each day that Commercial Operation was delayed beyond the First COD Date up to and including the one hundred eightieth (180th) day following the First COD Date as per diem liquidated damages for failing to timely achieve Commercial Operation by the First COD Date.

20.5.3. Failure to Achieve Second COD Date. If Seller fails to achieve Commercial Operation by the Second COD Date (i.e., within one hundred eighty (180) days following the First COD Date) then this Agreement will terminate and Seller will be liable to Buyer and will pay Buyer, within five (5) Business Days of such failure, additional liquidated damages (in addition to the Initial Liquidated Damages paid under Section 20.5.1) in the amount of [the Default Liquidated Damages [75% of the Default Liquidated Damages________________ U.S. dollars ($____________)].

20.5.4. Exclusive Remedy. The Parties agree that it would be extremely difficult and impracticable under the presently known and anticipated facts and circumstances to ascertain and fix the actual damages Buyer would incur if Seller does not achieve Commercial Operation by the promised Commercial Operation Date. Accordingly, the Parties agree that if Seller does not meet the promised Commercial Operation Date (as may be extended under this Section 20.5), Buyer's sole remedy for that delay shall be to recover from Seller as liquidated damages, and not as a penalty, the amount of liquidated damages specified in this Section 20.5. The agreed upon delay liquidated damages shall not limit Buyer's remedies for other breaches, actions or omissions of Seller under this Agreement.

20.6. Overpayment Reimbursement. Notwithstanding anything else in this Agreement to the contrary, including without limitation the Net Settlement Amount calculation and payment provisions set forth in Sections 20.1 through 20.5, and without limiting any of Buyer's other rights or remedies hereunder, Seller agrees and acknowledges that in the event this Agreement is terminated prior to the expiration of the Term for any reason other than an Event of Default by Buyer, that Seller will reimburse Buyer for all amounts paid by Buyer to Seller under this Agreement in excess of Buyer's Avoided Cost for energy and capacity over the period starting from the Commercial Operation Date through the date of termination of this Agreement plus interest on such amount calculated at the rate of [UPDATED EVERY YEAR, CURRENTLY - DEP 2.9% (two and nine tenths percent)] [DEC 3.7% (three and seven tenths percent)] until repaid (the "Overpayment Amount"). Seller agrees to reimburse Buyer for the Overpayment Amount notwithstanding anything to the contrary in this Agreement and without regard to whether Seller is or may be liable to Buyer for any additional amounts under this Agreement, including, without limitation, any Net Settlement Amount, Gains, and/or Losses determined or to be determined pursuant to this Agreement. The Seller will pay Buyer the Overpayment Amount no later than three (3) Business Days after the Early Termination Date.

20.7. Survival. This Section 20 will survive any expiration or termination of this Agreement.

21. **Cover Costs**.

21.1. Exclusive Remedies. Except where a specific and exclusive remedy is otherwise set forth in this Agreement, the remedies set forth in this Section shall be a Party's exclusive remedies prior to termination for the other Party's failure to deliver the Product or to receive the Product pursuant to and in accordance with this Agreement.

21.2. Seller's Failure to Deliver. If Seller fails to deliver Product that complies with the requirements set forth in this Agreement or fails to deliver all or part of the Contract Quantity (each will be deemed as a failure to deliver for purposes of calculating damages), and such failure is not excused by a Permitted Excuse to Perform or Buyer's failure to perform, then Buyer shall elect in its sole discretion: (i) to terminate and liquidate this

Agreement if such failure is an Event of Default as set forth herein, and in which case Buyer shall calculate its termination payment in accordance with this Agreement as though it were the Non-Defaulting Party; or, (ii) to require Seller to pay Buyer within three (3) Business Days of invoice receipt, liquidated damages in the amount obtained by multiplying the number of units of Product (or component thereof) that Seller failed to deliver to Buyer multiplied by two (2) times the ~~per unit Contract~~ Implied Energy Price.

21.3. Buyer's Failure to Accept Delivery. If Buyer fails to receive all or part of the Contract Quantity that Seller attempted to deliver to Buyer in accordance with this Agreement, and such failure by Buyer is not excused by a Permitted Excuse to Perform or Seller's failure to perform, then Seller shall elect in its sole discretion either to: (i) terminate and liquidate this Agreement if such failure is an Event of Default as set forth herein, and in which case Seller shall calculate its termination payment in accordance with this Agreement as though it were the Non-Defaulting Party; or, (ii) require Buyer to pay Seller within three (3) Business Days of invoice receipt, liquidated damages in the amount obtained by multiplying the number of units of Product (or component thereof) that Buyer failed to receive multiplied by ~~two (2) times the per unit Contract~~ the Implied Energy Price.

21.4. Event of Default. Any failure by ~~Seller~~ a Party to pay amounts due under this Section 21 will be an Event of Default under Section 19.2.

21.5. Survival. This Section 21 will survive any expiration or termination of this Agreement.

22. **Limitation of Liabilities & Liquidated Damages.**

22.1. Reasonableness. THE EXPRESS REMEDIES AND MEASURES OF DAMAGES, INCLUDING WITHOUT LIMITATION DETERMINATION OF LIQUIDATED DAMAGES, COVER COSTS, AND NET SETTLEMENT AMOUNT DAMAGES PROVIDED FOR IN THIS AGREEMENT (i) ARE REASONABLE AND SATISFY THE ESSENTIAL PURPOSES HEREOF FOR BREACH OF ANY PROVISION FOR WHICH THE EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, AND (ii) UNLESS OTHERWISE STATED IN SUCH PROVISIONS, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISIONS, AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. TO THE EXTENT ANY PROVISION OF THIS AGREEMENT PROVIDES FOR, OR IS DEEMED TO CONSTITUTE OR INCLUDE, LIQUIDATED DAMAGES, THE PARTIES STIPULATE AND AGREE THAT THE ACTUAL DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO ESTIMATE OR DETERMINE, THE LIQUIDATED AMOUNTS ARE A REASONABLE APPROXIMATION OF AND METHODOLOGY TO DETERMINE THE ANTICIPATED HARM OR LOSS TO THE PARTY, AND OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT. THE PARTIES FURTHER STIPULATE AND AGREE THAT ANY PROVISIONS FOR LIQUIDATED DAMAGES ARE NOT INTENDED AS, AND SHALL NOT BE DEEMED TO CONSTITUTE, A PENALTY, AND EACH PARTY HEREBY WAIVES THE RIGHT TO CONTEST SUCH PROVISIONS AS AN UNREASONABLE PENALTY OR AS UNENFORCEABLE FOR ANY REASON.

22.2. Limitation. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY HEREIN PROVIDED, (i) THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED; AND (ii) NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, EVEN IF SUCH DAMAGES ARE ALLOWED OR PROVIDED BY STATUTE, STRICT LIABILITY, ANY TORT, CONTRACT, OR OTHERWISE.

22.3. Damages Stipulation. Each Party expressly agrees and stipulates that the terms, conditions, and payment obligations set forth in Sections 20 and 21 are a reasonable methodology to approximate or determine harm or loss, each Party acknowledges the difficulty of determining actual damages or loss, and each Party hereby waives the right to contest such damages and payments as unenforceable, as an unreasonable penalty, or otherwise for any reason. The Parties further acknowledge and agree that damages and payments determined under Sections 20 and 21 are direct damages, will be deemed to be a direct loss, and will not be excluded from liability or recovery under the Limitations of Liabilities provisions of this Section 22.

22.4. Survival. This Section 22 will survive any expiration or termination of this Agreement.

23. **Disputes and Arbitration**

23.1. Resolution by the Parties. The Parties shall attempt to resolve any claims, disputes and other controversies arising out of or relating to this Agreement (collectively, "Dispute(s)") promptly by negotiation between executives who have authority to settle the Dispute and who are at a higher level of management than the persons with direct responsibility for administration of this Agreement. A Party may give the other Party written notice of a Dispute that has not been resolved in the normal course of business. Such notice shall include: (a) a statement of that Party's position and a summary of arguments supporting such position, and (b) the name and title of the executive who will be representing that Party and of any other person who will accompany the executive. Within ten (10) Business Days after delivery of the notice, the receiving Party shall respond with (a) a statement of that Party's position and a summary of arguments supporting such position, and (b) the name and title of the executive who will represent that Party and of any other person who will accompany the executive. Within twenty (20) Business Days after delivery of the initial notice, the executives of both Parties shall meet at Buyer's offices, and thereafter as often as they reasonably deem necessary, to attempt to resolve the Dispute. At the request of either Party, the Parties shall enter into a confidentiality agreement to cover any Dispute and discussions related thereto.

23.2. Demand for Arbitration.

23.2.1. If a Dispute has not been resolved by negotiation within thirty (30) Business Days of the disputing Party's initial notice, the Parties shall fully and finally settle the Dispute by binding arbitration administered by the American Arbitration Association ("AAA"), or such other nationally recognized arbitration association or organization as the Parties may mutually agree. The Arbitration shall be conducted in accordance with the AAA Commercial Arbitration Rules then in effect, and shall be governed by the Federal Arbitration Act, 9 U.S.C. §§ 1-16. To the extent the AAA Rules conflict with any provision of Section 23 of this Agreement, the terms of this Agreement shall govern and control.

23.2.2. Either Party may serve the demand for arbitration on the other Party; provided, however, no demand for arbitration shall be made or permitted after the date when the institution of a civil action based on the Dispute would be barred by the applicable statute of limitations or repose.

23.2.3. All arbitration proceedings shall take place in [DEC - Charlotte] [DEP - Raleigh], North Carolina.

23.2.4. A single arbitrator will arbitrate all Disputes where the amount in controversy is less than five-hundred thousand U.S. dollars ($500,000), and will be selected by the Parties or by the AAA if the Parties cannot agree to the arbitrator. Such arbitrator shall be a licensed attorney with at least ten (10) years of experience in the electric utility industry. The cost of the arbitrator(s) shall be borne equally by the Parties.

23.2.5. A panel of three (3) arbitrators will conduct the proceeding when the amount in controversy is equal to or more than five hundred thousand U.S. dollars ($500,000). If the Parties have not so agreed on such three (3) arbitrator(s) on or before thirty (30) days following the delivery of a demand for Arbitration to the other Party, then each Party, by notice to the other Party, may designate one arbitrator (who shall not be a current or former officer, director, employee or agent of such Party or any of its Affiliates). The two (2) arbitrators designated as provided in the immediately preceding sentence shall endeavor to designate promptly a third (3^{rd}) arbitrator.

23.2.6. If either Party fails to designate an initial arbitrator on or before forty five (45) days following the delivery of an arbitration notice to the other Party, or if the two (2) initially designated arbitrators have not designated a third (3^{rd}) arbitrator within thirty (30) days of the date for designation of the two (2) arbitrators initially designated, any Party may request the AAA to designate the remaining arbitrator(s) pursuant to its Commercial Arbitration Rules. Such third (3rd) arbitrator shall be a licensed attorney with at least ten (10) years of experience in the electric utility industry.

23.2.7. If any arbitrator resigns, becomes incapacitated, or otherwise refuses or fails to serve or to continue to serve as an arbitrator, the Party entitled to designate that arbitrator shall designate a successor.

23.3. Discovery. Either Party may apply to the arbitrators for the privilege of conducting discovery. The right to conduct discovery shall be granted by the arbitrators in their sole discretion with a view to avoiding surprise and providing reasonable access to necessary information or to information likely to be presented during the course of the arbitration, provided that such discovery period shall not exceed sixty (60) Business Days.

23.4. Binding Nature. The arbitrator(s)' decision shall be by majority vote (or by the single arbitrator if a single arbitrator is used) and shall be issued in a writing that sets forth in separately numbered paragraphs all of the findings of fact and conclusions of law necessary for the decision. Findings of fact and conclusions of law shall be separately designated as such. The arbitrator(s) shall not be entitled to deviate from the construct, procedures or requirements of this Agreement. The award rendered by the arbitrator(s) in any arbitration shall be final and binding upon the Parties, and judgment may be entered on the award in accordance with applicable law in any court of competent jurisdiction.

23.5. Consolidation. No arbitration arising under the Agreement shall include, by consolidation, joinder, or any other manner, any person not a party to the Agreement unless (a) such person is substantially involved in a common question of fact directly relating to the Dispute; provided however, such person will not include any Governmental Authority, (b) the presence of the person is required if complete relief is to be accorded in the arbitration, and (c) the person has consented to be included.

23.6. Mediation. At any time prior or subsequent to a Party initiating arbitration, the Parties may mutually agree to (but are not obligated to) attempt to resolve their Dispute by non-binding mediation, using a mediator selected by mutual agreement. The mediation shall be completed within thirty (30) Business Days from the date on which the Parties agree to mediate. Unless mutually agreed by the parties, any mediation agreed to by the Parties shall not delay arbitration. The Parties shall pay their own costs associated with mediation and shall share any mediator's fee equally. The mediation shall be held in Raleigh, North Carolina, unless another location is mutually agreed upon. Agreements reached in mediation shall be enforceable as settlement agreements in any court of competent jurisdiction.

23.7. Remedies. Except for Disputes regarding confidentiality arising under Section 16 of this Agreement, the procedures specified in this Section 23 shall be the sole and exclusive procedures for the resolution of Disputes between the Parties arising out of or relating to this Agreement; provided, however, that a Party may file a judicial claim or action on issues of statute of limitations or repose or to seek injunctive relief, sequestration, garnishment, attachment, or an appointment of a receiver, subject to and in accordance with the provisions of Section 26.5 (Venue/Consent to Jurisdiction). Preservation of these remedies does not limit the power of the arbitrator(s) to grant similar remedies, and despite such actions, the Parties shall continue to participate in and be bound by the dispute resolution procedures specified in Section 23.

23.8. Settlement Discussions. All negotiations and discussion concerning Disputes between the Parties pursuant to Section 23 of this Agreement are to be deemed confidential and shall be treated as compromise and settlement negotiations for purposes of applicable rules of evidence and settlement privilege. No statement of position or offers of settlement made in the course of the dispute resolution process can be or will be offered into evidence for any purpose, nor will any such statements or offers of settlement be used in any manner against any Party. Further, no statement of position or offers of settlement will constitute an admission or waiver of rights by either Party. At the request of either Party, any such statements or offers, and all copies thereof, shall be promptly returned to the Party providing the same.

23.9. Survival. This Section 23 will survive any expiration or termination of this Agreement.

24. **Assignment**

24.1. Limitation. Except as set forth below in Section 24.2 with respect to pledging as collateral security, Seller shall not assign, or encumber (collectively, the "Assignment") this Agreement, any rights or obligations under the Agreement, or any portion hereunder, without Buyer's prior written consent. Seller shall give Buyer at least thirty (30) days prior written notice of any requested Assignment. Subject to Seller providing Buyer with information demonstrating to Buyer, in Buyer's sole Commercially Reasonable Discretion, that Seller's proposed assignee has the technical, engineering, financial, and operational capabilities to perform under this Agreement, Buyer may not unreasonably withhold its consent; *provided, however*, that any such assignee shall agree in writing to be bound by the terms and conditions hereof and shall deliver to Buyer such tax, credit, Performance Assurance in the required amount, and enforceability assurance as the Buyer may request in its sole Commercially Reasonable discretion. Notwithstanding anything to the contrary herein, Buyer may pledge, encumber, or assign this Agreement without the consent of Seller to any Person that is Creditworthy, or that has a Creditworthy credit support provider, and that has agreed in writing to assume the obligations of Buyer hereunder, .

24.2. Pledge. Seller may, without prior consent of Buyer but with no less than ten (10) Business Days prior written notice to Buyer, pledge as collateral security this Agreement to a financing party in connection with any loan, lease, or other debt or equity financing arrangement for the Facility. Any pledge of this Agreement as collateral security will not relieve Seller of any obligation or liability under this Agreement or compromise, modify or affect any rights, benefits or risks of Buyer under this Agreement.

24.3. Acknowledgement of Non-Default. Provided that Seller is not in default of its obligations under this Agreement, upon reasonable request by Seller, Buyer will execute a written acknowledgement of non-default in the form of Exhibit 8 attached hereto (the

"Acknowledgement") which shall be based on the actual knowledge of Buyer's personnel responsible for administering the Agreement at the time of the execution of the Acknowledgement and after due inquiry of Buyer's internal records only. Notwithstanding any provision to the contrary set forth in the Acknowledgment, Buyer reserves all rights and defenses available to it under the Agreement, and nothing stated therein shall be deemed to have waived, amended or modified any such rights or defenses. In no event shall the issuance of any Acknowledgement introduce any third party to this Agreement or create any rights, including third party beneficiary rights for any Person under this Agreement.

24.4. Change of Control. Any Change of Control of Seller (however this Change of Control occurs) shall require the prior written consent of Buyer, which shall not be unreasonably withheld or delayed. Seller shall give Buyer at least thirty (30) days prior written notice of any such requested consent to a Change of Control.

24.5. Delivery of Assurances & Voidable. Any Assignment or Change of Control will not relieve Seller of its obligations hereunder, unless Buyer agrees in writing in advance to waive the Seller's continuing obligations under this Agreement. In case of a permitted Assignment and/or Change of Control, such requesting party or parties shall agree in writing to assume all obligations of Seller and to be bound by the terms and conditions of this Agreement and shall deliver to Buyer such tax, credit, performance, and enforceability assurances as Buyer may request, in its sole Commercially Reasonable discretion. Further, Buyer's consent to any Assignment may be conditioned on and subject to Seller's proposed assignee having first obtained all approvals that may be required by any Requirements of Law and from all applicable Governmental Authorities. Any sale, transfer, Change of Control, and/or Assignment of any interest in the Facility or in the Agreement made without fully satisfying the requirements of this Agreement shall be null and void and will be an Event of Default hereunder with Seller as the Defaulting Party.

24.6. Cost Recovery. Without limiting Buyer's rights under this Section 24, to the extent Buyer agrees to a request from Seller for an Assignment, Change of Control, or other changes in administering this Agreement, Seller shall pay Buyer ten thousand dollars ($10,000) prior to Buyer processing Seller's request.

25. **Notices**.

25.1. Process. All notices, requests, or invoices shall be in writing and shall be sent to the address of the applicable Party as specified on the first page of this Agreement. A Party may change its information for receiving notices by sending written notice to the other Party. Notices shall be delivered by hand, certified mail (postage prepaid and return receipt requested), or sent by overnight mail or courier. This section shall be applicable whenever words such as "notify," "submit," "give," or similar language are used in the context of giving notice to a Party.

25.2. Receipt of Notices. Hand delivered notices shall be deemed delivered by the close of the Business Day on which it was hand delivered. Notices provided by certified mail (postage prepaid and return receipt requested), mail delivery or courier service, or by overnight mail or courier service will be deemed received on the date of delivery recorded by the delivery service or on the tracking receipt, as applicable. Notwithstanding anything to the contrary, if the day on which any notice is delivered or received is not a Business Day or is after 5:00 p.m. EPT on a Business Day, then it shall be deemed to have been received on the next following Business Day.

26. **Miscellaneous.**

26.1. Costs. Each Party shall be responsible for its own costs and fees associated with negotiating or disputing or taking any other action with respect to this Agreement, including, without limitation, attorney costs, except that the cost of the arbitrator(s) will be allocated equally between the Parties as provided in Section 23.

26.2. Access. Upon reasonable prior notice, Seller shall provide to Buyer and its authorized agents (including contractors and sub-contractors), employees, auditors, and inspectors reasonable access to the Facility to: (i) tour or otherwise view the Facility; (ii) ascertain the status of the Facility with respect to construction, start-up and testing, or any other obligation of Seller under this Agreement; and, (iii) read meters and perform all inspections, maintenance, service, and operational reviews as may be appropriate to facilitate the performance of this Agreement or to otherwise audit and/or verify Seller's performance under this Agreement. Upon reasonable prior notice, Seller shall provide to Buyer and its guests or customers reasonable access to the Facility to only tour or otherwise view the Facility. While at the Facility, the foregoing agents, employees, auditors, inspectors, guests, and customer shall observe such reasonable safety precautions as may be required by Seller, conduct themselves in a manner that will not interfere with the operation of the Facility, and adhere to Seller's reasonable rules and procedures applicable to Facility visitors. Seller shall have the right to have a representative of Seller present during such access.

26.3. Safe Harbor and Waiver of Section 366. Each Party agrees that it will not assert, and waives any right to assert, that the other Party is performing hereunder as a "utility," as such term is used in 11 U.S.C. Section 366. Further, each Party hereby waives any right to assert and agrees that it will not assert that 11 U.S.C. Section 366 applies to this Agreement or any transaction hereunder in any bankruptcy proceeding. In any such proceeding each Party further waives the right to assert and agrees that it will not assert that the other Party is a provider of last resort with respect to this Agreement or any transaction hereunder or to otherwise limit contractual rights to accelerate amounts owed, net, recoup, set-off, liquidate, and/or early terminate. Without limiting the generality of the foregoing or the binding nature of any other provision of this Agreement on permitted successors and assigns, this provision is intended to be binding upon all successors and assigns of the Parties, including, without limitation, judgment lien creditors, receivers, estates in possession, and trustees thereof.

26.4. Governing Law. THIS AGREEMENT AND THE RIGHTS AND DUTIES OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY AND CONSTRUED, ENFORCED, AND PERFORMED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NORTH CAROLINA [SOUTH CAROLINA], WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAW, AND, IF APPLICABLE, BY THE FEDERAL LAW OF THE UNITED STATES OF AMERICA.

26.5. Venue/Consent to Jurisdiction. Except for Disputes that are subject to Arbitration as provided herein, any judicial action, suit, or proceedings arising out of, resulting from, or in any way relating to, this Agreement, or any alleged breach or default under the same or the warranties and representations contained in the same, shall be brought only in a state or federal court of competent jurisdiction located in [DEP - Wake County, North Carolina or DEC - Mecklenburg County, North Carolina]. The Parties hereto irrevocably consent to the jurisdiction of any federal or state court within in [DEP - Wake County, North Carolina, DEC - Mecklenburg County, North Carolina] and hereby submit to venue in such courts. Without limiting the generality of the foregoing, the Parties waive and agree not to assert by way of motion, defense, or otherwise in such suit, action, or proceeding, any claim that (i) such Party is not subject to the jurisdiction of the state or federal Courts within North Carolina; or (ii) such suit, action, or proceeding is brought in an inconvenient forum; or

(iii) the venue of such suit, action, or proceeding is improper. The exclusive forum for any litigation between them under this Agreement that is not subject to Arbitration shall occur in federal or state court within in [DEP - Wake County, North Carolina, DEC - Mecklenburg County, North Carolina].

26.6. Limitation of Duty to Buy. If this Agreement is terminated due to a default by Seller, neither Seller, nor any affiliate and/or successor of Seller, nor any affiliate and/or successor to the Facility, including without limitation owner and/or operator of the Facility will require or seek to require Buyer to purchase any output (Energy or otherwise) from the Facility under any Requirements of Law (including without limitation PURPA) or otherwise for any period that would have been covered by the Term of this Agreement had this Agreement remained in effect at a price that exceeds the Contract Price. Seller, on behalf of itself and on behalf of any other entity on whose behalf it may act, and on behalf of any successor to the Seller or successor to the Facility, hereby agrees to the terms and conditions in the above sentence, and hereby waives its right to dispute the above sentence. Seller authorizes the Buyer to record notice of the foregoing in the real estate records.

26.7. Entire Agreement and Amendments. This Agreement represents the entire agreement between the Parties with respect to the subject matter of this Agreement, and supersedes all prior negotiations, binding documents, representations and agreements, whether written or oral. No amendment, modification, or change to this Agreement shall be enforceable unless agreed upon in a writing that is executed by the Parties.

26.8. Drafting. Each Party agrees that it (and/or its counsel) has completely read, fully understands, and voluntarily accepts every provision, term, and condition of this Agreement. Each Party agrees that this Agreement shall be considered for all purposes as prepared through the joint efforts of the Parties, and no Party shall have any provision hereof construed against such Party by reason of such Party drafting, negotiating, or proposing any provision hereof, or execution of this Agreement. Each Party irrevocably waives the benefit of any rule of contract construction that disfavors the drafter of a contract or the drafter of specific language in a contract.

26.9. Headings. All section headings in this Agreement are included herein for convenience of reference only and shall not constitute a part of this Agreement for any other purpose.

26.10. Publicity.

26.10.1. Limitation on Seller. Seller shall not make any announcement or release any information concerning or otherwise relating to this Agreement to any member of the public, press, Person, official body, or otherwise without Buyer's prior written consent, which shall not be unreasonably withheld; provided, however, any content approved by Buyer shall be limited to the non-confidential facts of the Agreement and will not imply, directly or indirectly, any endorsement, partnership, support, or testimonial of Seller by Buyer.

26.10.2. Limitation on the Parties. Neither Party shall make any use of the other Party's name, logo, likeness in any publication, promotional material, news release, or similar issuance or material without the other Party's prior review, approval, and written consent. Seller agrees and acknowledges that any reference or likeness to "Duke" shall be a prohibited use of Buyer's name, logo, likeness. Seller agrees and acknowledges that any direct or indirect implication of any endorsement, partnership, support, or testimonial of Seller by Buyer is prohibited, and any such use, endorsement, partnership, support, and/or testimonial will be an Event of Default under this Agreement. Subject to the foregoing, either Party may disclose to the public general information in connection with the Party's respective business activities; *provided, however,* no such disclosure or publicity by Seller will directly or indirectly imply any endorsement, partnership, support, or testimonial of Seller by Buyer.

26.11. Waiver. No waiver by any Party of any of its rights with respect to the other Party or with respect to any matter or default arising in connection with this Agreement shall be construed as a waiver of any subsequent right, matter or default whether of a like kind or different nature. Any waiver under this Agreement will be effective only if it is in writing that has been duly executed by an authorized representative of the waiving Party.

26.12. Partnership and Beneficiaries. Nothing contained in this Agreement shall be construed or constitute any Party as the employee, agent, partner, joint venture, or contractor of any other Party. This Agreement is made and entered into for the sole protection and legal benefit of the Parties, and their permitted successors and assigns. No other person or entity, including, without limitation, a financing or collateral support provider, will be a direct or indirect beneficiary of or under this Agreement, and will not have any direct or indirect cause of action or claim under or in connection with this Agreement.

26.13. Severability. Any provision or section hereof that is declared or rendered unlawful by any applicable court of law, or deemed unlawful because of a statutory change, shall not, to the extent practicable, affect other lawful obligations under this Agreement.

26.14. Counterparts. This Agreement may be executed in counterparts, including facsimiles hereof, and each such executed document will be deemed to be an original document and together will complete execution and effectiveness of this Agreement.

[Remainder of page intentionally left blank. Signature page follows.]

IN WITNESS WHEREOF, Seller and Buyer have caused this Agreement to be executed by their respective duly authorized officers as of the Effective Date.

[DUKE ENERGY CAROLINAS, LLC]
[DUKE ENERGY PROGRESS, LLC]

BY: ______________________________________
NAME:
TITLE:
DATE:

SELLER ______________________

BY: _______________________________
NAME: ____________________________
TITLE: _____________________________
DATE:

Exhibit 1

Estimated Monthly Available Facility Energy ~~Production of the Facility~~

Month	Estimated Available Facility Energy ~~Production~~ (MWh)
January	
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	
Total	

Exhibit 2

Contract Price

Relevant Portion of the Delivery Period	Contract Price ($/MW-month)

Exhibit 3

Operational Milestone Schedule

Deadline	Performance / Result Seller Must Timely Achieve
	Interconnection Agreement Executed
	Financing Milestone Commitment
	Final System Design under Interconnection Agreement
	Required Permits and Approval Deadlines
	Commencement Readiness Requirements
90 calendar days after the Interconnection Facilities and System Upgrades In-Service Date, and extended day-to-day for any delays not caused by the Seller.	Commercial Operation Date

1. **Financing Milestone Commitment.** Seller shall deliver to Buyer a letter of commitment for full project financing meeting all of the minimum requirements set forth below, as determined by Buyer in Buyer's sole Commercially Reasonable discretion. Buyer has no responsibility or obligation of any kind to Seller or any other person or entity with respect to Seller in connection with Seller's financing or the Financing Milestone Commitment.
   1.1. Fully-underwritten and binding (not "best efforts," a term sheet, or some lesser commitment).
   1.2. In an amount that is, along with fully underwritten and committed equity, adequate funding for the construction and operation of the project.
   1.3. Full agreement of the lender and Seller with respect to term, interest rates, fees and other economics of the lending transaction.
   1.4. Lender has approved the form of the power purchase agreement, turbine/panel supply agreement, engineering procurement and construction contract and other significant project agreements, subject only to the execution and delivery of those documents, as well as the construction budget for the project, and that the lender has completed all necessary due diligence.
   1.5. Lender retains no further approval rights with respect to size, site or technical aspects of the project.
   1.6. Free of conditions to effectiveness relating to further equity commitments, the confirmation of tax attributes, the approvals of other public or private third parties or the satisfactory completion of third party reports or assessments (environmental, insurance or otherwise).
   1.7. Not require any bonds or performance guarantees that have not already been obtained.
   1.8. No general condition to financing that the lender be satisfied with the project in its discretion.
   1.9. Fully executed by the lender and the Seller.

2. **Final System Design Under Interconnection Agreement.** Seller shall deliver to Buyer a copy of the design specifications delivered by Seller to the Transmission Provider as of Seller's execution of the facility study agreement with the Transmission Provider, which design specifications shall be deemed as the "final" system design for purposes of Seller's obligation to timely achieve the Commercial Operation Date set forth above in this Exhibit 3. The final design specification documents delivered by Seller shall be labeled as "***FINAL***", and shall be sealed with a [North Carolina/South Carolina] Professional Engineer for purposes of establishing the final design submitted by the Seller based on which the Transmission Provider will determine impacts to the System and construct interconnection facilities for Seller to interconnect with the System and perform under this Agreement. Seller understands that changes in system design may be deemed as material or significant design changes by the Transmission Provider, and could result in the Transmission Provider withdrawing Seller's position in the transmission queue or otherwise withdrawing Seller's transmission request, as may be determined by the Transmission Provider.

3. **Required Permits and Approval Deadlines.** Seller shall deliver to Buyer a list of required Permits and deadlines to secure each of those Permits. Seller shall identify and list all Permits customary and necessary for Seller to design, construct, test, commission, and fully operate the Facility. Seller shall also identify and list the deadline by which Seller must secure the final Permits for Seller to achieve the Commercial Operation Date set forth above in this Exhibit 3. Each required Permit that Seller must secure shall be deemed to be an Operational Milestone, and the deadline by which Seller must secure the Permit shall be deemed to be a Milestone Deadline. Seller shall keep Buyer informed of its efforts to secure the Permits, including, without limitation, date when the request for the Permit is submitted to and date that the final Permit is obtained from the Governmental Authority. For each identified Permit, Seller shall provide Buyer written notice, and any supporting documentation requested by Buyer in its Commercially Reasonable Discretion, that the identified Permits have been obtained, including, without limitation, any approvals from the local Governmental Authority approving the land use, site plan and construction of the Facility.

4. **Commencement Readiness Requirements.** Seller shall deliver to Buyer the list of major development and construction activities, together with deadlines for the commencement and successful completion of those activities for Seller to achieve the Commercial Operation Date set forth in this Exhibit 3. The list of major development and construction activities, together with commencement and completion deadlines, shall include each of the activities set forth below. Each such major development and construction activity shall be deemed to be an Operational Milestone, and the deadline by which Seller must successfully complete each such activity for Seller to achieve the Commercial Operation Date set forth in this Exhibit 3shall be deemed to be a Milestone Deadline. For each identified activity, Seller shall provide Buyer written notice, and any supporting documentation requested by Buyer in its Commercially Reasonable Discretion, that the identified activity has been commenced and/or successfully completed.
   - 4.1.Proof of Seller's rights and interest in the site upon which the Facility is to be constructed, including the applicable sale agreement or long-term lease.
   - 4.2.Delineation of any long lead-time procurement items, including a schedule for ordering and proof of such activity.
   - 4.3.A project key milestone schedule, reflecting the critical milestone events for design and construction of the facility including the date upon which Seller shall achieve: thirty and ninety percent detailed design; site mobilization and commencement; mechanical completion; substantial completion; and final completion.
   - 4.4.Identification of Seller's key personnel, with primary responsibility for the design and construction of the Facility and communications with Buyer.
   - 4.5.Seller's operations and maintenance plan.
   - 4.6.Seller's performance and capacity testing plan and performance guarantees, in which Seller defines the performance output requirements of the Facility and describes the procedures and timing for all testing that will be conducted to demonstrate whether the Facility meets the applicable performance requirements and conditions.

Exhibit 4

Facility Information

The Facility covered under this Agreement is hereby identified as follows:

1. Facility Name:

2. Facility Address:

3. Description of Facility (include number, manufacturer and model of Facility generating units, and layout):

4. Nameplate Capacity Rating:

5. Fuel Type/Generation Type:

6. Site Map (include location and layout of the Facility, equipment, and other site details):

7. Delivery Point Diagram (include Delivery Point, metering, Facility substation):

8. Control Equipment. Subject to final approval by Buyer as of the date of final execution of the Interconnection Agreement, such approval not to be unreasonably withheld, the following control equipment shall be installed at the Facility: A Power Plant Controller (PPC) which includes ~~all features required to comply with this Agreement and the Interconnection Agreement, including, but not limited to, active power control (dispatch), power factor set point control, voltage schedule set point control, active power ramp rates, and frequency response control (from regulation signal sent from System Operator)~~ the following features:

   - Power Factor Requirement: Must be able to provide dynamic reactive between .95 leading power factor and .95 lagging power factor.
   - Voltage Control: Must be able to support the specified voltage schedule at the high side of the generator step-up transformer.
   - Automatic Voltage Control System: Must be able to control voltage through an automatic voltage regulating device (AVR capability). The reactive power should be capable of being injected in a controllable manner within the ramping rate of 20% of the total reactive capability per minute.
   - Steady state Ramping Capability: Must be capable of operating at a ramp rate of 10% of the nameplate capacity per minute in both the upward or downward direction.
   - Voltage and Frequency Ride Through Capability: Must be capable of operating in accordance with NERC Standard PRC-024.
   - Dispatch capability: Must be able to accept dispatch instruction from the operators.
   - Telemetry: Telemetry requirements to be similar to synchronous resources plus met data to support accurate forecasting.
   - Frequency response: Must be able to provide primary frequency response, with the ability to operate with 5 % droop and deadband of ±0.036 Hz.
   - AGC: Must have capability to follow AGC signal. Set points such as active power control, as required by this Agreement, will be made available to Buyer via a hard-wired DNP3 path at the Facility's Point of Interconnection. Remote access to the Facility's HMI (the Plant Controller Interface) will be given for control of the required variables, by the Buyer .

9. Storage Resources. Subject to final approval by Buyer as of the date of final execution of the Interconnection Agreement, the following Storage resources shall be connected to or incorporated into the Facility [identify the design and all material components of any battery storage or other energy storage device connected to or incorporated into the Facility]

   UPON EXECUTION OF THE AGREEMENT TO WHICH THIS EXHIBIT IS ATTACHED, ANY MATERIAL MODIFICATION TO THE FACILITY SHALL REQUIRE BUYER'S PRIOR APPROVAL, AND SHALL BE MEMORIALIZED IN WRITING IN AN AMENDMENT TO THE AGREEMENT.

Exhibit 5
~~Expected Annual Output~~
Operating Characteristics

[Insert table describing applicable operating characteristics]

Exhibit 6
Form of Guaranty

THIS GUARANTY AGREEMENT (this "Guaranty"), dated as of [date], is issued and delivered by [**enter corporate legal name**], a [state] [form of entity] (the "Guarantor"), for the account of [**enter corporate name**], a [state] [form of entity] (the "Obligor"), and for the benefit of **[enter corporate name]**, a **[state] [form of entity]** (the "Beneficiary").

Background Statement

WHEREAS, the Beneficiary and Obligor entered into that certain _____________ dated (the "Agreement"); and

WHEREAS, Beneficiary has required that the Guarantor deliver to the Beneficiary this Guaranty as an inducement to enter into the Agreement.

Agreement

NOW, THEREFORE, in consideration of the foregoing and for good and valuable consideration, the Guarantor hereby agrees as follows:

1. Guaranty; Limitation of Liability. Subject to any rights, setoffs, counterclaims and any other defenses that the Guarantor expressly reserves to itself under this Guaranty, the Guarantor absolutely and unconditionally guarantees the timely payment of the Obligor's payment obligations under the Agreement (the "Guaranteed Obligations"); provided, however, that the Guarantor's aggregate liability hereunder shall not exceed **[amount] U. S. Dollars (U.S. [$xx,xxx,xxx])**.

Subject to the other terms of this Guaranty, the liability of the Guarantor under this Guaranty is limited to payments expressly required to be made under the Agreement, and except as specifically provided therein, the Guarantor shall not be liable for or required to pay any consequential or indirect loss (including but not limited to loss of profits), exemplary damages, punitive damages, special damages, or any other damages or costs.

2. Effect of Amendments. The Guarantor agrees that the Beneficiary and the Obligor may modify, amend and supplement the Agreement and that the Beneficiary may delay or extend the date on which any payment must be made pursuant to the Agreement or delay or extend the date on which any act must be performed by the Obligor thereunder, all without notice to or further assent by the Guarantor, who shall remain bound by this Guaranty, notwithstanding any such act by the Beneficiary.

3. Waiver of Rights. The Guarantor expressly waives (i) protest, (ii) notice of acceptance of this Guaranty by the Beneficiary, and (iii) demand for payment of any of the Guaranteed Obligations.

4. Reservation of Defenses. Without limiting the Guarantor's own defenses and rights hereunder, the Guarantor reserves to itself all rights, setoffs, counterclaims and other defenses that the Obligor may have to payment of all or any portion of the Guaranteed Obligations except defenses arising from the bankruptcy, insolvency, dissolution or liquidation of the Obligor and other defenses expressly waived in this Guaranty.

5. Settlements Conditional. This guaranty shall remain in full force and effect or shall be reinstated (as the case may be) if at any time any monies paid to the Beneficiary in reduction of the indebtedness of the Obligor under the Agreement have to be repaid by the Beneficiary by virtue of any provision or enactment relating to bankruptcy, insolvency or liquidation for the time being in force, and the liability of the Guarantor under this Guaranty shall be computed as if such monies had never been paid to the Beneficiary

6. Notice. The Beneficiary will provide written notice to the Guarantor if the Obligor defaults under the Agreement.

7. Primary Liability of the Guarantor. The Guarantor agrees that the Beneficiary may enforce this Guaranty without the necessity at any time of resorting to or exhausting any other security or collateral. This is a continuing Guaranty of payment and not merely of collection.

8. Representations and Warranties. The Guarantor represents and warrants to the Beneficiary as of the date hereof that:

a. The Guarantor is duly organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation and has full power and legal right to execute and deliver this Guaranty and to perform the provisions of this Guaranty on its part to be performed;

b. The execution, delivery and performance of this Guaranty by the Guarantor have been and remain duly authorized by all necessary corporate action and do not contravene any provision of its certificate of incorporation or by-laws or any law, regulation or contractual restriction binding on it or its assets;

c. All consents, authorizations, approvals, registrations and declarations required for the due execution, delivery and performance of this Guaranty have been obtained from or, as the case may be, filed with the relevant governmental authorities having jurisdiction and remain in full force and effect, and all conditions thereof have been duly complied with and no other action by, and no notice to or filing with, any governmental authority having jurisdiction is required for such execution, delivery or performance; and

d. This Guaranty constitutes the legal, valid and binding obligation of the Guarantor enforceable against it in accordance with its terms, except as enforcement hereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting the enforcement of creditors' rights or by general equity principles.

9. Nature of Guaranty. The Guarantor hereby agrees that its obligations hereunder shall be unconditional

irrespective of the impossibility or illegality of performance by the Obligor under the Agreement; the absence of any action to enforce the Agreement; any waiver or consent by Beneficiary concerning any provisions of the Agreement; the rendering of any judgment against the Obligor or any action to enforce the same; any failure by Beneficiary to take any steps necessary to preserve its rights to any security or collateral for the Guaranteed Obligations; the release of all or any portion of any collateral by Beneficiary; or any failure by Beneficiary to perfect or to keep perfected its security interest or lien in any portion of any collateral.

10. Subrogation**.** The Guarantor will not exercise any rights that it may acquire by way of subrogation until all Guaranteed Obligations shall have been paid in full. Subject to the foregoing, upon payment of all such Guaranteed Obligations, the Guarantor shall be subrogated to the rights of Beneficiary against the Obligor, and Beneficiary agrees to take at the Guarantor's expense such steps as the Guarantor may reasonably request to implement such subrogation.

11. Term of Guaranty. This Guaranty shall remain in full force and effect until the earlier of (i) such time as all the Guaranteed Obligations have been discharged, and (ii) [date] (the "Expiration Date"); provided however, the Guarantor will remain liable hereunder for Guaranteed Obligations that were outstanding prior to the Expiration Date.

12. Governing Law. This Guaranty shall be governed by and construed in accordance with the internal laws of the State of New York without giving effect to principles of conflicts of law.

13. Expenses. The Guarantor agrees to pay all reasonable out-of-pocket expenses (including the reasonable fees and expenses of the Beneficiary's counsel) relating to the enforcement of the Beneficiary's rights hereunder in the event the Guarantor disputes its obligations under this Guaranty and it is finally determined (whether through settlement, arbitration or adjudication, including the exhaustion of all permitted appeals), that the Beneficiary is entitled to receive payment of a portion of or all of such disputed amounts.

14. Waiver of Jury Trial. The Guarantor and the Beneficiary, through acceptance of this Guaranty, waive all rights to trial by jury in any action, proceeding or counterclaim arising or relating to this Guaranty.

15. Entire Agreement; Amendments. This Guaranty integrates all of the terms and conditions mentioned herein or incidental hereto and supersedes all oral negotiations and prior writings in respect to the subject matter hereof. This Guaranty may only be amended or modified by an instrument in writing signed by each of the Guarantor and the Beneficiary.

16. Headings. The headings of the various Sections of this Guaranty are for convenience of reference only and shall not modify, define or limit any of the terms or provisions hereof.

17. No Third-Party Beneficiary. This Guaranty is given by the Guarantor solely for the benefit of the Beneficiary, and is not to be relied upon by any other person or entity.

18. Assignment. Neither the Guarantor nor the Beneficiary may assign its rights or obligations under this Guaranty without the prior written consent of the other, which consent may not be unreasonably withheld or delayed. Notwithstanding the foregoing, the Beneficiary may assign this Guaranty, without the Guarantor's consent, provided such assignment is made to an affiliate or subsidiary of the Beneficiary

Any purported assignment in violation of this Section 18 shall be void and without effect.

19. Notices. Any communication, demand or notice to be given hereunder will be duly given when delivered in writing or sent by electronic mail to the Guarantor or to the Beneficiary, as applicable, at its address as indicated below:

If to the Guarantor, at:

[Guarantor name]
[Address]
Attention: [contact]
Email:[email address]

With a copy to:

[Seller name]
[Address]
Attention: [contact]
Email:[email address]

If to the Beneficiary, at:

[Beneficiary name]
[Address]
Attention: [contact]
Email:[email address]

or such other address as the Guarantor or the Beneficiary shall from time to time specify. Notice shall be deemed given (a) when received, as evidenced by signed receipt, if sent by hand delivery, overnight courier or registered mail or (b) when received, as evidenced by email confirmation, if sent by email and received on or before 4 pm local time of recipient, or (c) the next business day, as evidenced by email confirmation, if sent by email and received after 4 pm local time of recipient.

IN WITNESS WHEREOF, the Guarantor has executed this Guaranty as of the day and year first above written

[Guarantor name]

By: ________________________________
Name:
Title:

Exhibit 7
Form of Letter of Credit

[LETTERHEAD OF ISSUING BANK]

Irrevocable Standby Letter of Credit No.: ____________

Date: ______________

Beneficiary:
[Duke Energy Carolinas, LLC][Duke Energy Progress, LLC]
550 S. Tryon Street, DEC 40C
Charlotte, North Carolina 28202
Attn: Chief Risk Officer

Ladies and Gentlemen:

By the order of:

Applicant:
____
____
____

We hereby issue in your favor our irrevocable standby letter of credit No.: _________ for the account of____ for an amount or amounts not to exceed ___________ US Dollars in the aggregate (US$_____________) available by your drafts at sight drawn on [Issuing Bank] effective _________________ and expiring at our office on ________________ (the "Expiration Date").

The Expiration Date shall be deemed automatically extended without amendments for one year from the then current Expiration Date unless at least ninety (90) days prior to the then applicable Expiration Date, we notify you in writing by certified mail return receipt requested or overnight courier that we are not going to extend the Expiration Date. During said ninety (90) day period, this letter of credit shall remain in full force and effect

Funds under this letter of credit are available against your draft(s), in the form of attached Annex 1, mentioning our letter of credit number and presented at our office located at [Issuing Bank's address must be in US] and accompanied by a certificate in the form of attached Annex 2 with appropriate blanks completed, purportedly signed by an authorized representative of the Beneficiary, on or before the Expiration Date in accordance with the terms and conditions of this letter of credit. Partial drawings under this letter of credit are permitted.

Certificates showing amounts in excess of amounts available under this letter of credit are acceptable, however, in no event will payment exceed the amount available to be drawn under this letter of credit.

We engage with you that drafts drawn under and in conformity with the terms of this letter of credit will be duly honored on presentation if presented on or before the Expiration Date. Presentation at our office includes presentation in person, by certified, registered, or overnight mail.

Except as stated herein, this undertaking is not subject to any agreement, condition or qualification. The obligation of [Issuing Bank] under this letter of credit is the individual obligation of [Issuing Bank] and is in no way contingent upon reimbursement with respect hereto.

This letter of credit is subject to the International Standby Practices 1998, International Chamber Of Commerce Publication No. 590 ("ISP98"). Matters not addressed by ISP98 shall be governed by the laws of the state of New York.

We shall have a reasonable amount of time, not to exceed three (3) business days following the date of our receipt of drawing documents, to examine the documents and determine whether to take up or refuse the documents and to inform you accordingly.

Kindly address all communications with respect to this letter of credit to [Issuing Bank's contact information], specifically referring to the number of this standby letter of credit.

All banking charges are for the account of the Applicant.

This letter of credit may not be amended, changed or modified without our express written consent and the consent of the Beneficiary.

This letter of credit is transferable, and we agree to consent to its transfer, subject to our standard terms of transfer and your payment to us of our standard transfer fee.

Very truly yours
[Issuing Bank]

__________________________ __________________________

Authorized Signer Authorized Signer

This is an integral part of letter of credit number: *[irrevocable standby letter of credit number]*

ANNEX 1

FORM OF SIGHT DRAFT

[Insert date of sight draft]

To: *[Issuing Bank's name and address]*

For the value received, pay to the order of ________________________ by wire transfer of immediately available funds to the following account:

[name of account]
[account number]
[name and address of bank at which account is maintained]
[aba number]
[reference]

The following amount:

[insert number of dollars in writing] United States Dollars
(US$ *[insert number of dollars in figures]*)

Drawn upon your irrevocable letter of credit No. *[irrevocable standby letter of credit number]* dated *[effective date]*

[Beneficiary]

By: ____________________________
Title: __________________________

This is an integral part of letter of credit number: *[irrevocable standby letter of credit number]*

ANNEX 2

FORM OF CERTIFICATE

[Insert date of certificate]

To: *[issuing bank's name and address]*

[check appropriate draw condition]

[_____] An Event of Default (as defined in the [Name of Agreement between [Beneficiary's Name] and [Insert Counterparty's Name] dated as of _________ (the "Agreement")) has occurred with respect to [Counterparty's Name] and such Event of Default has not been cured within the applicable cure period, if any provided for in the Agreement.

Or

[_____] [Counterparty's Name] is required, pursuant to the terms of the Agreement, to maintain a letter of credit in favor of [Beneficiary's Name], has failed to renew or replace the Letter of Credit and the Letter of Credit has less than thirty (30) days until the expiration thereof.

[Beneficiary]

By: ___________________________
Title:__________________________

Exhibit 8
Acknowledgement of Non-Default

[Print Duke Energy letterhead]

Date:

Address of Seller

Re: Acknowledgement of Non-Default (the "Acknowledgement") of the Renewable Power Purchase Agreement, between [Duke Energy Carolinas, LLC][Duke Energy Progress, LLC] ("Buyer") and [insert Seller name] dated as of _______________ (the "Agreement").

Dear Sir or Madam:

The undersigned, a duly authorized representative of Buyer hereby acknowledges to Seller that, as of the date of this Acknowledgement based on the actual knowledge of Buyer's personnel responsible for administering the Agreement after due inquiry of Buyer's internal records only, there is no current Event of Default by Seller under the Agreement, nor to Buyer's knowledge, has any event or omission occurred which, with the giving of notice or the lapse of time or both, would constitute an Event of Default under the Agreement and the Agreement is in full force and effect.

Notwithstanding any provision to the contrary set forth herein, Buyer reserves all rights and defenses available to it under the Agreement and nothing stated herein shall be deemed to have waived, amended or modified any such rights or defenses.

Except as specified herein to the contrary, capitalized terms used in this Acknowledgement shall have the meaning ascribed to such terms in the Agreement.

Sincerely,

[Duke Energy Carolinas, LLC][Duke Energy Progress, LLC]

By:_____________________________
Name:
Title:

Exhibit 9

Power Plant Controller Output Points			
Analog	**Units of Measure**	**Accuracy**	**Notes**
Estimated Unit Active Power Operating High Limit		± 5 %	Estimated Generation currently possible given current equipment status, equipment characteristics, and current ambient conditions. Calculation based on site rating, percentage of inverters in service, POA irradiance, DC/AC ratio, ambient conditions, etc.
Estimated Unit Active Power Operating Low Limit		± 5 %	Estimated Minimum Generation currently possible given current equipment status, equipment characteristics, and current ambient conditions. Calculation based on site rating, percentage of inverters in service, POA irradiance, DC/AC ratio, ambient conditions, etc.
Air Temperature	Degrees Celsius	± 1°	
Back Panel Temperature	Degrees Celsius	± 1°	Temperature sensor mounted behind a solar photovoltaic panel.
Plane Of Array Irradiance- Primary Meter	Watts/Meter Sq.	± 25 W/m^2	Measured with a Class II pyranometer or equivalent equipment. For fixed-tilt sites, the sensor shall be mounted on a meteorological station facing the same angle and direction as the solar photovoltaic panels at the site. For tracking sites, the sensor shall be mounted on a tracker to be oriented at the same angle and direction as the solar photovoltaic panels at the site.
Plane Of Array Irradiance- Secondary Meter	Watts/Meter Sq.	± 25 W/m^2	Measured with a Class II pyranometer or equivalent equipment. For fixed-tilt sites, the sensor shall be mounted on a meteorological station facing the same angle and direction as the solar photovoltaic panels at the site. For tracking sites, the sensor shall be mounted on a tracker to be oriented at the same angle and direction as the solar photovoltaic panels at the site.
Global Horizontal Irradiance	Watts/Meter Sq.	± 25 W/m^2	Measured with a Class II pyranometer or equivalent equipment. The sensor shall be mounted on a metrological station set at the global horizontal angle of the earth in reference to the sun solar radiation.
Global Horizontal Diffuse Irradiance	Watts/Meter Sq.	± 25 W/m^2	Measured with a Class II pyranometer or equivalent equipment. All Solar irradiance coming from the sky and other reflected surfaces except for solar radiation coming directly from the sun and the circumsolar

			irradiance within approximately three degrees of the sun. Global diffuse irradiance sensors follow the same accuracy and mounting requirements as the GHI sensors but shall be designed to measure diffused irradiance.
Direct Irradiance (Optional)	Watts/Meter Sq.	± 25 W/m²	Measured with a Class II pyranometer or equivalent equipment. Solar irradiance arriving at the earth's surface from the sun's direct beam, on a plane perpendicular to the beam and is typically measured on a solar tracker.
Number of Inverters in Ready Status			Sum of the Number of inverters currently in service. Can be a decimal if one or more inverters are partially available.
Digital	**Status**	**Accuracy**	**Notes**
Active Power Dispatch Event	ON/OFF		ON indicates the resource is currently being dispatched to the Active Power Automatic Generation Control Setpoint.
Plane Of Array Irradiance- Primary Meter Status	ON/OFF		Communications Online Offline Status
Plane Of Array Irradiance- Secondary Meter Status	ON/OFF		Communications Online Offline Status

For Facilities equipped with DC tied, behind a solar inverter, Storage Resources the following Power Plant Controller Output Points shall also be reported to Buyer.[1]

Analog	**Units of Measure**	**Accuracy**	**Notes**
Unit Net MW			The resource's real power output measured at the low side of the step-up transformer.
Unit Gross MW			The resource's real power output before subtracting the auxiliary real power load or step-up transformer real power losses.
Unit Auxiliary MW			The resource's real power load the generating unit provides to maintain its station service power.
Storage Device Active Power Operating (Discharging) High Limit	+MWs		Storage Device's Active Power Operating High Limit given current equipment status, equipment characteristics, and current ambient conditions.
Storage Device Active Power Operating (Charging) Low Limit	-MWs		Storage Device's Active Power Operating Low Limit given current equipment status, equipment characteristics, and current ambient conditions.
Number of Storage Device DC-DC Converters in Ready Status			Sum of the Number of DC-DC Converters currently in service. Can be a decimal if one or more DC-DC Converters are partially available.

