COM/CJS/ar9/lil **Date of Issuance 7/1/2016**

Decision 16-06-052 June 23, 2016

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to improve distribution level interconnection rules and regulations for certain classes of electric generators and electric storage resources.	Rulemaking 11-09-011 (Filed September 22, 2011)

ALTERNATE DECISION INSTITUTING COST CERTAINTY, GRANTING JOINT MOTIONS TO APPROVE PROPOSED REVISIONS TO ELECTRIC TARIFF RULE 21, AND PROVIDING SMART INVERTER DEVELOPMENT A PATHWAY FORWARD FOR PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY

Table of Contents

ALTERNATE DECISION INSTITUTING COST CERTAINTY, GRANTING JOINT MOTIONS TO APPROVE PROPOSED REVISIONS TO ELECTRIC TARIFF RULE 21, AND PROVIDING SMART INVERTER DEVELOPMENT A PATHWAY FORWARD FOR PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY

Summary

Today's decision grants joint motions improving Electric Tariff Rule 21 to: (1) provide earlier and more reliable interconnection cost information to electric generation developers and (2) set forth the process for analyzing requests for interconnection of electricity storage devices. These motions are the result of an exemplary collaborative process among the parties, all of whom are to be commended for their tireless work. Today's decision also grants a cost envelope pilot policy for interconnection cost certainty.

This proceeding is closed.

1. Background

The Commission initiated Rulemaking (R.) 11-09-011 on September 22, 2011 to review and, if necessary, revise the rules and regulations governing interconnecting generation and storage resources to the electric distribution systems of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E). The utilities' rules and regulations pertaining to the interconnection of generation are generally set forth in Electric Tariff Rule 21 (or Rule 21).

On September 20, 2012, the Commission issued Decision (D.) 12-09-018 which adopted a settlement agreement that included revisions to Electric Tariff Rule 21 and provided a separate Generator Interconnection Agreement (GIA) for Exporting Generating Facilities and Exporting Generating Facility Interconnection Request. The revisions to Electric Tariff Rule 21 focused on the interconnection study process. The settlement agreement required that each utility revise its Electric Tariff Rule 21 to assign all interconnection requests to either the "Fast Track" - a screen-based, streamlined review process for net energy metering, non-export, and small exporting facilities or the Detailed Study with three study processes for more complicated generating facilities.

On December 18, 2014, the Commission issued D.14-12-035 which granted joint motions proposing revisions to Electric Tariff Rule 21 to require "smart" inverters for PG&E, SCE, and SDG&E. The purpose of inverters is to convert direct current (DC) from the generating resource to the voltage and frequency of the alternating current (AC) distribution system. Wind and photovoltaic resources produce DC, and therefore need inverters, while hydroelectric and biomass generating units, which produce AC, do not. Generally, in California, about 90% of small scale renewable generation is connected to the distribution grid through inverters.

The Commission agreed with the moving parties that bringing the benefits of today's "smart inverters" to California required changes to Electric Tariff Rule 21 and, in D.14-12-035, the Commission adopted the revisions recommended by the Smart Inverter Working Group (SIWG) in their January 2014 "Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources." The Commission granted the parties' request and ordered the utilities to file Tier 1 Advice Letters making the following changes to their respective Electric Tariff Rule 12:

a. Anti-Islanding Protection: Revise Electric Tariff Rule 21, Section H.1.a.(2) to reflect proposed new voltage ride-through settings;

b. Low and High Voltage Ride-Through: Revise Electric Tariff Rule 21, Section H.1.a.(2) and Table H.1 to reflect proposed new default voltage ride-through requirements;

c. Low and High Frequency Ride-Through: Revise Electric Tariff Rule 21, Section H.1.a.(2) and R21 Table H.2 to reflect proposed new frequency ride-through settings;

d. Dynamic Volt-Var Operation: Revise Electric Tariff Rule 21, Sections H.2.a, H.2.b, H.2.i and R21 table H.1 to reflect proposed new dynamic volt/var operations requirements;

e. Ramp Rates: Add new Electric Tariff Rule 21 subsection within Electric Tariff Rule 21, Section H to include proposed new ramp rate requirements;

f. Fixed Power Factor: Revise Electric Tariff Rule 21, Section H.2.i to reflect the proposed new fixed power factor requirements; and

g. Soft Start Reconnection: Revise Electric Tariff Rule 21, Section H.1.a.(2) to reflect proposed new reconnection by soft-start method.

On August 6, 2015, the assigned Commissioner and assigned Administrative Law Judge (ALJ) convened a Status Conference to determine the state of the parties' work on the issues of: (1) behind-the-meter storage interconnection requests, and (2) interconnection cost certainty. The parties appeared and presented the results of their meetings, which have been facilitated by Staff from the California Public Utilities Commission's Energy Division.

On August 19, 2015, the assigned ALJ issued a ruling setting forth the schedule proposed by the parties and approved by the assigned Commissioner and assigned ALJ:

DATE	EVENT
August 6, 2015	Pursuant to Rule 13.14(a), record submitted for decision by the Commission on the issue of the Utilities' fixed cost option proposal versus parties' alternative cost envelope proposal.
August 24, 2015	Clean Coalition distribute to service list Cost Guide Proposal.
August 31, 2015	Solar City and California Solar Energy Industries Association distribute to service list Pre-Application Report Expansion Proposal.
August 31, 2015	Utilities, and other parties should they so desire, distribute to service list written proposal on Storage Load Issues, including any changes to Rule 21 screens.
September 14, 2015	Utilities and Solar City, and other parties should they so desire, distribute to service list Non-Exporting Storage Proposal.
Before September 30, 2015	Utilities conduct informational webinar providing an overview of the process for reviewing storage projects pursuant to Rule 21.
September/October 2015	Energy Division Staff to facilitate workshops on issues, including follow-ups as needed.
November 9, 2015	Joint Motion Requesting Commission action on Cost Certainty Issues filed and served, alternative motions, if any, also filed and served.
November 4, 2015	Joint Motion Requesting Commission action on Storage Interconnection issues filed and served, alternative motions, if any, also filed and served.
As provided in Rule 11 of the Commission's Rules of Practice and Procedure (Rules).	Responses and replies, if authorized, to motions.

DATE	EVENT
With the filing of the last response or reply to the motions.	Remaining issues in proceeding Submitted for decision by Commission Pursuant to Rule 13.14(a).

1.1. Joint Motion on Cost Certainties

In compliance with the August 2015 Ruling, Clean Coalition, SolarCity and California Solar Energy Industries Association distributed their proposals as directed and the Energy Division hosted a Workshop on the two cost certainty issues on October 2, 2015. Subsequently, on October 20, 2015, the Energy Division facilitated a second, follow-up workshop on the Cost Certainty Issues.

As a result of the workshops, the parties developed a set of agreed-upon principles to support interconnection efficiency and transparency. On November 9, 2015, SCE, SDG&E, PG&E, California Solar Energy Industries Association, Clean Coalition, CODA Energy and Interstate Renewable Energy Council, Inc., filed and served their joint motion proposing Pre-Application Report Enhancements and the development of a Unit Cost Guide. The moving parties explained that the Unit Cost Guide will give generation developers a readily available price list of typical interconnection facilities and equipment, and that adding specific data, with associated costs and timing, to the Enhanced Pre-Application report will also give generation developers better cost information.

Unit Cost Guide. The purpose of Unit Cost Guide is additional cost transparency in support of generation interconnection. Based upon the numerous discussions and workshops, the moving parties requested that the Commission direct the Utilities to prepare and issue an annual Cost Guide that conforms to a set of agreed-upon principles. The Guide Implementation Principles are set forth in complete detail in Attachment A to today's decision.

The Cost Guide Implementation Principles provide for the Utilities to develop the Guide within 90 Calendar Days of the Commission's decision. Each Utility will publish a Cost Guide for facilities generally required to interconnect generation to their respective Distribution systems, but the Utilities will coordinate to develop a consistent Cost Guide format. The Cost Guide, however, will not be binding for actual facility costs. The Cost Guide will reflect a forecasted annual adjustment for five years to provide estimates for future procurement timing. The Utilities will include illustrative scenarios reflecting stakeholder input to assist in understanding and readability of the guide, and will describe various requirements for interconnection facilities and distribution upgrades; an annual proposed stakeholder review process can act as a forum to discuss the usefulness of such scenarios and provide for updates. The Cost Guide will set forth assumptions used in the calculations in a format similar to that used by the California Independent System Operator, and will provide utility operation and maintenance along with recovery cost calculation method calculations.

The Utilities will update their Cost Guides annually. Prior to posting updates to the Cost Guide, the Utilities will meet and confer with stakeholders to obtain comment on proposed revisions pursuant to a schedule set forth in the Principles. Overall, the Cost Guides developed by the Utilities will not replace any project-specific study costs, but rather, the Cost Guide is intended to be used as a point of reference for projects that are considering the existing study processes.

Enhanced Pre-Application Reports. The moving parties explained that enhancement of the existing Rule 21 Pre-Application Report would address interconnection customer data needs while ensuring overall tariff consistency and achieving the underlying purpose and intent of the existing Pre-Application Report. The complete set of all requested enhancements to the Rule 21 Pre-Application Report is set forth in Attachment B to today's decision.

The requested enhancements rename the current report "Standard Pre-Application Report" and create a new "Enhanced Pre-Application Report" that permits requests for more detailed data points/packages on a project-specific basis. Overall, the goal is for the Utilities to move towards a single application process for both the Standard and Enhanced Pre-application Reports in order to promote simplicity and streamlined procedures.

Attachment B shows the anticipated method and pricing for the data items available within the Enhanced Pre- Application Report. While the (Standard) Pre-Application Report in its current form and pricing will remain an Available option for interconnection customers, the Enhanced Pre-Application Report data items will be available to an Interconnection Customer based upon specific cost and timing, reflective of the scope of work required for these new enhanced report data items. The Utilities intend to automate as much of the Standard and Enhanced Pre-application request form and related process as is feasible and appropriate.

On November 23, 2015, the Commission's Office of Ratepayer Advocates (ORA) responded in support of the joint motion, and commended the Utilities and other parties for the extensive discussion during the August and September workshops. ORA stated that the Joint Parties had worked hard to reach consensus on the Joint Motion.

ORA also recommended that the Commission direct the Utilities to track the time it takes to prepare the Enhanced Pre- Application Report and the costs associated with its preparation. This information should be used to refine the fee charged to developers in its preparation and avoid undue shifting of these costs to ratepayers such that future updates to the Enhanced Pre-Application Report will reflect the actual price incurred to prepare it.

Solar City also supported the joint motion and noted that there are still outstanding issues that may require additional reforms to Rule 21 and that this or another proceeding should be open to address those issues.

1.2. Joint Motion on Behind the Meter Energy Storage

On November 18, 2015, PG&E, SCE, SDG&E, the Interstate Renewable Energy Council, Inc., the Clean Coalition, Robert Bosch LLC and Stem, Inc. filed and served a joint motion setting forth proposed revisions to Electric Tariff Rule 21 to address interconnection of behind-the-meter, non-exporting energy storage. The joint motion requested Commission authorization for the following revisions to the interconnection process for these storage resources:

- Insert clarifications regarding the treatment of load from energy storage charging to the Rule 21 tariff;
- Allocate costs for upgrades that are attributable to both the load and generation impacts of storage by prioritizing the load impacts before the generation impacts;
- Provide additional detail on energy storage charging load processes through a public Guide; and
- Modify the Interconnection Application and Agreement to capture energy storage load information for the applicable energy storage agreements.

Furthermore, parties to the Joint Motion propose a process for moving forward on the following additional items pertaining to energy storage interconnection that were discussed during the workshops but that require additional review and consideration by the stakeholders:

- Define criteria and propose an implementation process for an expedited interconnection process for non-exporting storage;
- Address the use of AC/DC converters (or other defined term as agreed upon) and specify the certification of and Rule 21 process applicable to such technology that would allow Generating Facilities utilizing such equipment to immediately pass Rule 21 Fast Track Initial Review; and
- Continue discussions regarding the criteria and certification process for providing an Inadvertent Export option for Rule 21 Fast Track Initial Review based on advanced inverter functionality.

The parties' specific recommendations are set forth in Attachment C to today's decision. The parties also requested that the Commission identify a forum in which additional identified issues related to the interconnection of energy storage will be addressed.

On December 2, 2015, ORA responded in support of the motion to revise Electric Tariff Rule 21 to address interconnection of behind-the-meter, non-exporting energy storage. ORA commended the moving parties for their efforts during the September and October workshops. In addition to the requests set forth in the motion, ORA recommended that the Commission direct the Utilities to record the monetary allowances permitted under Rules 15 and 16 and report back to the Commission the total costs, annually. ORA explained that the allowances of Rules 15 and 16 are allocated to ratepayers and such a report would help determine rate-payer impact in using these rules. Additionally, the report should also include the amount collected via deficiency billing to help to determine the effectiveness of using Rules 15 and 16 allowances for storage interconnection, and to determine if using Rules 15 and 16 is the proper mechanism for cost allocation.

On December 3, 2015, California Solar Energy Industries Association, California Energy Storage Alliance, and SolarCity Corporation each filed responses to the motion. All parties supported the motion. The California Solar Energy Industries Association supported opening a new proceeding for the remaining issues. The California Energy Storage Alliance argued for a "no review necessary" option for energy storage systems under a certain defined energy storage threshold and for energy storage systems operating under standardized operational modes. SolarCity supported the motion but also asked that the interconnection process guide be submitted initially via a Tier 2 advice letter with subsequent modification submitted via a Tier 1 advice letter. Solar City also argues that the operational modes should be expanded to include a "constrained grid charging mode" through which the storage system owner/operator would limit charging to time periods and levels that do not result in system upgrade requirements, leading to more systems qualifying for a cursory review as part of the Rule 21 Fast Track Initial Review Timeline. SolarCity also supported creating an ongoing forum for consideration of a number of outstanding issues related to interconnection.

1.3. Interconnection Cost Certainty

On April 1, 2015, SCE, SDG&E, and PG&E (the Utilities) jointly filed a motion with proposed revisions to Electric Tariff Rule 21 to enhance the predictability and reliability of interconnection cost estimates, referred to as "cost certainty," by inserting a Fixed Price Option into Tariff Rule 21.

The Utilities explained that their proposed fixed price option will be available to a significant portion of the Interconnection Requests that pass the

Fast Track Interconnection Review Process or qualify for the Independent Study Review Process. Qualifying projects must not only meet the requirements for Fast Track Interconnection Review Process, but must also not require substation upgrades, and require less than $500,000 in upgrades to the electric system. The Utilities stated that projects that do not meet these eligibility requirements are high-impact projects that are likely to require significant distribution upgrades, network upgrades, and/or are dependent upon facilities triggered by earlier queued projects. The Utilities contended that they lacked sufficient data on high-impact projects to extend any fixed price option to such projects.

The fee for the fixed price option is $10,000, which is non-refundable. The Utilities stated that this fee is necessary to pay for the additional resources required to prepare the fixed price estimate.

The Utilities stated that Interconnection Requests that meet the eligibility criteria may opt for the Fixed Price Option whereby the Utility will prepare a Fixed Price Option Estimate which includes an estimate of the costs to interconnect a generating facility with certain specified elements will be offered by the Utility on a fixed price basis. In this way, for all interconnection applicants proceeding under the Fixed Price Option, such specified elements included in the fixed price will be carried through to the Interconnection Agreement and will not be subject to later true-up to actual cost.

Within 20 days following selection of the Fixed Price Option and payment of the Fixed Price Option fee, the interconnection applicant must provide additional technical details, and 60 business days later the Utility will complete the fixed price that will be offered to the interconnection applicant and will include a description of any cost elements not included in the fixed price. Such excluded cost elements are costs of required environmental studies, environmental mitigation, permits, or easements related to the construction and installation of the Utility's facilities, which are excluded due to the unpredictability and potential magnitude of these costs. Accordingly, the interconnection applicant will be responsible for the actual cost of these excluded items.

In the cost certainty motion, the Utilities proposed, "…that any difference, either due to overcollection or undercollection, would be trued up in customer rates through the normal General Rate Case (GRC) capital work order process." No further details on this proposal were included in the motion or the utilities' proposed revisions to Tariff Rule 21.

On April 16, 2015, the assigned ALJ ruled that additional information was needed for the parties and the Commission to evaluate this proposal, and directed that no later than May 1, 2015, the Utilities shall file and serve a supplement to their April 1, 2015, motion setting forth details of this ratemaking proposal. The Utilities were required to describe how differences in project interconnection costs, either over or under-collections, would be treated for purposes of a utility's plant-in-service and regulated rate base. The Utilities were also required to explain their justification for including any such costs in the regulated revenue requirement, and particularly address the incentives created by their ratemaking proposal and customer rates.

On May 8, 2015, the Utilities responded and stated that their Fixed Price Option is designed to minimize any difference between the fixed price given to an interconnection applicant and the actual cost to interconnect the applicant, but that such differences may still occur. Thus, the Utilities stated that they crafted a proposal that ensures their legal right to cost recovery, using a currently established recording methodology, while still improving interconnection cost predictability by offering price certainty to a subset of Rule 21 interconnection applicants. Specifically, the Utilities proposed truing up the difference, either due to overcollection or undercollection, in customer rates through the GRC process by treating the fixed price contracts for the Rule 21 interconnections consistent with existing practices for other applicant-requested distribution construction work. The Utilities explained that an estimate is developed for the work to be performed and payment is made prior to work commencing. After an estimate is provided, if the applicant wishes to proceed, the applicant pays that estimate. The work is then performed. If the estimated costs are equal to the recorded costs, this activity is recorded as net zero plant. For PG&E and SCE, if the estimated costs exceed the recorded costs, the balance is recorded as miscellaneous Other Operating Revenue. If the estimated costs are less than the recorded costs, the excess is net rate base recorded, which is booked to plant-in-service or rate base for recovery through customer rates. For SDG&E, any over-collection or under-collection is recorded to rate base. In short, any cost over or under recovery is allocated to ratepayers.

The Utilities emphasized that their joint price certainty proposal is designed to minimize interconnection cost variances because eligibility for the fixed price option is limited to Interconnection Requests that do not have large impacts to the distribution system. Although the Utilities foresee that many Interconnection Requests will be eligible for the fixed price option, the eligible projects will be projects that do not require significant distribution upgrades and/or are not dependent upon facilities triggered by earlier-queued projects, which is designed to ensure a high level of confidence in the fixed price estimate, and thus minimize cost variances. The Utilities also point out that other proposed restrictions reduce the risk of cost variances such as: (1) the exclusion of certain cost elements, such as costs of required environmental studies, environmental mitigation, etc., due to the unpredictability and potential magnitude of these costs, and (2) a firm deadline for fixed cost estimate payment to ensure cost estimates do not become stale. In summary, the Utilities argued that impacts to customer rates, if any, would be minimal from the fixed cost option.

On May 22, 2015, the following parties filed comments to the Utilities' Joint Cost Certainty proposal and Supplement: BioEnergy Association of California (BioEnergy)/Placer County Air Pollution Control District (PCAPCD), SolarCity, California Solar Energy Industries Association, NRG Energy, Inc., California Energy Storage Alliance, Clean Coalition, and the Interstate Renewable Energy Council. Generally, the commenting parties supported the concept of cost certainty reflected in the Utilities' proposal, but a number of parties also provided critiques regarding specific aspects of the Utilities' Fixed Price Option proposal:

- **Eligibility requirements**: Some parties argued that the eligibility requirements for the Fixed Price Option are overly constrained and apply to a limited scope of the simplest projects. In order to open the Fixed Price Option up to a greater number of projects, Clean Coalition and Interstate Renewable Energy Council call for the $500,000 upper limit on system upgrades to be dropped. One party also proposed dropping the No Substation Upgrades requirement for Fixed Price Option eligibility, as well as the 5 MW eligibility limit for Independent Study Review projects.
- **$10,000 fee**: Some developers opposed the $10,000 fee to elect the Fixed Price Option as excessive and lacking justification.

- **60 Business Day study period**: SolarCity contended that the 60 Business Day timeline for developing a fixed price estimate should be reduced to 20 Business Days, as this would be consistent with timelines to complete a Supplemental Review. Clean Coalition stated that the proposed 60 Business Day timeline for developing a fixed price estimate would significantly lengthen the Fast Track process and has not been properly justified by the Utilities, and instead suggested a 30-Business Day timeline.
- **Fixed Price Estimate Granularity and Review**: Interstate Renewable Energy Council proposed that the Fixed Price Option estimate includes a detailed breakdown of equipment costs, labor hours and rates, and all other components of the estimate, and also believes that the Fixed Price Option process should include the ability for the applicant to discuss the fixed price estimate with the Utility.

Some parties' comments included alternative proposals to increase cost certainty and predictability within the interconnection process, either alongside or in lieu of the Utilities' Fixed Price Option proposal. For instance, a number of parties expressed support for more up-front data on system upgrade component costs and local system configurations at a customer's site, which led to the Unit Cost Guide and Enhanced Pre-Application Report proposals put forth in the November 9, 2015 Joint Motion on Cost Certainty.

However, some parties sought a more expansive cost certainty model than the Utilities' Fixed Price Option proposal, referred to as a Cost Envelope, which they propose be available to more projects and have a wider band of applicant responsibility for variations between estimated and actual costs than the Fixed Price Option. BioEnergy/(PCAPCD) suggested a hybrid cost certainty framework in which the Utilities' Fixed Price Option can exist alongside a Cost Envelope option that covers all other projects that are ineligible for the Fixed

Price Option. BioEnergy/PCAPCD proposed a cost envelope with a declining envelope range that narrows as a project progresses through the application stages: a 25% envelope after System Impact Study, or a 15% envelope after Facilities Study. Overestimations beyond the lower limit would be refunded to the applicant, whereas underestimations over the upper limit would be picked up by Utility shareholders. This would hold Utilities accountable for making accurate estimations and would encourage greater accuracy and predictability of interconnection costs.

Clean Coalition, on the other hand, proposed a 10 – 25% envelope for all projects that pass Fast Track or Independent Study Review — i.e., in lieu of the Utilities' Fixed Price Option — to be elected by applicant any time before entering into an Interconnection Agreement. Clean Coalition's proposal would maintain the No Substation Upgrade requirement as in the Fixed Price Option proposal, would allow 30 days for preparation of the estimate, and would allocate actual costs beyond the cost envelope limit to the Utilities' proposed GRC true-up mechanism. Clean Coalition suggests that an Independent Evaluator review balancing account entries to ensure cost estimates are accurate and consistent.

ORA, however, supported an alternative approach – "the Massachusetts model." As explained by ORA, under the Massachusetts cost envelope model, interconnection applicants pay cost overruns of up to ten percent over the estimated cost and utility shareholders absorb any overruns that exceed the ten percent. Ratepayers do not assume any risk for cost overruns.[1]

---

[1] ORA also opposed the Clean Coalition's proposal for a modified Massachusetts Model which would similarly allocate cost overruns to ratepayers.

ORA reasoned that the Massachusetts cost envelope model serves to better protect ratepayers by keeping any interconnection cost overruns shared between the applicant (the entity creating the cost) and the Utility (the entity responsible for the cost estimate.) ORA contended that the Massachusetts cost envelope model also protects applicants from excessive increases in costs charged by the Utilities, while also providing an incentive for the Utilities to provide accurate cost estimates since the shareholders are responsible for any costs incurred above the 10% cap.

ORA argued that the Utilities improperly implied in their Supplement to the Joint Utilities' Cost Certainty Proposal that utilities are always guaranteed a rate of return on their investments. ORA contended that the Commission may authorize cost recovery for utilities if they show that the costs incurred are justified, and the Utilities' Cost Certainty Proposal with a "true-up" for the difference between actual and recovered costs in future GRCs is fundamentally flawed and presumptuous because it does not provide for Commission review.

ORA concluded that the Utilities' Cost Certainty Proposal improperly shifts a utility's revenue shortfall resulting from their inaccurate cost estimates to ratepayers, which, under the current ratemaking principles, is the responsibility of the generators, and the Utilities have provided no rationale to support the reasonableness of this proposed cost shift. ORA stated that the Commission's longstanding ratemaking principles include avoiding cross-subsidies between customer classes by ensuring that the entity that creates costs pay those costs. ORA recommended adopting the Massachusetts model for Cost Certainty of Interconnection and rejecting the Joint Utilities' Cost Certainty Proposal.

2. Pre-Application Report Enhancements and Unit Cost Guide

As set forth above, the moving parties explained that Electric Tariff Rule 21 would be improved with the development of: (1) a Unit Cost Guide to give generation developers a readily available price list of typical interconnection facilities and equipment, and (2) adding specific data, with associated costs and timing, to be included in the Enhanced Pre-Application report.

The goal of the Pre-Application Report and Unit Cost Guide is to make cost data available earlier to prospective interconnection applicants. The moving parties' proposal is captured in the Cost Guide Implementation Principles, reproduced in Attachment A, which provide for the Utilities to develop the Guide within 90 Calendar Days of the Commission's decision. Using a consistent format, each Utility will publish a Cost Guide for facilities generally required to interconnect generation to their respective Distribution systems. While not be binding for actual facility costs, the Cost Guide will provide the anticipated cost of procuring and installing delineated facilities during the current year, acknowledging that costs may vary among the Utilities and within an individual Utility's service territory. The Cost Guide will include forecast costs for five years to allow project planning.

The specific proposals for Enhancements to the Pre-Application Report are set forth in Attachment B. These enhanced and optional aspects will allow interconnection applicants to obtain a Report tailored to the specific needs of the project and the applicant.

We find that providing prospective interconnection applicants cost estimates at an earlier stage and in a readily available format will improve the operation of Electric Tariff Rule 21. We, therefore, conclude that the jointly requested and unopposed proposed revisions to Tariff Rule 21 as set out in

Attachments A and B should be approved. The Utilities should comply with the filing schedules as agreed-to in Attachments A and B.

3. Behind-the-Meter Storage

We similarly grant the joint request for improvements to the treatment of non-exporting, behind-the-meter storage pursuant to Rule 21. Those improvements include clarifications of the manner in which storage charging load will be addressed in evaluating requests to interconnect energy storage devices, with load aspects being dealt with pursuant to Electric Rules 2, 3, 15 and 16 just like other load. Cost allocation will also use the new load impacts as the determining factor, and a new Interconnection Process Guide detailing the processes by which the load aspects of energy storage are reviewed, including specific size thresholds and cost responsibility of load-related upgrades not already included in Rule 21 or Rules 2, 3, 15 and 16, will improve the process for interconnection of behind the meter storage.

We also approve and endorse the proposed process for continuing the collaborative efforts that have to date been so fruitful. The moving parties seek to continue discussions initiated during the workshops to consider additional potential changes to Rule 21. Specifically, the parties intend to work on defining criteria for an expedited interconnection process for non-exporting energy storage, for a particular AC/DC converter to immediately pass Rule 21 Fast Track Initial Review after successful compliance testing, and a filing date for a status report on developing consensus-based requirements to address the "inadvertent export" issue. We, therefore, conclude that the jointly requested and unopposed proposed revisions to Tariff Rule 21 as set out in Attachment C should be approved, and the on-going process proposed in Attachment C adopted as well. The Utilities should comply with the filing schedules as agreed to in Attachment C, and summarized in the Master Filing Schedule shown in Attachment D to today's decision.

4. Establishing a Cost Certainty Framework

Senate Bill (SB) 350 established a variety of new procurement standards, including an increase in renewable procurement to 50% by 2030 and additional penetration of electric vehicles and various greenhouse gas (GHG) emissions reduction targets.[2] In addition, SB 1122 established a 250 megawatt (MW) bioenergy procurement target, bolstered by Governor Brown's October 30, 2015 Emergency Order on Forest Biomass.[3] These statutes and policies directly inform today's decision and our overall commitment to facilitating resource interconnection and grid integration of intermittent renewable generating resources.[4] We anticipate the need to expeditiously integrate more wind and solar resources, responding to the changes in system-wide customer load due to anticipated increase of customer rooftop solar and Electric Vehicles deployment: integration through interconnection. The role and functionality of distributed energy resources (DERs) on the distribution and transmission grid informs today's actions. DERs, such as electric vehicles and distributed storage, are tools we need harness to balance out the intermittency of wind and solar resources,

---

[2] Public Utilities Code Section 454.51 and Section 454.52.

[3] Governor Brown's Emergency Order: https://www.gov.ca.gov/docs/10.30.15_Tree_Mortality_State_of_Emergency.pdf.

[4] CPUC Staff Whitepaper. "Beyond 33% Renewables: Grid Integration Policy for a Low Carbon Future." November 25, 2015. http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/Beyond33PercentRenewables_GridIntegrationPolicy_Final.pdf.

and they can play that balancing role only if timely interconnected. DERs are a critical piece in meeting the grid integration challenge.

D.12-09-018 established interconnection rules for developers and utilities in adopting Electric Tariff Rule 21 (Rule 21) which governs the process by which grid-interactive DER projects interconnect and integrate to the distribution grid. Rule 21 establishes the standards to enable new facilities to connect to the distribution grid while enabling utility engineers to interconnect new DER facilities safely and investor-owned utilities (IOUs) to maintain overall the system safety and reliability critical to ratepayers, electric workers, and our economy.

To recover the costs of interconnection, our rules require DER developers to finance distribution grid capacity upgrades to accommodate the new two-way power flows on the distribution grid introduced by their generation. As part of the Rule 21 study process, the utility produces an electrical plan of service and an estimated cost to construct any identified system upgrades. Under the current framework, the project developer includes these estimated upgrade costs in the course of securing project financing to fund the project. Under our current rules, project developers assume unlimited liability for any cost overruns incurred,[5] even those stemming from circumstances unforeseen by the utility or by the developer, or which might have been predictable to the utility with additional data and grid analysis. These costs are either directly passed onto ratepayers via higher prices or would lead to a high failure rate of applicant DER projects. In either circumstance, this unlimited liability creates a large risk profile for DER

[5] Rule 21 Section E.4.c, Interconnection Cost Responsibility - Timing of Cost Identification.

project development in California, raising the cost of investing in DER, and thus the cost to ratepayers for an eventual Power Purchase Agreement (PPA). One party cites instances of ten- and thirteen-fold variations in interconnection costs over the original estimate, and describes such degree of uncertainty "crippling for private developers and discouraging for public agencies that are working with the state to achieve its climate and clean energy goals."[6] Today's decision reduces cost uncertainty, diminishes risk for project development, and is calculated to spur investment needed to meet California's statutory GHG reduction and renewable procurement and integration goals. Providing cost certainty to developers, utilities, and ratepayers is also a part of the Commission's overall mandate to provide safe reliable service at just and reasonable rates.[7]

Cost certainty is a framework that clearly communicates the precise level of financial risk assumed when funding capacity upgrades for DER projects. As early as September 26, 2012 Amended Scoping Memo and Ruling in this proceeding, the Commission asked parties to propose ways to address barriers to the interconnection process, including the implementation of a cost certainty framework.[8] Over the course of the proceeding, parties have focused discussions around two proposed frameworks: a Fixed Price Option as proposed by the Joint Utilities, and a Cost Envelope, described in various permutations by IREC, Clean

---

[6] Bioenergy/PCAPCD *Comments on the Joint Utilities' Motion for Interconnection Cost Certainty*, May 22, 2015, p. 5.

[7] Public Utilities Code Section 451.

[8] Amended Scoping Memo and Ruling, September 26, 2012.

Coalition, ORA, and BioEnergy/PCAPCD.[9] The cost envelope was also recommended, in part, in the July 18, 2014 Energy Division Staff Proposal.[10] Both proposals intend to achieve greater cost certainty in the interconnection process. These two proposals are described in additional detail, below.

A successful cost certainty framework limits developer liability for inaccurate cost estimates provided by the utility to a reasonable level. Cost certainty shifts the balance between timeliness of creating the cost estimate and the accuracy of the estimate. The two primary Rule 21 study processes, Fast Track and Independent Study, balance these competing goals. We adopt a cost certainty framework, in part, to establish higher-confidence cost estimates and to reduce the impact of inaccurate cost estimates on project financing costs, with the express hope that ratepayers will benefit from reduced PPA prices.

The crux of the debate between the two cost certainty frameworks center on two main questions: (1) does the proposed regime provide an adequate level of cost certainty to Rule 21 project developers, and (2) does the ratemaking treatment for actual cost incurred beyond the adopted limit of a developer's financial responsibility adequately align with the interests of ratepayers, developers, and utility shareholders.

In adopting a cost certainty framework, the Commission recognizes the challenges that utilities face in producing timely high-confidence cost estimates. These challenges include the need to produce interconnection studies in a timely

---

[9] *See*, Comments filed by Interstate Renewable Energy Council Inc., October 25, 2012, pg 7.

[10] CPUC Staff Proposal. "Cost Certainty for the Interconnection Process." July 18, 2014. *Found in,* Administrative Law Judge Ruling Setting Schedule for Comments on Staff Reports and Scheduling Prehearing Conference, Sept 29, 2014.

manner while lacking adequate data on field conditions. We also recognize that, as a product of D.12-09-018, the Fast Track and Independent Study Process are relatively new, and that the utilities' execution of these processes will continue to evolve and improve as the utilities gain more experience processing applications for various types of Rule 21 projects.

We further anticipate that the Integration Capacity Analysis being developed in the Distribution Resources Plan proceeding (R.14-08-013) will help direct developers to grid locations with adequate hosting capacity (and thus a lower chance of triggering significant distribution system upgrades). Cost uncertainty is also reduced through the adoption of the Unit Cost Guide and Enhanced Pre-Application Report in today's decision because they will make system upgrades and associated costs more predictable.

We are also motivated by the need to encourage increasing the access, resolution, and representativeness of data utilized by the utilities in the interconnection process. Modernizing the interconnection process is the essential component to achieve our policy and statuary goals of interconnecting renewable energy, deploying DERs and reducing GHG emissions. In adopting a cost certainty framework, we aim to encourage and incentivize the utilities to take the necessary steps that will allow them to use the highest-resolution, most up-to-date asset management databases in performing interconnection studies. Increased access and use of higher-quality, timely data will improve the accuracy of cost estimates.

Under the Fixed Price Option, utilities would provide developers with a binding cost estimate in exchange for more up-front study time. As proposed, the Fixed Price Option would be available to DER projects that meet the specific eligibility requirements, pay a $10,000 fee, and allow for a 60-businsess day up-front study period. The Fixed Price Option would then allocate the difference between estimated and actual costs to ratepayers. The utilities would put into rate base the capital expenditures associated with any system upgrades beyond the estimated cost funds provided by the developer, as the utilities would be funding the system upgrade costs themselves. If the fixed price estimate was too high, any unspent funds would be recorded as Other Operating Revenue.[11] This revenue would presumably offset revenue requirement collections from ratepayers.

Critics of the Joint Utilities' Fixed Price Option anticipate that the eligibility requirements will prevent the projects that are in most need of cost certainty—i.e., projects applying to interconnect in the grid locations for which cost estimates are the most unpredictable—from accessing the Fixed Price Option and a cost certainty regime.[12] Other pre-requisites would deter many otherwise-eligible developers from electing it.[13] ORA argues that the Fixed Price Option improperly transfers the risk of inaccurate cost estimates from developers to ratepayers.[14] Other parties believe that transferring the risk of cost overruns

---

[11] Joint Utility *Supplement to the Joint Utility Motion Proposing Rule 21 Tariff Language Implementing Joint Cost Certainty Proposal*, May 22, 2015, pp. 5-6.

[12] E.g., Bioenergy/PCAPCD *Comments on the Joint Utilities' Motion for Interconnection Cost Certainty*, May 22, 2015, p. 7.

[13] E.g., Clean Coalition *Comments on Joint Utility Motion on Language Implementing Joint Cost Certainty Proposal,* May 22, 2015, p. 2.

[14] ORA *Reply Comments on the Joint Utility Motion Proposing Rule 21 Tariff Language Implementing Joint Cost Certainty Proposal, June 8, 2015*, p. 8.

from developers to utility shareholders would better align the incentivizes for the utilities to improve cost estimate accuracy.[15]

Under the Cost Envelope, a developer's responsibility for inaccurate cost estimates would be capped at a given percent of the provided interconnection cost estimate. The Cost Envelope framework would limit developer risk for inaccurate utility cost estimates to a given percent rage around the cost estimate provided by the utilities to the developer on the GIA signed by both parties. The cost envelope framework, as proposed, could be applied to all Rule 21 projects.[16] The Cost Envelope framework pushes the utility towards providing developers an accurate cost estimate while allowing the utility a reasonable buffer to absorb unanticipated overages.

The Joint Utilities argue that across-the-board DER interconnection cost certainty is premature given the unpredictable nature of studying larger, more complex projects in older and/or constrained grid locations. The utilities also argue that they lack experience interconnecting Rule 21 export projects.[17][18]

---

[15] E.g., ORA *Reply Comments*, June 8, 2015, p. 5; IREC *Comments on the Staff Reports Regarding Interconnection Cost Certainty and Energy Storage Interconnection*, September 12, 2014, p. 4; Bioenergy/PCAPCD *Comments on the Joint Utilities' Motion*, May 22, 2015, p. 10.

[16] E.g., IREC *Comments on the Staff Reports Regarding Interconnection Cost Certainty and Energy Storage Interconnection*, September 12, 2014, p. 4.

[17] Rule 21 Non-Export projects are unlikely to trigger system upgrades and thus are not germane to the cost certainty discussion.

[18] This lack of experience, according to the utilities, combined with the fact that data on estimated versus actual costs for post-D.12-09-018 Rule 21 export projects are not included in the proceeding record renders any adopted cost envelope range arbitrary and unsupported by evidence. The Joint Utilities, however, submit quarterly interconnection data reports to the CPUC's Energy Division containing confidential data on estimated costs, actual costs, and true-up.

Parties such as IREC, Clean Coalition, ORA, and BioEnergy/PCAPCD assert that making utility shareholders responsible for cost overruns beyond the percent cap would squarely place the risk of inaccurate cost estimates on the utility.[19] This would be appropriate, parties reason, as utilities are the entities that are solely responsible for developing the estimates. The Joint Utilities counter by stating such a proposal violates cost-of-service ratemaking tenets, contradicts the Public Utilities Regulatory Policy Act of 1978 (PURPA), lacks detailed analysis, and unfairly shifts substantial risk to the utility without regard for critical inherent uncertainties in the interconnection review process and Rule 21's compromise between the level of estimate certainty and interconnection process efficiency.[20]

For reasons detailed below, we elect to adopt a 25% Cost Envelope as a five-year pilot as a cost certainty framework for all interconnection under Rule 21 under certain provisions as detailed in this decision.

4.1. Adoption of 25% Cost Envelope

Based on our review of the record, we conclude that the current Rule 21 interconnection process is not yielding sufficient ratepayer benefit and needs to be adjusted to create more cost certainty to achieve the state's statutory renewable procurement integration, and GHG reduction goals.

We acknowledge that a cost certainty framework is a new and innovative adjustment enabling more efficient integration of DERs. We anticipate that it

[19] ORA *Reply Comments on the Joint Utility Motion Proposing Rule 21 Tariff Language Implementing Joint Cost Certainty Proposal*, June 8, 2015, p. 8.