[1] For non-DC tied, behind a solar inverter, Storage Resources Buyer may require additional Power Plant Controller Output Points to be reported upon reasonable notice to Seller.

Allowable Depth of Discharge	MWh		MWh energy storage potential, considering OEM recommendations and any emergent operating limitations, at a given point in time.
State of Charge			Percentage of the Allowable Depth of Discharge currently charged within the storage device. Example: A nameplate rated 10 MWh storage device is currently allowed to store energy up to 80% of its nameplate rating and down to 20% of its nameplate rating. The storage device currently has 4 MWhs stored in the device. The Allowable Depth of Discharge is 10 MWh *80% - 10 MWH * 20% = 6 MWh The State of Charge = 4 MWh / 6 MWh = 66.66%
Max MWh Charge			Maximum amount of energy currently allowed to be stored in the energy device given current equipment status, equipment characteristics, and current ambient conditions.
Min MWh Charge			Minimum amount of energy currently allowed to be stored in the energy device given current equipment status, equipment characteristics, and current ambient conditions.
Bulk Discharge Window Start Timestamp			The Timestamp of the start of the next Bulk Discharge Window.
Bulk Discharge Window End Timestamp			The Timestamp of the end of the next Bulk Discharge Window.
Bulk Discharge Window Active Power Setpoint			Active Power Setpoint for the current or next Bulk Discharge window taking into account the storage device's current State of Charge and Allowable Depth of Discharge.
Digital	**Status**	**Accuracy**	**Notes**
Storage Device Breaker Status	OPEN/CLOSED		Indicates whether a the Unit Generator Breaker is Open or Closed.

Exhibit 10
Energy Storage Protocol
[Note: to be updated]

1. The Storage Resource must be on the DC side of the inverter and charged exclusively by the Facility.

2. The Storage Resource will be controlled by the Seller, within operational limitations described below.

3. The maximum output of the Facility, including any storage capability, at any given time shall be limited to the Facility's maximum Nameplate Capacity Rating (AC) as specified in the Agreement.

4. The Seller may not increase the Facility's Capacity, including any DC Nameplate Capacity Rating (MW) or AC Nameplate Capacity Rating (MW) or Storage Resource capacity (MW/MWh) beyond what is specified in the Agreement.

5. The discharge of stored energy is not permitted while the Facility has received or is subject to a Dispatch Down instruction or control signal from the System Operator.

6. Ramp rates for Storage Resource shall not exceed 2 percent of the Facility's Nameplate Capacity Rating on a per minute basis, whether up or down, at any time that the Facility is not generating.
7. When the Facility is generating, the Storage Resource shall not act to increase the net ramp rate of the Facility by more than 1 percent of the Facility's Nameplate Capacity Rating per minute in relation to the output from the Facility alone, over a one minute interval, up or down.
8. Scheduling and other storage limitations:
    a. Seller shall, by 8am each day, provide a day-ahead forecast of planned initial state of energy storage (MWh) and planned charging (MWh) of storage for each hour.
    b. By 4pm each day, Buyer will make commercially reasonable efforts to provide Seller with a window for bulk discharge with start and end times for the following day, including off-peak days.
        i. Outside of the bulk discharge window, discharge of the Storage Resource will not be permitted until the Storage Resource reaches and remains at a state of charge of at least 70% of the Allowable Depth of Discharge (as defined below).
        ii. During on-peak days, the bulk discharge window will be entirely contained within the respective on-peak hours.
        iii. Buyer will make commercially reasonable efforts to provide a minimum of 3 hours to discharge remaining battery capacity within each on-peak period.
        iv. The discharge rate (in MW) shall be levelized across the bulk discharge window except as limited by ramp rate criteria or inverter capability.
        v. For non-summer periods, if the bulk discharge window is not long enough to empty the battery before solar generation is expected to be at full output, the

bulk discharge window may be moved up to allow full storage discharge within the on-peak window.

c. The storage charging (Active Power) when the Storage Resource is not inverter limited, shall be limited to 30% of a Facility's storage Allowable Depth of Discharge (e.g., a 10MWh battery with an Allowable Depth of Discharge of 8MWh could charge Active Power at a maximum of 2.4MW).

9. Buyer reserves the right to add or modify operating restrictions if later determined necessary to ensure renewable plus storage facilities do not increase challenges of balancing load and generation on the System relative to a comparable stand-alone renewable facility.

10. Seller will only be compensated for Energy and Capacity actually provided to Buyer in accordance with the terms of the Agreement.

Notes:

a) For facilities equipped with energy storage devices, Seller shall be required to provide the "Nameplate Capacity Ratings" for the Facility in both AC and DC and include in Exhibit 4.

b) The storage device capacity (MW and MWh) shall be specified in Exhibit 4.

Definitions:

"Allowable Depth of Discharge" shall mean the MWh energy storage potential, considering the original equipment manufacturer's recommendations and any emergent operating limitations, at a given point in time.

Other capitalized terms used in this Exhibit which have not been defined herein shall have the meaning ascribed to such terms in the Agreement to which this exhibit is attached.

Exhibit 11
Capacity Tests

[Capacity Testing Protocols to be developed for a Facility capacity test and a Storage Resource capacity test (if applicable)]

Document comparison by Workshare Compare on Wednesday, March 20, 2019 9:14:16 AM

Legend:	
Insertion	
~~Deletion~~	
~~Moved from~~	
Moved to	
Style change	
Format change	
~~Moved deletion~~	
Inserted cell	
Deleted cell	
Moved cell	
Split/Merged cell	
Padding cell	

Statistics:	
	Count
Insertions	229
Deletions	162
Moved from	2
Moved to	2
Style change	0
Format changed	0
Total changes	395

PROACTIVE SOLUTIONS TO CURTAILMENT RISK

IDENTIFYING NEW CONTRACT STRUCTURES FOR UTILITY-SCALE RENEWABLES

Prepared for the Hawaiian Electric Companies by:

John Sterling, Christine Stearn, & Ted Davidovich – Smart Electric Power Alliance

Paul Quinlan, John Pang, & Chris Vlahoplus – ScottMadden Inc.

Smart Electric Power Alliance

Table of Contents

Table of Figures

Table of Tables

Executive Summary

A basic principle of power system operation is that production and consumption of electric power must be equal to each other (i.e., balanced). Variable resources such as wind and solar produce power when wind and solar energy are available, which may not correlate to periods of electricity demand. With the substantial growth of variable renewable energy generation resources on each of the Hawaiian Islands' autonomous systems, including relatively large numbers of distributed resources, Hawai'i's electric utilities are faced with increasing periods when electricity supply exceeds demand and actions are necessary to balance the system. Increasingly, system operators must reduce output of (curtail) renewable energy in order to preserve system reliability, because energy production capability exceeds each island's net load. Continuing to add variable resources to these systems, which face increasing periods of over-supply, requires changes to the historical commercial and contractual terms for procuring energy from these resources, which this paper will consider. Historical procurement compensated variable renewable resources strictly based on energy delivered to the utility. Some certainty of sale was provided by a combination of increasing demand on the systems (increasing the need for the energy), the right to serve energy first by designation as "must-take" resources, and with the philosophy of implementing excess energy curtailments in reverse order of project connection dates. The goal of 100 percent renewable generation requires greater flexibility in the contracting and dispatch of future projects. As the Hawaiian Electric Companies transition to higher levels of renewable resources, optimizing use of such resources helps maintain grid reliability while managing costs.[1] For purposes of this paper, curtailment is defined as a reduction in the output of a generator from what could otherwise have been produced, given the availability of the relevant variable renewable resource (e.g., solar and wind).

As the islands evolve to ever-increasing levels of renewable energy, the ability to treat any type of energy as must-take is increasingly limited. The islands serve only the demand on the island systems and cannot export excess production, as is done in other interconnected areas. Accommodating the renewable resources will displace existing generation that provides dispatchable energy, adjusted to meet demand, and affect many other characteristics to keep the power system stable and operable. Variable resources and firm renewable resources will increasingly need to provide these capabilities to adjust output to serve demand, respond to frequency, regulate voltage, etc., as the systems are transformed to economically and reliably serve the energy needs of the future with 100 percent renewable energy. This increasing contribution to grid management will necessitate changes to both procurement terms and technical and operational capabilities of all renewable resources, including distributed and variable energy resources such as solar and wind, as well as firm renewables such as biomass and geothermal resources.

[1] "Hawaiian Electric Companies" refers collectively to Maui Electric, Hawaiian Electric Company, Inc., and Hawai'i Electric Light Company, Inc. (collectively the "Companies").

The inability of the systems to export excess generation to neighboring systems, as is commonly done in mainland interconnections, further limits options available for excess energy.

Under a traditional Power Purchase Agreement (PPA) arrangement, variable resources have been compensated based on actual energy delivered to the utility. The need for the utility to reduce energy output during periods of low net demand results in uncertainty about how much energy the utility will be able to purchase, resulting in a financial risk to the Independent Power Producer (IPP). Basing compensation on energy delivered to the utility can have a direct, negative impact on any IPP's ability to finance projects, due to the risk of under-collected revenues resulting from curtailed energy (IPP Risk model). However, if a utility off-taker reduces the impact on the IPP by guaranteeing payments for undelivered/curtailed energy, the utility's customers may experience a higher "effective price" for energy delivered than the stated unit price under the PPA (Customer Risk model). Contractual terms based solely on energy sales fail to allocate curtailment risk in a way that is equitable to all parties, transparent to all stakeholders, and sustainable in the future with increasing need to control energy production to match demand.

As Hawai'i moves forward towards its Renewable Portfolio Standard goal of obtaining 100 percent renewable generation by 2045, all generation sources must contribute to grid management by providing not only the ability to match supply and demand (through curtailment), but also other grid services that conventional plants have historically provided. If procured with the appropriate technical and operational capabilities and the appropriate policies that allow system operators to leverage these capabilities, renewable resource utilization can be further increased while maintaining system reliability by providing the necessary capabilities to operate a grid without reliance on conventional fossil plants or costly supplemental technologies. To that end, new contractual approaches are needed for variable renewables that incentivize the dispatchability of these resources and preserve flexibility for future system needs, all while maximizing value for the utilities' customers. This increased flexibility has the added benefit of allowing for common handling of future firm and variable resources. This report outlines some new concepts that may better achieve these objectives.

Table 1 - Preferred Contract Alternative

Solution	Description

Renewable Dispatchable Generation	○ Request for Proposals (RFP) requires bidders to break pricing into fixed ($/MW-month) and variable O&M ($/MWh) components
	    ○ The $/MW-month covers the fixed cost of the facility, ensuring that the project is financeable.
	    ○ The variable $/MWh component is based on the variable O&M cost (if any) to run the facility.
	    ○ Project selection is based on a "blended" levelized price that considers anticipated demand for the energy through a resource planning process.
	○ The seller guarantees a resource conversion factor (i.e., power curve) to convert solar irradiance or wind speed into energy production (MWh).
	○ The IPP is required to meet minimum availability metrics to ensure equipment is maintained and available for production.
	○ The IPP is required to meet technical and operational characteristics that support grid operation, including voltage regulation, disturbance ride-through, frequency response, and active power control (curtailment).
	○ The IPP is required to provide an indication to the utility of the available energy.
	○ On a real-time basis, the utility controls the output of the facility (real and reactive) based on impacts to system cost and grid reliability considerations.
	    ○ Undelivered available energy provides system reserves
	○ The utility integrates the variable resource into system planning and operations as dispatchable energy, limited by available energy used by the variable resource.

Source: SEPA & ScottMadden, 2016

For all proposed structures in this report, the long-term goal is to transition Hawaiʻi away from treating resources as must-take energy, with the excess energy curtailment of resources on the basis of contract connection date, and towards treating all generation as dispatchable in nature. This paradigm shift places all generators on a more equal footing. With proper contract structures, technical and operational characteristics, and planning, this shift should lead to more economic- and reliability-focused dispatch.

Based on the work completed for this report, the Hawaiian Electric Companies' preliminary preferred option is summarized in Table 1. New PPAs would no longer be curtailed in a sequential order based on the seniority of each project's contract approval date; rather, the utility would dispatch the generating facility as required to operate the grid in a reliable manner. The fixed monthly payment would give developers more certainty of recovering the cost of the facility as long as it is maintained to meet predetermined criteria for availability; penalties would be assessed if the facility cannot meet the required metrics.[2]

[2] Because this option provides for fixed cost recovery regardless of production, it would necessarily be used only after evaluation through a resource planning process to determine customer value from anticipated energy delivered to the utility and ancillary services.

This report considers two other options:

- Capacity & Energy PPAs where under which bidders would propose pricing based on fixed ($/MW-month) and energy ($/MWh) components. Bidders would price their curtailment risk outlook into the proposed breakdown between fixed and variable components. For this model, the report contemplates two structures: (1) 25 percent of costs recovered via a fixed payment; and (2) 75 percent of costs recovered via fixed payment. The report also varies the amount of anticipated curtailment that is forecast in their proposal: 0 percent and 20 percent. These options provide plausible bookends for how an IPP may approach curtailment risk mitigation.
- Time-of-Day (ToD) pricing in which the energy prices are lower (or negative) during expected low-load periods, and energy prices are higher during peak load hours. The uncertainty of predicting the long-term system load profile makes this option difficult to align with forecast production costs, and therefore, appropriate energy prices.

When comparing potential pricing approaches for each of these scenarios with today's current alternatives (where either the IPP or the utility owns all of the financial risk caused by the uncertainty in the amount of energy the systems can accept), identifying ways to spread the risk more equitably can lead to less price variability for the customer and less financing risk for the developer.[3]

The modeling included in this report contemplates the impacts on new solar projects; however, these structures could be translated to any new variable or firm renewable resource, including wind, biomass, or geothermal resources. For the Renewable Dispatchable Generation model, this report assumes for simplicity that there is no variable component and that all costs are recovered via the fixed payment.

The structures identified in this report resulted in less downside risk of revenues collected for IPPs on a net present value (NPV) basis. This reduced volatility should translate into stronger project financing due to the ability to better forecast stable revenues regardless of curtailment, as compared to the traditional IPP Risk Model. Such improved financeability can be further quantified by examining the resulting Debt Service Coverage Ratio (DSCR) for each structure under zero curtailment and high curtailment scenarios. DSCR represents the likelihood that a project's future revenue streams can cover its debt obligations. Lenders frequently use this metric to set rates when financing a project. Reduced NPV risk translates into more stable DSCRs across these structures. In turn, this should lead to more attractive financing costs and, ultimately, lower PPA prices.

Lastly, the structures identified here would reduce variability for the utility's customers in the effective price of the energy delivered, after factoring in fixed and variable payments. While none of the approaches are able to eliminate curtailment risk entirely, these structures limit the upside risk in the effective price paid for delivered energy. By more

[3] All structures presented here, with the exception of the Time-of-Day Price Caps, do not assume the use of energy storage technologies.

equitably splitting economic risks with IPPs across the board, customer risk can be mitigated as well.

Continued research into how customers may be impacted by these new agreements is ongoing. Potential unintended consequences as a result of increased fixed payments and the curtailment conditions need to be identified and further discussed. One potential consequence identified is that if a PPA is considered a capital lease under current accounting guidance (or a lease under recently issued revised accounting rules), the present value of the estimated lease payments would need to be reflected as a liability on the utility company's financial statements. The impact to the utility's financial statements from having to recognize the present value of the estimated lease payments can be significant to the Hawaiian Electric Companies' credit metrics and cost of capital. Recently revised accounting rules may increase this risk, and such assessment is ongoing.

Detailed conversations with key market participants are also needed to ensure that any future procurement practices are structured in a transparent, fair, and equitable manner.

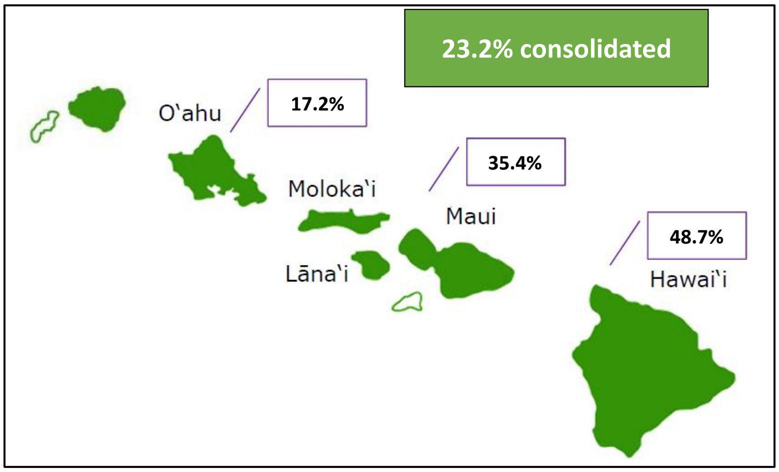
The systems have finite quantities of demand, and as a result, have finite need for new resources to meet the demand. The procurement of resources through contracts that recover fixed costs requires careful resource planning to avoid fixed expenses for resources without consumer benefit. The mix of energy resources must be designed to cost-effectively meet customer demand, while maintaining acceptable reliability. The evaluation of resource type and location must include its correlation with net demand and total impacts on system interconnection and operational costs. Care must be taken to design a mix of resources whose fixed costs that result in a net cost-benefit from the energy production and grid services, compared to resource alternatives. Alternative resource considerations can include storage options, dispatchable renewable resources, demand response, and conversion of conventional fossil plants to renewable resources through fuel conversions.

Hawai'i's place as the nation's leader in renewable energy adoption places an increasing importance on including these considerations, with a resource plan to meet 100 percent renewable energy goals while managing costs and ensuring grid stability. With time, as other states transition away from conventional generation and increase the amount of intermittent renewable resources on their systems, the lessons learned in Hawai'i will be valuable to utilities and grid operators in much larger interconnected systems. The examples and successes from Hawai'i that emerge from this effort will ripple across the industry and set the stage for a new way of thinking about renewable resources.

State of the State

Hawai'i is leading the United States with a vision of 100 percent renewable energy by 2045. This vision challenges the state's utilities to tap plentiful, natural, clean sources of power, while building grids, interconnection infrastructure, and business models to make these power sources accessible and affordable. As of December 2015, the Hawaiian Electric Companies, comprised of Hawaiian Electric Company, Inc. (Hawaiian Electric), Maui Electric Company, Limited (Maui Electric), and Hawai'i Electric Light Company, Inc. (Hawai'i Electric Light), obtained over 23 percent of their generation from renewable energy sources[4]

Figure 1 - Renewable Energy Utilization, December 2015



Source: Hawaiian Electric Companies, 2016

The Hawaiian Electric Companies serve 95 percent of the state's 1.4 million residents on the islands of Hawai'i, Lana'i, Moloka'i, Maui, and O'ahu. To meet the energy needs of Hawai'i's residents and integrate higher levels of renewable energy, the Hawaiian Electric Companies are working aggressively to empower their customers and communities with affordable, reliable, clean energy, and provide innovative energy leadership for Hawai'i. To achieve that vision, through their resource planning process, the Hawaiian Electric Companies have produced a Power Supply Improvement Plan (PSIP) to reach the 2045 goal of 100 percent of renewable resources by:[5]

- Implementing a smart grid foundation project;
- Implementing a demand response management system (DRMS);
- Pursuing market-based distributed energy resources (DER) for O'ahu, Hawai'i Island, and Maui and high distributed generation (DG) in the form of solar photovoltaics (PV) for Moloka'i and Lana'i;
- Installing circuit level improvements on all islands;

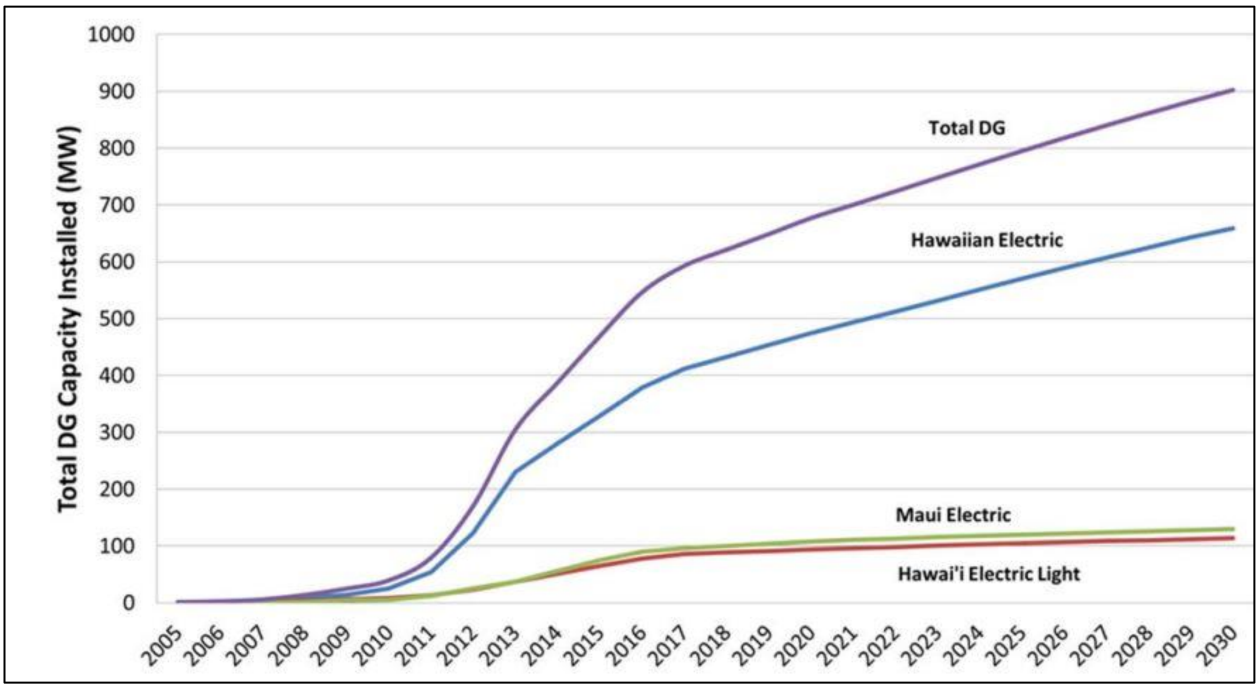
[4] Under Hawai'i's Renewable Portfolio Standards, each electric utility company that sells electricity for consumption in Hawai'i must establish the following percentages of "renewable electrical energy" sales by December 31 in each of the following years: 10% by 2010, 15% by 2015, 30% by 2020, 40% by 2030, 70% by 2040, and 100% by 2045.

[5] Hawaiian Electric Companies' "April 2016 PSIP Update Report", Docket No. 2014-0183 (April 1, 2016). All references to the PSIP in this document refer to this version.

- Pursuing energy storage options;
- Implementing community-based renewable energy;
- Issuing RFPs to seek over 350 MW of additional renewable energy by 2022;
- Researching alternative curtailment policies;
- Deactivating generation not well suited to support the integration of renewables; and,
- Improving flexibility of existing generation.

Electricity prices in Hawai'i are the highest in the country at over twice the national average. This has incentivized utility customers to evaluate and often deploy their own customer-sited DERs, such as rooftop solar. To that end, the Hawaiian Electric Companies forecast nearly tripling the amount of DERs by 2030.

Figure 2 - DG Penetration Forecast by Utility



Source: Hawaiian Electric Companies, 2014 [6]

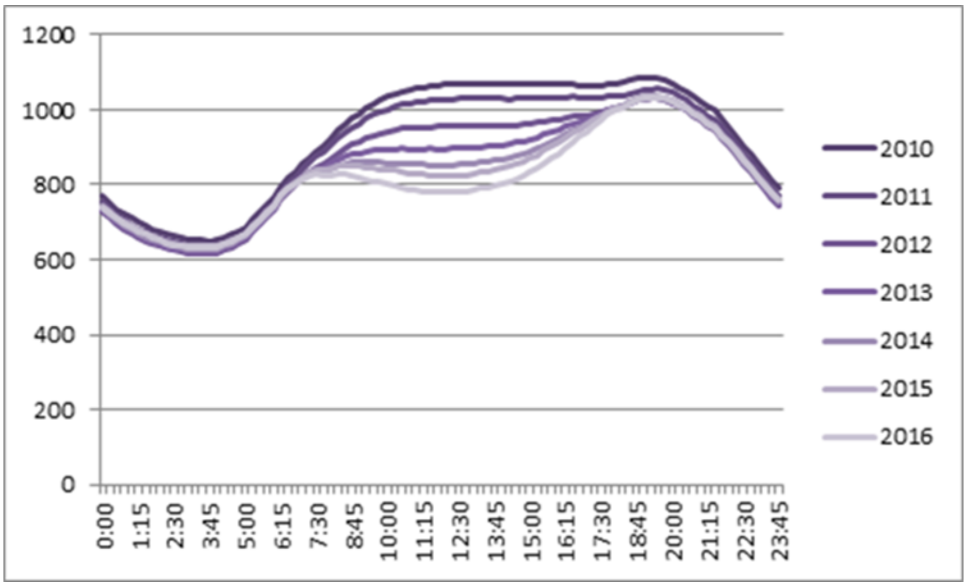
In conjunction with installed and planned DER generation, the Hawaiian Electric Companies also plan to significantly increase the amount of utility-scale wind and solar generation on each island. Because DERs meet a large portion of each islands' load, and existing interconnection programs do not provide a capability to control the output of these resources, the amount of available load to serve with utility-scale renewable resources is increasingly limited during peak sunshine hours. The resulting net load profile

[6] *See* Hawaiian Electric Companies' Letter submitting its Distributed Generation Interconnection Plan ("DGIP"), filed on August 26, 2014 in Docket 2011-0206, Reliability Standards Working Group.

will require increased access to flexible generation resources to manage supply and demand.

As shown in Figure 3, representing load profiles for O'ahu, gross and net system load are nearly identical and can be approximated by the 2010 load shape. From 2011 onward, however, net system load begins to exhibit the dip in mid-day due to behind-the-meter PV. Despite this challenge, the Hawaiian Electric Companies are committed to finding ways to maintain safe and reliable operations while reducing the amount of load that conventional generation serves.

Figure 3 - O'ahu Net Load Potential



Source: Hawaiian Electric Companies, 2016

Challenges in Contracting for Utility-Scale Renewables

Increasing penetration of distributed PV has created a surplus of daytime, non-dispatchable generation on all of the Hawaiian Islands.[7] This generation, which utilities do not directly control, is effectively "must-take"; that is, the utilities must manage other conventional and renewable generation resources around the output of these systems.

The large amount of distributed PV that exports to the grid, relative to total system demand, exceeds levels in other parts of the country. Incorporating large amounts of non-dispatchable utility-scale renewable resources then becomes a challenge – the system simply does not have the demand to accept all of the production at some times during the day. Subsequently, the Hawaiian Electric Companies are faced with the reality of needing to curtail utility-scale renewable resources to maintain grid stability and reliability.

The purpose of this report is to identify potential new approaches to contracting for utility-scale variable renewable energy resources that enable a focus on economic dispatch and system reliability going forward. Transitioning must-take resources into dispatchable resources (similar to conventional generators) could spur higher penetration levels of these assets without incurring an increased financial burden for customers or IPPs. Any outcome that mitigates those challenges will empower Hawai'i to move towards its vision of an affordable and reliable 100 percent clean energy future.

Impact of Curtailment Concerns

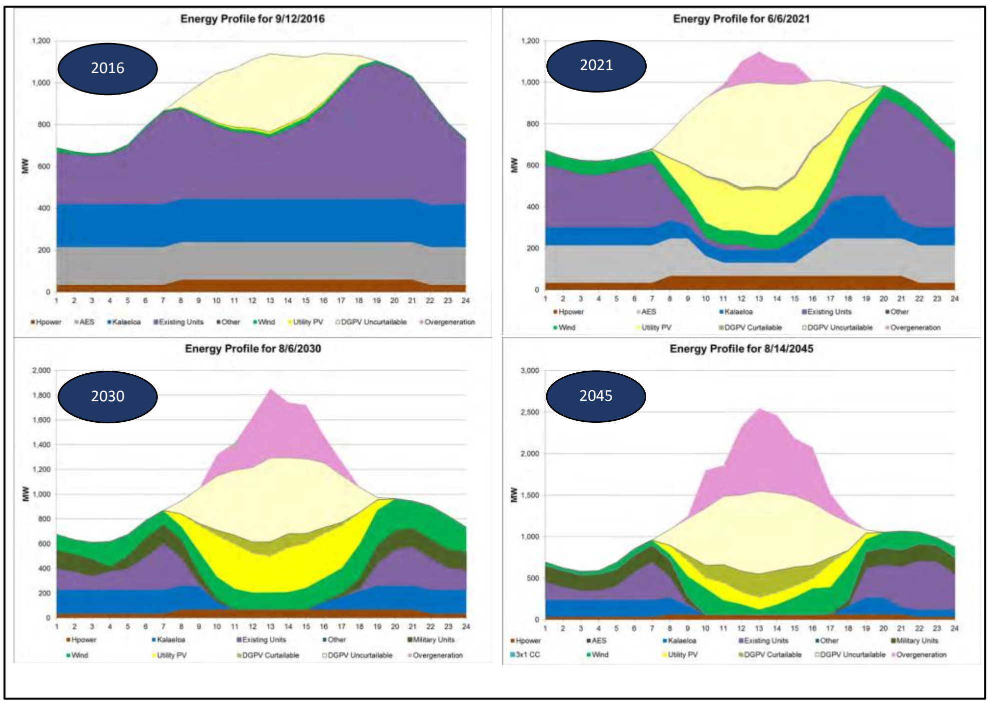
Curtailment is the reduction of a given purchased power resource below its otherwise theoretical output level. Curtailment is largely an issue reserved for resources that do not rely on a stored fuel source (e.g., coal, natural gas, biomass, etc.). For conventional generation resources that have the ability to stockpile their fuel supply, a decrease in the dispatch of the resource from its maximum output level does not *necessarily* forego energy sales forever; rather, it likely just delays the conversion of their fuel source into electricity. For solar and wind assets, however, that electricity is permanently foregone. The reality of curtailment is becoming a recurring theme on many islands in Hawai'i for its utility-scale wind and solar projects. Variable renewable resources such as wind and solar are not dispatchable by nature, meaning their production profile cannot be modified to meet system needs without forfeiting energy production. In other words, there is no ability to defer production to a more valuable time without the use of energy storage. The availability of sunlight or wind dictates energy production. The production can only be used or curtailed, resulting in the potential for lost sales for the asset owner.

[7] Most distributed generation in Hawai'i is contracted via Net Energy Metering (NEM), which historically has been compensated at retail rates. NEM systems and associated compensation are not within the scope of this report, which focuses on utility-scale transactions only.

A further complication for variable projects is that anticipated energy production (and, therefore, sales) requires an estimated availability of the wind or solar resource. The resulting capacity factor represents the amount of energy produced from the installed capacity. A project with a higher capacity factor than anticipated may experience greater curtailment risk than expected, although net energy sales could still be higher than planned.[8]

This issue is not isolated to the state of Hawai'i. Concerns have arisen in states such as California where at high levels of distributed solar penetration, other large and low cost renewable assets may be curtailed during light load situations;[9] however, due to its small islanded market and high penetration of distributed solar, the magnitude of curtailment necessary to balance supply and demand in Hawai'i far outpaces that of other regions of the country. As shown in Figure 4, increasing distributed PV creates overgeneration in greater and greater quantities during sunny daytime hours, requiring other generators to modify dispatch.[10]

Figure 4 - Future Daily Load Profiles for Hawaiian Electric



Source: Hawaiian Electric Companies, 2016

---

[8] For simplicity purposes, this report does not consider the implications of capacity factor forecast inaccuracies on curtailment.

[9] For a discussion on the frequency of this at different renewable penetration levels, *see* "Impact of High Solar and Energy Storage Levels on Wholesale Power Markets" (Black & Veatch / SEPA 2015).

[10] *See* April 2016 PSIP Update Report, pages 5-11, 5-13, 5-15, and 5-17.

Given the isolated nature of the independent grids on each of the Hawaiian Islands, the ability to dispatch the output of renewable generation is inherently an essential tool to manage system stability and is likely the lowest cost solution in many circumstances given the large quantities of DERs on this autonomous system. It is conceivable that curtailment levels on O'ahu may be 10 percent (of a given generator's output potential) or greater, and 20 percent possibly up to as much as 50 percent on Maui and Hawai'i Island. If compensation for IPPs is based on energy sales only, these non-trivial curtailment levels will have a direct and measurable impact on the financeability of large renewable projects in Hawai'i. Moreover, increasingly high levels of must-take energy creates operational constraints on system operators, creating challenges for balancing and managing costs to optimize the total resource portfolio.

Translating Curtailment Risk into Project Economics

Executing a PPA for large renewable resources is increasingly complicated by the uncertainty over curtailment. There are two main ways today that this curtailment risk has been captured, representing opposite ends of a risk spectrum:

- Placing all risk on the developer (IPP Risk Model); or,
- Placing all risk on the utility and its customers (Customer Risk Model).

PPA Price = The price stated in the PPA for energy produced by the solar asset; or, in a take-or-pay contract, the price stated for energy that is or could have been produced.

Effective $/MWh = The all-in price that customers pay for energy delivered, after considerations for fixed and variable costs, and payments for undelivered energy.

In the IPP Risk model, the PPA provides for energy purchases at a given $/MWh price point with no minimum required offtake (or minimum purchase commitment) by the utility. In essence, the utility can curtail the asset and not incur any financial penalty for doing so. The developer then must attempt to forecast the likelihood of curtailment into its energy price so that the project can be financed.

The alternative Customer Risk approach, sometimes known as the "take-or-pay" contract, is structured such that the utility must pay for any energy that is produced or could have been produced if not for being curtailed. For the IPP, this type of agreement is much easier to finance and can allow for lower PPA prices. For the utility and its customers, however, this type of agreement results in payment for energy that is never delivered – a result that imputes a higher effective energy price for the resource in question.[11] This approach can also be administratively complex, relying upon calculations of "available" versus "delivered" energy that can be challenging to calculate and verify.

[11] Effective $/MWh does not include additional costs associated with the provision of electrical service, such as delivery fees, grid services, etc.

At times when there is greater certainty of energy purchases due to minimal need for curtailment, the difference in price bid to the utility should be minimal between these two structures. The price diverges, however, as curtailment risk appears.

But that is only half the story. The actual impact to developers and consumers is the delta between *anticipated* curtailment and *experienced* curtailment. Consider, for example, a utility-scale solar asset that would normally cost $100/MWh over the 20-year term of its PPA. This project has all assurances that the energy will be delivered and sold, with no risk of curtailment. If we insert the anticipation of curtailment at 20 percent, the price for the same project increases to $125/MWh so that the developer retains the revenue stream needed to finance the project. Even if it is a take-or-pay agreement and the price remains at $100/MWh, the utility and its customer base effectively pay $125/MWh for the energy that is ultimately delivered.

The challenge arises when the experienced curtailment varies significantly from what is anticipated at the time of contract execution. Continuing with the example above, consider two scenarios: (1) no anticipated curtailment, and (2) anticipated curtailment for a utility-scale solar asset.

Table 2 demonstrates the impacts to a project's revenue stream when curtailment is unexpectedly introduced into a project.[12] If the IPP owned all of the risk associated with curtailment, they could conceivably under-earn by several million dollars. In this example, the delta in revenue could pose severely negative implications on project finance, including the repayment of debt for the asset. For a take-or-pay contract, customers would be paying as much as 43 percent more per MWh for the energy delivered than was originally anticipated.

Table 2 - Impacts to Project Economics with No Curtailment Anticipated

	IPP Risk Model		Customer Risk Model
	Project NPV	Change in Project NPV	Take-or-Pay Effective $/MWh
No Actual Curtailment	$1.06 M	$ -	$100
10% Actual Curtailment	$0.15 M	($0.91 M)	$111
20% Actual Curtailment	($0.76 M)	($1.82 M)	$125
30% Actual Curtailment	($1.67 M)	($2.73 M)	$143

Source: SEPA & ScottMadden, 2016

[12] Assumes a 10-MW solar project and the anticipated revenues over a 20-year timeframe.

When curtailment risk is known in advance, there is still the potential for significant impacts to the overall economics of the project. As shown in Table 3, if the solar developer anticipates 20 percent curtailment over the course of the project, they will adjust the price of the PPA to ensure revenues are maintained. A 10 percent swing in actual curtailment, however, can still negatively impact the developer (from an NPV perspective). For customers under a take-or-pay agreement, they would pay that higher PPA price for any energy delivered. Curtailment below 20 percent would still have an effective rate of $125/MWh, which is 10-25 percent higher than the price needed to meet the developer's revenue requirements. Curtailment at the 30 percent level would again result in paying an effective price of $143/MWh for energy delivered.[13]

Table 3 - Impacts to Project Economics with 20 Percent Curtailment Anticipated

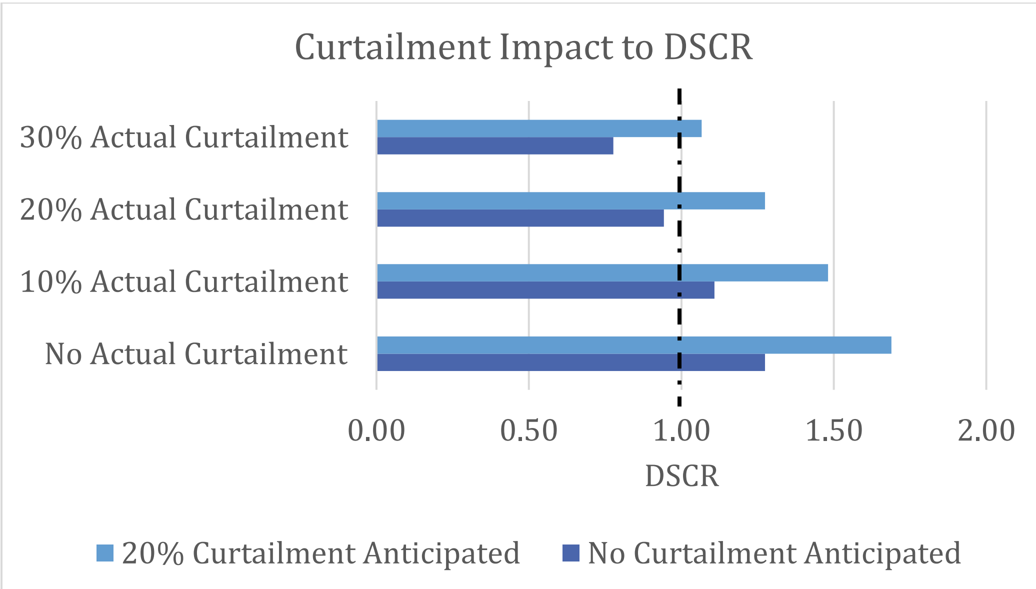
	IPP Risk Model		Customer Risk Model
	Project NPV	Change in Project NPV	Take-or-Pay Effective $/MWh
No Actual Curtailment	$3.33 M	$2.27 M	$125
10% Actual Curtailment	$2.20 M	$1.14 M	$125
20% Actual Curtailment	$1.06 M	$ -	$125
30% Actual Curtailment	($0.08 M)	($1.14 M)	$143

Source: SEPA & ScottMadden, 2016

Another metric that provides visibility into project health and financeability is the DSCR. DSCR measures a project's ability to meet debt obligations with net operating income. In this analysis, DSCR is calculated using earnings before interest, taxes, depreciation, and amortization. A ratio greater than 1.0 indicates that net operating income exceeds debt obligations. A project becomes more attractive (from a financing perspective) as the DSCR increases. Figure 5 outlines the impact to a project's DSCR based on the risk of curtailment. In the face of likely curtailment, a developer would need to raise its PPA price to maintain the targeted DSCR.

[13] One natural reaction to addressing curtailment is to promote energy storage as part of projects. While this solution is discussed further below, at certain levels, curtailment of a resource may in fact be lower cost than requiring storage. Based on the pricing assumptions used in this report, it is actually more cost effective to curtail 60% or more of a project before its effective price reaches parity with solar plus storage. As storage costs decrease, however, including storage as part of future solar projects may warrant consideration.

Figure 5 - Curtailment Impact to DSCR



Source: SEPA & ScottMadden, 2016

Millions of dollars can shift between customers and developers depending upon the difference between anticipated curtailment at the time of contract execution and actual curtailment levels experienced over the life of the project. This swing represents a major unknown for all parties, and can significantly impact how developers seek to finance agreements and how the Hawaiian Electric Companies (and the utilities' regulators) view the value proposition on behalf of customers.

Grid Stability & Reliability in a Majority Renewable Future

A certain combination of resources, which includes synchronous generation, is required to maintain system reliability. Disturbances in frequency, from either load fluctuations or generation trips, is an issue that must be actively managed on any system. For island systems such as exists in Hawai'i, this issue is exacerbated. With no interconnected neighbors to provide support in the form of shared reserves or ancillary services, the grid is highly susceptible to system disturbances from generation trips or sudden load changes. As distributed solar penetration has increased, the potential for load and frequency fluctuations has been exacerbated – weather changes can cause generation loss and increased load on a moment's notice.

Maintaining a reliable system requires a delicate balance between load and generation. If load increases without a commensurate increase in generation, the frequency will drop. If generation is overproduced compared to load, frequency increases. With frequency, small changes can be problematic. Synchronous generation is critical to providing system inertia, which can be thought of as "frequency friction". Inertia simply means that there is a large rotating mass generator that – if frequency drops unexpectedly – can help slow that drop and ramp up its own generation levels to restore system frequency.

As renewable penetration increases, the amount of available synchronous generation has decreased in kind. In island systems such as Hawai'i, more of one resource must translate into less of another, because there are no neighboring systems with which to exchange energy. The Hawaiian Electric Companies have already taken steps to reduce the minimum run levels of its conventional generation resources; however, as the state moves towards its 100 percent clean energy future, the ability to continue to run conventional generation to provide system inertia may become difficult if not impossible.

This factor also has important implications for the utilities' ability to provide ancillary services. Ancillary services support the transmission of energy between generation and load and ensure that the system maintains reliable operational characteristics. Two key ancillary services warrant mention with relation to the Hawaiian Electric Companies' systems:

- Spinning reserves are generators that are synchronized to the grid but have available headroom (unloaded generation) to respond to system needs on a moment's notice by increasing their generation level.
- Regulation/frequency response are generators that ramp themselves both up and down on a moment-by-moment basis to respond to the natural variations in supply and demand in an effort to maintain frequency.

Ancillary services represent an added (and often hidden) cost to an energy system's economics. In organized Regional Transmission Organization/Independent System Operator (RTO/ISO) markets such as the Electric Reliability Council of Texas (ERCOT) or the PJM Interconnection, active ancillary services markets create transparency around costs and pricing and incent resource owners to provide ancillary services to the grid.[14]

Table 4 – 2014 Ancillary Services Pricing from Organized Markets

Ancillary Service	PJM	ERCOT
Spinning reserves	$4.21/MWh	$12.89/MWh
Regulation	$43.68/MWh	$14.22/MWh

Source: SEPA & ScottMadden, 2016

Large markets such as PJM and ERCOT have a plethora of available generation that can bid in and provide these types of services to the grid. In Hawai'i, each individual island's available generation is all that can provide these supporting services for grid reliability. With a predominantly oil-fired fleet, Hawai'i's conventional generators likely have a higher

[14] http://www.pjm.com/markets-and-operations/ancillary-services.aspx

https://www.potomaceconomics.com/uploads/ercot_documents/2014_ERCOT_State_of_the_Market_Report.pdf implied cost to provide spinning reserves and frequency regulation services than the natural gas-driven markets in PJM and ERCOT.

In 2012, GE Energy Consulting conducted a study for the Hawaiʻi Natural Energy Institute (HNEI) on the capability of certain generators to provide ancillary services.[15] Examining only the Kahe and Kalaeloa plants on Oʻahu and their opportunity costs to provide 1 MW of regulation services, GE found an approximate range of costs from $20-85/MWh per unit.[16]

Table 5 - Approximate Opportunity Costs at Kahe and Kalaeloa Plants

Plant-Unit	Nameplate – MW	Approximate Opportunity Cost
Kahe-1	81.6	$20/MWh
Kahe-2	81.6	$25/MWh
Kahe-3	85.8	$30/MWh
Kahe-4	90.9	$25/MWh
Kahe-5	134.9	$30/MWh
Kahe-6	134.9	$20/MWh
Kalaeloa-1	119.2	$85/MWh
Kalaeloa-2	119.2	$85/MWh
Kalaeloa-3	61	$40/MWh
Weigthed Average		**$42/MWh**

Sources: GE Energy Consulting & HNEI, 2012; EIA, 2016; SEPA & ScottMadden, 2016

While this specific study is a bit dated (and due to oil prices at the time of its publication may be inflated relative to operating costs today), it is illustrative of the fact that non-trivial costs are a natural part of maintaining system reliability in the provision of certain ancillary services. The actual cost of providing these services is dependent upon several factors, including the amount of reserves required, fuel costs, and available resources. To that end, the Hawaiian Electric Companies are in the process of filing ancillary services costs as part of a recent docket related to demand response.[17] Until those more accurate values are available, the costs listed in the tables above can be considered proxies for the purposes of this report.

With ever-increasing penetration levels of distributed PV, and a desire to phase out oil-fired conventional generation over time, solutions must be developed so that utilities can continue to provide system inertia and ancillary services over the long term.

---

[15] GE Energy Consulting. December 2012. Ancillary Services Definitions and Capability Study.

[16] *Id.,* Part 2, Task 3-4, Final Report (December 19, 2012). *See* slide 44.

[17] Docket 2015-0412 – Application for Approval of Demand Response Program Portfolio Tariff Structure.

Potential Contract Structures for Utility-Scale Renewables

Facilitating a future of 100 percent renewable energy in the most cost-effective manner will require a fundamental shift in thinking on how to contract for large scale renewable resources. This is driven by the need to proactively address and plan for high curtailment scenarios, while also identifying potential sources of ancillary services over the long term. This section of the report identifies three approaches to restructuring PPAs and redefining how curtailment is managed: Capacity & Energy PPAs; Time-of-Day Price Caps; and, Renewable Dispatchable Generation.[18] All three of these address curtailment risk allocation issues, and the latter also provides an avenue for renewable assets to provide ancillary services for the first time. For all of these structures, any new PPA would move away from reverse chronological curtailment decisions and towards curtailment based on economics or system reliability needs.

I. Capacity & Energy PPAs

Renewable energy projects are fuel-free resources, where virtually all of the costs of the assets are tied up in the cost to finance and construct the facility; however, the historical PPA payment stream for these resources is entirely variable in nature. When curtailment is introduced, the IPP loses revenue that will never be recovered, which has negative implications on project financing. Riskier projects inherently result in higher costs of borrowing, driving up the ultimate price offered to the utility.

The first model proposed for future contracts in Hawai‘i is targeted at creating more surety in revenues for IPPs so that projects become less risky – the Capacity & Energy PPA. Under this contract structure, the utility creates an RFP that specifically requires bidders to allocate their pricing into two components: a $/MW-month fixed charge and a $/MWh energy charge. The fixed charge provides bidders the ability to identify a guaranteed cash flow stream for their project. Curtailment risk is limited to the energy charge only.

This structure provides the opportunity for the market to price its own risk outlook on curtailment into the bidding process. Rather than forcing either the utility and its customers or the IPP to own all risk, this revised contract structure creates a sharing of curtailment risks and associated costs. Further, it creates a more transparent way to monetize that risk. Executing a contract that allocates capacity and energy payments for a renewable resource necessarily also contains clauses that hold IPPs to minimum availability metrics or risk forfeiting some of the capacity payment each month. Overall, however, this approach should result in less price risk for customers than would be experienced in a take-or-pay arrangement; customers are only exposed to the fixed

[18] These three main approaches were the result of a larger effort to identify a wide variety of approaches that could be pursued. A summary of the approaches considered but not included in the final analysis is available in Appendix A: Additional Models Considered.

portion of the project's total revenue stream when curtailment occurs as opposed to the full take-or-pay PPA price.

For developers, the strategy behind how to bid into this type of RFP is likely founded in their view of curtailment risk and need for more predictable cash flows. Two main triggers are now available for the developer in bidding to the utility: (1) the amount of revenues recovered in a fixed manner; and (2) the level of curtailments that are anticipated over the contract life.

Table 6 – Project Economic Implications: 25 percent of Project Costs Recovered in Capacity Payment

	0% Anticipated Curtailment			20% Anticipated Curtailment		
	Project NPV	Change in Project NPV	Customer Effective $/MWh	Project NPV	Change in Project NPV	Customer Effective $/MWh
No Curtailment	$1.06 M	$ -	$100	$2.76 M	$1.70 M	$119
10% Curtailment	$0.38 M	($0.68 M)	$103	$1.91 M	$0.85 M	$122
20% Curtailment	($0.30 M)	($1.36 M)	$106	$1.06 M	$ -	$125
30% Curtailment	($0.98 M)	($2.04 M)	$111	$0.21 M	($0.85 M)	$130

Source: SEPA & ScottMadden, 2016

Table 7 – Project Economic Implications: 75 percent of Project Costs Recovered in Capacity Payment

	0% Anticipated Curtailment			20% Anticipated Curtailment		
	Project NPV	Change in Project NPV	Customer Effective $/MWh	Project NPV	Change in Project NPV	Customer Effective $/MWh
No Curtailment	$1.06 M	$ -	$100	$1.63 M	$0.57 M	$106
10% Curtailment	$0.83 M	($0.23 M)	$108	$1.34 M	$0.28 M	$115
20% Curtailment	$0.61 M	($0.45 M)	$119	$1.06 M	$ -	$125
30% Curtailment	$0.38 M	($0.68 M)	$132	$0.78 M	($0.28 M)	$138

Source: SEPA & ScottMadden, 2016

As shown in Table 6 and Table 7, the customer's Effective $/MWh upside risk has been reduced compared to today's paradigm, while the NPV at risk for the IPP has also been limited. By allowing IPPs to factor their own risk profile into this structure, while providing for some floor level of revenue recovery, the Capacity & Energy PPA creates a platform for all participants to share the risk of curtailments equitably. It reduces the revenue at risk for the developer and reduces price fluctuations for the end customer. The ability for IPPs to manage two different levers (fixed cost recovery and anticipated curtailment) in their future bids to the utility allows the market to define curtailment risk much more effectively.

II. Time-of-Day Price Caps

The second model under consideration creates an avenue for prospective bidders to use innovative system technology and design in a much more transparent manner. Traditionally, RFPs are oriented towards identifying the least cost project over the course of the contract term, which is typically 20 years. In some cases, utilities signal to the market specific hours of delivery that are more valuable than others in order to provide signals on relative value of production. This same idea can be leveraged to create strong incentives for developers to engineer solutions to limit curtailment.

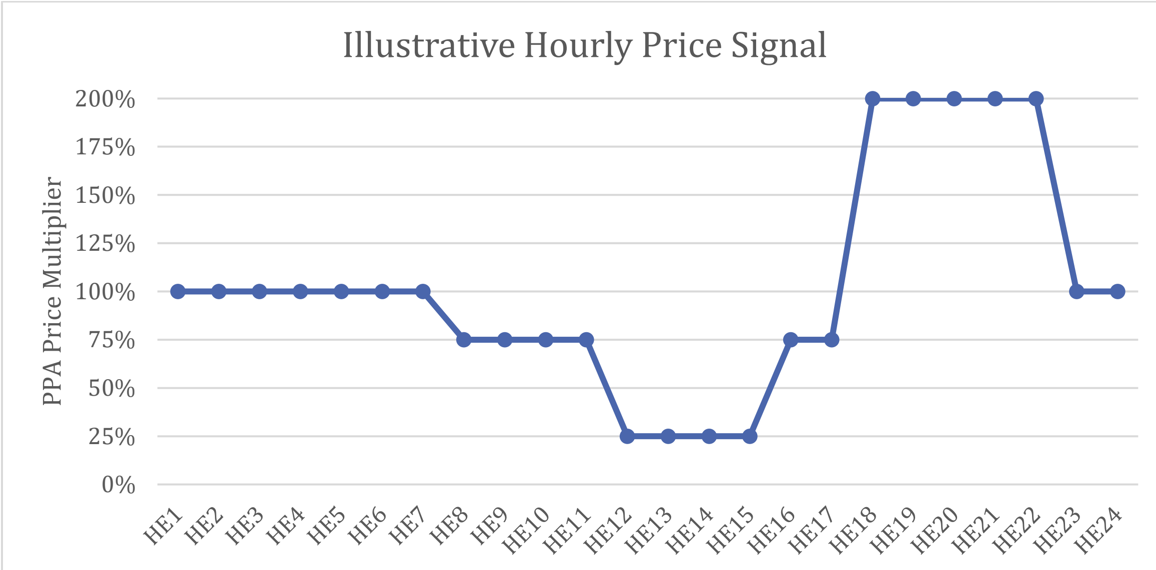
In the Time-of-Day Price Caps (ToD) contract structure, the utility issues an RFP that sets firm caps on the price it is willing to pay for energy delivered in each hour of the day, and potentially, for different months of the year. Bidders respond with prices up to, but not exceeding, the price caps by hour. Alternatively, the utility could establish a PPA price multiplier that limits what it would pay of the PPA price during each hour of the day (*see* Figure 6). Once the contract is executed, the utility pays the IPP based on those ToD price caps for energy delivered.