[20] Joint Utility *Comments on the Staff Report Regarding Cost Certainty for the Rule 21 Interconnection Process*, September 12, 2014, p. 18.

will take some time to evaluate whether or not ratepayers are receiving adequate benefits from the framework. In consideration of the above, we adopt a cost envelope framework on a five-year pilot basis to test the model. The range of the cost envelope should be set at 25% (both above and below the utility provided estimate), per Clean Coalition,[21] and available to all projects applying for interconnection under the Fast Track or Independent Study Processes in Electric Tariff Rule 21, per IREC.[22] The pilot we authorize today is available to projects applying to the Fast Track and Independent Study Processes; the Utilities may file an advice letter to extend the Cost Envelope to projects in the Distribution Group Study Process[23] or Cluster Study. The Cost Envelope shall be applied to the estimated cost provided by the utility on the GIA documentation. In order to inform the GIA and to elect the Cost Envelope, projects that successfully complete either Fast Track Initial Review or Supplemental Review must pay a new $2,500 deposit and allow an additional 20 business days for the Utility to develop a cost estimate following the completion of the engineering review phase.[24] Developers applying under the Independent Study Process must pay

---

[21] Clean Coalition *Opening Comments on Staff Proposals for Cost Certainty*, September 12, 2014, Attachment 3; Clean Coalition *Comments on Joint Utility Motion on Language Implementing Joint Cost Certainty Proposal*, May 22, 2015, p. 10.

[22] IREC *Comments on the Staff Report Regarding Interconnection Cost Certainty*, September 12, 2014, p. 4.

[23] We note that the distribution group study process may be the appropriate process to interconnect microgrids; we direct Energy Division to monitor microgrid development and to determine if applying the cost envelope to the distribution group study process will facilitate microgrid deployment.

[24] To clarify, projects that pass either Fast Track Initial or Supplemental review must pay the $2500 deposit for a supplemental 20 business day cost envelope estimate development process within 10 business days of receiving the utility's non-binding cost estimate following completion of Initial or Supplemental Review

the required deposits and complete both a System Impact Study and Facilities Study in order to elect the Cost Envelope. These processes were established in D.12-09-018. This cost envelope framework appropriately balances study timeliness and estimate accuracy by providing the Utilities additional up-front study time and financial resources to produce high-confidence cost estimates for Fast Track projects, and by requiring Independent Study Process projects to undergo the maximum available course of study, while limiting developer liability to 25% above estimated interconnection costs. The cost envelope framework is designed to balance risk factors between developers, utility shareholders, and ratepayers.

The Cost Envelope framework will work to better facilitate the interconnection of distribution energy resources and limit developer risk exposure for cost estimate overruns. Capping developer responsibility for inaccurate cost estimates, however, does not adequately address many of the root causes of these inaccuracies. According to the Joint Utilities, a primary source of cost estimate inaccuracy is the fact that a majority of field verification tasks—including environmental studies, biological studies, easement/rights checks, wind loading for poles, engineering and design, and "job walks"—as well as final detailed engineering are not currently performed until after completion of the Fast Track or Independent Study processes and the execution of a GIA.[25] The Joint Utilities explain that while the decision to delay field verifications and detailed engineering until after the GIA adds a level of uncertainty to the study phase's cost estimate, it permits faster, more efficient

[25] Joint Utilities' *Response to Energy Division Staff Proposal on Cost Certainty*, September 12, 2014, pp. 13-14.

processing of an applicant's interconnection request and conserves the resources necessary to perform such tasks until an applicant reaches a high level of confidence that it wishes to pursue interconnection.[26]

We conclude that we need to improve the interconnection study process to make it more likely to yield an accurate cost estimate at the execution of the GIA. In adopting the 25% Cost Envelope, we establish new data collection requirements to track overestimates and underestimates to determine the effectiveness of this new cost envelope framework, as well as reporting metrics that will help the Commission and parties gauge the utilities' progress in modernizing the interconnection study process and producing high-confidence cost estimates. We also require more up-front work by the developer and the utility, as described below, in order to access this cost certainty framework. Overall, our pilot adds steps to the work that must be completed by the developer and the utility to reduce the margin of cost estimate uncertainty.

The five-year pilot we adopt in this decision includes a requirement that developers shall submit a more thorough and detailed Rule 21 interconnection application in order to elect the Cost Envelope framework. We take from the Joint Utilities' Fixed Price Option proposal the "Technical Scope Package," as it would provide the utility with additional details on the applicant generator as it performs its study and derives its cost estimates.[27] As part of this requirement,

---

[26] *Ibid,* p. 10.

[27] Joint Utility *Motion Proposing Rule 21 Tariff Language Implementing Joint Cost Certainty Proposal*, April 1, 2015, pp. 5-6.

the developer in electing the cost envelope for interconnection shall provide the following "Technical Scope Package" as part of its interconnection application:[28]

1. Final location of the Point of Common Coupling (Point of Change of Ownership);
2. Final location of the Point of Interconnection;
3. Confirmation of service voltage;
4. Confirmation that technical data provided in the Interconnection Request is accurate, including equipment type, model and manufacturer;
5. A site drawing of a scale of 1:30 or less, which shows the final location of the Point of Common Coupling, Point of Interconnection, and final location and routing of conductors and equipment between the Point of Common Coupling and the Point of Interconnection; and
6. Identification of any constraints or limitations related to the siting or routing of conductors and equipment between the Point of Common Coupling and the Point of Interconnection.

The Cost Envelope will be enacted upon the cost estimate provided to the developer in the GIA documentation. In signing a GIA, the utility and developer agree that the Cost Envelope shall be applied to the actual cost of facilities and system upgrades upon final accounting true-up, following the utility's issuance of Permission to Operate. Estimated and actual cost documentation provided to a developer shall be itemized, such that a developer and the Commission can understand the exact breakdown of labor, Operations and Maintenance, and capital expenditures for each job activity and installed piece of equipment. Upon

[28] The utility will evaluate any modifications to determine if such modifications constitute a Material Modification to the Interconnection Request, consistent with Rule 21 Sections C and F.3.b.v.

final accounting true-up, the utility shall provide documentation to the developer and the Commission stating itemized actual costs.

We clarify that the Cost Envelope shall only apply to the interconnection costs that are under the utilities' control and should be thus reasonably expected to be estimated within 25% accuracy. For instance, the Joint Utilities' Fixed Cost Option proposal would exclude costs associated with required environmental studies, environmental mitigation, permits, or easements related to the construction and installation of interconnection facilities or distribution system upgrades.[29] These cost elements are incurred in response to a developer's interconnection request and do not directly pertain to upgrades to a utility's distribution system. As such, these costs shall remain the sole responsibility of the project developer.

We further order the creation of a memorandum account to track actual interconnection costs that fall above or below the 25% envelope.[30] Each entry into the memorandum account shall utilize standardized line-item accounting and shall include itemized actual and estimated costs broken down into relevant categories of component costs, labor, and Operations and Maintenance, a description of the main driver(s) of the inaccurate estimate, and an explanation of how the utility attempted to mitigate or take steps to prevent estimates outside of the 25% range. The net of both cost and proceeds incurred should be reflected in the account balance. The utilities shall file a Tier 2 advice letter adopting the cost

[29] Joint Utilities *Cost Certainty Proposal*, January 18, 2013, p 6; *Joint Utilities Motion Proposing* Rule *21 Tariff Language Implementing Joint Cost Certainty Proposal*, April 1, 2015, p 7.

[30] Clean Coalition *Opening Comments on Staff Proposals for Cost Certainty*, September 12, 2014, *Attachment 3; Joint Utility Comments on Proposed Decision Granting Joint Motions to Approve Proposed Revisions to Electric Tariff Rule 21*, March 7, 2016, p. 6.

envelope and associated memorandum accounts within 60 days of today's decision. At minimum, the advice letter should include interconnection application documentation including cost envelope selection box and "technical scope package," and memorandum account details, including explanation about each project expense, how project expenses will be tracked over time and how booked expenses will be netted across projects. The utilities shall also provide a technical report, which includes comprehensive and detailed information about each entry into the memorandum account, attached as an appendix.

Each utility would then be able to request recovery of the account balance in a separate section of its triennial General Rate Case, subject to reasonableness review. Utilities may be able to recover from ratepayers the net of inaccurate estimates upon a showing that such costs were prudently incurred, given the causes of cost estimate inaccuracy within a utility's ability to control. Net cost overruns deemed imprudently incurred would be allocated to utility shareholders.

In our determination, the memorandum account equitably spreads the risk of inaccurate cost estimates between developers and utility shareholders across the entire portfolio of Rule 21 projects. The Commission deems that the potential shareholder responsibility for imprudently incurred interconnection costs through a reasonableness review properly aligns the impetus for better cost estimating by the entity that is solely responsible for developing the estimate: the utility. Understandably, records submitted that do not use a traditional line item accounting format will be more challenging to review. Using line-item accounting, interconnection cost overruns will be knowable and sharable. This type of accounting methodology used to describe cost driver information will assist the reasonably knowledgeable accountant. Component pieces, labor, expenses for upgrading different elements of the grid, all of these numbers are knowable, countable, recordable, and sharable. Any submission of cost overruns should identify where costs accrued, when, and how the utility attempted to mitigate the situation.

4.2. Imposing Potential Shareholder Liability for Inaccurate Cost Estimates is Permissible

The Joint Utilities comments regarding the Staff Report,[31] claiming that the Staff Proposal's Cost Envelope Model "appears to violate PURPA, in that it denies the IOUs of the recovery of interconnection costs."[32] The Joint Utilities imply that unforeseeable complications may arise after its estimate of interconnection cost, and thus a utility may be reasonably required to spend in excess of the cost envelope margin beyond its binding estimate to safely and reliably interconnect the facility to the distribution grid. We disagree.

The cost envelope process described herein does not violate PURPA because it allows the utility to recover costs that exceed the 125% cost estimate that would be presumed reasonable. Specifically, the utility could seek to show in its next GRC or in a standalone application that the cost overruns themselves were reasonable, and if the Commission finds that those costs were reasonably incurred then the utility may recover costs exceeding the 125% envelope from ratepayers. If the utility either decides not to seek compensation for excess costs

---

[31] *Comments of Southern California Edison Company (U 338-E), San Diego Gas & Electric Company (U 902-E) and Pacific Gas and Electric Company (U 39-E) on The Staff Report Regarding Cost Certainty For The Rule 21 Interconnection Process* (Joint Utilities' Comments), filed on September 12, 2014 in R.11-09-011.

[32] Joint Utilities' Comments at p. 22.

or the Commission fails to find such costs to be reasonable, then such overages will accrue to the utility's shareholders.

Qualifying Facilities, as defined by PURPA, may apply for interconnection under Rule 21. PURPA defines the interconnection costs that a utility may recover from Qualifying Facilities in 18 Code of Federal Regulations Section 292.306 (emphasis added):

> Interconnection costs means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility . . ..

The Joint Utilities acknowledge:

> [Section 292.306] is designed to provide the State regulatory authorities . . . with the flexibility to ensure that all costs which are shown to be reasonably incurred by the electric utility as a result of interconnection with the qualifying facility will be considered as part of the obligation of the qualifying facility under it.[33]

The reasonableness review appropriately balances risk between developers, shareholders, and ratepayers. While the utilities assert that PURPA creates a barrier, we disagree because we give the utilities the opportunity to demonstrate reasonableness.

---

[33] Joint Utilities Comments at p. 22, citing 1977-1981 Regulations Preambles ¶ 30,128,866 (1980) (emphasis added).

4.3. Utilities must update their interconnection process data usage capabilities

The aforementioned procurement mandates, and the anticipated proliferation of DERs generally, point to a fundamental need for better data and back-end IT systems at the disposal of the utility engineers who perform interconnection studies. In adopting the memorandum account, we stress that we view the opportunities afforded by the current Rule 21 study processes as a floor and not a ceiling. The utilities should perform the necessary in-house and field studies that can produce an estimate within a 25% range of actual interconnection costs.

The utilities' current cost estimating process relies on a desk review of the applicant generator's impact on the local distribution system, without the benefit of detailed power flow modeling, field verification, or final detailed engineering. Cost estimate inaccuracy can be attributed to a utility's inability to predict actual conditions in the field for the utility's distribution system or the site itself. This lack of accuracy results in part from the project information provided in a developer's application and the system data the utility utilizes to complete an interconnection study. The future interconnection process should be able to inform developers about dispatch priority concerns, conflicting real-time grid needs,[34] and other real-time distribution grid signals to facilitate the timely interconnection of various types of DER facilities with bidirectional capabilities.[35] We invite the utilities to submit applications, as necessary, to ensure that they have the tools required to produce the accurate cost estimates required for this

[34] Administrative Law Judge's Ruling 14-10-003. Noticing Workshop Jointly Led by the California Independent System Operator, March 24, 2016, p. 5.

[35] D.16-01-025. Decision Regarding Underlying Vehicle Grid Integration Application and Motion to Adopt Settlement Agreement, January 14, 2016, p. 150.

process. The applications should be well-calibrated to produce a higher degree of cost certainty, achieve the renewable procurement and integration goals the legislature has mandated, and are well-designed to maintain system safety, reliability, and just and reasonable rates.

Utility distribution engineers should utilize their creativity, talents and expertise, to analyze distribution grid data provided through multiple gateways in developing interconnection upgrade cost estimates. For projects electing the Cost Envelope, the final cost estimate, provided in the GIA will attach after two study processes. These study processes should adequately allow the utility to estimate interconnection costs within 25% accuracy when interconnection and integrating a new DER facility to the distribution grid in a safe and reliable manner at just and reasonable rates.

4.4. Cost Envelope Pilot and Required Reporting

The discussion above outlines our expectations for appropriately balancing risk between the developer, utility shareholders and ratepayers to facilitate timely and accurate interconnection cost estimates to enable the integration of more DERs to the distribution grid. In light of the data that we will gather (as described above) and as additional experience is gained using the Cost Envelope framework, we recognize that the framework will need to be revisited as the utilities and developers gain experience. Therefore, we treat the Cost Envelope framework that we adopt in this decision as a five-year pilot period. A five-year pilot period is an appropriate length of time to allow the utilities to collect a representative sample of projects from which to evaluate the effectiveness of the 25% Cost Envelope to interconnect and integrate DER into the distribution grid. Given that the interconnection process can take over two years to complete for certain projects, the pilot period will allow the Commission, in conjunction with utilities and other stakeholders, to inform a permanent cost certainty framework based on empirical cost estimating data and the improvements to the utilities' data access and utilization we order in this decision. We direct the utilities, in consultation with the Commission's Energy Division, to host a series of workshops, at least semi-annually, to provide a forum for parties and the Commission to discuss the cost envelope pilot and the utilities' progress in improving the interconnection process.

To help evaluate the pilot period, the utilities shall continue to submit, on a quarterly basis, all pending and completed Rule 21 interconnection project true-up documents to the Commission. In the quarterly report, we further direct the utilities to use consistent measurements, to produce records and to develop tools to track the progress by which the utilities increase the accuracy of their cost estimates in the interconnection process. At minimum, the utilities shall include in this report metrics that indicate progress towards realizing improved data access and utilization in the course of modernizing the interconnection process and producing higher confidence cost estimates. These metrics will help us evaluate the pilot period. The quarterly reports shall also track actual costs of preparing a cost envelope estimate for Fast Track applicants as well as cost differential data and narrative technical descriptions of all entries into the memorandum account. The utilities shall host a workshop with parties to discuss the format of the new sections of the quarterly report within 120 days of today's decision. In consultation with Energy Division, the utilities shall also establish a working group to refine these metrics and reporting, with the objective of improving the interconnection process to create an agile distribution grid.

The utilities shall continue to provide both the public and private Rule 21 Quarterly Report to ensure that utilities continue to develop robust tracking and metrics of success to submit to Energy Division for further analysis. The Quarterly Report shall be broken down by facility type for greater analysis capacity.[36] Any further reporting or metrics requests by Energy Division shall be added to the Rule 21 Quarterly Report.

We adopt the cost envelope and associated new processes as a five-year pilot because such changes do not provide for an "apples to apples" comparison to past interconnection projects, and thus the cost envelope need not be limited to cost overruns or underestimates as indicated by the average or range of past projects. We intend to evaluate the efficacy of the interconnection process, including the deviations between estimated cost and actual cost, under the cost envelope framework pilot. The process we pilot is calibrated to reduce uncertainty, and yield more information that will incentivize and reduce the cost for renewable development, and for the ratepayers who pay PPA prices. We note that this five-year pilot period will also see an overall increase in customer energy choices, bolstered by the rollout of time-of-use pricing. We acknowledge that a reduction in risk and uncertainty in the deployment and integration of DERs will facilitate expanded customer choice. At the end of the pilot, the utilities may file an application to make the cost envelope pilot permanent if the pilot successfully enables DERs to interconnect to the grid. The Commission will

[36] Reporting should differentiate applications for storage facilities, electric vehicle projects, solar, wind, bioenergy and other types of projects, including combined DER project facilities, so that Energy Division can determine where more guidance is required.

need to consider at the conclusion of this pilot how the Cost Envelope framework has impacted both PPAs and the accessibility of customer choice.

5. Smart Inverted Working Group – Continued Collaboration

Early in the nearly five-year time this proceeding has been open, the parties created the SIWG as a forum for collaboratively developing advanced inverter functionality for inclusion in Rule 21. The productive history, current work, and a compliance filing requirement for the Working Group is detailed in Attachment E. We encourage the parties and other interested stakeholders to continue to participate in the Working Group. Our Staff in the Energy Division will also continue to monitor emerging issues as improved inverters are deployed and communication protocols developed.

Consensus proposals pertaining to SIWG recommendations or Rule 21 interconnection more broadly may be brought forward for Commission consideration by the Utilities in the form of Advice Letters or Applications as appropriate. Other parties may file Petitions for Rulemaking pursuant to Rule 6.3 of the Commission's Rules of Practice and Procedure or Complaints as set forth in Rule 4. The Commission has opened two proceedings related to distributed resources where interconnection issues may also be addressed: Rulemakings (R.) 14-08-013 and R.14-10-003.

6. Comments on Alternate Proposed Decision

The alternate proposed decision of Commissioner Catherine J.K. Sandoval in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on May 26, 2016 by Fronius USA, California Solar Energy Industries Association, Bioenergy Association of California, Clean Coalition, Interstate Renewable

Energy Council, Solar City, ORA, and jointly by SCE, PG&E and SDG&E. Reply Comments were filed on May 31. 2016 by ORA, SolarCity, IREC, Clean Coalition and SCE, PG&E and SDG&E jointly.

In response to comments, we make several minor clarifications. We summarize these changes. We clarify that the Cost Envelope pilot does not apply to the Distribution Group Study Process or the Cluster Study process; however, the utilities may file an advice letter at a later date to expand the pilot to these processes once there is sufficient data available. We clarify how the pilot applies to the Fast Track study process. In response to comments from ORA, we clarify the information required for the memorandum accounts being piloted. We also clarify that the utility may seek reasonableness review through a GRC or a standalone application. In response to the joint comments from the Utilities, we extend the timeline for the filing of the initial tariff to 60 days. Other minor clarifications are made throughout the decision.

7. Assignment of Proceeding

Michael Picker is the assigned Commissioner and Maribeth A. Bushey is the assigned ALJ in this proceeding.

Findings of Facts

1. On November 9, 2015, SCE, SDG&E, PG&E, California Solar Energy Industries Association, Clean Coalition, CODA Energy and Interstate Renewable Energy Council, Inc., filed and served their joint motion proposing Pre-Application Report Enhancements and the development of a Unit Cost Guide.

2. The specific elements of the Unit Cost Guide are set forth in Attachment A to today's decision.

3. The specific elements of the Pre-Application Report Enhancements are set forth in Attachment B to today's decision.

4. No party opposed the proposed Pre-Application Report Enhancements and development of a Unit Cost Guide.

5. The proposed Pre-Application Report Enhancements and development of a Unit Cost Guide are reasonable.

6. On November 18, 2015, PG&E, SCE, SDG&E, the Interstate Renewable Energy Council, Inc., the Clean Coalition, Robert Bosch LLC and Stem, Inc. filed and served a joint motion setting forth proposed revisions to Electric Tariff Rule 21 to address interconnection of behind-the-meter, non-exporting energy storage. The specific actions to be taken and the applicable timetable for behind-the-meter, non-exporting energy storage are set forth Attachment C to today's decision.

7. No party opposed the proposed revisions to Electric Tariff Rule 21 to address interconnection of behind-the-meter, non-exporting energy storage.

8. The proposed revisions to Electric Tariff Rule 21 to address interconnection of behind-the-meter, non-exporting energy storage are reasonable.

9. DERs, such as electric vehicles and distributed energy storage, are tools for balancing out intermittency of interconnected wind and solar resources. Electric Tariff Rule 21 generally governs the interconnection process for distribution energy resources.

10. A cost certainty framework establishes a higher-confidence cost estimate and reduces the impact of inaccurate cost estimates on financing costs for distribution energy resource projects. It is reasonable to assume that ratepayers should benefit from reduced PPA prices from a cost certainty framework.

11. The cost envelope framework with the process improvements adopted herein appropriately balances risk factors between developers, utility shareholders and ratepayers. This cost envelope framework appropriately balances study timeliness and estimate accuracy by requiring projects to undergo the maximum available course of study while reducing unbound developer liability.

12. It is reasonable that the cost envelope framework be set at 25%.

13. It is reasonable to create a memorandum account for the cost envelope framework accounting with a technical report attached as an appendix within 60 days.

14. It is reasonable to utilize the cost envelope framework on a five-year pilot basis.

15. It is reasonable to require the utilities to provide robust reporting and metrics to enable the Commission to monitor progress in developing an interconnection process that supports an agile distribution grid. Increased access and use of higher-quality, timely data will improve the accuracy of cost estimates.

16. New data collection requirements are needed to reduce the margin of cost estimate uncertainty.

17. It is reasonable for the utilities to require the developers to include a technical scope package in their generator interconnection application if they elect the cost envelope framework.

18. It is reasonable for the utilities to create memorandum accounts to track all interconnection costs that exceed the 25% cost envelope.

19. It is reasonable for the utilities to host semi-annual workshops about the changing interconnection process and receive input from parties and the Commission.

20. The SIWG has completed its technical recommendations for Phase 2 communication protocols and Phase 3 additional advanced inverter functions after three years of collaboration and consensus-building.

21. It is reasonable for the utilities to revise Rule 21 to reflect the technical requirements of the Smart Inverter Working Group's recommendations for Phase 2 communication protocols and Phase 3 additional advanced inverter functions, following additional discussions to refine areas that require further consensus.

Conclusions of Law

1. The November 9, 2015, Joint Motion of SCE, SDG&E, PG&E, California Solar Energy Industries Association, Clean Coalition, CODA Energy and Interstate Renewable Energy Council, Inc., should be granted consistent with today's decision.

2. The November 18, 2015, joint motion of PG&E, SCE, SDG&E, the Interstate Renewable Energy Council, Inc., the Clean Coalition, Robert Bosch LLC and Stem, Inc. setting forth proposed revisions to Electric Tariff Rule 21 to address interconnection of behind-the-meter, non-exporting energy storage, with specific actions and applicable timetable for behind-the-meter, non-exporting energy storage are set forth Attachment C to today's decision, should be granted.

3. Senate Bill (SB) 350 (de León, Chapter 547, 2015) requires the Commission to focus energy procurement decisions on reducing GHG emissions by 40 percent by 2030, including efforts to achieve at least 50 percent renewable energy procurement, doubling of energy efficiency, and promoting transportation electrification. Public Utilities Code Sections 451.51 and 451.52.

4. Decision 12-09-018 establishes interconnection rules for developers and utilities in adopting Electric Tariff Rule 21 (Rule 21). Rule 21 should be updated to apply a cost envelope of 25% for interconnection processes. This cost envelope should apply for a provisional five-year term.

5. The cost envelope should be applied to the estimated cost provided by the utility on the GIA documentation. In order to inform the GIA and to elect the Cost Envelope, projects that successfully complete either Fast Track Initial Review or Supplemental Review must pay a new $2,500 deposit and allow an additional 20 business days for the Utility to develop a cost estimate following the completion of the engineering review phase. Developers applying under the Independent Study Process must pay the required deposits and complete both a System Impact Study and Facilities Study in order to elect the Cost Envelope.

6. The utilities should continue to provide both the public and private Rule 21 Quarterly Report to ensure that utilities continue to develop robust tracking and metrics of success to submit to Energy Division for further analysis. The Quarterly Report shall be broken down by facility type for greater analysis capacity. Any further reporting or metrics requests by Energy Division shall be added to the Rule 21 Quarterly Report.

7. The utilities should host workshops, in consultation with Energy Division, at least semi-annually, to provide a forum to inquire about the utilities interconnection process progress and to provide guidance.

8. The utilities should create a memorandum account to track interconnection costs that are either above or below the 25% cost envelope for reasonableness review for recovery in either a GRC or in a subsequent application. The memorandum account should include a description of the main driver(s) of the

inaccurate estimate, and an explanation of how the utility attempted to mitigate or take steps to prevent estimates outside of the 25% range.

9. Code 18 of Federal Regulations Section 292.306 enables Qualifying Facilities to interconnect to the grid and allows the utility to recover those interconnection costs that are reasonable.

10. The utilities may seek to recover from ratepayers the actual interconnection costs that exceed the cost envelope framework upon a showing of reasonableness. This reasonableness review may occur in the utility's GRC or in a standalone application.

11. The parties should be encouraged to continue their now well-established collaborative process to raise and resolve interconnection issues.

12. This proceeding should be closed.

13. This decision should be effective immediately.

O R D E R

Therefore, **IT IS ORDERED** that:

1. The November 9, 2015 Joint Motion of Southern California Edison Company, San Diego Gas & Electric Company, Pacific Gas and Electric Company, California Solar Energy Industries Association, Clean Coalition, CODA Energy and Interstate Renewable Energy Council, Inc. setting forth proposals for the development of a Unit Cost Guide, as further specified in Attachment A, and Pre-Application Report Enhancements, as shown in Attachment B, is granted consistent with today's decision.

2. The November 18, 2015 Joint Motion of Southern California Edison Company, San Diego Gas & Electric Company, Pacific Gas and Electric Company, the Interstate Renewable Energy Council, Inc., the Clean Coalition,

Robert Bosch LLC and Stem, Inc. setting forth proposed revisions to Electric Tariff Rule 21 to address interconnection of behind-the-meter, non-exporting energy storage as described in Attachment C, is granted as set forth in Today's Decision.

3. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall file Tier 2 advice letters within 60 days of the effective date of today's decision proposing revisions to Electric Tariff Rule 21 establishing a cost envelope of 25% for interconnection-related expenses. This cost envelope shall apply for five-year term. At minimum, the Tier 2 advice letter shall include:

- Interconnection application documentation including cost envelope selection box and "technical scope package."
- Memorandum account details, including explanation about each project expense, how project expenses will be tracked over time and how booked expenses will be netted across projects.

4. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall apply the 25% Cost Envelope to the estimated cost provided by the utility on the Generator Interconnection Agreement (GIA) documentation. In order to inform the GIA to elect the Cost Envelope, projects that successfully complete either Fast Track Initial Review or Supplemental Review must pay a new $2,500 deposit and allow an additional 20 business days for the Utility to develop a cost estimate following the completion of the engineering review phase. Developers applying under the Independent Study Process must pay the required deposits and complete both a System Impact Study and Facilities Study in order to elect the Cost Envelope.

5. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall file a Tier 2 Advice Letter within

60 days of the effective date of today's decision updating their Electric Tariff Rule 21 generator interconnection application to reflect the "technical scope package" if a developer elects to use the cost envelope framework.

6. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall file a Tier 2 Advice Letter within 60 days of the effective date of today's decision creating a memorandum account to track interconnection costs that are either above or below the 25% cost envelope for reasonableness review for recovery in either a general rate case or in a subsequent application. The memorandum account shall include a description of the main driver(s) of the inaccurate estimate, and an explanation of how the utility attempted to mitigate or take steps to prevent estimates outside of the 25% range. A technical report including comprehensive and detailed information about each entry into the memorandum account shall be attached as an appendix.

7. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall host workshops, in consultation with the Commission's Energy Division, at least semi-annually, to provide a forum for parties and the Commission to inquire about the utilities' interconnection process progress and to provide guidance.

8. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall host a workshop within 120 days of the effective date of today's decision to discuss new data reporting requirements and formats. The utilities shall consult with Energy Division and create a working group to refine metrics and reporting. These metrics shall be added to the Rule 21 Quarterly Report.

9. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall file proposed revisions to Tariff Rule 21 setting forth any agreed-upon technical requirements, testing and certification processes, and effective dates for Phase 2 communication protocols and Phase 3 additional advanced inverter functions in separate Tier 3 advice letters no later than six months from the effective date of this decision.

10. The parties must comply with the filing and event schedule set out in Attachment D.

11. Rulemaking 11-09-011 is closed.

This order is effective today.

Dated June 23, 2016, at San Francisco, California.

MICHAEL PICKER
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
LIANE M. RANDOLPH
Commissioners

I will file a concurrence.

/s/ CATHERINE J.K. SANDOVAL
Commissioner

ATTACHMENT A

COST GUIDE IMPLEMENTATION PRINCIPLES

1. **Initial Development Timing** – The Cost Guide will be developed within 90 Calendar Days of the issuance date of the Commission's decision approving the request. The initial review of the Cost Guide will incorporate steps as described within the Annual Stakeholder process as described in Section 2(h) below.[1]
2. **Cost Guide Scoping Principles** – The following principles stated below will be incorporated within the Cost Guide development process and supporting tariff requirements (as necessary):
   a. Each Utility shall publish a Cost Guide for facilities generally required to interconnect generation to their respective Distribution systems.[2] The Utilities will coordinate to develop a consistent Cost Guide format;
   b. The Cost Guide is not binding for actual facility costs and is provided only for additional cost transparency and developer reference availability;
   c. The Cost Guide will include the anticipated cost of procuring and installing such facilities during the current year and may vary among the Utilities and within an individual Utility's service territory;[3]
   d. An annual adjustment will be performed within the Cost Guide for five years to account for the anticipated timing of procurement to accommodate a potential range of commercial operation dates;
   e. The Cost Guide will be consulted as part of the Utilities' study estimate;
   f. The Utilities will work with stakeholders after issuance of the initial Cost Guide and review whether a proposed narrative explanation regarding cost deviation between the Cost Guide estimate and system study facility proposed estimate should be prepared and under what threshold conditions the narrative explanation would apply;

[1] For the initial cost guide development, the Utilities anticipate an approximate 30-45 calendar day stakeholder process utilizing the review guidelines as outlined within Section 5(h) below. Upon conclusion of the stakeholder process, an Advice Letter will be filed as discussed within Section 2(h)(vi).

[2] Distribution voltages are defined under Rule 2, Section B.

[3] The Cost Guide will also include an "assumptions" sheet/tab akin in detail to what is currently provided within the CAISO Cost Guide. In particular, the assumptions tab would provide utility operation and maintenance along with recovery cost calculation method calculations as currently approved by each Utility along with other relevant information to support the cost estimates provided (ex: commentary regarding the unit cost guide elements based on utility reviews). The cost additions as described above would be incorporated into proposed project examples as described in Section 2(g) consistent with a total project cost amount as calculated within a Generator Interconnection Agreement. Please note that as consistent with the current CAISO guide, confidential proprietary vendor information will not be disclosed within the Cost Guide.

g. The Cost Guide will include illustrative scenarios reflecting stakeholder input to assist in understanding and readability of the guide, and will describe various requirements for interconnection facilities and distribution upgrades[4]; the annual proposed stakeholder review process can act as a forum to discuss the usefulness of such scenarios; and

h. A proposed annual update of the Cost Guide would be performed in accordance with the following process:[5]

   i. During the first quarter (January to March) of the year each Utility will post to their Open Access public web page the proposed Cost Guide; the posting would be made no later than March 31 of each year;[6]

   ii. At least 15 business days prior to posting, the Utilities will facilitate a Pre-Posting workshop (via phone or in person) with stakeholders to gather comments on a previously posted Cost Guide or to discuss the initial proposed Cost Guide;

   iii. No less than 10 Business Days prior to the Pre-Posting workshop, the Utilities will notify interested parties;[7] and

   iv. Within 10 Business Days of posting the Cost Guide, the Utilities will host a post-posting workshop (via phone or in person) to review with stakeholders any changes made to the previous year's posted Cost Guide data (if any) and to address any outstanding matters raised at the initial Pre-Posting workshop;

   v. Once established, the Utilities will also post dates for Pre-Posting Workshop, Cost Guide posting date and any Post workshop dates on their respective Open Access public site;

   vi. Upon the conclusion of the annual process described above, each Utility will each file a Tier 1 advice letter with the California Public Utilities Commission to formally establish and subsequently update the Cost Guide.

(END OF ATTACHMENT A)

---

[4] Scenario description will also provide editorial notes regarding potential items that would cause variability from a Cost Guide derived estimate (for example, construction timelines that would be impacted by traffic control limitations).

[5] Please see footnote 5 for discussion of initial Cost Guide review timeline. The initial review stakeholder outreach will be governed in accordance with the principals highlighted within 5(ii)-5(vi).

[6] For the case of the initial Cost Guide, the Utilities propose to issue the Cost Guide within 90 calendar days of the issuance date of the Commission's decision on this Motion. As discussed during the Commission sponsored workshops, the Unit Cost Guide would be required to be updated on an annual basis in accordance with tariff requirements, but the Utility may provide interim Cost Guide updates if market conditions warrant such revision.

[7] Interested parties will include, at a minimum, the Service list of R.11-09-011 or a successor proceeding that includes Rule 21 within its scope.

ATTACHMENT B

PROPOSED ENHANCEMENTS TO PRE-APPLICATION REPORTS

1. **Initial Development Timing –** The Joint Parties request that the Utilities be directed to file tariff revisions to implement the described enhancements to the Pre-Application Report below via an Advice Letter within 15 Calendar Days of the issuance date of the Commission's decision on this Motion.
2. **Item Request Protocol –** The table below summarizes the anticipated method and pricing for the agreed upon enhanced report data items available within the Enhanced Pre-Application Report. In particular, the Joint Parties believe that the availability of the existing (Standard) Pre-Application Report in its current form and pricing should remain an available option for Interconnection Customers, and that Enhanced Pre-Application Report data items will be available to an Interconnection Customer based upon specific cost and timing, reflective of the scope of work required for these new enhanced report data items.[8] Requests that exclude the Standard Pre-Application Report and select only Enhanced Pre-Application Report items will be assessed an additional administrative fee of one hundred dollars to account for the processing, review, and management of the Enhanced Pre-Application Report items. If an Interconnection Customer requests a combination of reports with varying timeframes for completion (e.g. Standard Pre-Application Report and an Enhanced Pre-Application Report that require 10 Business Day and 30 Business Day respective timeframes for completion), the longer timeframe will be applied to all aspects of the request.
3. **Automation –** The Utilities will automate as much of the Standard and Enhanced Pre-Application Report request form and related process as is feasible and appropriate.

The table below summarizes the data included in the Enhanced Pre-Application report, the associated costs, and timing involved.

Data Package	Cost	Time	Proposed Report
Primary Service Package: Nominal Distribution circuit voltage and wiring configuration	$225	10 Business Days (timeline is 30 Business	Enhanced Pre-Applicatio

[8] The proposed data item of Nominal Distribution Circuit Voltage and Wiring Configuration will be incorporated within the Standard Pre-Application Report at no additional cost in recognition of streamlining efforts proposed for the processing of the data packages.

i) Relevant line section(s) absolute minimum load, and minimum load during the 10 AM – 4 PM period (provided when SCADA data is available). ii) Existing upstream protection including: (a) Device type (Fuse Breaker, Recloser) (b) Device controller (device make/model ex: 50E/50T) (c) Phase settings [IEEE Curve, Lever, Min Trip (A), Inst Trip(A)] (d) Ground settings [IEEE Curve, Lever, Min Trip (A), Inst Trip(A)] (e) Rated continuous current (f) Short Circuit interrupting capability (g) Confirm if the device is capable of bi-directional operation iii) Provide the Available Fault Current at the proposed point of interconnection including any existing distributed generation fault contribution.		Days if requested with Behind-the-Meter Interconnection Package)	n Report
Behind The Meter Interconnection Package (Package does assume a physical verification based on field confirmation): i) Relevant line section(s) absolute minimum load, and minimum load during the 10 AM – 4 PM period (provided when SCADA data is available) ii) Transformer data (a) Existing service	$800	30 Business Days	Enhanced Pre-Application Report

transformer kVA rating (b) Primary Voltage and Secondary Voltage rating (c) Configuration on both Primary and Secondary Side (*i.e.*, Delta, Wye, Grounded Wye, etc.) (d) Characteristic impedance (%Z) (e) Confirm if the transformer is serving only one customer or multiple customers[9] (f) Provide the Available Fault Current on both the Primary and Secondary Side iii) Secondary Service Characteristics (a) Conductor type (AL or CU) and size (AWG) (b) Conductor insulation type (c) Number of parallel runs (d) Confirm if the existing secondary service is 3 wire or four wire. iv) Primary Service Characteristics (a) Conductor type (AL or CU) and size (AWG) (b) Conductor insulation type (c) Number of parallel runs (d) Confirm if the existing primary service is three wire or four wire.			

(END OF ATTACHMENT B)

[9] As discussed during the workshops, it is expected that customer authorization will be required for release of customer specific information. If customer authorization is required, the Utilities will notify the applicant if additional processing time will be required.

ATTACHMENT C

RECOMMENDATIONS FOR STREAMLINING AND STANDARDIZING THE INTERCONNECTION PROCESS FOR BEHIND-THE-METER, NON-EXPORTING ENERGY STORAGE

I. PROPOSALS FOR COMMISSION APPROVAL

1. Clarifications Regarding Treatment of Storage Load in the Rule 21 Tariff

The Parties recommend that the following language be added to the Rule 21 tariff:

> "B.4. Interaction with other Tariffs for Storage Charging Load Treatment For retail Customers interconnecting energy storage devices pursuant to this Rule, the load aspects of the storage devices will be treated pursuant to Electric Rules 2, 3, 15 and 16 just like other load, using the incremental net load for non-residential customers, if any, of the storage devices."

2. Cost Allocation for Upgrades Attributable to Both Load and Generation System Impacts Should Prioritize Load Impacts

If a Utility determines that a given upgrade would be triggered independently by the load or generation (charging or discharging) aspects of an energy storage device, the Utility would first apply the cost allocation principles of Rules 15 and 16 for the upgrades required to serve any permanent, bona fide addition of load with allowances based on the net incremental revenue contributed by added storage charging load; the Utility would then apply the provisions of Rule 21 to anything in addition to what is necessary to serve the load and that was triggered as a result of the generation.