Because the Hawaiian Electric Companies' systems currently have excess generation from distributed PV in the daytime hours, it is highly likely that a ToD RFP would set extremely low (or negative) prices for those same hours, with higher prices allowed for the delivery of energy in hours where net load is highest.[19]

---

[19] The multipliers selected for Figure 6 and the associated modeling are illustrative in nature only and are not the result of detailed system dispatch analytics. Rather, they are meant to approximate an exaggerated signal to developers to shift power to better match system net load. Actual PPA price multipliers would be the result of a detailed system modeling exercise.

Figure 6 - Illustrative Time-of-Day Price Cap Curve



Source: SEPA & ScottMadden, 2016

This structure, in which price transparency that proactively takes curtailment into consideration is presented to the market, should create strong incentives for IPPs to engineer innovative solutions that maximize their revenue potential while minimizing the likelihood of curtailed energy. One potential solution could be the incorporation of energy storage; another could be to focus on alternative renewable technologies such as fuel cells. A solar developer could still theoretically bid in and win the RFP, delivering only during hours that are likely lower on the ToD cap scale. If curtailment becomes necessary, this structure would dictate that the price paid for undelivered energy would be set at the ToD caps negotiated in the contract, with curtailment events prioritized towards the lowest caps. This cements the incentive for the developer to be flexible in shifting production away from periods when it can be anticipated that energy is less valuable. And it is not inconceivable that at some point in the future, negative price caps could be required to create enough economic incentive to shift production into the hours with the highest value.

To allow flexibility in the future, as net load patterns changes over time, the PPA may also allow for regular adjustments (e.g., every 5 to 10 years) to the ToD cap curve, as long as the utility maintains a commitment to keep the overall volume under the cap constant. For example, if distributed storage becomes prevalent at the residential level, the net load shape served by the Hawaiian Electric Companies would look substantively different from the illustrative load shape contemplated in Figure 6. Building in a refresh to the ToD price caps at specific intervals would significantly increase the flexibility offered by projects under this structure.[20] One factor working against this structure is that it is extremely complicated, both for the utility in how it designs the price caps and subsequently reviews proposals, and for the IPP in how it attempts to shape production to meet the needs of the utility.

For simplistic purposes, assume two different approaches to building a project for this price structure. In the first approach, a solar developer builds a traditional south-facing project. Given the price multipliers outlined in Figure 6, the developer knows in advance that generation during the middle of the day, which coincides with solar DER production, would only be paid out at 25 percent of the applicable PPA price. To make their project financially viable, the PPA price would therefore need to be set at $192/MWh, so that production during periods that allow for higher pricing can generate enough revenue overall.

Table 8 - Project Economic Implications: Time-of-Day Alternatives

	South-Facing Solar PPA Price = $192/MWh			South-Facing Solar with Storage PPA Price = $238/MWh		
	Project NPV	Change in Project NPV	Effective $/MWh	Project NPV	Change in Project NPV	Effective $/MWh
No Actual Curtailment	$1.1 M	$ -	$100/MWh	$2.7 M	$ -	$274/MWh
10% Actual Curtailment	$0.6 M	($0.5 M)	$106/MWh	$2.7 M	$ -	$275/MWh
20% Actual Curtailment	$0.2 M	($0.9 M)	$113/MWh	$1.5 M	($1.2 M)	$284/MWh
30% Actual Curtailment	($0.2 M)	($1.3 M)	$122/MWh	($0.2 M)	($2.9 M)	$298/MWh

Source: SEPA & ScottMadden, 2016

To the utility's customers, the same revenue stream and associated energy is delivered. Assuming no curtailment occurs, the Effective Price is $100/MWh. As curtailment is incorporated, revenue allocation is shifted to times of the day when curtailment is less likely. The IPP retains a positive project NPV across virtually all curtailment scenarios modeled. For the customer, their upward price risk (on an Effective $/MWh basis) is limited compared to today's take-or-pay structure as well.

A second approach for the IPP is to incorporate energy storage into the project. For purposes of this report, a 17-MW lithium-ion battery, which is large enough to shift several hours of on-peak production, was incorporated into the project. The battery was modeled to shift energy out of the lowest tier price cap period and into the highest tier.

[20] This flexibility would likely come at a cost, as it may necessarily require storage to be incorporated. Alternatively, it could favor more dispatchable renewable technologies such as biomass and biogas.

As shown in Table 8, this battery shifts enough energy in its base design to avoid up to 20 percent curtailment. To the customer, the result is a significantly higher Effective $/MWh; however, this approach did succeed in shifting energy outside of a window of time when there was excess generation on the system and into a window when the utility likely does need firm power supply. While not economic for the customer at present, continued reductions in storage pricing and increases in efficiency could make this a viable option in the future.[21]

This structure, incorporating solar and storage together and responding to a set of firm price signals from the utility, is functionally similar to the announced project between Kauai Island Utility Cooperative (KIUC) and SolarCity. In that agreement, SolarCity is developing a 13-MW-ac solar project coupled with a 13-MW/52-MWh battery, which will be dispatched based on KIUC's preference. In its filing in support of this PPA, KIUC mentions intending to use 80-85 percent of the output to charge the battery so that it can be used for late afternoon ramping and evening peak shave purposes.[22] This same concept and structure could arise organically out of a ToD RFP, in which developers have the opportunity to identify unique engineering solutions to a specific utility problem statement.

III. Renewable Dispatchable Generation

One of the fundamental issues with resources such as solar or wind is that they are, at their current state, non-dispatchable. The final new contract option for consideration leverages an agreement structure that is prevalent for natural gas contracts and transfers it to the world of renewable resources in an effort to create dispatchability. This new structure converts the utility's role from a passive taker to a proactive asset manager.

In the world of natural gas generation, the tolling agreement is a structure in which the utility schedules in natural gas to the third-party-owned plant, providing a schedule for production.[23] The third-party's role is to guarantee a heat rate and availability for its plant. The utility pays the IPP a fixed capacity payment and then assumes all price volatility for the fuel.

Renewable Dispatchable Generation (RDG) takes a similar approach to dispatching generation; however, rather than basing the schedule and dispatch on the delivery of the fuel source under utility control, this structure schedules the *percentage of potential production* based on the solar or wind resource available on any given day, factoring in

[21] Based on modeling, the cost of lithium-ion batteries would need to decline by 32 percent from today's estimated levels for this approach to break even with the south-facing solar system modeled under the ToD structure.

[22] *See* Docket No. 2015-0331 application, filed September 10, 2015.

[23] While not currently used in Hawai'i, the tolling agreement is a relatively common contractual arrangement in other U.S. markets.

the needs of the system from both a cost and reliability standpoint. Under ideal circumstances the IPP would:

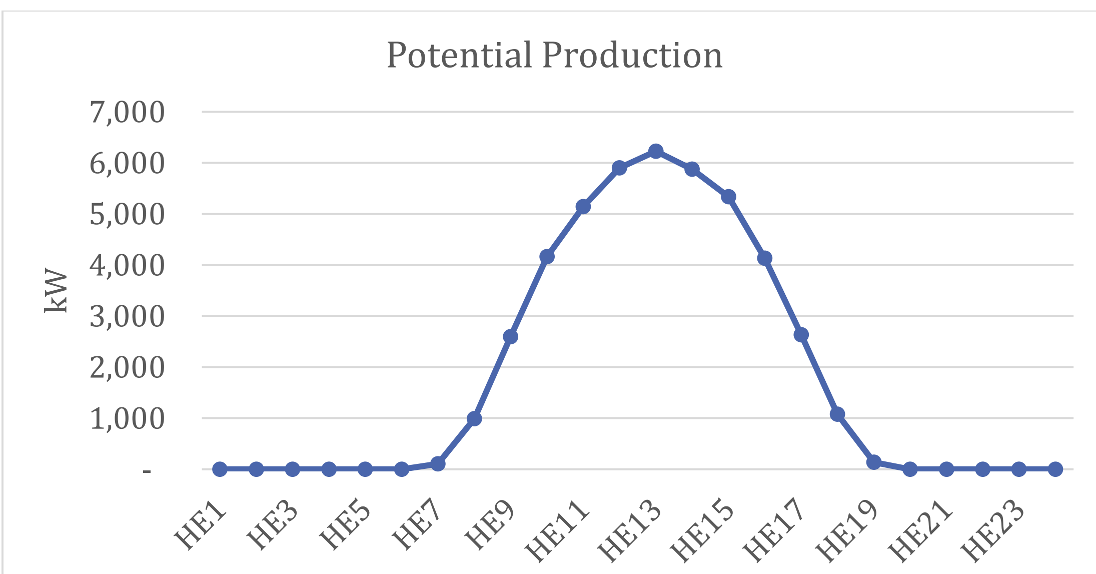
- Guarantee minimum availability metrics to ensure the equipment is maintained and available for production;
- Meet technical and operational characteristics which support grid operation, including voltage regulation, disturbance ride-through, frequency response, and active power control; and,
- Provide an indication to the utility of the available energy in the near real-time.

Similar to a tolling agreement for a conventional resource, these guarantees provide the basis for the energy production (MWh) expected for a given solar irradiance or wind speed. The utility, in turn, controls the output of the facility (both real and reactive power) on a real-time basis.

From an economic standpoint, the utility pays a fixed payment per month to ensure that the system is financeable and a variable $/MWh component to cover variable operations and maintenance (O&M) costs (if applicable, depending upon the resource). Any unscheduled energy, up to the amount capable of being produced given existing weather, becomes spinning reserves – unloaded generation that can be called upon in minutes – or is deployed automatically according to defined frequency response parameters, in a manner similar to conventional plant droop response.

For example, assume a solar plant with a nameplate capacity of 10 MW. Figure 7 depicts an average day's production curve for that plant.

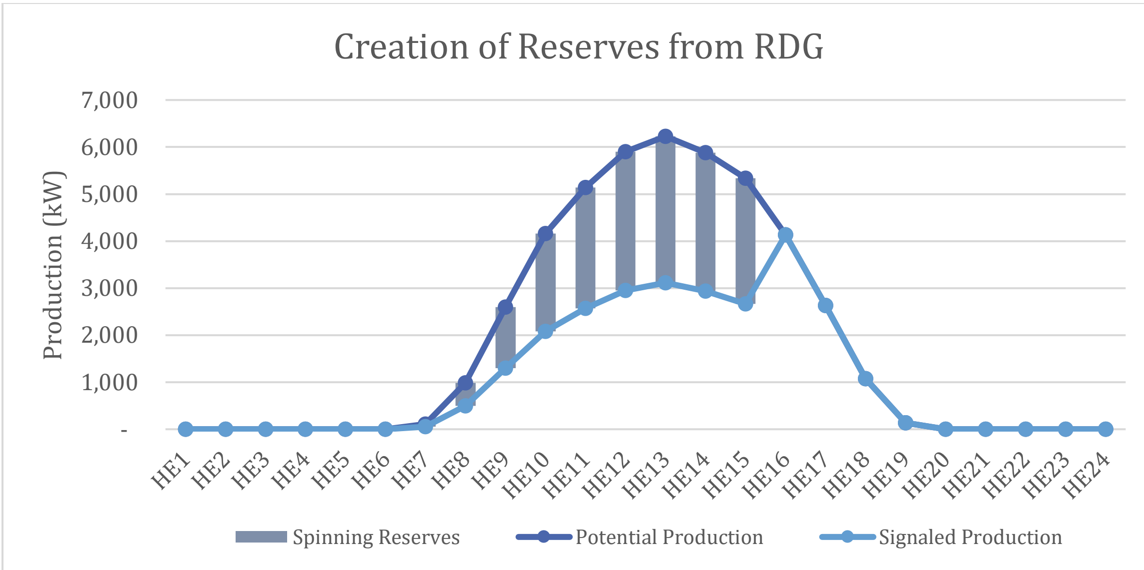
Figure 7 - Average Day Solar Production Curve



Source: SEPA & ScottMadden, 2016

Now assume that under the RDG structure, the utility intentionally dispatches the resource at 50 percent production. Later, due to a need to serve greater demand, the utility increases the production to 100 percent in the late afternoon.

Figure 8 - Potential Ancillary Services Created by Renewable Dispatchable Generation



Source: SEPA & ScottMadden, 2016

As shown in Figure 8, the ability to ramp up that solar asset created over 3 MW of upward spinning reserves on this average day, with over 2 MW of increased generation actually leveraged from 3-4pm. This resource can also provide downward spinning reserves during all producing hours. Alternatively, that same unloaded generation could be used for regulation purposes, with the inverter allowed to vary output based on the system frequency at any given moment. By purposefully under-scheduling the solar asset, the solar generator can contribute to the provision of ancillary services. Historically, variable renewables resources have not provided these types of grid services. Adding the ability to provide spinning reserves and frequency response reduces the integration costs of adding these assets to the system, effectively increasing their overall value to the Hawaiian Electric Companies. With a push towards a 100 percent clean energy future, these added capabilities may become critical to system reliability.

From a purely economic perspective, the RDG must be measured against both nominal impacts and net impacts after factoring in the benefits associated with the provision of ancillary services from the renewable resource. Using the approximated weighted average opportunity cost for the Kahe and Kalaeloa plants outlined in Table 5, a proxy value for spinning reserves and regulation services of $42/MWh is assumed for any synchronized, unloaded (rather than curtailed) generation from a RDG asset.[24] While increased unloaded generation results in a higher gross effective payment by customers, the ability to provide ancillary services from that facility provides a quantifiable value stream, creating a lower net effective price.[25]

Table 9 - Customer Economic Impacts of Renewable Dispatchable Generation

	Project NPV	Gross Effective $/MWh	Ancillary Services Impact	Net Effective $/MWh
Full Asset Utilization	$1.11 M	$100	$ -	$100
10% Unloaded		$112	($5)	$107
20% Unloaded		$126	($9)	$115
30% Unloaded		$144	($18)	$126

Source: SEPA & ScottMadden, 2016

From a financing perspective, the RDG provides guaranteed revenues (assuming the asset manager meets its minimum availability and energy production potential requirements), which should result in more certainty around debt service coverage and equity returns.

Challenges remain in transitioning directly to this new contract structure from today's paradigm. There will likely be several iterations related to resource forecasting and associated availability metrics, as well as additional operational challenges to overcome.

The idea of limiting the production from a renewable resource may seem counterintuitive – the energy produced is clean and lacks any real fuel dispatch cost. In Hawai'i, however, this may be the exact type of solution needed to help the state achieve its 100 percent renewable energy goal. At some point renewable, non-dispatchable resources will have to contribute ancillary services to support grid reliability.

Identifying Minimum Availability Metrics

For both the RDG and the Capacity & Energy PPA approaches, the concept of minimum availability metrics was broached. For these structures to succeed, the IPP must be contractually obligated to guarantee a specific availability for, and maintenance of, the equipment used to transform the raw renewable resource into energy. For the Capacity & Energy PPA, this obligation becomes the foundation of the monthly fixed payment for

[24] Net Effective $/MWh = Delivered Energy x Gross Effective $/MWh + Ancillary Services Impact. Ancillary services impact is the levelized value of having the unloaded energy available for spinning reserves or regulation services.

[25] Because solar O&M costs tend to be more fixed/predictable in nature than variable costs, this example assumes that all costs are recovered via the fixed payment, with no variable payment included.

the resource. Failure to provide the capacity dictated in the agreement (with adjustments allowed for seasonal production differences and degradation) would result in IPP overpayment for the offered product. The RDG concept hinges on the ability to accurately predict potential renewable resource production at a given point in time, which becomes increasingly challenging as the forecast periods lengthens.

The agreed upon metrics for each of these structures may be different. In a contract that leverages the Capacity & Energy PPA structure, the peak hourly production each month is the basis of the capacity payment, and the minimum availability metric could be simply a monthly minimum MW guarantee for the plant's production (with adjustments annually for natural degradation). The fixed capacity payment would be reduced if the contracted capacity is not available. This simple structure allows for transparency between the utility and the IPP.

In an ideal RDG structure, the parties must be able to calculate resource availability based not only on equipment condition but also on the availability of the renewable resource at any given moment; to be clear, a challenge exists in gathering the necessary data. Therefore, a more formulaic approach becomes necessary. The parties must have a transparent and agreed upon approach to understanding what the production in any given hour should be so that the percentage dispatch can be calculated and tracked accordingly. One approach could be for the IPP to monitor the hourly solar radiation on site and guarantee a solar panel yield and performance ratio (covering losses, panel-specific shading, and any temperature adjustments necessary). The IPP would be required to provide equipment status as well as all telemetry required for the utility's energy forecasting purposes. Resource forecasting is performed today, and the same processes and calculations can become the foundation for codifying minimum availability metrics in the RDG contract.

Long-Term Impacts to Dispatch and Curtailment Order

Legacy renewable contracts have very stringent restrictions surrounding the ability to curtail those resources. Consequently, in Hawai'i, curtailment order has been defined on a reverse-chronological basis, with the newest projects curtailed first, regardless of the relative costs or impacts to system reliability. As new contracts are executed and those legacy agreements term out, the curtailment order can be changed so it is based more closely on economics rather than execution date. For standard agreements, the PPA price is the most logical trigger for curtailment order, with flexibility outside of economic dispatch based on specific local system needs.

The same would hold true for the Capacity & Energy PPA structure. Contracts structured with a lower fixed cost and higher energy cost would be more likely to be curtailed. While this may motivate developers to bid high capacity costs and low energy costs, that approach may not align with how the Hawaiian Electric Companies value proposals in a competitive RFP process. However, placing the impetus on market players to determine how to best manage their risk surrounding curtailments should provide more certainty to the Hawaiian Electric Companies, as they pursue a least cost alternative for consumers.

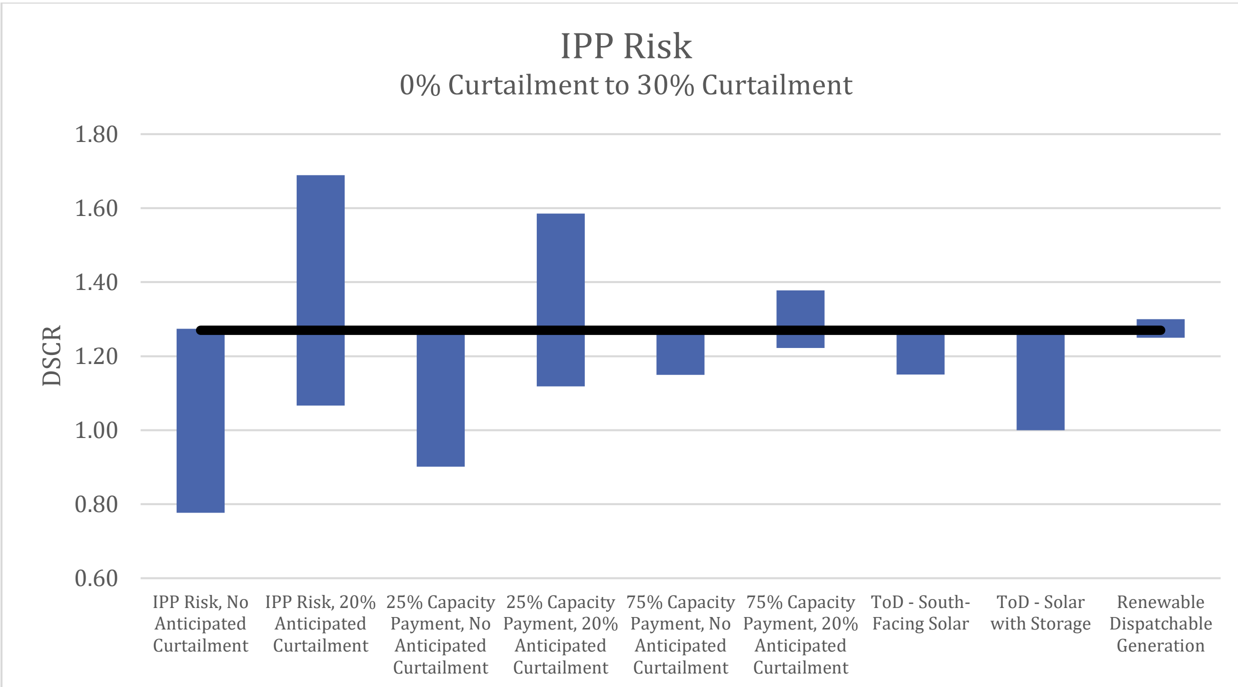
For the ToD Price Caps structure, curtailment would actually start with the lowest energy priced deal. This is because the price signals embedded in the contract already encourage energy production outside the most likely window of time that curtailments occur. Developers seek to maximize energy production outside of that timeframe and recognize contractually that production during those hours is at risk.

The RDG reframes the discussion on curtailment completely, as it is designed to provide system reliability services first and deliver energy second; the system operator has the ability to consider the most optimal dispatch of the system. Therefore, it is more appropriate to consider how that type of project fits into the economic dispatch stack. There may be many days of the year when that asset should produce power at 100 percent of its capability at an effective dispatch cost of $0/MWh, because all costs associated with the project are fixed in nature. Other times of the year, that asset should be dispatched at a much lower level (e.g., 50 percent of its potential) so that it has headroom to move up and down based on system needs or because there is insufficient demand for the energy.

Impacts to Debt Service Coverage

DSCR was chosen as a key metric because it can act as a proxy measure for the riskiness of a project. Curtailment has a direct impact on the perceived risk of a project to financiers, which can translate directly into a higher required DSCR for the project to move forward. For each of the scenarios contemplated in this report, the downside risk for IPPs is less than they currently experience under contracts in which they “own” all curtailment risk.

Figure 9 - DSCR @ Risk: 0% to 30% Actual Curtailment



Source: SEPA & ScottMadden, 2016

The range of possible DSCR values, based on the variety of curtailment scenarios modeled, narrowed considerably for several contract structures. The Capacity & Energy PPA structure provided less DSCR at risk for the scenario in which 25 percent of project costs were recovered via a fixed payment, with the 75 percent fixed payment structure providing significantly less variability overall. The RDG guaranteed the DSCR target was met because of the fixed nature of the revenues.

Next Steps

To start down this path to innovation, the following items are suggested for additional discussion and review. These and many other conversations will help better identify "win/win" solutions for Hawai'i.

Understanding Accounting Treatment

One issue that requires examination prior to transitioning to new contract structures is that, depending on the particulars of the agreement in question, utility accounting principles could require significantly different treatment of project costs. This is because certain PPAs could, for accounting purposes, be treated as a lease agreement. If the agreement is considered a capital lease under current accounting guidance (or simply a lease under ASU 2016-02), the utility must record a lease asset and a corresponding liability (i.e., lease obligation) on its financial statements. The lease obligation is considered a form of debt that results in the inclusion of additional leverage in the utility's capital structure. This negatively affects the utility's financial ratios. Under current accounting guidance, if the agreement is an operating lease, it is disclosed in the footnotes and not reported on the balance sheet.

Determination of whether a PPA constitutes an operating or capital lease is extremely contract-specific and project-specific, and two different solar assets could be classified differently based on their unique contractual terms and conditions. This determination is important, because the impact to the utility's financial statements from recognizing a project as a capital lease rather than an operating lease can be significant. Because recently revised accounting rules that will become effective in 2019 may increase this risk, this assessment is ongoing.

Updating Procurement Practices

Moving from concept to execution on any of the above ideas requires a reshaping of the procurement process from one driven predominantly by lowest price for delivered energy, to one that balances multiple pricing and delivery options against long-term price risk for consumers. For each of the structures identified, IPPs, regulators, utility companies, and other major stakeholders need to work together to determine how future RFPs can be designed so that: (1) IPPs have a clear picture of how projects will be valued; and (2) the Hawaiian Electric Companies can receive clear, transparent, and detailed information from IPPs to expedite the review process. These parties also need to agree on how to manifest these new ideas into contract language.

Leveraging New Technology

This report focuses on how to:

- Modify existing contract structures with developers to both lessen their risk to finance projects while also limiting the risk of severe price fluctuations to the end consumer; and,
- Reduce the constraints on the system operator to manage available resources according to their relative costs and reliability impacts on the system.

Other technologies, such as grid-facing solutions, that could meet similar end goals, were not examined here. One example to highlight is the integration of energy storage on a system level, rather than on a project level as contemplated in the ToD concept. Larger, centralized energy storage assets could help balance supply and demand more efficiently by storing solar generation for later dispatch. Storage could also be used to provide ancillary services. Indeed, the Hawaiian Electric Companies have already begun researching the potential for energy storage to provide synthetic inertia – near instantaneous response to frequency fluctuations. This and other applications for energy storage warrant further discussion and research, as the best solution for Hawai'i is most likely a holistic package of customer, developer, and utility investments that are collaboratively planned. These considerations and others can be part of a robust integrated resource planning process that weighs the relative pros and cons of different resources and contract structures for the benefit of all customers over the long term.

Conclusion

The procurement of incremental utility-scale renewable resources will be critical to meeting Hawai'i's energy future; however, those resources will be called upon to become increasingly more flexible as they comprise larger portions of the total energy portfolio. The question that must be answered is how to address the need for flexible, renewable generation while mitigating the potential costs to consumers. This requires PPA structures that:

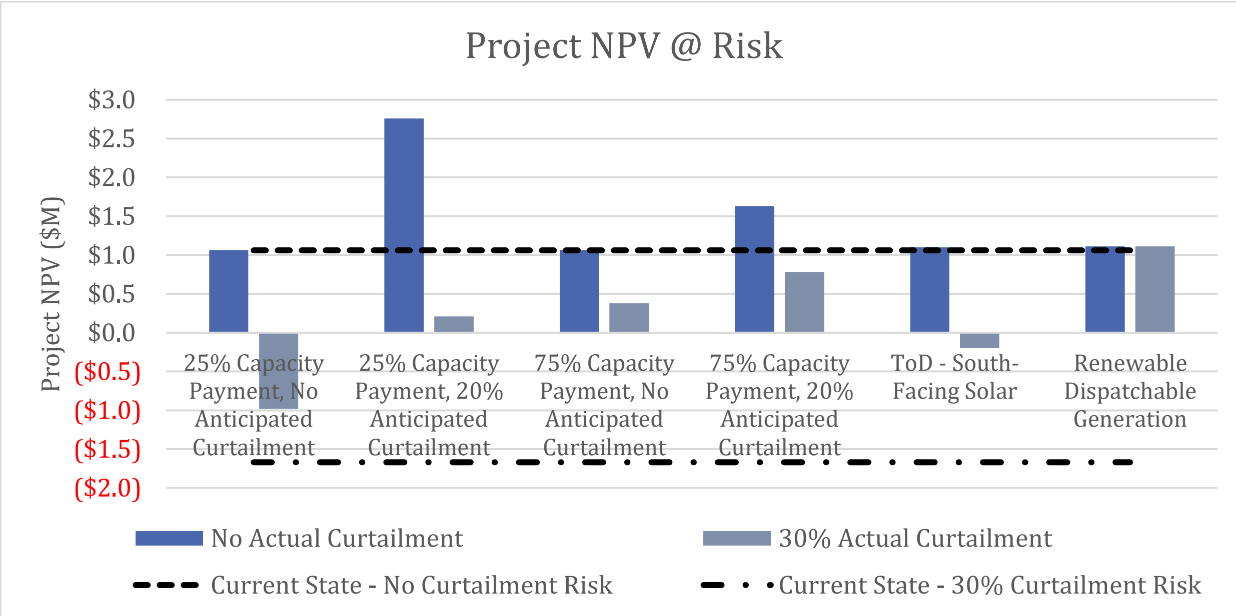
- Provide flexibility to adjust to the changing nature of the grid;
- Create adequate value to the developer;
- Deliver energy at a reasonable price for the utility; and,
- Meet the risk parameters amenable to regulators.

The goal of this report is to begin identifying new ways to contract for non-dispatchable renewable resources that meet each of these criteria; and with the complexities envisioned in the future, more than one alternative contract structure may be desired.

To varying degrees, both the Capacity & Energy and ToD contract structures shift the identification and quantification of curtailment risk away from the utility and onto the IPP. In this way, the development community can incorporate this major risk factor into how they structure proposals in future RFPs, creating the potential for the market to converge on a least-risk solution in a transparent manner. The RDG shifts the intent of contracting for utility-scale renewables away from an energy-only model and towards increasing system reliability while delivering clean energy. Large solar and wind projects mimicking the dispatchability of a conventional asset will be key in Hawai'i to achieve its vision of 100 percent renewable energy.

While the applicability of any of these proposed contract structures could vary depending on the type of project, location, and developer risk profile, understanding the impacts of curtailment across a variety of payment structures to the IPP's financing risk is important. The IPP's incorporation of that risk, driven by issues such as curtailment, will be directly reflected in the price the customer sees. This report considers both IPP and customer risk in an effort to identify "win-win" solutions for future PPA negotiations. The results of this analysis are summarized in the below graphics.

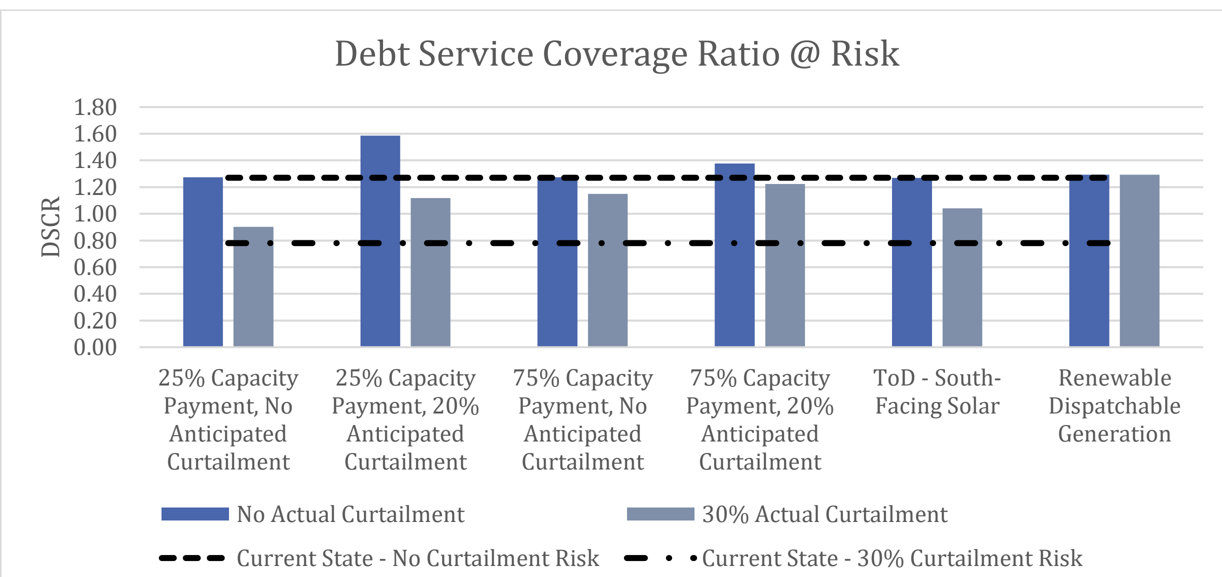
Figure 10 - Impact of New Structures on NPV @ Risk



Source: SEPA & ScottMadden, 2016

All identified contract structures have decreased NPV at risk for the IPP (*see* Figure 10). By agreeing to shift to any of these structures for new PPAs, the IPP can gain more confidence in cost recovery and their ability to earn their desired return on the project in question.

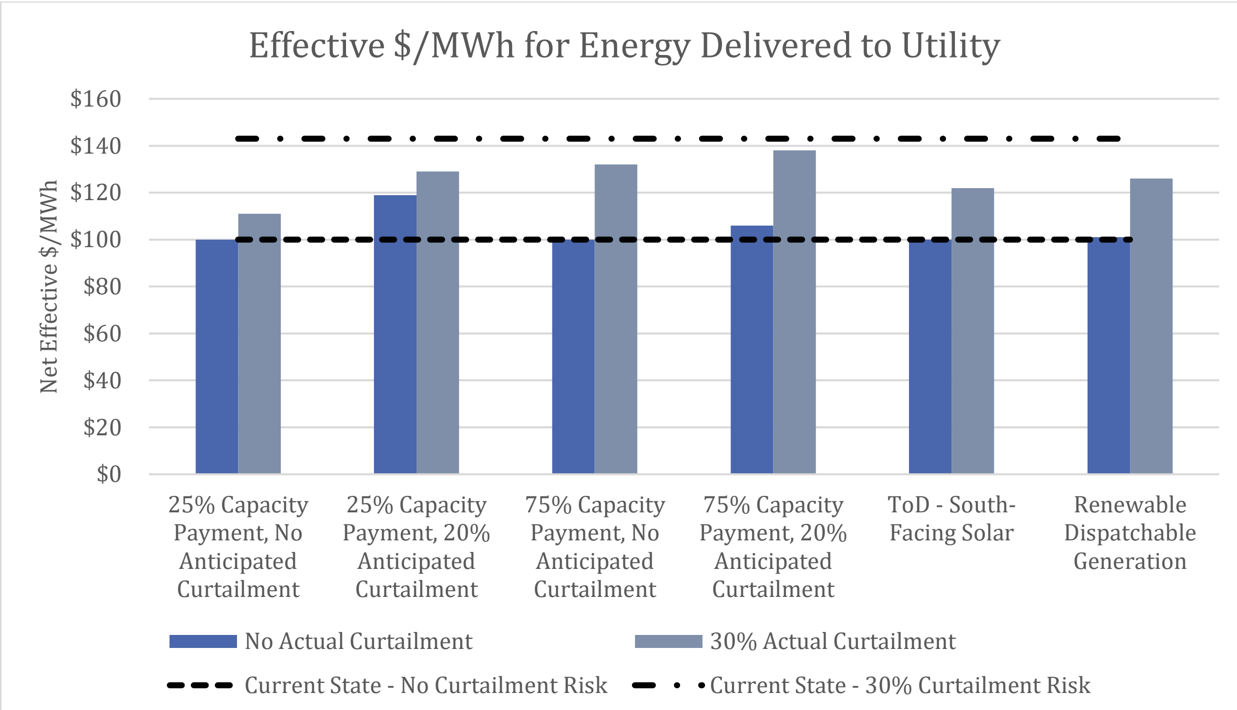
Figure 11 - Impact of New Structures on DSCR @ Risk



Source: SEPA & ScottMadden, 2016

All considered contract structures improved the project's DSCR compared to the current state approach with high curtailment risk, with all but one scenario resulting in a DSCR higher than 1.0 under 30 percent actual curtailment (*see* Figure 11). This provides further comfort for IPPs and their financiers when determining how curtailment will impact project cash flows.

Figure 12 - Impact of New Structures on Effective $/MWh for Energy Delivered to Utility



Source: SEPA & ScottMadden, 2016

All modeled contract structures resulted in lower Effective $/MWh for energy delivered, meaning the customer is better off even under high curtailment situations (*see* Figure 12).

By proactively identifying and allocating the risk of curtailed energy, it is possible to create contract structures for utility-scale renewable generation that result in net benefits for all parties. Taking advantage of these types of innovative contract structures in Hawai'i can lead to better integration of utility-scale projects that are both cost-effective and have the ability to support system reliability as the state moves towards 100 percent clean energy.

Table of Acronyms

BESS: Battery Energy Storage System

CEP: Curtailed Energy Price

DA: Day Ahead

DEP: Delivered Energy Price

DER: Distributed Energy Resources

DSCR: Debt Service Coverage Ratio

EIA: Energy Information Administration

ERCOT: Electric Reliability Council of Texas

GE: General Electric

HA: Hour Ahead

HNEI: Hawai'i Natural Energy Institute

IPP: Independent Power Producer

ISO: Independent System Operator

KIUC: Kauai Island Utility Cooperative

kW: Kilowatt

MW: Megawatt

MWh: Megawatthour

NEM: Net Energy Metering

NREL: National Renewable Energy Laboratory

NPV: Net Present Value

O&M: Operations and Maintenance

PPA: Power Purchase Agreement

PV: Photovoltaic

RDG: Renewable Dispatchable Generation

RFP: Request for Proposals

RTO: Regional Transmission Organization

SDC: System Decremental Cost

SEPA: Smart Electric Power Alliance

ToD: Time-of-Day

References

Energy Information Administration. April 2013. *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*.

Energy Information Administration. Form EIA-861 data. https://www.eia.gov/electricity/data/eia861/.

GE Energy Consulting. December 2012. *Ancillary Services Definitions and Capability Study*.

GTM Research / SEIA. 2015. *US Solar Market Insight Q3 2015 Report.*

Hawaiian Electric Companies' PSIPs Update Report, Docket No. 2014-0183, April 1, 2016.

Joe, B., Hong, M., and Sterling, J. 2015. *Impact of High Solar and Energy Storage Levels on Wholesale Power Markets*.

Kauai Island Utility Cooperative Application, Docket No. 2015-0331, September 10, 2015).

Lazard. November 2015. *Levelized Cost of Energy Analysis v 9.0*.

Lazard. November 2015. *Levelized Cost of Storage Analysis v 1.0*.

NREL. June 2012. *Photovoltaic Degradation Rates – An Analytical Review.*

NREL System Advisor Model, Version 2015.6.30.

PJM. 2014. *Ancillary Services Market Results 2014 Excel Spreadsheet*. http://www.pjm.com/markets-and-operations/ancillary-services.aspx

Potomac Economics, Ltd. July 2015. *2014 State of the Market Report for the ERCOT Wholesale Electricity Markets*.

PricewaterhouseCoopers LLP. 2013. *Guide to Accounting for Utilities and Power Companies*.

Appendix A: Additional Models Considered

Table 10 - Additional Contractual Models Considered

Solution	Description	Potential Implications
DEP / CEP PPAs	○ Require bidders to provide a Delivered Energy Price (DEP) and a Curtailed Energy Price (CEP), both in $/MWh ○ No floor or cap imposed on CEP pricing ○ Could allow for tiered CEP pricing ○ Curtailed energy compensated at CEP	○ Bidders can price their risk outlook into the breakout in payment streams, but not likely to result in major cost savings
Curtailment Bank	○ For any curtailed energy that is paid for by the utility, the same amount of energy must be delivered after the end of the base contract term	○ Proposed unsuccessfully in recent PPAs
BESS for Curtailment	○ Require Battery Energy Storage Systems (BESS) at all new non-dispatchable resources ○ BESS is sized to meet a minimum curtailment window of storage ○ Curtailment beyond BESS sizing paid at a predetermined rate	○ Deploying BESS strictly for curtailment is unlikely to be cost-effective; would need to incorporate additional BESS value streams like smoothing, frequency control, etc.
Rotating Monthly Bands	○ Create monthly min/max bands for PPAs, where the bands differ based on anticipated curtailment issues in those months ○ Each new PPA is treated uniquely for the bands, allowing for the potential to rotate which months are most curtailable at each	○ Creates opportunity for curtailment diversity among projects
SDC Curtailment	○ For any curtailed energy, the utility pays the developer their System Decremental Cost (SDC) rather than the PPA stipulated price ○ SDC would be calculated based on a cost-based rate formula that would be approved and routinely updated	○ Aligns cost borne by ratepayers with a measure more akin to the value of that decremental energy ○ Unknown SDC introduces additional risk for the IPP
Pro Rata Decrease	○ When curtailment is required, all applicable projects are required to back down at the same percentage so that, in total, the needed curtailment is met	○ May limit the magnitude of an individual IPP's curtailment risk, but may not reduce the nominal risk across an individual island for those customers

Source: SEPA & ScottMadden, 2016

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant

Clyde Loutan, Peter Klauer, Sirajul Chowdhury, and Stephen Hall
California Independent System Operator

Mahesh Morjaria, Vladimir Chadliev, Nick Milam, and Christopher Milan
First Solar

Vahan Gevorgian
National Renewable Energy Laboratory

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Technical Report
NREL/TP-5D00-67799
March 2017

Contract No. DE-AC36-08GO28308

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant

Clyde Loutan, Peter Klauer, Sirajul Chowdhury, and Stephen Hall
California Independent System Operator

Mahesh Morjaria, Vladimir Chadliev, Nick Milam, and Christopher Milan
First Solar

Vahan Gevorgian
National Renewable Energy Laboratory

Prepared under Task No. ST6S.1010

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
303-275-3000 • www.nrel.gov

Technical Report
NREL/TP-5D00-67799
March 2017

Contract No. DE-AC36-08GO28308

NOTICE

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Available electronically at SciTech Connect http:/www.osti.gov/scitech

Available for a processing fee to U.S. Department of Energy and its contractors, in paper, from:

U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831-0062
OSTI http://www.osti.gov
Phone: 865.576.8401
Fax: 865.576.5728
Email: reports@osti.gov

Available for sale to the public, in paper, from:

U.S. Department of Commerce
National Technical Information Service
5301 Shawnee Road
Alexandria, VA 22312
NTIS http://www.ntis.gov
Phone: 800.553.6847 or 703.605.6000
Fax: 703.605.6900
Email: orders@ntis.gov

Cover Photos by Dennis Schroeder: (left to right) NREL 26173, NREL 18302, NREL 19758, NREL 29642, NREL 19795.

NREL prints on paper that contains recycled content.

Acknowledgments

We thank and acknowledge the substantial contributions to this work provided by the staff of First Solar’s corporate office, located in Tempe, Arizona, during the planning and implementation stages of this project.

The authors also thank Dr. Guohui Yuan of the U.S. Department of Energy’s Solar Energy Technologies Office for his continuous support of this project.

List of Acronyms

ACE	Area control error
AGC	Automatic generation control
APC	Active power control
BAAL	Balancing Authority ACE Limit
BA	Balancing authority
CAISO	California Independent System Operator
FERC	Federal Energy Regulatory Commission
FFR	Fast frequency response
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
PFR	Primary frequency response
POI	Point of interconnection
PPC	Power plant controller
PV	Photovoltaic
ROCOF	Rate of change of frequency
RPS	Renewable portfolio standard
SCADA	Supervisory Control and Data Acquisition

Executive Summary

The California Independent System Operator (CAISO), First Solar, and the National Renewable Energy Laboratory (NREL) conducted a demonstration project on a large utility-scale photovoltaic (PV) power plant in California to test its ability to provide essential ancillary services to the electric grid. With increasing shares of solar- and wind-generated energy on the electric grid, traditional generation resources equipped with automatic governor control (AGC) and automatic voltage regulation controls—specifically, fossil thermal—are being displaced. The deployment of utility-scale, grid-friendly PV power plants that incorporate advanced capabilities to support grid stability and reliability is essential for the large-scale integration of PV generation into the electric power grid, among other technical requirements.

A typical PV power plant consists of multiple power electronic inverters and can contribute to grid stability and reliability through sophisticated "grid-friendly" controls. In this way, PV power plants can be used to mitigate the impact of variability on the grid, a role typically reserved for conventional generators. In August 2016, testing was completed on First Solar's 300-MW PV power plant, and a large amount of test data was produced and analyzed that demonstrates the ability of PV power plants to use grid-friendly controls to provide essential reliability services. These data showed how the development of advanced power controls can enable PV to become a provider of a wide range of grid services, including spinning reserves, load following, voltage support, ramping, frequency response, variability smoothing, and frequency regulation to power quality. Specifically, the tests conducted included various forms of active power control such as AGC and frequency regulation; droop response; and reactive power, voltage, and power factor controls.

This project demonstrated that advanced power electronics and solar generation can be controlled to contribute to system-wide reliability. It was shown that the First Solar plant can provide essential reliability services related to different forms of active and reactive power controls, including plant participation in AGC, primary frequency control, ramp rate control, and voltage regulation. For AGC participation in particular, by comparing the PV plant testing results to the typical performance of individual conventional technologies, we showed that regulation accuracy by the PV plant is 24–30 points better than fast gas turbine technologies. The plant's ability to provide volt-ampere reactive control during periods of extremely low power generation was demonstrated as well.

The project team developed a pioneering demonstration concept and test plan to show how various types of active and reactive power controls can leverage PV generation's value from being a simple variable energy resource to a resource that provides a wide range of ancillary services. With this project's approach to a holistic demonstration on an actual, large, utility-scale, operational PV power plant and dissemination of the obtained results, the team sought to close some gaps in perspectives that exist among various stakeholders in California and nationwide by providing real test data.

Table of Contents

List of Figures

List of Tables

1 Introduction

Solar photovoltaic (PV) generation is growing rapidly. At the end of 2015, the United States had 25 GW of installed solar PV capacity, with an additional 1.8 GW of concentrating solar power [1], [2]. As PV continues to grow, questions are arising about the ability of PV to contribute to maintaining grid reliability. In this study, we demonstrated various grid-friendly controls on First Solar's 300-MW PV plant located in the California Independent System Operator's (CAISO's) footprint. Our analysis shows that advanced power electronics and solar generation can be controlled to contribute to system-wide reliability. More specifically, we show that the First Solar plant can provide essential reliability services related to different forms of active and reactive power controls, including plant participation in automatic generation control (AGC), primary frequency control, ramp rate control, and voltage regulation. For AGC participation in particular, by comparing the PV plant testing results to the typical performance of conventional individual technologies, we showed that regulation accuracy by the PV plant is 24–30 points better than fast gas turbine technologies. The plant's ability to provide volt-ampere reactive (VAR) control during periods of extremely low power generation was demonstrated as well.

The project team—consisting of experts from CAISO, First Solar, and the National Renewable Energy Laboratory (NREL)—developed a demonstration concept and test plan to show how various types of active and reactive power controls can leverage PV generation's value from being a simple variable energy resource to a resource that provides a wide range of ancillary services. With this project's approach to a holistic demonstration on an actual, large, utility-scale, operational PV power plant and dissemination of the obtained results, the team sought to close some gaps in perspectives that exist among various stakeholders in California and nationwide by providing real test data. If PV-generated power can offer a supportive product that benefits the power system and is economic for PV power plant owners and customers, this functionality should be recognized and encouraged. This project showed, through real-world testing, that PV power plants can contribute to maintaining grid reliability.

Pioneering work done by NREL, First Solar, and AES in 2015 in West Texas and Puerto Rico provided a detailed understanding of the advanced capabilities offered by modern PV power plants [3]. The current CAISO-First Solar-NREL project is aimed at breaking new barriers to the provision of ancillary services by PV generation in terms of both plant capacity (300 MW) and system-level impacts. Taken as a whole, these three studies show that PV power plants can be used to manage a variety of grid challenges on island systems, isolated interconnections, and within market environments in large synchronous systems.

Renewable energy in the United States accounted for 13.44% of domestically produced electricity in 2015 [3]. California is a leading state for integrating renewable resources and for renewable portfolio standards (RPSs), with approximately 29% of its electricity provided from RPS-eligible renewable sources (including small hydropower) [4]. In addition, California is leading the way in climate change policies that are intended to reduce emissions from all sectors, including electricity, by 40% from 1990 levels by 2030 and by 80% from 1990 levels by 2050. If California is to achieve these goals while enhancing grid reliability, all resources, including renewables, must be leveraged to provide essential reliability services.

Rapid penetrations of variable renewable generation into an electric grid are changing the ways power system operators manage their systems. Higher levels of variable generation are creating real-time reliability and operational changes. For example, the California Independent System Operator (CAISO) is trying to adapt to rapid increases in its solar PV generation during sunrise and rapid losses in solar production during sunset.

CAISO currently has more than 9,000 MW of transmission-connected solar resources within its operational footprint. To meet its RPS goal of 33% by 2020, CAISO is expecting an additional 4,000–5,000 MW of solar. Beyond 2020, to meet a 50% RPS goal, CAISO is expecting an additional 15,000 MW of renewable resources, and a significant portion of this is anticipated to be transmission-connected solar PV because of the expected reduction in the price of solar panels (Figure 1). Thus, the capability of solar PV resources to provide essential reliability services is necessary to achieve a low-carbon grid.

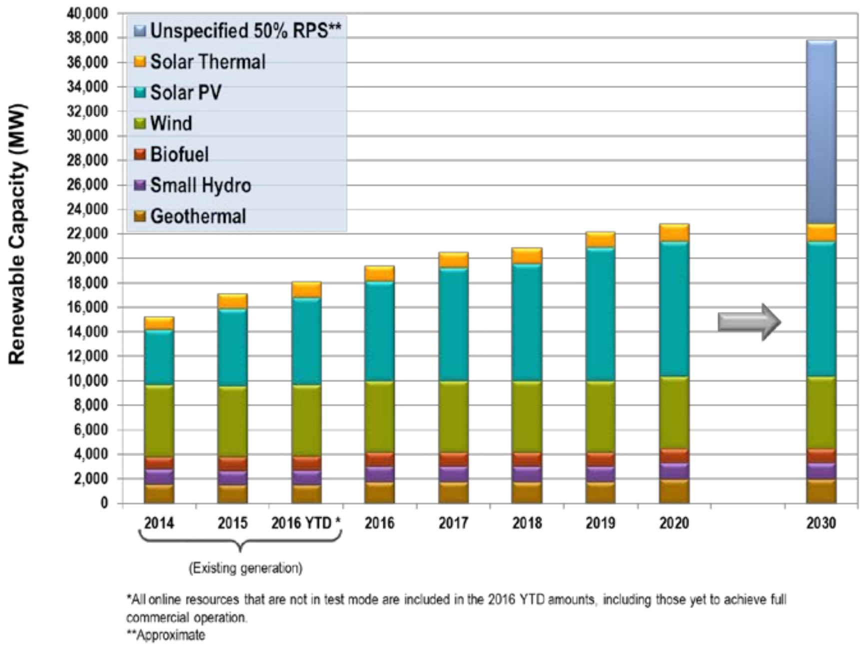


Figure 1. CAISO's expected renewable capacity build-out to meet its 50% RPS goal.
Illustration from CAISO

In addition, CAISO has experienced a significant increase in rooftop solar PV installations (Figure 2). Currently, more than 5,000 MW of rooftop solar PV is installed within CAISO's footprint, and it is expected to exceed 9,000 MW by 2020. Rooftop solar PV does not count toward RPS, but it does have an impact on grid operations, especially during sunrise and sunset.

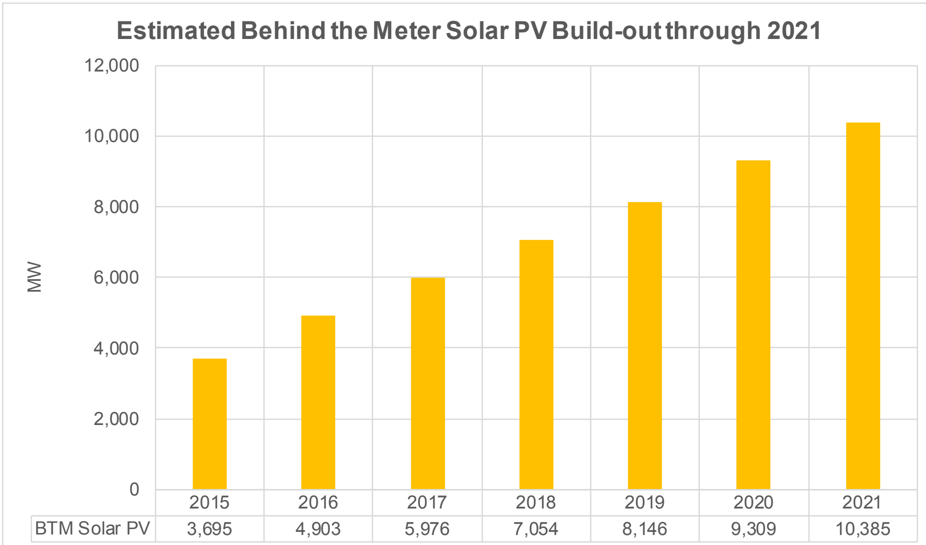


Figure 2. CAISO's expected build-out of rooftop solar PV. *Illustration from CAISO*

High levels of solar generation during midday hours are already contributing to oversupply, especially on light load days when renewable production is high. Therefore, it is during these conditions that opportunity is created if renewable resources could provide essential reliability services that have traditionally been provided by conventional resources. Sharp changes in the real-time ramping needs are also happening during afternoon-to-evening hours. This is especially evident during the spring and fall months, when loads are relatively light and hourly penetrations of renewable generation are high. In its "duck chart" (Figure 3), CAISO shows these integration changes and opportunities for a typical spring day as a significant drop in its midday net load is met by an increased share of PV in the system. These changes and opportunities to leverage the capability of these new resources are growing at a faster rate than previously expected; and during certain days in the spring of 2016, CAISO's minimum net load was already less than the predicted 2020 level.

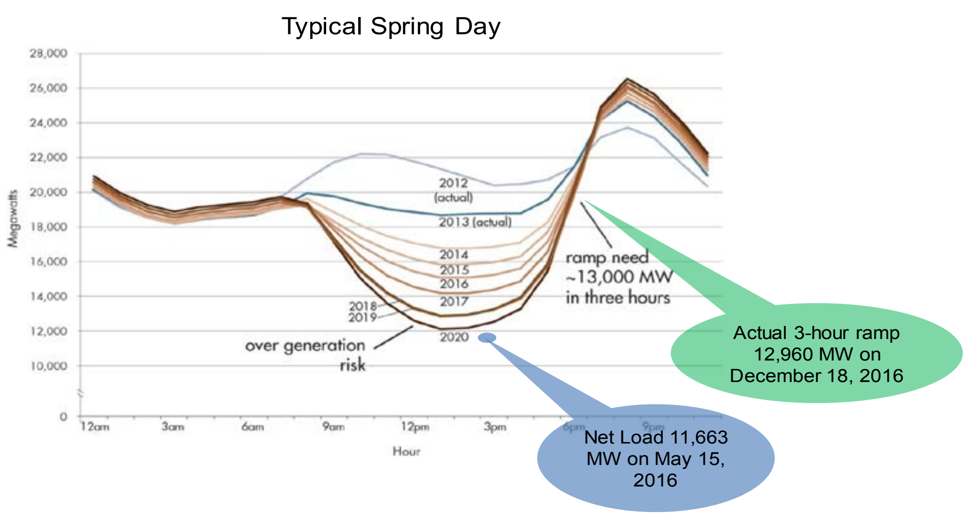


Figure 3. CAISO duck chart. *Illustration from CAISO*

Because of low net loads, the risk of oversupply increases, so significant curtailment of renewables took place during certain days in the spring of 2016. An example of this type of curtailment period is shown in Figure 4. During certain daytime hours on April 24, 2016, more than 2 GW of renewable generation were curtailed to maintain reliable operation of the system. With increased curtailment, more opportunity is created if the industry can tap into the controllability of renewable resources and thus reduce reliance on conventional resources to provide such services.

Advanced inverter functions and how projects are designed and operated can help address grid stability problems during such periods. A typical modern utility-scale PV power plant is a complex system of large PV arrays and multiple power electronic inverters, and it can contribute to mitigating the impacts on grid stability and reliability through sophisticated automatic "grid-friendly" controls. Many of the PV control capabilities that were demonstrated in this project have already generally been proven to be technically feasible, and a few areas throughout the world have already started to request or require PV power plants to provide some of them; however, in the United States, utility-scale PV plants are rarely recognized as having these capabilities, and typically they are not used by utilities or system operators to provide electric grid services.

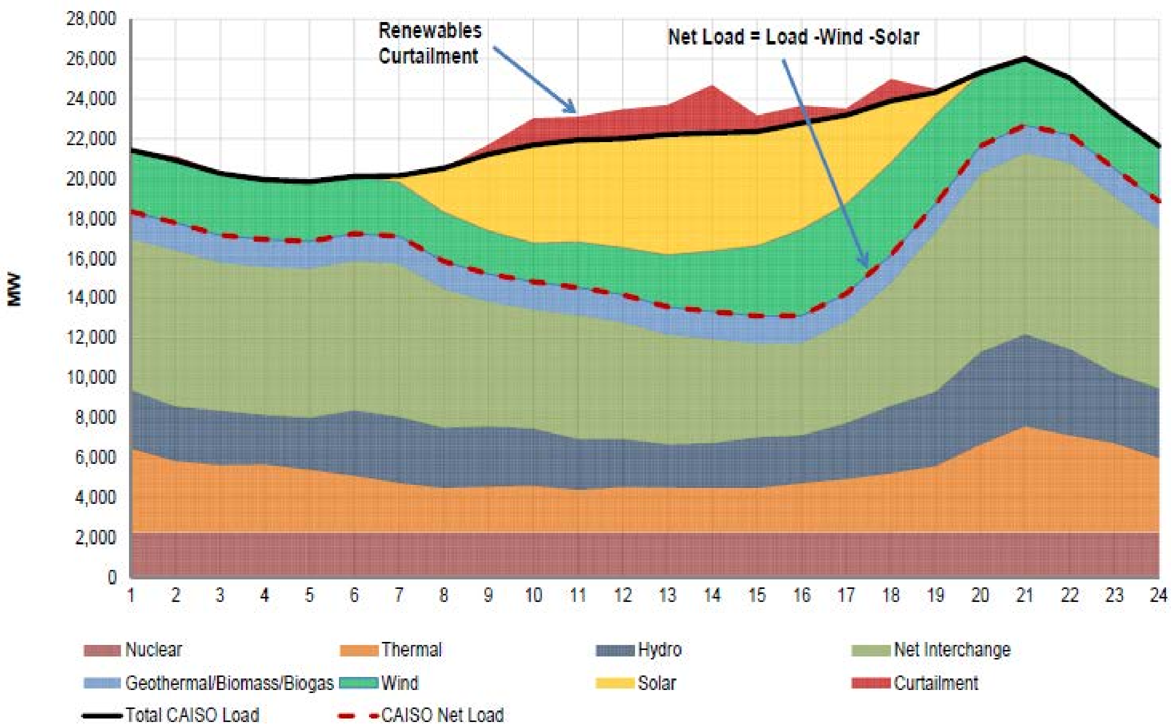


Figure 4. CAISO's generation breakdown for April 24, 2016. ***Illustration from CAISO***

CAISO is continually adapting its operational practices and market mechanisms to make the integration of shares of fast-growing variable renewable generation both reliable and economic. This new reality leads to growing needs by CAISO and other independent system operators to:

- Better coordinate between day-ahead and real-time markets
- Increase flexibility in the form of fast ramping capacity

- Better utilize ancillary service capabilities by variable renewable generation
- Deepen regional coordination
- Implement new market mechanisms incentivizing the participation of renewables in ancillary service markets
- Develop new market products to take advantage of faster and higher-precision ancillary service providers
- Add energy storage capacity
- Align time-of-use rates with system demand.

Currently, regulation-up and regulation-down are two of the four ancillary service products that CAISO procures through co-optimization with energy in the day-ahead and real-time markets. The other two products are spinning and nonspinning reserves. Most ancillary service capacity is procured in the day-ahead market. CAISO procures incremental ancillary services in the real-time market processes to replace unavailable ancillary services or to meet additional ancillary service requirements. A detailed description of the ancillary service market design, which was first implemented in 2009, is provided in CAISO's 2016 market report [5], [6].

From February 20, 2016, through June 9, 2016, CAISO increased the requirements to a minimum of 600 MW for regulation-up and regulation-down in both the day-ahead and real-time markets. Average prices for these two ancillary services increased immediately following the change in requirements in February and reverted to lower levels again in June 2016 (Figure 5). Regulation procurement costs continued to average more than $400,000 per day when the requirements were high and fell to $80,000 per day when the requirements were lowered, beginning on June 10, 2016.

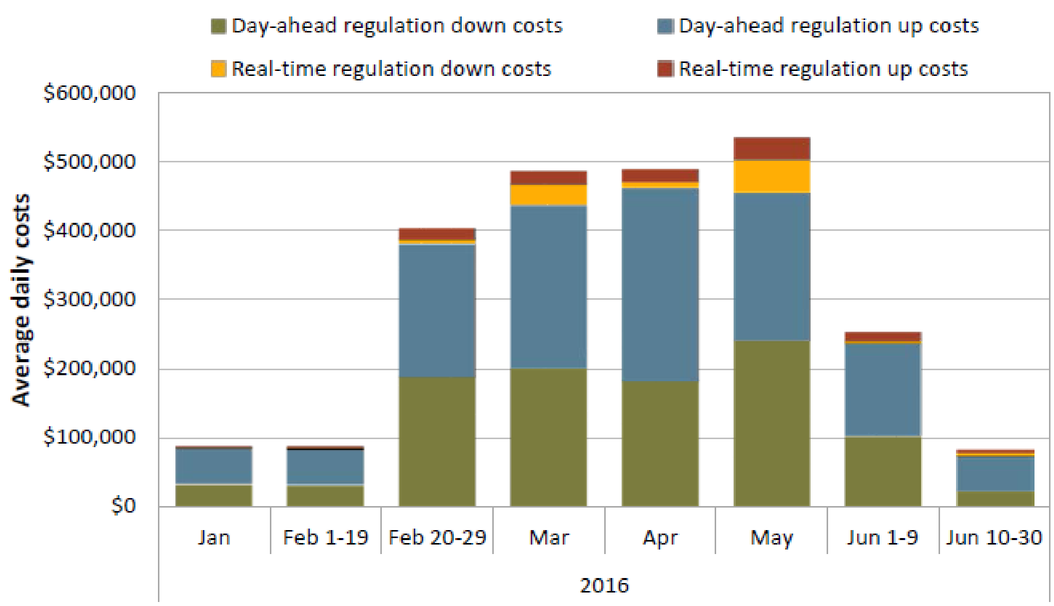


Figure 5. CAISO's average daily regulation procurement costs from January–June 2016.
Illustration from CAISO

In 2012, CAISO implemented standards for importing regulation service [7]. These standards implemented CAISO's tariff provisions relating to the imports of regulation services, either bid or self-provided, by scheduling coordinators with system resources located outside CAISO's balancing authority area. In addition to imported regulation services, regulation provided by PV power plants within CAISO's footprint can become an additional stability tool at CAISO's disposal.

As power system continues to evolve, the Federal Energy Regulatory Commission (FERC) noted that there is a growing need for a refined understanding of the services necessary to maintain a reliable and efficient system. In orders 755 and 784, FERC required improving the mechanisms by which frequency regulation service is procured and enabling compensation by fast-response resources such as energy storage. CAISO is working on a new market design in which aggregated distributed resources (rooftop PV, behind-the-meter batteries, electric vehicles, fast demand response) can bid in its market. In addition, FERC recently issued a notice of proposed rulemaking to enable aggregation of distributed storage and distributed generation [8].

The Electric Reliability Council of Texas and the New York Independent System Operator are also working on similar ancillary service markets for utility-scale and distributed generation [9].

In 2012, the North American Electric Reliability Corporation's (NERC) Integration of Variable Generation Task Force made several recommendations for requirements for variable generators (including solar) to provide their share of grid support, including active power control (APC) capabilities [7, 10]. These recommendations address grid requirements such as voltage control and regulation, voltage and frequency fault ride-through, reactive and real power control, and frequency response criteria in the context of the technical characteristics and physical capabilities of variable generation equipment.

- APC capabilities include:
    - Ramp-rate-limiting controls
    - Active power response to bulk power system contingencies
        - Inertial response
        - Primary frequency response (PFR)
        - Secondary frequency response, or participation in AGC
        - Ability to follow security-constrained economic dispatch (SCED) set points that are sent every 5 minutes through its real-time economic dispatch market software.
- Performance during and after disturbances
    - Fault ride-through
    - Short-circuit current contribution.
- Voltage, reactive, and power factor control and regulation (both dynamic and steady state).

In 2015, the NERC task force on Essential Reliability Services published a report exploring important directional measures to help the energy sector understand and prepare for the increased deployment of variable renewable generation [11], [12]. According to this report, to maintain an adequate level of reliability through this transition, generation resources need to provide sufficient voltage control, frequency support, and ramping capability—essential components of a reliable bulk power system.

The California state legislature passed Senate Bill 350 in the fall of 2015, which requires all utilities in the state to produce 50% of their electricity sales from renewable sources with the objective of reducing carbon emissions. To reach that 50% RPS goal, California operators will need to find additional ways to balance generation and load to manage the variability of increased renewable generation and maintain grid reliability. In this context, the curtailment of renewables can be viewed as a resource, not only a problem. Because wind and solar generation can be ramped up and down, curtailment can become a helpful resource to relieve oversupply and provide frequency regulation and ramping services. In combination with the 1.3-GW California energy storage mandate, ancillary services provided by renewables can enhance system flexibility and reliability and reduce needs in spinning reserves by conventional power plants. Thus, unleashing these capabilities from renewable resources helps achieve the broader objective of a resilient, reliable, low-carbon grid.

Currently, only a few grid operators in the United States are using curtailed renewables as a resource. For example, the Public Service Company of Colorado (PSCO) has means to control its wind generation to provide both up and down regulation reserves (the PSCO has had periods of 60% wind power generation in its system). The PSCO is able to use wind reserves as an ancillary service for frequency regulation by integrating the wind power plants in their footprint to provide AGC. Similar services can be provided by curtailed PV power plants in California; however, regulatory, market, and operational issues need to be resolved for this to become possible [13], [14].

Prior to testing, the team developed a plan that was coordinated with technical experts from First Solar. The test plan is shown in the appendix of this report). The following sections describe the tests and results conducted by the team:

1. CAISO-NREL-First Solar custom-developed test scenarios (conducted on August 24, 2016)
    A. Regulation-up and regulation-down, or AGC tests during sunrise, middle of the day, and sunset
    B. Frequency response tests with 3% and 5% droop settings for overfrequency and underfrequency conditions
    C. Curtailment and APC tests to verify plant performance to decrease or increase its output while maintaining specific ramp rates
    D. Voltage and reactive power control tests
    E. Voltage control at near zero active power levels (nighttime control).

2. More standardized First Solar's power plant controller (PPC) system commissioning tests (conducted on August 23, 2016)

    A. Automatic manual control of inverters (individual, blocks of inverters, whole plant)

    B. Active power curtailment control, generation failure and restoration control, frequency control validation

    C. Automatic voltage regulation at high and low power generation

    D. Power factor control

    E. Voltage limit control

    F. VAR control.

2 PV Power Plant Description

First Solar constructed a 300-MW AC PV power plant in CAISO's footprint. An aerial photo of the plant using First Solar's advanced thin-film cadmium-telluride PV modules is shown in Figure 6. The plant is tied to 230-kV transmission lines via two 170-MVA transformers (34.5/230 kV). The 34.5-KV side of each transformer is connected to the plant's MV collector system with four blocks each rated 40 MVA. Individual PV inverter units, each rated 4 MVA, operate at 480 VAC and are connected to a 34.5-kV collector system via pad-mounted transformers. Switched capacitor banks are connected to both 34.5-kV buses to meet the power factor requirements of FERC's Large Generator Interconnection Agreement (LGIA) power factor requirements. Two phasor measurement units (PMUs) were set to collect data at the 230-kV sides of both plant transformers.

Figure 6. Aerial photo of First Solar's 300-MW PV power plant. ***Photo from First Solar***

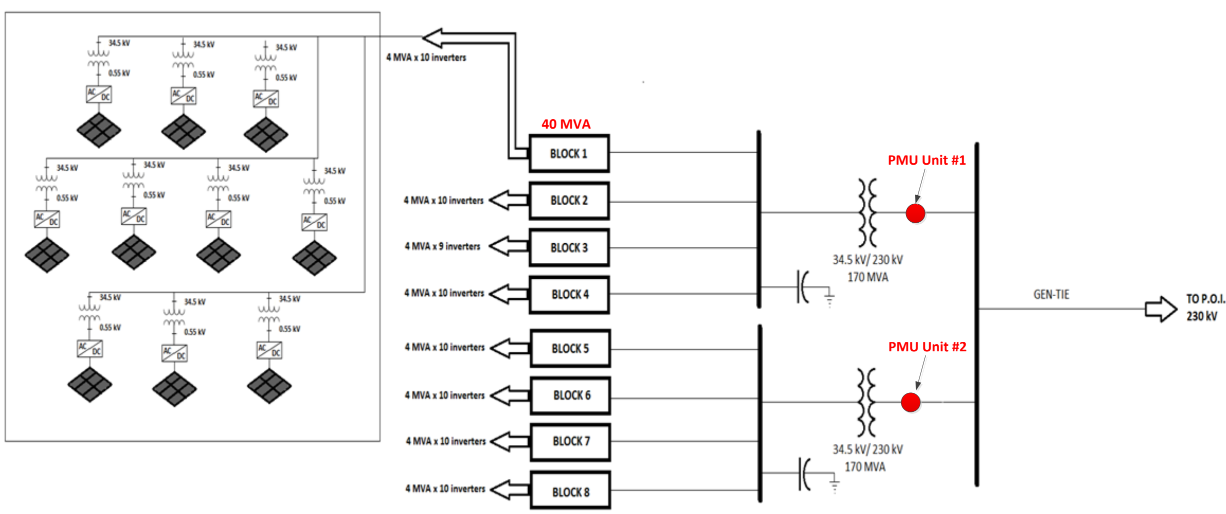


Figure 7. Electrical diagram of First Solar's 300-MW PV plant. ***Illustration from First Solar***

A key component of this tested grid-friendly solar PV power plant is a PPC developed by First Solar. It is designed to regulate real and reactive power output from the PV power plant so that it behaves as a single large generator. Although the plant comprises individual inverters, with each inverter performing its own energy production based on local solar array conditions, the plant controller's function is to coordinate the power output to provide typical large power plant features, such as APC and voltage regulation through reactive power regulation [16].

First Solar's PPC is capable of providing the following plant-level control functions:

- Dynamic voltage and/or power factor regulation and closed-loop VAR control of the solar power plant at the point of interconnection (POI)
- Real power output curtailment of the solar power plant when required so that it does not exceed an operator-specified limit
- Ramp-rate controls to ensure that the plant output does not ramp up or down faster than a specified ramp-rate limit, to the extent possible
- Frequency control (governor-type response) to lower plant output in case of an overfrequency situation or increase plant output (if possible) in case of an underfrequency situation
- Start-up and shutdown control.

The PPC implements plant-level logic and closed-loop control schemes with real-time commands to the inverters to achieve fast and reliable regulation. It relies on the ability of the inverters to provide a rapid response to commands from the PPC. Typically, there is one controller per plant controlling the output at a single high-voltage bus (referred to as the POI). The commands to the PPC can be provided through the Supervisory Control and Data Acquisition (SCADA) human-machine interface or even through other interface equipment, such as a substation remote terminal unit.

Figure 8 illustrates a general block diagram overview of First Solar's control system and its interfaces to other devices in the plant. The PPC monitors system-level measurements and determines the desired operating conditions of various plant devices to meet the specified targets. It manages capacitor banks and/or reactor banks, if present. It has the critical responsibility of managing all the inverters in the plant, continuously monitoring the conditions of the inverters and commanding them to ensure that they are producing the real and reactive power necessary to meet the desired voltage schedule at the POI [16].

A conceptual diagram of the plant's control system architecture is shown in Figure 9. The plant operator can set an active power curtailment command to the controller. In this case, the controller calculates and distributes active power curtailment to individual inverters. In general, some types of inverters can be throttled back only to a certain specified level of active power and not any lower without causing the DC voltage to rise beyond its operating range. Therefore, the PPC dynamically stops and starts inverters as needed to manage the specified active power output limit. It also uses the active power management function to ensure that the plant output does not exceed the desired ramp rates, to the extent possible. It cannot, however, always accommodate rapid reductions in irradiance caused by cloud cover.

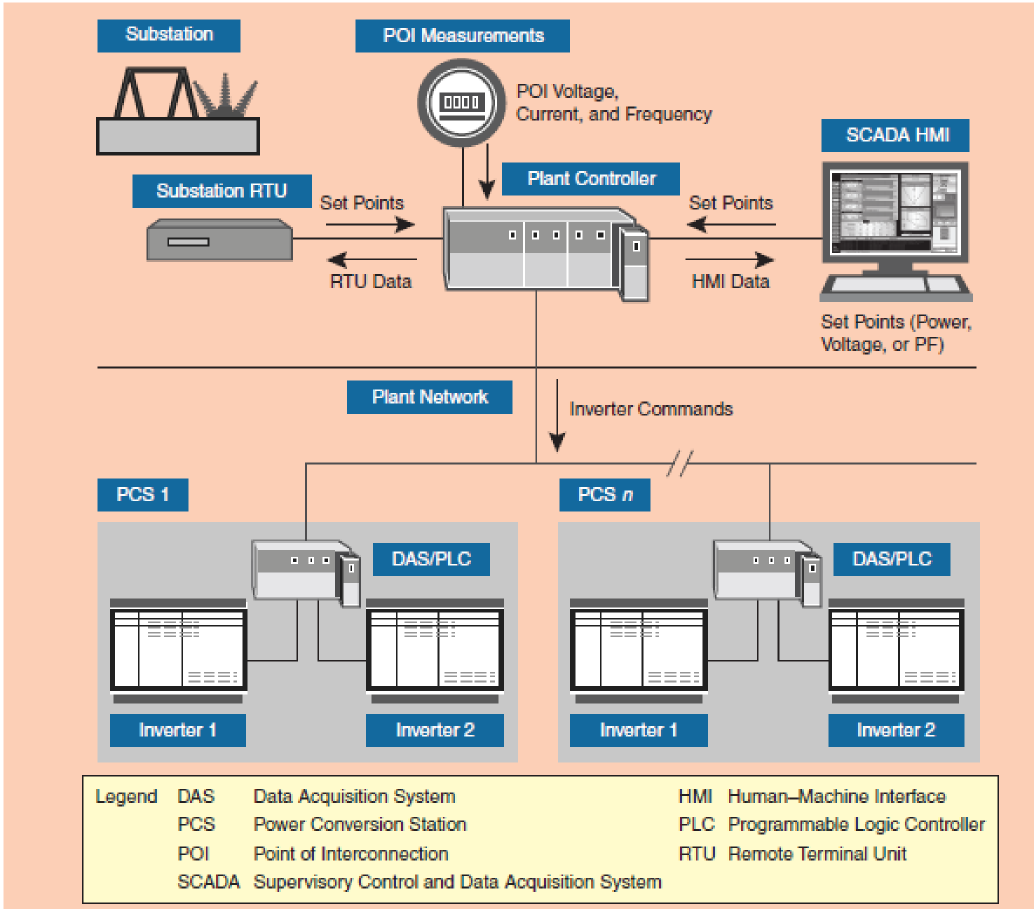


Figure 8. General diagram of First Solar's PV power plant controls and interfaces.
Illustration from First Solar

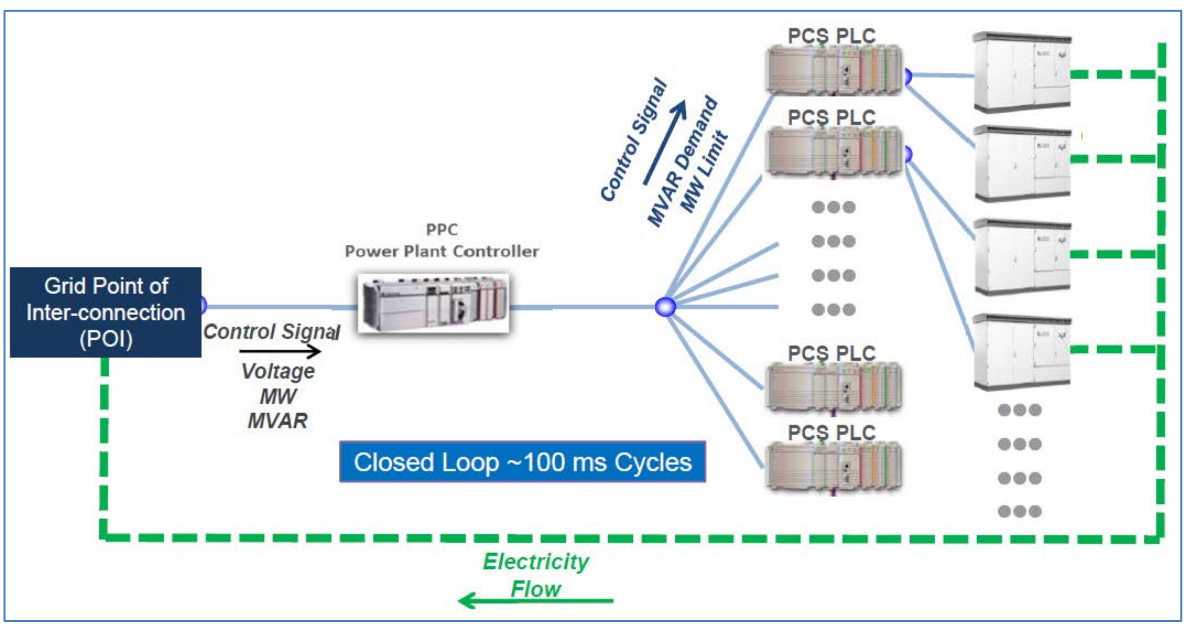


Figure 9. Diagram of First Solar's PV power plant control system architecture.
Illustration from First Solar

The testing of the 300-MW plant within CAISO’s footprint was conducted remotely by the First Solar team from their operations center located in First Solar’s corporate offices, in Tempe, Arizona (Figure 10). As a NERC-registered generator operator, the First Solar staff was capable of remotely supervising the ongoing testing activities at the 300-MW PV plant in California, tracking the plant’s performance and making changes to test set point and plant control parameters from the center in Arizona.

Figure 10. First Solar’s operations center in Tempe, Arizona. ***Photo from First Solar***

3 AGC Participation Tests for First Solar's 300-MW PV Power Plant

3.1 Description and Rationale for AGC Tests

The purpose of the AGC tests is to enable the power plant to follow the active power set points sent by CAISO's AGC system. The set point signal is received by the remote terminal unit in the plant substation and then scaled and routed to the PPC in the same time frame. When in AGC mode, the PPC initially set the plant to operate at a power level that was 30 MW lower than the estimated available peak power to have headroom for following the up-regulation AGC signal (see hypothetical example in Figure 11). The lower boundary of AGC operation can be set at any level below available peak power, including full curtailment if necessary.

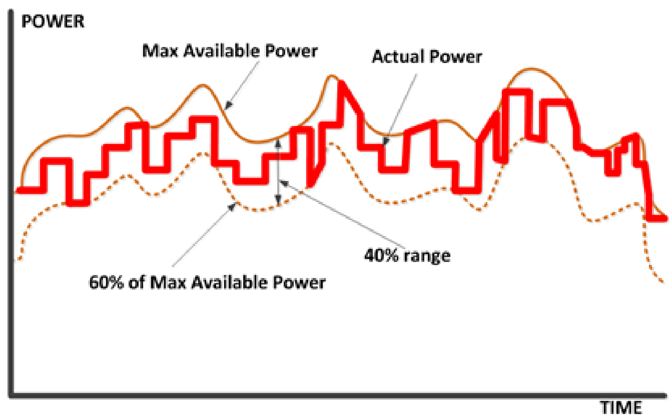


Figure 11. Concept of AGC following by a PV power plant (e.g., with 40% headroom).
Illustration from NREL

CAISO's AGC is normally set to send a direct MW set point signal to all participating units every 4 seconds. All ramp-rate settings in the PV power plant's PPC were set at very high level of 600 MW/min (10 MW/sec) during the AGC tests. AGC control logic for a balancing authority with interconnections (such as CAISO) is based on determining the:

- Area's total desired generation
- Base points for each AGC participating unit
- Regulation obligation for each AGC participating unit.

Area control error (ACE) is an important factor used in AGC control. For a balancing authority area, ACE is determined as:

$$ACE = -\Delta P_{tie} - 10B(f_a - f_s) + I_{ME} + I_T \quad (1)$$

where ΔP_{tie} is the net tie-line interchange error, B is the frequency bias (MW/0.1Hz); f_a and f_s are the actual measured and scheduled frequencies (typically 60 Hz, but they can also be 59.8 Hz or 60.2 Hz during time error corrections), respectively; and I_{ME} and I_T are the meter error correction and time error correction factors, respectively (MW). The ACE value is then used by the AGC control logic to determine the total desired generation that will drive it to zero. The desired generation for each participating generating unit is split into two components: the base point and regulation. The base point for each generating unit is set at its economic dispatch point, and the system's total regulation is calculated as the difference between the total desired generation and the sum of the base points for all AGC participating units. The total regulation for the whole system is allocated among all participating regulating units. The 300-MW plant under test is considered as one plant-level generating unit, and individual inverter outputs are not considered by CAISO's operations. Various unit-specific parameters are used in its regulation allocation, such as ramp rates and operating limits. Figure 12 shows a general diagram of CAISO's AGC distributing set point signals to individual generating units. The raw ACE signal is filtered first, and it is then processed by a proportional-integral (PI) filter that has proportional and integral control gains. The filtered ACE is then passed to the AGC calculation and distribution module that generates the ramp-limited AGC set points for the individual participating units based on their participation factor, dispatch status, available headroom, unit physical characteristics, etc., as shown in Figure 12.

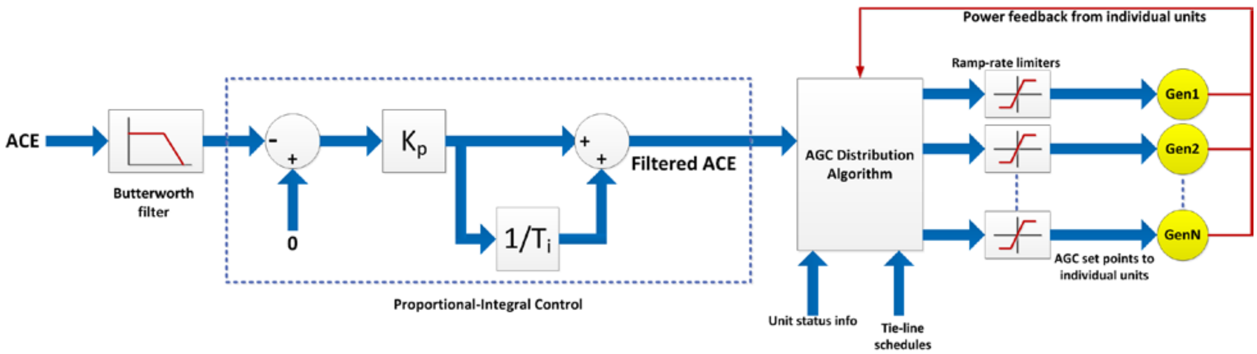


Figure 12. Simplified diagram of CAISO's AGC system. ***Illustration from NREL***

AGC operates in conjunction with supervisory control and data acquisition (SCADA) systems [17]. SCADA gathers information on system frequency, generator outputs, and actual interchange between the system and adjacent systems. Using system frequency and net actual interchange, plus knowledge of net scheduled interchange, an AGC system determines the system's energy balancing needs with its interconnection in near real time. CAISO's SCADA system polls sequentially for electric system data with a periodicity of 4 seconds. The degree of success of AGC in complying with balancing and frequency control is manifested in a balancing authority's control performance compliance statistics and metrics as defined by NERC's control performance standards (CPS). In particular, CPS1 is a measure of a balancing authority's long-term frequency performance with the control objective to bound excursions of an average 1-minute frequency error during 12 months in the interconnection. CPS1 allows for evaluating how well a balancing authority's ACE performs in conjunction with the frequency error of the whole interconnection. CPS2 is a measure of the balancing authority's ACE during all 10-minute periods in a month with the control objective to limit ACE variations and bound unscheduled power flows among balancing authority areas.

NREC's Standards Committee approved the replacement of CPS2 with the Balancing Authority ACE Limit (BAAL) in June 2005. BAAL is unique for each balancing authority and provides dynamic limits for its ACE value limits as a function of its interconnection frequency. The objective of BAAL is to maintain the interconnection frequency within predefined limits. A field trial of BAAL began in the Eastern Interconnection in July 2005 and in the Western

Interconnection in March 2010. Enforcement of BAAL began on July 1, 2016 [18]. Both CPS1 and BAAL scores are important metrics for understanding the impacts of variable renewable generation on system frequency performance. NERC's reliability standards require that a balancing authority balances its resources and demand in real time so that the clock-minute average of its ACE does not exceed its BAAL for more than 30 consecutive clock-minutes.

PV generation participation in CAISO's AGC is expected to maintain CPS above the minimum NERC requirements and BAAL within predefined operating limits and avoid degradation in reliability. AGC participation by faster and higher-precision responsive generation is potentially more valuable because these types of generation allow for applying controls at the exact moment in time and exact amount needed by the system. Faster AGC control is desirable because it facilitates more reliable compliance with NERC's operating standards at relatively less regulation capacity procurements [19]. Currently, CAISO practices and markets do not differentiate between faster and slower providers, with the exception of some minimum ramping capabilities. The data produced by AGC testing of the 300-MW PV plant in California are intended to provide real field-measured results to confirm the above-described benefits and facilitate the transition to improved ancillary service markets that value and incentivize superb performance by inverter-coupled renewable generation.

3.2 AGC Test Results

The AGC tests were conducted on August 24, 2016, at three different solar resource intensity time frames: (1) sunrise, (2) middle of the day (noon–2 p.m.), and (3) sunset (for 20 minutes at each condition). Historic 4-second AGC signals that CAISO previously sent to another regulation-certified resource of similar capacity were provided to the plant controller.

The 300-MW PV plant under test was not connected to CAISO's AGC system because the plant's owner did not request this control option at the time of construction; instead, historical CAISO ACE data were provided to the PPC for AGC performance testing. Each test was conducted using actual 4-second AGC signals that CAISO had previously sent to a regulation-certified resource of similar size. The historical AGC signal provided by CAISO had a regulation range of 30 MW, or 10% of rated plant power (Figure 13). This signal is represented as ΔP_{AGC} in the equation below:

$$P_{command} = (P_{available} - 30MW) + \Delta P_{AGC} \qquad (2)$$

where $P_{available}$ is the maximum available instantaneous power that the plant can produce for a given solar irradiation conditions, and $P_{command}$ is the actual commanded MW set point sent to the PPC.

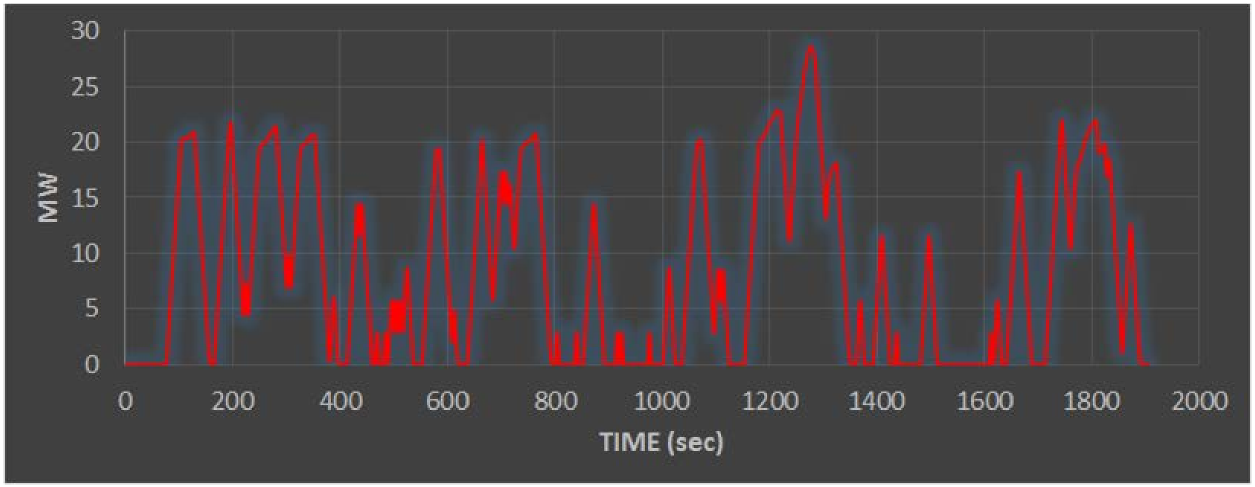


Figure 13. Historic CAISO AGC signal used in testing. ***Illustration from NREL***

In this way, the plant's response to the AGC-like set point signal can be tested within a 30-MW range. CAISO's regulation system has a significant total ramping capability for shorter periods of time. Longer ramps may cause regulation problems after faster units exhaust their regulation range. CAISO's real-time economic dispatch software would try to return units that are not awarded service to their preferred point of operation (POP), so sufficient up-regulation and down-regulation capabilities can be maintained. Because the plant under test was not participating in CAISO's real AGC scheme, the adopted method of AGC mimicking provides a sufficient approximation of real conditions because both the up-regulation and down-regulation characteristics of the plant can be tested.

For this PV plant to be able to maintain the desired regulation range (30 MW in this case), the plant PPC must be able to estimate the available aggregate peak power that all the plant's inverters can produce at any point in time. The available power is normally estimated by an algorithm that considers solar irradiation, PV module I-V characteristics and temperatures, inverter efficiencies, etc. The plant under test did not have this estimation function because the plant owner did not request it during construction; instead, the project team implemented a less sophisticated approach to evaluate the available maximum power. For this purpose, a single 4-MVA inverter was taken from the APC scheme by the First Solar team, and it was set to operate at the power level determined by its maximum power point tracking (MPPT) algorithm. The measured AC power of this inverter was used as an indicator of available power for the other 79 inverters (80 inverters total). The available maximum power was then calculated as:

$$P_{available} = 79 \times P_i^{MPPT} \tag{3}$$

where P_i^{MPPT} is the measured AC power of the single inverter that was designated to operate at its MPPT point. Therefore, Eq. 2 can be rewritten as:

$$P_{command} = (79 \times P_i^{MPPT} - 30MW) + \Delta P_{AGC} \tag{4}$$

So the aggregate power command sent to the PPC for the remaining 79 inverters was calculated using Eq. 4. This method has inherent uncertainties because it assumes uniform solar irradiation conditions across the whole 300-MW plant. Fortunately, cloud conditions were favorable for this method to be acceptable because there was a clear sky above the plant during most of the day on August 24. Of course, under moving cloud conditions the accuracy of this method would drop significantly due to the large geographical footprint of the 300-MW PV plant. The importance of accurate peak power estimation for any type of up-regulation was also emphasized in Ref. 11, and it is a crucial factor for AGC performance accuracy by PV plants.

The measured 1-second time series for the August 24, 2016, AGC tests are shown in Figures 14–18. In particular, Figure 14 shows the results of the morning AGC test. The test started when the plant was commanded to curtail its production to a lower level (orange trace), which was 30 MW below its available peak power (green trace), according to Eq. 4. The AGC signal was then fed to the PPC (red trace), so the plant output (yellow trace) was changing accordingly, demonstrating good AGC performance by following the set point during this period of smooth power production. A similar test was conducted during the peak production hour, as shown in Figure 15. A magnified view of the same test is shown in Figure 16 allowing a closer look to the plant AGC performance. The plant's response to each new AGC set point is almost immediate; however, there were periods when the plant was not able to reach the set point with this high level of precision. This mismatch can be explained by the internal active ramp rate limit in individual inverters. The absolute control error for the same test is small, as shown in Figure 16, and it is confined within the range of ±5 MW (or ±1.67% of the plant's rated power capacity).

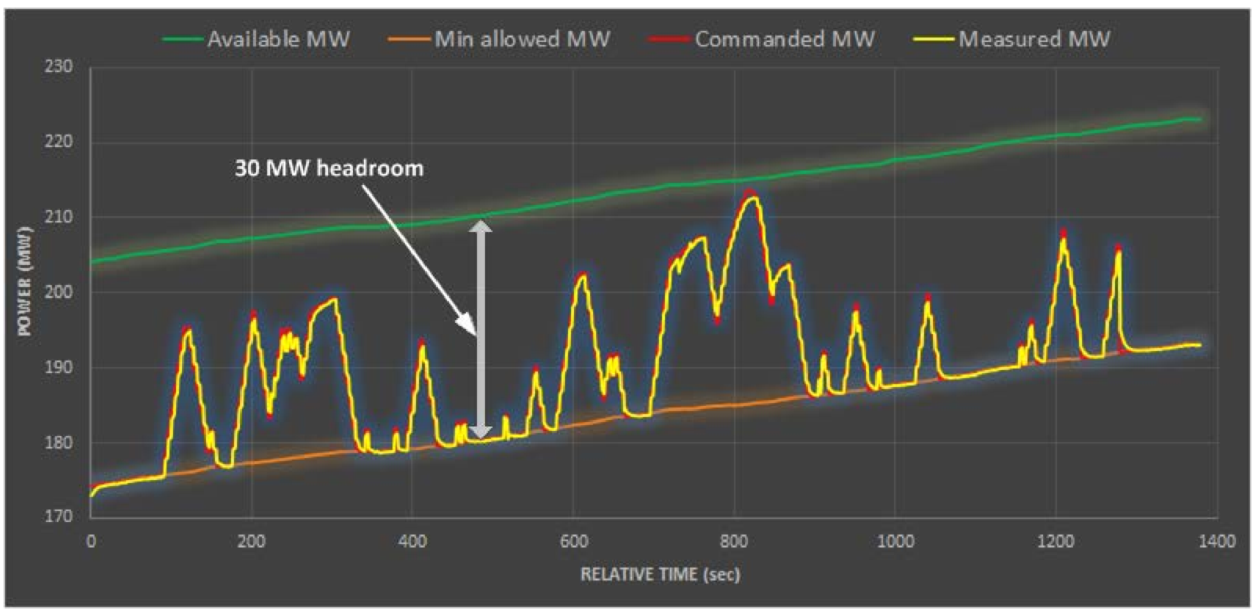


Figure 14. Morning AGC test (9:47 a.m.–10:10 a.m.). ***Illustration from NREL***

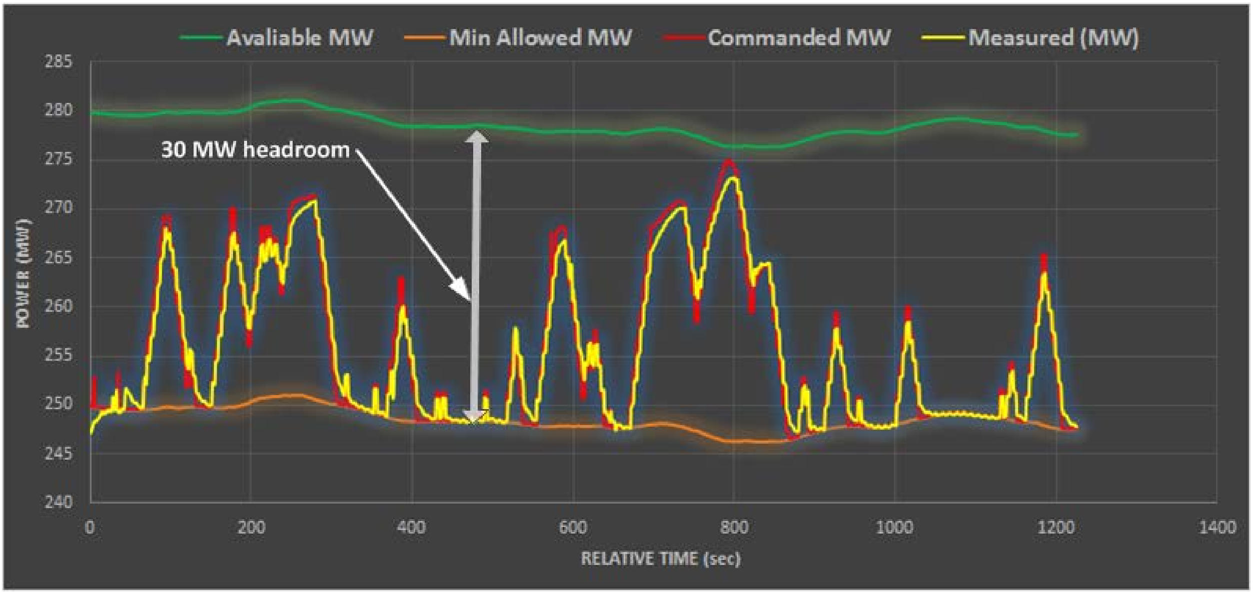


Figure 15. Midday AGC test (12:40 p.m.–1 p.m.). ***Illustration from NREL***

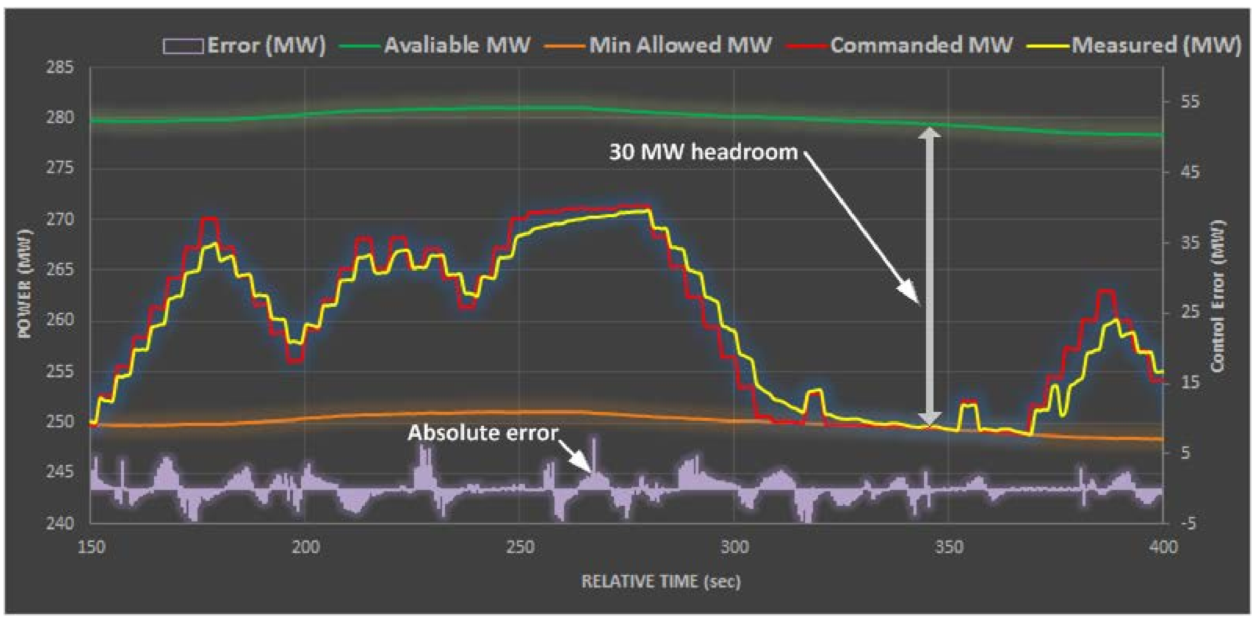


Figure 16. Midday AGC test (12:40 p.m.–1 p.m.) magnification. ***Illustration from NREL***

Results of the AGC test conducted during the afternoon are shown in Figure 17. The plant demonstrated similar AGC performance as in the previous cases; however, a cloud front was moving over the plant on the afternoon of August 24, which introduced variability in the plant's output. During these periods, the available peak power from the plant was reduced significantly, causing the AGC set point to decrease as well, according to Eq. 4; however, even during these periods, the plant demonstrated good AGC performance by closely following the commanded set point, as shown in Figure 18 for one such event.

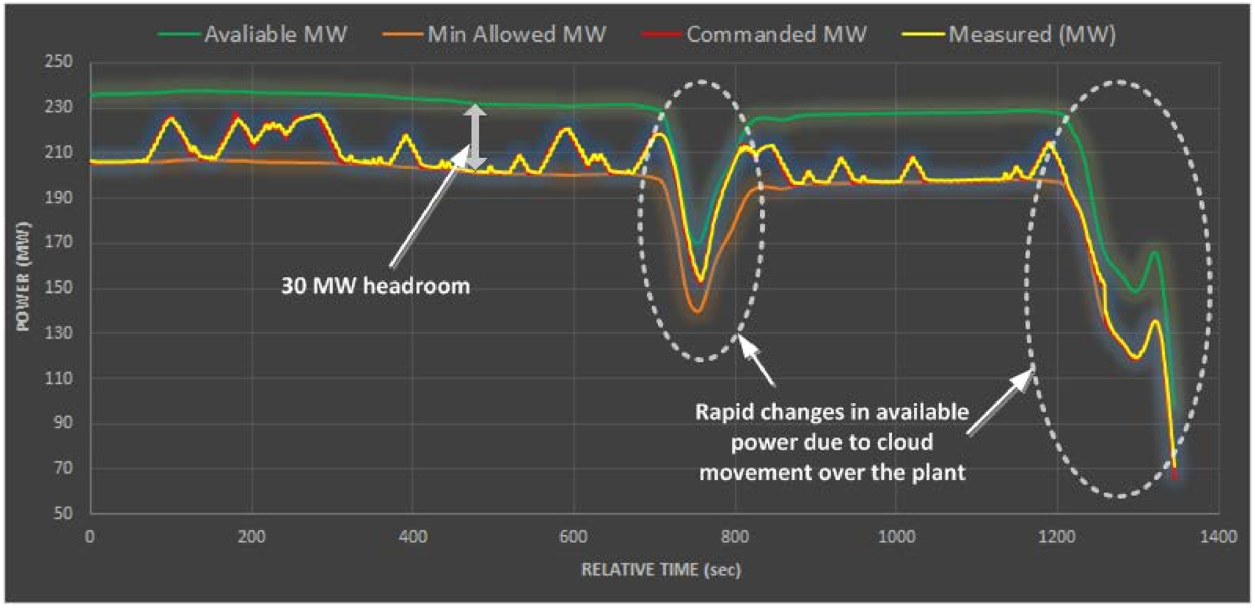


Figure 17. Afternoon AGC test (2:54 p.m.–3:16 p.m.). ***Illustration from NREL***

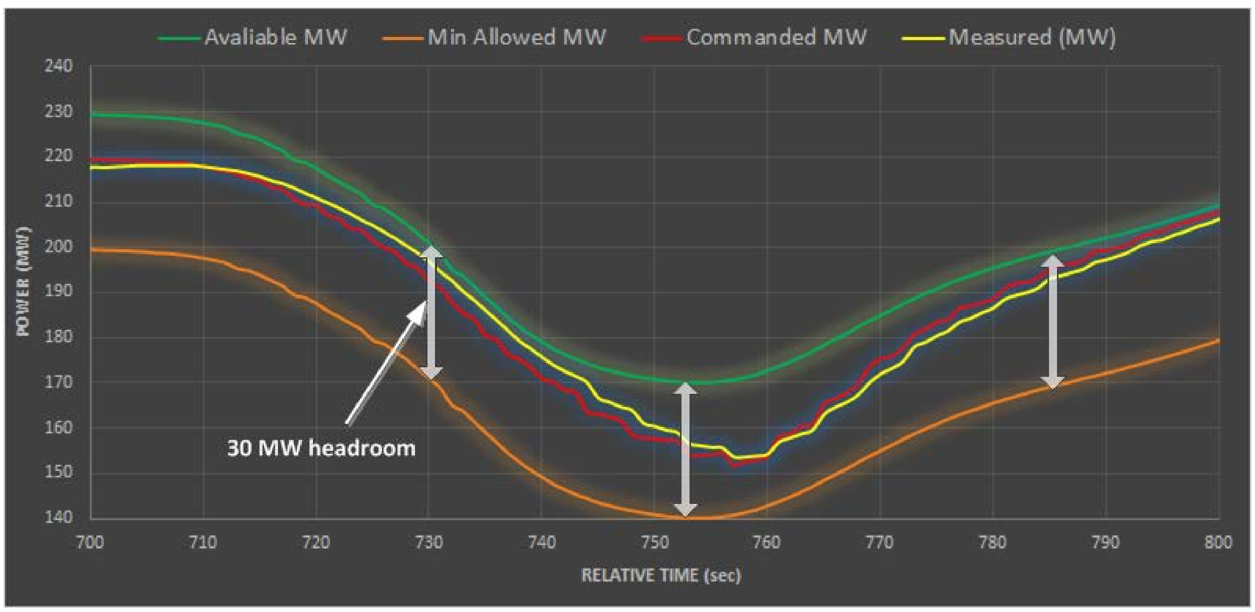


Figure 18. Afternoon AGC test (2:54 p.m.–3:16 p.m.) magnification. ***Illustration from NREL***

The performance results for all three AGC tests are consolidated in an X-Y plot (Figure 19) that shows the linear correlation between the commanded and measured plant power for the morning, midday, and afternoon testing periods (red, blue, and green dots, respectively). The slope and offset of the linear regression for each test indicate low scatter and good linearity. In addition, the R-squared values of the correlation coefficients for each time period also show a high degree of correlation between the set point and measured plant power.