3. Provide Additional Detail on Storage Charging Load Processes via a Public "Guide"

The Utilities will develop an Interconnection Process Guide detailing the processes and implementations by which the load aspects of energy storage are reviewed, including specific size thresholds and cost responsibility of load-related upgrades not already included in Rule 21 or Rules 2, 3, 15 and 16. The guide will contain, at a minimum:

- A description of the review process including specific requirements for cursory load review,
- A description of the kind of information that will be provided by the Utility as a result of the load study, including proposed charging profiles to avoid identified potential system upgrade needs.
- A transparent stakeholder process will be used so that modifications to the Guides may be made quickly and collaboratively.
- The Guide publically available and served on the R.11-09-011 service list or any successor proceeding within 90 Business Days of the date of issuance of a Commission's Final Decision approving this proposal.

4. **Modify Interconnection Application and Agreement to Capture Load Related Information**

Within 30 business days of the Commission's decision approving this proposal, the Utilities will file and serve a Tier 2 Advice Letter with proposed modifications to their respective Interconnection Application and pro-forma Interconnection Agreement Forms used for facilities that include non-export energy storage. Such proposed modifications shall include:

- ensure storage charging behavior is adequately described in the Rule 21 Interconnection Request.
- memorialize the relevant commitments of an interconnection customer and Utility to respectively operate and serve a generating facility as proposed.
- Clarify the customer's responsibility to notify the Utilities of changes in operations, and to provide data to the Utilities upon request regarding the agreed upon constraints.
- With regard to fees and costs, changes in the load characteristics will be treated in a manner consistent with Rules 2, 3, 15 and 16 using the incremental net load, if any, of the storage device.

II. PROPOSALS FOR ADDITIONAL STEPS FOLLOWING THE COMMISSION ISSUANCE OF THE DECISION ADDRESSING THIS MOTION

In addition to the items discussed in Section I, the Joint Parties propose a process for moving forward on the following additional items that were discussed during the workshops but that require additional review and consideration by the stakeholders to properly balance increased efficiency and flexibility with the need to maintain safety and reliability. For these items, the Joint Parties request Commission approval of the *process* specified to move forward on these items.

1. Expedited Interconnection Process for Certified Standard Storage Applications

The Joint Parties propose that Utility staff and interested industry members collaborate on defining criteria for an expedited interconnection process for non-export energy storage no later than 60 Business Days after issuance of a Final Decision approving this proposal.

Each Utility will file an advice letter on the later of 120 Business Days after filing of the Motion or 30 Business Days after the Commission issues a decision approving the proposal, to create an expedited interconnection process for non-export energy storage that may also be functional for other technologies or configurations in the future.

The expedited process will include:

- For currently known technologies, physical specifications and standard configurations for eligibility, including converter-based storage facilities such as the Bosch DC Microgrid technology;
- For future technologies, process and any related costs to establish new physical specifications and standard configurations for eligibility;
- Information required in an Interconnection Request under this process and any changes needed to filed Application forms;
- Definition of final testing or commissioning activities required prior to interconnection, which may be specific to the configurations or technologies;
- Process flow diagram with mapping to Rule 21 requirements;
- Expected process timelines, as applicable;
- State of automation needed to support the process (if any);
- Date by which the proposed process will be available to customers, allowing time needed to develop process optimizations or automation, as needed;
- Proposed interconnection application fee for projects using the proposed process; and,

- Specification of process documentation that the IOU will make available.

2. Streamlined Rule 21 Review Process for AC/DC Converter

Within 60 Business Days of the delivery to the Utilities of the results of a mutually agreed upon, between the Utilities and Bosch, test of Bosch's AC/DC converter by Underwriters Laboratory, including data on backfeed current and duration that occurs during normal and fault conditions and harmonics contribution of its converter meeting the requirement of IEEE 519 Harmonic Limit, each Utility will file a Tier 2 advice letter(s) requesting Commission approval of amendments to Rule 21 tariff and forms, as applicable, to address the use of AC/DC converters (or other defined term as agreed upon) and specify the certification of and Rule 21 process applicable to such technology that would allow Generating Facilities utilizing such equipment to immediately pass Rule 21 Fast Track Initial Review.

3. Creation of an Option to Utilize Advanced Inverter Functionality for Inadvertent Export

Within 30 Business Days of a Commission Decision approving the Joint Parties' motion, the Joint Parties and interested stakeholders shall provide a status update to the service list for R.11-09-011 on additional progress that has been made toward developing consensus-based requirements to address the "inadvertent export" issue. This update will include detail on the timeline of further actions, including any expected filings. Within these 30 days, the Joint Parties shall schedule a minimum of three stakeholder calls to engage in continued discussions. If agreement is reached, tariff changes could be proposed to the Commission via advice letter to modify the corresponding tariff sections and filed forms to accommodate the change.

(END OF ATTACHMENT C)

ATTACHMENT D – FILING SCHEDULE

Event	Responsible Party	Due Date
Cost Certainty		
File and serve Tier 1 Advice Letter revising Rule 21 to provide for Unit Cost Guide and Annual Review Process	Each utility	15 Calendar Days after Commission decision approving proposal
File and serve Tier 1 Advice Letter revising Rule 21 to provide for Enhanced Pre-Application Report	Each utility	15 Calendar Days after Commission decision approving proposal
File and serve Tier 1 Advice Letter publishing first Unit Cost Guide, subsequent versions not to be filed as an Advice Letter	Each utility	90 Calendar Days after Commission decision approving proposal
Behind-the-Meter, Non-Exporting Storage		
File and serve Tier 1 Advice Letter revising Rule 21 to clarify rules applicable to load review	Each utility	15 Calendar Days[10] after Commission decision approving proposal
Serve status report after three stakeholder telephone conferences on advanced inverter inadvertent export option	Each utility	45 Calendar Days after Commission decision approving proposal
File and Serve Tier 2 Advice Letter revising Rule 21 to include a modified interconnection application and agreement	Each utility	45 Calendar Days after Commission decision approving proposal
Serve on service list and Energy Division Director list of criteria for expedited interconnection process for non-exporting storage facilities	Each utility	90 Calendar Days after Commission decision approving proposal
If agreement reached on inverter inadvertent export option, File and serve Tier 2 Advice Letter revising Rule 21 to incorporate agreement	Each utility	90 Calendar Days after Commission decision approving proposal
Publish and Serve first Interconnection Guide	Each utility	120 Calendar Days after Commission decision approving proposal

[10] Pursuant to Rule 1.15 of the Commission's Rules of Practice and Procedure, the Commission's normal practice is to count calendar days. The Joint Motion on Behind-the-Meter, Non-Exporting Energy Storage proposes filing deadlines in business days, but here we adopt filing deadlines in comparable calendar days.

File and serve Tier 2 Advice Letter revising Rule 21 to incorporate expedited interconnection process for non-exporting storage	Each utility	120 Calendar Days after Commission decision approving proposal
Serve on service list and Energy Division Director notice of agreement on AC/DC converter certification test	Each utility	No deadline
File and serve Tier 2 Advice Letter revising Rule 21 review process for AC/DC converters	Each utility	90 Calendar Days after notice of results of agreed-upon Underwriters Laboratory certification test for AD/DC converter
25% Cost Envelope		
File and serve Tier 2 Advice Letter revising Rule 21 to incorporate the 25% Cost Envelope consistent with today's decision	Each utility	30 Calendar Days after Commission decision approving proposal
File and serve Tier 2 Advice Letter revising Rule 21 to incorporate the "Technical Scope Package" in a generator interconnection application for developers that elect the Cost Envelope framework	Each utility	30 Calendar Days after Commission decision approving proposal
Smart Inverter Working Group		
File and serve Tier 3 Advice Letter revising Rule 21 to incorporate technical requirements for Phase 2 communication protocols	Each utility	180 Calendar Days after Commission decision approving proposal
File and serve Tier 3 Advice Letter revising Rule 21 to incorporate technical requirements for Phase 3 additional advanced inverter functions	Each utility	180 Calendar Days after Commission decision approving proposal

(END OF ATTACHMENT D)

ATTACHMENT E – HISTORY AND STATUS OF THE SMART INVERTER WORKING GROUP

A. Background

Tariff Rule 21 sets forth the protective functions and equipment requirements for interconnection to the Utilities' distribution systems. These requirements are based on the Institute of Electrical and Electronics Engineers' (IEEE) Standard 1547, which was last issued in 2003.

Most generating resources require an inverter to convert direct current (DC) from the generating resource to the voltage and frequency of the alternating current (AC) distribution system. Wind and photovoltaic resources produce DC, and therefore need inverters, while hydroelectric and biomass generating units, which produce AC, do not. Generally, in California, about 90% of small-scale renewable generation is connected to the distribution grid through inverters.

Since 2003, the technical capabilities of inverters have advanced substantially. The Smart Inverter Working Group (SIWG) was formed by parties to this proceeding in early 2013 to develop proposals to take advantage of these new capabilities in order to better integrate and mitigate the impacts of distributed energy resources (DERs) at increasingly high penetrations. In January 2014, the SIWG issued its "Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources," which proposed the following revisions to Electric Tariff Rule 21 in what it characterizes as "Phase 1":

1. Anti-Islanding Protection: Revise Electric Tariff Rule 21, Section H.1.a.(2) to reflect proposed new voltage ride through settings;
2. Low and High Voltage Ride-Through: Revise Electric Tariff Rule 21, Section H.1.a.(2) and Table H.1 to reflect proposed new default voltage ride-through requirements;

3. Low and High Frequency Ride-Through: Revise Electric Tariff Rule 21, Section H.1.a.(2) and R21 Table H.2 to reflect proposed new frequency ride-through settings;
4. Dynamic Volt-Var Operation: Revise Electric Tariff Rule 21, Sections H.2.a, H.2.b, H.2.i and R21 table H.1 to reflect proposed new dynamic volt/var operations requirements;
5. Ramp Rates: Add new Electric Tariff Rule 21 subsection within Electric Tariff Rule 21, Section H to include proposed new ramp rate requirements;
6. Fixed Power Factor: Revise Electric Tariff Rule 21, Section H.2.i to reflect the proposed new fixed power factor requirements; and
7. Soft Start Reconnection: Revise Electric Tariff Rule 21, Section H.1.a.(2) to reflect proposed new reconnection by soft-start method.

The SIWG Phase 1 recommendations were circulated to the parties via a February 7, 2014 assigned ALJ ruling and were the subject of a February 29, 2014 prehearing conference. The Commission, in a May 13, 2014 assigned Commissioner Scoping Ruling, directed the Utilities to file and serve draft Advice Letter filings seeking Commission approval of revisions to Electric Tariff Rule 21 to conform to the seven Phase 1 recommendations made by the SIWG, and any other revisions needed to Tariff Rule 21 to facilitate deployment of smart inverter capabilities. The Utilities duly filed a Joint Motion containing the draft Advice Letters on July 18, 2014, with party comments and Joint Utility reply comments filed on August 18, 2014 and September 8, 2014, respectively. The Commission agreed with the moving parties that bringing the benefits of today's smart inverters to California required changes to Electric Tariff Rule 21 and on December 18, 2014 issued D.14-12-035 adopting, with modifications, the revisions proposed by the SIWG in its January 2014 Phase 1 recommendations.

B. Current Work of the Smart Inverter Working Group

The May 13, 2014 Assigned Commissioner Scoping Ruling also noted that the SIWG Phase 1 Recommendations document recommended a second phase to focus on communications between the grid operator and a DER (Phase 2) and a third phase to identify and address additional advanced inverter functionalities (Phase 3), and directed the SIWG to file and serve a proposed description of issues ready for Commission resolution and a proposed schedule for these issues no later than July 18, 2014. SDG&E, on behalf of the SIWG, filed a timely Motion that described the SIWG's progress on Phase 2 deliberations and put forth an estimated schedule for completing the remaining Phase 2 tasks.

1. Communications Protocols

The Smart Inverter Working Group completed its recommendations for Phase 2 communication protocols in February 2015, which are attached to this decision as a reference exhibit. The recommendations for Phase 2 communication protocols include inverter communication capabilities and standards that are delineated across Rule 21, the utilities' Generator Interconnection Handbooks, a California IEEE 2030.5 Implementation Guide, by mutual utility-distributed energy resource (DER) owner/operator agreements, or left up to vendor or market decisions.

Specific recommendations for communication requirements to be added to Rule 21 are:

i. All inverter-based DER systems shall be capable of communications;

ii. Initially, the communications requirements shall be between (1) Utilities and individual DER Systems, (2) Utilities and Facility DER Energy Management Systems which manage DER systems within a facility, plant, and/or microgrid, and (3) Utilities and Retail Energy Providers / Aggregators / Fleet Operators which manage and operate DER systems at various facilities;

iii. Each utility shall include sections in their individual "[Utility] Generation Interconnection Handbook" providing complete details and guidelines for the implementation of communications with DER systems;

iv. Each utility handbook shall make reference to a common "California IEEE 2030.5 Implementation Guide" that will be developed and maintained collectively by the California IOU's. This implementation guide shall provide detailed communication requirements and implementation guidelines that ensure consistent interoperability of DER systems with all of the IOU's. This guide may be updated periodically to support advances in technology or updates in tariffs and other California DER rules;

v. The data exchange requirements shall be defined in "DER Data Exchange Requirements" document that shall be referenced by each utility's Generation Interconnection Handbook as the minimal that must be available to be compliant with Rule 21 (see example of minimal data exchange requirements in Section 3). Additional types of data may be exchanged by mutual agreement between the utility and DER operator/owner;

vi. The DER system software shall be updateable via communications either remotely or at the customer site. The update protocol may be vendor specific;

vii. The Transport Level protocol shall be TCP/IP

viii. The default Application Level protocol shall be the IEEE 2030.5. The details of the IEEE 2030.5 profile are defined in the California IEEE 2030.5 Implementation Guide;

ix. Other Application Level protocols may be used by mutual agreement, including IEEE 1815/DNP3 for SCADA real-time monitoring and control and IEC 61850;

x. Utility Generation Handbooks and the Protocol-Specific documents shall include cyber security and privacy requirements; and

xi. Generic device communications registration management requirements shall be defined in each Utility Generation Implementation Handbook, including how to register individual DERs, Facility DER Energy Management Systems, and Aggregators.

2. Additional Advanced Inverter Functions

In March 2016, the Working Group completed its technical recommendations for the following eight advanced inverter functions, which are attached to this decision as a reference exhibit. In its recommendations, the Working Group identified a number of outstanding issues with these eight functions that need further resolution before the technical requirements can be included in Rule 21. The term "function" encompasses single "DER direct commands" as well as "DER modes" which entail continuous autonomous internal analysis and actions by the DER once the mode is enabled. These eight capabilities would only be enabled or permitted after contractual or market agreements are made.

i. **Monitor Key DER Data**: DER systems identified by utilities during the interconnection process shall have the capability to provide key DER data at the DER's Electrical Connection Point (ECP) and at the Point of Common Coupling (through the meter), including key administrative, status, and measurements on current energy and ancillary services;

ii. **DER Disconnect and Reconnect Command**: The disconnect command shall either cause a "cease to energize" state or shall initiate the opening of the DER switch at the referenced ECP in order to galvanically isolate the DER system from the Local or Area EPS, while the reconnect command shall initiate the closing of the DER switch at the referenced ECP or shall end the cease to energize state;

iii. **Limit Maximum Real Power Mode**: This mode shall limit the maximum real power level at the referenced ECP either as a percent of the maximum real power capability or to a specific real power value;

iv. **Set Real Power Mode**: This mode shall set the real power level at the referenced ECP as a percent of the maximum real power capability or to a specific real power value;

v. **Frequency-Watt Emergency Mode**: This mode shall provide settings to counteract frequency excursions during high or low frequency ride-through events by decreasing or increasing real power;

vi. **Volt-Watt Mode**: This mode shall set the volt-watt curve parameters necessary to respond to changes in the voltage at the referenced ECP by decreasing or increasing real power;

vii. **Dynamic Reactive Current Support**: This mode shall provide reactive current support in response to dynamic variations in voltage (i.e., rate of voltage change) rather than changes in voltage; and

viii. **Scheduling Power Values and Modes**: Schedules shall be capable of setting real and reactive power values as well as enabling and disabling DER modes for specific time periods.

C. Advice Letter Compliance Filing

No later than six months after the effective date of this decision, the Utilities are directed to propose revisions to Tariff Rule 21 setting forth any agreed-upon technical requirements, testing and certification processes, and effective dates for Phase 2 communication protocols and Phase 3 additional advanced inverter functions in separate Tier 3 advice letters (i.e., one advice letter each for Phase 2 and Phase 3). In the absence of consensus on certain issues, the Utilities shall file a status report and work plan on these efforts. We stress that any proposed Rule 21 revisions shall solely concern technical inverter requirements and not any regulatory, legal, or compensation issues that are out of scope for the SIWG.

The Commission understands that the Utilities are presently leading an implementation effort to establish and test the back-end systems that will oversee utility-to-inverter communications, as delineated in the Phase 2 recommendations. Judging from the Phase 3 recommendations document, however, it is apparent that further consensus is needed on a number of specific Discussion Issues regarding the eight Phase 3 functions. The Working Group is encouraged to reconvene in order to reach the necessary consensus on these Discussion Issues in advance of possible tariff revisions. Energy Division shall assist in bringing forth consensus proposals on SIWG issues.

California Energy Commission

&

California Public Utilities Commission

Recommendations for Utility Communications with Distributed Energy Resources (DER) Systems with Smart Inverters

Smart Inverter Working Group Phase 2 Recommendations

Draft v9

February 28, 2015

Contents

Figures

Tables

1. Introduction

1.1 Background to SIWG Phase 2

In the January 2014 recommendations to the CPUC on Rule 21, the Smart Inverter Working Group (SIWG) described a three phase approach to the updating of Rule 21. Phase 1 defined seven autonomous functions (approved by the CPUC on December 18, 2014). Phase 2 described the need for communications, "*During Proposed Phase 2, the SIWG will define and propose an implementation plan for communication capabilities and standards for inverters. Some parts of the Proposed Phase 2 implementation plan are defined [in the SIWG recommendations document], in order to set out a broad road map. For example, basic communications requirements draw on existing communications standards, such as Internet specifications and the IEC 61850 communications standards for DER systems. Future SIWG discussions will adapt and refine communications standards to California-specific needs in a structure similar to that set out for Proposed Phase 1: definition of the standards, a transitional permissive period, collection and publication of operational data, and CPUC consideration of mandatory standards.*"

As stated in the May 13, 2014 Scoping Ruling of Commissioner Picker, "*Next Steps for Improving Interconnections with Distributed Energy Resources: The Working Group Report also recommended a second phase to focus on communications between the grid operator and distributed energy resource, and a third phase to identify and address additional advanced inverter functionalities. The Working Group should file and serve a proposed description of issues ready for Commission resolution and a proposed schedule for these issues no later than July 18, 2014.*"

The SIWG filed those issues and continued to work on the Phase 2 issues via weekly calls and additional subgroup calls. A workshop to discuss many of the issues was held at the CPUC on October 24, 2014, covering data exchange requirements, the selection of a protocol, and cyber security requirements.

Over the next months, decisions were made on initial recommendations for these and other communication issues, classifying them in one of the following categories:

- Recommended to be included in Rule 21
- Recommended to be included in each utility's "[Utility][1] Generation Interconnection Handbook" on requirements and options
- Recommended to be included in a single "California IEEE 2030.5 Implementation Guide"
- Recommended to be decided by mutual utility-DER owner/operator agreements on a utility basis or an installation basis

[1] [Utility] will be replaced by the name of the utility

- Recommended to be left up to vendor or market decisions

1.2 Utility Principles

The utilities identified the following principles in developing their communication requirements:

1) Our goal is to establish communications between the utility and external smart inverters and aggregator systems, and not define internal utility systems communications which are out of scope for Rule 21.
2) Where DER systems may have a "material impact" on the power system, utilities will create the necessary communication infrastructure for real-time monitoring and control.
3) While SEP 2.0 / IEEE 2030.5 is our default protocol, there is potential under mutual utility/3rd party agreement that alternative protocols may be used.
4) Utility communication requirements are just a subset of what any DER implementation may consider, so DER implementations may add other "value added" functionality as long as they are not in conflict with the set of requirements as defined by the default protocol.
5) For external system interactions, utilities want a single default mandatory communications profile that addresses all communications layers to ensure interoperability across California.
6) A common test harness and 3rd party certification processes are preferred for validating implementations. The utilities do not want to be in the device/protocol validation business for DER.
7) Utilities want the communication requirements for all Phase 1 and Phase 3 DER use cases identified, including the functional requirements for DER management (including administrative actions), as well as the non-functional/performance requirements.
8) Utilities recognize that communications with DER systems under Rule 21 are not intended for sub-second interactions and protection.
9) This is a technical specification only, other issues such as regulatory support and tariff issues are assumed to be handled outside of this specification and should not drive decisions
10) The utilities expect that technology both in DER systems and communications technology will continue to evolve and future revisions of our default protocol may be needed.
11) The primary use of DER performance data coming from inverters at this time is initially to improve planning models and generation/load forecasts. However it is

understood that this purpose will evolve over time, possibly to provide more near-real-time operational support.

2. SIWG Phase 2 Recommendations for Communication Aspects to be Included in Rule 21

2.1 Overview of Scope of Recommendations

The scope of the SIWG Phase 2 recommendations comprises the communications requirements between (see red lightning bolts indicating Wide Area Networks in Figure 1):

1. Utilities and individual DER Systems
2. Utilities and Facility DER Energy Management Systems (FDEMS) which manage DER systems within a facility, plant, and/or microgrid
3. Utilities and Retail Energy Providers (REP) / Aggregators / Fleet Operators which manage and operate DER systems at various facilities

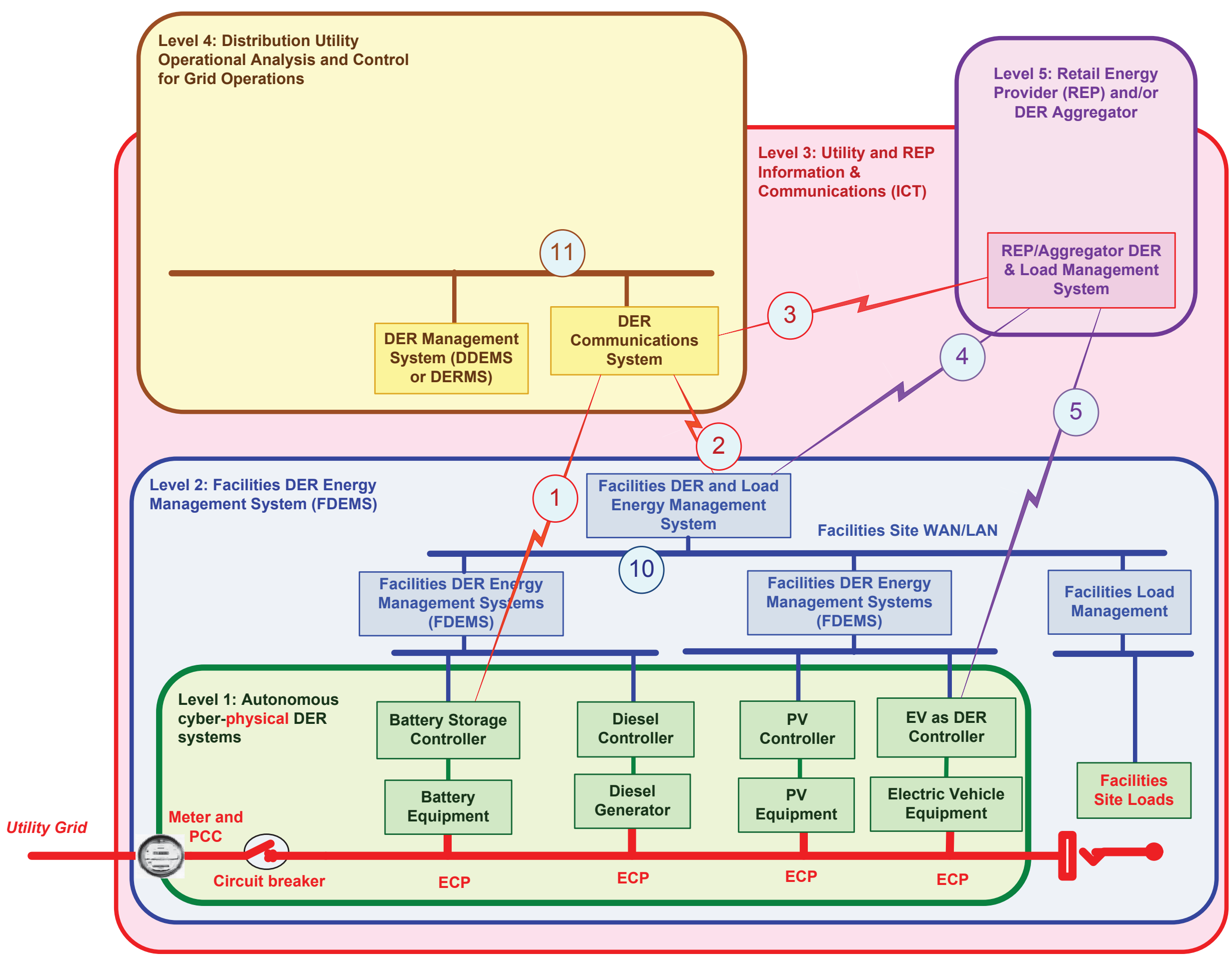

Figure 1: Communications between Utilities and individual DER systems, FDEMS, and REPS

Other communications are indicated by the brown utility LAN (11), the purple REP/Aggregator lightning bolts (4, 5) and the blue facility LANs (10), but these are out of scope for Rule 21.

At a high level, communications include the following aspects:

- Data "profiles" of the data to be exchanged for monitoring and control, including the complete specification at all communication stack levels.
- Data object models that define abstract data constructs and services
- Application level protocols and services mapped from the data object models, including encoding protocols
- Transport level protocols
- Communication media or telecommunication provider services
- Cyber security requirements

These communication aspects are identified in Figure 2. The status of general agreement by the SIWG is indicated (green denotes general agreement), although there is not necessarily complete agreement. The expectation of which communication aspects will be covered in Rule 21 (and which will not) is also indicated.

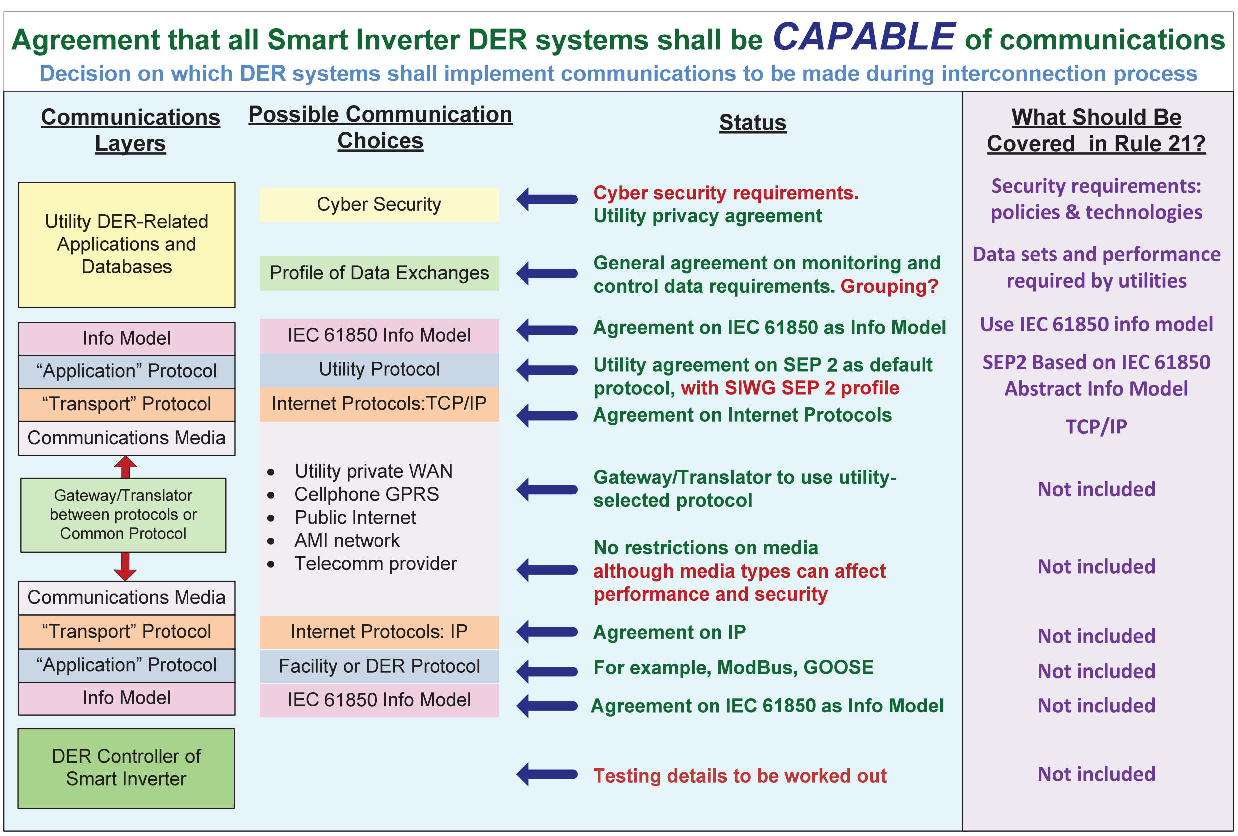

Figure 2: Status and expected coverage in Rule 21 for communication aspects

These agreements include:

1. **Communications capability**: DER systems with smart inverters shall be capable of communications although the implementation of those communication capabilities is a deployment decision and/or an upgrade decision.
2. **Utility data monitoring and control requirements**: The utilities have determined what data will be required at a minimum for the Phase 1 functions and selected Phase 3 functions, based on Use Cases, internal discussions, and discussions during the SIWG calls with the SunSpec Alliance which has worked with DER manufacturers and others on determining what data exchanges are supported by most smart inverter-based DER systems. Performance requirements have been outlined.
3. **IEC 61850 abstract information model**: The IEC 61850 abstract information model has been selected as providing the basis for the communications required for the Phase 1 functions and Phase 3 functions. Specifically IEC 61850-7-420 provides abstract information models for general data exchanges with DER systems, while IEC 61850-90-7 provides specific object models for the Phase 1 and Phase 3 functions.
4. **Utility protocol**: The utilities have determined that IEEE 2030.5 (also known as the Smart Energy Profile 2.0 (SEP 2)), is the default protocol which must be supported by individual DER systems, by facility DER energy management systems (FDEMS), and by aggregators of DER systems in order to communicate with the utility in support of smart inverter-defined functionality. The DER objects in IEEE 2030.5 were derived from the IEC 61850 abstract information model, and meet most if not all SIWG data requirements. See Figure 3 for an illustration of the use of IEEE 2030.5.
5. **Internet protocols**: The Internet protocols TCP/IP will be used.
6. **Communications media**: No restrictions or constraints are expected to be placed on the communications media so long as they can meet the utility performance and security requirements. Expected media types include cellphone channels, AMI networks, private utility networks, and the Internet. Telecommunications providers may also supply communication channels which are combinations of different media.
7. **Cyber security requirements**: Utilities are expected to identify cyber security requirements based in part on IEEE 2030.5 cyber security specifications and in part on utility security policies and procedures. These cyber security requirements are expected to include appropriately configured firewalls, role-based access control mechanisms, authentication and integrity of all messages, ability to provide confidentiality for some messages, key management requirements, communications channel performance requirements and monitoring, time synchronization across all systems, security monitoring, and audit logs of all significant alarms and events.

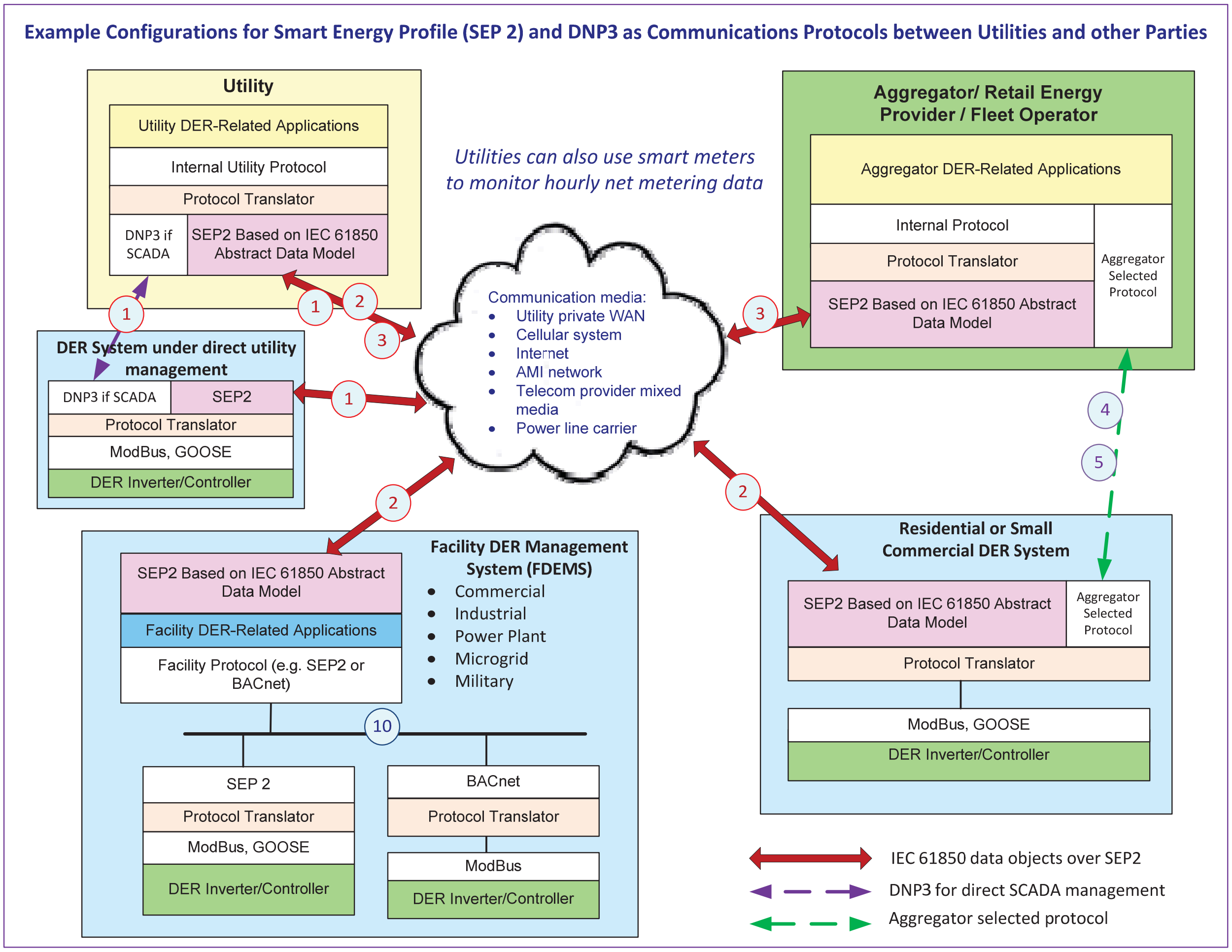

Figure 3: Conceptual Implementation of IEEE 2030.5 (SEP2) Communications with DER.

2.2 SIWG Recommendations for Communication Requirements to be Included in Rule 21

The SIWG recommends that the following communication requirements are included in Rule 21:

1. All inverter-based DER systems shall be capable of communications
2. The scope of the SIWG Phase 2 shall be the communications requirements between (1) Utilities and individual DER Systems, (2) Utilities and Facility DER Energy Management Systems (FDEMS) which manage DER systems within a facility, plant, and/or microgrid, and (3) Utilities and Retail Energy Providers (REP) / Aggregators / Fleet Operators which manage and operate DER systems at various facilities.
3. Each utility shall include sections in their individual "[Utility] Generation Interconnection Handbook" providing complete details and guidelines for the implementation of communications with DER systems.

4. Each utility handbook shall make reference to a common "California IEEE 2030.5 Implementation Guide" that will be developed and maintained collectively by the California IOU's. This implementation guide shall provide detailed communication requirements and implementation guidelines that ensure consistent interoperability of DER systems with all of the IOU's. This guide may be updated periodically to support advances in technology or updates in tariffs and other California DER rules.
5. The data exchange requirements shall be defined in "DER Data Exchange Requirements" document that shall be referenced by each utility's Generation Interconnection Handbook as the minimal that must be available to be compliant with Rule 21 (see example of minimal data exchange requirements in Section 3). Additional types of data may be exchanged by mutual agreement between the utility and DER operator/owner.
6. The DER system software shall be updateable via communications either remotely or at the customer site. The update protocol may be vendor specific.
7. The Transport Level protocol shall be TCP/IP.
8. The default Application Level protocol shall be the IEEE 2030.5. The details of the IEEE 2030.5 profile are defined in the California IEEE 2030.5 Implementation Guide.
9. Other Application Level protocols may be used by mutual agreement, including IEEE 1815/DNP3 for SCADA real-time monitoring and control and IEC 61850.
10. Utility Generation Handbooks and the Protocol-Specific documents shall include cyber security and privacy requirements..
11. Generic device communications registration management requirements shall be defined in each Utility Generation Implementation Handbook, including how to register individual DERs, Facility DER Energy Management Systems, and Aggregators.

2.3 SIWG Communication Requirements Recommended to Be Included in each Utility's "Generation Interconnection Handbook"

The SIWG recommends that the following topics are included in each utility's "[Utility] Generation Interconnection Handbook" that will be maintained by each utility Although each utility will develop and maintain their own Handbook, it is also recommended that coordination among the utilities ensure that these separate requirements are not contradictory:

1. Date and version of the [Utility] Generation Interconnection Handbook
2. Registration and enrollment processes for each utility's communication network
3. Categorizations of DER systems, such as by type of DER system, type of DER owner/operator, size of DER, location of DER within the utility grid, types of Groups for aggregated information, etc. These categorizations can be referred to when identifying certain requirements which may have different options.

4. A separate "DER Data Exchange Requirements" document containing the minimum data exchange requirements (monitoring, settings, control) as agreed among the California utilities shall be referenced in each Handbook, based on the example data exchange items shown in Section 3.
5. Reference to the appropriate "California IEEE 2030.5 Implementation Guide" which provides detailed specifications for implementing IEEE 2030.5-based communications.
6. Additional optional parameters and messages to the shared California IEEE 2030.5 implementation guidelines. These options must be specified in a non-contradictory manner to avoid one utility's IEEE 2030.5 requirement from being incompatible with another utility's requirement
7. Additional communication profiles that may be permitted upon mutual agreement (e.g. IEEE 1815 (DNP3) for real-time interactions and IEC 61850)
8. Performance requirements, including periodicity of data exchanges, latency of data requests-responses, sizes of data files, error management, and cyber security impacts on data latency
9. Cyber security requirements for communications, including Authentication, Authorization, Accountability, and Data Integrity shall be included at a minimum. Other cyber security requirements, such as confidentiality shall be supported but may be enabled only when needed. References to relevant cyber security standards shall be included.
10. Cyber security management requirements outside the protocol cyber security, including key management, certificate authorities, and cyber security management procedures
11. Cyber security-related passwords and cryptographic keys shall be secured from unauthorized access
12. Privacy policies shall clearly define what types of data shall be not available publicly, including individual data elements, utility aggregations of customer data, and third party aggregations of data
13. Testing and certification requirements (with references to the IEEE 2030.5 Implementation Guidelines for IEEE 2030.5 testing and certification.)