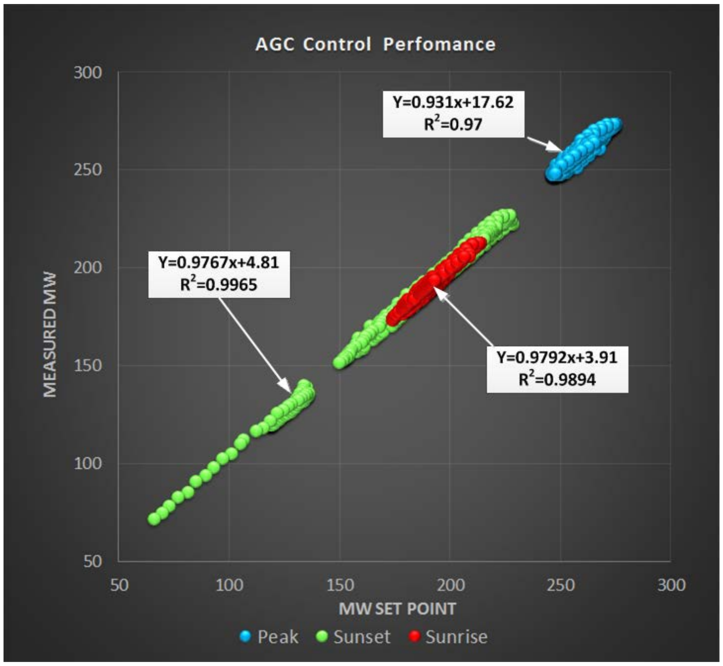


Figure 19. AGC performance for three time periods. ***Illustration from NREL***

The relative AGC control error as a percentage of installed plant capacity for all three AGC tests is shown in Figure 20 for a 20-minute time interval for comparison. Table 1 lists the mean, min/max, and standard deviation values of the AGC control error. The mean value of the AGC control error during the whole period of testing for all three data sets is very low (-0.013% of the plant's rated capacity), with standard deviation of error equal to 0.439%.

Figure 20. AGC control error for all three tests. ***Illustration from NREL***

Table 1. AGC Control Error Statistics

	Sunrise	Peak	Sunset	Total for the Period of Testing
Mean error (% of rated power)	0.02	0.0	-0.06	-0.01
Min error (% of rated power)	-1.16	-1.85	-2.1	-2.1
Max error (% of rated power)	1.25	2.35	2.12	2.35
Standard deviation (% of rated power)	0.31	0.47	0.51	0.44

The frequency distribution of the AGC control errors for all three periods of observation are shown in Figure 21 in logarithmic scale as a visual representation of the difference between the number of error magnitude occurrences for each test. These distribution shapes are not exactly symmetric, but they are still concentrated around the center with visible tails. Only a few AGC control errors with large magnitudes occurred during the periods of observation. Of course, longer testing (many days or weeks) under different cloud conditions will be required to collect sufficient statistics on AGC control accuracy. Yet even such a short testing opportunity allows some preliminary conclusions on the accuracy of AGC control by a large utility-scale power plant. These results also suggest that relatively small and short-term energy storage can help reduce the AGC error to essentially 0% by taking care of small control inaccuracies due to cloud impact and uncertainties of peak power calculation methods.

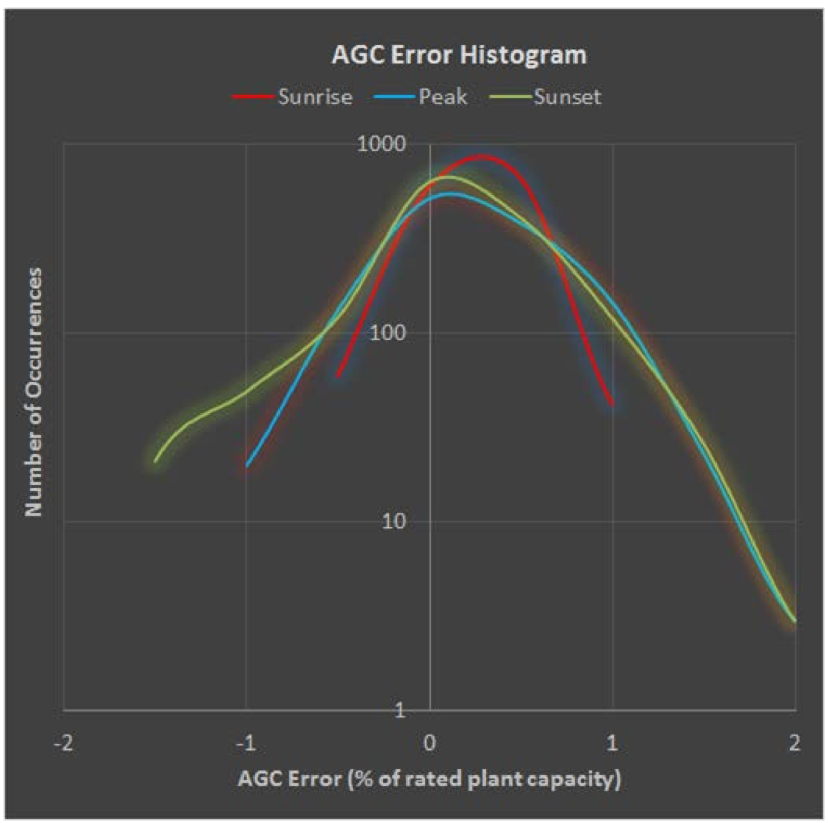


Figure 21. Distribution of AGC control error. ***Illustration from NREL***

Normally, CAISO measures the accuracy of a resource's response to energy management system (EMS) signals during 15-minute intervals by calculating the ratio between the sum of the total 4-second set point deviations and the sum of the AGC set points. The future CAISO resource instructed mileage percentage is also being calculated during 15-minute intervals. The plant's monitored delayed response time and the accuracy of the plant's response to the regulation set point changes were used to calculate its regulation accuracy values, which are shown in Table 2 for all three testing periods. Table 3 lists the typical regulation-up accuracies for CAISO's conventional generation for comparison. By comparing the PV plant testing results from Table 2 to the values for individual technologies in Table 3, a conclusion can be made that regulation accuracy by the PV plant is 24–30 points better than fast gas turbine technologies. The data from these tests will be used by CAISO in the future ancillary service market design to determine the resource-specific expected mileage to award regulation-up and regulation-down capacity.

Table 2. Measured Regulation Accuracy by 300-MW PV Plant

Time Frame	Measured Accuracy of Solar PV Plant
Sunrise	93.7%
Middle of the day	87.1%
Sunset	87.4%

Table 3. Typical Regulation-Up Accuracy of CAISO Conventional Generation

	Combined Cycle	Gas Turbine	Hydro	Limited Energy Battery Resource	Pump Storage Turbine	Steam Turbine
Regulation-Up Accuracy	46.88%	63.08%	46.67%	61.35%	45.31%	40%

4 Frequency Droop Control Tests

4.1 Rationale and Description of Frequency Droop Tests

The ability of a power system to maintain its electrical frequency within a safe range is crucial for stability and reliability. Frequency response is a measure of an interconnection's ability to stabilize the frequency immediately following the sudden loss of generation or load. An interconnected power system must have adequate resources to respond to a variety of contingency events to ensure rapid restoration of the balance between generation and load. On January 16, 2014, FERC approved Reliability Standard BAL-003-1 ("Frequency Response and Frequency Bias Setting"), submitted by NERC. By approving this standard, NERC created a new obligation for balancing authorities, including CAISO, to demonstrate that they have sufficient frequency response to respond to disturbances resulting in the decline of system frequency. The purpose of this initiative is to ensure that CAISO provides sufficient primary frequency response to support system reliability while complying with the new NERC requirement [16]. NERC determines the Western Interconnection's frequency response obligation (IFRO) based on the largest potential generation loss of two Palo Verde generating units (2,626 MW). NERC created this standard to ensure that balancing authorities have sufficient frequency response capability on hand. Like all balancing authorities, CAISO must plan on having an adequate amount of frequency response capability available to respond to actual frequency events. CAISO's estimated frequency response obligation is 258 MW/0.1 Hz. Based on historical events during 2015–2016, CAISO recognized that its median frequency response rate might fall short of its frequency response obligation (FRO) by as much as 100 MW/0.1Hz [16]. From this perspective, the participation of curtailed PV power plants in CAISO's frequency response could help address this potential deficiency. The objective of the frequency response test conducted under this project was to demonstrate that the plant can provide a response in accordance with 5% and 3% droop settings through its governor-like control system.

The definition of implemented droop control for PV is the same as that for conventional generators:

$$\frac{1}{Droop} = \frac{\Delta P/P_{rated}}{\Delta f/60Hz} \tag{5}$$

The plant's rated active power (300 MW) is used in Eq. 5 for the droop setting calculations. For the purposes of the droop test, the plant was set to operate at a curtailed power level that was 10% lower than the available estimated peak power. The PPC was programmed to change the plant's power output in accordance with a symmetric droop characteristic, shown in Figure 22 at both the 5% and 3% droop values. The upper limit of the droop curve was the available plant power, and the lower limit was at a level that was 20% below the then-available peak power. The implemented droop curve also had a ±36-mHz frequency deadband.

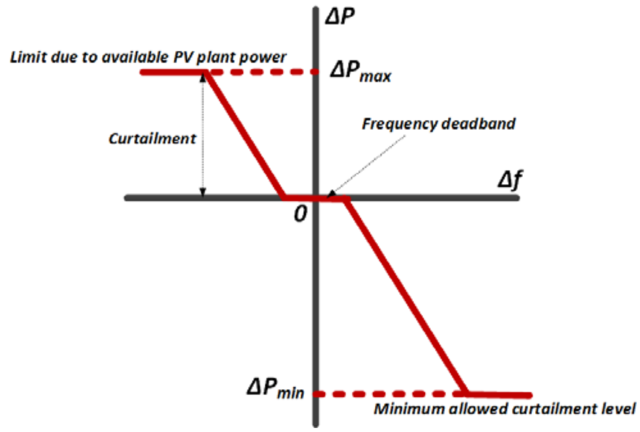


Figure 22. Frequency droop characteristic. ***Illustration from NREL***

The frequency droop capability of the plant was tested using the actual underfrequency and overfrequency events in the Western Interconnection measured by NREL in Colorado (Figure 23 and Figure 24, respectively).

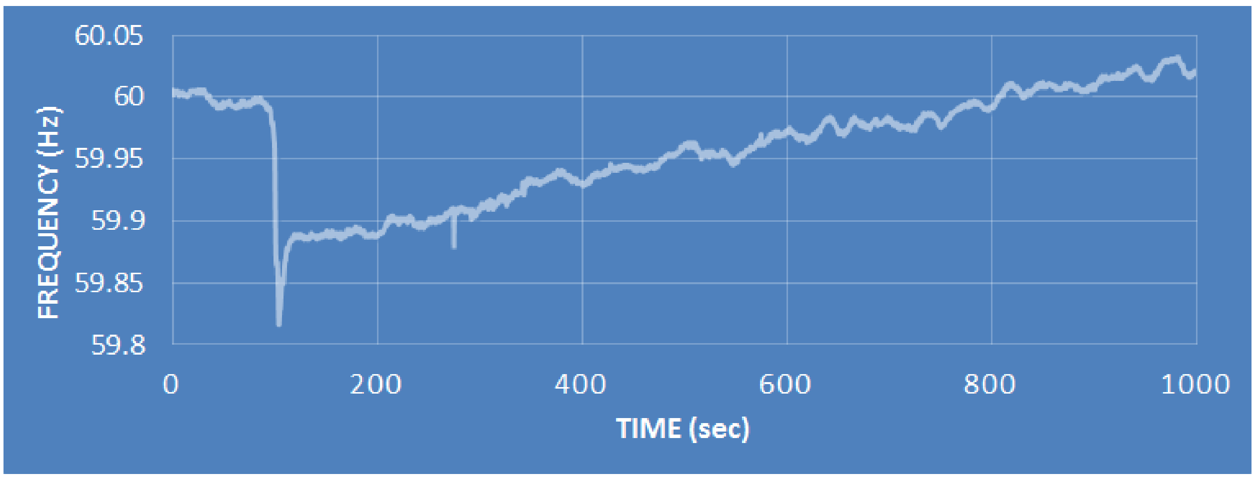


Figure 23. Underfrequency event. ***Illustration from NREL***

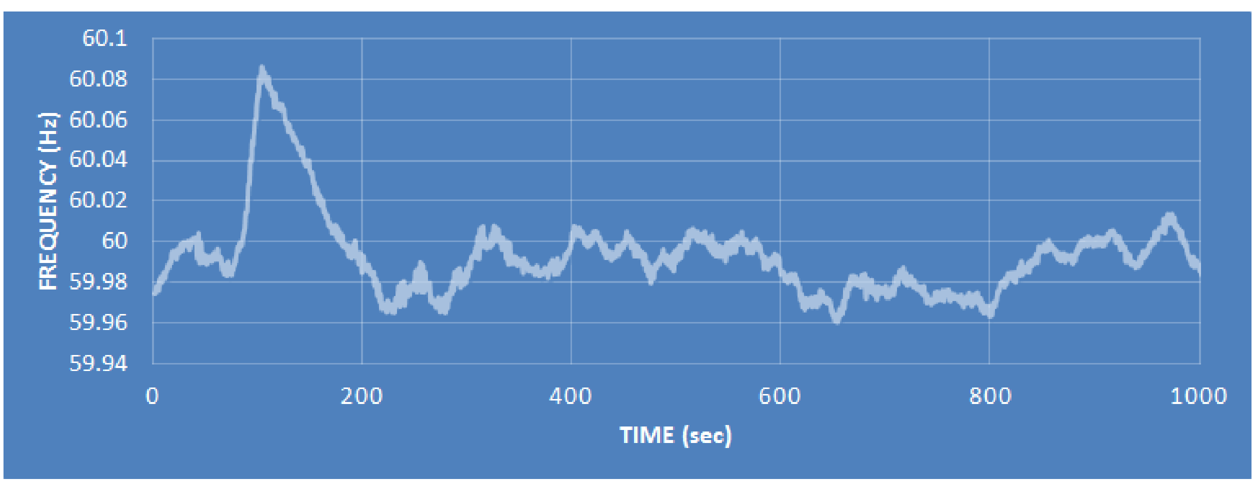


Figure 24. Overfrequency event. ***Illustration from NREL***

The frequency event time series shown in Figure 23 and Figure 24 were provided to the PPC, so the plant can demonstrate a frequency response as if it were exposed to a real frequency event measured at the plant's POI. This is the common method for testing the frequency response of inverter-coupled generation because waiting for a real frequency event to occur in the power system may be time consuming because large contingency events do not happen very often (two to three times per month for the Western Interconnection). The active power ramp-rate limit in the PPC was set at 600 MW/min (10 MW/sec) during the droop control tests.

4.2 Droop Test Results

The 5% and 3% frequency droop tests on the 300-MW PV power plant were conducted on August 24, 2016. For this purpose, the First Solar team remotely set the PPC into droop control mode in accordance with the control method shown in Figure 22, with 5% and 3% droop values and 10% power curtailment. The minimum allowed power level for down-regulation was set to 20% below the available peak power for all droop tests (to minimize plant revenue losses).

4.2.1 Droop Tests during Underfrequency Event

The results of one 3% droop test during the morning on August 24, 2016, are shown in Figure 25. The plant's active power response in MW to the underfrequency event was measured by the phasor measurement units at the plant's POI. The calculated active power time series show that the plant increased its power output during the initial grid frequency decline, and then gradually returned to its original pretest level as frequency returned to its normal prefault level. The droop response of the plant can be observed on the X-Y plot shown in Figure 26, wherein a linear dependence between frequency and measured power can be observed once the frequency deviation exceeded the deadband.

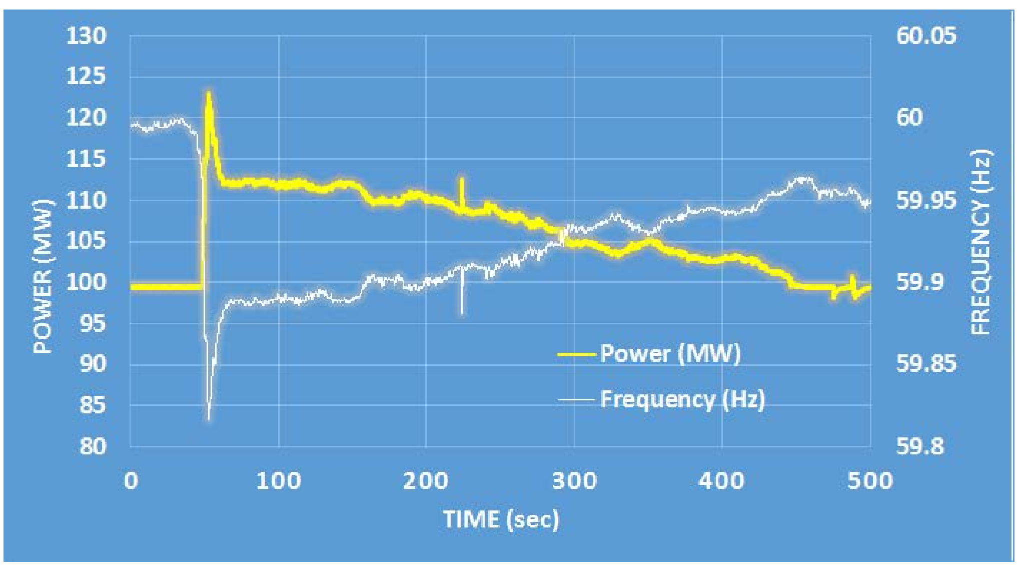


Figure 25. Example of the plant's response to an underfrequency event (3% droop test during sunrise). ***Illustration from NREL***

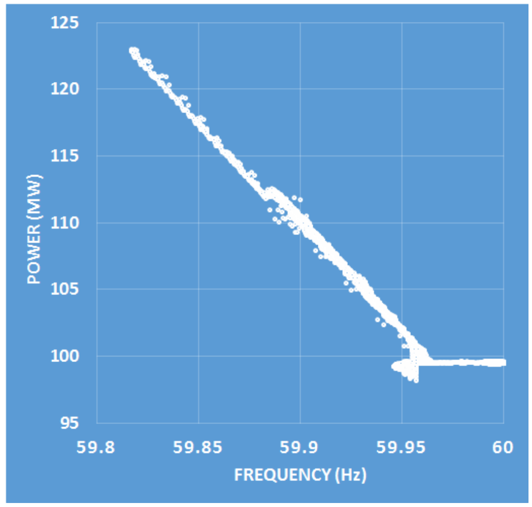


Figure 26. Measured droop characteristic for an underfrequency event (3% droop test during sunrise)

Similarly, 3% and 5% droop tests were conducted during midday (peak solar production period) and during the afternoon. Example test results for these periods are shown in Figure 27 (a and b) and Figure 28. Some nonlinearity in the plant's response was observed during these tests when the frequency deviation exceeded 120 mHz from its prefault level, causing some mismatch between the expected and actual droop response. Such nonlinearity was not observed during the morning droop tests when the solar resource was increasing steadily during the test under clear-sky conditions. One reason for this mismatch could be the decreasing solar resource and increased resource variability due to cloud conditions during the afternoon. It is expected that further fine-tuning the PPC control parameters can help mitigating such nonlinearity, and the First Solar team will address this issue in the future.

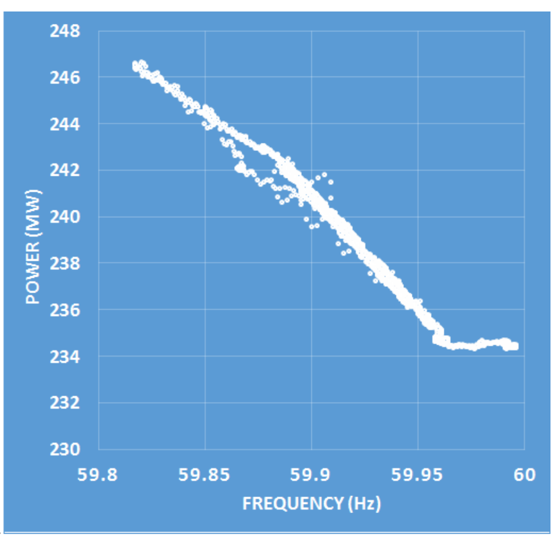
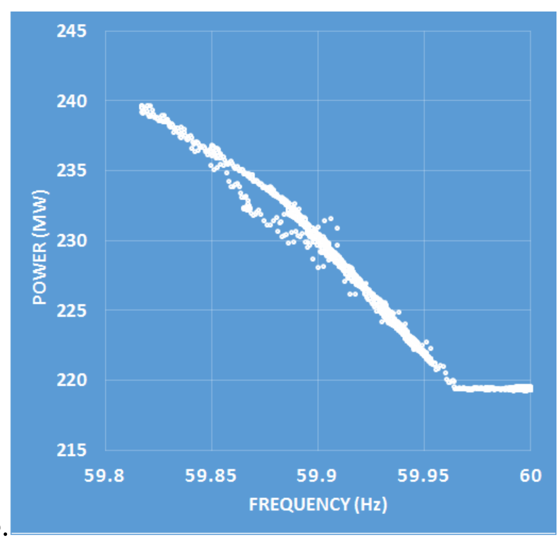
a.  b. 

Figure 27. Measured droop characteristics for an underfrequency event: (a) 5% droop test and (b) 3% droop test during midday. ***Illustration from NREL***

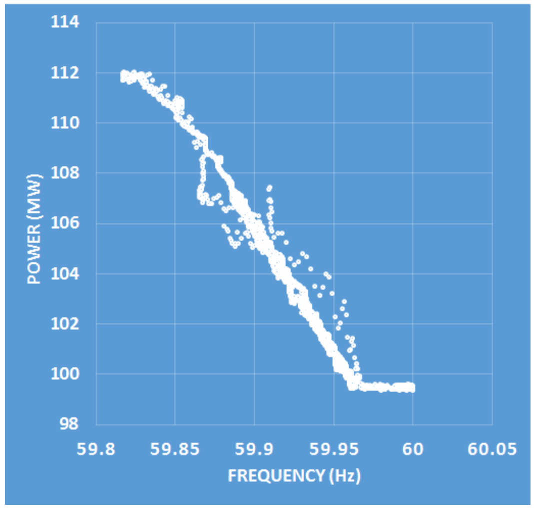


Figure 28. Measured droop characteristics for an underfrequency event (5% droop test during sunset). *Illustration from NREL*

Results of the individual droop tests are shown in greater detail in figures 29–33. The first plot in each figure shows the data points scattered around the calculated target droop characteristic (figures29[a]–33[a]). In these X-Y plots, the X-axis represents the frequency deviation, Δf (or change in frequency), from its prefault value, calculated as:

$$\Delta f = f_{grid} - 60Hz \tag{6}$$

where f_{grid} is the value of grid frequency from the event time series.

The Y-axis represents the plant's active power response, $\Delta P_{measured}$ (or change in the plant's active power output), calculated as:

$$\Delta P_{measured} = P_{actual} - P_{max.estimated} \tag{7}$$

where P_{actual} is the measured plant's active power at the POI, and $P_{max.estimated}$ is the estimated peak power for a given level of solar resource.

The calculated plant response, $\Delta P_{calculated}$ (or target response), for a given droop value can be calculated as (frequency deadband is not included in this equation, but it is added in the control logic):

$$\Delta P_{calculated} = \frac{\Delta f}{60Hz} \cdot \frac{1}{Droop} \cdot P_{nom} \tag{8}$$

where $P_{nom} = 300\ MW$ is the plant's nameplate capacity.

The droop control error is then calculated as a difference between the calculated target and actual plant response for any given droop setting:

$$Error = \Delta P_{calculated} - \Delta P_{measured} \tag{9}$$

The frequency distribution of the control error data for each droop test along with the error statistics data are shown in figures29(b)–33(b). The detailed comparison of these test results concluded that the PV plant demonstrated a satisfactory droop performance during the underfrequency events for the morning, midday, and afternoon time frames. Some nonlinearities in the response can be further improved by fine-tuning the controller parameters. The observed scatter around the target response is due to the short-term solar resource variability, and it can be mitigated if such a response is generated by a number of PV plants within a larger geographical footprint.

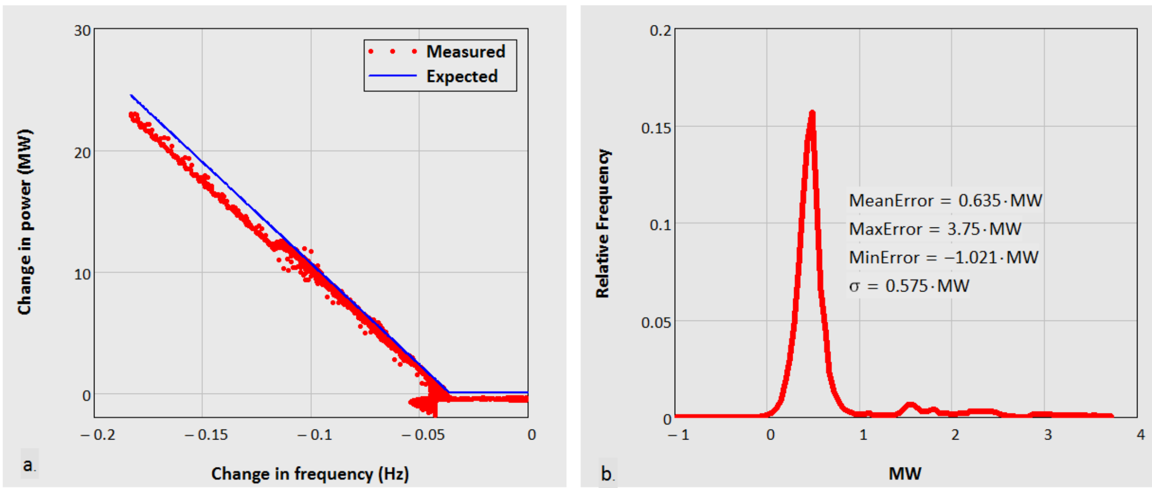


Figure 29. (a) Results and (b) control error during the sunrise 3% droop test for an underfrequency event. *Illustration from NREL*

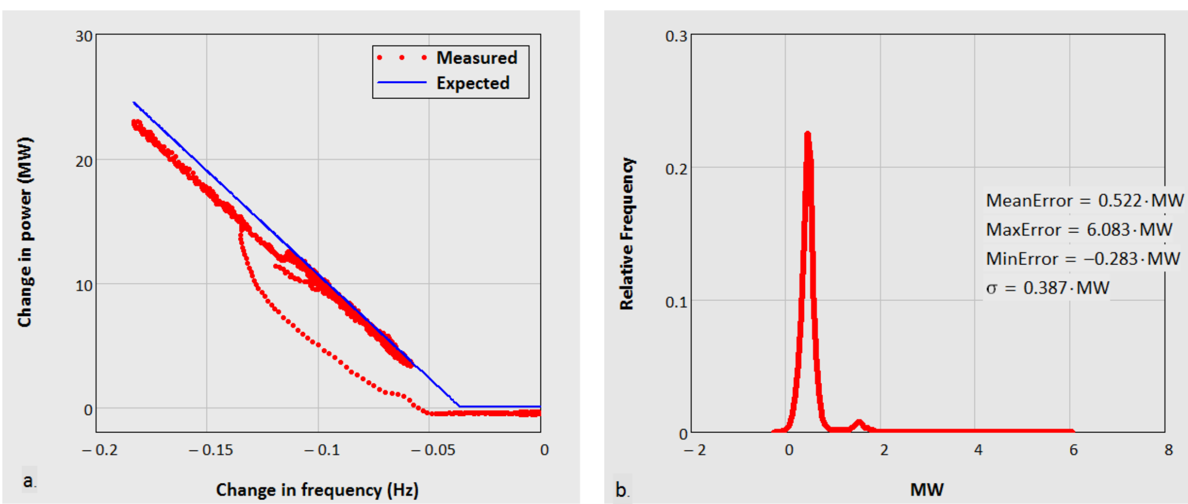


Figure 30. (a) Results and (b) control error during a second sunrise 3% droop test for an underfrequency event. *Illustration from NREL*

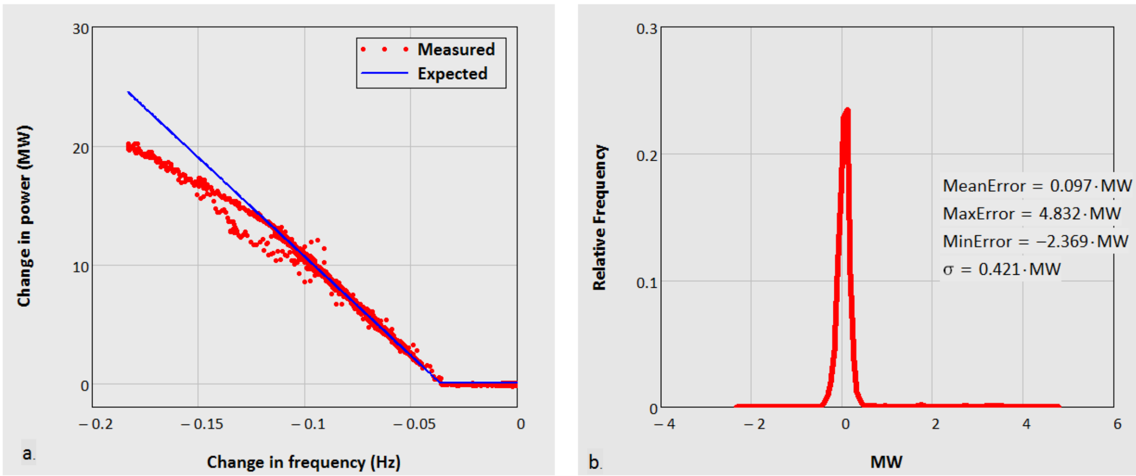


Figure 31. (a) Results and (b) control error during the midday 3% droop test for an underfrequency event. *Illustration from NREL*

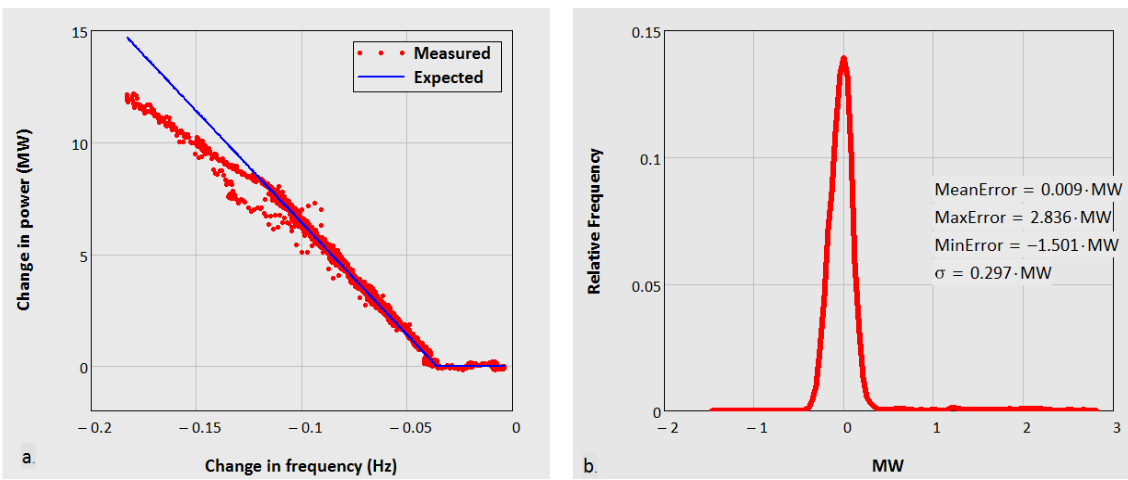


Figure 32. (a) Results and (b) control error during the midday 5% droop test for an underfrequency event. *Illustration from NREL*

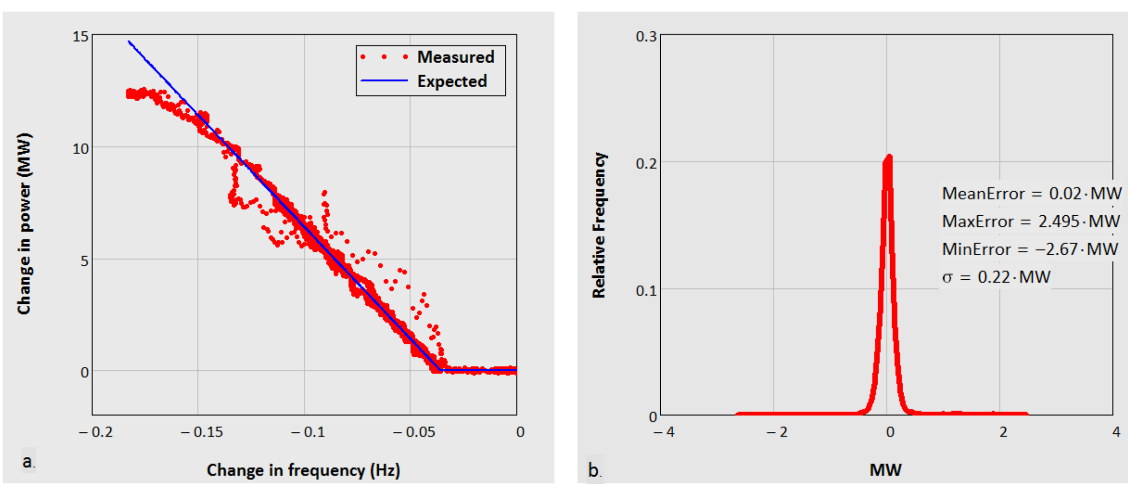


Figure 33. (a) Results and (b) control error during the sunset 5% droop test for an underfrequency event. *Illustration from NREL*

Table 4 and Table 5 show the control error statistics for the underfrequency droop tests in absolute MW units and percentage of plant capacity, respectively. Despite observed nonlinearities and scatter, the mean control error is very small, ranging from 0%–0.21% of the plant's rated capacity. The standard deviation control error is also small (0.07%–0.19% of rated capacity). The largest measured positive and negative error values are 2.03% and -0.89% of the plant's rated capacity. Figure 34 shows the consolidated data for many up-regulation tests for comparison.

Table 4. Droop Control Error Statistics (Absolute Values in MW)

Test Type	Mean Error (MW)	Max + Error (MW)	Max – Error (MW)	Standard Deviation (MW)
3% droop, sunrise	0.63	3.75	-1.02	0.57
3% droop, sunrise	0.52	6.08	-0.28	0.39
3% droop, midday	0.1	4.83	-2.37	0.42
5% droop, midday	0.0	2.84	-1.5	0.3
5% droop, sunset	0.02	2.5	-2.67	0.22

Table 5. Droop Control Error Statistics (Percentage of Plant Rated Capacity)

Test Type	Mean Error (%)	Max + Error (%)	Max – Error (%)	Standard Deviation (%)
3% droop, sunrise	0.21	1.25	-0.34	0.19
3% droop, sunrise	0.17	2.03	-0.09	0.13
3% droop, midday	0.03	1.61	-0.79	0.14
5% droop, midday	0.00	0.95	-0.5	0.1
5% droop, sunset	0.01	0.83	-0.89	0.07

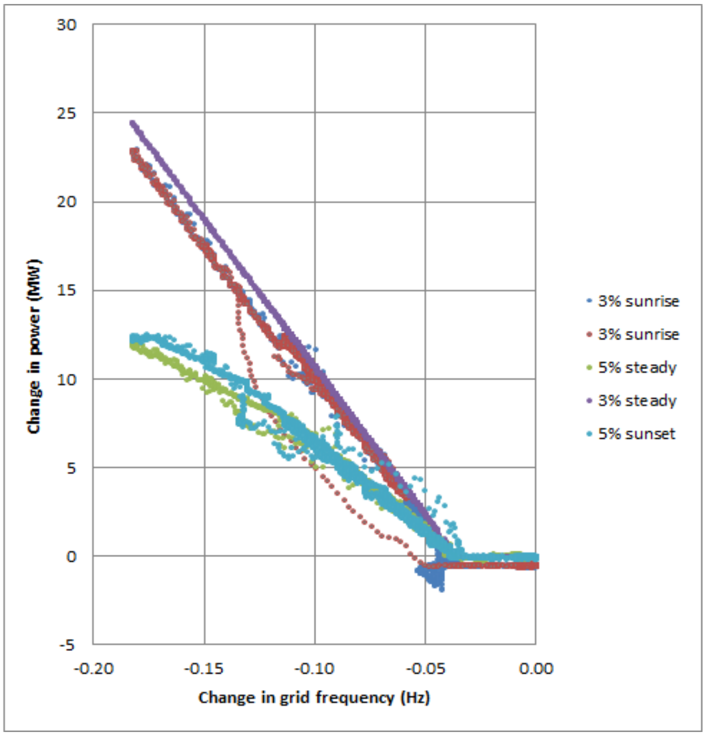


Figure 34. Consolidated underfrequency droop test results. ***Illustration from NREL***

4.2.2 Frequency Droop Tests during Overfrequency Event

Frequency droop tests for the overfrequency events were also conducted on August 24, 2016. The results of one 5% droop test on the morning on August 24, 2016, are shown in Figure 35. The plant's response to the overfrequency event was measured at the plant's POI. The calculated active power time series shows that the plant decreased its power output during the initial grid frequency increase, then gradually returned to its original pretest level as frequency returned to its normal prefault level. The droop response of the plant from several tests can be observed in the X-Y plots shown in Figure 36 (a and b) and Figure 37, wherein a linear dependence between frequency and measured power can be observed once the frequency deviation exceeded the deadband. The plant' demonstrated consistent and accurate down-regulation performance during all overfrequency droop tests.

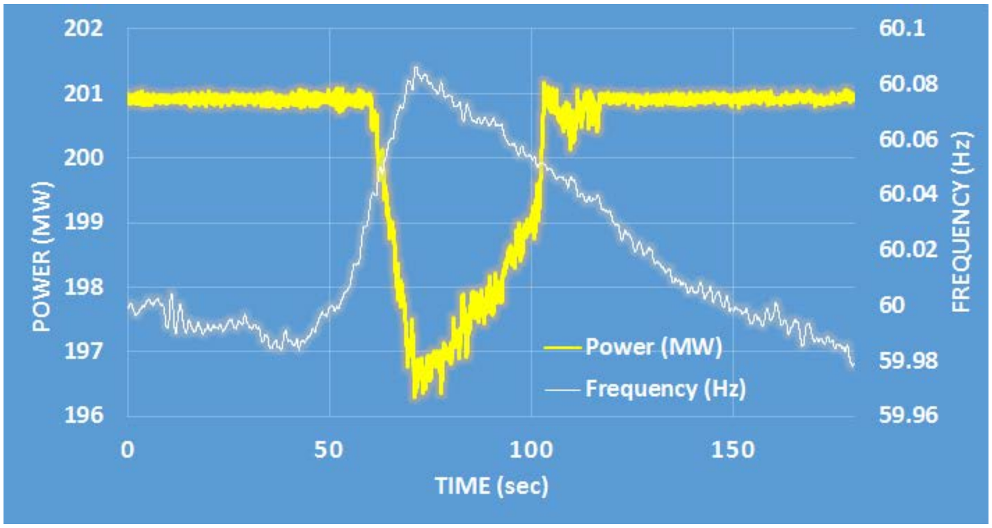


Figure 35. Example of the plant's response to an overfrequency event (5% droop test during sunrise). ***Illustration from NREL***

a. b.

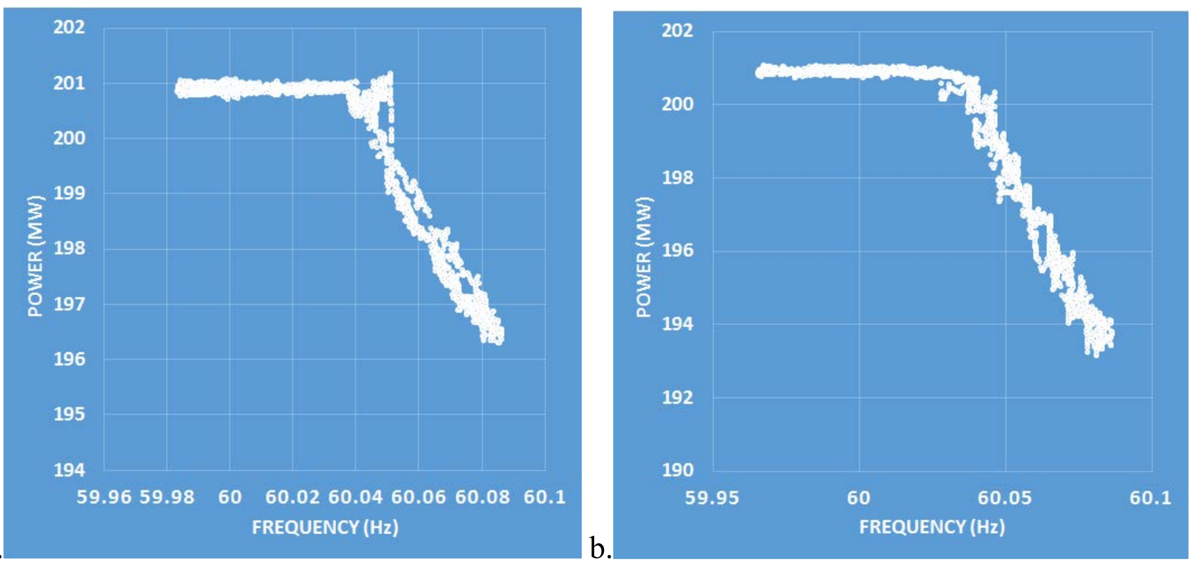


Figure 36. Measured droop characteristics for an overfrequency event: (a) 5% droop test and (b) 3% droop test during midday. ***Illustration from NREL***

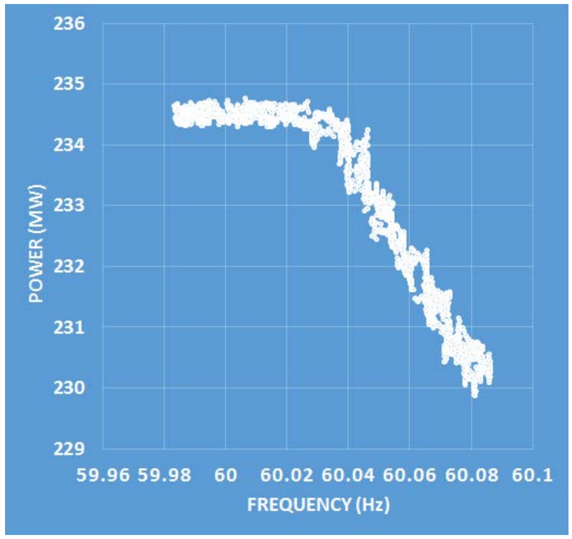


Figure 37. Measured droop characteristics for an overfrequency event (5% droop test during sunset). ***Illustration from NREL***

A PV plant must operate in curtailed mode to provide enough reserve for PFR response during underfrequency conditions. During normal operating conditions with near-nominal system frequency, the control is set to provide a specified margin by generating less power than is available from the plant. The reserve available (i.e., headroom) is the available power curtailed, which is shown as the reserve between the operational point and P_0 in Figure 38. If required by reliability consideration, a nonsymmetric droop curve is possible with solar PV power, depending on system needs, as shown in Figure 38. More aggressive droops (e.g., 1% or 2%) can be implemented for overfrequency regulation because PV plants are able to provide very fast curtailment. This type of nonsymmetric droop response will likely be demonstrated in future stages of this testing project.

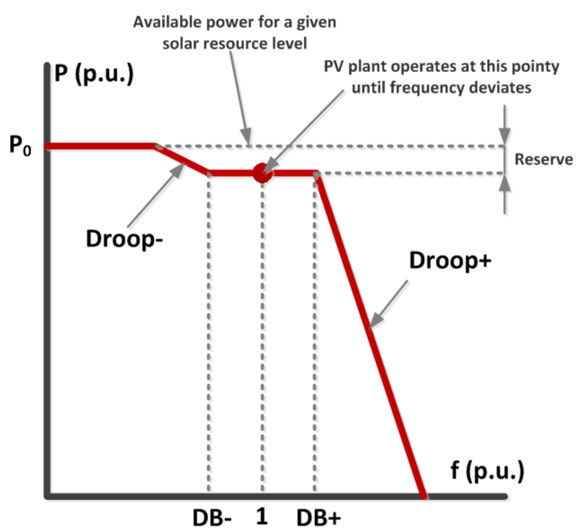


Figure 38. Concept of nonsymmetric droop characteristic for PV plants. ***Illustration from NREL***

5 Reactive Power and Voltage Control Tests

5.1 Rationale and Description of Reactive Power Tests

Voltage on the North American bulk system is normally regulated by generator operators, which are typically provided with voltage schedules by transmission operators [17]. The growing level of penetration of variable wind and solar generation has led to the need for them to contribute to power system voltage and reactive regulation because in the past the bulk system voltage regulation was provided almost exclusively by synchronous generators. According to FERC's LGIA [18], the generally accepted power factor requirement of a large generator is ±0.95. In conventional power plants with synchronous generators, the reactive power range is normally defined as dynamic, so synchronous generators need to continuously adjust their reactive power production or absorption within a power factor range of ±0.95. For PV power plants, the reactive power requirements are not well defined. FERC Order 661-A [19] is applicable to wind generators but sometimes applied to PV plants as well. It also requires a power factor range of ±0.95 measured at the POI and requires that the plant provide sufficient dynamic voltage support to ensure safety and reliability (the requirement for dynamic voltage support is normally determined during interconnection studies). Utility-scale wind power plants are designed to meet the ±0.95 power factor requirements; however, the common practice in the PV industry is to configure PV inverters to operate at unity power factor. It is expected that similar interconnection requirements for power factor range and low-voltage ride-through will be formulated for PV in the near future. To meet this requirement, PV inverters need to have MVA ratings large enough to handle full active and reactive current.

In its recent Order 827, FERC issued a final rule requiring all newly interconnecting nonsynchronous generators, including wind generators, to design their facilities to be capable of providing reactive power [20]. The generating facilities need to be capable of maintaining a composite power delivery at continuous rated power output at the high side of the generation substation at ±0.95 power factors.

Conventional synchronous generators of power plants have reactive power capability that is typically described as a "D curve," as shown in Figure 39. The reactive power capability of conventional power plants is limited by many factors, including their maximum and minimum load capability, thermal limitations due to rotor and stator current-carrying capacities, and stability limits. The ability to provide reactive power at zero loads is usually not possible with many large plant designs. Only some generators are designed to operate as synchronous condensers with zero actives loads. The reactive power capability of a PV inverter is determined by its current limit only. With proper MW and MVA rating, the PV inverter should be able to operate at full current with reactive power capability, similar to the one shown in Figure 39. In general, for the same MVA rating, a PV power plant is expected to have much superior reactive power capability than a conventional synchronous generator-based plant, as indicated notionally in Figure 39. In principle, PV inverters can provide reactive power support at zero power, similar to a STATCOM (see definition in [21]); however, this functionality is not standard because PV inverters are disconnected from the grid at night.

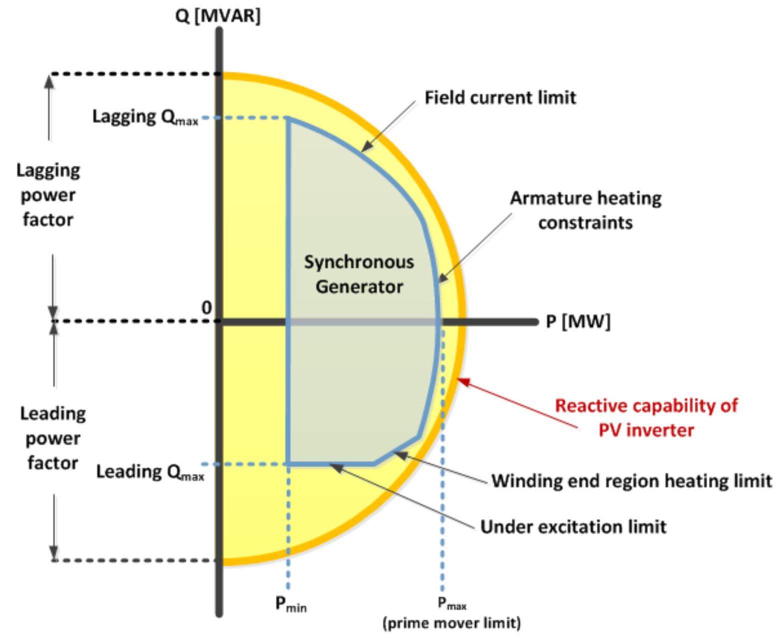


Figure 39. Comparison of reactive power capability for a synchronous generator and PV inverter of the same MVA and MW ratings. ***Illustration from NREL***

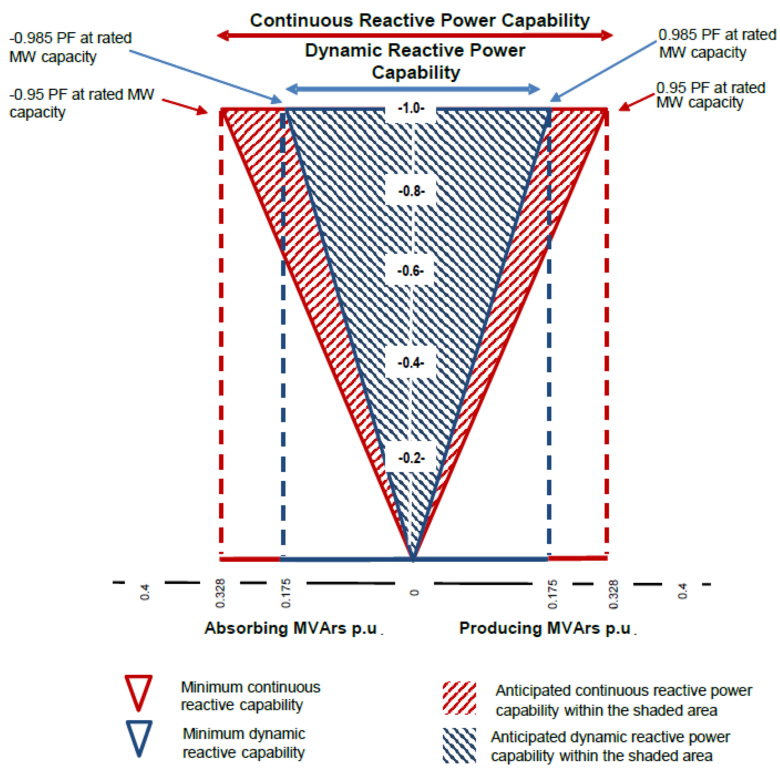


Figure 40. Proposed reactive power capability for asynchronous resources. ***Illustration from CAISO***

In its proposed reactive power capability characteristic for asynchronous generation (Figure 40), CAISO defined the requirements for dynamic and continuous reactive power performance by such resources [21]. The red vertical lines shown in Figure 40 represent the expected reactive capability of the asynchronous generating plant at the high side of the generator step-up bank. At all levels of real power output, the plant is expected to produce or absorb reactive power equivalent to approximately 33% of the plant's actual real power output. For example, at the plant's maximum 300-MW real power capability, the expected dynamic reactive capability should be 100 MVARS lagging or 100 MVARS leading. Also, at 50% real power output, the expected reactive capability should be 50 MVARS lagging or 50 MVARS leading, and at zero MW output, the expected reactive output should be zero. Figure 41 shows the expected reactive capability of the 300-MW PV plant under test if it must comply with the proposed CAISO requirement for asynchronous generating facilities at the POI. The PV plant is supposed to absorb or produce 100 MVAR of reactive power when operating at full MW capacity at a power factor of -0.95 or +0.95, respectively.

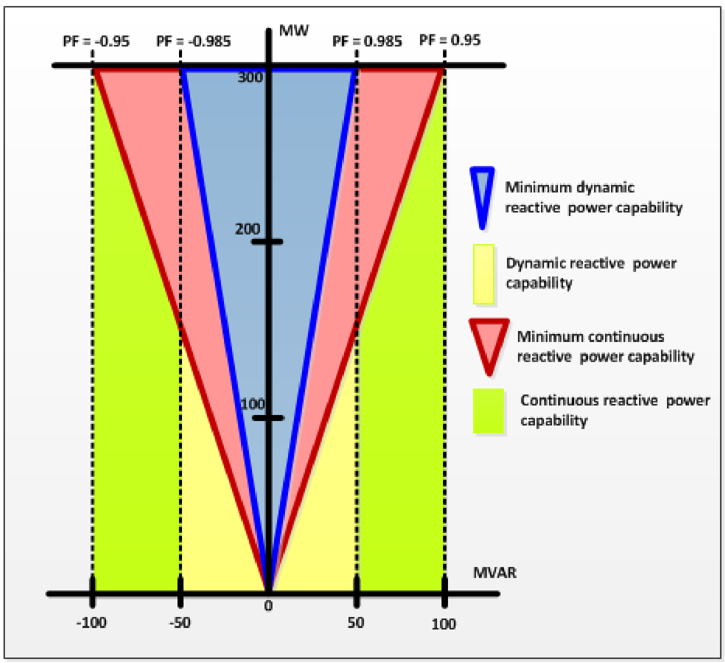


Figure 41. CAISO's proposed reactive capability applied to the 300-MW PV plant under testing.
Illustration from NREL

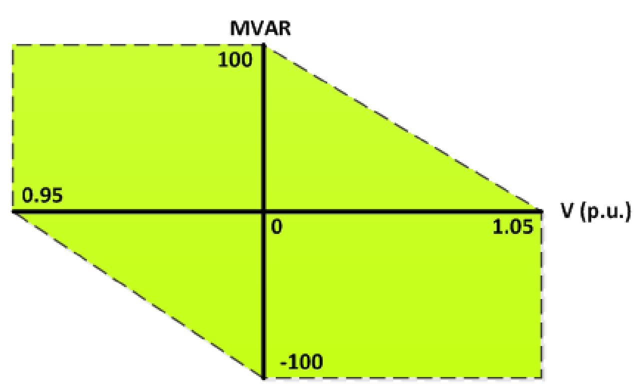


Figure 42. The plant's reactive power capability at different voltage levels at full MW output.
Illustration from NREL

The voltage at the POI may change because of grid conditions, but the plant must maintain its reactive power capability. For this purpose, CAISO's proposed reactive power requirement specifies a voltage operating window for the asynchronous generating facility to provide reactive power at 0.95 lagging power factor when voltage levels are between 0.95–1 p.u. at the POI. Likewise, it should be able to absorb reactive power at 0.95 leading power factor when voltage levels are between 1–1.05 p.u. The proposed capability at different voltage levels applied to the 300-MW PV plant at its full production level is shown in Figure 42.