2.4 SIWG Communication Requirements Recommended to Be Included in a Single "California IEEE 2030.5 Implementation Guide"

The SIWG recommends that the following topics are included in a single "California IEEE 2030.5 Implementation Guide" that has been agreed to and will be maintained by the utilities:

1. Date and version of the California IEEE 2030.5 Implementation Guide
2. The default data schemas for the data exchange requirements defined in the "DER Data Exchange Requirements" document.

3. Any specific configuration requirements for individual DER systems, facility energy management systems, and/or aggregators
4. Any additions or modifications to the minimal data exchange requirements that may be required for different types of implementations.
5. The default IEEE 2030.5 profile, including:
    a. An interpretation of all data elements and objects
    b. IEEE 2030.5 services for retrieving data, setting data values, and notifications
    c. IEEE 2030.5 services for updating Groups of DERs
    d. IEEE 2030.5 cyber security technologies and procedures
    e. IEEE 2030.5 optional fields, values and commands such that they do not conflict with the base interoperability standard.
6. References to other documents as necessary for details on compliance or as useful as guidelines
7. Testing and certification requirements with references to facilities certified for performing such testing, such as the IEEE 2030.5 CSEP – Testing Certification Program and the SunSpec Alliance on ModBus Gateway to IEEE 2030.5
8. Identification of additional abstract IEC 61850 information model objects which could be translated to IEEE 2030.5 for additional functions.

2.5 SIWG Communication Requirements Recommended to Be Decided by Mutual Utility-DER Operator Agreements

The following issues are recommended to be decided by mutual utility-DER operator agreements which may vary by utility and/or by installation:

1. Whether communications are to be established between the utility and (directly or indirectly) the DER system For instance, the larger DER systems already require communications, but the protocol and types of data to be exchanged may be updated.

2. Which DER systems are allocated to which Groups for purposes of aggregation. The method for updating these allocations dynamically is provided in the protocol-specific Implementation Guides.

3. Which protocol to be used (e.g. the default IEEE 2030.5, a real-time protocol such as IEEE 1815/DNP3, or another protocol)

4. What optional data may be exchanged

5. What options in the IEEE 2030.5 protocol may be used

6. Which cyber security options may be used in addition to those defined in the California IEEE 2030.5 Implementation Guide or could be needed for securing other protocols

2.6 SIWG Communication Requirements Recommended to Be Left Up to Vendor or Market Decisions

At a minimum the following issues are recommended to be left up to "industry", vendor, and/or general market decisions, although many additional issues are expected to be industry decisions:

1. The development of "gateways" that translate from other protocols to the utility communication protocols
2. The communication technologies used by the DER system between its communication module and the "gateway" to the utility
3. The communications media used between the "gateways" and the utility, so long as it does not pose a performance or security issue for the utility
4. Any other issues not covered in Rule 21 or the Utility Generation Interconnection Handbook

3. Examples of Utility Data Monitoring and Control Requirements

3.1 Smart Inverter Use Cases as Basis for Data Requirements

The utilities reviewed the Phase 1 and Phase 3 functions as Use Cases to determine their data requirements. These are summarized below, along with indications of the importance to utilities (H, M, L):

- Real Power DER Functions
  - Real power output at the PCC is limited to a maximum value by the DER owner/operator. This information must be provided to the utility. (H)
  - The utility limits the maximum real power output at the PCC by a command to the DER system, the facility energy management system, or the aggregator who manages the DER system. (H)
  - The utility sets the actual real power output at the PCC if permitted by tariff agreements. (M)
  - The utility schedules the actual real power output or limits the maximum real power output at the PCC for specific time periods. (H)
  - The utility sets the voltage-watt parameters for the DER system to modify its real power output autonomously in response to local voltage variations. (H)
  - The utility sets or schedules the storage of energy for later delivery, indicating time to start charging, charging rate and/or "charge-by" time. (Applicable for energy storage; NA for PV systems)
- Reactive Power DER Functions
  - The utility sets a fixed power factor parameter for the DER system (having a fixed power factor is a Phase 1 capability; updating the power factor is a Phase 3 capability). (H)
  - The utility sets the curves for volt-var control for the DER system to provide dynamic reactive power injection through autonomous responses to local voltage measurements (volt-var control is a Phase 1 function; updating the volt-var curves is a Phase 3 capability). (H)
  - The utility provides and/or updates the temperature/current/time-of-day var curves for the DER system to provide reactive power through autonomous responses to temperature, current, or time-of-day. (H for temperature)
- Frequency Support DER Functions
  - Utility uses DER systems for frequency regulation by setting the curves for the DER systems to autonomously and rapidly modify real power output to counter minor frequency deviations. The utility can enable/disable the function. (H)
  - Utility uses DER systems for frequency regulation by issuing automatic generation control (AGC) commands. (M)

- DER Response to Emergencies
  - Utility receives notification that a DER system disconnected from or reconnected to the utility grid. (H?)
  - Utility issues commands to the DER system to disconnect or reconnect. (M)
  - Utility updates the voltage ride-through curves (voltage ride-through is a Phase 1 function; updating the curves is a Phase 3 capability). (H)
  - Utility updates the frequency ride-through curves (frequency ride-through is a Phase 1 function; updating the curves is a Phase 3 capability). (H)
  - Utility receives notification that a facility or microgrid disconnected from or reconnected to the utility grid. (H)
  - Utility issues a command to disconnect or reconnect a microgrid from the utility grid. (L)
  - Utility requests that the DER system provide “spinning” or operational reserve
- Scheduling DER Output, Modes, and/or Functions
  - Utility provides schedules for real power settings, reactive settings, real power or reactive power limits, power factors, operational reserves, activating/deactivating modes, and other operational settings. Schedules may be for specific time periods or may repeat periodically, e.g. daily, weekly, or seasonally. Multiple schedules may be in effect so long as they do not conflict. Higher priority schedules preempt lower priority schedules. (H)
  - Utilities activate/deactivate schedules
  - Utility receives schedules from DER systems that forecast their net real power and storage schedules.

3.2 Example of Minimal Data Requirements for Direct Interactions with DER Systems and/or Facility DER Management Systems

Table 1 contains examples of the expected utility data monitoring and control requirements for direct interactions with DER systems. The “DER Data Exchange Requirements” document will provide the minimum data exchange requirements. Additional data exchanges are always allowed.

Table 1: Utility data monitoring and control requirements

Administrative Messaging Requirements	
Information in headers	
	Unique Plant or FDEMS ID
	Meter ID, Service Point ID, or other ECP ID
	Utility ID
	Timestamp of message and other header information
Nameplate and/or “as installed” base information of DER System (for each DER System registered with utility)	

	DER system manufacturer
	DER system model
	DER system version
	DER system serial number
	DER system type
	Location (lat long and/or street address)
Basic information of DER system or of facility or plant (FDEMS) (ratings are the installed ratings which are different from capabilities which may change or be forecast based on customer or market issues)	
	Operational authority (role)
	Watt rating
	VA rating
	Var rating
	Current rating
	PF rating
Monitoring Data Sets	
Monitored analog measurements, aggregated by the FDEMS to reflect the PCC	
	Watts
	VArs
	Power Factor
	Hz, Frequency
	VA, Apparent Power
	A, Phase Currents
	PPV, Phase Voltages
	TmpCab, Temperature (as applicable)
	{Type of data collection or aggregation, e.g. indication of whether instantaneous, average over period, max, min, first, last}
Monitored status, aggregated by the FDEMS for the PCC	
	DER Connection Status
	PCC or ECP Connection Status
	Inverter status
	De-rated real power due to inability to meet stated rating
	Available real power
	Available vars
	Status of limits (flags that get raised when a specified limit is reached)
	Active modes (flags that get raised when a control (mode) is enabled)
	Ride-through status (flags on instantaneous ride-through state; does not count R-T events)
Metered DER system values	
	Wh, Watt-hours, lifetime (or from reset time) accumulated AC energy

	VAh, VA-hours, lifetime (or from reset time) accumulated
	VArh, VArh, lifetime (or from reset time) accumulated
Notification of alarms	
	Binary alarm values (flags that get raised for specific types of alarms of a specific DER)
	Binary alarm values (flags that get raised for specific types of facility/plant alarms)
Sending Updates to Settings and/or Issuing Control Commands	
Voltage Ride-Through	
	Default L/HVRT curves and settings
	Custom L/HVRT curves and settings
	Voltage
	Duration
Frequency Ride-Through	
	Default L/HFRT curves and settings
	Custom L/HFRT curves and settings
	Frequency
	Duration
Dynamic Volt/VAr Control	
	Enable a specific curve
	V reference, V reference offset
	Tolerance
	Selected curve
	Curves
	Disable (default upon start-up)
	Custom Volt-Var Curves
Ramping	
	Default ramp rate
	Customized ramp rates
Power Factor	
	Value
Soft Start	
	Ramp Rate
	Time Delay
	Fixed
	Randomized within window
Connect/Disconnect Command	
Limit Real Power (both readable and settable at the PCC)	
Frequency-Watt	

	Default Frequency-Watt
	Custom Frequency-Watt
Volt-Watt	
	Enable/disable
	Collection of settings
Possible Future Functions (Optional)	
Dynamic Current Support	
	Enable/disable
	Collection of settings
Frequency Deviation Support	
	Enable/disable
	Collection of settings
Limit Reactive Power (both readable and settable at the PCC)	
Schedule output and/or modes at PCC (see pending IEC 61850-90-10)	
	Set schedules
	Start Time
	End Time
	Real Power
	Reactive Power
	Schedule of operations and modes
	Enable/disable specific schedule

3.3 Additional Information for Interactions with Aggregators

Utilities will require aggregators to supply the same data as in Table 1, but aggregated by Group. In particular, utilities will provide aggregators with Groups that contain lists of DER systems. Groups may contain other nested Groups. DER systems may be in multiple Groups. These Groups may reflect different organizations of DER systems, such as:

- Group of DER systems connected to a specific substation
- Group of DER systems connected to a specific feeder
- Group of DER systems connected to a specific feeder segment
- Group of PV-based DER systems
- Group of energy storage DER systems
- Group of DER systems capable of providing "operational reserves" within specific time periods
- Group of DER systems capable of providing black start services

- Group of DER systems capable of providing volt-var support
- Group of DER systems capable of providing frequency support

In addition to the Group data, Table 2 identifies the additional data information which is expected to be needed for interactions between utilities and aggregators.

Table 2: Additional information required for interactions with aggregators

Administrative Information for Aggregators	
Heading information for all messages	
	Unique Aggregator ID
	Utility ID
	Group ID for this message
	Timestamp of message and other header information
Aggregator information (may be handled off line)	
	Aggregator information
	Aggregator capabilities
	List of DER UUIDs for each group
Group information	
	Watt rating
	VA rating
	Var rating
	Current rating
	PF rating

3.4 Utility Performance Requirements for Interacting with Different Types of DER Systems

Utilities have identified the performance requirements for the high priority DER functions, as summarized in Table 3:

Table 3: Smart Inverter Use Cases

Use Case	Requirement	Type			Protocol
		Industrial	Aggregator	Residential	SEP2 Object
Real Power DER Functions					
Real power output at the PCC is limited to a maximum value by the DER owner/operator. This information must be provided to the utility.	Limit Power	Seconds	Minutes	Hourly / Day Ahead	SetMaxWatts DERcontrol Opmodfixw

Use Case	Requirement	Type			Protocol
		Industrial	Aggregator	Residential	SEP2 Object
The utility sets the voltage-watt parameters for the DER system to modify its real power output autonomously in response to local voltage variations.	Set Voltage / Watt Parameters	Seconds	Minutes	Hourly / Day Ahead	DERcontrol opmodvoltwatt
The utility sets or modifies ramp rates, or settings for inverters, that gradually raise or lower power output.	Set or Update Ramp Rates	Seconds	Minutes	Hourly / Day Ahead	DERCurve object rampDecTms rampIncTms
Reactive Power DER Functions					
The utility sets a fixed power factor parameter for the DER system (having a fixed power factor is a Phase 1 capability; updating the power factor is a Phase 3 capability).	Set Fixed Power Factor	Seconds	Minutes	Hourly / Day Ahead	opmodfixedpf
The utility sets the curves for volt-var control for the DER system to provide dynamic reactive power injection through autonomous responses to local voltage measurements (volt-var control is a Phase 1 function; updating the volt-var curves is a Phase 3 capability).	Set Volt Var control curve	Seconds	Minutes	Hourly / Day Ahead	opmodvoltvar Selection between multiple curves not supported
The utility provides and/or updates the var curves for the DER system to provide reactive power through autonomous responses	Update VAR curves	Seconds	Minutes	Hourly / Day Ahead	opmodvoltvar Only single curves supported
Frequency Support DER Functions					
Utility uses DER systems for frequency regulation by setting the curves for the DER systems to autonomously and rapidly modify real power output to counter minor frequency deviations. The utility can enable/disable the function.	Update, enable, disable frequency watt curves	Seconds	Minutes	Hourly / Day Ahead	opmodfreqwatt
DER Response to Emergencies					
Utility issues commands to the DER system to disconnect or reconnect.	Disconnect Reconnect	Seconds	Minutes	Hourly	setgenconnect

Use Case	Requirement	Type			Protocol
		Industrial	Aggregator	Residential	SEP2 Object
Utility updates the voltage ride-through curves to change the anti-islanding settings.	Update Voltage ride through curves	Seconds	Minutes	Hourly	opmodhvrt opmodlvrt
Utility updates the frequency ride-through curves to change the anti-islanding settings .	Update frequency ride through curves	Seconds	Minutes	Hourly	Not Supported
Scheduling DER Output, Modes, and/or Functions					
Utility provides full lifecycle control for schedules. Schedules may be for specific time periods or may repeat periodically, e.g. daily, weekly, seasonally. Multiple schedules may be in effect so long as they do not conflict. Higher priority schedules preempt lower priority schedules.	Add, update, delete schedules	Daily	Daily	Daily	DER programs
Registration					
Utility registers a DER system or facility after interconnection approval and installation	Registration	Hours	Hours	Hours	Registration - Out of band process
System Health and Monitoring					
Utility Monitors DER system operating status	Receive operating status	Seconds	Hourly	Hourly	DERinfo/DERstatus
Utility Monitors DER system operating capability, as opposed to name plate	Receive system operating capability	Seconds	Hourly	Hourly	DERcapability
Utility receives DER system metering information	Receive DER system metering information	Seconds	Hourly	Hourly	Meterreading/usagepoint

4. Cyber Security and Privacy Requirements

4.1 Cyber Security Requirements

General requirements for cyber security shall be covered in Rule 21. Specific cyber security requirements may be included in utility handbooks or auxiliary documents. Basic cyber security requirements include:

- Cyber security requirements shall be end-to-end, including across any intermediary systems.

- The implementation of these cyber security requirements shall be validated before data exchanges are commenced with utilities.
- Cyber security requirements include Authentication, Authorization, Accountability, and Data Integrity at a minimum. Other cyber security requirements, such as confidentiality shall be supported but may be enabled only when needed.
- Stored cyber security data, such as cryptographic keys and passwords, shall be secured from unauthorized access, including in any intermediary systems between the utility and DER systems
- Privacy policies shall clearly define what types of data shall be not available publicly, including individual data elements and aggregations of data.

When the following cyber security questions are being answered by utilities, the responses should clarify what should be included in Rule 21, what should be handled by in the Utility Generation Interconnection Handbook, and what should be provided by other sources.

- What are the utility security policies for interacting with non-utility sites and equipment where the data to be exchange has operational impacts?
- What utility security procedures must be followed by such non-utility sites in order for operational data to be exchanged? In particular, how can new DER sites be "registered" and tested for security compliance?
- Are there different security requirements for different types of sites, e.g. small < 10 MW DER sites versus > 10 MW sites?
- Have these security policies and procedures been clearly established or are they still being worked on?
- Are there specific security technologies that must be used? Are there specific technologies that must not be used?
- Some security technologies are specific to different communication protocols - are there preferred protocols from a security perspective?
- Is there agreement that at least authentication and data integrity must be ensured?
- When should non-repudiation / accountability be ensured?
- When should confidentiality be ensured?
- How is key management expected to be handled? PKI? What Certificate Authorities can/must be used?
- Will Role-based Access Control (RBAC) be used to constrain the permitted actions?
- Are these cyber security requirements accepted by all California utilities or are there major differences?
- What other cyber security issues need to be resolved?

4.2 Privacy Requirements

Utilities can utilize the confidentiality provisions that already exist in Rule 21 and make any associated provisions within the Rule 21 tariff. One such provision would be to require aggregators to have privacy agreements with their customers. The agreement would say that the meter data, or solar output data, or whatever data is in question could be conveyed from the aggregator to the utility. Once the utility had the data the utility would abide by their own privacy rules and other applicable state, federal, and CPUC rules.

A. Appendix A: Definitions of Terms and Acronyms

Term	Definition
Aggregator	A legal organisation that consolidates or aggregates a number of individual customers and/or small generators into a coherent group of business players.
Area EPS	electric power system (EPS) that serves Local EPSs
CEC	California Energy Commission
Connected	Condition of the DER system during which it is electrically linked to an EPS through an ECP.
CPUC	California Public Utilities Commission
CVR	Conservation Voltage Reduction
DER	Distributed Energy Resource. Sources of electric power that are not directly connected to a bulk power transmission system. DER includes both generators and energy storage technologies, and sometimes may include controllable loads.
DOE	Department of Energy
ECP	Electrical Connection Point: point of electrical connection between the DER source of energy (generation or storage) and any electric power system (EPS)
EPRI	Electric Power Research Institute
EPS	Electric Power System: facilities that deliver electric power to a load
FDEMS	Facilities DER Energy Management Systems
ICT	Information and Communications Technologies
I-DER	For the purposes of this document, I-DER is defined as inverter-based Distributed Energy Resources
IEC	International Electrotechnical Commission
IEC 61850-7-420	Communication networks and systems for power utility automation - Part 7-420: Basic communication structure - Distributed energy resources logical nodes
IEC 61850-90-7	Communication networks and systems for power utility automation - Part 90-7: Object models for power converters in distributed energy resources (DER) systems
IEEE	Institute of Electrical and Electronic Engineers

Term	Definition
IEEE 1815	IEEE Standard for Electric Power Systems Communications—Distributed Network Protocol (DNP3)
IEEE 2030.5	IEEE Standard for Electric Power Systems Communications— IEEE Adoption of Smart Energy Profile 2.0 Application Protocol Standard
Inverter	A machine, device, or system that changes direct-current power to alternating-current power.
ISO	Independent System Operator
ISO	International Standards Organization
Local EPS	An EPS contained entirely within a single premises or group of premises.
OIR	Order Instituting Rulemaking
P	Real power (measured in watts)
PCC	Point of Common Coupling, the point where a Local EPS is connected to an Area EPS.
PF	Power Factor (ratio between real power and apparent power), expressed as W/VA or as cos ϕ, the phase angle between the current and the voltage)
Q	Reactive power (measured in volt-ampere reactive or VArs)
REP	Retail Energy Provider
RTO	Regional Transmission Organization
SIWG	Smart Inverter Working Group
UL	Underwriters Laboratory
VAr or var	Volt-ampere reactive

B. Appendix B: Smart Inverter Working Group Participants

The following list includes all participants in the Smart Inverter Working Group through February 2015.

Table 4: List of SIWG Participants

Company	Full Name
ABB	Jaspreet Singh
ABB	Roger White
ABB	Ronnie Pettersson
Advanced Energy	Travis Bizjack
AE Solar Energy	Verena Sheldon
AEI	Alvaro Zanon
AEI	Christopher Heinzer
AEI	John Foster
AEI	Michael Mills-Price
AEI (Advanced Energy Inverters)	Bill Randle
American Solar Direct	Paolo Guggia
Apparent Inc	Jacqueline Desouza
Apparent Inc	Stefan Matan
APS	David Narang
APS	Jimi Diaz
APS	Marques Montes
APS America	Ryan Simpson
Aspen	Ashley Spaulding
Aspen	Katie Elder
ASU	Faraz Ebneali
Balch	Leonard Tillman
Black & Veatch	Dan Wilson
Black & Veatch	E.A. Sutton
Bloom Energy	Carl Cottuli
Bloom Energy	Prasad PMSVVSV
Bloom Energy	Rajesh Gopinath
Bonfiglioli	Davide Grandi
Bonfiglioli	Elie Nasr
Bonfiglioli	Matthew Charles
Bonfiglioli	Robert Lenke
Bonfiglioli	Sven Kollbach
Bosch	Ian Tilford
California Energy Commission	Cassandra Ayala
California Energy Commission	Gabriel Taylor
California Energy Commission	John Mathias
California Energy Commission	Linda Kelly

Company	Full Name
California Energy Commission	Matt Coldwell
California Energy Commission	Rachel MacDonald
California Independent System Operator	Dennis Peters
California Independent System Operator	John Blatchford
California Public Utilities Commission	Adam Langton
California Public Utilities Commission	Aloke Gupta
California Public Utilities Commission	Anthony Mazy
California Public Utilities Commission	Charles Mee
California Public Utilities Commission	Connie Chen
California Public Utilities Commission	Eric Martinot
California Public Utilities Commission	Jamie Ormond
California Public Utilities Commission	Keith White
California Public Utilities Commission	Marc Monbouquette
California Public Utilities Commission	Noel Crisotomo
California Public Utilities Commission	Rachel Peterson
California Public Utilities Commission	Radu Ciupagea
California Public Utilities Commission	Ryan Yamamoto
California Public Utilities Commission	Thomas Roberts
California Public Utilities Commission	Valerie Kao
California Public Utilities Commission	Wendy Al-Mukdad
CASEIA	Brad Heavner
Clean Coalition	Bob O'Hagan
Clean Coalition	Sahm White
Clean Power Finance	David Inda
Clean Power Finance	Greg Sellers
CODA Energy	Milissa Marona
Consultant	John Nunneley
Consultant	Michael Sheehan
Department of Energy	Alvin Razon
Department of Energy	Guohui Yuan
Eaton	Derek Pearson
Electric Power Research Institute	Brian Seal
Electric Power Research Institute	Lindsey Rogers
Empower Micro Systems	Jon Bonanno
Empower Micro Systems	Mika Nuotio
Empower Micro Systems Inc.	Regan Arndt
Enecsys	Aaron Jungrieis
Enecsys	Jim Miller
Enecsys	Steve Deffley
EnerNex	Grant Gilchrist
Enphase Energy	Chris Eich
Enphase Energy	Daniel Lewis

Company	Full Name
Enphase Energy	John Berdner
Enphase Energy	Ken Laudel
Enphase Energy	Mark Baldassari
Enphase Energy	Vladimir Bronstein
Federal Energy Regulatory Commission	Ray Palmer
Five Star International	Mark Osborn
Fronius	Brian Lydic
General Electric	Bebic
General Microgrids	Terry Mohn
Grid Cloud Systems Inc.	John Gillerman
Gridco Systems	Darrell Furlong
Gridco Systems	Jeff Lo
Gridco Systems	Jim Simonelli
GSD Energy Consultants	Paul Duncan
Hamon Engineering, Inc	Marvin Hamon
Hawaii Public Utilities Commission	David C. Parsons
Hawaiian Electric Company, Inc.	Demy Bucaneg
Imperial Irrigation District	Enrique De Leon
Imperial Irrigation District	Guadelupe Ontiveros
Imperial Irrigation District	Javier Meza
Individual (energy storage focus)	Gary Sorkin
IoT Connected Industries & Energy Practice	Faramarz Maghsoodlou, Ph.D.
Itron, Inc.	George Simons
Itron, Inc.	Joe Ballif
Itron, Inc.	William Marin
Kaco Energy	Bill Reaugh
Kaco Energy	D Devir
LADWP	Fernado Pardo
LADWP	Matt Hone
LLC, Power Innovation Consultants	Russ Neal
Loggerware	Bob Fox
Matzinger-Keegan	Josh Barklow, PE
Minnesota Department of Commerce	Lise Trudeau
Minnesota Department of Commerce	Stacy Miller
MIS Labs	James W. Romlein Sr. PE
National Grid	Babak Enayati
National Grid	James Cleary
National Institute of Standards and Technology	Allen Hefner
National Renewable Energy Laboratory	James Cale
National Renewable Energy Laboratory	Michael Coddington
National Renewable Energy Laboratory	Sudipta Chakraborty
National Renewable Energy Laboratory	Thomas Basso

Company	Full Name
Navy	Paul McDaniel
Navy	Vern Novstrup
New England Independent System Operator	John Black
New York Dept. of Public Service	Jason Pause
Nordex	Michael Edds
Northern California Power Agency	Jonathan Changus
Northern Plains Power	Michael Ropp
NRG West	Brian Theaker
Office of Rate Payer Advocates	Jose Aliaga-Caro
Outback Power	John Ummel
Outback Power	Phil Undercuffler
Pacific Gas and Electric	Art Anderson
Pacific Gas and Electric	Caitlin Henig
Pacific Gas and Electric	Chase Sun
Pacific Gas and Electric	Dewey Day
Pacific Gas and Electric	Jason Yan
Pacific Gas and Electric	Phuoc Tran
Pacific Gas and Electric	Stacy Walter
PacificCorp	Dennis Hansen
PacificCorp	Rohit Nair
PG&E	Natsu Cardenas, M
PJM	Bhavana Keshavamurthy
PJM	John Baranowski
PJM	Ken Schuyler
PNG	Joe Barra
PowerHub Systems	Glenn Skutt
Princeton Power	Darren Hammell
Princeton Power	Ken McCauley
Princeton Power	Martin Becker
PsomasFMG	Scott Harris
Researcher	Jonathan Kobayashi
Researcher - California Smart Grid Center at CSU Sacramento	Mohammad Vaziri, Ph.D., P.E
Sacramento Municipal Utilities District	Dave Brown
Sacramento Municipal Utilities District	Mark Rawson
Sacramento Municipal Utilities District	Obadiah Bartholomy
Sacramento Municipal Utilities District	TJ Vargas
Salt River Project	Catherine O'Brien
San Diego Gas & Electric	Bill Cook
San Diego Gas & Electric	Brian Proctor
San Diego Gas & Electric	Chris Vera
San Diego Gas & Electric	David Weber

Company	Full Name
San Diego Gas & Electric	Dean Kinports
San Diego Gas & Electric	Ellis Jones
San Diego Gas & Electric	Frank Goodman
San Diego Gas & Electric	Greg Smith
San Diego Gas & Electric	John Baranowski
San Diego Gas & Electric	Jonathan Newlander
San Diego Gas & Electric	Mike Turner
San Diego Gas & Electric	Ronald Simmons
San Diego Gas & Electric	Tom Bialek
San Diego Gas and Electric	Kahveh Atef
Sandia National Laboratory	Jay Johnson
Sandia National Labs	Sig Gonzalez
SatCon Technology	Leo Casey
Schneider Electric	Ben Baczenas
Schneider Electric	Taylor Hollis
Siemens Industry, Inc.	Prashanth Duvoor
SMA	Bernhard Ernst
SMA	Brett Henning
SMA	Joshua Hickman
SMA America, LLC	Emily Hwang
SMA Global SE-Asia & N-America	Christian Tschendel
SmartSense Inc.	Aaron Gregory
SoCore Energy	Frank Bergh
Solar Bridge Technologies	Kelly Mekechuk
Solar Bridge Technologies	Miles Bintz
Solar Bridge Technologies	Jonathan Ehlmann
Solar City	Alex Mayer
Solar City	Eric Carlson
Solar City	Jon Fiorelli
Solar City	Justin Chebahtah
Solar City	Ryan Hanley
Solar Edge Technologies	Dru Sutton
Solectria	Aegir Jonsson
Solectria	Soonwook Hong
Solren	Michael Zuercher-Martinson
Solren	Samer Arafa
Southern California Edison	Araya Gebeyehu
Southern California Edison	Jeff Gooding
Southern California Edison	Kathryn Enright
Southern California Edison	Matt Dwyer
Southern California Edison	Ricardo Montano
Southern California Edison	Richard Bravo

Company	Full Name
Southern California Edison	Roger Salas
Southern California Edison	Steven Robles P.E.
Sparq Systems	Ali Khajehoddin
Sparq Systems	Joe Drobrnik
Sparq Systems	Randy MacEwen
SRA	Joseph McCabe
Sun Edison	Curtis Seymour
Sunspec Alliance	Tom Tansy
Turlock Irrigation District	Ken Nold
Turlock Irrigation District	Wes Monier
TÜV Rheinland Group	Matthias Heinze
TÜV Rheinland Group	Zhiwang Zhu
TÜV Rheinland of North America, Inc.	Gary Sorkin
UCLA	EK Lee
Underwriters Laboratories	Timothy Zgonena
Underwriters Laboratories	Tony Dorta
University California Los Angeles	Rajit Gadh
Varentec, Inc.	Andrew Dillon
Varentec, Inc.	Dr. Deepak Divan
Varentec, Inc.	Rohit Moghe
Western University, Ontario Canada	Rajiv K. Varma, Ph.D
Winston	Matthew Narensky
Xanthus Consulting International	Frances Cleveland
Zenergy Studios	Kristen Nicole

SIWG Phase 3 DER Functions: Recommendations to the CPUC for Rule 21, Phase 3 Function Key Requirements, and Additional Discussion Issues

March 2016

FINAL

Version 8

Table of Contents

Table of Figures

Table of Tables

1. Scope of this Document

This document provides the recommendations of the Smart Inverter Working Group (SIWG) on the Phase 3 Distributed Energy Resource (DER) functions for inclusion in Rule 21.

- Section 2 describes the key requirements for the eight (8) Phase 3 DER functions that are recommended to be included in Rule 21. These key requirements still include issues that need discussion and resolution before they should be used to update Rule 21.
- Section 3 identifies the proposed timeframe for implementing the mandatory requirements.
- Section 4 covers the general informative background and terminology used in describing the Phase 3 functions
- Sections 5-12 provide informative material on the Phase 3 DER functions to better ensure common understandings of the functions

2. Key Requirements of Recommended SIWG Phase 3 Functions

2.1 Key Concepts for Phase 3 Functions

SIWG Phase 3 functions for Rule 21. As identified by the SIWG, the eight (8) Phase 3 functions that are included in Table 1 are recommended to be included in Rule 21 as mandatory capabilities for all inverter-based DER systems. However the key requirements described for the functions still identify issues that need discussion and resolution before they should be used to update Rule 21. These capabilities would only enabled or permitted after contractual or market agreements are made; those contractual and market arrangements are out-of-scope for this SIWG document.

Discussion Issues. For most of the functions, some issues have been identified as needing further discussion and resolution before Rule 21 is actually updated. In certain cases, these discussion could take place as part of the revision process to IEEE 1547. In other cases, on-going discussion groups and workshops should be formed to resolve the details. Since many of these issues are still just starting to be recognized as needing discussion, it may take some time to resolve the details. Flexibility in these resolutions is urged until more experienced is gained over time.

Rule 21 vs. IEEE 1547 requirements. For each of the Phase 3 functions, the key requirements are recommended to be defined in Rule 21, including actions, boundaries, tolerances, constraints, as provided in Table 1. In addition, the minimal data exchange capabilities that are listed in Table 2 are recommended to be included in Rule 21. These key requirements will provide compliance metrics and help to ensure common understandings. Although the SIWG recommends these key requirements, if eventually the revision to IEEE 1547 identifies additional or even conflicting requirements for the functions, it may be necessary to clarify which requirements take precedence in Rule 21 when the Rule 21 reference to IEEE 1547 is updated to include the revised IEEE 1547. Rule 21 requirements for Phase 3 functions will then need to be reviewed and updated as needed.

Guidelines outside of Rule 21. It is recommended that these functions and the data exchange requirements are discussed in more detail in a separate Phase 3 guidelines document so that the concepts and interactions are clearly understandable. Sections 5-12 of this document provide initial content for that separate Phase 3 guidelines document.

Concept of Referenced Point (Local or Remote). The term "Electrical Connection Point (ECP)" is used to denote the point on the local electric power system (EPS) at which the DER is interconnected. An ECP can also be the connection point between a group of DER systems and the local EPS. ECPs can be nested. If loads can be controllable, then they also have an ECP. The point of common coupling (PCC) is the ECP between the local EPS and the area EPS. An external location can also have a remote ECP or PCC.

Many Phase 3 functions may be referencing a point that is not the one where the DER system is interconnected. In particular, utilities usually expect a function to take effect at the PCC, so some functions would need to have access to measurement data from the local PCC. However other remote points could also be referenced, such as an energy storage system referencing a PV plant a few miles away at a separate facility in order to counteract PV fluctuations. Synchrophasors would also need to collect data from other remotely located synchrophasors.

Therefore many of the Phase 3 functions use the term "Referenced Point" to indicate that the identifier of the point of interest must be one of the parameters. It is assumed, of course, that these Referenced Points have been mutual agreed to, and that some means of receiving the necessary power system measurements from the Referenced Point is available to the DER system.

2.2 Recommended SIWG Phase 3 DER Functions and Key Requirements for Inclusion in Rule 21

Table 1 describes the recommended SIWG Phase 3 DER functions and their key requirements. The SIWG recommends that these requirements be included in Rule 21.

Table 1: Discussions on Phase 3 DER Functions and Key Requirements for Rule 21

SIWG Phase 3 DER Functions	Discussions on Key Requirements for Rule 21
Monitor Key DER Data: Provide key administrative, status, and measurements on current energy and ancillary services (Section 5)	**Monitor Key DER Data**: All DER systems shall have the capability to provide key DER data at the DER's ECP and/or at the PCC. Utilities shall define in the Utility Handbooks when and under what conditions the data exchange requirements shall be provided, including what types of data, whether and how it may be aggregated, frequency of monitoring, time latency, etc. Key data requirements include as a minimum the data items listed in Section 2.3, Table 2. These cover: • **Administrative Data**: DER system identification, facility identification, updates to nameplate information, updates to DER ratings, indications of which functions are supported, and other essentially static data. • **Monitored Data**: Individual and/or aggregated DER state of readiness – define this more clearly (on/off, changes from nameplate, major alarm that would take it off line), real-time measurements, metered data, and any future states that deviate from planned or scheduled states. • **Error conditions:** If the mutually agreed upon exchanges of data are not taking place within the agreed upon time latency and completeness, these conditions shall be reported. **Discussion Issues** that have been raised and need further resolution before these requirements could be included in Rule 21: • When and under what conditions will utilities require communications either during or after the interconnection process, given the unknown future grid issues and since there may be financial implications? Should utilities identify what communications are required during the interconnection process or can that decision also be made later? This data could also be used in future DRPs to determine locational and functional benefits. • IEEE 1547 includes draft conditions on whether functional requirements are to be met at the PCC or at the DER's ECP, based on aggregated DER size and average load. Since monitoring requirements will need to reflect the functional requirements and will be required over the life of the DER systems and since smaller DER systems may be required to shift to meeting the functional requirements at the PCC over time, how will the monitoring requirements change over the life of DER systems? • Utilities will need to specify the retrieval rates for collecting the data for different scenarios. Data from some DER systems may be needed in "real-time" (seconds), but most will only be needed over many minutes, hours, or even days. Communication media requirements and constraints will

SIWG Phase 3 DER Functions	Discussions on Key Requirements for Rule 21
	also need to be specified. • Utilities will need to specify latency and accuracy requirements of information (SCADA timeframes vs. "loosely-coupled" monitoring, time skew, available data, location of data access, revenue-grade metered data versus non-revenue-grade metering, etc.) • Utilities will need to determine which DER systems need to provide individual data, which may aggregate their data by "group", and which may only need to provide the metered data from "smart meters". • Are there specific monitoring requirements for energy storage systems while they are charging? What about non-exporting DER and storage systems, which may mask loads or become significant loads? • While not within the scope of these recommendations, market and compensation mechanisms will need to be developed for providing DER data to the utilities.
DER Cease to Energy and Return to Service Request (Section 6) Cease to energize and return to service at the Referenced Point	**DER Cease to Energize:** The cease to energize request shall cause a "cease to energize" state at the ECP or optionally shall allow the opening of a switch at a Referenced Point. The cease to energize shall cause the DER to output zero active current flow and (*close to zero*) reactive power flow. Key requirements include: • **Cease to energize request** shall cause the DER to enter the cease to energize state. • **Referenced Point identifier:** The identity of the Referenced Point shall be provided where the cease to energize state shall be applied. If none is provided, the default is the DER's ECP. • **A ramp rate** or **time window** shall be settable. A time window of 0 seconds or a ramp rate of 100% shall indicate immediate action. • **Reversion time** shall be included determining when the DER can return to service if communications are not available. • **Acknowledge** and/or **monitor the data** (export of power or switch status) at the Referenced Point: These requests shall either be directly acknowledged or the switch status at the Referenced Point shall be monitored. • **Error conditions:** If DER did not cease to energize at the Referenced Point, this condition shall be reported. **DER Return to Service:** The return to service request shall end the "cease to energize" state or shall initiate the closing of the DER switch at the Referenced Point. Additional key requirements include: • **Ramp rate or a time window** for random return to service shall be settable. • "**Permission to return to service**" shall be supported to allow actual connection to take place at

SIWG Phase 3 DER Functions	Discussions on Key Requirements for Rule 21
	some later time. • **Acknowledge** and/or **monitor the data** (export of power or switch status) at the Referenced Point: These requests shall either be directly acknowledged or the switch status at the Referenced Point shall be monitored. • **Error conditions:** If DER is not ready or capable of returning to service at the Referenced Point, this condition shall be reported. **Discussion Issues** that have been raised and need further resolution before these requirements are included in Rule 21: • Is there ever a need to issue a "disconnect command" that isolates DER from the grid? For larger DER should the utility be able to require a galvanic disconnect? Manually operated disconnects can also be used. In IEEE 1547, DER systems in secondary networks are currently required to disconnect upon Area EPS command – or will that requirement just become a cease to energize? Again in trying to coordinate with IEEE 1547 requirements, will all utilities agree on only cease to energize? • If the cease to energize request is sent to a facility or aggregator, does that facility or aggregator cause each DER to cease to energize or can it just ensure that no export of power occurs at the PCC? If so, how is this different from limiting power output at the PCC to zero? • What happens if load decreases such that non-exporting DERs now become exporting? How would this be requested and tested? • What does "close to zero" reactive power mean? What about non-zero real power if the equipment cannot go to zero? What amount of non-zero power can be exported and for how long? • Under what conditions does there need to be a distinction between "return to service" and "permission to return to service"? Are they the same command, but with ramifications as contractual issues? • Does cease to energize also apply to the charging of energy storage systems? For instance, could an energy storage device increase charging to avoid exporting power at the PCC?
Limit Maximum Real Power Mode (Section 7) Limit real power at the Referenced Point	The **Limit Maximum Real Power Percent** mode shall limit the real power level at the Referenced Point as a percent of the maximum real power capability, *and/or* The **Limit Maximum Real Power Level** mode shall limit the real power level at the Referenced Point to a specific real power value. Key requirements include: • **Real power limit value**: Value of percent of maximum real power or value of real power. • **Referenced Point identifier:** The identity of the Referenced Point shall be provided where the real

SIWG Phase 3 DER Functions	Discussions on Key Requirements for Rule 21
	power is measured or calculated for the PCC or other Referenced Point. • **Accuracy:** Delta real power allowed to exceed the limit and time allowed to exceed the limit shall be settable, indicating the precision required for the functional requirements to be met. • A **Ramp Rate** or **Time Window** within which the real power limit shall be met shall be settable. A time window of 0 seconds or a ramp rate of 100% shall indicate immediate action. • **Reversion Timeout** in seconds shall be settable, after which the real power limit is removed. A reversion timeout = 0 means that there is no timeout. • **Enable** and **Disable** settings for the Limit Maximum Real Power mode shall be provided. When enabled, the real power at the Referenced Point shall be limited to be within the percent or level established. When disabled, the DER shall revert to a previously defined state at the established ramp rate. • **Acknowledge and/or monitor the data at the Referenced Point**: Receipt of the mode parameters and the enable/disable commands shall be acknowledged or the real power at the Referenced Point shall be monitored. • **Error conditions**: If the commanded limit at the Referenced Point cannot be met or is not being met, this condition shall be reported. **Discussion Issues** that have been raised and need further resolution before these requirements are included in Rule 21: • Who makes the choice on using percent versus absolute value as the limit? The utility? The DER manufacturer? The installer based on the type of installation? Should either be allowed or just "translated" by the DER? • Need to define ramp rates, including a window in which to ramp down to the Limit Power level if a load trips off "instantaneously" but the DER can't ramp down that fast • Should ramp rates be defined as percent of the present maximum capacity per second? Or nameplate capacity per second? If it is a percentage of maximum capacity per second, should the utility always want to know what that maximum capacity is at any point in time, or is that not important except in certain situations? • Performance accuracy needs to be addressed, including measurement accuracy, time exceeding the limit, real power exceeding the limit, time latency, cumulative errors, etc. Should specific performance accuracy be required by utilities or should DER manufacturers describe what their DER can provide? • Should energy storage systems while they are charging also be subject to this function, possibly increasing charging rates?
Set Real Power	For DER systems that can control their real power output (such as energy storage, synchronous generators,

SIWG Phase 3 DER Functions	Discussions on Key Requirements for Rule 21
Mode (Section 8) Set real power at the Referenced Point	etc.), the **Set Real Power Percent** mode shall set the real power level at the Referenced Point as a percent of the maximum real power capability, *and/or* the **Set Real Power Level** mode shall set the real power level at the Referenced Point to a specific real power value. Key requirements include: • **Real power value**: Value of percent of maximum real power or value of real power. • **Referenced Point identifier:** The identity of the Referenced Point shall be provided where the real power is measured or calculated for the PCC or other Referenced Point. • **Accuracy:** Maximum delta real power allowed to deviate from the required setting and the time allowed to deviate from the setting shall be settable, indicating the precision required for the functional requirements to be met. • A **Ramp Rate** or **Time Window** within which the real power level shall be met shall be settable. A time window of 0 seconds or a ramp rate of 100% shall indicate immediate action. • **Reversion Timeout** in seconds shall be settable, after which the real power limit is removed. A reversion timeout = 0 means that there is no timeout. • **Enable** and **Disable** settings for the Set Real Power mode shall be provided. When enabled, the real power at the Referenced Point shall be set to the percent or level established. When disabled, the DER shall revert to a previously defined state at the established ramp rate. • **Acknowledge and/or monitor the data at the Referenced Point**: Receipt of the mode parameters and the enable/disable commands shall be acknowledged or the real power at the Referenced Point shall be monitored. • **Error conditions:** If the commanded real power level at the Referenced Point cannot be met or is not being met, this condition shall be reported. **Discussion Issues** that have been raised and need further resolution before these requirements are included in Rule 21: • When should ramp rates be used and when should/could ramp times be used? For instance, in setting real power, ramp rate might be more appropriate, while in Regulation Up and Regulation Down, a fixed ramp time might be more appropriate. Should each function specify which type and range of ramp rate/time should be used? • Should ramp rates be defined as percent of the present maximum capacity per second? Or nameplate capacity per second? (See previous function discussion on this issue).
Frequency-Watt Emergency Mode (Section 9)	The **Frequency-Watt Emergency mode** shall counteract frequency excursions during H/LFRT events by decreasing or increasing real power. The change in real power may be provided by changing generation, changing load, or a combination of the two. Details of the function will be provided by IEEE 1547.

SIWG Phase 3 DER Functions	Discussions on Key Requirements for Rule 21
Counteract frequency excursions during H/LFRT events by decreasing or increasing real power	Key requirements include: • **High and low frequency threshold to initiate changing real power:** This mode applies to both decreasing real power output on high frequency and increasing real power output on low frequency for units that can provide that capability at that point in time. • **Rate of real power change** shall be settable. • **High and low frequency stop settings** at which to stop changing real power, including a ramp rate. • **Hysteresis:** If hysteresis is enabled, then the rate of change is also set for returning from the hysteresis level to the normal real power level. • **Enable** and **Disable** settings of the Frequency-Watt Emergency mode shall be provided. When enabled, the DER shall counteract frequency excursions during H/LFRT events by decreasing or increasing real power. • **Acknowledge and/or monitor the data at the Referenced Point**: Receipt of the mode parameters and the enable/disable commands shall be acknowledged or the real power at the Referenced Point shall be monitored. • **Error conditions:** If the frequency-watt emergency mode requirements cannot be met or is not being met, this condition shall be reported. Use of this **Frequency-Watt function for frequency smoothing** during normal operations shall be permitted but is not mandatory. **Discussion Issues** that have been raised and need further resolution before these requirements are included in Rule 21: • If we wait for IEEE 1547 on details, will that delay Rule 21 updates? • Are the frequency thresholds absolute values or offsets from nominal?
Volt-Watt Mode (Section 10) Respond to changes in the voltage at the Referenced Point by decreasing or increasing real power	The **Volt-Watt mode** shall respond to changes in the voltage at the Referenced Point by decreasing or increasing real power. The change in real power may be provided by changing generation, changing load, or a combination of the two. Details of the function will be provided by IEEE 1547. Key requirements include: • **High and low voltage thresholds to initiate changing real power:** This mode applies to both decreasing real power output on high voltage and increasing real power output on low voltage for units that can provide that capability at that point in time. • **Referenced Point identifier:** The identity of the Referenced Point shall be provided where the voltage is measured or calculated for the PCC or other Referenced Point.

SIWG Phase 3 DER Functions	Discussions on Key Requirements for Rule 21
	• **Offset to the reference voltage*:*** The offset to the referenced voltage measurement or calculation shall be provided. • **Rate of real power change** shall be settable to establish a maximum rate of change of real power. Default in IEEE 1547 is 20% with adjustability between 10% and 100%) • **Enable** and **Disable** settings for the volt-watt mode shall be provided. When enabled, the DER shall respond to voltage levels at the Referenced Point by modifying real power according to the volt-watt curve parameters. When disabled, the DER shall revert to a previously defined state at the established ramp rate. • **Acknowledge and/or monitor the data at the Referenced Point**: Receipt of the mode parameters and the enable/disable commands shall be acknowledged or the real power at the Referenced Point shall be monitored. • **Error conditions:** If the volt-watt mode requirements cannot be met or is not being met, this condition shall be reported. **Discussion Issues** that have been raised and need further resolution before these requirements are included in Rule 21: • DER systems in areas of high voltage may be affected more by this function and therefore may seem to be unfairly impacted. Therefore, as with most other functions, compensation methods will need to be addressed.
Dynamic Reactive Current Support Mode (Section 11) Provide reactive current support in response to dynamic variations in voltage rather than the voltage itself	The **Dynamic Reactive Current Support mode** shall provide reactive current support in response to dynamic variations in voltage (rate of voltage change) rather than changes in voltage. Details of the function will be provided by IEEE 1547. Key requirements include: • **Enable** and **Disable** settings for the dynamic reactive current support mode shall be provided. When enabled, the DER shall respond to voltage variations at the Referenced Point by modifying reactive current according to the mode settings. When disabled, the DER shall revert to a previously defined state at the established ramp rate. • **Acknowledge and/or monitor the data at the Referenced Point**: Receipt of the mode parameters and the enable/disable commands shall be acknowledged or the power measurements at the Referenced Point shall be monitored. • **Error conditions:** If the dynamic reactive current support mode requirements cannot be met or are not being met, this condition shall be reported. Additional key requirements include the following basic requirements: • The minimum voltage deviation relative to the average voltage, expressed in terms of % of VRef • The maximum voltage deviation relative to the average voltage, expressed in terms of % of

SIWG Phase 3 DER Functions	Discussions on Key Requirements for Rule 21
	VRef • The gradient, expressed in unit-less terms of %/%, to establish the ratio by which capacitive % Var production is increased as %delta-voltage decreases below DbVMin • The gradient, expressed in unit-less terms of %/%, to establish the ratio by which Inductive % Var production is increased as %Delta-Voltage increases above DbVMax • The time, expressed in seconds, over which the moving linear average of voltage is calculated to determine the Delta-Voltage Additional possible settings include: • The selection setting that identifies whether the dynamic reactive current support acts according to the basic method (see Figure 17) or the alternative method (see Figure 20) • The voltage limit, expressed in terms of % of VRef, used to define a lower voltage boundary, below which dynamic reactive current support is not active. • The hysteresis added to BlkZnV in order to create a hysteresis range, expressed in terms of % of VRef. • The time (in milliseconds), before which reactive current support remains active regardless of how deep the voltage sag. • Enable/Disable Event- Based Behavior, the selection of whether or not the event-based behavior is enabled. • Dynamic Reactive Current Mode, the selection of whether or not watts should be curtailed in order to produce the reactive current required by this mode. • The time (in milliseconds) that the delta-voltage must return into or across the dead-band before the dynamic reactive current support ends, frozen parameters are unfrozen, and a new event can begin. **Discussion Issues** that have been raised and need further resolution before these requirements are included in Rule 21: • This function is still being discussed in IEEE 1547 and changes may occur as a result of those discussions. What key requirements should be included in Rule 21 at this time?
Scheduling power values and modes (Section 12) Scheduling of real and reactive	**Schedules** shall be capable of setting **real and reactive power values** as well as enabling and disabling **DER modes** for specific time periods. Key requirements include: • **Schedule consisting of an array of time periods** of arbitrary length that define the offset from a starting date and time.

SIWG Phase 3 DER Functions	Discussions on Key Requirements for Rule 21
power, as well as the enabling and disabling of the DER modes	• **Scheduled value or mode:** Each time period shall be associated with a real or reactive value or shall indicate which mode, which set of parameters for the mode, and whether to enable or disable the mode. • **Starting date and time:** The start date and time shall be provided before the schedule is enabled. • **Referenced Point identifier:** The identity of the Referenced Point shall be provided where the relevant measurements or calculations are provided for the PCC or other Referenced Point. • **Time Window** within which the value or mode shall be achieved or a **Ramp Rate** shall be settable. A time window of 0 seconds or a ramp rate of 100% shall indicate immediate action. • **Schedule repeat interval:** Schedules shall be able to be repeated periodically. • **Schedule event trigger:** Schedules shall be able to be initiated by an event • **Multiple schedules** which may be active at the same time shall be supported • **Schedule priority** to determine which schedules take precedence if they overlap with mutually exclusive requirements. • **Schedule ending process**: When a schedule ends, the default state of the DER shall be reverted to, with any ramping or other settings to arrive at that default state. • **Enable** and **Disable** settings for the schedules. When a schedule is enabled, the schedule shall take effect at the first scheduled time. The DER shall then modify its output to achieve the scheduled value at the established ramp rate. When a schedule ends or is disabled, the DER shall revert to a previously defined state at the established ramp rate. • **Acknowledge and/or monitor the data at the Referenced Point**: Receipt of the mode parameters and the enable/disable commands shall be acknowledged or the power measurements at the Referenced Point shall be monitored. • **Error conditions:** If the schedule requirements cannot be met or are not being met, this condition shall be reported. **Additional scheduling capabilities** may optionally be supported, such as providing pricing signals for different scheduled times. **Discussion Issues** that have been raised and need further resolution before these requirements are included in Rule 21: • Schedules have not been discussed in detail and need more in-depth definitions of what they may or may not be required to do. • DER systems will need to have accurate time and will need to include time synchronization methods to an adequate accuracy to respond to schedules. Is this a problem? Should time accuracy be included in Rule 21, such as within 10 seconds for most DER? It is understood that

SIWG Phase 3 DER Functions	Discussions on Key Requirements for Rule 21
	with communications, time synchronization is possible.

2.3 Key Monitored Information

As identified during the Phase 2 discussions, Table 2 describes the recommended SIWG Phase 3 key monitored data that DER systems shall be capable of providing at a minimum. Guidelines will be described in more detail in the Utility DER Handbooks, covering issues such as:

- Utilities will need to determine at what point this data will be required from any particular DER system, facility, or aggregator. For instance, high penetration scenarios will require this data sooner, while lower penetrations may not yet need this data right away. This data could also be used in future DRPs to determine locational benefits.
- Utilities will need to specify the retrieval rates for collecting the data for different scenarios. Data from some DER systems may be needed in "real-time" (seconds), but most will only be needed over many minutes, hours, or even days.
- Utilities will need to specify latency and accuracy requirements of information (SCADA timeframes vs. "loosely-coupled" monitoring, time skew, available data, revenue-grade, etc.)
- Utilities will need to determine which DER systems need to provide individual data, which may aggregate their data by "group", and which may only need to provide the metered data from "smart meters".
- Who pays for this communications is out of scope for Rule 21, but needs to be discussed in other forums – in a rate setting process.

Table 2: Utility data monitoring and control requirements

Administrative Messaging Requirements	
Information in headers	
	Unique Plant or FDEMS ID
	Meter ID, Service Point ID, or other ECP ID
	Utility ID
	Timestamp of message and other header information
Nameplate and/or "as installed" base information of DER System (for each DER System registered with utility)	
	DER system manufacturer
	DER system model
	DER system software version

	DER system serial number
	DER system type
	Location (latitude/longitude and/or street address)
Basic information of DER system or of facility or plant (FDEMS) (ratings are the installed ratings which are different from capabilities which may change or be forecast based on customer or market issues)	
	Operational authority (role)
	Watt rating
	VA rating
	Var rating
	Current rating
	PF rating
Monitoring Data Sets	
Monitored analog measurements, aggregated by the FDEMS to reflect the ECP and/or the PCC	
	Watts
	VArs
	Power Factor
	Hz, Frequency
	VA, Apparent Power
	A, Phase Currents
	PPV, Phase Voltages
	{Type of data collection or aggregation, e.g. indication of whether instantaneous, average over period, max, min, first, last}
Monitored status, aggregated by the FDEMS for the ECP and/or the PCC	
	DER Connection Status
	PCC or ECP Connection Status
	Inverter status
	De-rated real power due to inability to meet stated rating
	Available real power
	Available vars
	Status of limits (flags that get raised when a specified limit is reached)
	Active modes (flags that get raised when a control (mode) is enabled)
	Ride-through status (flags on instantaneous ride-through state; does not count R-T events)
Metered DER system values, aggregated by the FDEMS for the ECP and/or the PCC	
	Wh, Watt-hours, lifetime (or from reset time) accumulated AC energy
	VAh, VA-hours, lifetime (or from reset time) accumulated
	VArh, VArh, lifetime (or from reset time) accumulated

Notification of alarms	
	Binary alarm values (flags that get raised for specific types of alarms of a specific DER)
	Binary alarm values (flags that get raised for specific types of facility/plant alarms)

3. Timeframe for Implementing Mandated Phase 3 Functions

Just as with Phase 1, there will need to be testing and certification requirements before these Phase 3 functions can have mandatory implementation requirements. Therefore it is expected that the implementation of mandatory functions will require at least a 12-month window between the approval of such testing and certification requirements and mandatory date of implementation.

Discussion Issues that have been raised and need further resolution before these requirements are included in Rule 21:

- May need to be tied to 1741 SA for some functions and to other testing sources for other functions.
- The industry needs testing and certification requirements as rapidly as possible. Utilities don't need certification, but would like it to be tested.
- Also need communications testing. IEEE 2030.5 is also open to revision and then will need to be tested. Whichever protocols are used, cyber security testing will need to be included.
- Self-certification of some functions could be done rapidly after the completion of 1741 SA, but NRTL certification would need 1547.1 completion.
- Maybe involve the creation of 1741 SB, which could then be rolled into the revision of IEEE 1547.1. It is hoped that IEEE 1547.1 would be essentially completed by the time IEEE 1547 goes to ballot. Any additional Phase 3 functions would be placed into UL 1741 revision as optional.
- Will need to harmonize all of the schedules of these efforts.

4. Background Information

4.1 DER Functions: Direct Actions and Modes

The term “function” encompasses single “*DER direct commands*” as well as “*DER modes*” which entail continuous autonomous internal analysis and actions by the DER once the mode is enabled.

DER modes usually require the DER system to receive some measurement either at the DER’s ECP, from a remote ECP within the facility, or from an external ECP (termed the “Referenced Point” in mode descriptions), or reacting to some event, and then responding to that measurement or event according the mode’s parameters. These modes are defined in IEC/TR 61850-90-7 (now incorporated into the IEC 61850-7-520 Guidelines for IEC 61850-7-420) and described in EPRI Common Functions version 3.

4.2 Use of EPRI Report as Input for SIWG Phase 3 Functions

The EPRI report *“Common Functions for Smart Inverters”*, Version 3, 3002002233[1], describes many of the SIWG Phase 3 functions in enough detail to provide good understanding of their purposes and capabilities. It also includes references to parameters which can be used to establish the settings for these functions. These parameters are useful for helping to understand the functions but are not necessarily exactly the same as communication controls and settings, since some parameters may just be preset values while other parameters may be exchanged using different communication protocols with different types and structures. Nonetheless, the EPRI report provides an excellent base for describing the SIWG Phase 3 functions, and is therefore used as the core input to this SIWG Phase 3 document.

Over the past few years, additional functions have been identified, and the SIWG review of the EPRI document has also modified some of the descriptions of the functions. Therefore, this SIWG Phase 3 document is an extraction, modification, and update of the original EPRI document. In turn, this document may be used by EPRI to update their document to version 4.

Background of EPRI Report

“The genesis of this body of work dates to 2009, when EPRI began working with a number of utilities doing large scale Smart Grid demonstrations. These demonstrations were focused on the deployment of Distributed Energy Resources (DER) and the communication integration of these resources with the utility. Many of these projects involved the integration of inverter-based systems, such as solar photovoltaic and energy storage systems, including diverse sizes and manufacturers.

EPRI worked together with the Department of Energy, Sandia National Laboratories, and the Solar Electric Power Association to form a collaborative team to facilitate this initiative. Several face-to-face workshops have been conducted, and a focus-group of volunteers have met every 1-2 weeks over a two year period to discuss,

---

[1] Electric Power Research Institute, “*Common Functions for Smart Inverters, Version 3*”, Product ID:3002002233, February 2014

debate, and develop a proposed set of common approaches to a range of high-value functions. This document, "Common DER Functions, version 3, 3002002233", compiles the results of this work thus far.

As a result, this work has been a useful and significant contribution to several standards groups and activities. The common functions support use cases collected by the NIST Priority Action Plan (PAP) 07, have provided technical input into work in the IEC TC57 WG17 and IEEE 1547.8, and have been or are being mapped into the DNP3, SEP2.0, and ModBus protocols."[2]

4.3 Use of IEC 61850-7-420 Information Model for DER System Interactions

Formed in April 2004, the International Electrotechnical Commission (IEC) Technical Committee (TC) 57 Working Group (WG) 17 started the development of the requirements for interacting with DER systems using the IEC 61850 information model. Over the years many efforts provided input to first IEC 61850-7-420:2009 for the basic DER functions, and a couple of years later to the IEC 61850-90-7 for "smart DER" functions. Instrumental in the development of the IEC 61850 information model was EPRI projects, the IEEE 1547.3 Communications for DER, reports from the Smart Grid Interoperability Panel (SGIP), and, more recently, the SIWG Phase 1 functions. The IEC 61850-7-420/90-7 DER information model has also been used as a source for developing mappings to other protocols, such as IEEE 1815 (DNP3) and IEEE 2030.5 (SEP 2) which is recommended to be the default protocol for the SIWG Phase 2.

IEC 61850 consists of three main components:

- An **abstract information model** in which each data item has a human-understandable name that uniquely identifies it, along with standardized formatting. These are the "nouns." The IEC 61850-7-420 is the abstract information model for DER systems.
- An **abstract definition of communication services** that can be used to read and write data as well as metadata, issue control commands, receive alarms and events, and manage audit logs. These are the "verbs."
- **Communication protocols** that map the information model data and the services to the actual "bits and bytes" for transporting between interfaces. These are the instantiation of the abstract models to the real world. The current standardized protocols include the Manufacturing Messaging Specification (MMS) ASN.1 data structures, MMS services, GOOSE protocol, and more recently XML/XER over XMPP.

Therefore, it is suggested that the IEC 61850-7-420 standard be regarded as the information model for the information exchanges required by the Phase 3 functions.

[2] EPRI, *Common Functions for Smart Inverters*, Version 3, 3002002233, Extract from Chapter 1

4.4 Use of Parameters to Help Describe the Phase 3 Functions

The functions are described both in terms of what they are expected to accomplish as well as the various parameters which define the settings and actions of the DER systems. These parameters are not necessarily set through communications – they may be preset or manually entered – but they provide one means for clearly and explicitly describing the key requirements of the functions.

Although these parameters can also be used for external parties to interact with the DER functions, no assumptions are made on the types of communications that might be used and indeed the functions may operate autonomously. Any interactions with external parties can be viewed as “requests” with the understanding that the DER systems will validate any changes to parameters and will perform the function to the best of its ability within its capabilities, while still protecting itself as a first priority.

Some Phase 3 functions may need to identify specific values. If those values are included in the revision to IEEE 1547 or other standards, then those documents should be identified and included as references. If they need to be defined in Rule 21, then we will need discussions to develop those values.

5. Basic Device Settings and Limits

5.1 Electrical Connection Points (ECP) and Referenced Points

As illustrated in Figure 1, the term “Electrical Connection Point (ECP)” is used to denote any point on the local electric power system (EPS). An ECP can the connection point between a single DER and the local EPS, or it can be the connection point between a group of DER systems and the local EPS. ECPs can be nested. If loads can be controllable, then they also have an ECP. The point of common coupling (PCC) is the ECP between the local EPS and the area EPS.

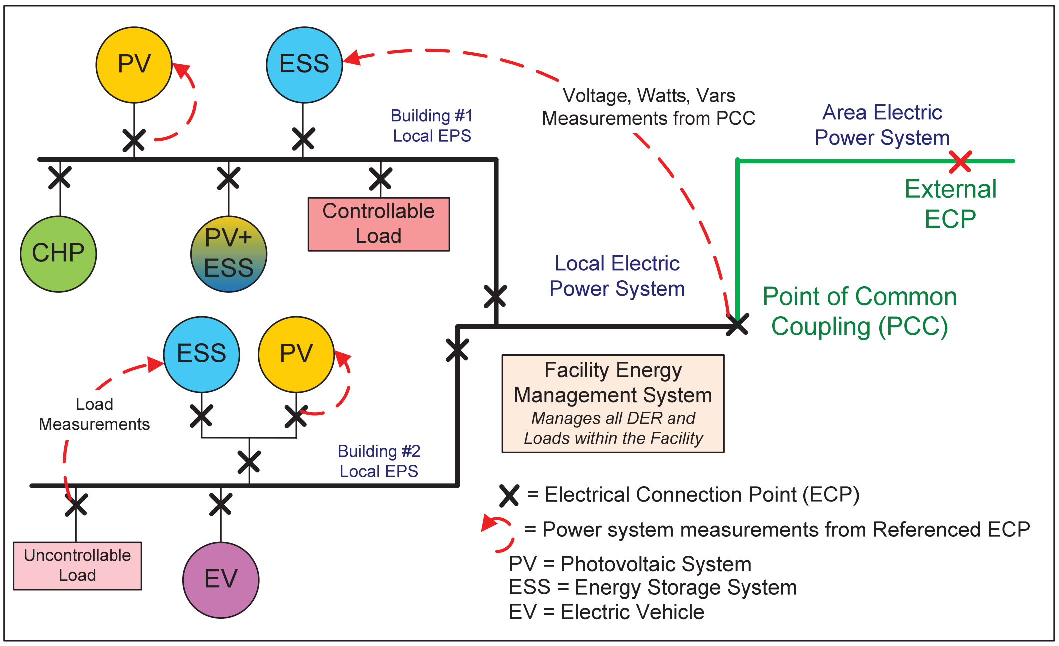

Figure 1: DER electrical connection points (ECP) and the point of common coupling (PCC)

Many Phase 3 functions may be referencing a point that is not the one where the DER system is interconnected. In particular, utilities usually expect a function to take effect at the PCC, so, for that case, the limit power output function would reference the local PCC. However other remote points could also be referenced, such as an energy storage system referencing a PV plant a few miles away at a separate facility in order to counteract PV fluctuations. Synchrophasors would also need to collect data from other remotely located synchrophasors.

Therefore many of the Phase 3 functions use the term “Referenced Point” to indicate that the identifier of the point of interest must be one of the parameters. It is assumed, of course, that these Referenced Points have been mutual agreed to, and that some means of receiving the necessary power system measurements from the Referenced Point is available to the DER system.

5.2 Key Monitored Information

The key monitored data that the DER shall be capable of providing shall include at a minimum the information shown in Table 3. Guidelines will be described in more detail in the Utility DER Handbooks, covering issues such as:

- Utilities will need to determine at what point this data will be required from any particular DER system, facility, or aggregator. For instance, high penetration scenarios will require this data sooner, while lower penetrations may not yet need this data right away. This data could also be used in future DRPs to determine locational benefits.
- Utilities will need to specify the retrieval rates for collecting the data for different scenarios. Data from some DER systems may be needed in "real-time" (seconds), but most will only be needed over many minutes, hours, or even days.
- Utilities will need to specify latency and accuracy requirements of information (SCADA timeframes vs. "loosely-coupled" monitoring, time skew, available data, revenue-grade, etc.)
- Utilities will need to determine which DER systems need to provide individual data, which may aggregate their data by "group", and which may only need to provide the metered data from "smart meters".
- Who pays for this communications is out of scope for Rule 21, but needs to be discussed in other forums – in a rate setting process.

Table 3: Utility DER data monitoring requirements – individually and/or aggregated

Administrative Messaging Requirements	
Information in headers	
	Unique Plant or FDEMS ID
	Meter ID, Service Point ID, or other ECP ID
	Utility ID
	Timestamp of message and other header information
Nameplate and/or "as installed" base information of DER System (for each DER System registered with utility)	
	DER system manufacturer
	DER system model
	DER system software version
	DER system serial number
	DER system type
	Location (latitude/longitude and/or street address)
Basic information of DER system or of facility or plant (FDEMS) (ratings are the installed ratings which are different from capabilities which may change or be forecast based on customer or market issues)	
	Operational authority (role)

	Watt rating
	VA rating
	Var rating
	Current rating
	PF rating
Monitoring Data Sets	
Monitored analog measurements, aggregated by the FDEMS to reflect the ECP and PCC	
	Watts
	VArs
	Power Factor
	Hz, Frequency
	VA, Apparent Power
	A, Phase Currents
	PPV, Phase Voltages
	{Type of data collection or aggregation, e.g. indication of whether instantaneous, average over period, max, min, first, last}
Monitored status, aggregated by the FDEMS for the ECP and PCC	
	DER Connection Status
	PCC or ECP Connection Status
	Inverter status
	De-rated real power due to inability to meet stated rating
	Available real power
	Available vars
	Status of limits (flags that get raised when a specified limit is reached)
	Active modes (flags that get raised when a control (mode) is enabled)
	Ride-through status (flags on instantaneous ride-through state; does not count R-T events)
Metered DER system values	
	Wh, Watt-hours, lifetime (or from reset time) accumulated AC energy
	VAh, VA-hours, lifetime (or from reset time) accumulated
	VArh, VArh, lifetime (or from reset time) accumulated
Notification of alarms	
	Binary alarm values (flags that get raised for specific types of alarms of a specific DER)
	Binary alarm values (flags that get raised for specific types of facility/plant alarms)

400

5.3 Basic Power Settings and Nameplate Values

The settings described in this section are the DER nameplate values that are fixed for the life of the product, as well as certain basic pre-set parameters that may be site or implementation specific. These would notionally be set by the manufacturer and would represent the as-built capabilities of the equipment. These settings are not expected to be modified through communications, but might be modified locally and could be read for background and assessment purposes.

The settings listed in Table 4 are defined as illustrated in Figure 2.

Table 4: Basic Power and Nameplate Settings

Name	Description
WMax	The maximum real power that the DER can deliver to the grid, in Watts
VAMax	The maximum apparent power that the DER can conduct, in Volt-Amperes
VarMax	The maximum reactive power that the DER can produce or absorb, in Vars
WChaMax	The maximum real power that the DER (e.g. ESS) can absorb from the grid, in Watts. Note that WChaMax may or may not differ from WMax.
VAChaMax	The maximum apparent power that the DER can absorb from the grid, in Volt-Amperes. Note that VAChaMax may or may not differ from VAMax.
ARtg	A nameplate value, the maximum AC current level of the DER, in RMS Amps.

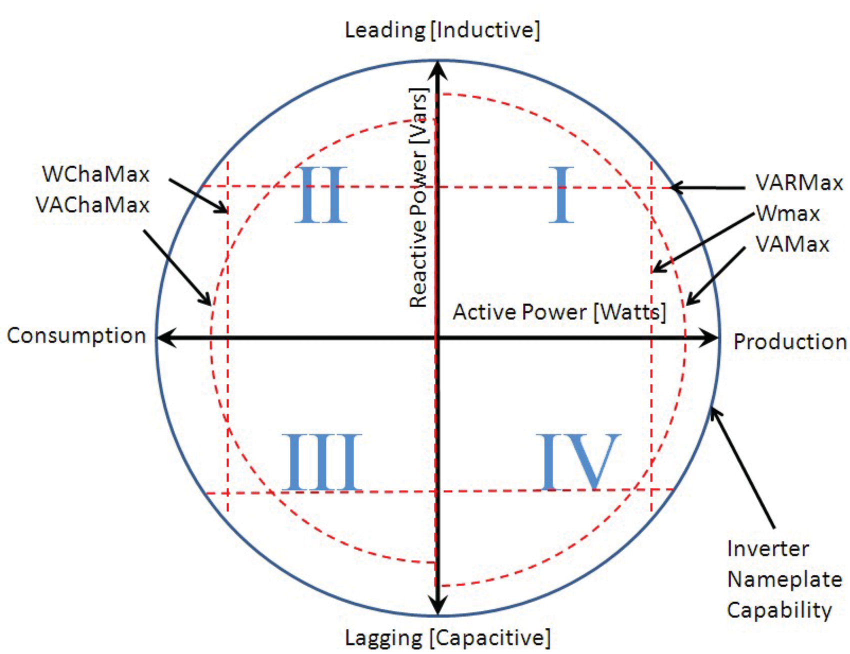

Figure 2: Basic Power Settings Illustration

It is recognized that DER units may have limitations at any time regarding their ability to produce power or perform other functions. These limitations might stem from primary generation source availability, internal malfunctions, maintenance needs, or other special conditions. In this sense,

5.4 Voltage Normalization Settings

For functions using voltage parameters (e.g. Volt-Var modes, Volt-Watt modes, Dynamic Grid Support), a reference voltage and an offset voltage are defined as listed in Table 5 and illustrated in Figure 3.

All inverters behind one Point of Common Coupling (PCC) have a common reference voltage, but may differ in the voltage between their own Electrical Connection Point (ECP) and the PCC due to instrumentation errors or voltage shifts within a plant. These differences can be corrected by the parameter VRefOfs that is to be applied by each inverter. This correction voltage can be set once, or infrequently, and allows for homogenous controls and setting to be used for broadcasts to many DER.

Table 5: Voltage Normalization Settings

Name	Description
VRef	The normal operating voltage for this DER site / service connection, in Volts.
VRefOfs	An offset voltage that represents an adjustment for this DER, relative to VRef, in Volts. VRefOfs is defined as the voltage at the ECP, relative to the PCC. For example, if the PCC VRef is 120V, and the nominal voltage at the DER's ECP is 122V, then VRefOfs = +2V. VRefOfs may be preset or dynamically determined.

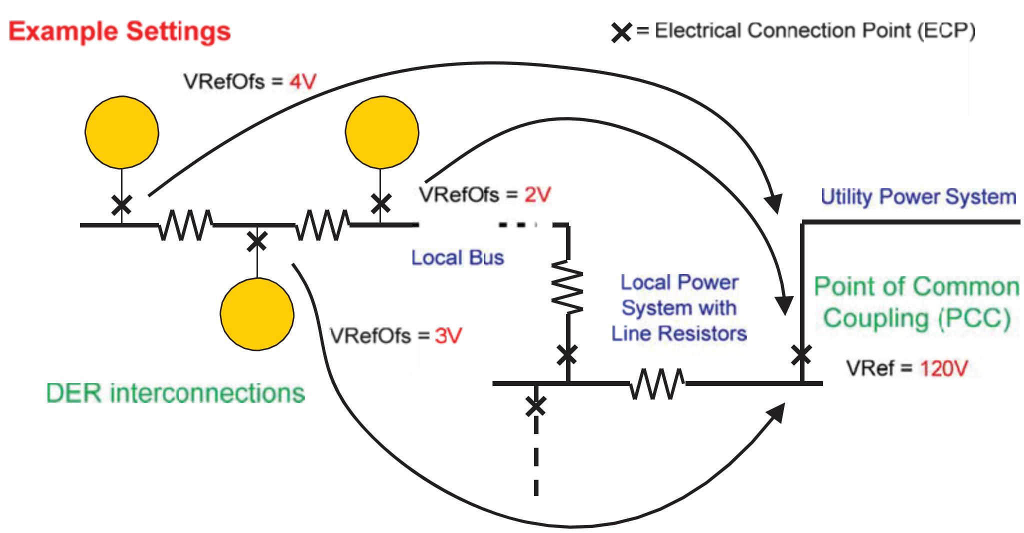

Figure 3: Offset Voltage Illustration

As will be seen in the descriptions of functions that are based on local voltage as a control variable, settings are provided in terms of the effective percent voltage, which is defined as:

$$\textit{Effective Percent Voltage} = 100 * (\textit{local measured voltage} - \textit{VRefOfs}) / (\textit{VRef})$$

5.5 Real Power Ramp Rate Settings

The default ramp rate of change of active power is provided by the parameter WGra. This parameter limits the rate of change of real power delivered or received due to either a change by a command or by an internal action such as a schedule change. This ramp rate (gradient) does not replace the specific ramp rates that may be directly set by the commands or schedules, but acts as the default if no specific ramp rate is specified with a command. For generating systems, WGra is defined as a percentage of WMax per second. Equivalently for the charging of energy storage systems, WChaGra is defined as a percentage of WChaMax.

Table 6: Real Power Ramp Rate Settings for generation and storage systems

Name	Description
WGra	The default ramp rate of real power output in response to control changes. WGra is defined as a percentage of WMax per second.
WChaGra	The default ramp rate of real power input (charging) in response to control changes. WChaGra is defined as a percentage of WChaMax per second.

Additional ramp rates are needed for emergency conditions, for soft reconnection, and other scenarios.

5.6 Accuracy Settings

The accuracy that the DER systems are required to meet the functional requirements at the Referenced Point is very important for determining compliance. The metrics needed to measure compliance include the following:

- Range of the measured values from the nominal value at the Referenced Point
- Time allowed for the measured values to be outside the range
- Average (mean) of the measured values

6. DER Cease to Energize and Return to Service Request

6.1 Scope of this Function

The cease to energize command causes a DER system either to galvanically disconnect from or to "cease to energize" the local and/or area EPS at the Referenced Point. The return to service command initiates the closing of the DER switch or ends the cease to energize state. A "permission to return to service" command may be used to permit the return to service but to allow the actual return to service to take place at a later time.

6.2 Requirements and/or Use Cases for this Function

The purpose this function is generally for emergency situations, with examples such as:

- **Emergency reduction in distributed generation.** Under certain circumstances, system voltage may rise to unacceptably high levels or certain grid assets (e.g. wires, transformers) may become overloaded. In these cases it might become desirable or even necessary to cease to energize certain DER systems from the grid.

- **Malfunctioning DER equipment.** Distributed generation or storage devices may be found to be malfunctioning – disrupting the grid due to some form of failure. In these cases, it might be desirable to cease to energize the device from the power system.

- **Grid maintenance or repair.** Utilities may wish to cease to energize DER devices from the grid during certain repairs or maintenance.

- **Concern that a DER or facility may have formed an unintentional island.** Utilities may wish to issue a cease to energize command to DER systems or facilities to ensure that an unintentional island has not inadvertently formed.

6.3 Description of the Cease to energize Command

The cease to energize command causes the DER or facility to either galvanically disconnect or "cease to energize". Possible points of disconnection are shown in Figure 4. The Referenced Point indicates which switch is opened for a galvanic disconnect or where the "cease to energize" function takes place. The cease to energize causes the DER or facility to go to zero active current flow and (close to zero) reactive power flow at the Referenced Point, such as at the DER's ECP or at the PCC. This function does not necessarily affect DERs if they are acting as loads.

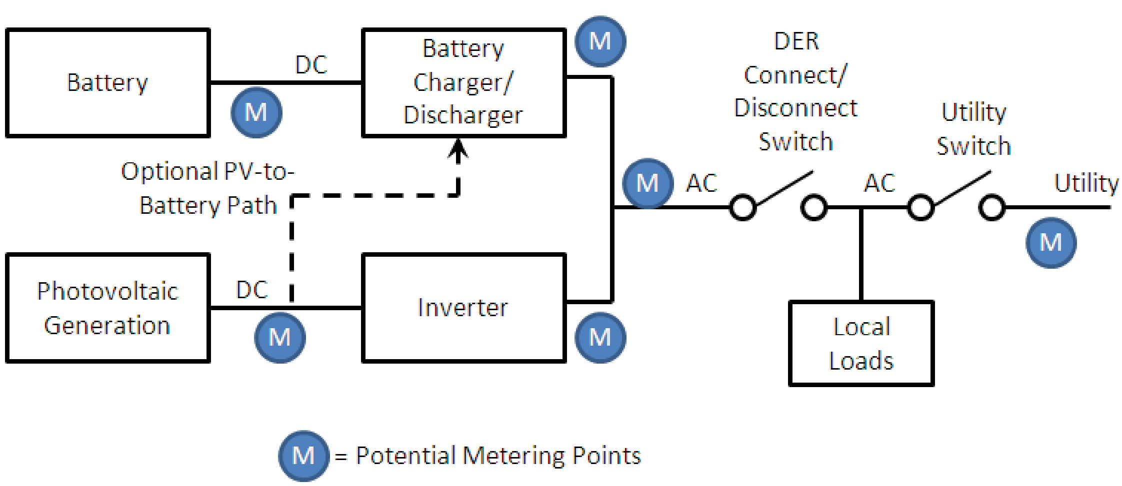

Figure 4: Example DER Diagram showing possible disconnect locations including switches

The cease to energize function consists of a "Cease to energize" command, with optionally the monitoring of the state at the Referenced Point:

- **Set Referenced Point State**: a command which either instructs the switch at the Referenced Point to open or causes a "cease to energize" state at the Referenced Point. The function may include a time window or ramping for when the action take place.
- **Monitor Referenced Point State**: a query to monitor the Referenced Point.