CAISO proposed adopting a uniform requirement of asynchronous inverter-coupled resources to provide reactive power capability and voltage regulation, as shown in Figure 40 [21]. According to CAISO's draft proposal on reactive power and financial compensation, the asynchronous generating facility shall have dynamic and continuous reactive capability for power factor ranges of ±0.985 and ±0.95, respectively. Through its initiative, CAISO has explored mechanisms to compensate resources for the capability and provision of reactive power. In some regions transmission providers make payments for reactive power capability, but not all. These regions conclude that requiring the capability for this operation is a good utility practice and a necessary condition for conducting normal business [21], [22].

The primary objective of the reactive power test was to demonstrate the capability of the PV plant to operate in the voltage regulation mode within the power factor range of 0.95 leading/lagging. The plant controller maintained the specified voltage set point at the high side of the generator step-up bank by regulating the reactive power produced by the inverters.

The tests were conducted at three different real power output levels: (1) maximum production during the middle of the day, (2) during sunset when the plant is at approximately 50% of its maximum capability, and (3) during sunset when the plant is close to zero production. Measurements were conducted to verify the plant's capability to absorb and produce reactive power in accordance with Figure 40, within a range of ±100 MVAR during various levels of real power output.

- The plant was first tested at its maximum real power output for a given irradiance level. At maximum real power output, the plant must demonstrate that it can produce approximately 33% of real output as dynamic reactive. Similarly, at maximum real power output, the plant must demonstrate that it can absorb approximately 33% of its real power output as reactive output.
- During sunset, as solar production drops off to approximately 50% of the resource's maximum capability, the plant must demonstrate that it can produce and absorb approximately 33% of its real power output as dynamic reactive output.
- During sunset, as the plant production approaches zero MW, the plant must demonstrate that it can produce and absorb approximately 33% of its real power output as dynamic reactive output.

5.2 Results of Reactive Capability Power Tests

The plant's reactive power capability was tested at two different power levels on August 23, 2016, and August 24, 2016. First, the plant's reactive power capability was measured during a number of tests when the plant was producing high levels of active power (250 MW and more).

Then the reactive power capability was measured at extremely low levels of MW production (less than 5 MW). The results of both tests are consolidated in a graph showing MVAR compared to MW, Figure 43, wherein the blue dots represent the data points measured by the plant's PMUs. The measurements are compared to the proposed CAISO reactive power requirement for asynchronous generation (yellow triangle), demonstrating that the plant meets the expected reactive power capability. In addition, the plant is capable of producing and absorbing reactive power at close to zero power production. Another, more articulate view of the same test results is shown in a three-dimensional view in Figure 44, which combines measured MW, MVAR, and POI voltage, allowing for the positioning of measured data points with respect to the proposed CAISO requirements.

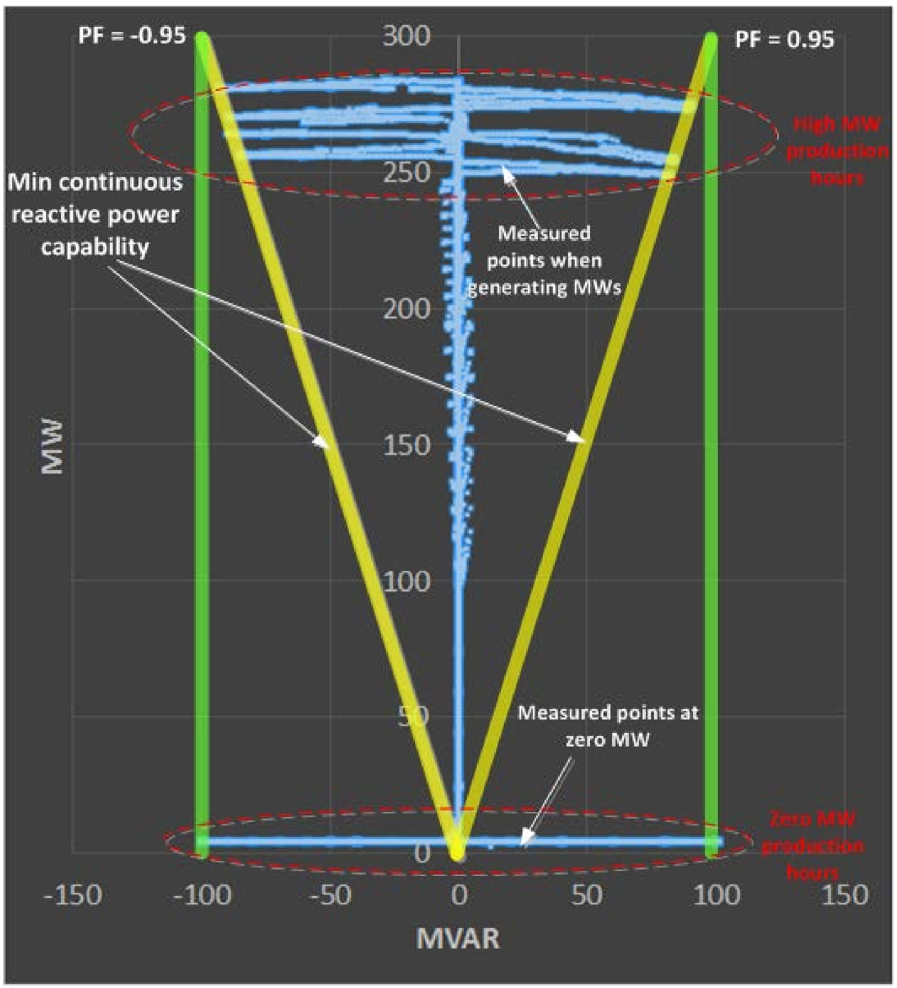


Figure 43. Measured reactive power capability at the POI. ***Illustration from NREL***

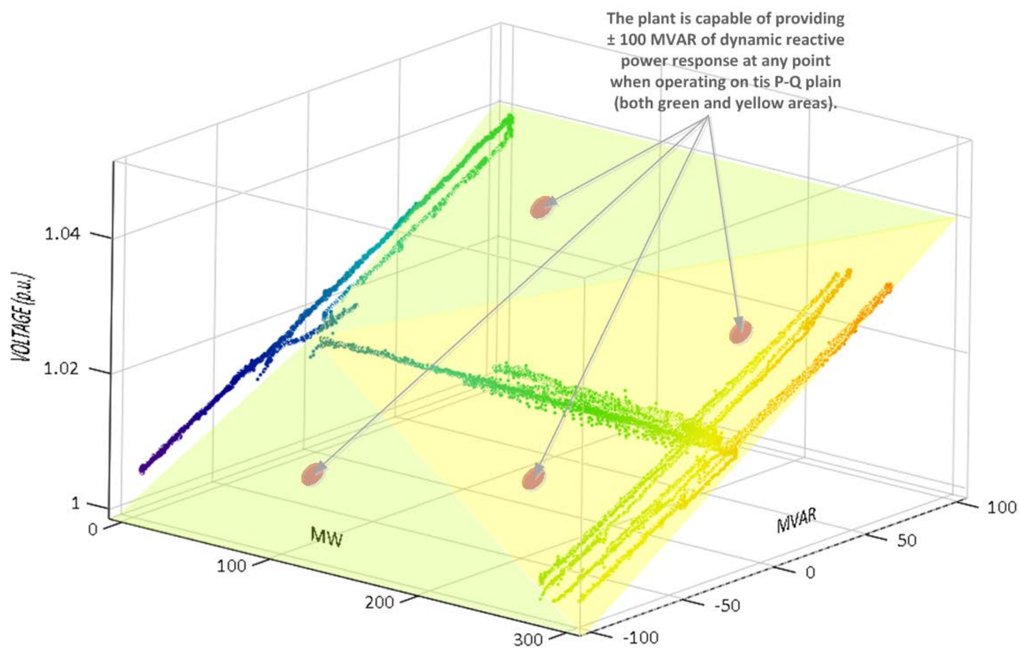


Figure 44. Measured reactive power capability and voltages at the POI. ***Illustration from NREL***

The voltage limit control test was conducted to verify the ability of the plant's control system capability to maintain a power factor target at the same time as maintaining voltage at the POI between the low and high limits (0.95 p.u. and 1.05 p.u., respectively), as shown in Figure 45. First, the plant was operating at nearly maximum active power generation in close to unity power factor control mode. An artificial POI voltage signal was provided to the plant controller to override the real measurement. While in power factor control mode, the control automatically switched to voltage limit mode to maintain the voltage within safe operating limits. Upon completion of the POI voltage increase or decrease with the power factor near the unity value, the control system switched back to power factor control mode.

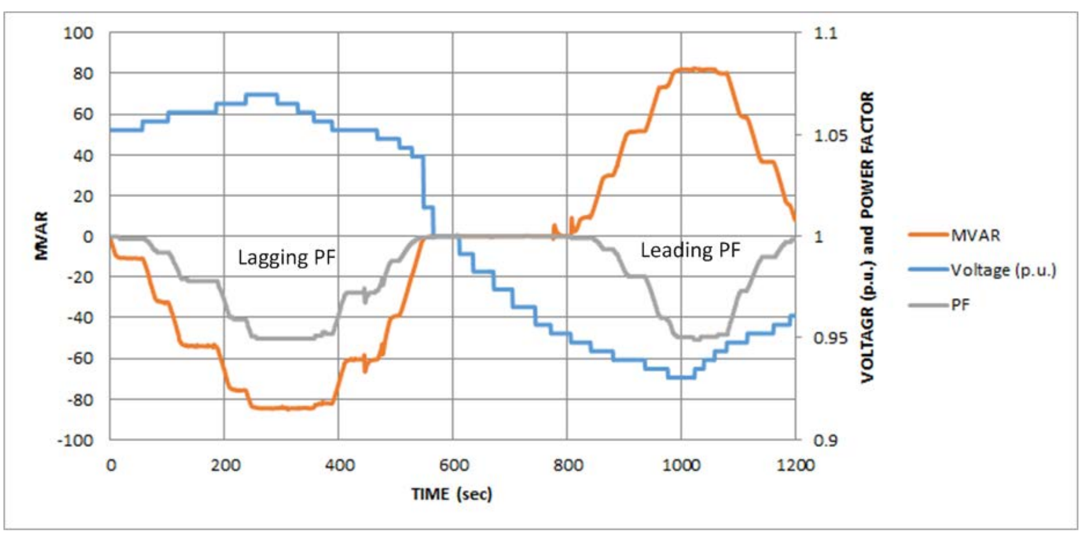


Figure 45. Results of the voltage limit control test. ***Illustration from NREL***

The same test is shown in Figure 46, wherein the measured reactive power is compared to the reactive power capability window from Figure 42. As shown in Figure 46, the plant is fully capable of operating within CAISO's proposed window at PF=±0.95.

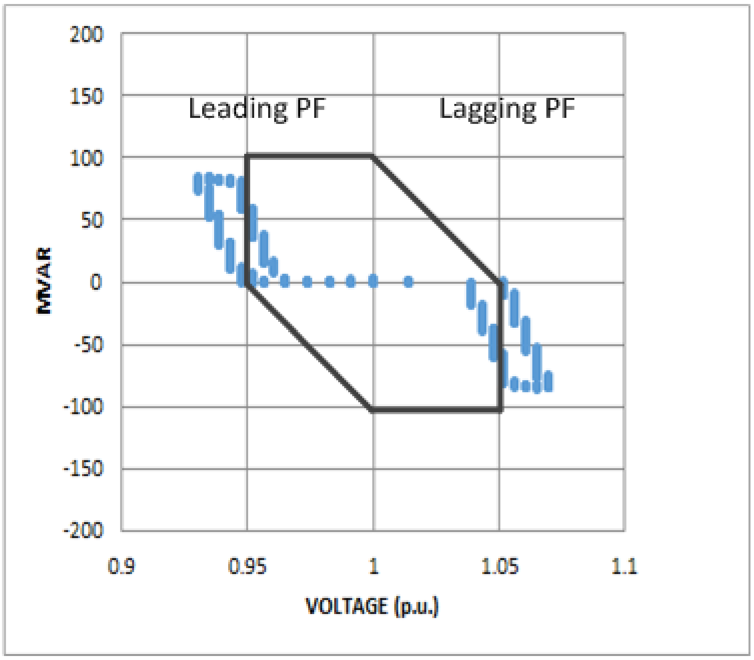


Figure 46. Voltage limit control test and reactive power capability. ***Illustration from NREL***

In addition, the plant was tested to demonstrate the control operation in power factor control mode and characterize control system response to changes in power factor set point. Reactive power ramp rates and power factor limits for this test were specified at ±100 MVAR/min and ±0.95, respectively. The results of the leading and lagging power factor control tests are shown in Figure 47. For both tests, the system was operating at nearly full power output. It reached its power factor targets with specified ramp rates in the PPC without any oscillation and stability issues.

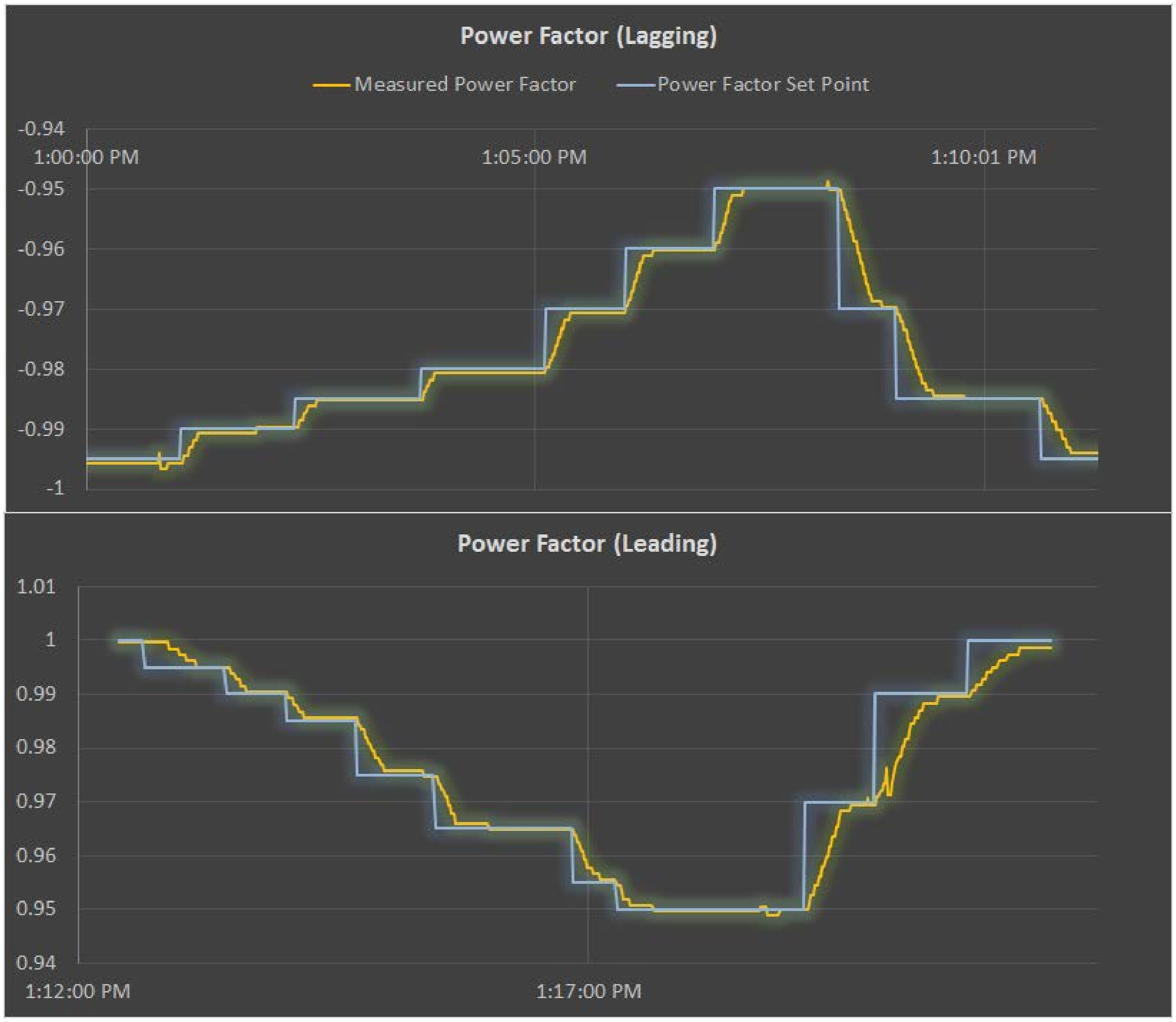


Figure 47. Lagging and leading power factor control tests. ***Illustration from First Solar***

Results of the reactive power set point control test are shown in Figure 48. This test was conducted during a period of high power generation, and it was intended to demonstrate the ability of the plant to maintain capacitive or inductive VARs at the POI. As shown in Figure 48, the plant was fully capable of following the reactive power set points with prescribed PPC reactive power ramp rates.

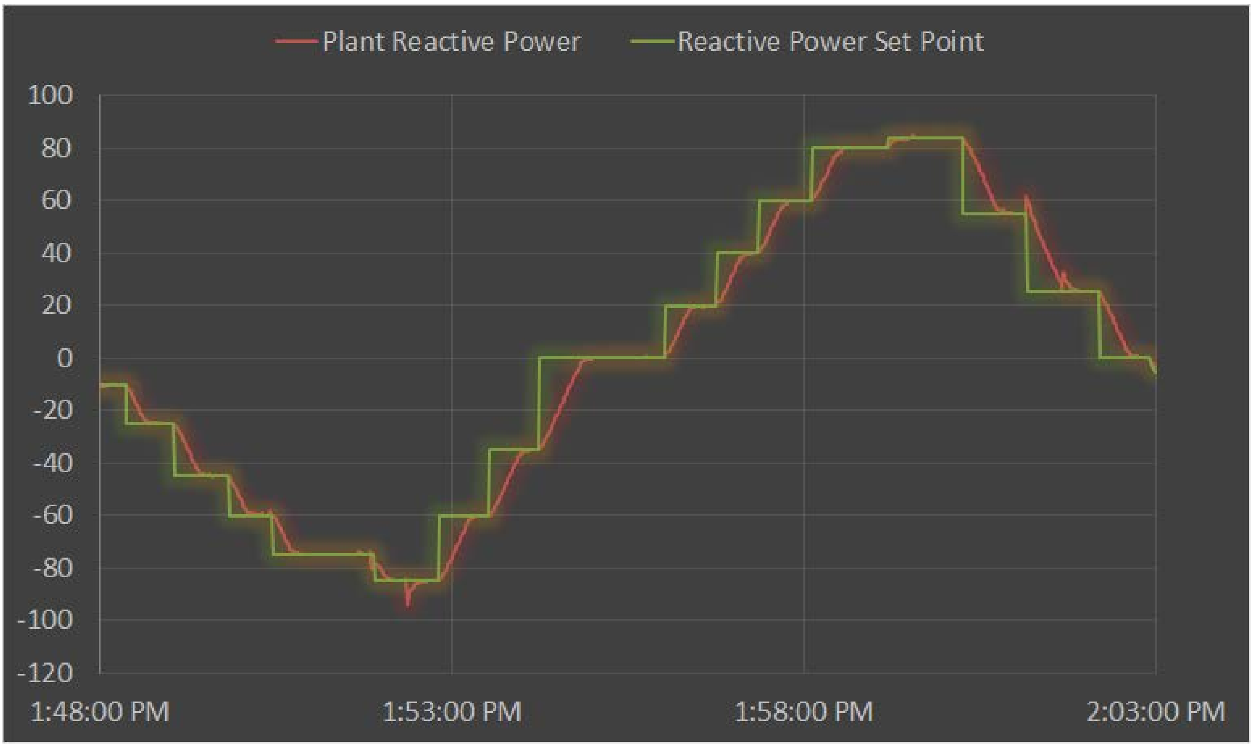


Figure 48. Reactive power control test. ***Illustration from First Solar***

5.3 Low-Generation Reactive Power Production Test

One way to increase the optimal utilization of PV power plants is to use their capability to provide VAR support to the grid during times when the solar resource is not available. For this purpose, the capability of the grid-tied inverters of the 300-MW PV plant to provide reactive power support during a period of no active power generation was demonstrated. Due to the limited time window available for this testing, it was not possible to test this capability during dark hours of the day; instead, the team decided to demonstrate the VAR support capability of the plant at nearly zero active power generation. The plant's active output was curtailed to nearly zero MW on August 24, 2017. Then the command was sent to the plant controller to ramp the reactive power to produce or absorb 100 MVAR. The results of these tests along with the measured POI voltage are shown in Figure 49. The plant was fully capable of producing or absorbing the commanded MVAR levels during the whole testing time. Note that the conditions of this test are only partially realistic because special control schemes are needed for grid-tied inverters to operate as STATCOM when a PV array is fully de-energized, and a certain amount of active power needs to be drawn from the grid to compensate for inverter losses. A more realistic test for nighttime VAR mode is planned for the near future.

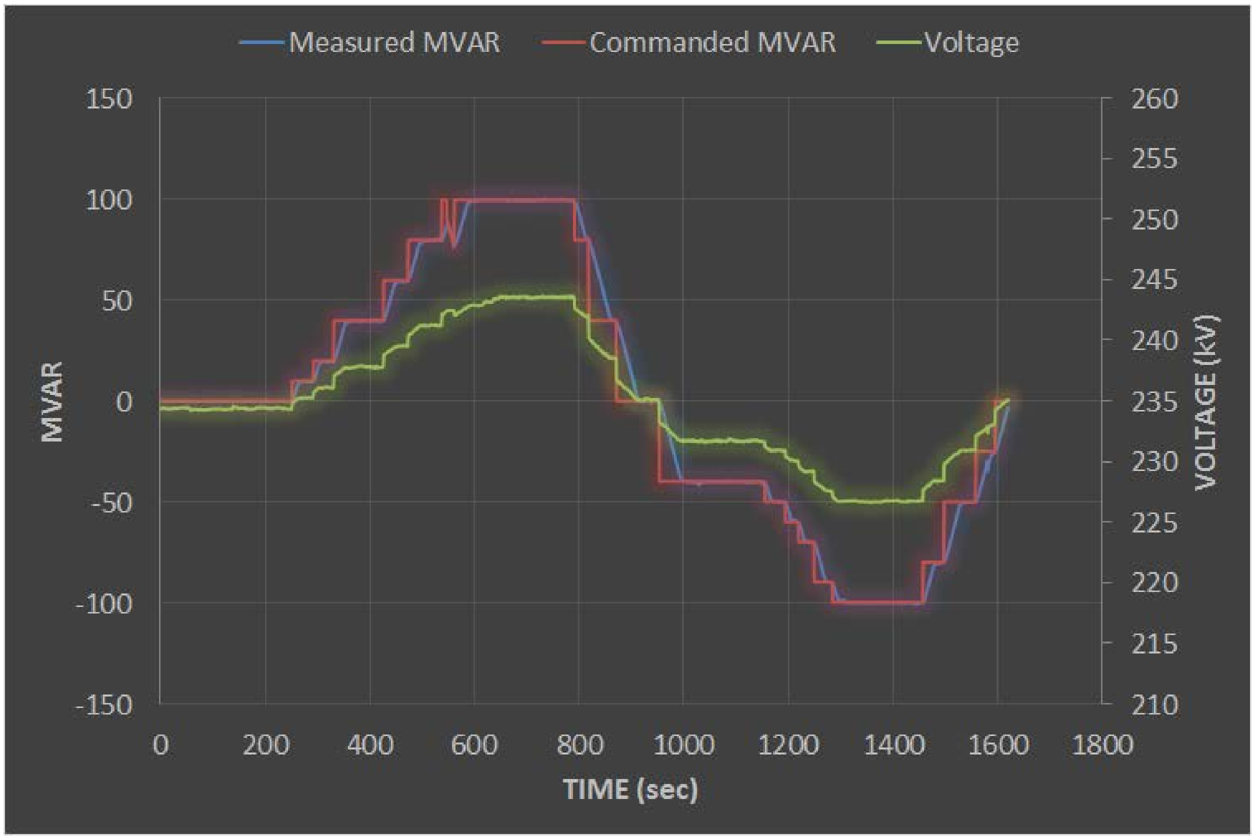


Figure 49. Reactive power production test at no active power (P≈0 MW). ***Illustration from NREL***

6 Additional Tests

The time series of the plant's measured active and reactive power and POI voltage for the whole period of testing on August 23, 2016, is shown in Figure 50. This summary combines results of several commissioning tests conducted between 10 a.m. and 3 p.m. on August 23, 2016. The tests conducted in the morning were related to various forms of APC, and the tests conducted in the afternoon involved various forms of reactive power, voltage, and power factor controls.

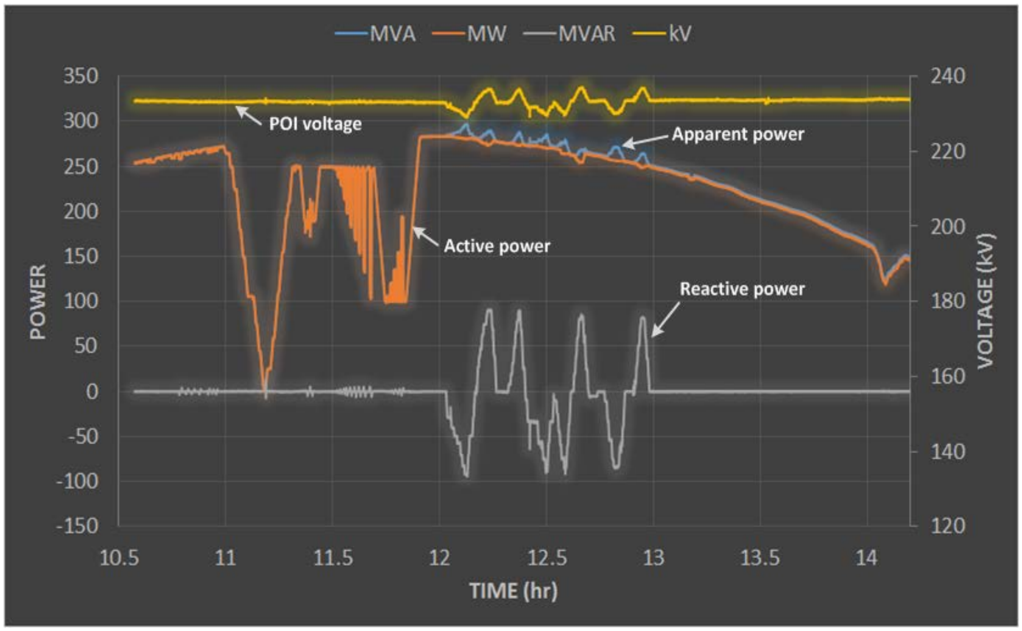


Figure 50. Plant output during the August 23, 2016, tests. ***Illustration from NREL***

The curtailment control test was conducted to demonstrate the plant's ability to limit its active power production and then restore it to any desired level. The results of the test are shown in Figure 51. The plant was accurately following the active power set point from a nearly full production level to the zero level with a preset ramp rate of 30 MW/min. The plant's active power was then commanded to increase in accordance with the increasing set points. Note that the reactive power of the plant remained unchanged at a level of nearly zero MVAR for the whole range of active power. This is an indicator of the PV inverters' capability to independently control active and reactive power.

The curtailment control test also demonstrates that PV generation can provide additional ancillary services in the form of spinning and nonspinning reserves. According to CAISO's definitions, spinning reserve is a standby capacity from generation units already connected or synchronized to the grid and that can deliver their energy in 10 minutes when dispatched. With a demonstrated 30-MW/min ramp rate capability, the PV plant under test is capable of deploying 300 MW of spinning reserve in only 10 minutes for some hypothetical case of full curtailment. Nonspinning reserve is capacity that can be synchronized to the grid and ramped to a specified load within 10 minutes. Similarly, the PV plant can provide nonspinning reserve as well. In fact, in a PV plant, unlike any conventional generation, there is no differentiation between spinning and nonspinning reserve capacity due to the nature of PV generation.

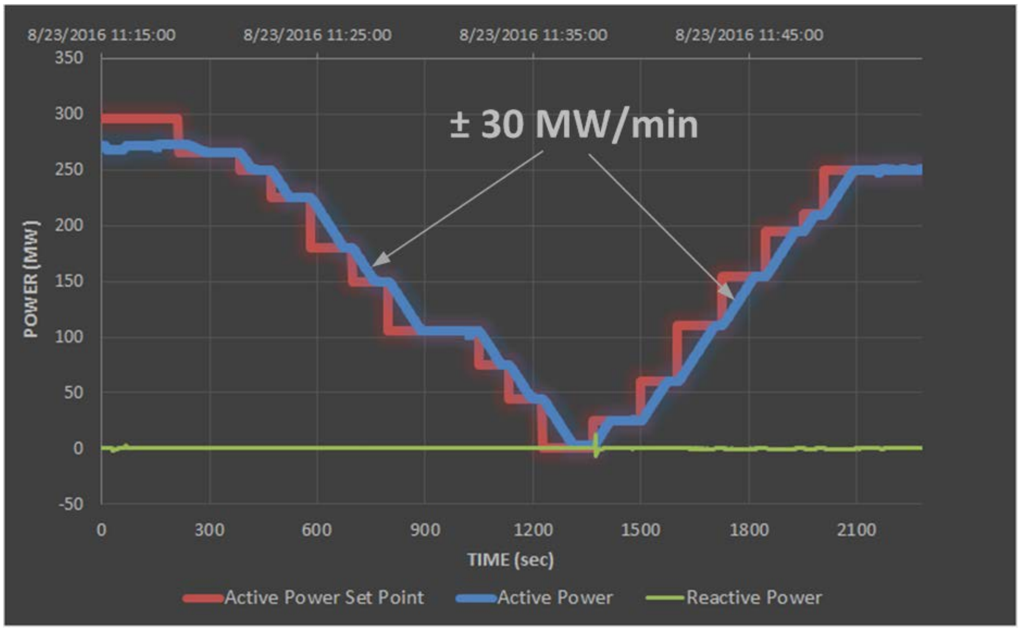


Figure 51. Results of the active power curtailment test. ***Illustration from NREL***

Another type of APC test, called frequency validation, was conducted to demonstrate the control system response to frequency disturbances. Unlike the frequency droop tests described in Section 4 of this report, the frequency validation tests were conducted with artificially commanded step changes in POI frequency. Figure 52 shows the plant's response to the commanded frequency values. The plant's response corresponds to a 5% frequency droop setting with an excellent match between the measured and calculated target power levels. (All active power ramp rates in the PPC were bypassed when the plant is in frequency regulation mode.)

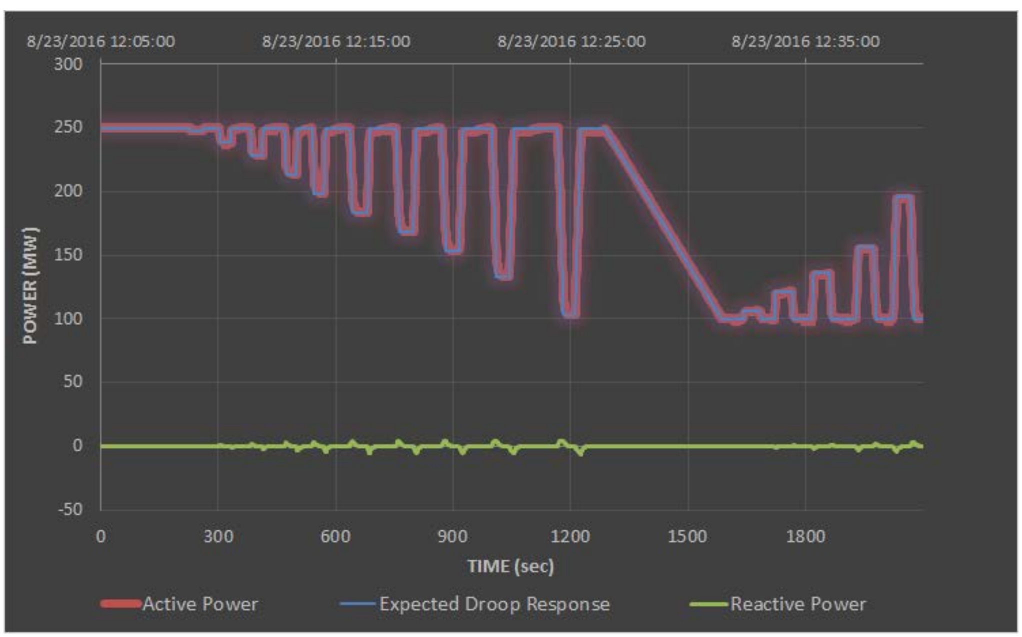


Figure 52. Results of the frequency validation test. ***Illustration from NREL***

7 Conclusions and Future Plans

This project demonstrated how solar PV generating plants can provide a wide range of essential reliability services. Tests showed fast and accurate PV plant response to AGC, frequency, voltage, power factor, and reactive power signals under a variety of solar conditions.

7.1 Test Summary

The focus of this project was on demonstrating the controls of a 300-MW utility-scale PV power plant within CAISO's footprint to provide various types of active and reactive power controls for ancillary services.

Active power control capabilities for inverter-connected plants such as PV power plants have been acknowledged and available for a number of years; however, many of these capabilities have not been proven in a real, commercially operational setting by interfacing with the plant's operator on the ground as well as the system operator (either utility off-taker or transmission system operator).

This project is a result of collaboration among NREL, CAISO, and First Solar; NREL's participation was funded through DOE's Solar Energy Technologies Office. The project team gained valuable real experience for all industry players regarding (1) a PV power plant's implementations of these capabilities, (2) the system operators' interface and communications acceptance of measured plant parameters and use of the parameters, (3) the iterative loop for the system operators to send back appropriate set points, (4) the logic of the PV PPCs to respond to the set points, and (5) the PV power plant's return of up-to-date information (such as available peak plant power) to complete the iterative loop.

The AGC tests demonstrated the plant's ability to follow CAISO's AGC dispatch signals during three different solar resource intensity time frames: (1) sunrise, (2) middle of the day (noon–2 p.m.), and (3) sunset. For this purpose, the plant was curtailed by 30 MW from its available peak power to have maneuverability to follow CAISO's AGC signal. During these tests, fast and accurate AGC performance was demonstrated at different solar resource conditions.

For the frequency response tests, the plant was also operated in curtailed mode to have enough headroom to increase its output in response to a frequency decline outside of a defined deadband. Headroom is achieved by sending a curtailment command to the PPC after initially computing its estimation of maximum capability using real-time solar irradiance data from the network of pyranometers, real-time measurements of panel and inverter data, and other static characteristics of the system's components. Assuming that the plant will be reimbursed for the energy loss due to curtailment for these ancillary services, it is likely that the maximum power estimation will need to be refined and validated. The plant demonstrated fast and accurate frequency response performance for different droop settings (3% and 5%) under various solar resource conditions for both underfrequency and overfrequency events.

The plant also demonstrated the ability to operate in three modes related to reactive power control: voltage regulation, power factor regulation, and reactive power control. The plant can operate in only one of the three modes at a time, with a seamless transition from one mode to another. The plant controller was able to maintain the specified voltage set points at the POI by regulating the reactive power produced or absorbed by the PV inverters. Also, the plant's ability to produce or absorb reactive power at nearly zero MW production (STATCOM mode) was demonstrated as well.

7.2 Detailed Conclusions

General conclusions include the following:

- Advancements in smart inverter technology combined with advanced plant controls allow solar PV resources to provide regulation, voltage support, and frequency response during various operation modes.
- Solar PV resources with these advanced grid-friendly capabilities have unique operating characteristics that can enhance system reliability, like conventional generators, by providing:
    - Essential reliability services during periods of oversupply
    - Voltage support when the plant's output is near zero
    - Fast frequency response (inertia response time frame)
    - Frequency response for low as well as high frequency events.
- Accurate estimation of available peak power is important for the precision of AGC control.
- It makes sense to include specifications for such available peak power estimations into future interconnection requirements and resource performance verification procedures.
- System-level modeling exercises will be needed to determine the exact parameters of each control feature to maximize the reliability benefits to CAISO or any other system operator that will be utilizing such controls in its operations.
- All hardware components enabling PV power plants to provide a full suite of grid-friendly controls are already in existence in many utility-scale PV plants. Fully enabling these is mainly a matter of activating these controls and/or implementing communications upgrades. Issues to be addressed in the process include communications protocol compatibility and proper scaling for set point signals. Although these are not significant barriers, dialogue and interaction among the plant operators and the system operators is an important component of implementing APC capabilities. Modifying programming logic may be necessary at multiple places in the chain of communications.
- Fine-tuning the PPC to achieve rapid and precise responses might be a necessary step in many PV plants. It may be easier with newer equipment because of the faster response times of newer inverters and controller systems.
- Many utility-scale PV power plants are already capable of receiving curtailment signals from grid operators; each plant is different, but it is expected that the transition to AGC operation mode will be relatively simple with modifications made only to the PPC and interface software (Figure 53).
- Fast response by PV inverters coupled with plant-level controls make it possible to develop other advanced controls, such as STATCOM functionality, power oscillation

damping controls, subsynchronous controls oscillations damping and mitigation, active filter operation mode by PV inverters, etc.

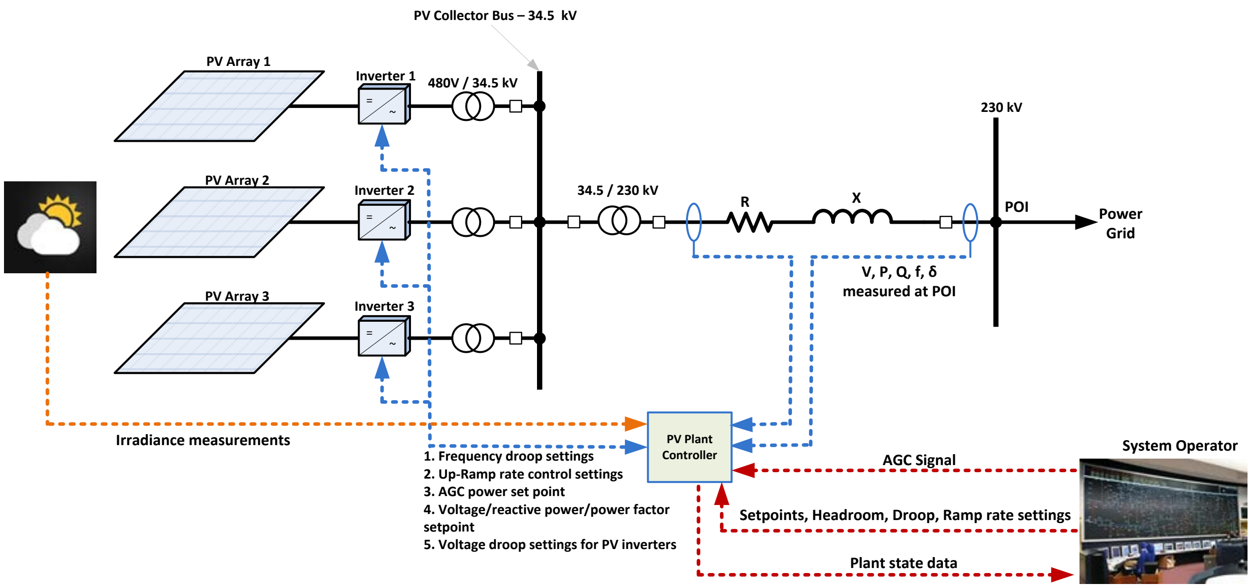


Figure 53. A grid-friendly PV power plant. ***Illustration from NREL***

The project team conducted tests that demonstrated how various types of active and reactive power controls can leverage PV generation's value from being a simple variable energy resource to a resource providing a wide range of ancillary services. With this project's approach to a holistic demonstration on an actual large utility-scale operational PV power plant and dissemination of the obtained results, the team sought to close some gaps in perspectives that exist among various stakeholders in California and nationwide by providing real test data. If PV-generated power can offer a supportive product that benefits the power system and is economic for PV power plant owners and customers, this functionality should be recognized and encouraged.

7.3 Future Plans

Future plans by the project team include:

- Identifying potential barriers to providing essential reliability services to make these services operationally feasible
- Exploring economic and/or contractual incentives to maximize production and not hold back production to provide reliability services
- Identifying necessary steps to unlock opportunities to use reliability services from renewable resources by:
    - Assessing and quantifying the fleet's capability to provide reliability services
    - Evaluating policies such as FERC Notice of Inquiry RM16-6, which recommends requiring all synchronous and asynchronous machines to provide primary frequency response

    - Considering how renewable resources already dispatched or curtailed can provide upward regulation and frequency response
    - Identifying what tariff changes are necessary to remove barriers and allow variable energy resources to provide reliability services
    - Exploring ways to allow inverter-based resources and associated control systems to be used to enhance reliability and response to frequency events
    - Exploring further opportunities for inverter-based resources to participate in the various markets for energy and ancillary services.
- Developing further modifications to control algorithms and fine-tune control parameters for improved performance of the demonstrated services
- Demonstrating true PV STATCOM functionality during nighttime hours
- Demonstrating ancillary services by a number of PV plants within CAISO's footprint to understand the impacts of solar resource geographical diversity on the aggregate response by solar generation on various types of ancillary services
- Finally, CAISO and NREL are interested in exploring the possibility of conducting simultaneous demonstration testing of ancillary service controls by solar PV and wind generation to understand the aggregate response by two different renewable energy resources when providing various combinations of ancillary services.

References

1. Mike Munsell, "U.S. Solar Market Sets New Record, Installing 7.3GW of Solar PV in 2015," *Greentech Media*, February 22, 2016.
2. Solar Energies Industry Association, *U.S. Solar Market Insight* (Technical Report) (Washington, D.C.: December 13, 2016), www.seia.org/research-resources/us-solar-market-insight.
3. Vahan Gevorgian and Barbara O'Neill, *Advanced Grid-Friendly Controls Demonstration Project for Utility-Scale PV Power Plants* (Technical Report NREL/TP-5D00-65368) (Golden, CO: January 2016), www.nrel.gov/docs/fy16osti/65368.pdf.
4. "Electric Power Monthly," U.S. Energy Information Administration, December 23, 2016.
5. California Public Utilities Commission, *Renewables Portfolio Standard Quarterly Report 1st and 2nd Quarter 2012* (Technical Report) (San Francisco, CA), accessed March 26, 2013, www.cpuc.ca.gov.
6. CAISO, *2010 Annual Report on Market Issues and Performance* (Technical Report) (Folsom, CA: 2011, pp. 139–142). www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.
7. CAISO, *Q2 2016 Report on Market Issues and Performance* (Technical Report) (Folsom, CA: August 22, 2016).
8. CAISO, *Standards for Imports of Regulation* (Technical Report) (Folsom, CA: November 1, 2013).
9. FERC, "Docket No. RM16-23-000: Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators."
10. Argonne National Laboratory, *Survey of U.S. Ancillary Service Markets* (Technical Report) (Lemont, IL: 2016).
11. NERC, *Integration of Variable Generation Task Force Report* (Technical Report) (Washington, D.C.: 2012).
12. NERC, *Integration of Variable Generation Task Force Report* (Technical Report) (Washington, D.C.: 2012).
13. NERC, *Essential Reliability Services Working Group and Distributed Energy Resources Task Force Measures* (Technical Report) (Washington, D.C.: 2012), www.nerc.com/comm/Other/Pages/Essential-Reliability-Services-Task-Force-(ERSTF).aspx.
14. Smart Grid Interoperability Panel, "*Regulatory Challenges to Deploying Distributed Energy Resour*ces" (White Paper), April 2015, www.sgip.org/wp-content/uploads/Regulatory-Challenges-WP-APRIL-2015.pdf.
15. Rachel Golden and Bentham Paulos, "Curtailment of Renewable Energy in California and Beyond," *The Electricity Journal* 28:6 (July 2015).
16. Mahesh Morjaria, Dmitriy Anichkov, Vladimir Chadliev, and Sachin Soni, "A Grid-Friendly Plant," *IEEE Power and Energy Magazine* (May/June 2014).
17. NERC, *Balancing and Frequency Control* (Technical Report) (Atlanta, GA: January 2011).

18. NERC, "Standard BAL-001-2: Real Power Balancing Control Performance," www.nerc.com.
19. Y.V. Makarov, S. Lu, J. Ma, and T. N. Nguyen, *Assessing the Value of Regulation Resources Based on Their Time Response Characteristics* (Technical Report) (Richland, WA: Pacific Northwest National Laboratory, June 2008).
20. CAISO, *California ISO Frequency Response: Draft Final Proposal* (Technical Report) (Folsom, CA: February 2016).
21. "Proposed Terms and Definitions for Flexible AC Transmission System (FACTS)," *IEEE Transactions on Power Delivery* 12:4 (Oct. 1997): 1,848–1,853.
22. NERC, *NERC 2012 Special Assessment Report: Interconnection Requirements for Variable Generation* (Technical Report) (Atlanta, GA: September 2012).
23. FERC, "Large Generator Interconnection Agreement," www.ferc.gov/industries/electric/indus-act/gi/stnd-gen.asp.
24. FERC, "Order 661A," www.ferc.gov/EventCalendar/Files/20051212171744-RM05-4-001.pdf.
25. FERC, "Order 827: Reactive Power Requirements for Non-Synchronous Generation," June 2016.
26. CAISO, *Reactive Power and Financial Compensation: Draft Final Proposal* (Folsom, CA: November 2015).
27. FERC, "Docket No. EL07-65-001."

Appendix: Test Plan

Objective

Perform multiple tests, and document the performance of a 300-MW PV solar facility in a commercially operational setting. The plant currently has a maximum capacity of 299.9 MW and participates in the independent system operator's (ISO's) market. The plant is in the process of completing its final acceptance testing by mid- to late August 2016.

The California Independent System Operator (CAISO) is responsible for ensuring that sufficient ancillary services are available to maintain the reliability of the grid controlled by the ISO. Modern utility-scale PV power plants consist of multiple power electronic inverters and can contribute to grid stability and reliability through sophisticated "grid-friendly" controls. The findings of this testing project will provide valuable information to the ISO concerning the ability of variable energy resources to provide ancillary services, enhance system reliability, and participate in future ancillary service markets in a manner that is similar to that of traditional generators. All tests would be done in a manner to minimize curtailment to the plant below its current commercial P_{max}. Curtailment details and actual test times would be worked out prior to the tests.

The project team—consisting of experts from CAISO, First Solar, and the National Renewable Energy Laboratory (NREL)—developed the demonstration concept and test plan to show how various types of active and reactive power controls can leverage PV generation's value from being a simple intermittent energy resource to providing a wide range of ancillary services. Through this demonstration and the subsequent dissemination of the results, the team will provide valuable real test data from an actual utility-scale operational PV power plant to all stakeholders in California and nationwide. If PV-generated power can offer a supportive product that benefits the power system and is economic for PV power plant owners and customers, this functionality should be recognized and encouraged.

Regulation-Up and Regulation-Down

This test will demonstrate the plant's ability to follow the ISO's automatic generation control (AGC) dispatch signals. The purpose of AGC is to enable the power plant to follow the active power set point dispatched by the ISO at the end of every 4-second time interval. The ISO will conduct the test at three different solar resource intensity time frames: (1) sunrise, (2) middle of the day (noon–4 p.m.), and (3) sunset. Each test will provide actual 4-second AGC signals that the ISO has previously sent to a regulation-certified resource of similar size. Normally, CAISO measures the accuracy of a resource's response to energy management system signals during 15-minute intervals by calculating the ratio between the sum of the total 4-second set point deviations and the sum of the AGC set points.

- Sunrise

  During sunrise, the plant would be instructed to operate within a real power range of *20 MW below its peak power capability*. Approximately 10 minutes of actual 4-second AGC signals would then be fed into the plant's controller, and the plant's response would be monitored.

- Middle of the day

During the middle of the day, the plant would be instructed to operate within a real power range of *20 MW below its peak power capability*. Approximately 20 minutes of actual 4-second AGC signals would then be fed into the plant's controller, and the plant's response would be monitored.

- Sunset

  During sunset, the plant would be instructed to operate within a real power range of *20 MW below its peak power capability*. About 20 minutes of actual 4-second AGC signals would then be fed into the plant's controller, and the plant's response would be monitored.

Expectation

During the test, the ISO will monitor the delayed response time of the plant (i.e., the time between the resource receiving a control signal indicating a change in set point and the instant the resource's MW output changes). The ISO will also monitor the accuracy of the plant's response to the regulation set-point changes. The data from this test will be used by ISOs in future resource-specific expected mileage for the purposes of awarding regulation-up and regulation-down capacity.

Curtailment

It is expected that the plant would be curtailed by 20 MW for approximately 45 (3 x 15 minutes) minutes.

Voltage Regulation Control

The ISO will test the plant in the voltage regulation mode, whereby the controller maintains a scheduled voltage at the terminal of the generator step-up transformer by regulating the reactive power produced by the inverters. The voltage regulation system is based on the reactive capabilities of the inverters using a closed-loop control system similar to automatic voltage regulators in conventional generators.

The reactive power capability would be tested to show the Federal Energy Regulatory Commission's (FERC's) proposed reactive capability (Order 827), which requires that all newly interconnecting nonsynchronous generators design their generating facilities to meet the reactive power requirements at all levels of real power output. (*Refer to the vertical red lines in Figure A-1*.)

Objective

The primary objective of this test is to demonstrate the capability of the plant to operate in voltage regulation mode within a power factor range of 0.95 leading/lagging. The plant controller maintains the specified voltage set point at the high side of the generator step-up bank by regulating the reactive power produced by the inverters.

Test Procedure

The ISO would test the plant at *three* different real power output levels: (1) maximum production during the middle of the day, (2) during sunset when the plant is at approximately 50% of its maximum capability, and (3) during sunset when the plant is close to zero production. The ISO will test the plant's reactive power capability to absorb and produce reactive power in accordance with Figure A-1, within a range of ±100 MVAR during various levels of real power output.

- The plant would first be tested at its maximum real power output for a given irradiance level. At maximum real power output, the plant must demonstrate that it can produce approximately 33% of real output as dynamic reactive. Similarly, at maximum real power output, the plant must demonstrate that it can absorb approximately 33% of its real power output as reactive output.
- During sunset, as the solar production drops off to approximately 50% of the resource's maximum capability, the plant must demonstrate that it can produce and absorb approximately 33% of its real power output as dynamic reactive output.
- During sunset, as the plant production approaches zero MW, the plant must demonstrate that it can produce and absorb approximately 33% of its real power output as dynamic reactive output.

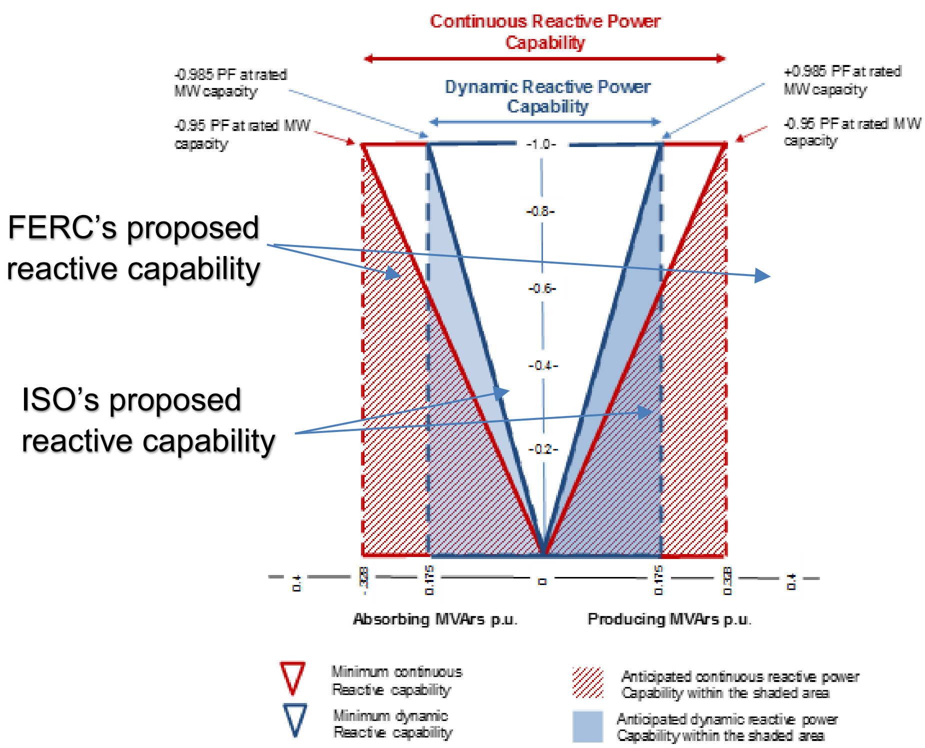


Figure A-1. Reactive power capability at the POI. *Illustration from NREL*

Note: The red vertical lines shown in Figure A-1 represent the expected reactive capability of the asynchronous generating plant at the high side of the generator step-up bank. At all levels of real power output, the plant is expected to produce or absorb reactive power equivalent to approximately 33% of the plant's actual real power output. For example, at the plant's maximum real power capability, the expected reactive capability should be 33 MVARS lagging or 33 MVARS leading. Also, at zero real power output, the expected dynamic reactive capability should be zero MVARS lagging or zero MVARS leading.