The function may be supported by the following information, which may be preset or exchanged as part of the command:

- **Time Window**: a time, over which the cease to energize operation is randomized. For example, if the Time Window is set to 60 seconds, then the cease to energize operation occurs at a random time between 0 and 60 seconds. This setting is provided to accommodate communication systems that might address large numbers of devices in groups.
- **Ramp Down Rate**: a ramp down rate that specifies the rate that the DER uses to decrease output to reach the cease to energize state
- **Reversion Timeout**: a time, after which a command to cease to energize expires and the device return to services. Reversion Timeout = 0 means that there is no timeout.

6.4 Description of the Return to service Command

The return to service command is assumed to be subordinate to any local safety switch operations, including any lock-out/tag-out system. In other words, a remote switch-connect request (or the timeout of a switch disconnect request) would NOT result in return to service of a system that was disconnected by some other means.

A "permission to return to service" may be issued to indicate that the DER may return to service when it chooses to do so. The DER may then start up its return to service process or may continue to be disconnected.

The return to service command either causes the disconnect switch at the Referenced Point to close or causes the cease-to-energize state to be discontinued:

- **Permission to Return to service**: a command indicating that return to service is permitted.
- **Set Referenced Point State**: a command which either instructs the switch at the Referenced Point to close or discontinues the "cease to energize" state at the Referenced Point. The function may include a time window or ramping for when the action take place.
- **Monitor Referenced Point State**: a query to monitor the Referenced Point.

The function may be supported by the following information, which may be preset or exchanged as part of the command:

- **Time Window**: a time, over which the return to service operation is randomized. For example, if the Time Window is set to 60 seconds, then the return to service operation occurs at a random time between 0 and 60 seconds. This setting is provided to accommodate communication systems that might address large numbers of devices in groups.

- **Ramp Up Rate**: a ramp up rate that specifies the rate that the DER uses to increase output after discontinuing the cease-to-energize state.

7. Limit Maximum Real Power Mode

7.1 Scope of this Function

This specification provides a mechanism through which the maximum real power of one DER system or an aggregation of DER systems and load within a facility can be limited at a Referenced Point.

7.2 Requirements/Use Cases

The context for the inclusion of this function includes a variety of needs. For example:

- **Localized (Customer Side of the Distribution Transformer) Overvoltage Conditions**. This function could be used to reduce DG output to prevent localized overvoltage conditions.
- **Localized Asset Stress.** This function could be used to limit the maximum output from DG to prevent the overloading of local assets such as transformers.
- **Feeder Overvoltage Conditions.** This function could be used across a large number of devices to prevent high-penetration DG from driving distribution system voltages too high during periods of light load.

7.3 Description of Function

This function establishes an upper limit on the real power that a DER system can produce or use (deliver to its local EPS) at its ECP or, in aggregate with other DER systems and loads, at the PCC, or at some other Referenced Point. The limit value may be positive if net export of real power is limited, or may be negative if net import of real power is to be greater than the limit value. This function is opposite of Peak Power Limiting, which limits the net import of real power and may require the net export of real power.

The maximum generation level function may either be percentage based, according to the nominal capability of the DER system, or may be an absolute value, particularly if referring to the maximum export at the PCC. For the percentage setting, the effect is illustrated in Figure 5.

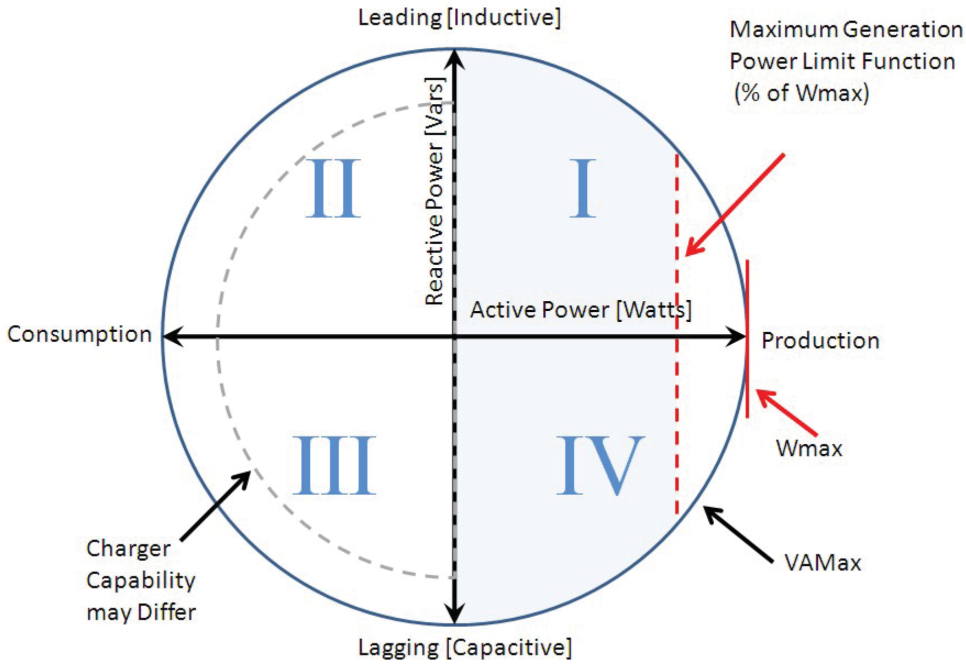

Figure 5: Example of Limit Maximum Real Power

The following information exchanges are associated with this function, either as default values or as provided at the same time as the maximum limit command:

- **Monitor Real Power at the Referenced Point:** a query to read the real power output at the Referenced Point.
- **Set Limit Real Power Level:** a command to set the maximum real power level as a percent of nominal or as a real power value. Percentage based settings allow communication to large groups of devices of differing sizes and capacities.
- **Range of Accuracy Optionally,**
- **Time Window:** a time in seconds, over which a new setting is to take effect. For example, if the Time Window" is set to 60 seconds, then the DER would delay a random time between 0 and 60 seconds prior to beginning to make the new setting effect. This setting is provided to accommodate communication systems that might address large numbers of devices in groups.
- **Reversion Timeout:** a time in seconds, after which a setting below 100% expires and the device returns to its natural "WMax, delivered" limits. Reversion Timeout = 0 means that there is no timeout.
- **Ramp Time:** a time in seconds, over which the DER linearly places the new limit into effect. For example, if a device is operating with no limit on Watts generated (i.e. 100% setting), then receives a command to reduce to 80% with a "Ramp Time" of 60 seconds, then the upper limit on allowed

Watts generated is reduced linearly from 100% to 80% over a 60 second period after the command begins to take effect. (See illustration in Figure 6).

.

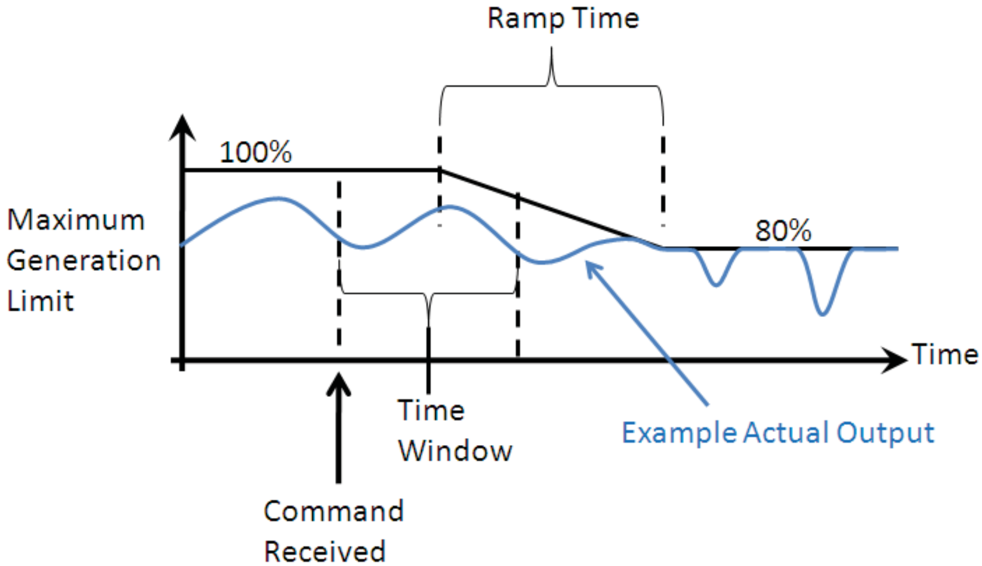

Figure 6: Example of limiting maximum real power output at a Referenced Point

8. Set Real Power Mode

8.1 Scope of this Function

This function provides a mechanism through which the real power export or import of one or more DER systems is set at the Referenced Point.

8.2 Requirements/Use Cases

Setting the real power export or import permits the management of real power at a Referenced Point.

8.3 Description of Function

This function establishes the real power that a DER system produces or uses at its ECP (OutWSet) or, in aggregate with other DER systems and loads, exports or imports at the PCC (ImptExptSet) or some other Referenced Point.

The real power export/import function may either be percentage based, according to the nominal capability of the DER system, or may be an absolute value , particularly if referring to the export or import at the PCC. The function is constrained by the capabilities of the DER systems or facility. The following parameters should be provided:

- **Monitor Real Power at the Referenced Point:** a query to read the real power output at the Referenced Point.
- **Set Maximum Generation Level:** a command to set the maximum generation level as a percent of WMax or as a real power value. Percentage based settings allow communication to large groups of devices of differing sizes and capacities.
- **Time Window:** a time in seconds, over which a new setting is to take effect. For example, if the Time Window" is set to 60 seconds, then the DER would delay a random time between 0 and 60 seconds prior to beginning to make the new setting effect. This setting is provided to accommodate communication systems that might address large numbers of devices in groups.
- **Reversion Timeout:** a time in seconds, after which a setting below 100% expires and the device returns to its natural "WMax, delivered" limits. Reversion Timeout = 0 means that there is no timeout.
- **Ramp Time:** a time in seconds, over which the DER linearly places the new limit into effect. For example, if a device is operating with no limit on Watts generated (i.e. 100% setting), then receives a command to reduce to 80% with a "Ramp Time" of 60 seconds, then the upper limit on allowed Watts generated is reduced linearly from 100% to 80% over a 60 second period after the command begins to take effect. (See illustration in Figure 6).

9. Frequency-Watt Emergency Mode

9.1 Scope of this Function

This function establishes curves that define the changes in watt output based on frequency deviations from nominal, as a means for countering those frequency deviations. The watt output may reflect rapid frequency changes or may be configured only to respond to longer term frequency deviations.

9.2 Requirements/Use Cases

Possible use cases include:

- **Short-Term (Transient) Frequency Deviations.** Under certain circumstances, system frequency may dip suddenly. Some discussion of this type of event may be found in reports from PNNL's Grid Friendly Appliance project. Autonomous responses to such events are desirable because response must be fast to be of benefit.
- **Long-Term Frequency Deviations or Oscillations.** Particularly in smaller systems or during islanded conditions, frequency deviations may be longer in duration and indicative of system generation shortfalls or excesses relative to load.

9.3 Frequency-Watt Function for Emergency Situations

These functions address the issue that high frequency often is a sign of too much power in the grid, and vice versa. One method for countering the over-power problem is to reduce power in response to rising frequency (and vice versa if storage is available). Adding hysteresis provides additional flexibility for determining the active power as frequency returns toward nominal.

Table 7 shows the Function 1 settings for the active power reduction by frequency.

The parameters for frequency are relative to nominal grid frequency (ECPNomHz). The parameter HzStr establishes the frequency above nominal at which power reduction will commence. If the delta grid frequency is equal or higher than this frequency, the actual active power will be frozen, shown as P_M. If the grid frequency continues to increase, the power will be reduced by following the gradient parameter (WGra), defined as percent of P_M per Hertz. This reduction in output power continues until either the power level is zero or some other limit (e.g. a 1547 turn off limit) is reached.

The parameter HystEna can be configured to activate or deactivate hysteresis. When hysteresis is activated, active power is kept reduced until the delta grid frequency reaches the delta stop frequency, HzStop.

Whether or not hysteresis is active, the maximum allowed output power will be unfrozen when the delta grid frequency becomes smaller than or equal to the parameter HzStop.

In order that the increase in power is not abrupt after releasing the snap shot value (frozen power) a time gradient is defined. The parameter HzStopWGra can bet set in Pmax/minute. Default is 10% Pmax/minute.

Table 7: Frequency-Watt Function 1 Settings

Name	Description	Example Settings
WGra	The slope of the reduction in maximum allowed Watt output as a function of frequency	40% Pref/Hz
HzStr	The frequency deviation from nominal frequency (ECPNomHz) at which a snapshot of the instantaneous power output is taken as a maximum power output reference level (Pref) and above which reduction in power	0.2 Hz
HzStop	The frequency deviation from nominal frequency (ECPNomHz) at which curtailed power output may return to normal and the snapshot value is released	0.05 Hz
HystEna	A boolean indicating whether or not hysteresis is enabled	On
HzStopWGra	The maximum time rate of change at which power output returns to normal after having been curtailed by an over	10%

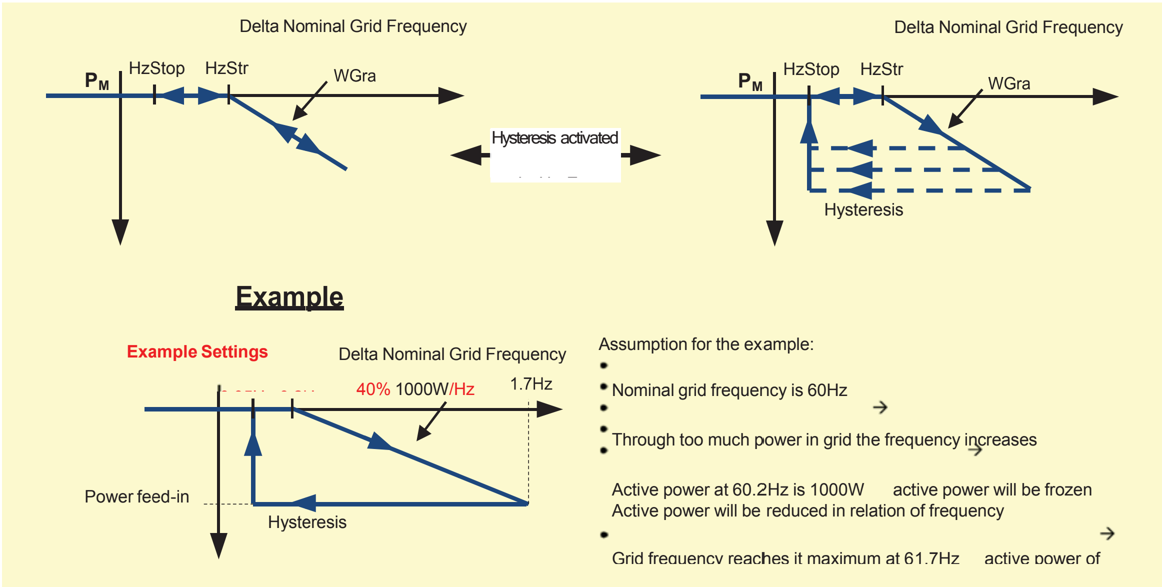

Figure 7: Frequency-Watt Function 1 Visualization

9.4 Frequency-Watt Function for Smoothing Frequency

This function provides a configurable curve-shape method for establishing the desired Frequency-Watt behavior in the end device. The general approach follows that of the previously defined Volt-Watt function.

As with the Volt-Var modes, multiple Frequency-Watt Function 2 modes may be configured into an inverter. For example, the desired frequency-watt curve-settings might be different on- peak vs. off-peak, or different when islanded vs. grid connected. A simple mode change broadcast could move the inverters from one pre-configured frequency-watt mode to another.

The basic idea is illustrated in Figure 8.

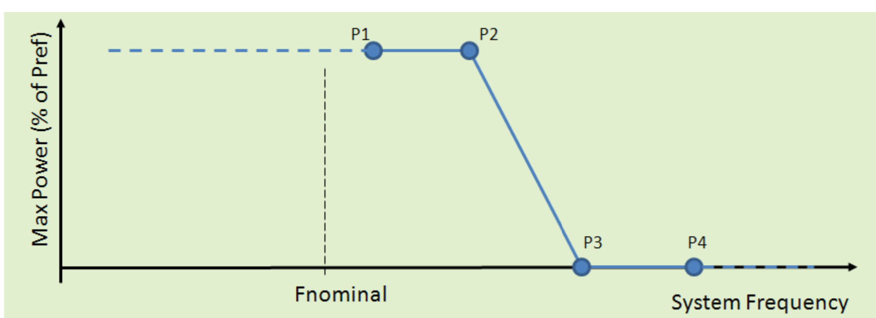

Figure 8: Example of a Basic Frequency-Watt Mode Configuration

The desired frequency-watt behavior is established by writing a variable-length array of frequency-watt pairs. Each pair in the array establishes a point on the desired curve such as those labeled as P1-P4. The curve is assumed to extend horizontally to the left below the lowest point and to the right above the highest point in the array. The horizontal X-axis values are defined in terms of actual frequency (Hz). The vertical Y-axis values are defined in terms of a percentage of a reference power level (Pref) which is, by default, the maximum Watt capability of the system. WMax (defined in prior work), is configurable and may differ from the nameplate value. As will be explained later in this document, these Y-axis values are signed, ranging from +100% to -100%, with positive values indicating real power produced (delivered to the grid) and negative values indicating power absorbed.

Optional Setting of a SnapShot Power Reference (Pref) Value

In some cases, it may be desirable to limit and reduce power output relative to the instantaneous output power at the moment when frequency deviates to a certain point. To enable this capability, each frequency-watt mode configuration may optionally include the following parameters.

- **Snapshot_Enable**: A Boolean, which when true, instructs the inverter that the Pref value (the vertical axis reference) is to be set to a snapshot of the instantaneous output power at a certain frequency point. When Snapshot is enabled, no reduction in output power occurs prior to reaching the Pref_Capture_Frequency
- **Pref_Capture_Frequency**: The frequency setting, in hertz, at which the Pref value is established at the instantaneous output of the system at that moment. This parameter is only valid if Snapshot_Enable is true.
- **Pref_Release_Frequency**: The frequency setting, in hertz, at which the Pref value is released, and system output power is no longer limited by this function. This parameter is only valid if Snapshot_Enable is true.

Optional Use of Hysteresis

Hysteresis can be enabled for this frequency-watt function in the same way as with the Volt-Watt function defined previously. Rather than the configuration array containing only points incrementing from left to right (low frequency to high frequency), as indicated in Figure 11-2, hysteresis is enabled by additional points in the configuration array which progress back to the left. Figure 9 illustrates this concept.

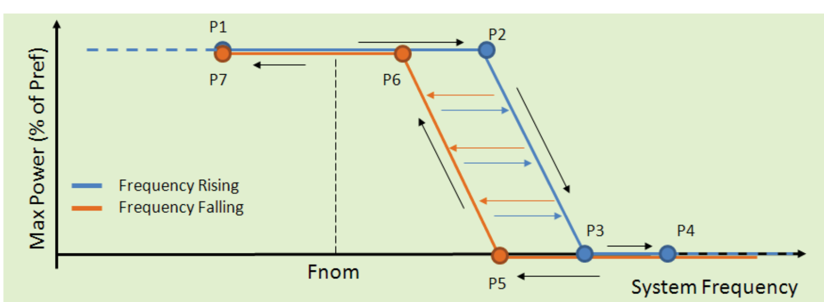

Figure 9: Example Array Settings with Hysteresis

In this case, the points in the configuration array can be thought-of as the coordinates for an X-Y plotter. The pen goes down on the paper at the first point, then steps through the array to the last point, tracing out the resulting curve. As with any configuration (including those without hysteresis), inverters must inspect the configuration when received and verify its validity before accepting it. The hysteresis provides a sort of dead-band, inside which the maximum power limit does not change as frequency varies. For example, if frequency rises until the max power output is being reduced (somewhere between points P2 and P3), but then the frequency begins to fall, the maximum power setting would follow the light orange arrows horizontally back to the left, until the lower bound is reached on the line between points P5 and P6.

The return hysteresis curve does not have to follow the same shape as the rising curve. Figure 10 illustrates an example of such a case.

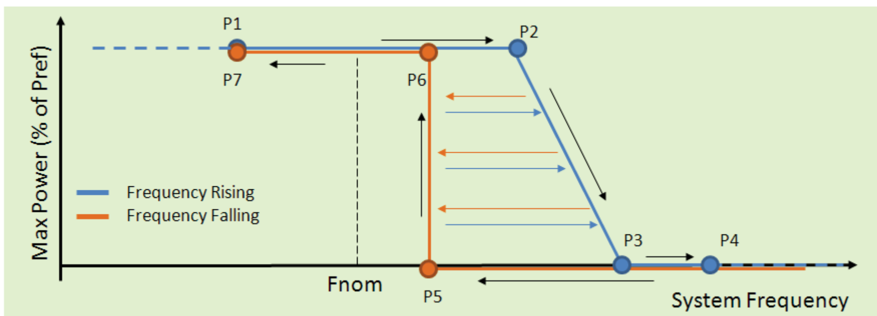

Figure 10: Example of an Asymmetrical Hysteresis Configuration

Controlling Ramp Time

It may be desirable to limit the time-rate at which the maximum power limit established by these functions can rise or fall. To enable this capability, each frequency-watt mode configuration will include the following parameters, in addition to the array.

- **Ramp_Time_Increasing** and **Ramp_Time_Decreasing**: The maximum rates at which the maximum power limit established by this function can rise (defined as moving away from zero power) or fall (defined as moving toward zero power) , in units of %WMax/second.

Supporting Two-Way Power Flows

Some systems, such as energy storage systems, may involve both the production and the absorption of Watts. To support these systems, a separate control function is defined, which is identical to that described above, except the vertical axis is defined as maximum watts absorbed rather than maximum watts delivered. This allows for energy storage systems to back-off on charging when grid frequency drops, in the same way that photovoltaic systems back-off on delivering power when grid frequency rises. Figure 11 illustrates an example setting.

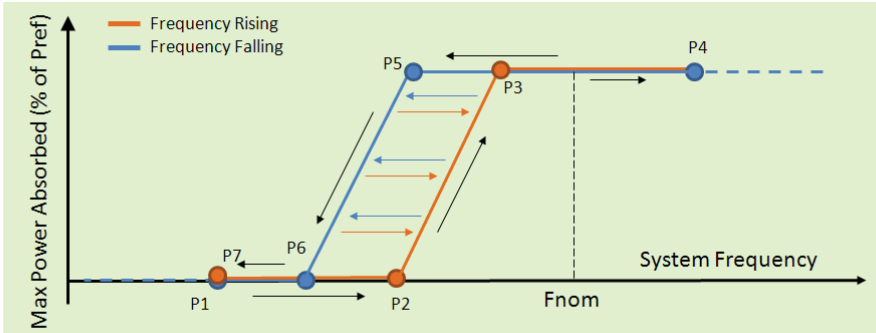

Figure 11: Example Array Configuration for Absorbed Watts vs. Frequency

A further characteristic of systems capable of two-way power flows is that the maximum power curtailment need not stop at 0%. It may pass through zero, changing signs, and indicating that power must flow in the opposite direction (unless prevented from doing so by some other hard limitation) as illustrated in Figure 12.

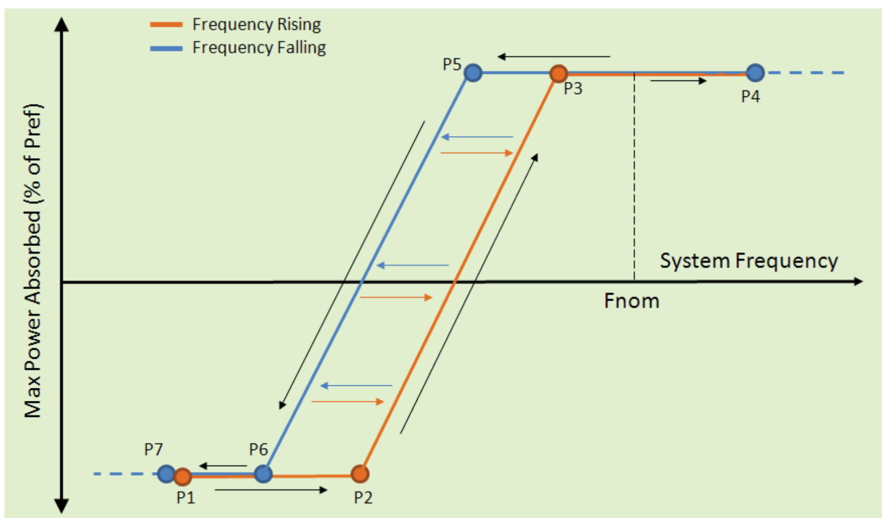

Figure 12: Example Configuration for Reversing Sign on $P_{ABSORBED}$ Limit

For example, an energy storage system may be in the process of charging, absorbing power from the grid. If the grid frequency then falls below normal, the maximum absorbed power level may begin to be curtailed. Once it has been curtailed to zero, if the frequency keeps falling, the system could be configured to produce watts, delivering power to the grid. Likewise, a energy storage system could curtail discharging if the grid frequency rises too high, and begin charging if frequency continues to rise further. These array configurations would utilize the signed nature of the array Y-values, as mentioned above.

9.4.1 Configuration Data

The resulting configuration data for this function, as described, is summarized in Figure 28.

Table 8: Summary Configuration Data for each Frequency-Watt Function (Per Mode)

Parameters for Frequency-Watt Function 1	**Description**
WGra	The slope of the reduction in maximum allowed Watt output as a function of frequency (%WMax/sec)
HzStr	The frequency deviation from nominal frequency (ECPNomHz) at which a snapshot of the instantaneous power output is taken as a maximum power output reference level (Pref) and above which reduction in power output occurs (Hz)
HzStop	The frequency deviation from nominal frequency (ECPNomHz) at which curtailed power output may return to normal and the snapshot value is released (Hz)
HystEna	A boolean indicating whether or not hysteresis is enabled
HzStopWGra	The maximum time rate of change at which power output returns to normal after having been curtailed by an over frequency event (Hz)
Frequency-Watt Function 2	Note: The following parameter set exists once for each “Frequency-Watt Produced” mode, and once for each “Frequency-Watt Absorbed mode”
Configuration Array	The variable length array of Frequency-Watt pairs that traces out the desired behavior. (%PRef vs. Hz)
Snapshot_Enable	A boolean determining whether snapshot mode is active
Pref_Capture_Freq	The frequency at which the power reference point is to be captured if in snapshop mode (Hz)
Pref_Release_Freq	The frequency at which the power reference point is to be released if in snapshop mode (Hz)
Ramp_Time_Inc	The maximum time rate of increase in the max power limit associated with this mode configuration (%WMax/Second)
Ramp_Time_Dec	The maximum time rate of decrease in the max power limit associated with this mode configuration (%WMax/sec)
Time_Window	This is a window of time over which the inverter randomly delays before beginning execution of the command. For example, an inverter given a new Volt-Watt configuration and a Time-Window of 60 seconds would wait a random time between 0 and 60 seconds before beginning the change to the new setting. The purpose of this parameter is to avoid large numbers of devices from simultaneously changing state if addressed in groups. (in seconds)
Ramp_Time	This setting, which exists for most functions, is replaced by the separate Ramp_Tme_Inc and Ramp_Time_Dec settings for this function.
Time-Out Window	This is a time after which the command expires. A setting of zero means to never expire. After expiration, the Volt-Watt curve would no longer be in effect. (in seconds)

9.4.2 Relative Prioritization of Modes

Multiple modes which may act to limit Watt production, such as the Volt-Watt and Frequency-Watt functions, may both be simultaneously active. In that situation, the one that indicates the lower max-power level (closest to zero) at any point in time should be the one that establishes the limit at that time.

10. Volt-Watt Mode

10.1 Scope of this Function

This function modifies watts based on voltage, using curves to establish the associations.

10.2 Requirements/Use Cases

A number of purposes for the volt-watt function have been identified, for instance:

- **During High/Low Voltage Ride-Through**, the volt-watt function can be activated autonomously to modify watt output in the high voltage ranges, potentially decreasing output until reaching a "cease-to-energize" state.
- **High penetration of DER systems at the distribution level, driving feeder voltage too high.** Some utilities described circumstances where high PV output and low load is causing feeder voltage to go too high at certain times. Existing distribution controls are not able to prevent the occurrence.
- **Localized High Service Voltage.** Several utilities described circumstances where a large number of customers served by the same distribution transformer have PV systems, causing local service voltage that is too high. The result is certain PV inverters that do not turn on at all.

10.3 Description of Function

The Volt-Watt function utilizes a "configurable-curve". This mechanism allows the inverter to be configured using an array of points, where the points define a piece-wise linear "curve" that establishes an upper limit on Watt output as a function of the local voltage. Figure 13 illustrates the concept.

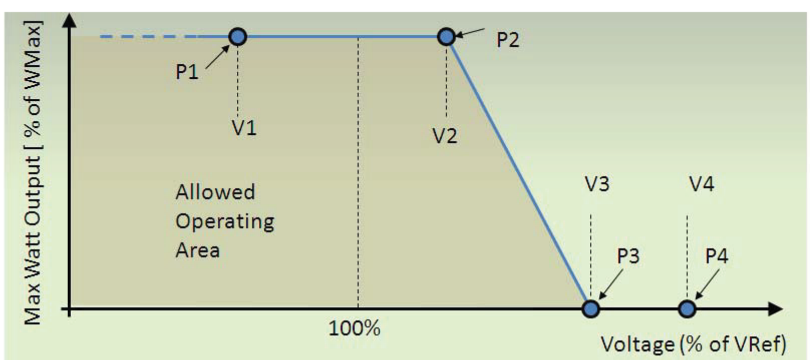

Figure 13: Example Configuration Curve for Maximum Watts vs. Voltage

The exact curve shape shown in Figure 13 is only an example. The array of points could be chosen so as to produce whatever behavior is desired. By definition of this function, the curve extends horizontally below the lowest voltage point and above the highest voltage point until such level that some other operational limit is reached. This means that in this example, point 1 and point 4 could be deleted, leaving only two configuration points, with no change in the resulting function.

In this configuration, the voltages are to be represented in the form of "Percent of VRef", consistent with the voltage axis on the previously defined Volt-Var curves. "VRef" is a single global setting for the inverter that represents the nominal voltage at the PCC or some other point between the DER's ECP and the PCC. See the "Configuration Curve Axis Definitions" section below for further explanation.

In addition to this curve configuration, it is proposed that the Volt-Watt configuration also include a time window, ramp time, time-out window, a filter time constant and a gradient limit, as defined in Table 9.

10.3.1 Defining "Percent Voltage", the Array X-Values

As defined previously in the "Device Limits Settings" document form this initiative's work, each DER will locally compute an "Effective Percent Voltage" based on its real-time local voltage measurement, nominal voltage setting, and offset voltage setting, as:

Effective Percent Voltage = 100% * (local measured voltage-VRefOfs) / (VRef)

The inverter shall compare this "Effective Percent Voltage" Value to the voltages (X-Values) in the curve, such that the X-Values of the curve points shall be calculated as follows:

Percent Voltage (X-Value of Curve) = (Voltage at the Curve Point / VRef) * 100%

Such that a "Percent Voltage" value of 100% represents the desired behavior when the voltage is exactly at the systems nominal or reference value.

This calculation permits the same configuration curves to be used across many different DER without adjusting for local conditions at each DER. For example, a utility might create a general "normal operation" Volt-Var curve that is to be used across many different DER. This works, even though the actual nominal voltage might be 240V at some DER and 480V at others. Each DER is configured with a VRef, and VRefOfs such that the same Volt-Var curve works for all.

10.3.2 Application to ESS (Two-Way Power Flows)

The limits for Watts-absorbed by ESSs are managed by a separate setting than that used for Watts-produced, although the method and parameters of the "Absorbed Volt-Watt" function would be identical to those for the Produced Volt-Watt function, except that a typical curve setting might look as illustrated in Figure 14.

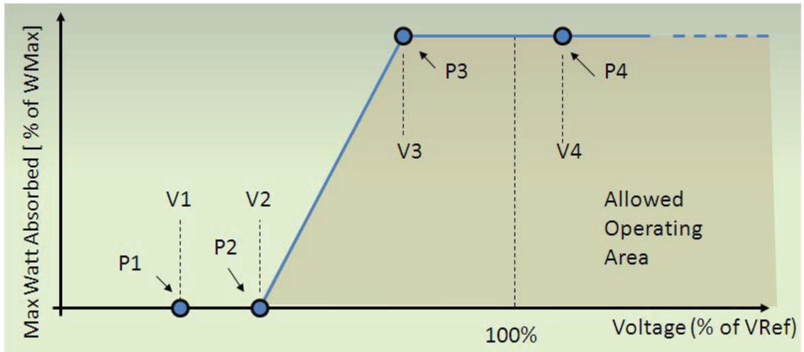

Figure 14: Example Configuration Curve for Maximum Watts Absorbed vs. Voltage

There may be a “Watts-Produced versus Voltage” mode and a “Watts-Absorbed versus Voltage” mode effective at the same time, each limiting the power flow in only one direction.

10.3.3 Limiting the Rate of Change of the Function

This function ultimately results in an upper limit on the Watts produced by the inverter, and likewise a limit on Watts absorbed for energy storage systems. Two mechanisms are proposed for limiting the rate of change of these limits. These may be configured such that they are used individually, together, or not at all.

10.3.4 Using Modes for Handling of Multiple Volt-Watt Configurations

Just as with the Volt-Var modes defined in Phase 1, it is proposed that inverters may accept and store multiple Volt-Watt curve configurations, each constituting a Volt-Watt “Mode”. In this way, an inverter may be commanded to change from one Watts-Voltage Mode to another by simply setting the desired pre-configured mode to “active”. Different inverters may have specific tailored curve shapes for a given mode, but all may be addressed in a single broadcast or multicast command to change the Volt-Watt mode.

There are multiple scenarios in which different Volt-Watt modes may be desired. For example, a DER that is sometimes connected near the sourcing substation, and sometimes at the end of the line due to distribution switching, might be best managed with different settings in each of the two conditions. “Mode” settings may help prepare smart inverters for integration with advanced distribution automation systems. Another example may be intentional islanding, where different settings for the inverter are desired when operating as part of an island.

This “Mode” concept is facilitated by adding to the list of configuration parameters listed in Table 9, a “Mode number” (unique ID for the mode) and a single global field for the “Currently Active Watt Produced-Voltage Mode”.

10.3.5 Scheduling Volt-Watt Modes

Just as with the Volt-Var modes defined in Phase 1, it is proposed that the Volt-Watt modes be schedulable. The schedules will essentially define which Volt-Watt mode is in effect at a given time.

10.3.6 Resulting Block Diagram

The combination of a setting for maximum Watts-Produced vs. Voltage and another for maximum Watts-Absorbed vs. Voltage results in a functional block diagram as in Figure 15. Note that for either function, several mode configurations might be stored in the inverter, and separate mode selection switches exist for each.

The diagram presently illustrated both a "steady-state filter" on the voltage input, and rate of change limitations on the effective operating bounds (Max Watts-Produced, and Max Watts- Absorbed). The configuration data depicted in Table 9 indicates that each rate-of-change limiter would have separate rising and falling limits, as shown.

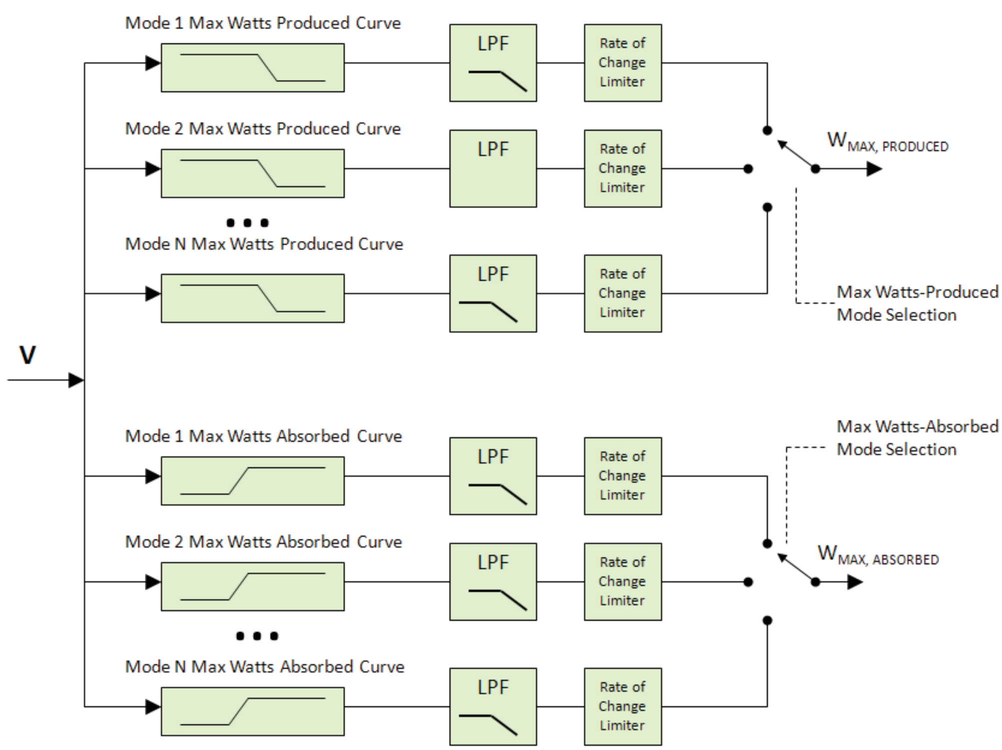

Figure 15: Overall Functional Block Diagram

10.3.7 Resulting Configuration Data

The resulting configuration data for this function, as described, is summarized in Table 10-1. Note that this data set is replicated for each Watts-Delivered and Watts-Absorbed mode that is defined.

Table 9: Summary Configuration Data for one Volt-Watt Mode

Parameter	Description
Enable/Disable	This enables / disables this Volt-Watt Mode
Number of Array Points	The number of points in the Volt-Watt Curve Array (N points)

Parameter	Description
Array Voltage Values	A length=N array of “percent of VRef” values
Array Wattage Values	A length=N array of “Percent of WMax values
Randomization Time Window	Delay before a new command or newly activated mode begins to take effect
Mode Transition Ramp Time	Rate of change limit for new commands as they take effect. This ramp time only manages the rate at which Watt output may transition to a new level when a configuration change is made (by communication or by schedule). It does not affect the rate of change of Watt output in response to voltage variations during normal run time.
Time Out	Duration that a new command remains in effect
Maximum Watt Capability (WMax)	Configured Value. Defined in Phase 1 work
VRef	Reference Voltage. Defined in Phase 1 work
VRefOfs	Reference Voltage Offset. Defined in Phase 1 work
Fall_Limit	The maximum rate at which the Max Watt limit may be decreased in response to changes in the local voltage. This is represented in terms of
Rise_Limit	The maximum rate at which Max Watt limit may be increased in response to changes in the local voltage. This is represented in terms of
Low Pass Filter Time	Equal to three time-constants (3) of the first order low-pass filter in seconds (the approximate time to settle to 95% of a step change).

10.3.8 Interaction of this Function with the Intelligent Volt-Var Function

The Volt-Var modes that were described in Phase 1 of this project were designed in such a way that watts take precedence over Vars. The vertical axis of any Volt-Var curve can be thought of as the “requested” Var level, with the understanding that an inverter that is producing its full Watt capacity at any point in time may have no Vars to offer.

The interaction between the Volt-Var function and the present Watt-Volt function is direct and intentional. The vertical axis of the Volt-Var function’s configuration curve was defined as “percent of available Vars”, meaning that watts production always takes precedence over Vars, regardless of voltage. This agreement came from focus group discussion that included the consideration of the interests of the PV owner, the preference for clean watts generation in general, and the recognition that in almost all cases, there is a good margin between the inverter rating and the peak array output, meaning that significant Var production capability usually exists.

When this definition of the Volt-Var function is coupled with a Watt-Volt function, one gains the ability to back off on watts as voltage rises, forcing more Var capability to be available, and in effect enabling the Volt-Var function to be active and produce Vars even in situations when the array output is capable of driving the full rating of the inverter.

As an example, consider an inverter with the two functions shown in Figure 10-5 (top = Volt- Var function, Bottom = Volt-Watt function), both active simultaneously.

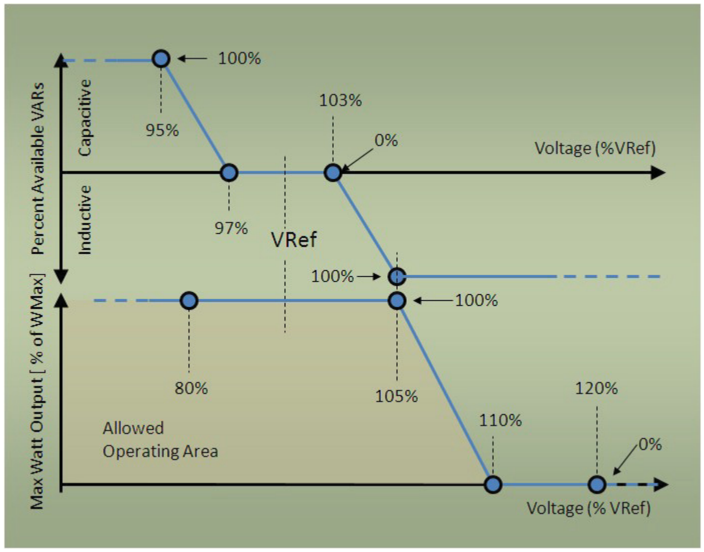

Figure 16: Example Settings for Volt-Var and Volt-Watt Modes

11. Dynamic Reactive Current Support Mode

11.1 Scope

In the Dynamic Reactive Current mode, the DER provides reactive current support in response to dynamic variations in voltage. This function is distinct from the steady-state Volt-Var function in that the controlling parameter is the change in voltage rather than the voltage level itself. In other words, the power system voltage may be above normal, resulting in a general need for inductive Vars, but if it is also falling rapidly, this function could produce capacitive reactive current to help counteract the dropping of the voltage.

11.2 Requirements/Use Cases

This is a type of dynamic system stabilization function. Such functions create an effect that is in some ways similar to momentum or inertia, in that it resists rapid change in the controlling parameter.

Power quality, such as flicker, may be improved by the implementation of functions of this type and when implemented in fast-responding solid-state inverters, these functions may provide other (slower) grid equipment with time to respond.

11.3 Description of Function

It is proposed to provide support for a behavior as illustrated in Figure 17. This function provides dynamic reactive current support in response to a sudden rise or fall in the voltage at the Point of Common Coupling (PCC).

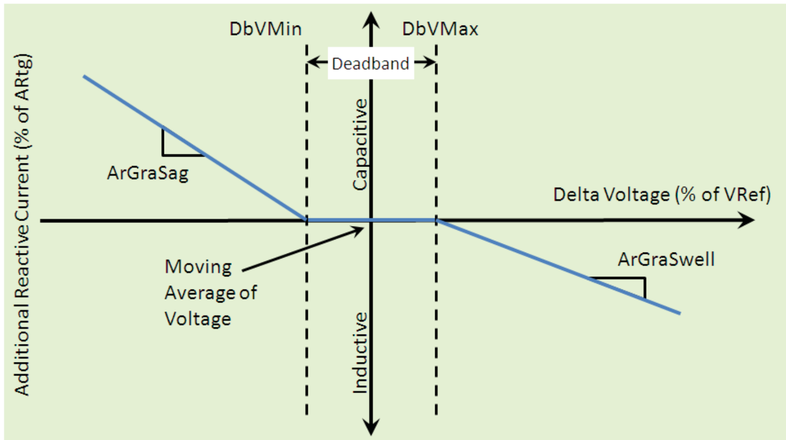

Figure 17: Dynamic Reactive Current Support Function, Basic Concept

This function identifies “Delta Voltage” as the difference between the present voltage and the moving average of voltage, VAverage (a sliding linear calculation), over a preceding window of time specified by FilterTms. The calculation of Delta Voltage (Delta Voltage = Present Voltage – Moving Average Voltage, expressed as a percentage of VRef) is illustrated at time = “Present” in Figure 18.

The “present voltage” in this context refers to the present AC_{RMS} voltage, which requires a certain period to calculate. For example, some inverters might calculate voltage every half-cycle of the AC waveform. It is outside the scope of this specification to define the method or timing of the AC_{RMS} measurement.

Parameters DbVMin and DbVMax allow the optional creation of a dead band inside which zero dynamic current is generated. The separate ArGraSag and ArGraSwell parameters make it possible to independently define the rate that the magnitude of additional reactive current increases as delta-voltage increases or decreases, as illustrated.

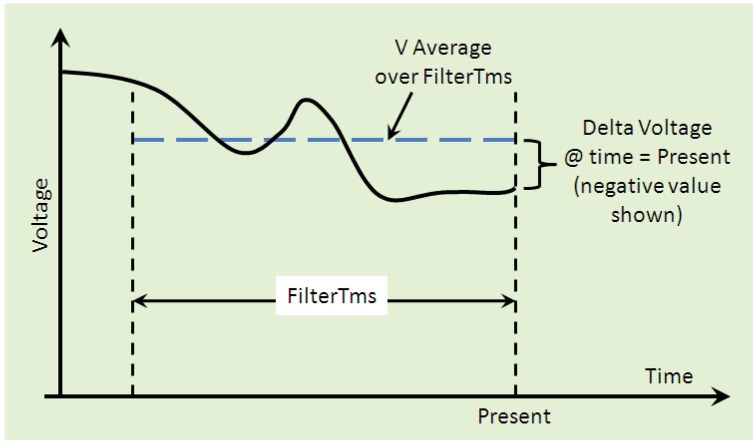

Figure 18: Delta-Voltage Calculation

11.3.1 Event-Based Behavior

This function includes an option to manage how the dynamic reactive current support function is managed, as indicated in Figure 19 and described below.

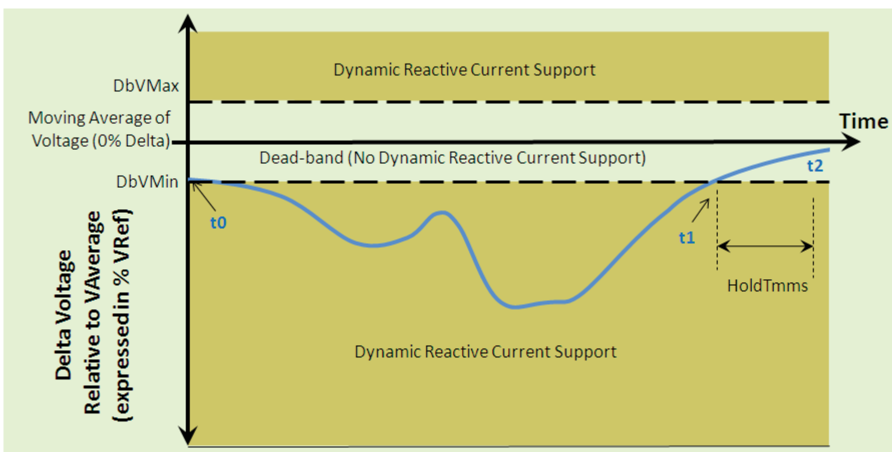

Figure 19: Activation Zones for Reactive Current Support

Activation of this behavior allows for a voltage sag or swell to be thought of as an “event”. The event begins when the present voltage moves above the moving average voltage by DbVMax or below by DbVMin, as shown by the blue line and labeled as t0.

In the example shown, reactive current support continues until a time HoldTmms after the voltage returns above DbVMin as shown. In this example, this occurs at time t1, and this event continues to be considered active until time t2 (which is t1 + HoldTmms).

When this behavior is activated, the moving average voltage (VAverage) and any reactive current levels that might exist due to other functions (such as the static Volt-Var function) are frozen at t0 when the “event” begins and are not free to change again until t2 when the event ends. The reactive current level specified by this function continues to vary throughout the event and be added to any frozen reactive current.

11.3.2 Alternative Gradient Shape

This function includes the option of an alternative behavior to that shown in Figure 20. ArGraMod selects between the behavior of Figure 16-1 (gradients trend toward zero at the deadband edges) and that of Figure 16-4 (gradients trend toward zero at the center). In this alternative mode of behavior, the additional reactive current support begins with a step change when the "event" begins (at DbVMin for example), but then follows a gradient through the center until the event expires, HoldTmms after the voltage returns above the DbVMin level.

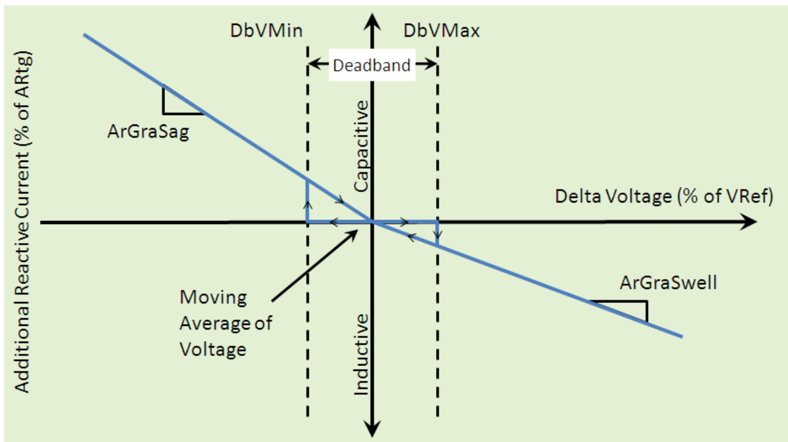

Figure 20: Alternative Gradient Behavior, Selected by ArGraMod

11.3.3 Blocking Zones

This function also allows for the optional definition of a blocking zone, inside which additional reactive current support is not provided. This zone is defined by the three parameters BlkZnTmms, BlkZnV, and HysBlkZnV. It is understood that all inverters will have some self- imposed limit as to the depth and duration of sags which can be supported, but these settings allow for specific values to be set, as required by certain country grid codes.

As illustrated in Figure 21, at t0, the voltage at the ECP falls to the level indicated by the BlkZnV setting and dynamic reactive current support stops. Current support does not resume until the voltage rises above BlkZnV + HysBlkZnV as shown at t1. BlkZnTmms provides a time, in milliseconds, before which dynamic reactive current support continues, regardless of how low voltage may sag. BlkZnTmms is measured from the beginning of any sag "event" as described previously.

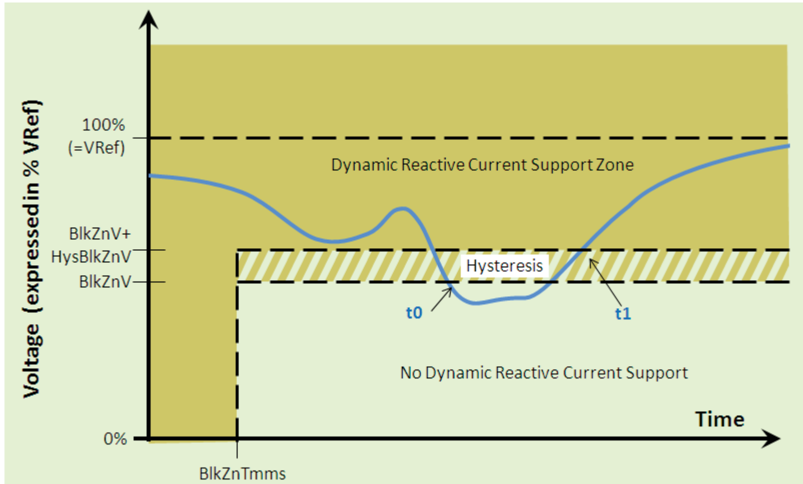

Figure 21: Settings to Define a Blocking Zone

11.3.4 Relationship to the Static Volt-Var Function

As indicated in Figure 16-1, the reactive current level indicated by this dynamic stabilization function is defined as "additional" Current. This means that it is added to the reactive current that might exist due to a static Volt-Var function or fixed power factor setting that is also currently active.

For example, a static volt-var configuration may involve a curve that, at the present operating voltage, results in Var generation of +1000[Vars]. At the same time, this function may be detecting a rising voltage level, and may be configured to produce a reactive current amounting to -300[Vars] in response. In this case, the total Var output would be +700[Vars].

Units may also be configured so that the Var level indicated by this dynamic Volt-Var function are the only Vars, by not activating other Var controls, such as the static Volt-Var modes or non- unity power factor settings.

11.3.5 Dynamic Reactive Current Support Priority Relative to Watts

Under certain operating conditions, the production of the additional reactive current specified by this function could imply a reduction in real-power levels based on the inverter's limits. Such a reduction may or may not be beneficial in terms of providing optimal dynamic support to the grid.

To handle this possibility, an optional setting called "DynamicReactiveCurrentMode" is defined, with associated behaviors as identified in Table 10: Dynamic Reactive Current Mode ControlTable 10. Implementation and utilization of this Boolean is optional. If it is not used or supported, the default behavior is that real power levels (Watts) are curtailed as needed to support this function.

Table 10: Dynamic Reactive Current Mode Control

Setting	Implication	Present Condition	Behavior of this Function
DynamicReactive CurrentMode = 0 (default)	Reactive current is preferred over Watts for grid	Inverter is Delivering Real Power, Voltage Sags	Dynamic reactive current takes priority over Watts
		Inverter is Delivering Real Power, Voltage Swells	Dynamic reactive current takes priority over Watts
		Inverter is Absorbing Real Power, Voltage Sags	Dynamic reactive current takes priority over Watts
		Inverter is Absorbing Real Power, Voltage Swells	Dynamic reactive current takes priority over Watts
DynamicReactive CurrentMode = 1	Watts are preferred over reactive current for grid	Inverter is Delivering Real Power, Voltage Sags	Watts take priority over dynamic reactive current
		Inverter is Delivering Real Power, Voltage Swells	Dynamic reactive current takes priority over Watts
		Inverter is Absorbing Real Power, Voltage Sags	Dynamic reactive current takes priority over Watts
		Inverter is Absorbing Real Power, Voltage Swells	Watts take priority over dynamic reactive

11.3.6 Settings to Manage this Function

As shown in the previous figures, the settings used to configure this function are:

Table 11: Settings for Dynamic Reactive Current Mode

Name	Description
Enable/Disable Dynamic Reactive Current Support Function	This is a parameter that indicates whether the dynamic reactive current support function is active or inactive.
DbVMin	This is a voltage deviation relative to Vaverage, expressed in terms of % of Vref (for example -10%Vref). For negative voltage deviations (voltage below the moving average) that are smaller in amplitude than this amount, no additional dynamic reactive current is produced.
DbVMax	This is a voltage deviation relative to Vaverage, expressed in terms of % of Vref (for example +10%Vref). For positive voltage deviations (voltage above the moving average) that are smaller in amplitude than this amount, no additional dynamic reactive current is produced. Together, DbVMin and DbVMax allow for the creation of a dead-band, inside of which the system does not generate additional reactive current support.
ArGraSag	This is a gradient, expressed in unit-less terms of %/%, to establish the ratio by which Capacitive % Var production is increased as %Delta-Voltage decreases below DbVMin. Note that the % Delta-Voltage may be calculated relative to Moving Average of Voltage + DbVMin (as shown in Figure 16-1) or relative to Moving Average of Voltage (as shown in Figure 16-4), according to the ArGraMod setting.

Name	Description
ArGraSwell	This is a gradient, expressed in unit-less terms of %/%, to establish the ratio by which Inductive % Var production is increased as %Delta-Voltage increases above DbVMax. Note that the % Delta-Voltage may be calculated relative to Moving Average of Voltage +DbVMax (as shown in Figure 16-1) or relative to Moving Average of Voltage (as shown in Figure 16-4) according to the ArGraMod setting
FilterTms	This is the time, expressed in seconds, over which the moving linear average of voltage is calculated to determine the Delta-Voltage.
Additional Settings (Optional)	
ArGraMod	This is a select setting that identifies whether the dynamic reactive current support acts as shown in Figure 16-1 or Figure 16-4. (0 = Undefined, 1 = Basic Behavior (Figure 16-1), 2 = Alternative Behavior (Figure 16-4).
BlkZnV	This setting is a voltage limit, expressed in terms of % of Vref, used to define a lower voltage boundary, below which dynamic reactive current support is not active.
HysBlkZnV	This setting defines a hysteresis added to BlkZnV in order to create a hysteresis range, as shown in Figure 16-5, and is expressed in terms of % of VRef.
BlkZnTmms	This setting defines a time (in milliseconds), before which reactive current support remains active regardless of how deep the voltage sag.
Enable/Disable Event-Based Behavior	This is a Boolean that selects whether or not the event-based behavior is enabled.
Dynamic Reactive Current Mode	This is a Boolean that selects whether or not Watts should be curtailed in order to produce the reactive current required by this function.
HoldTmms	This setting defines a time (in milliseconds) that the delta-voltage must return into or across the dead-band (defined by DbVMin and DbVMax) before the dynamic reactive current support ends, frozen parameters are unfrozen, and a new event can begin.

12. Scheduling Power Values and Modes

12.1 Scope of this Function

This function addresses scheduling of real and reactive power, as well as the enabling/disabling of the different types and variations of DER modes.

12.2 Requirements/Use Cases

Larger DER systems and large aggregations of small DER systems have significant influence on the distribution system and have local volt-var characteristics that may vary throughout the day. As a result, a single function or operational mode such as a specific volt-var curve may not be suitable at all times. Yet sending many control commands every few hours to many different DER systems may impact bandwidth-limited communications systems or may not be received in a timely manner, leading to inadequate DER system responses. However, if schedules can be established that the DER systems can follow autonomously, then these communication impacts can be minimized.

Schedules establish what behavior is expected during specified time periods. A schedule consists of an array of time periods of arbitrary length, with each time period associated with a value or mode.

Schedules use relative time, so that increasing time values are the delta seconds from the initial time value. The actual start date/time replaces the initial time value when the schedule is activated. A ramp rate sets the rate at which the function or mode in one time period moves to the function or mode in the subsequent time period, while the ramp type indicates how the ramp is to be understood. A stop time indicates when the schedule is deactivated.

Schedules can be used to allow even more autonomous control of the behavior of DER equipment. They may be sent ahead of time, and then activated at the appropriate time.

12.3 Description of Function

The relations between schedule controller, schedules and entity controlled by the schedule are shown in

Figure 22. The schedule controller monitors state and priority of its associated schedules and informs the scheduled entity about the reference to the active schedule. The scheduled entity can then receive the scheduled value from the active schedule.

- Schedule controllers: One or more schedule coordinators may be available at the ECP. Each schedule controller can control multiple schedules so long as they are not running at the same time. The schedule controller indicates which schedule is currently ready-to-run or running. For one schedule controller, only one schedule can be running.

- Schedules: Each schedule must have a non-zero identifier that is a unique schedule identity within the ECP. A schedule consists of time periods of arbitrary length that reference delta time from the initial entry.

- Scheduled entities: Each entry in a schedule references a specific value, a mode, or a function. Configuration parameters indicate the units and other characteristics of the entries.

  - Values are direct settings, such as maximum watt output. These are absolute values or a percentage, to be used primarily where specific values are needed.

  - Modes are the identities of the mode type (e.g. volt-var, frequency-watt) and the specific set of pre-established parameters (e.g. volt-var curve #2, frequency-watt curve #5).

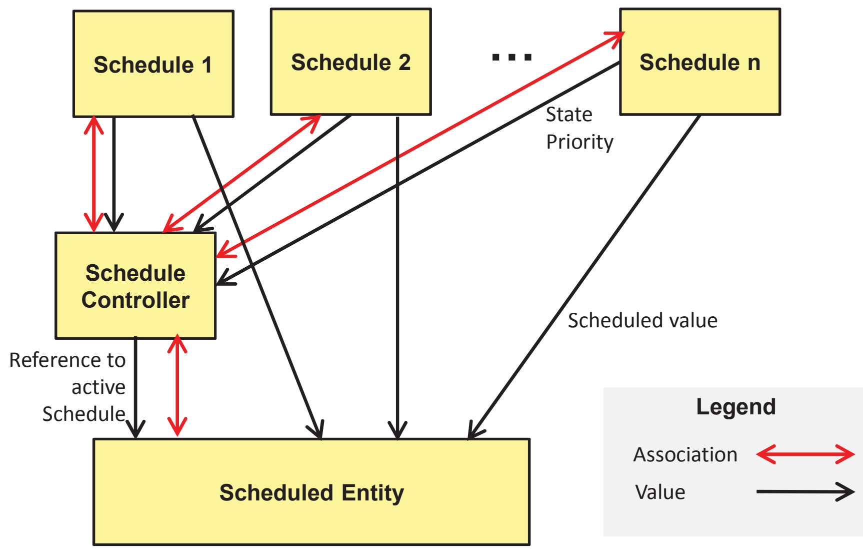

Figure 22: Relation between schedule controller, schedules and entity controlled

Different schedules may be combined over a given period of time, including with different priorities, thereby providing richer ways to utilize the ESS without requiring manual intervention. For example, a power scheduler may provide one schedule which directs the ESS to charge the batteries during nighttime hours when energy is cheap, and provide a subsequent schedule which directs the ESS to operate in Fixed Power Factor mode during the day. An illustration of priority management is shown in Figure 23.

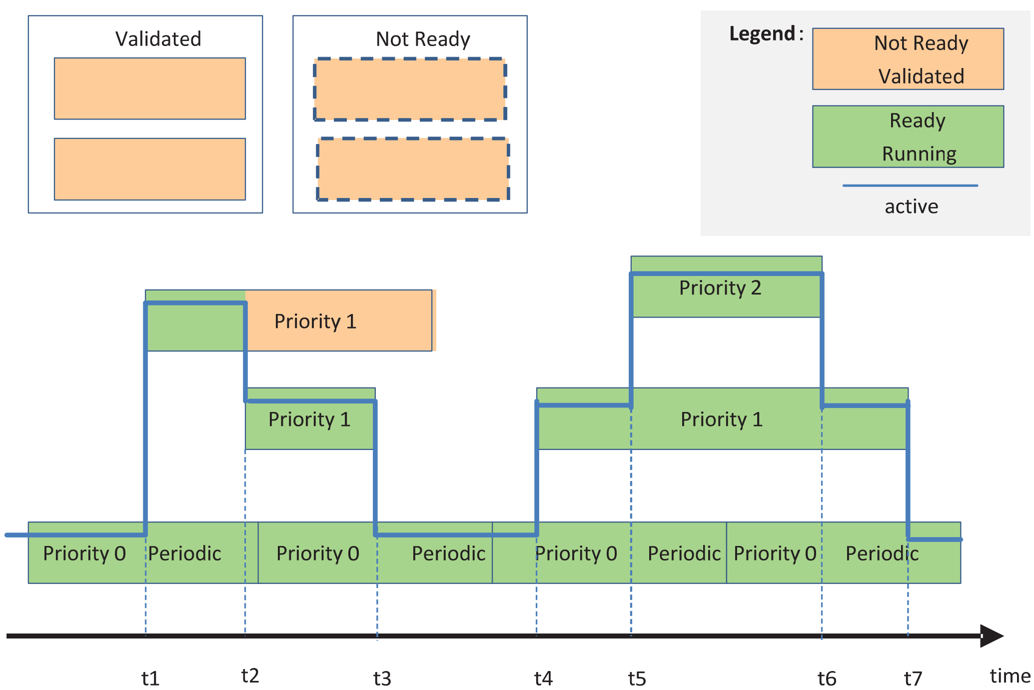

Figure 23: Handling priorities of schedules

997 The settings for scheduling include those in Table 12.

998 Table 12: Settings for Scheduling

Name	Description
FSCHxx (the xx refers to the schedule number (index)	Select which schedule to edit
FSCHxx.ValASG (with FSCH.ClcIntvTyp set to seconds)	Set the Time Offset (X-Value) for each schedule point. Time Offsets must increase with each point. Time Offsets represent relative seconds from each repetition of the schedule.
FSCHxx.ValASG (set for power system values, such as W or Vars)	Set the Y-value for each schedule point for power system values (watts, vars, PF, etc.)
FSCHxx.ING (set to the operating mode identity)	Set the Y-value for enabling or disabling operating modes (VV, FW, VW, etc.) at each schedule point
FSCHxx.NumEntr	Set the number of points used for the schedule. Set this value to zero to disable the schedule (there are other ways to enable and disable schedules).
FSCHxx.SchdPrio	Set the priority for the schedule.
FSCHxx.ValMV (for power system values) or **FSCH.ValINS** (for operating modes)	Set the meaning of the Y-values of the schedule.
FSCHxx.StrTm	Set the start time for the selected schedule
FSCHxx.IntvPer	Set the repeat interval for the selected schedule
FSCHxx.ClcIntvTyp	Set the repeat interval units for the selected schedule
FSCHxx.Enable	Enable the Schedule by changing its state to “ready”.

999

13. DER Functions "Also Important" to DER Integrators and Other Third Parties

13.1 Overview of Additional DER Functions

The list of DER functions selected as part of the Phase 3 document was developed in response to utility assessments of their relative importance to utilities. However, other stakeholders, such as aggregators, integrators, manufacturers, and consultants, also expressed their opinions on the relative importance of certain DER functions in the Phase 3 survey. Although there was significant agreement on which of the functions should be rated of high importance, a few were deemed higher in importance by the other stakeholders than by utilities. Although there was no consensus on exactly which ones are the most important, those "also important" functions are listed here:

1. **Real Power Smoothing mode:** This function provides settings by which a DER may dynamically absorb or produce additional watts in response to a rise or fall in the power level of a Referenced Point.

2. **Dynamic Volt-Watt mode**: This function involves the dynamic absorption or production of real power in order to counteract fast variations in the voltage at the Referenced Point.

3. **Watt-Power Factor mode**: This function shifts the power factor based on real power level. The power factor is not fixed but changes with the power level. It might be slightly capacitive at very low output power levels and becoming slightly inductive at high power levels.

4. **Real Power Following**: This function involves the variable dispatch of energy in order to maintain the DER's real power to track the real power level of the Referenced Point. In the case of load following, the output of the DER power output rises as the consumption of the reference load rises. In the case of generation following, the power output counteracts the output of the reference generation to maintain a total steady value. The DER may apply a percentage of the Referenced Point real power level to its real power output, thus compensating only a part of that real power.

5. **Frequency-Watt Smoothing mode**: This function rapidly modifies real power to counteract and smooth minor frequency deviations. The frequency-watt settings define the percentage of real power to modify for different degrees of frequency deviations on a second or even sub-second basis.

6. **Participate in AGC**: Support frequency regulation by automatic generation control (AGC) commands. The DER system (or aggregations of DER systems, particularly energy storage systems) implements modification of real power based on AGC "reg-up" and "reg-down" signals on a multi-second basis.

7. **Imitate capacitor bank triggers:** Provide reactive power through autonomous responses to weather, current, or time-of-day. Similar to capacitor banks on distribution circuits, the DER system implements temperature-var curves that define the reactive power for different ambient temperatures, similar to use of feeder capacitors for improving the voltage profile. Curves could also be defined for current-var and for time-of-day-var.

8. **Short Circuit Current Limit**: DER must have short circuit limits. DER should limit their short circuit current to no more than 1.2 p.u. This is useful for utilities in order to perform short circuit impact studies.

9. **Provide black start capabilities**: The DER system operates as a microgrid (possibly just itself with no load) and supports additional loads being added, so long as they are within its generation capabilities.

10. **Provide "spinning" or operational reserve as bid into market**: The DER system provides emergency real power upon command at short notice (seconds or minutes), either through increasing generation or discharging storage devices. This function would be in response to market bids for providing this reserve.

11. **Reactive Power Support during non-generating times**: Support the grid with reactive power during non-generating times. DERs support the grid with reactive power (VARs) when there is no primary energy (i.e. solar irradiance). This can be used by utilities to reduce the stress in the system in areas with high motor load (A/C) during peak times.

12. **Flow Reservation**: Energy Storage System requests permission to either charge or discharge a defined amount of energy (kWh) starting at a defined time and completing by a defined time at a rate not exceeding a defined charge or discharge power level. The utility or other authorized entity responds with an authorized energy transfer, start time, and maximum power level. The utility can update the response periodically to modulate the power flow during transfer, but cannot change from discharging to charging, or the reverse, without a new flow reservation request by the storage unit.

13. **FDEMS or Aggregator provides expected schedules:** The FDEMS or Aggregator provides schedules of expected generation and storage reflecting customer requirements, maintenance, local weather forecasts, etc.

14. **FDEMS or Aggregator provides forecasts of available energy or ancillary services**: The FDEMS or Aggregator provides scheduled, planned, and/or forecast information for available energy and ancillary services over the next hours, days, weeks, etc., for input into planning applications. Separate DER generation from load behind the PCC.

15. **FDEMS or Aggregator provides micro-locational weather forecasts**: The FDEMS or Aggregator provides micro-locational weather forecasts, such as: ambient temperature, wet bulb temperature, cloud cover level, humidity, dew point, micro-location diffuse insolation, micro-location direct normal insolation, daylight duration (time elapsed between sunrise and sunset), micro-location total horizontal insolation, micro-location horizontal wind direction, micro-location horizontal wind speed, micro-location vertical wind direction, vertical wind speed, micro-location wind gust speed, barometric pressure, rainfall, micro-location density of snowfall, micro-location temperature of snowfall, micro-location snow cover, micro-location snowfall, water equivalent of snowfall.

16. **Initiate Periodic Tests**: Test DER functionality, performance, software patching and updates Initial DER software installations and later updates are tested before deployment for functionality and for

meeting regulatory and utility requirements, including safety. After deployment, testing validates the DER systems are operating correctly, safely, and securely.

17. **DC Fault Test during start-up**: DER tests its primary energy mover (DC solar PV modules) for fault conditions. This feature will try to alarm plant operators, owners, public that the DC side has a potential short that could lead to a fire hazard.

18. **Provide low cost energy:** Utility, aggregator, or FDEMS determines which DER systems are to generate how much energy over what time period in order to minimize energy costs. Some DER systems, such as PV systems, would provide low cost energy autonomously, while storage systems would need to be managed.

19. **Provide low emissions energy**: Utility, REP, or FDEMS determines which non-renewable DER systems are to generate how much energy in order to minimize emissions. Renewable DER systems would operate autonomously.

20. **Provide renewable energy**: Utility, Aggregator, or FDEMS selects which non-renewable DER systems are to generate how much energy in order to maximize the use of renewable energy. Renewable DER systems would operate autonomously.

21. **Respond to real power pricing signals**: Manage real power output based on demand response (DR) pricing signals The DER system receives a demand response (DR) pricing signal from a utility or aggregator for a time period in the future and determines what real power to output at that time.

22. **Respond to ancillary services pricing signals:** Manage selected ancillary services based on demand response (DR) pricing signals. The DER system receives a DR pricing signal from a utility or retail energy provider (REP) for a time period in the future and determines what ancillary services to provide at that time.

13.2 Real Power Smoothing Mode

13.2.1 Scope of this Mode

The Real Power Smoothing Function compensates for intermittent renewables and transient loads by a smoothing function for loads or generation. This function involves the dynamic dispatch of energy in order to compensate for variations in the power level a reference signal. With proper configuration, this function may be used to compensate for either variable load or variable generation.

13.2.2 Requirements/Use Cases

This function was identified as a requirement by several utilities working together in EPRI's storage research program (P94). These utilities have developed a specification for a large scale Lithium Transportable Energy Storage System (Li-TESS) which includes a requirement for a Load/Generation Smoothing function.

13.2.3 Description of the Function

This proposal describes a method by which distributed energy resources (DER) may perform a load/generation smoothing function as described in the following subsections.

13.2.3.1 Real Power Smoothing

This function provides settings by which a DER may dynamically absorb or produce additional Watts in response to a rise or fall in the power level of a reference point of load or generation. This function utilizes the same basic concepts and settings as the "Dynamic Var Support Function" described separately.

The Watt levels indicated by this function are additive – meaning that they are in addition to whatever Watt level the DER might otherwise be producing. The dynamic nature of this function (being driven by the change (dW/dt) in load or generation level as opposed to its absolute level makes it well suited for working in conjunction with other functions.

As illustrated in the left pane of Figure 24, this function allows the setting of a "Smoothing Gradient" which is a unit-less quantity (Watts produced per Watt-Delta). This is a signed quantity. The example in Figure 24 shows a negative slope. A value of -1.0 would absorb one additional Watt (or produce one less Watt) for each Delta Watt (Present Wattage – Moving Average) of the reference device. Negative settings would be a natural fit for smoothing variable generation, where the DER would dynamically reduce power output (or absorb more) when the reference generation increased.

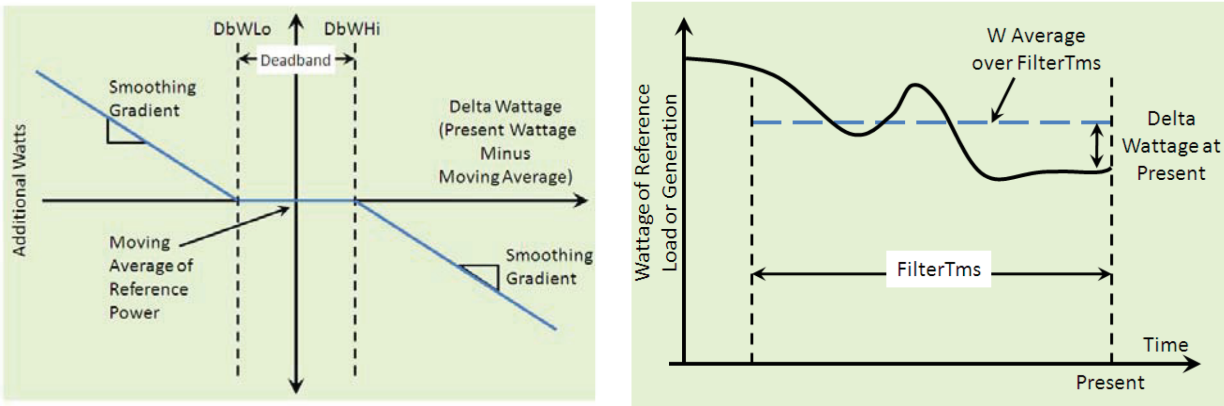

Figure 24: Smoothing Function Behavior

Likewise, a gradient setting of +1.0 would generate one additional Watt (or absorb one less Watt) for each Delta Watt (Present Wattage – Moving Average) of the reference device. Positive settings would be a natural fit for smoothing variable load, where the DER would dynamically increase power output (or absorb less) when the reference load increased.

As illustrated in the right frame of Figure 24, The Delta Wattage is to be computed as Present Wattage – Moving Average, where the Moving Average is calculated as a sliding linear average over the previous "FilterTms" period. FilterTms is configurable.

13.2.3.2 Limitations of the Function

As with all functions, DER systems will operate within self-imposed limits and will protect their own components. These limits are acknowledged to vary, depending on many factors (e.g. state of maintenance, damage, temperature). In addition, it is acknowledged that the load/generation following and real power smoothing functions are limited by present device limit settings, such as WMax.

There are also practical limits to a DER system's ability to provide load/generation following. For example, an energy storage system cannot necessarily follow load or generation indefinitely, and may at some point reach its upper or lower SOC limits. Methods to handle this could include scheduling of the load/generation following modes so that regular charge/discharge commands are used at other times.

13.2.3.3 Settings to Manage this Function

The following settings are defined to manage this function:

Table 13: Real Power Smoothing Function Settings

Setting Name	Description
Enable/Disable Real Power Smoothing	This parameter indicates whether the function is active or inactive.
Smoothing Gradient	This is a signed quantity that establishes the ratio of smoothing Watts to the present delta-watts of the reference load or generation. Positive values are for following load (increased reference load results in a dynamic increase in DER output), and negative values are for following generation (increased reference generation results in a dynamic decrease in DER output).

Setting Name	Description
FilterTms	This is a configurable setting that establishes the linear averaging time of the reference power (in Seconds).
DbWLo and DbWHi	These are optional settings, in Watts, that allow the creation of a dead-band inside which power smoothing does not occur.
Time Window	This is a window of time over which the inverter randomly delays before beginning execution of the command. For example, an inverter given a new smoothing configuration (or function activation) and a Time-Window of 60 seconds would wait a random time between 0 and 60 seconds before beginning to put the new settings into effect. The purpose of this parameter is to avoid large numbers of devices from simultaneously changing state if addressed in
Ramp Time	This is a fixed time in seconds, over which the inverter settings (Watts in this case) are to transition from their pre-setting level to their post-setting level. The purpose of this parameter is to prevent sudden changes in output as a result of the receipt of a new command or mode activation. Note: this setting does <u>not</u> impact the rate of change of Watt output during run-time as a result of power changes at the reference point.
Time-Out Window	This is a time after which the setting expires. A value of zero means to never expire. After expiration, the Power Smoothing settings would no longer be in effect.

13.3 Dynamic Volt-Watt Function

13.3.1 Scope of this Function

The Dynamic Volt-Watt Function provides a mechanism through which inverters, such as those associated with energy storage systems, can be configured to dynamically provide a voltage stabilizing function. This function involves the dynamic absorption or production of real power (Watts) in order to resist fast variations in the local voltage at the ECP.