Expectation

The plant must demonstrate that its reactive capability follow FERC's proposed reactive capability, as shown in Figure A-1.

Curtailment

None.

Active Power Control Capabilities

CAISO seeks to test the APC capability to assess the plant's ability to control its output in specific increments by being able to mimic a specified ramp rate. The results of this test would be used to determine the plant's ability to provide ancillary services such as spinning reserve and nonspinning reserve.

Objective

This objective of this test is to demonstrate that the plant can decrease output or increase output while maintaining a specific ramp rate.

Test Procedure

This test is similar to starting up and shutting down the plant in a coordinated and controllable manner. The test would be done at *two different ramp rates*.

- The plant would be instructed to reduce its output to three different set points *(not to exceed 60 MW)* at a predetermined ramp rate, as shown in Figure A-2.
- The plant would then be instructed to ramp back up to full production following predefined set points at the predetermined ramp rate, as shown in Figure A-2.
- Repeat the above test using a different ramp rate.

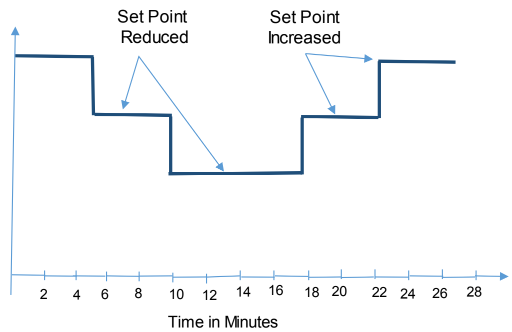


Figure A-2. Increase/decrease output at a specified ramp rate. *Illustration from CAISO*

Expectation

The plant must demonstrate its capability to move from its current set point to a desired set point at a specified ramp rate.

Curtailment

It is expected that the plant would be curtailed up to 60 MW for a period of 60 minutes.

Frequency Response

The frequency response capability would entail two separate tests: (1) a droop test and (2) a frequency response test.

The definition of implemented frequency droop control for PV plant is the same as that for conventional generators:

$$Droop = \frac{\Delta P/P_{rated}}{\Delta f/60Hz}$$

The plant's rated power (299.9 MW) is used in the above equation from the droop setting calculation. The plant should adjust its power output in accordance with the droop curve with a symmetric deadband, as shown in Figure A-3. The upper limit of the droop curve is the available plant power based on the current level of solar irradiance and panel temperatures.

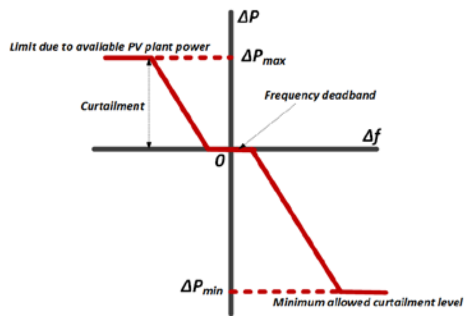


Figure A-3. Frequency droop explained. ***Illustration from NREL***

Frequency Droop Test (Capability to Provide Spinning Reserve)

Objective

The objective of this test is to demonstrate that the plant can provide a response in accordance with the 5% and 3% droop settings through its governor-like control system. The plant would be instructed to operate *below its maximum capability during both tests*.

Test Procedure

For the first test, the plant would be instructed to operate at *20 MW below its maximum capability*. This test would be done using a *5%* droop and a deadband of ± 0.036 Hz.

- The ISO would test the frequency droop capability of the plant by using an actual underfrequency event that occurred in the Western Interconnection during the past year. The underfrequency event data set *(approximately 10 minutes of data)* would be fed into the plant's controller, and the plant response would then be monitored.
- The frequency droop capability would be demonstrated using one actual high-frequency time series data set provided by NREL. Examples of underfrequency and overfrequency event time series measured by NREL are shown in Figure A-4 and Figure A-5, respectively.

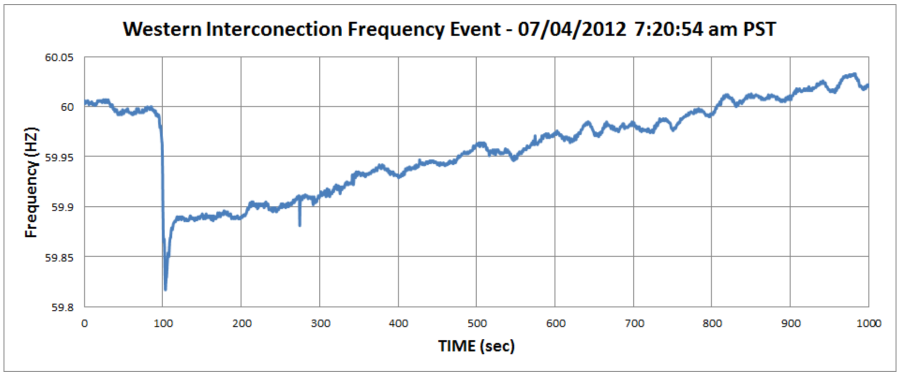


Figure A-4. Example of an underfrequency event. ***Illustration from NREL***

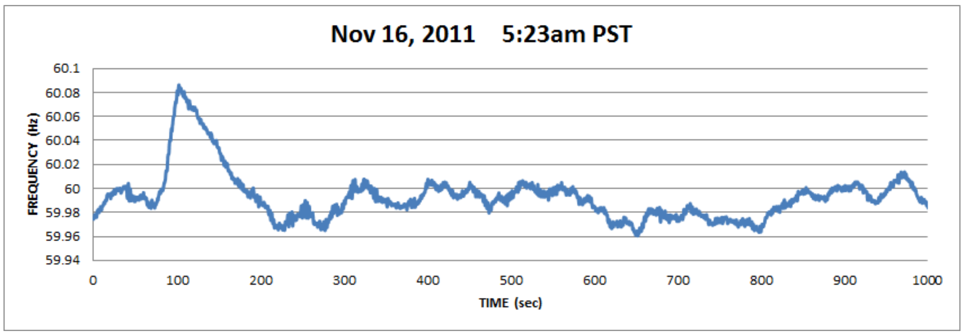


Figure A-5. Example of an overfrequency event. ***Illustration from NREL***

- The frequency event time series data will be used by the power plant controller to trigger the droop response by the plant.
- The above test would be repeated with the plant at 20 MW below its maximum capability. This test would be done using a *3%* droop and a deadband of ± 0.036 Hz.

Expectation

Through the action of the governor-like control system, the plant must respond automatically within 1 second in proportion to the frequency deviations outside the deadband.

Curtailment

It is expected that the plant would be curtailed by 30 MW for approximately 60 minutes.

Capability to Provide Frequency Response

Objective

The objective of this test is to demonstrate that the plant can provide frequency response consistent with the North American Electric Reliability Corporation's BAL-003-1.

Test Procedure

- The plant would be instructed to operate *20 MW* below its maximum capability before applying a step change of rapid frequency decline. An actual frequency event (approximately 10 minutes) would be fed into the plant's controller, and the plant's response would be monitored. This test may require tuning a delay in response to ensure that the frequency response occurs within 20–52 seconds following the step change in frequency.

- The plant *does not have headroom* and can only reduce output in response to large frequency deviations below the scheduled frequency. The test would entail feeding the plant controller with a frequency more than 0.036 Hz above scheduled frequency.
- Repeat the above test with the plant operating *40 MW* below its capability for a given irradiance level.

Expectation

Through the action of the governor-like control system, the plant must respond automatically in proportion to frequency deviations.

Curtailment

It is expected that the plant would be curtailed by 20 MW for 60 minutes and by 40 MW for 60 minutes.

Investigating the Economic Value of Flexible Solar Power Plant Operation

October 2018

Energy+Environmental Economics

Investigating the Economic Value of Flexible Solar Power Plant Operation

October 2018

Energy and Environmental Economics, Inc.
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
415.391.5100
www.ethree.com

Abstract

Solar power is growing rapidly around the world, driven by dramatic cost reductions and increased interest in carbon-free energy sources. Solar is a variable resource, requiring grid operators to increase the available operating range on conventional generators, sometimes by committing additional units to ensure enough grid flexibility to balance the system. At very high levels of penetration, operators may not have enough flexibility on conventional generators to ensure reliable operations.

However, modern solar power plants can be operated flexibly; in fact, they can respond to dispatch instructions much more quickly than conventional generators. Flexible solar not only contributes to solving operating challenges related to solar variability but can also provide essential grid services. This study simulates operations of an actual utility system – Tampa Electric Company (TECO) – and its generation portfolio to investigate the economic value of using solar as a flexible resource. The study explores four solar operating modes: "Must-Take," "Curtailable," "Downward Dispatch," and "Full Flexibility."

The study finds that for this relatively small utility system, *Must-Take* solar becomes infeasible once solar penetration exceeds 14% of annual energy supply due to unavoidable oversupply during low demand periods, necessitating a shift to the *Curtailable* mode of solar operations. As the penetration continues to grow, the operating reserves needed to accommodate solar uncertainty become a significant cost driver, leading to more conservative thermal plant operations and increasingly large amounts of solar curtailment. Flexible solar reduces uncertainty, enabling leaner operations and providing significant economic value. At penetration levels exceeding 20% on the TECO system, solar curtailment can be reduced by more than half by moving from the *Curtailable* to the *Full Flexibility* solar operating mode. This results in significant additional value due to reduced fuel costs, operations and maintenance costs, and air emissions.

Finally, the study evaluates the impact of flexible solar in combination with energy storage. We find that flexible solar can provide some of the same grid services as energy storage, thereby reducing the value of storage on a high-solar grid.

Table of Contents

Study Sponsor

First Solar, Inc.

Study Team

Energy and Environmental Economics, Inc. (E3)

- Jimmy Nelson
- Saamrat Kasina
- John Stevens
- Jack Moore
- Arne Olson

First Solar, Inc.

- Mahesh Morjaria

Tampa Electric Company (TECO)

- John Smolenski
- Jose Aponte

Acknowledgements

+ Beth Bremer and Uday Guntupalli of First Solar were instrumental in providing the solar production data used in this study.
+ Vladimir Chadliev, Eran Mahrer, John Sterling, Rob van Haaren, and Dirk Weiss of First Solar provided valuable comments on this report.
+ Brian Buckley, John Cornett, Elena Vance, Dave Darden, Marc Duquella, Jordan Ekhlassi, Regan Haines, John Heisey, Tom Hernandez, John Hrabe, Steve Joseph, Mark Ward, and Beth Young of TECO provided data and valuable feedback.
+ Dan Mullen of E3 provided editorial support.
+ The following reviewers provided valuable feedback on a draft of this report: Mark Ahlstrom (NextEra & ESIG), Vahan Gevorgian (NREL), Jennie Jorgenson (NREL), Julia Matevosjana (ERCOT), Nick Miller (Hickoryledge), Ric O'Connell (Grid Lab), John Simonelli (NE-ISO), Charlie Smith (ESIG), and Ryan Wiser (LBNL). E3, First Solar, and TECO are solely responsible for the contents of this report, and for the data, assumptions, methodologies, and results described herein.

1 Introduction

Solar electricity is becoming an important part of the electric generation portfolio in many regions due to rapidly declining costs and policies favoring non-emitting renewable generation. The installed capacity of solar has grown exponentially over the past two decades.

Further solar growth is expected in subsequent decades. Policy targets for renewable energy installation and decarbonization of the energy system are driving solar installations around the world. Both India and China have targets to reach more than 100 GW of installed solar capacity by the early 2020s.[1] California and Hawaii have passed legislation to reach 100% renewable or zero-carbon electricity by 2045, and it is expected that solar energy will be one of the primary energy sources used meet these ambitious targets. Recent analysis on deep decarbonization pathways in California suggests that solar power could supply a large fraction of the economy-wide demand for energy by 2050.[2] Europe is also expected to increase solar energy capacity to meet decarbonization targets.

1.1 Operational challenges and opportunities

Existing or "conventional" utility-scale solar is typically designed and operated to generate and deliver the maximum amount of electricity in real-time. This approach is motivated by the desire to minimize the cost per unit of energy by amortizing the capital cost of solar across the maximum amount of energy that system could produce.

Increasing the level of solar can make it more challenging for grid operators to balance electricity supply and demand. For example, grid operators must manage rapid increases in solar generation during sunrise

[1] International Energy Agency, "IEA/IRENA Joint Policies and Measures Database: Global Renewable Energy," accessed September 2018, https://www.iea.org/policiesandmeasures/renewableenergy/.

[2] A. Mahone, Z. Subin, J. Kahn-Lang, D. Allen, V. Li, G. De Moor, N. Ryan and S. Price, "Deep Decarbonization in a High Renewables Future: Updated Results from the California PATHWAYS Model," Energy and Environmental Economics, Inc., June 2018, https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf.

and rapid decreases in solar production during sunset, in addition to variations in solar output caused by regional weather conditions. This often requires managing ramping events by rapidly varying the output of conventional thermal generation. At higher levels of solar penetration, operational challenges become more acute.

Many operational challenges can be addressed by making utility-scale solar available to provide flexibility for grid operations when needed. For example, ramping demands on conventional generation resources can be reduced if solar plants can control ramp rates during both morning and evening hours, thereby providing the means to flexibly operate the grid even in the presence of higher levels of solar generation. While operating solar generators in a flexible manner leads to occasional curtailment of solar output, this may still be a more economical operating mode than other options.

Recent studies have shown that utility-scale solar photovoltaic (PV) plants can provide essential grid reliability services that are typically associated with conventional generation.[3] In the most recent study, First Solar teamed with the National Renewable Energy Laboratory (NREL) and the California Independent System Operator (CAISO) to test a 300 MW utility-scale photovoltaic power plant in California. The power plant was equipped with advanced power controls by combining multiple power-electronic inverters and advanced plant-level controls. The test demonstrated that PV plants can have the technical capabilities to provide grid services such as spinning reserves, load following, voltage support, ramping, frequency response, variability smoothing, frequency regulation, and power quality improvement. Specifically, the tests included various forms of active power controls such as automatic generation control and frequency regulation, droop response, and reactive power/voltage/power factor controls. The results showed that regulation accuracy by the PV plant is significantly better than fast-ramping gas turbine technologies.

By leveraging the full suite of operational capabilities of utility-scale solar resources, solar can go beyond a simple energy source and become an important tool to help operators meet flexibility and reliability

[3] See V. Gevorgian and B. O'Neill, "Advanced Grid-Friendly Controls Demonstration Project for Utility-Scale PV Power Plants," National Renewable Energy Laboratory, January 2016, **https://www.nrel.gov/docs/fy16osti/65368.pdf**; M. Morjaria, D. Anichkov, V. Chadliev and S. Soni, "A Grid-Friendly Plant: The Role of Utility-Scale Photovoltaic Plants in Grid Stability and Reliability," IEEE Power and Energy Magazine, vol. 12, no. 3, 2014; and California ISO, National Renewable Energy Laboratory, and First Solar, "Using Renewables to Operate a Low-Carbon Grid: Demonstration of Advanced Reliability Services from a Utility-scale Solar PV Plant," 2017, **https://www.caiso.com/documents/usingrenewablestooperatelow-carbongrid.pdf**.

needs of the grid. To date, the economic value of including solar as an active participant in balancing requirements has not been widely studied. To quantify the value of flexible solar operation, our study introduces solar flexibility constraints into a detailed multi-stage production cost model. We do not explore the economic value of voltage control in this study.

Recent cost declines in energy storage technologies enable solar to further extend its capability by providing firm dispatchable capabilities, which in turn enables even higher solar penetrations. Adding storage to the grid can shift energy to when it is most needed, even if the sun has already set. Adding storage to a grid can combine the flexibility of solar with the firm capacity and energy shifting capabilities of storage, but requires significant capital investment in storage resources. The last section of this study investigates the interplay of solar flexibility and storage value.

1.2 Uncertainty and variability in grid operations

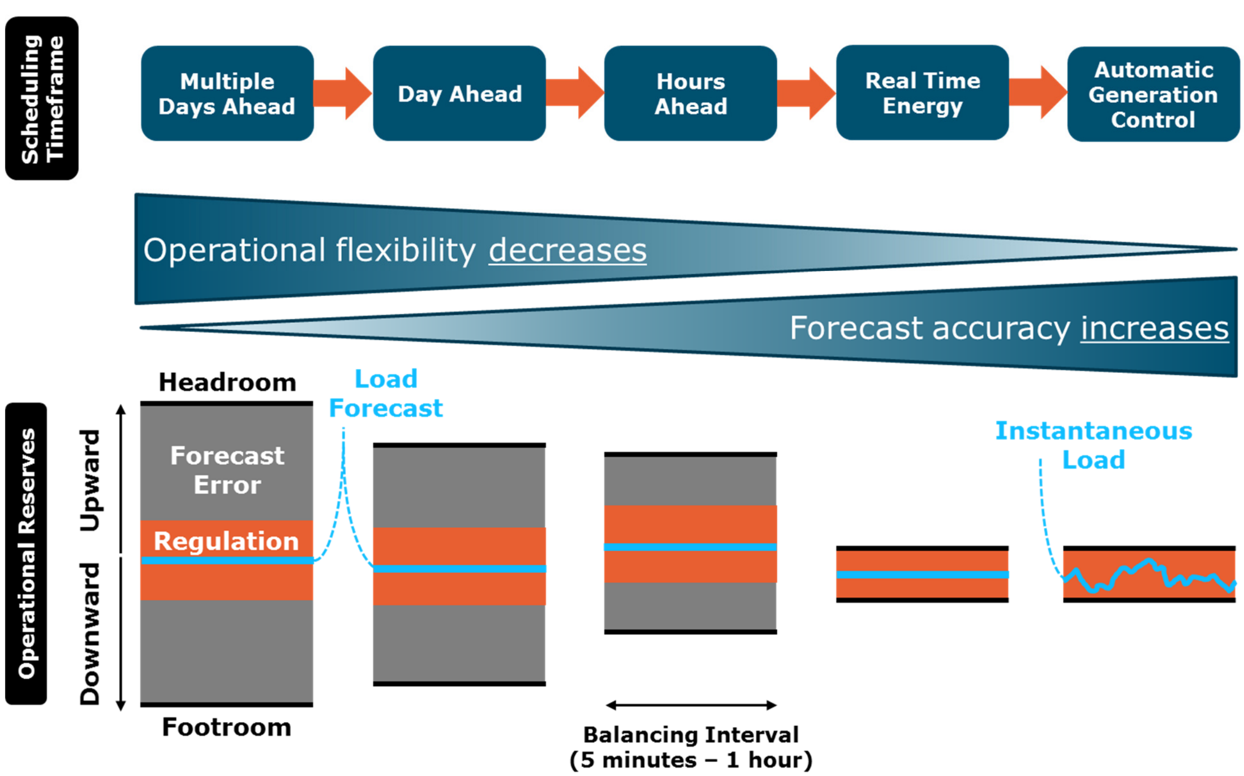
Much like musicians following the conductor in an orchestra, the system operator coordinates the dispatch of an ensemble of power plants. The system operator's goal is to meet demand at least cost while maintaining reliability.

Operational challenges are often described using the terms *variability* and *uncertainty*. Variability refers to increases and decreases in demand or resource availability that would exist even with a perfect forecast. For example, diurnal patterns in human activity are a source of demand variability because these patterns occur naturally over the course of a day. Uncertainty represents the inability to perfectly forecast future demand or other grid conditions. Even in the absence of wind and solar power plants, system operators must maintain system reliability at all times under significant variability and uncertainty of demand, as well as uncertainty with respect to generator and transmission availability.

To balance the system, operators must have information about the level of uncertainty in their forecasts as well as the capabilities of their resources to respond. Forecast accuracy increases closer to real time, but the ability to respond to unexpected events decreases because the operating range of conventional power plants is smaller over shorter time intervals. This problem is magnified by the challenges of generator scheduling ("unit commitment"), because thermal generators typically require significant lead time – hours to days, or even weeks – to be turned on or off. Once running, thermal plants must generate at minimum levels that are typically at least 20 – 50% of maximum output. For some coal-fired generation, the minimum generation level can be as high as 70%. Thus, system operators must frequently make decisions about which units will be operating and at what levels far in advance, and with imperfect information about the level of demand and renewable production.

If actual demand turns out to be much higher than forecasted, there may not be enough resources available to meet demand. To deal with this uncertainty, grid operators maintain a safety margin on top of forecasted demand ("headroom") when scheduling power plants so that a demand under-forecast does not turn into a power shortage. This is shown schematically in Figure 1. In the opposite direction, operators may also retain the ability to turn down or turn off generation ("footroom") to avoid oversupply conditions in the event of a demand over-forecast.

Figure 1: Commitment timeframes, forecast uncertainty, headroom and footroom



System operators are constantly balancing economics and reliability when making commitment and dispatch decisions. If they are conservative and commit too many power plants, generators will be forced to run at less efficient set points or cycle on and off quickly, both of which can be costly. If operators are not conservative enough, they may have to buy expensive energy from neighbors in real-time, call on expensive demand response resources, or incur penalties for violating reliability standards. The worst case is that there simply is not enough generation capacity committed to serve demand and the operator must temporarily disconnect customer loads.

In addition to the challenges of forecasting demand long before real-time, operators must also be prepared for the natural variability of demand in real-time. Common practice is to hold headroom and footroom on quick-moving units ("regulation") to ensure adequate flexibility. Organized markets – the California Independent System Operator (CAISO), the Electric Reliability Council of Texas (ERCOT), PJM Interconnection, the Midcontinent Independent System Operator (MISO), etc. – procure regulation as part of market operations, and centrally dispatched utilities typically have a similar requirement in their dispatch procedures. Operators also address variability by committing units more frequently closer to real-time operations. It is common to commit and dispatch generators on an hourly basis a day-ahead of real-time, and every five to fifteen minutes during real-time operations.

Increasing the level of solar (and wind) generation on the grid increases the variability and uncertainty of electricity supply, both because of imperfect forecasts of wind and solar output and because of fluctuations in output on a minute-to-minute basis. This frequently increases the overall forecast error and regulation requirements needed to balance supply and demand. Higher balancing requirements raise the stakes of power plant commitment decisions.

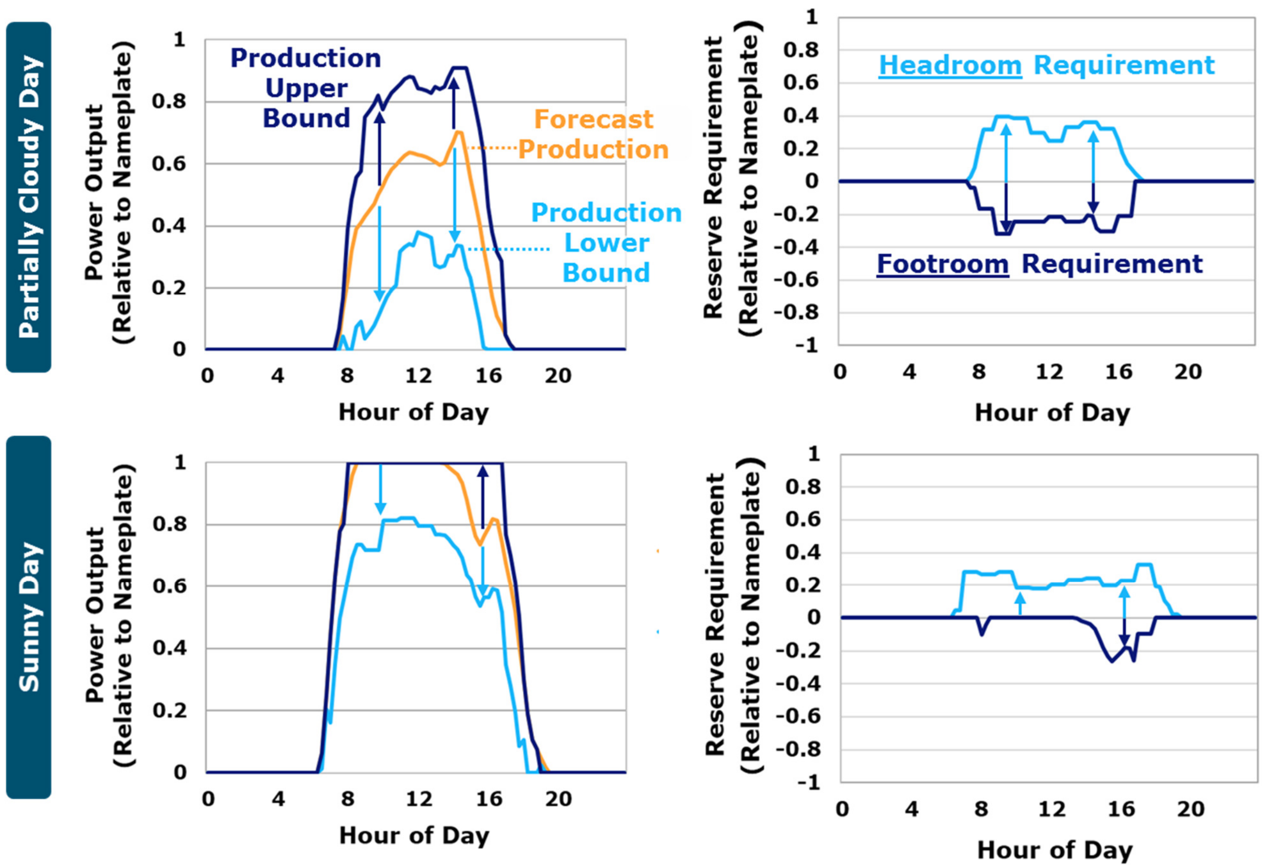
1.3 System balancing with flexible solar generators

Many modern solar power plants have the technical capabilities to contribute to regulation and balancing requirements through precise output control – this is referred to as "flexible" or "dispatchable" solar. In this operating mode, the entire suite of solar dispatch capabilities is made available to the system operator in determining economic dispatch. System operators can elect to use the solar resources to provide energy or essential grid services (e.g., regulation reserves), and this choice may vary by dispatch time interval throughout the day. Provision of these services requires downward dispatch of solar, and some services require the plant operator to maintain headroom to enable upward dispatch. While this results in lost solar production, solar plants incur no measurable variable costs from providing these services. Instead, the cost of solar providing these services is an opportunity cost that can be estimated in the context of economic dispatch. Obtaining grid services from solar plants can, in some instances, enable system operators to reduce fuel costs by reducing thermal generator commitments and increasing the efficiency at which they operate.

Sourcing essential grid services from solar requires the system operator to have an appropriate degree of confidence in the level of solar output minutes, hours, or days ahead of real-time dispatch. As shown in Figure 2, historical solar forecast errors can be used to calculate expected lower and upper bounds on solar production when making commitment decisions ahead of real-time. The lower and upper bounds are used to 1) set system-wide headroom and footroom needs for solar forecast error, and 2) if solar is represented as dispatchable, set limits on how much the solar plant could be dispatched. There are a variety of means for establishing confidence bounds, and this would be an interesting topic for future research. For the current study, we use a single standard deviation above and below the solar forecast as the upper and lower bounds when committing units ahead of real-time.

Our study focuses on the flexible operation of solar power plants in the absence of battery storage. To date, much emphasis has been placed on the role that storage can play in managing solar and wind variability and uncertainty. In this study, we focus on the operation of the solar or wind power plants themselves, and the economic benefits that may result from operating these assets in a more flexible manner. Interactions with battery storage value are explored in a sensitivity study.

Figure 2: Confidence in solar forecasts hours ahead of real-time (left) and resulting forecast error reserve levels (right) on an example partly cloudy day (top) and sunny day (bottom), normalized to solar power plant capacity. As discussed below, reserve requirements must be met by non-solar resources if solar flexibility is not integrated into system operator dispatch procedures, but can be partially met by solar power plants when solar is represented as more flexible.



1.4 Solar operating modes

In this study we explore different solar "operating modes," which represent the extent to which system operators have incorporated the inherent flexibility of many modern utility-scale solar power plants into their operational procedures. We define four solar operating modes to explore the value of solar dispatch flexibility, ordered from least to most flexible:

Solar Operating Mode	Solar can be curtailed	Solar can contribute to footroom requirements	Solar can contribute to headroom requirements
Must-Take	×	×	×
Curtailable	✓	×	×
Downward Dispatch	✓	✓	×
Full Flexibility	✓	✓	✓

In the Must-Take and Curtailable operating modes, other resources – in this study, thermal generators and batteries – are committed such that solar can produce at maximum possible output even in the case of solar under- or over-forecast. In the Downward Dispatch operating mode, solar can be dispatched downward (curtailed) to meet footroom requirements but cannot contribute to headroom requirements. In the Full Flexibility operating mode, solar can be fully dispatched to meet grid needs via economic optimization of energy production and operational reserves while accounting for physical limits imposed by solar insolation availability. When solar is scheduled to be curtailed ahead of real-time, the amount of forecast error headroom that is held on other resources is reduced.

Renewable integration studies include a range of assumptions with respect to solar (or wind) operating modes. Most studies simulate solar (or wind) in Curtailable or Downward Dispatch operating mode, though the implementation of solar operating mode in these studies depends on modeling methodology and may not map precisely onto the operating modes defined above. A smaller set of studies explores the Full Flexibility operating mode for solar, frequently as a sensitivity study. Appendix B, "Prior Research," contains citations to example renewable integration studies.

1.4.1 MUST-TAKE OPERATING MODE

Many system operators and solar integration studies treat solar power plants as "must-take." The common convention is to subtract solar production from electricity demand, which assumes there is neither the ability nor the desire to control solar output. The resulting "net load" is the amount of power that must be produced by other "dispatchable" resources.

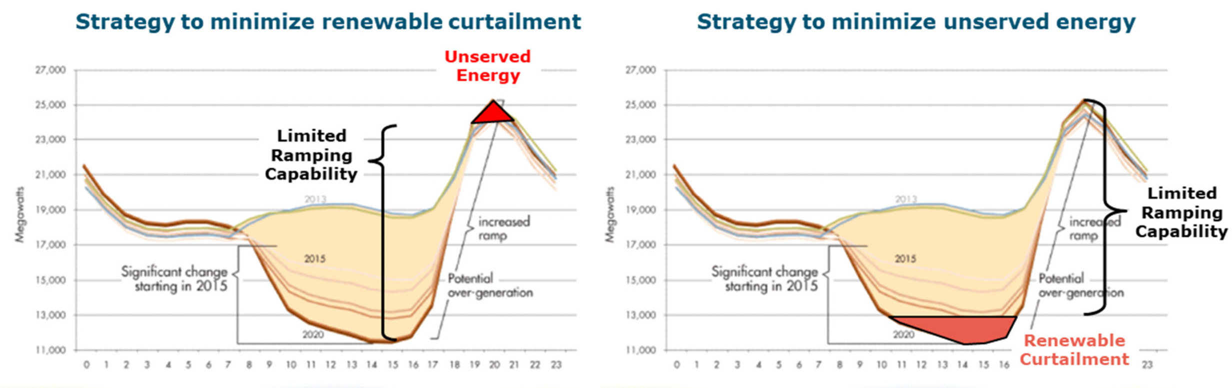
Quick thought experiments demonstrate that the concept of net load was not designed for high penetrations of solar. What if there is so much solar on the grid that there is more solar electricity production than demand? In this scenario, net load would be negative. Balancing supply and demand with negative net load would be very challenging, requiring some level of exports, flexible demand, or energy storage. In the extreme case, the system simply cannot be brought into balance without drastic action such as the temporary disconnection of generators. The term “solar overgeneration” has been used to describe the situation of solar production levels that exceed the ability of the power system to absorb all solar generation. Challenges related to overgeneration and system balancing led early analyses to conclude that power systems could accept only a small fraction of annual energy penetration from variable renewables (wind and solar) before encountering reliability challenges.

It is worthwhile to note that present-day rooftop solar installations are operated as “must-take” because they are almost never visible to or curtailable by the system operator. One of the corollaries to this study’s conclusions is that reaching high rooftop solar penetrations will require some control of these resources – operator dispatch signals, pricing mechanisms, local autonomous control, or other control methods.

The CAISO’s widely-circulated “duck curve” is a prominent example of operational concerns in the context of must-take solar.[4] Figure 3, based on the duck curve, demonstrates this phenomenon for a system with limited ramping capability. In the left panel, operational limitations lead to a reliability problem: unserved energy, which occurs when the system cannot ramp up fast enough to meet high demand in the evening. In the right panel, prospective curtailment of renewable generation has been used to avoid loss of load by ensuring that sufficient upward ramping capability is online and available. However, this strategy comes at the cost of lost renewable production.

[4] California ISO, “What the duck curve tells us about managing a green grid,” 2016, https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

Figure 3: Prospective curtailment of renewable energy resources eliminates a reliability challenge, but introduces an economic challenge



1.4.2 CURTAILABLE OPERATING MODE

As solar penetration has increased, curtailment of solar output has become a reality during hours in which inflexibility, lack of load, or transmission constraints prevent absorption of all available solar energy. Curtailment can occur through analog means if necessary – for example, a phone call from the system operator to the plant operator requesting a reduction in output. Increasingly, solar and wind generators are providing decremental energy bids into organized markets such as CAISO, MISO and ERCOT, enabling curtailment to occur as a market outcome rather than through an emergency phone call. In many instances, power purchase agreements (PPA) between independent power producers (IPP) and utility off-takers of solar project output have evolved to accommodate some degree of curtailment flexibility to reflect this emerging reality. Many regions (e.g., Germany, Denmark, California, Hawaii, etc.) have successfully reached higher penetrations of variable renewables – as high as 42% of annual energy in the case of Denmark – by using renewable curtailment and interties with neighboring regions as important integration tools.[5]

Solar curtailment to date has been largely, if not exclusively, focused on avoiding oversupply. Even though solar output can be controlled to an extent, many renewable integration studies and grid operators continue to include solar forecast error in their calculations of headroom and footroom balancing

[5] A. Bloom, U. Helman, H. Holttinen, K. Summers, J. Bakke, G. Brinkman and A. Lopez, "It's Indisputable: Five Facts About Planning and Operating Modern Power Systems," IEEE Power and Energy Magazine, 2017.

requirements while excluding solar generators from meeting any portion of those requirements. In other words, solar can be curtailed during normal grid operations, but regulation and forecast error reserve requirements are still determined based on net load and must be met by resources other than solar generators. We refer to solar operated in this mode as "Curtailable," since curtailment is used only to avoid oversupply and the precise control of solar output is not considered in generator scheduling and economic dispatch.

1.4.3 DOWNWARD DISPATCH OPERATING MODE

The deployment of more variable renewable capacity has increased the need for "downward" flexibility, or footroom. If renewable production unexpectedly increases, other resources must ramp downward to accommodate the additional energy flowing onto the system. This is particularly a concern in real-time, after commitment decisions have been made. In this case, insufficient footroom might result in large quantities of energy flowing onto neighboring systems, violating North American Electric Reliability Corporation (NERC) control performance standards.

However, if the system operator can control output from the solar plant in real-time, it is possible to reduce solar generation to avoid overgeneration conditions. Utilizing the footroom that is available on a flexible solar resource reduces or eliminates the need to hold footroom on other resources to accommodate unexpected spikes in solar production. Stated differently, solar can provide its own downward reserves or footroom. Consequently, our simulations with the Downward Dispatch solar operating mode system operations do not require any footroom for solar uncertainty and variability.

But solar that can be dispatched downward is not limited to providing *its own* footroom – it can also provide footroom to accommodate unexpected decreases in *demand*. In other words, flexible solar can be used to provide the downward regulation service that system operators have for more than a century sourced exclusively from conventional generators. If enough solar is forecasted to be online in real-time, operators can plan to dispatch solar downwards if demand drops unexpectedly. In this study, we limit the footroom that solar can provide for meeting variability and uncertainty in demand to the lower bound of forecasted solar production potential – the distance between zero and the light blue Production Lower

Bound line in Figure 2. This limit ensures that footroom on solar will be available even if solar generation is over-forecasted.

One potential issue with relying on variable renewables for balancing services is that the operator cannot be certain that the resource will produce enough power to provide the balancing service. This concern is minimal in the case of solar footroom, because the service is needed predominantly *during the times when solar is producing too much energy*. Our production simulation results do not show any significant overgeneration events in real-time even at very high solar penetration levels, indicating that system operators can rely on solar to provide footroom when necessary. With enough flexible solar on the grid, it is unlikely that system operators will have reliability concerns related to downward flexibility in the daytime, although operators will continue to need footroom to cover load variations during nighttime hours.

1.4.4 FULL FLEXIBILITY OPERATING MODE

In this study, the Full Flexibility solar operating mode includes the most options of any operating mode for solar to contribute to essential grid services, and the highest degree of integration of solar resource characteristics into system operator dispatch procedures. The Full Flexibility operating mode includes all the footroom capability of solar from the Downward Dispatch operating mode but also allows solar to provide headroom (upward) flexibility.

Relying on solar to provide *headroom* (regulation up, spinning reserve, etc.) requires 1) plant output to be curtailed intentionally or under-scheduled (scheduled below the maximum available energy production) in order to create headroom, and 2) system operator confidence that additional solar production potential will be realized if called upon. We posit that solar can be forecasted with sufficient confidence within a lower bound as discussed above, but we recognize that system operators will naturally be conservative when relying on solar in the upward direction.

Under-scheduling solar reduces the uncertainty of solar production, and therefore the headroom that would be required for solar forecast error. For example, if at the day-ahead scheduling period it is anticipated that solar would be curtailed on the operating day due to oversupply, system operators can reduce the amount of headroom they would otherwise procure to accommodate a potential solar over-forecast. Put another way, headroom needed on other resources for solar forecast error is reduced when the operator forecasts the need to curtail solar before real-time.

In addition to reducing headroom reserves associated with solar forecast error, under-scheduled solar could be a potent provider of upward ramping service. Solar power plants can ramp up much more quickly than their conventional counterparts, suggesting that solar may be particularly well suited to provide frequency regulation or fast frequency response. This is especially true given that the supply of these fast-timescale balancing services tends to be the most limited during times of low demand and high variable renewable production.

In this study, we have allowed solar to provide upward regulation with available headroom. To ensure that the regulation headroom on solar is available in real-time, we require that additional forecast error headroom is held on other resources when scheduling solar regulation capacity before real-time. A summary of how solar provides headroom and footroom in this study is presented in Table 6 in Appendix A. We do not simulate the provision of fast frequency response in this study, nor do we simulate solar providing contingency reserve and headroom for load under-forecast events, although we believe it should be possible for solar to provide these services given enough certainty on solar production potential. This means that there may be additional value for solar headroom that is not included in this study, especially at higher solar penetration levels.

2 Description of Case Study

2.1.1 SYSTEM DESCRIPTION

To demonstrate the economic value of dispatching solar, we use the PLEXOS Integrated Energy Model to simulate unit commitment and dispatch of an actual utility system – Tampa Electric Company (TECO). TECO has good solar resource availability and a peak demand of ~ 5 GW. TECO operates its electricity system as a Balancing Authority.

TECO was an active participant in the study and provided data on its system, including real-time and forecast demand data, fuel cost projections, and detailed, unit-specific information on its thermal generation portfolio. Our study represents a snapshot of the TECO system in 2019.

TECO's thermal generation portfolio is similar to that found in many areas of the United States and other countries, making the results of this study broadly applicable. The expected 2019 portfolio consists of 60% of thermal capacity from natural gas combined cycle units, 6% from natural gas simple cycle combustion turbines, 20% from natural gas steam turbines, and 13% from coal steam and integrated gasification combined cycle units. TECO's generation portfolio does not include nuclear, wind, other renewable resources, or substantial behind-the-meter solar.

2.1.2 SOLAR DEPLOYMENT LEVELS

We simulate a range of utility-scale solar deployment levels ranging from 0% (no solar) to 28% annual energy penetration potential. The upper end of this range represents higher levels of solar energy than are currently operational in any balancing area in the United States. Annual solar energy penetration potential refers to the amount of energy available from a given capacity of solar energy facilities – the amount that would be produced in the absence of curtailment – normalized to annual balancing area electricity demand. We simulate each penetration level with four different solar operating modes: Must-Take, Curtailable, Downward Dispatch, and Full Flexibility.

This study focuses on operational cost savings of adding solar generation assets to the electricity system and does not include a full cost-benefit analysis of solar deployment. The solar penetration levels studied herein are academic in nature and are not indicative of TECO's future resource acquisition plans. TECO is currently developing 600 MW solar (~7% annual energy penetration) and a 10 MW / 27 MWh storage facility.

2.1.3 SOLAR PRODUCTION DATA

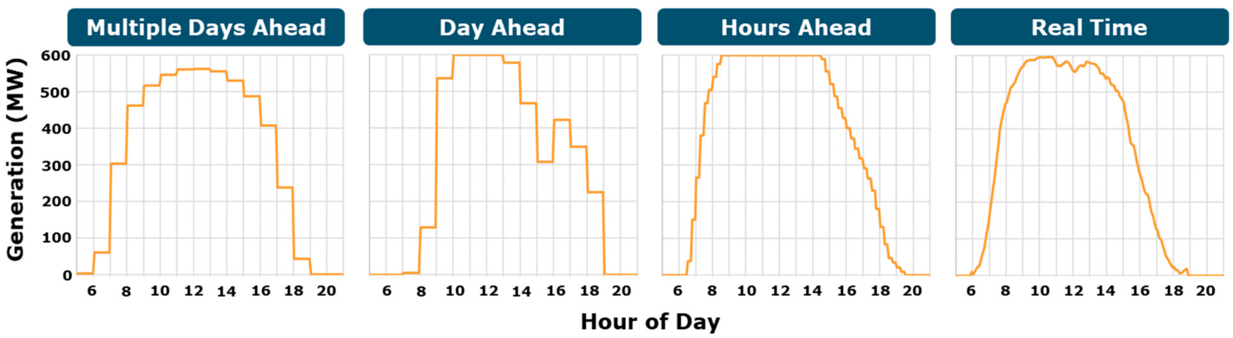
It is important to retain correlations between solar availability and weather-driven heating and cooling loads. We accomplish this by using historical data from 2017 as the basis of load and solar profiles. For demand, 2017 demand profiles are scaled to 2019 using projected 2019 annual TECO demand. For solar, TECO identified 15 sites in its service territory that are being considered for solar development. Locus Energy produced simulated 5-minute solar insolation data from 2017 for each site, and First Solar transformed the insolation data into solar plant output potential. We aggregate solar profiles for the 15 sites into a single TECO-wide solar profile and scale this profile to installed solar capacity. This approach assumes that all solar development occurs within TECO's service territory – a relatively small portion of the Florida peninsula – which therefore would not materially increase the geographic diversity of TECO's solar resources at higher levels of solar penetration. It may be possible to reduce the variability and uncertainty of solar generation by deploying solar power plants over a larger footprint.

Historical solar forecast data is not available from the Locus Energy dataset, so we synthesize solar forecasts through a day-matching algorithm utilizing a National Renewable Laboratory (NREL) solar dataset.[6] Three separate forecast error profiles from the Tampa area were averaged to generate one TECO-wide profile. The NREL dataset contains forecasts for one day ahead and four hours ahead of real-time, but TECO also uses forecasts to make commitment decisions for coal and gas steam units many days ahead of real-time. To generate multiple day-ahead solar forecasts, we simply use the month-hour

[6] National Renewable Energy Laboratory, "Solar Power Data for Integration Studies," accessed March 2018, **https://www.nrel.gov/grid/solar-power-data.html**.

average of the First Solar output profiles. Figure 4 shows how solar forecasts change ahead of real-time operations.

Figure 4: Solar profiles used for unit commitment across different timeframes from an example June day. Profiles are for 600 MW of installed solar capacity.



2.1.4 PLEXOS PRODUCTION COST MODEL

System operators have imperfect information about future grid conditions when making key operational decisions. The PLEXOS model we use in this study optimizes system unit commitment and dispatch for each day of the year in four sequential stages: multiple days-ahead, day-ahead, hours-ahead, and real-time (Table 1). The goal of each stage of the model is to represent the quality of information that TECO system operators would have at key operational decision points. To this end, load and solar production profiles are updated with better forecasts after each stage.

Table 1. PLEXOS model stages

Unit commitment stage	Dispatch and commitment decision timestep	Look-ahead length (after operating day)	Load timeseries data (provided by TECO)	Solar timeseries data
Multiple days-ahead	Hourly	Six days	Multiple days ahead forecast	Month-hour average of 5-minute real-time profiles
Day-ahead	Hourly	Eight hours	Day ahead forecast	NREL day ahead forecast
Hours-ahead	Every 15 minutes	Two hours	Average of day-of forecast and actual 5-minute demand	NREL 4-hour ahead forecast
Real-time	Every 5 minutes	None	Actual 5-minute demand profile	Simulated 5-minute profile

Based on input from TECO, each class of thermal generator is assigned a final stage beyond which commitment decisions are not allowed to be changed (Table 2). This reflects operational practice where, as real-time approaches, commitments of relatively inflexible units cannot be changed. For combined cycle gas turbines, multiple configurations (e.g., 1x1, 2x1, etc.) are modeled with the steam turbine's commitment decision preceding the associated combustion turbine commitments.

Table 2. Timing of final commitment decisions for each generator class

Generator Class	Final Commitment Decision Made in Stage:
Coal integrated gasification combined cycle	Not economically dispatched (must-run)
Simple cycle coal steam turbine	Multiple days-ahead
Simple cycle gas steam turbine	Multiple days-ahead
Steam turbine of gas combined cycle	Day-ahead (or must-run, depending on unit)
Combustion turbine of gas combined cycle	Hours-ahead
Market transactions	Hours-ahead
Simple cycle gas combustion turbine	Real-time

Thermal generators are represented using standard unit commitment and dispatch constraints, including ramping limitations, minimum uptime and minimum downtime constraints, and co-optimized energy and reserve provision. Reserve calculations and requirements are described in Appendix A. Generator economics are reflected via heat rate curves, variable operations and maintenance costs, fuel offtake at startup, and startup costs. TECO also provided unit-specific maintenance and outage schedules. Consistent with current TECO dispatch practices, a price on CO_2 emissions was not included.

For simplicity of case construction and interpretation, market transactions with external entities are restricted to hours in which the TECO system does not have enough generation available to serve load. Market transactions are limited by hourly transmission availability data provided by TECO. Exports from the TECO system to external entities were not considered. In reality, TECO would have additional opportunities to deliver solar energy to external entities and reduce operating cost beyond what is simulated here.

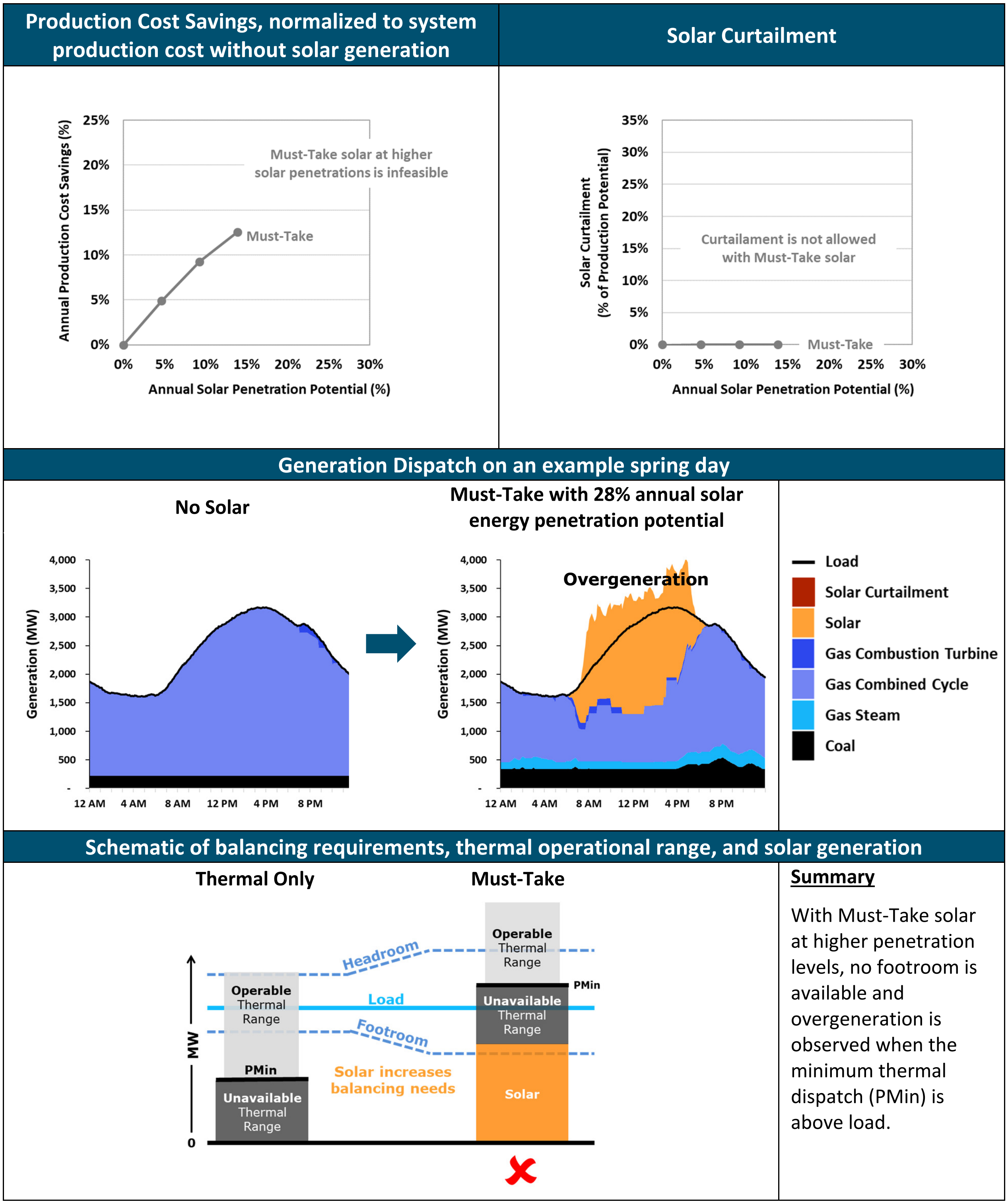
3 Flexible Solar Production Simulation Results

3.1 "Must-Take" operating mode: Limited by overgeneration

We first explore the limits of the Must-Take solar operating mode. We find that Must-Take solar can be absorbed by the TECO system up to about 14% of annual energy penetration potential. At solar penetrations above this level, we begin to observe overgeneration conditions, indicating that the system does not have enough flexibility to balance supply and demand while also accepting every MWh of solar generation. An example dispatch day demonstrating overgeneration conditions is shown in the middle panel of Figure 5. Solar penetrations above 14% on the TECO system are infeasible in Must-Take operating mode.

The appearance of overgeneration indicates that solar curtailment is a necessary tool to balance the system above a threshold level of solar penetration. This result is generalizable to any system, though the annual energy penetration threshold will depend on the characteristics of each individual system, including the load shape and the flexibility of its generation fleet. Shown schematically in the bottom panel of Figure 5, Must-Take solar at high solar generation levels can cause conflicting requirements to 1) accept all solar generation and 2) maintain headroom and footroom on thermal generation. Most thermal generators have minimum power (PMin) requirements; if turned on, a typical thermal generator must generate at a minimum of 20 – 50% of its rated capacity (PMax). The commitment decision for many generators must be made hours to days ahead of real-time, when the actual real-time solar output is not known with great certainty. Committing enough generation capacity to create the headroom and footroom required to plan for many possible levels of solar generation (cloudy to sunny) exhausts the operational range (PMin to PMax) of the thermal fleet. Our results demonstrate that planning to absorb all solar generation is untenable at higher solar penetration levels.