13.3.2 Requirements/Use Cases

Use cases have been identified (TBD).

13.3.3 Description of Function

This function describes the dynamic volt-watt function by which a DER may dynamically absorb or produce additional Watts in response to a rise or fall in the voltage level at the ECP. This function utilizes the same basic concepts and settings as the “Power Smoothing Function” described separately, except in this case the controlling parameter is the local voltage at the ECP rather than the power level of a remote reference point.

The Watt levels indicated by this function are additive – meaning that they are in addition to whatever Watt level the DER might otherwise be producing. The dynamic nature of this function (being driven by the change (dV/dt) in local voltage level as opposed to its absolute level makes it well suited for working in conjunction with other functions.

As illustrated in the left pane of Figure 25, this function allows the setting of a "Dynamic Watt Gradient" which determines how aggressively additional Watts are produced relative to the amplitude of voltage deviation. This is a signed, unit-less quantity, expressed as a %/%, or more specifically, as Watts (%WMax) / Volts (%VRef). The example shows a negative slope. A value of -1.0 would absorb one additional %WMax (or produce 1% less) for each 1% VRef increase in Delta Voltage (Present Voltage – Moving Average). Negative settings would be a natural fit for compensating for variable voltages caused by intermittent generation.

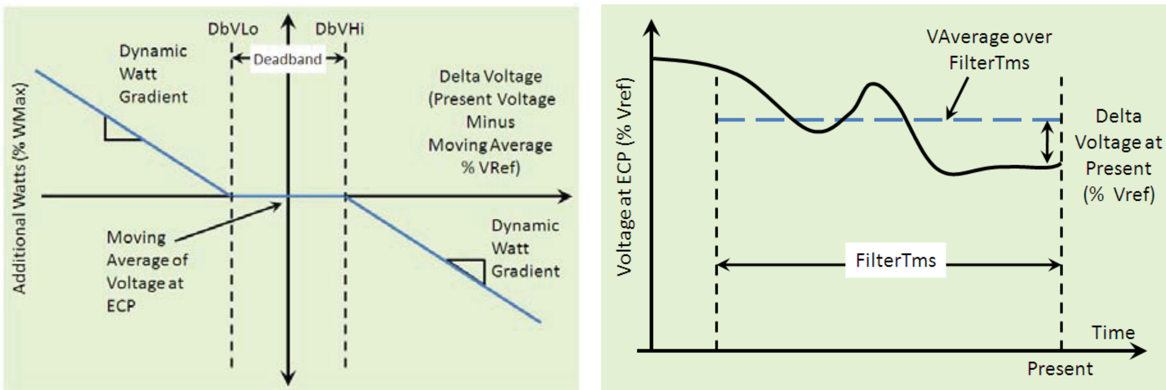

Figure 25: Dynamic Volt-Watt Function Behavior

As illustrated in the right frame, The Delta Voltage is to be computed as Present Voltage – Moving Average, and expressed as a percent of VRef, where the Moving Average is calculated as a sliding linear average over the previous "**FilterTms**" period. **FilterTms** is configurable.

13.3.3.1 Limitations of the Function

As with all functions, DER will operate within self-imposed limits and will protect their own components. These limits are acknowledged to vary, depending on many factors (e.g. state of maintenance, damage, temperature). In addition, it is acknowledged that the dynamic Volt-Watt function is limited by present device limit settings, such as WMax, and physical limitations such as a PV-only system that has no additional Watts to offer.

13.3.3.2 Settings to Manage this Function

The following settings are defined to manage this function:

Table 14: Dynamic Volt-Watt Function Settings

Setting Name	Description
Enable/Disable the Dynamic Volt-Watt Function	This parameter indicates whether the function is active or inactive.
Dynamic Watt Gradient	This is a signed unit-less quantity that establishes the ratio of dynamic Watts (expressed in terms of % WMax) to the present delta-voltage of the reference ECP (expressed as % VRef).
FilterTms	This is a configurable setting that establishes the linear averaging time of the ECP voltage (in Seconds).

Setting Name	Description
DbVLo and DbVHi	These are optional settings, expressed in %VRef, that allow the creation of a dead-band inside which the dynamic volt-watt function does not produce any additional Watts. For example, setting DbVLo = 10 and DbVHi = 10 results in a dead-band that is 20% of VRef wide.
Time-Out Window	This is a time after which the setting expires. A value of zero means to never expire. After expiration, the Dynamic Volt-Watt settings would no longer be in effect.
	Note that this function does not have a “Time Window” or “Ramp Time” parameter because the nature of the function starts out with no action upon activation.

13.4 Watt-Power-factor Function

13.4.1 Scope of this Function

This function modifies PF based on watts.

13.4.2 Requirements/Use Cases

TBD.

13.4.3 Description of Function

As illustrated in Figure 26, this function will use the curve method used in other functions. The curve will be defined by writing an array of X,Y point pairs which create a piece-wise linear “curve”. The X-values of the array (the controlling parameter) will be the present real power output, expressed as a percentage of maximum nameplate real power output (Wmax). The Y- values of the array (controlled parameter) will be the power factor, expressed as a signed value greater than 0 and up to 1.

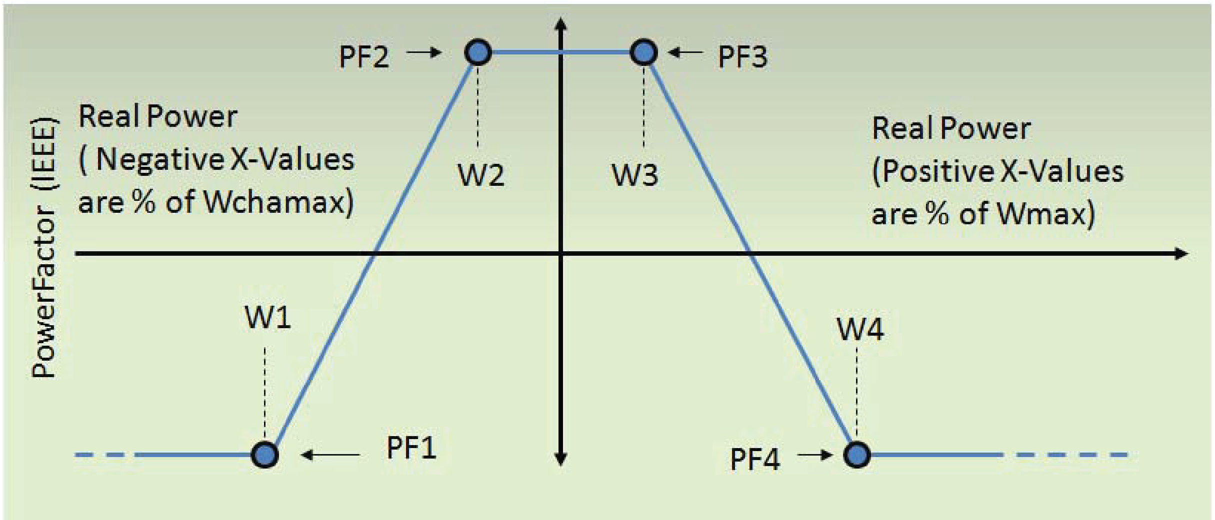

Figure 26: Example Watt – Power Factor Configuration

As illustrated, the X-values for this configuration may be signed, with negative percentage values relating to Watts received from the grid, and being percentages of the maximum charging rate, **WChaMax** and positive percentage values relating to Watts delivered to the grid, and being percentages of the maximum real power output Wmax. For devices that only produce power (to the grid), configurations may be used that only include positive X-values.

Like other functions, this function will include settings for:

- **Time_window**: a time window over which a random delay will be applied prior to activating this function after the command is received or scheduled to take effect.
- **Ramp_time**: a time over which this function gradually takes effect, once the time-window is past
- **Time_out**: a time after which this function expires.

This function is mutually exclusive with the Volt-Var and other static Var curves.

13.5 Real Power Following Mode

13.5.1 Scope of this Function

This function involves the variable dispatch of energy in order to maintain the DER's real power to track the real power level of the Referenced Point. In the case of load following, the output of the DER power output rises as the consumption of the reference load rises. In the case of generation following, the power output counteracts the output of the reference generation to maintain a total steady value. The DER may apply a percentage of the Referenced Point real power level to its real power output, thus compensating only a part of that real power.

13.5.2 Load Following

Load following uses the DER to generate in order to follow the power consumption of a reference load. Figure 27 illustrates the concept.

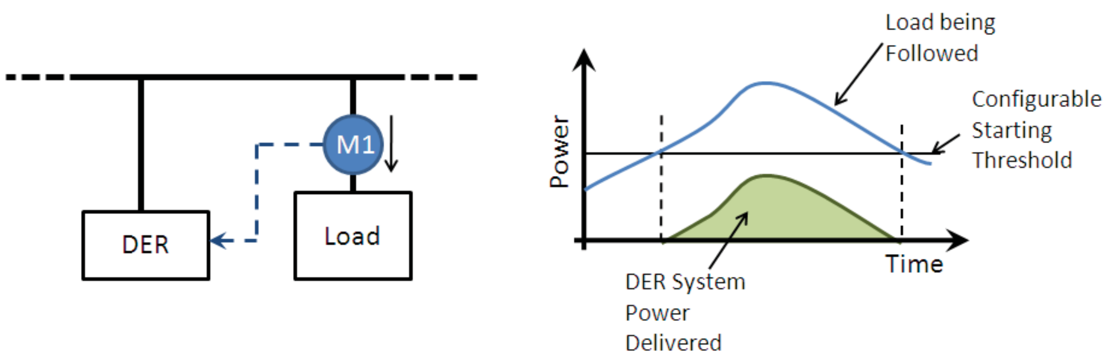

Figure 27: Example Load Following Arrangement and Waveform

As shown in the waveform to the right, this function allows for the use of a “Configurable Starting Threshold”. The DER then produces a power output that is proportional to the level of power consumed by the reference load that is above this threshold.

As indicated in the diagram to the left, this function requires that the DER has access to an indicator of the power level consumed by the reference load. The polarity of this data/signal is such that a positive value indicates power absorbed by the load.

13.5.3 Generation Following

Generation following is handled by the same mechanism, with the direction of power flows reversed. Generation following uses the DER to absorb power in order to follow the output of a reference generation device. Figure 28 illustrates the concept.

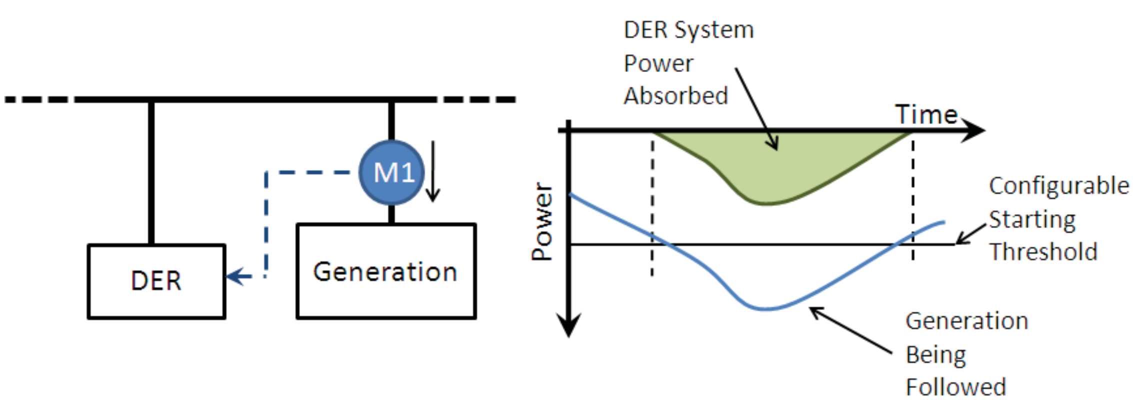

Figure 28: Example Generation Following Arrangement and Waveform

As shown in the waveform to the right, this function uses the same "Configurable Starting Threshold", but it is now set as a negative quantity to be consistent with the polarity of the signals. The DER then absorbs power at a level that is equal to the level of power output from the reference generator that is below this threshold.

As indicated in the diagram to the left, this function requires that the DER has access to an indicator of the power level produced by the reference generator. The polarity of this data/signal is such that a negative value indicates power produced by the generator.

13.5.4 Allowing for Proportional Load/Generation Following

The illustrations in Figure 27 and Figure 28 show the DER following 100% of the load/generation once its magnitude exceeds the configurable threshold. This function, however, allows the "following" to be set to any proportional level by way of a percentage setting. This allows for the possibility that several DER are used collectively to follow a given load.

13.5.5 Settings to Manage this Function

The following settings are defined to manage this function:

Table 15: Peak Power Limiting Function Settings

Setting Name	Description
Enable/Disable Real Power Following Mode	Enable Real Power Following mode
Referenced Point	Set the Real Power Following Mode Referenced Point
Referenced Point Real Power Level	This is the power measurement in Watts which the DER is using as the reference for load/generation following. From the perspective of this function, this quantity is read-only. As discussed previously, it is the responsibility of the DER manufacturer and user to configure and establish how the DER acquires this measurement.
Real Power percentage	Set the Real Power Following percentage as percent of the external real power level
Real Power threshold	Set threshold for starting Real Power Following
Real Power Following percentage	This is a configurable setting that controls the ratio by which the DER follows the load once the magnitude of the load exceeds the threshold. This setting is a unit-less percentage value. As an example, consider a DER that is following load, with a present load level of 200KW, a threshold setting of 80kW and a following ratio setting of 25%. The amount of the load above the threshold is 120kW, and 25% of this is 30kW. So the output power of the DER would be 30kW.
Ramp Time	This is a fixed time in seconds, over which the inverter settings (Watts in this case) are to transition from their pre-setting level to their post-setting level. The purpose of this parameter is to prevent sudden changes in output as a result of the receipt of a new command. Note: this setting does not impact the rate of change of Watt output during run-time as a result of power changes at the reference point.

Setting Name	Description
Time-Out Window	This is a time after which the setting expires. A value of zero means to never expire. After expiration, the Peak-Power Limit settings would no longer be in effect.

13.6 Price or Temperature Driven Functions

13.6.1 Scope of this Function

These functions are intended to provide a flexible mechanism through which price or temperature may act as the controlling variable for a curve-based control function, such volt-var or frequency-watt.

13.6.2 Requirements/Use Cases

None captured.

13.6.3 Description of Function

This function is proposed to work by using a configurable array, just as with the volt-var or other array-based functions. As with the other curve-based functions, the settings would allow for a variable number of points and for hysteresis if desired.

An enumerated setting will be used to identify the X-variable (controlling parameter) of the array, whether price or temperature. The specific format and scaling of the X-variable will be implicit in the enumeration.

Likewise, the Y-variable (controlled variable) of the array will be identified by a separate enumeration, with format and scaling implicit in the enumeration. For example, the Y-values could be percentages of some maximum value, or an absolute value. If the output (Y-value) chosen is a percentage, it may require a reference value to be initialized before the curve should be enabled.

13.7 Peak Power Limiting Function

13.7.1 Scope of this Function

This proposal is for a Peak Power Limiting Function in which DER systems, particularly ESS, may be configured to provide a peak-power limiting function. This function involves the variable dispatch of energy in order to prevent the power level at some point of reference from exceeding a given threshold.

13.7.2 Requirements/Use Cases

Several energy storage system use cases have identified the requirement for this capability. For example:

- Large-scale energy storage units are strategically placed on distribution systems and designed to limit the power load on particular distribution system assets such as transformers. Such placement could be used to extend the useful life of products, or to defer investments in equipment upgrades.

- Small pad-mount energy storage systems could limit overloads on distribution transformers caused either by excess generation or load.

13.7.3 Description of Function

This proposal describes a method by which distributed energy resources (DER) may perform peak load limiting, as illustrated in Figure 29.

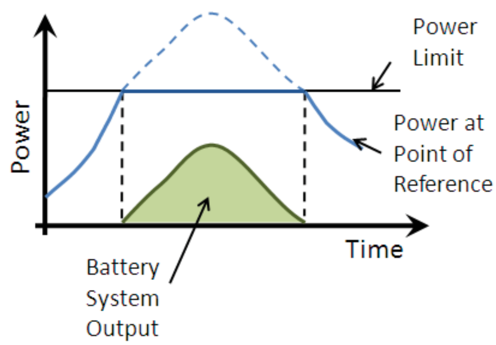

Figure 29: Example Peak Power Limiting Waveform

In this illustration, the solid blue line represents the power measurement at the selected point of reference for the function. As discussed below, this point could be physically located anywhere. Without support from the peak-power limiting function, this hypothetical power measurement would have followed the blue dashed line.

The horizontal black line represents a peak-power limit setting established at the DER by the utility or other asset owner.

The green shaded area represents the power output of the DER. This output follows the part of the blue curve that would have been above the desired power limit. The result is that the power level at the point of reference is limited to (or near to) the power limit setting.

13.7.3.1 *Limitations of the Function*

As with all functions, DER will operate within self-imposed limits and will protect their own components. These limits are acknowledged to vary, depending on many factors (e.g. state of maintenance, damage, temperature). In addition, it is acknowledged that the peak-limiting function is limited by present device limit settings, such as WMax.

There are also practical limits to a DER system's ability to provide peak-power limiting. Two common examples are the limitation of the power level that the DER can produce and the limitation on the total energy stored. As illustrated in Figure 30, these could result in failure to hold the power level at the reference point to the desired limit for the desired duration.

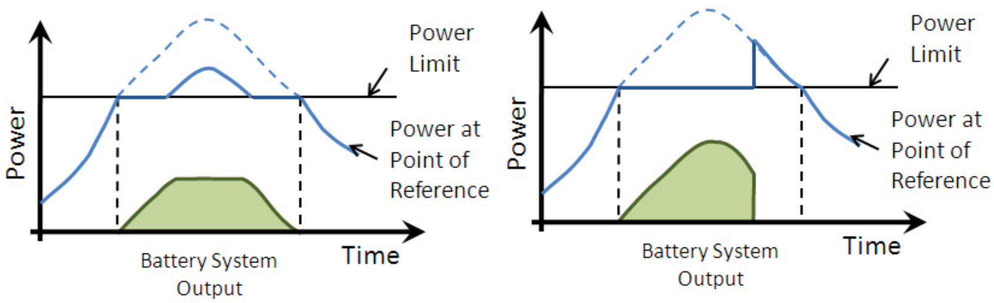

Figure 30: Examples of Practical Limitations – Watt Limit (left) and Battery Capacity Limit (right)

13.7.3.2 *Point of Reference for Power Limiting*

Several possibilities might exist for how a DER unit might receive the measurement data indicative of the power flow at the point of reference for the peak power limiting function. Figure 31 illustrates two such possibilities.

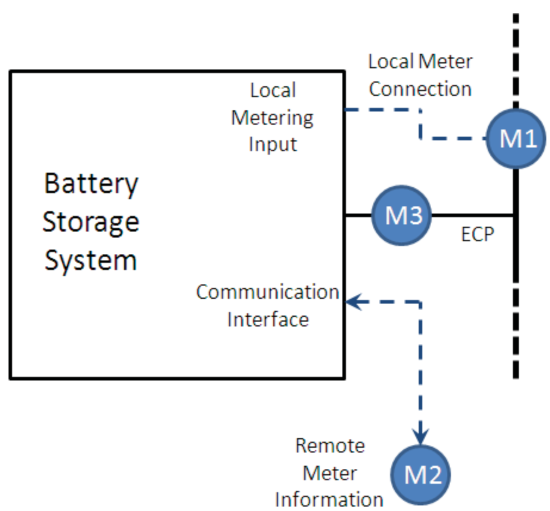

Figure 31: Example Points of Reference for Power Limiting

In this illustration, measurement M1 represents the option of an internal or local measurement that is connected to the DER unit via a local port or analog connection of some kind. M2 represents a remote measurement that could be a great distance from the DER, and providing readings via a communication interface (could be the same interface through which the DER is connected to the utility or another interface). Note that both M1 and M2 indicate the total power flow somewhere on the utility system, not the power flow of the DER itself. This function assumes that increases in the power output of the DER (M3) serve to decrease the power flow at the point of reference (M1 or M2).

It is outside the scope of this specification to dictate to the DER how the measurement data from the point of reference is to be acquired. The idea is that when a peak-power limiting function is supported and enabled, the manufacturer will have built into the product the knowledge of the proper source for the reference data and the user will have set-up and configured the product properly. Examples include:

- A product might include a local measurement that is used for peak limiting.
- A product might use a local communication port to interface with a nearby reference measurement for peak limiting.
- A product might use a local analog input to represent the reference measurement.
- A product might be designed to receive (pulled or pushed) reference measurement from a remote system via the standard communication interface.

13.7.3.3 *Settings to Manage this Function*

The following settings are defined to manage this function:

Table 16: Peak Power Limiting Function Settings

Setting Name	Description
Enable/Disable Peak Power Limit Mode	This is a Boolean that makes the peak power limiting mode active or inactive.
Peak Power Limit	This is the target power level limit, expressed in Watts.
Reference Point Power Level	This is the power measurement in Watts which the DER is using as the reference for peak power limiting. From the perspective of this function, this quantity is read-only. As discussed previously, it is the responsibility of the DER manufacturer and user to configure and establish how the DER acquires this measurement.
Time Window	This is a window of time over which the inverter randomly delays before beginning execution of the command. For example, an inverter given a new Peak Power Limit configuration and a Time-Window of 60 seconds would wait a random time between 0 and 60 seconds before beginning to put the new settings into affect. The purpose of this parameter is to avoid large numbers of devices from simultaneously changing state if addressed in groups.
Ramp Time	This is a fixed time in seconds, over which the inverter settings (Watts in this case) are to transition from their pre-setting level to their post-setting level. The purpose of this parameter is to prevent sudden changes in output as a result of the receipt of a new command. Note: this setting does not impact the rate of change of Watt output during run-time as a result of power changes at the reference point.
Time-Out Window	This is a time after which the setting expires. A value of zero means to never expire. After expiration, the Peak-Power Limit settings would no longer be in effect.

13.8 Price-Based Real Power Function

13.8.1 Scope of this Function

This function provides a mechanism through which ESSs may be informed of the price of energy so that they may manage charging and discharging accordingly. The ESS responds to this pricing signal according to preferences that set by the ESS owner/operator.

13.8.2 Requirements/Use Cases

In addition to direct settings for charging and discharging storage, utilities and storage system providers indicated a requirement for a mode in which the ESS manages its own charging and discharging. The idea for this function is that the storage system is provided with a signal indicative of the price (or value) of energy. The storage system then manages its own decisions about when to charge and discharge, and at what levels.

This kind of autonomous approach allows that the storage system might be taking into account a range of owner preferences and settings, such as considerations of battery life expectancy, anticipation of bad weather /outage, and predictions regarding real-time energy price swings. It enables battery system providers to develop innovative learning algorithms and predictive algorithms to optimize asset value for the owner rather than leaving these algorithms to another entity that may not understand the battery system's capabilities and limitations as well.

13.8.3 Description of Function

13.8.3.1 General ESS Settings

The price-based charge/discharge function will utilize the same general ESS settings identified in the direct charge/discharge function (i.e. only one set of these settings will exist in the unit). This includes Maximum Intermittency Ramp Rate, Minimum Reserve for Storage, Maximum Storage Charge Rate, and Maximum Storage Discharge Rate.

13.8.3.2 Price-Based Charge Discharge Mode

This function provides the ESS with energy price information. It is acknowledged that in some scenarios this price information could actually be an arbitrary "relative price indicator" or "energy value indicator", according to the arrangement between the entity generating the signal and the storage system owner.

This function be supported by the following information:

- **Activate Price-Based Charge/Discharge Management Mode:** a Boolean that activates the price-based charge/discharge mode (e.g. the storage system is managing based on the price signal, possibly incorporating its history, and forward-looking schedules, if provided. 1 = Price- Based C/D Mode is Active, 0 = Not active.

- **Set Price:** a setting of the price (or abstract energy value). The scaling of this value will be determined by the particular communication protocol mapping.

- **Present Price:** a query to read the present price setting.

- **Randomization Time Window:** a time in seconds, over which the DER randomly delays prior to beginning to put a new price setting into effect. The purpose of this setting is to allow multiple systems to be managed using a single broadcast or multicast message, while avoiding simultaneous responses from each device.

- **Reversion Timeout:** a time in seconds, after which a new price signal is no longer valid. A DER will return to its default behavior (typically an idle state). Reversion Timeout = 0 means that there is no timeout.

- **Ramp Time:** a time in seconds, over which the DER linearly varies its charge or discharge levels in response to a price change. The purpose of this setting is to avoid sudden or abrupt changes in energy input/output at step changes in price.

13.8.3.3 Price Schedules

In addition to an immediate price setting (i.e. the price now), a schedule can be used to provide ESSs with a forward-looking view of price. The use of schedules would allow the "Price" parameter defined in the setting above to be scheduled relative to time. Schedules will allow for daily, weekly, or seasonal recurrence (looping).

For some products, price-based management might not be possible without a forward-looking schedule. These might support a fixed rate structure such as Time-Of-Use, but not Real Time Pricing. Other products could include adaptive/learning algorithms that monitor the history of the price information they have received and manage based on that history.

This function will utilize the existing scheduling mechanisms that exist in most communication protocols, so no attempt will be made here to establish a new scheduling mechanism. At transition points in price schedules, the "Ramp Time" and "Randomization Time Window" settings apply, in order to prevent abrupt transitions.

13.9 Coordinated Charge/Discharge Management Function

13.9.1 Scope of this Function

This function identifies a set of quantities that can be used to enable the management of ESS to be coordinated with the local needs of the storage users in terms of target charge level and schedule. This function enables the separately-described direct charge/discharge function to be handled more intelligently, ensuring that the storage system achieves a target state of charge by a specified time.

The primary use of this function is to manage the charging of Electric Vehicles (EVs) by determining the most cost-effective charging rates and charging time-of-day while ensuring the EV is charged to the user's required state of charge by the time the user needs the EV. However any ESS that is expected to meet local user requirements while still actively participating in grid activities can utilize this function. For instance, this function could also be useful with a Community Energy Storage (CES) unit that may need to be fully charged by the time that a severe storm is forecast to arrive in the service area.

13.9.2 Requirements/Use Cases

The separately defined “direct charge/discharge” function only allows a controlling entity to directly manage the power flow of a storage system as bounded by being fully charged or discharged to a minimum reserve level. In such a case, it is assumed by the controlling entity that it is acceptable to terminate a session with the storage system depleted to its minimum reserve level and that any recharging will be a self-directed activity conducted by the storage system after it is released.

This could be a problem if the storage system must achieve a target state of charge by a specified time and there is not enough time to complete unrestricted charging from the minimum reserve level beginning at the time of release by the controlling entity. The storage system could either be left with insufficient charge to perform needed tasks or it might abruptly disengage early from the controlling entity and revert to charging to meet its own requirements. This coordinated charge/discharge management is intended to help avoid such circumstances.

13.9.3 Description of Function

13.9.3.1 Parameters from the Direct Charge/Discharge Function

This coordinated charge/discharge function builds on the direct charge/discharge function. The command structure is unchanged from that of the direct charge/discharge function. The following parameters described in the Charge/Discharge function are also used in relation to this function:

- Minimum Reserve for Storage
- Set Maximum Storage Charge Rate (WChaMax)
- Set Maximum Storage Discharge Rate (WMax)
- Randomization Time Window
- Reversion Timeout
- Ramp Time
- Read Charge/Discharge Rate
- Set Charge/Discharge Rate
- Activate Direct Charge/Discharge Management Mode

13.9.3.2 *Time-based Charging Model*

The charging model for this function is based on the ESS being authorized by the controlling entity to engage in unrestricted charging at up to 100% of its maximum charging rate (WMaxStoCh). The model is shown in Figure 32 and parameters are defined below. Not all of the parameters are shown in the figure. The figure shows a representative charging profile of power versus time. The area under the curve, shown in green, is the total energy remaining to be transferred to the system from the grid at a specific time of reference. It is not just the energy stored in the system and it includes losses.

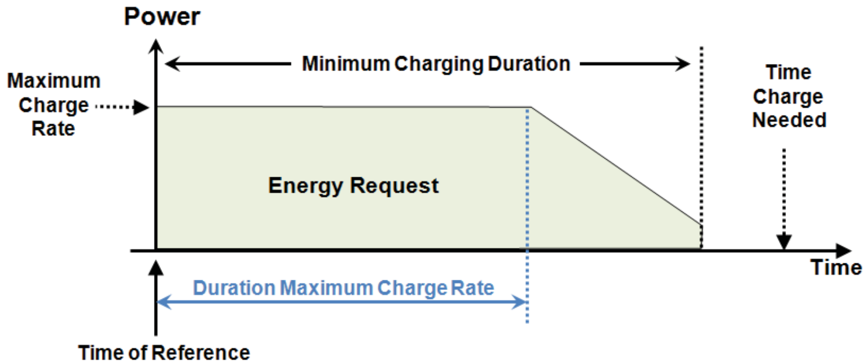

Figure 32: Storage System Model: Time-Base

13.9.4 Duration at Maximum Charging and Discharging Rates

To support this function, the reference charging and discharging power limit curves for a storage system are set forth, as illustrated in Figure 33. The discharging power limit is shown in blue on top and the charging power limit is shown in red on the bottom. The defined maximums represent levels that can be sustained across a broad range of SOC. The example profile shown identifies a certain SOC below which the DER can no longer sustain discharging at the Maximum Discharge Rate, and the discharge rate slows. Likewise, it identifies a certain SOC, above which the DER can no longer sustain charging at the Maximum Charge Rate. Such limitations are possible in practice, and while not passed across the communication interface, would be known to the storage system and reflected in the duration parameters that it reports.

These parameters are typically known to the DER by design, but may not be known by other entities that manage the DER. The shaded blue area represents the present energy in the storage system that is available for production at the Maximum Discharge Rate. Likewise, the shaded red area represents the capacity of the DER to store additional energy at the Maximum Charge Rate. As illustrated, this reference profile recognizes that more energy might be available for either charge or discharge, but not at the maximum charge/discharge rates.

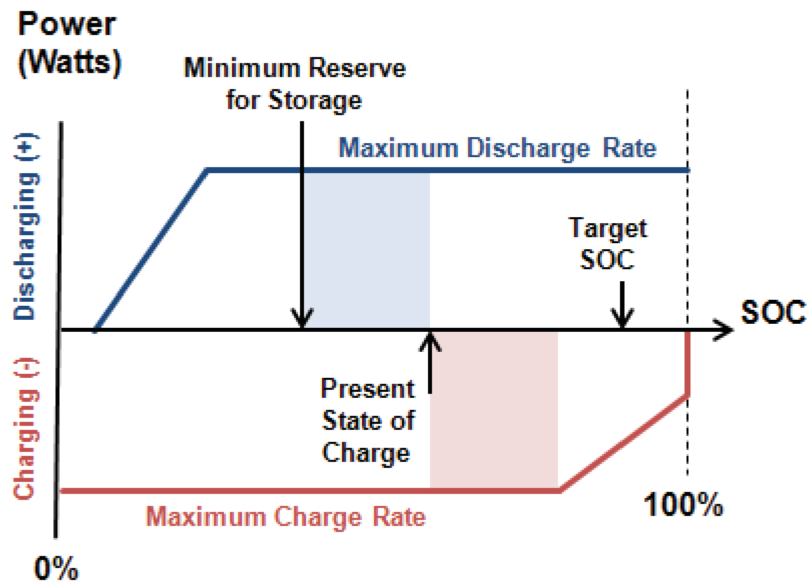

Figure 33: Storage System Model: SOC-Base

This function results in the following parameters in an ESS. In the event that coordinated charge/discharge management is needed (e.g. there is a local need for a certain target charge at a certain time) these parameters are relevant.

Table 17: Parameters for Coordinated Battery Management

Name	Description
Target State of Charge (read or write)	This parameter represents the target state of charge that the system is expected to achieve, as a percentage of the usable capacity. This quantity may be: Read-from the ESS, as in cases where the target state of charge is determined locally, such as when an electric vehicle is set locally to require a certain charge by a certain time. Written-to the ESS, as in cases where the target state of charge is determined by a remote managing entity, such as when a utility is informing community energy storage systems to be
Time Charge Needed (read or write)	This parameter represents the time by which the storage system must reach the target SOC. This quantity may be read-from, or written-to the ESS as described in the examples given in the "Target State of Charge" parameter description. Setting the value to that of a distant date would prevent any conflict which could cause the ESS to disengage and revert to charging at the Maximum Charge Rate.
Energy Request (read only)	This parameter represents the amount of energy (Watt-hours) that must be transferred from the grid to the charger to move the SOC from the value at the specific time of reference to the target SOC. This quantity is calculated by the ESS and must be updated as the SOC changes during charging or discharging. As possible, the calculation shall account for changes in usable capacity based on temperature, cell equalization, age, and other factors, charger efficiency, and parasitic loads (such as cooling systems).

Name	Description
Minimum Charging Duration (read only)	This parameter represents the minimum duration (seconds) to move from the SOC at the time of reference to the target SOC. This assumes that the ESS is able to charge at 100% of the Maximum Charge Rate (WMaxStoCh). This parameter is calculated by the ESS and must be updated as the SOC changes during charging or discharging. The calculation shall take into account all charging profile characteristics, such as a decrease in charging rate as 100% SOC
Time of Reference (read only)	This parameter identifies the time that the SOC is measured or computed by the storage system and is the basis for the Energy Request, Minimum Charging Duration, and other parameters. This parameter may be useful to a controlling entity to correct for any delays between measurement of SOC by the storage system and use of the calculated parameters by the controlling entity to aid in managing the charging and discharging of the ESS.
Duration at Maximum Charge Rate (read only)	This parameter identifies the duration that energy can be stored at the Maximum Charge Rate. This duration is calculated by the storage system based on the available capacity to absorb energy to the SOC above which the maximum charging rate can no longer be sustained. This calculation shall account for losses. In the event that “Time Charge Needed” is reached before reaching the SOC limit for Maximum Charge Rate, then this duration parameter is determined by the “Time Charge Needed”. In effect, the energy that can be stored from the grid is the product of the Duration
Duration Maximum Discharge Rate (read only)	This parameter identifies the duration that energy can be delivered at the Maximum Discharge Rate. This duration is calculated by the storage system based on the available capacity to discharge to the “Minimum Reserve for Storage” or the SOC below which the maximum discharging rate can no longer be sustained (whichever is greater). This calculation shall account for losses. In effect, the energy that can be delivered to the grid is the product of the Duration at Maximum Discharge Rate and the Maximum Discharge Rate. This discharge duration may be further limited by a target-charge requirement, if there is not sufficient time to discharge for this duration and then successfully recharge to the target SOC by Time Charge Needed. The storage system uses Energy Request, Minimum Charging Duration, and Time Charge

The Duration at Maximum Charge Rate and the Duration at Maximum Discharge Rate are key parameters that the controlling entity can use to plan storage DER management. The charging model constraints are embedded in the calculation of these two parameters. At any time of reference these parameters can be recalculated and read by a controlling entity. In this way, the controlling entity may know from the Duration at Maximum Discharge Rate how much energy is available to the grid from the storage system at the Maximum Discharge Rate.

The slack time in this example charging solution is provided by the difference between the Time Charge Needed less the Minimum Charging Duration and the Time of Reference. The slack time can be used as an additional way of planning use of the storage system.

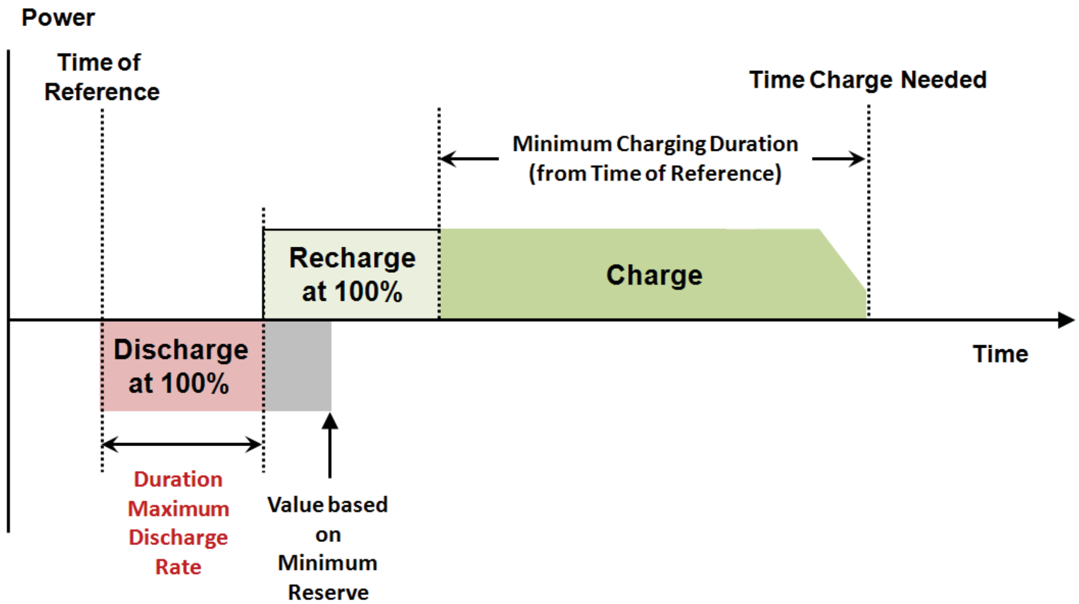

Figure 34: Example of Using the Duration at Maximum Discharge Rate

The **Target State of Charge** and **Time Charge Needed** parameters could result in a DER overriding other settings or modes affecting charging and discharging. This is true regardless of whether these parameters are set remotely or determined locally. This depends on the design and purpose of the DER, as to how it prioritizes achieving the target SOC at the specified time over following a power set-point. This DER default behavior may be selectable as part of an enrollment process for a specific application.

For example, an electric vehicle may prioritize its need to achieve a target SOC by its scheduled departure time. If a utility requests a fixed Charge Rate that would result in the vehicle being fully charged at 11:00 but the owner of the vehicle locally requested a full charge by 8:00, the electric vehicle would revert to charging at its maximum rate at the latest time needed to achieve that objective. The utility would know this could happen when remaining duration until the Time Charge Needed approaches the Minimum Charging Duration – so there would be no surprise.

This could also occur if the storage asset is completely managed remotely by the utility; for instance if the utility programmed a schedule in the inverter to discharge at a fixed rate for four hours, but during the second hour an operator changed the Target State of Charge such that it would require a reversion to charging at max charging rate after one more hour of discharging, the inverter would switch to charging at maximum rate in one hour.

As shown in these examples, a reversion by a storage DER to charging at maximum rate could occur if there becomes a conflict between continuing operation at the current power setpoint and the ability to achieve the Target SOC in the time remaining until the Time Charge Needed.

However, the reversion behavior can be defeated by setting the Time Charge Needed to a distant time (e.g. one year out, exact method to be defined by the protocol mapping), or whatever which eliminates any conflict.

1507