Figure 5: Summary: "Must-Take" Operating Mode



3.2 "Curtailable" operating mode: Feasible dispatch

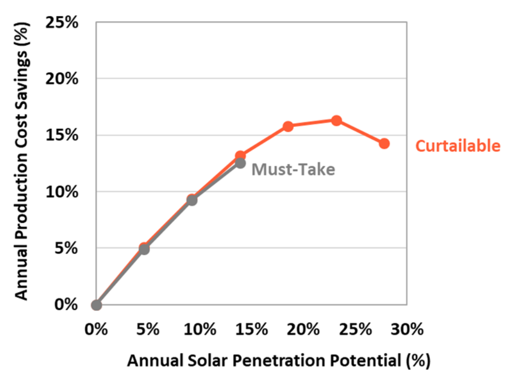
A key indicator of inadequate operational flexibility is the curtailment of variable renewable generation. As shown in the top right panel of Figure 6, solar can contribute up to 14% of energy with very low levels of curtailment, indicating that the thermal generation fleet has adequate flexibility to integrate up to this level of solar generation with minimal challenges. Since very little solar curtailment is necessary at this level of solar penetration, increasing the flexibility of solar generation provides limited additional value.

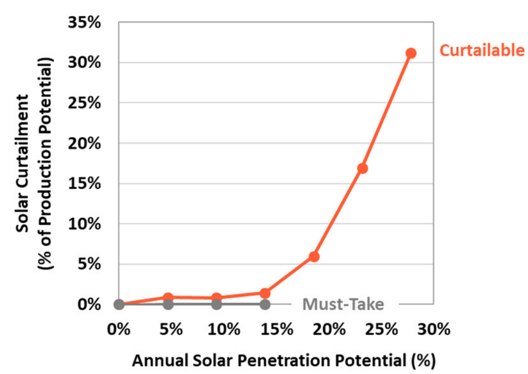
At intermediate levels of solar penetration on the TECO system (~15 – 25% solar energy penetration), curtailing solar generation allows what would otherwise be an inoperable system with Must-Take solar to become operable. Curtailing solar enables more thermal generators to be committed, thereby creating enough space within the dispatch stack to maintain adequate headroom and footroom on thermal units (Figure 6, bottom panel). Even though the system is operable, curtailment levels resulting from this operational strategy become very high as more solar is added to the system. Adding more solar causes additional thermal units to be committed to meet increased operational reserve requirements. Committing these units causes more fuel to be burned in conventional generators, which in turn reduces the energy value of solar generation.

The energy value (Figure 6, top panel) on the TECO system of additional solar energy in Curtailable operating mode decays rapidly above about 14% solar energy penetration. The energy value (or, equivalently, the production cost savings) is calculated as the change in annual production costs as solar penetration increases, excluding the capital cost of additional solar resources. Solar provides very little marginal energy value at penetration levels above 19%. In the extreme – above 23% solar energy production potential – solar has a *negative* marginal energy value. This occurs because the increase in headroom and footroom required to balance solar forecast error is so large, and the fuel penalty for providing these reserves on thermal units so significant, that adding solar actually increases fuel consumption. The relatively small footprint of TECO's balancing area and solar resources contribute to the steep drop-off in energy value in Curtailable operating mode. The solar penetration level at which Curtailable operating mode becomes ineffective will be system-specific, but we expect that other systems will show similar dynamics as the level of solar generation is increased. Given the economic inefficiencies that result from Curtailable operating mode at higher levels of solar penetration, our results suggest that as more solar is deployed, system operators should adapt dispatch procedures to include more flexible solar plant operation.

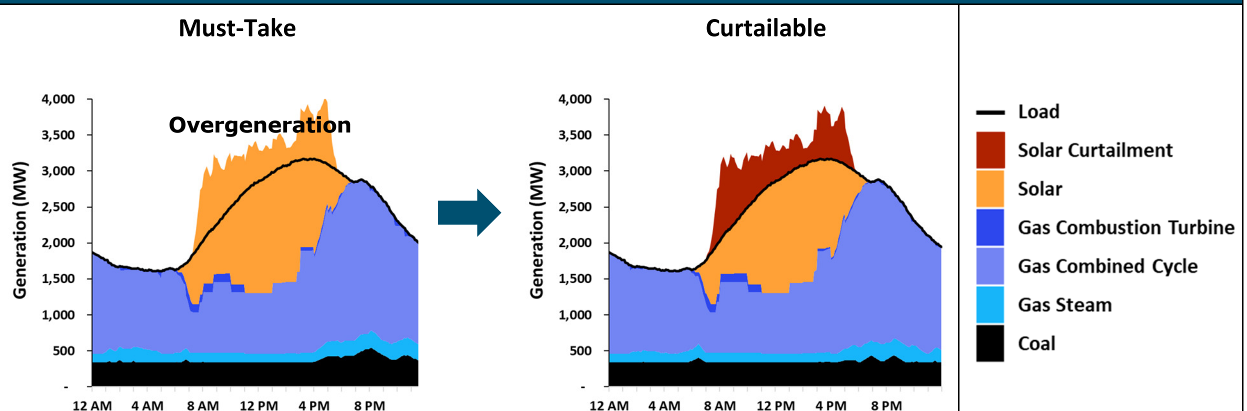
Figure 6: Summary: "Curtailable" Operating Mode

Production Cost Savings, normalized to system production cost without solar generation	Solar Curtailment

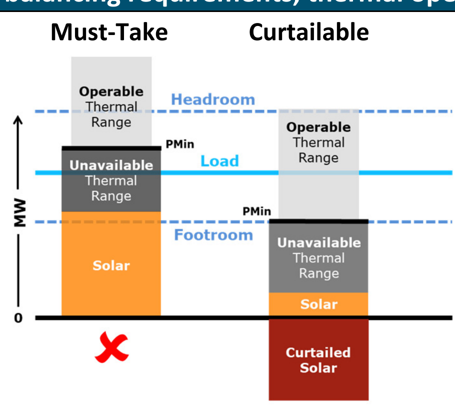




Generation Dispatch on an example spring day at 28% annual solar energy penetration potential



Schematic of balancing requirements, thermal operational range, and solar generation



Summary

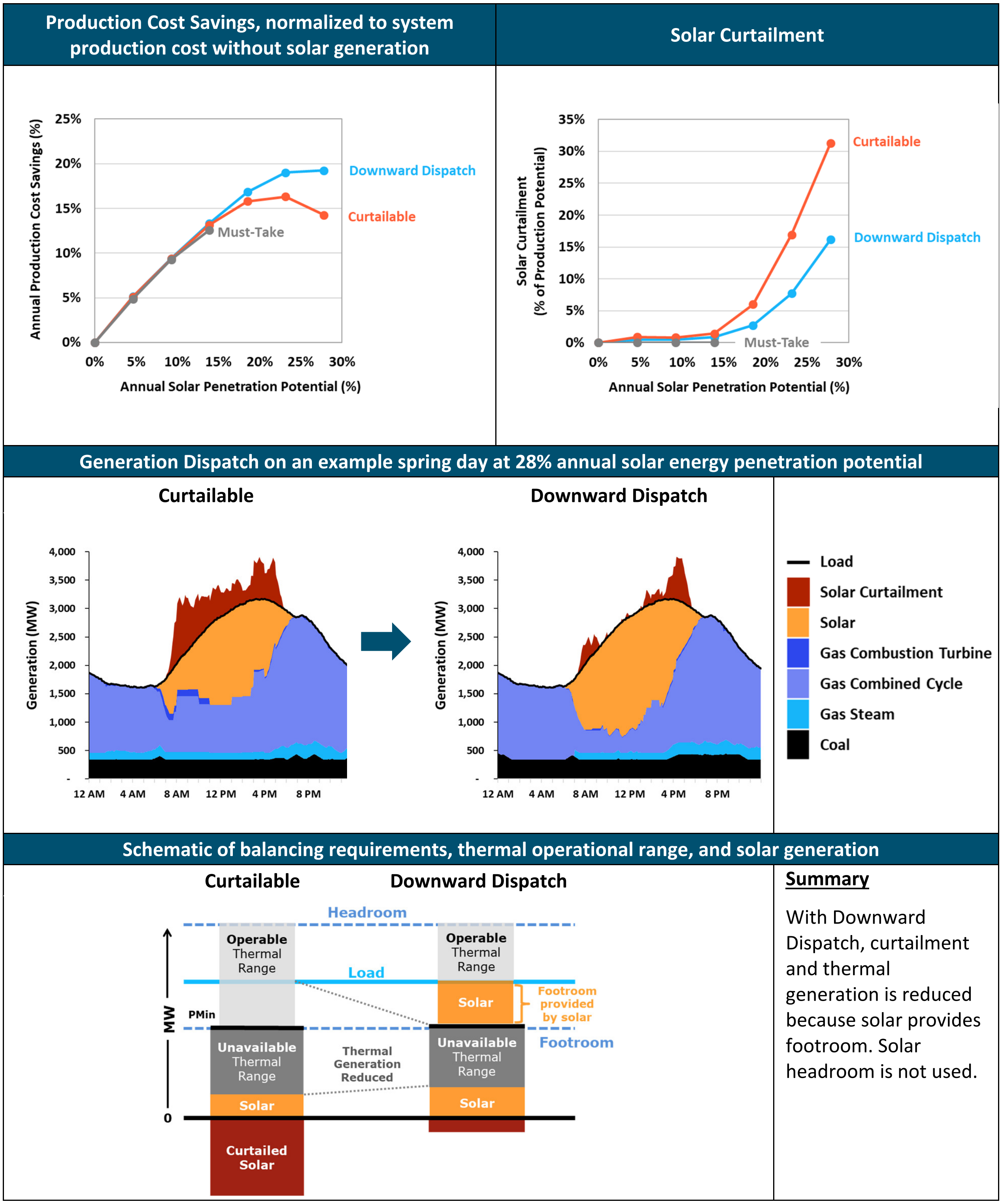
Dispatch is feasible with Curtailable solar because solar generation can be reduced until thermal dispatch is within the operable range.

3.3 "Downward Dispatch" operating mode: Reduced curtailment and thermal commitment, and increased value

Compared to Curtailable operating mode, Downward Dispatch operating mode allows solar to retain value at higher levels of solar generation (Figure 7, top panel). Downward Dispatch improves on Curtailable by allowing the system operator to plan to turn down solar generation if solar is over-forecasted ahead of real-time operations. Downward Dispatch also allows regulation footroom requirements to be provided by solar generators. The middle and bottom panels of Figure 7 demonstrate that, during hours of very high solar output, downward dispatch of solar enables the operator to commit fewer thermal power plants, which reduces the minimum output requirement for thermal generation and increases the quantity of solar delivered to the grid. It may seem paradoxical, but in our simulations, solar in Downward Dispatch operating mode has *more opportunities* to be curtailed, but *less actual curtailment* is observed.[7] At 28% solar penetration potential, Downward Dispatch would reduce expected curtailment by half – from 31%, in Curtailable operating mode, to 16% – enabling solar to provide positive incremental value at higher solar penetration levels. Our simulation results show that, with the right economic dispatch rules, solar curtailment can be minimized by allowing solar to provide the most constrained grid services at key times.

[7] We do not estimate the amount of regulation that would be dispatched by AGC below the 5-minute timescale, and the resultant differences in energy production from AGC dispatch. In the Downward Dispatch and the Full Flexibility operating modes, we develop rules by which the system operator can rely on solar to provide downward regulation, but we do not assess whether it would be most economical to turn down solar or other resources in response to an AGC signal. In some instances, it may be more economical to turn thermal generation down instead of solar, thereby avoiding fuel costs.

Figure 7: Summary: "Downward Dispatch" Operating Mode



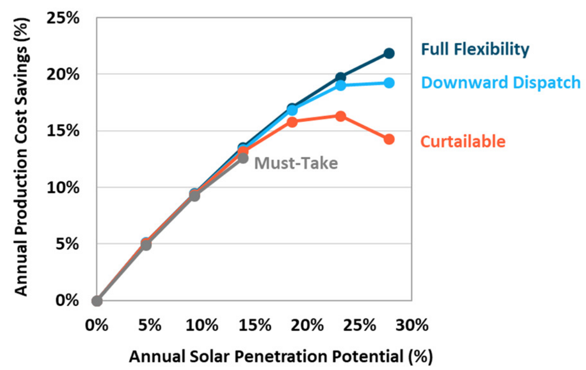
3.4 “Full Flexibility” operating mode: Additional value at higher solar penetrations

Sharing balancing requirements between thermal and solar generators becomes increasingly valuable as more solar capacity is added to the grid. Provision of balancing services from solar plants allows thermal generators to operate more efficiently by reducing the need for cycling and load following services, resulting in less fuel consumption. This also avoids commitment of inefficient thermal generation, reducing curtailment of solar during times of overgeneration.

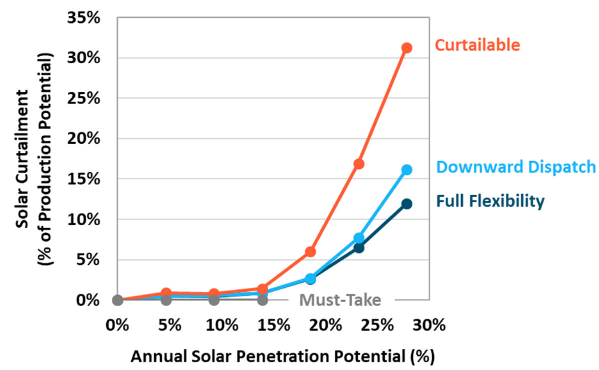
Figure 8 shows that these savings can be substantial for the TECO system. The curtailment observed in Downward Dispatch operating mode on an example spring day (Figure 8, middle panel) suggests that at higher solar penetration levels, it could be particularly challenging to ramp TECO’s thermal generation fleet down at sunrise and up at sunset. Operating solar in Full Flexibility operating mode would allow system operators to reduce forecast error headroom requirements and use any available solar headroom to meet regulation headroom requirements. On this example day, integrating these capabilities into operational procedures makes thermal generator ramping at sunrise and sunset more manageable.

Figure 8: Summary: "Full Flexibility" Operating Mode

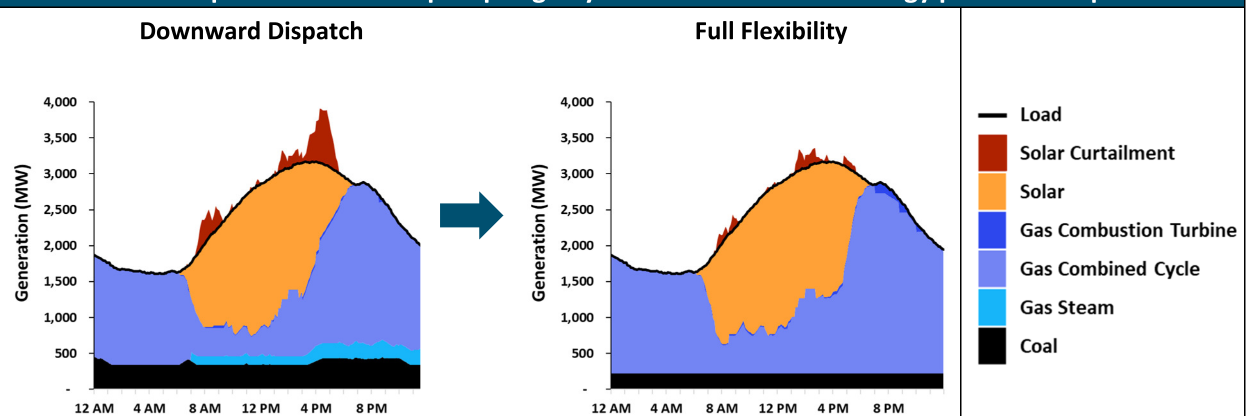
Production Cost Savings, normalized to system production cost without solar generation



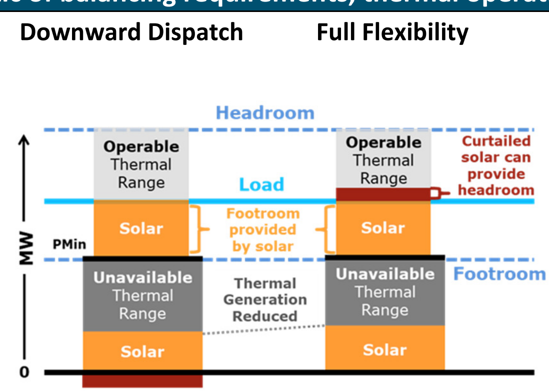
Solar Curtailment



Generation Dispatch on an example spring day at 28% annual solar energy penetration potential



Schematic of balancing requirements, thermal operational range, and solar generation



Summary

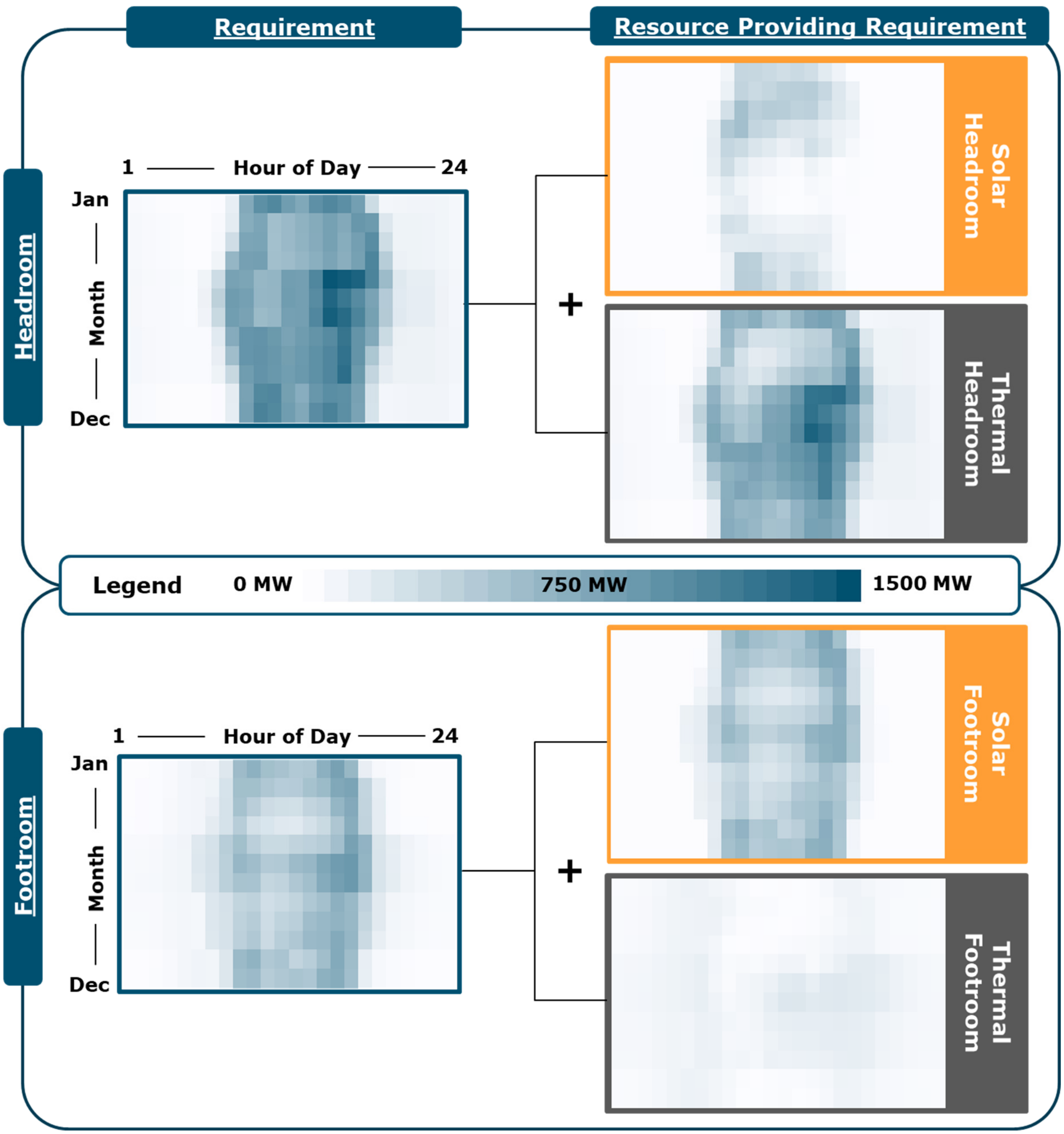
With Full Flexibility, curtailment and thermal generation are minimized because solar contributes to footroom and headroom.

Figure 9 shows the distribution of headroom requirements between thermal and solar resources for the hours-ahead unit commitment stage. Footroom requirements during the daytime are met predominantly by solar.[8] Solar provides headroom to mitigate forecast uncertainties via committing to curtail and by committing to provide regulation. For example, solar is curtailed frequently in spring morning and early afternoon hours, thereby creating headroom that could be used productively to meet operational requirements. During summer late afternoon and early evening hours, solar does not typically reduce headroom requirements by committing to curtail because load is high enough in these hours to absorb (not curtail) most solar generation, and the TECO generation fleet has enough headroom flexibility to absorb all solar generation. Our results confirm that headroom on solar is most likely to be available during periods of low load and high solar output, but that solar generators are unlikely to be curtailed for the purpose of creating headroom during higher-load hours.

The scope of this study is limited to the operation of resources within TECO balancing area, and consequently transactions with external entities are not represented in detail. Energy market transactions with neighboring regions may become more valuable and/or frequent at higher solar penetrations. These transactions would allow TECO to access the capabilities of a larger pool of thermal resources, thereby making it easier to meet headroom, footroom, and ramping requirements. Forecast error headroom requirements may be particularly impacted by increased regional coordination, because the aggregate forecast error of a larger footprint of solar resources will be reduced relative to the same capacity of solar resources deployed over a smaller footprint. Increasing the level of regional coordination would reduce flexibility challenges related to adding solar resources into TECO’s generation portfolio, thereby allowing solar energy to retain value at higher solar penetration levels. We expect that for a given level of solar generation, increased regional coordination would decrease the value of operating solar power plants in a more flexible manner. However, higher value for solar energy may hasten the pace of solar development across the region, thereby increasing solar penetration and consequently the value of solar flexibility.

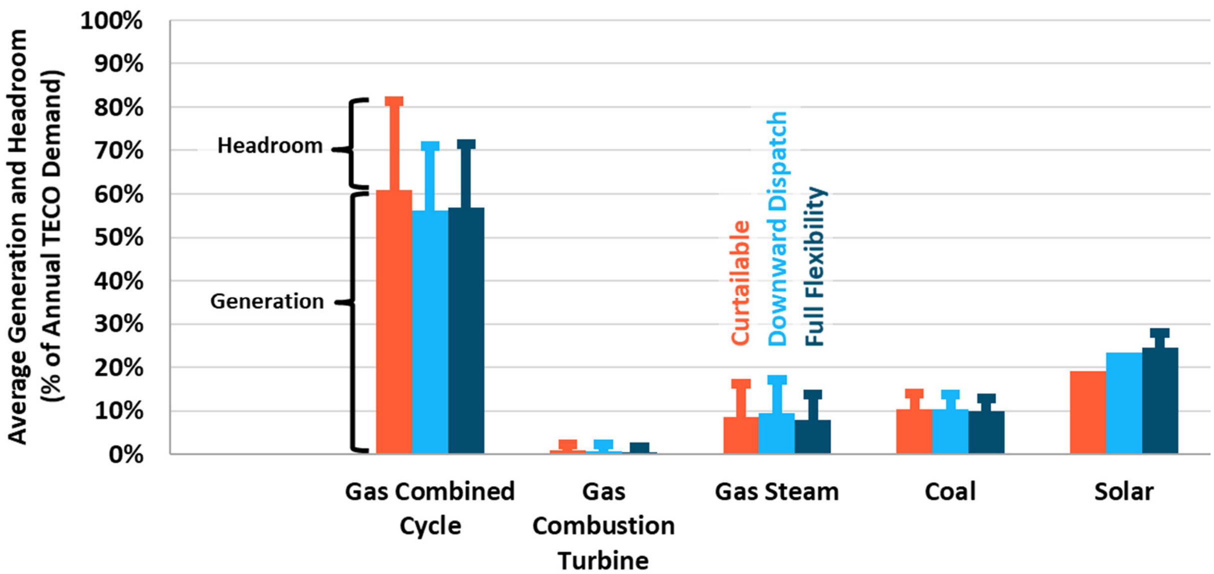
[8] When simulating the Downward Dispatch and Full Flexibility operating modes in PLEXOS, footroom requirements resulting from solar variability and uncertainty are not explicitly modeled because it is assumed that solar can provide these requirements if necessary. Simulation results do not show significant overgeneration events in real-time, confirming that footroom on solar for forecast error and within-hour variability is an effective balancing strategy. Our modeling does not simulate the dispatch of solar footroom held on AGC for balancing below the 5-minute timescale, but we expect solar to be effective on this timescale as well given the demonstrated capabilities of flexible solar plants.

Figure 9: Headroom and footroom requirements (left) and the portion of each requirement provided by solar and thermal resources (right) for the hours-ahead unit commitment stage at 28% annual solar energy production potential (2400 MW nameplate solar capacity) in the Full Flexibility operating mode. Values are month-hour averages.



Comparing thermal headroom and generation between the Curtailable and Full Flexibility operating modes (Figure 10, orange vs. dark blue bars) demonstrates that increasing solar flexibility reduces both thermal commitments and generation. The Curtailable, Downward Dispatch, and Full Flexibility simulations in Figure 10 have identical generator capacities and operational characteristics, except for their levels of solar flexibility. Note that no additional large capital investments would be necessary to reduce thermal capacity factors and commitment levels; increasing solar flexibility simply uses existing assets more efficiently, resulting in lower production costs.

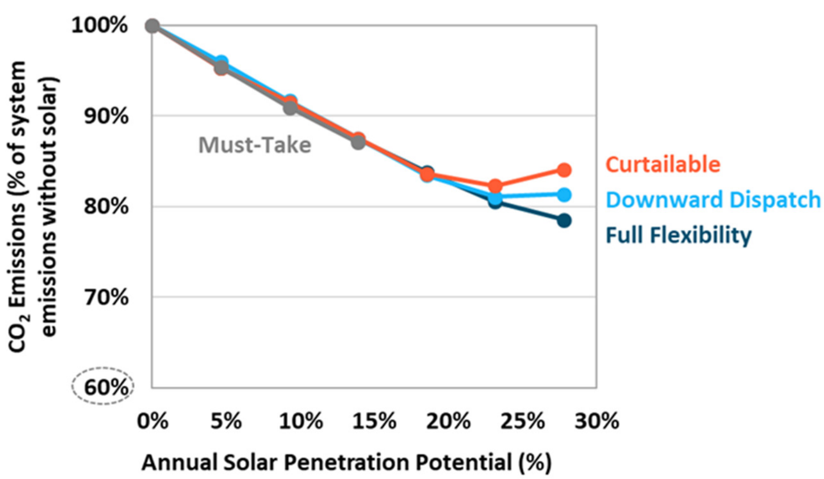
Figure 10: Annual average generation and headroom at 28% annual solar energy production potential, expressed as a fraction of annual TECO demand. Headroom is calculated as the difference between generation setpoint and committed capacity (or available production for solar) in real-time. Headroom on solar is only shown for the Full Flexibility operating mode.



3.5 CO_2 emissions results

Operating solar power plants in a more flexible manner enhances the ability of solar to reduce CO_2 emissions from electricity generation. As solar capacity increases, CO_2 emissions are reduced in all cases when solar is operated in Full Flexibility operating mode (Figure 11). At higher solar penetrations, Curtailable and Downward Dispatch operating modes result in more curtailment and higher levels of CO_2 emissions relative to Full Flexibility. At lower levels of solar penetration (less than ~19% annual solar penetration potential), we observe small differences in CO_2 emissions among the solar operating modes but do not believe them to be material.

Figure 11: CO_2 emissions as a function of solar deployment and solar operating mode



Flexibly scheduling and controlling solar plants can provide significant reliability, financial, and environmental value. Solar dispatch flexibility an important tool that grid operators can use to address challenges associated with higher solar penetrations and to integrate increasing amounts of solar cost-effectively. Dispatching solar power plants to the needs of the grid will reduce CO_2 emissions at higher solar penetrations and may reduce criteria pollutant emissions (such as NO_x), which can be significantly higher for power plants that frequently ramp up and down.

3.6 Summary tables

The numeric values in Table 3 and Table 4 indicate that increasing solar flexibility increases the value of solar energy and decreases solar curtailment. These values are for one specific system configuration, and depend on resource capabilities and capacity, fuel cost projections, and other many factors. Consequently, the values should not be applied to other jurisdictions or other TECO system conditions.

Table 3. Average and marginal energy value of solar, in $/MWh of solar production potential. The energy value of solar represents only production cost savings and does not include other value streams such as avoided peak capacity. The marginal energy value of solar is calculated as the change in production cost resulting from the addition of an incremental 400 MW of solar capacity.

Available Solar Generation			Average Energy Value of Solar ($/MWh)				Marginal Energy Value of Solar ($/MWh)			
Nameplate MW	Annual GWh	% of 2019 TECO Demand	Must-Take	Curtailable	Downward Dispatch	Full Flexibility	Must-Take	Curtailable	Downward Dispatch	Full Flexibility
400	958	4.6%	$28.7	$29.9	$30.1	$30.1	$28.7	$29.9	$30.1	$30.1
800	1,916	9.3%	$27.2	$27.5	$27.6	$27.8	$25.8	$25.1	$25.1	$25.5
1,200	2,874	13.9%	$24.6	$25.8	$26.1	$26.5	$19.5	$22.3	$23.2	$24.0
1,600	3,832	18.5%	N/A	$23.2	$24.7	$25.0	N/A	$15.5	$20.6	$20.5
2,000	4,790	23.2%	N/A	$19.2	$22.3	$23.2	N/A	$3.1	$12.8	$15.9
2,400	5,747	27.8%	N/A	$14.0	$18.9	$21.4	N/A	$ (12.1)	$1.4	$12.7

Table 4. Solar resource availability and solar curtailment results for each solar penetration level and operating mode.

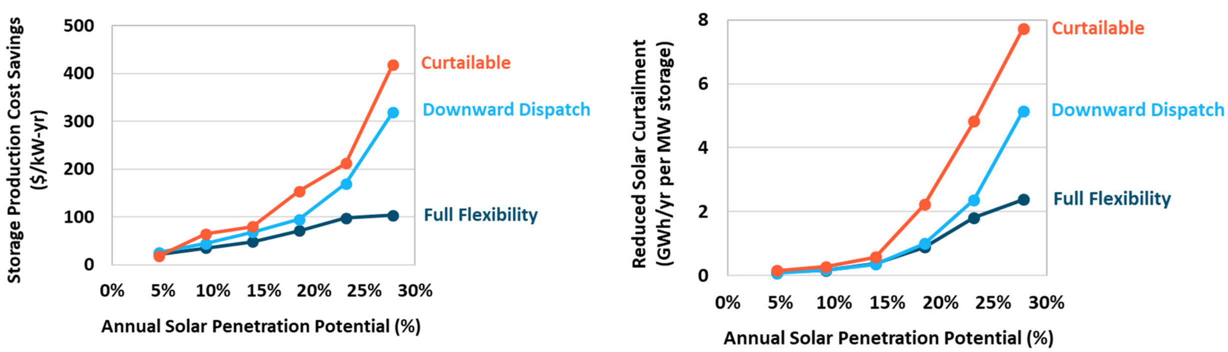
Available Solar Generation			Solar Curtailment (GWh)				Solar Curtailment (% of available solar energy)				Solar Penetration Achieved (% of 2019 TECO demand)			
Nameplate MW	Annual GWh	% of 2019 TECO Demand	Must-Take	Curtailable	Downward Dispatch	Full Flexibility	Must-Take	Curtailable	Downward Dispatch	Full Flexibility	Must-Take	Curtailable	Downward Dispatch	Full Flexibility
400	958	4.6%	0	8	5	5	0%	0.9%	0.5%	0.5%	4.6%	4.6%	4.6%	4.6%
800	1,916	9.3%	0	16	10	10	0%	0.8%	0.5%	0.5%	9.3%	9.2%	9.2%	9.2%
1,200	2,874	13.9%	0	41	24	26	0%	1.4%	0.8%	0.9%	13.9%	13.7%	13.8%	13.8%
1,600	3,832	18.5%	N/A	230	105	101	N/A	6.0%	2.7%	2.6%	N/A	17.4%	18.0%	18.0%
2,000	4,790	23.2%	N/A	811	370	311	N/A	16.9%	7.7%	6.5%	N/A	19.2%	21.4%	21.7%
2,400	5,747	27.8%	N/A	1,795	929	686	N/A	31.2%	16.2%	11.9%	N/A	19.1%	23.3%	24.5%

3.7 Sensitivity study: Incremental value of storage

Energy storage, particularly from fast-responding batteries such as lithium-ion, can quickly ramp from charging to discharge, providing an operating range that is double the nameplate capacity. Moreover, batteries can reduce fuel costs and avoid solar curtailment by charging during times of curtailment and discharging during times when thermal generation is on the margin.

For our final set of simulations, we add a small battery (50 MW, equivalent to ~1% of peak demand) with four hours of energy duration (200 MWh) to the TECO system at various levels of solar penetration to explore the value of storage in the context different solar operating modes. We find similar results to other storage production cost studies: storage provides production cost savings across all solar penetrations, with larger savings occurring at higher solar penetrations. Storage is used for a mix of regulation, forecast error reserves, and within-day energy shifting. Storage also reduces the magnitude of ramps during sunrise and sundown, which is more valuable at higher solar penetrations. The value of shifting energy increases significantly in the presence of solar curtailment (Figure 12). This study focuses on operational cost savings of storage, and therefore does not consider storage capital costs or a full cost-benefit analysis of storage.

Figure 12: Increasing solar operational flexibility can reduce the operational value of storage at a given solar penetration.



The opportunity for storage to add value is reduced when the system operator increases reliance on solar power plant flexibility, because flexible operation of solar can provide some of the same grid services as storage, especially footroom flexibility. Storage resources can be held in reserve ahead of real-time to address forecast errors in solar generation. The value of storage resources will be reduced if system operators can reduce forecast error footroom and headroom held on thermal generators by including solar curtailment in forecast error requirement calculations. In many renewable integration and storage valuation studies, a significant fraction of storage value comes from providing regulation. Solar resources could provide the same service during some portions of the day, potentially allowing the storage device to perform other functions. Also, solar curtailment decreases as solar operational flexibility is increased, thereby reducing the value of storage (see Figure 12) because fewer opportunities exist for energy shifting at a given solar penetration level. Renewable integration studies at higher renewable penetrations do not typically simulate wind or solar in the Full Flexibility operating mode, and therefore may overstate the value of storage. However, we recognize that if an electricity system already has a significant amount of storage or other flexible resources, the incremental value of increasing solar flexibility would be reduced relative to a system with less flexibility.

While our results suggest that increasing solar flexibility may reduce the need for storage (and/or other flexible resources) at intermediate solar penetrations, there is still a significant role for storage to play at high solar penetrations. As more and more solar is deployed in a grid, the operational value of adding energy storage will increase due to increased balancing requirements and increased solar curtailment. Storage can also provide significant system capacity value, whereas the marginal capacity contribution of solar resources tends to drop relatively quickly with increasing solar penetration.

4 Areas for Future Research

This study lays out some of the technical considerations that must be implemented to tap the full potential of flexible solar in grid operations. Further work is necessary on many fronts to fully realize the potential of flexible solar:

- Solar forecasts are key to unlocking the potential of flexible solar. Without some certainty on the possible bounds of power production, it is impossible to rely on a variable resource for balancing services, especially for services that require headroom. A method is needed to develop a confidence interval for flexible solar that is conservative enough to be workable in a control room while still providing a reasonable solar dispatch range. Providing footroom with solar requires significantly less forecast accuracy than is required to provide headroom.

- Disincentives for flexible solar exist in markets where Renewable Energy Certificates (RECs) are a primary revenue source, because RECs are only generated when the generator produces a MWh of renewable energy. A renewable power plant would not want to forgo REC revenue by offering to be dispatched unless doing so provided the generator with positive net revenue. Further research can shed light on the value of solar dispatch in a market with RECs.

- Many existing renewable power plants have contracts that do not envision using the plant for grid balancing, so contracts would need to be clarified or renegotiated to enable dispatchability from existing facilities.

- In organized electricity markets, it remains to be seen how variable renewables would bid their flexibility into energy and ancillary service markets. Existing methods of calculating opportunity cost for ancillary services are largely based on thermal opportunity cost of producing less energy and dispatching at less efficient setpoints. Compared to thermal generators, variable renewables have more uncertainty surrounding day-ahead or hour-ahead maximum production levels. Also, variable renewables may have no marginal cost of providing ancillary services if they are already curtailed due to system-wide conditions.

- Some organized markets do not separately procure upward (headroom) and downward (footroom) services. However, our study indicates that the cost for solar to provide headroom and footroom is highly asymmetric. Flexible solar is likely to have significantly higher value in markets, like the California ISO, with distinct upward and downward reserve products. Other market operators in areas with high wind and solar penetration should consider establishing separate downward and upward reserve products.

5 Conclusions

When envisioning a power system with large amounts of variable renewable energy, system planners must include information on the least-cost manner of reliably operating that system, in both the present and future. If system operators can control the power output of variable renewable resources, these resources can be viewed as assets that help to maintain reliability rather than liabilities that create operational challenges. Bringing the operational value of dispatching variable renewables into utility resource plans may change the investments made in resources going forward. The flexibility brought by dispatching variable renewable generators could reduce the need for investments in other types of flexible resources. But dispatching renewables helps to retain their value at higher penetrations, which may induce further renewable deployment and, in turn, increase the need for other flexible resources. In either scenario, reducing operational costs and CO_2 emissions from the power system is easier when solar power is treated as an active participant in grid balancing rather than an invisible part of the "net load."

6 Appendix A: Reserve Calculations and Requirements

Many renewable integration studies calculate headroom and footroom requirements such that unit commitment and dispatch decisions include enough flexibility to successfully navigate variability and uncertainty from load and variable renewable resources. Calculating reserve requirements is an active area of research, but at present most studies follow a similar calculation methodology.[9] In our study, we calculate reserve requirements largely using standard methods but make modifications necessitated by the multi-stage structure of our PLEXOS model and solar flexibility constraints.

We enforce three separate categories of reserve requirements in PLEXOS: forecast error (Section 6.1), regulation (Section 6.2), and contingency (Section 6.3). Section 6.4 describes how different classes of resources provide each category of reserves.

To calculate forecast error and regulation reserve requirements, we rely on year-long timeseries data for load and solar production. Both load and solar datasets include forecasted and real-time (5-minute actual) data. Solar timeseries data is described in Section 2.1.3. TECO provided a year-long timeseries of forecast and actual (5-minute) load data.

6.1 Forecast error reserves

Forecast error reserves ensure that enough capacity is committed before real-time such that load and solar forecast error do not cause reliability concerns. Both upward and downward requirements (headroom and footroom, respectively) are enforced in every model stage before real-time. Our

[9] E. Ibanez, I. Krad and E. Ela, “A Systematic Comparison of Operating Reserve Methodologies,” National Renewable Energy Laboratory, 2014, **https://www.nrel.gov/docs/fy14osti/61016.pdf**; I. Krad, E. Ibanez and W. Gao, “A Comprehensive Comparison of Current Operating Reserve Methodologies,” IEEE/PES Transmission and Distribution Conference and Exposition (T&D), 2016.

treatment of forecast error reserves is similar to “load following” or “flexibility” reserves in other renewable integration studies, with the exception that the within-hour variability traditionally associated with “load following” calculations is included as part of the regulation requirement in this study.

6.1.1 FORECAST ERROR REQUIREMENT CALCULATION

For each of the three model stages before real-time (i.e., multiple days-ahead, day-ahead, and hours-ahead), the difference between forecast and average actual output is calculated, resulting in a library of positive and negative MW forecast error values. The calculation is performed *individually* on demand and solar profiles. To capture correlations between demand and variable renewable resources, many studies in the literature subtract variable renewable output from demand to create a library of *net load* forecast error values. We do not employ this method because quantifying the level of solar forecast error is key to representing solar flexibility in the production simulation. At higher levels of solar penetration, we observe that solar forecast error is much larger than demand forecast error, which minimizes the difference between individual and net load forecast error calculation methodologies. In future analyses, it may be possible to retain correlations between solar and demand forecast errors when modeling solar flexibility.

To reflect different levels of forecast error at different times of the day, the library of forecast errors is divided into bins by hour of day. Because TECO experiences different weather conditions during different times of year, the hourly bins for solar forecast error are subdivided by season. Finally, to reflect differences in forecast accuracy resulting from cloud cover, the season-hour bins are divided into two separate bins: “cloudy” and “clear sky.” Solar forecasts are placed into the “cloudy” bin if the forecasted solar output is less than 80% of an estimate of the clear sky output.

System operators make conservative decisions when committing generation units, but it is not common practice to commit units to prepare the system for *every* possible future level of load or solar production. In the case of extreme forecast error, operators can perform a set of emergency actions that fall outside of the scope of production cost modeling, such as making an emergency phone call to a neighboring balancing area, dispatching contingency reserves, or allowing a small imbalance in supply and demand (thereby causing area control error) for a short period of time. Consequently, an appropriate threshold for forecast error reserves must be defined beyond which the system operator does not need to hold headroom or footroom for forecast error. This threshold can be the product of a detailed analysis that compares the value of a more reliable system with the incremental cost of holding more reserves. In many studies, a detailed cost/benefit analysis is not within scope so reserve requirement levels are selected by choosing a percentage of forecast errors based on prior studies of similar systems. Commonly used thresholds are either ~68 – 70% (roughly one standard deviation, 1σ, for a normally distributed set of forecast errors) or 95% (2σ), meaning that the unit commitment simulation will ensure that all but ~28 – 30% or 5% (respectively) of all possible forecast errors can be met by available resources.

To calculate forecast error reserves for solar in our study, we truncate the library of forecast errors to include 70% (~1σ) of all forecast errors when committing units ahead of real-time (i.e., the multiple days-ahead, day-ahead, and hours-ahead unit commitment stages). Doing so results in forecast error reserve requirements in both the upward (headroom) and downward (footroom) directions because both under- and over-forecast events are included in the timeseries datasets. We follow the same procedure for load forecast error, except that we expand the range of forecast errors that we included in the hours-ahead stage to include 95% (2σ) of all forecast errors. We truncate the library of forecast errors separately for load and solar, and then add the result to obtain the final reserve requirement.

The final step of the forecast error reserve calculation ensures that solar forecast error reserve levels remain within the bounds of possible solar production. Because solar production cannot go below zero, the forecast error headroom requirement is adjusted if the forecasted solar production minus the headroom requirement is less than zero. Because solar production cannot go above the level at which the power plant would produce under clear sky conditions, the forecast error footroom requirement is adjusted if the forecasted solar production plus the footroom requirement is greater than an estimate of the clear sky production potential for a given timestep.

Studies in the literature demonstrate that forecast error for a geographically diverse set of variable renewable resources is typically lower than forecast error for the same capacity of resources installed on a smaller footprint. For this study we assume that all solar deployment will occur within the TECO service territory, which is a relativity small portion of the Florida peninsula. Consequently, we do not reduce the marginal forecast error contribution of additional solar resources as more solar is added to the TECO system. If solar resources were to be deployed on a larger geographic footprint, forecast error requirements would be reduced and consequently the benefits of flexible solar operation would be lower at a given solar penetration. Similarly, improved solar forecasting would decrease the cost of solar integration, which would raise the value of solar facilities at any solar penetration and decrease the value of flexible solar operation at a given solar penetration.

6.2 Regulation reserves

Regulation reserves are held for short-timescale variation – less than 1 hour – of load and variable renewable output. In our study regulation reserves represent the amount of within-timestep variability that the system operator must manage if average load and solar production are perfectly forecasted at an hourly timestep for the multiple days and day-ahead unit commitment stages, a 15-minute timestep in the hours-ahead unit commitment stage, or a 5-minute timestep in the real-time unit commitment stage.

6.2.1 REGULATION RESERVE REQUIREMENT CALCULATION

We calculate regulation requirements on two different timescales (hourly to 5-minute and 5-minute to automatic generation control (AGC)) and add the result to obtain the final reserve requirement. Only the 5-minute to AGC component of the regulation requirement is held in real-time dispatch, because the real-time stage economically commits and dispatches on 5-minute intervals, thereby removing the need to hold additional headroom and footroom for variability between hourly and 5-minute commitment intervals. Regulation requirements for solar are calculated from a real-time 5-minute production profile that is the average of many individual production profiles from across the TECO region.

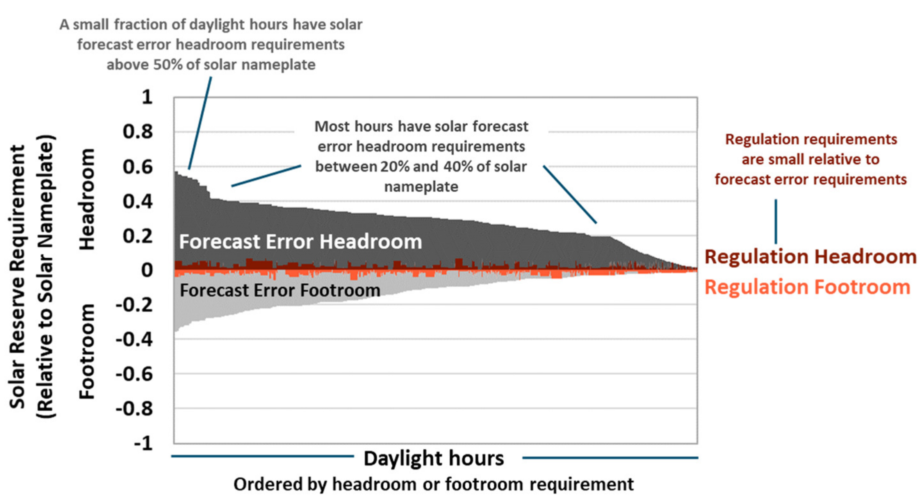
<u>Hourly to 5-minute timescale:</u> Real-time 5-minute load or solar production profiles are subtracted from a linear interpolation between hourly (multiple days-ahead and day-ahead) or 15-minute (hours-ahead) averages of the same real time profile. As with the forecast error calculation, this results in a library of positive and negative error values. Errors are divided into bins by hour of day for load, and by hour of day, season, and a cloudy/clear sky binary for solar. We calculate the hourly to 5-minute regulation requirement by truncating the library of errors within each bin to include 95% of errors.

5-minute to AGC timescale: To calculate the solar component of the AGC requirement, we estimate the short-term variation in plant output on a 5-minute timescale. We compare a cloud cover persistence forecast based on solar output in one 5-minute timestep to actual solar output in the next 5-minute timestep. Similar to other calculations, we bin the result by hour of day and season, and then apply a 95% error cutoff.

We calculate the 5-minute to AGC requirement for demand as 1% of demand, a value frequently used in other production simulations.

Figure 13 shows the combined regulation and forecast error headroom and footroom requirements for solar uncertainty and variability for the hours-ahead unit commitment stage. Only daylight hours are depicted in Figure 13. Forecast error requirements are typically much larger than regulation requirements. The relatively large magnitude of the forecast error headroom requirements is in part due to the small geographic scope of the TECO balancing area.

Figure 13: Solar reserve requirement duration curve for the hours-ahead unit commitment stage.



6.3 Contingency reserves

Contingency reserves are held for infrequent but extreme events, typically the loss of a large generation unit or transmission line. In our simulations, contingency reserves are held in all model stages, including real-time, because system operators must always be prepared for contingency events. Consistent with current operational practice, contingency reserves are only enforced in the upward (headroom) direction.

6.3.1 CONTINGENCY REQUIREMENT CALCULATION

Contingency reserve requirements for the TECO system were implemented with input from TECO staff. The magnitude of reserve need is calculated endogenously in PLEXOS for every time step as the maximum of:

- TECO's largest generation contingency
- TECO's share of the Florida reserve sharing obligation
- A minimum contingency reserve level of 315 MW

6.4 How resources provided reserves

Table 5. How different classes of resources provide headroom and footroom capacity to each reserve type.

Resource	Forecast error	Regulation	Contingency
Online thermal	Headroom and footroom*	Headroom and footroom, subject to ramp rate limits	Headroom, subject to ramp rate limits
Offline thermal	Nameplate capacity of generators that could start within the required timeframe, but combustion turbines in a combined cycle can only contribute if the steam turbine was committed	Could not contribute	Nameplate capacity of simple cycle combustion turbines that can start within the required timeframe
Batteries	Available headroom and footroom	Available headroom and footroom	Available headroom
Demand response	Does not contribute	Does not contribute	Available capacity
Solar	See Table 6 below		

*Online generators that can shut down with sufficient speed contribute capacity equal to their minimum production (PMin) to forecast error reserve footroom, in addition to available footroom between their setpoint and PMin.

Table 6. Schematic representing how solar generators provide reserves in this study.

	Reserve Type	Source of need	How does solar provide?	
Total Headroom	Contingency	Largest contingency	Headroom on solar for contingency reserves is not modeled in this study, but would be possible with enough production potential certainty	
Headroom (MW)	Forecast Error + Regulation Headroom	Solar variability and uncertainty	Forecast error up from solar is reduced when solar is curtailed	When solar provides regulation headroom, more forecast error reserve is held in case of solar over-forecast
		Load variability and uncertainty	Headroom on solar for load under-forecast is not modeled in this study, but would be possible with enough production potential certainty	
Forecast Load				
Footroom (MW)	Forecast Error + Regulation Footroom	Load variability and uncertainty	Solar provides footroom for load over-forecast, limited by the amount of solar generation below the lower bound on solar production	
Total Footroom		Solar variability and uncertainty	Reserve need is not modeled because solar can be curtailed in real time if energy cannot be absorbed	

7 Appendix B: Prior Research

Prior research that simulates solar (or wind) in Curtailable or Downward Dispatch operating mode includes the following:

- GE Energy, "Western Wind and Solar Integration Study," National Renewable Energy Laboratory, May 2010, **https://www.nrel.gov/docs/fy10osti/47434.pdf**.
- Mills, A., A. Botterud, J. Wu, Z. Zhou, B.-M. Hodge and M. Heaney, "Integrating Solar PV in Utility System Operations," Argonne National Laboratory, 2013, **http://eta-publications.lbl.gov/sites/default/files/lbnl-6525e.pdf**.
- Eber, K. and D. Corbus, "Hawaii Solar Integration Study: Executive Summary," National Renewable Energy Laboratory, June 2013, **https://www.nrel.gov/docs/fy13osti/57215.pdf**.
- Energy and Environmental Economics, "Investigating a higher renewables portfolio standard in California," 2014, **https://www.ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf.**
- California ISO, "Phase 1.A. Direct testimony of Dr. Shucheng Liu on behalf of the California Independent System Operator," 13 August 2014, **http://www.caiso.com/Documents/Aug13_2014_InitialTestimony_ShuchengLiu_Phase1A_LTPP_R13-12-010.pdf.**
- Energy and Environmental Economics, Inc. and National Renewable Energy Laboratory, "Western Interconnection Flexibility Assessment," Western Electricity Coordinating Council and Western Interstate Energy Board, 2015, **https://www.ethree.com/wp-content/uploads/2017/02/WECC_Flexibility_Assessment_Report_2016-01-11.pdf**.
- Brinkman, G., J. Jorgenson, A. Ehlen and J. Caldwell, "Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California," National Renewable Energy Laboratory, January 2016, **https://www.nrel.gov/docs/fy16osti/64884.pdf**.
- Seel, J., A. Mills, R. Wiser, S. Deb, A. Asokkumar, M. Hassanzadeh and A. Aarabali, "Impacts of High Variable Renewable Energy Futures on Wholesale Electricity Prices, and on Electric-Sector Decision Making," Lawrence Berkeley National Laboratory, May 2018, **http://eta-publications.lbl.gov/sites/default/files/report_pdf_0.pdf**.

Prior research that simulates solar (or wind) in Full Flexibility operating mode – frequently as a sensitivity – includes the following:

- Van Hulle, F., I. Pineda and P. Wilczek, "Economic grid support services by wind and solar PV: A review of system needs, technology options, economic benefits and suitable market mechanisms," REserviceS project, September 2014, http://www.reservices-project.eu/wp-content/uploads/REserviceS-full-publication-EN.pdf.
- Nelson, J. and L. Wisland, "Achieving 50 Percent Renewable Electricity in California," Union of Concerned Scientists, August 2015, https://www.ucsusa.org/sites/default/files/attach/2015/08/Achieving-50-Percent-Renewable-Electricity-In-California.pdf.
- Tabone, M. D., C. Goebel and D. S. Callaway, "The effect of PV siting on power system flexibility needs," Solar Energy, vol. 139, pp. 776-786, 2016.
- Denholm, P., J. Novacheck, J. Jorgenson and M. O'Connell, "Impact of Flexibility Options on Grid Economic Carrying Capacity of Solar and Wind: Three Case Studies," National Renewable Energy Laboratory, December 2016, https://www.nrel.gov/docs/fy17osti/66854.pdf.
- Hale, E. T., B. Stoll and J. Novacheck, "Integrating solar into Florida's power system: Potential roles for flexibility," Solar Energy, vol. 170, pp. 741-751, 2018.