OPEN MEETING AGENDA ITEM

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BEFORE THE ARIZONA CORPORATION COMMISSION

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ORIGINAL

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2015 RENEWABLE ENERGY STANDARD IMPLEMENTAITION PLAN.	**DOCKET NO. E-01933A-14-0248** **SUPPLEMENTAL COMMENTS OF TASC**

Supplemental Comments of The Alliance For Solar Choice Regarding The Ability of Third Parties to Offer Operational Grid Benefits At Lower Costs To Customers Than Utility Owned DG Proposals

Introduction And Summary

In The Alliance for Solar Choice's ("TASC") initial comments regarding Tucson Electric Power's ("TEP") and Arizona Public Service Company's ("APS") utility owned distributed generation proposals, TASC argued, among many other things, that certain operational benefits are not unique to utility ownership of distributed generation ("DG"). TASC files these Supplemental Comments to highlight the full magnitude and implications of pursuing the type of vertically integrated approach to grid modernization that are implicit in both TEP's and APS's DG ownership proposals.[1] Such an approach could be unnecessarily costly for customers, while

[1] TASC is filing these Supplemental Comments in both Docket Nos. E-01933A-14-0248 and E-01345A-13-0140. The comments filed in each docket are substantively identical.

also stifling the innovation and creativity that an open architecture distribution platform enables. Rather, prior to approving utility ownership programs, TASC recommends that the Commission investigate, thoughtfully consider and pursue policies that unlock the operational benefits of distributed solar generation while limiting additional rate base investments.

Both TEP and APS argue that their utility owned DG proposals provide certain "unique" operational benefits. These benefits generally fall into three categories:

1) **Advanced Inverters** - TEP claims that because "TEP would own and operate the systems, it can employ a distribution management program to control the inverters, providing voltage and frequency control to benefit the grid and all customers."[2] APS makes similar claims about benefits of utility owned inverters.[3]

2) **Strategic Deployment** - Both Companies also assert that ownership allows DG systems to be strategically deployed to areas of the local grid where DG benefits can be maximized.[4]

3) **Contribution to Peak Demand** - APS plans to prioritize west and southwest facing rooftops in order to provide more capacity benefits to the system and possibly avoid costly plant additions.

However, these benefits are not unique to utility ownership. Below, TASC provides information regarding some of the most current technological and regulatory approaches to grid modernization and integration of DG, which are being implemented in areas of the country with some of the highest DG penetration levels. **These examples demonstrate that utility**

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[2] TEP Application, p. 9.

[3] APS Project Description at p. 3.

[4] APS Project Description at p. 3. APS states that ownership give it the "opportunity to continue to study the ability of the grid to meet the challenge of higher penetrations of solar within its service area as well as test the ability of solar rooftop systems to provide operating benefits to the APS distribution grid."

ownership is not necessary, and in fact may be significantly more expensive than other policy approaches. Policies that lead to an open architecture distribution system - rather than a vertically integrated proprietary design - will encourage competition and are likely to spur innovation at lower costs to customers.

1. Smart Inverters

a. Smart Inverters are Already Deployed in Arizona and the Commission has the Power to Unlock Their Benefits Without Utility Ownership and without Raising Rates

TASC surveyed some of its members and can represent that there are currently almost two hundred "smart" inverters deployed by TPOs in APS's and TEP's service territories with enhanced grid management capabilities. Unfortunately, due to the interconnection protocols of both utilities, these enhanced functionalities are currently disabled. If smart inverter operational standards were approved by APS and TEP, or set by the Commission, these functionalities could be enabled via over-the-air updates to the existing smart inverters.

Inverters are a component of every solar DG installation. The primary function of an inverter is to convert a solar panel's DC power into AC power that is compatible with the grid and all of our modern appliances. However today's inverters are capable of doing much more, including:

1) The delivery of DC power into an AC system, such as photovoltaic power to the AC grid; and the delivery of AC power to a DC load, as in charging a battery from the grid.
2) The generation or absorption of reactive power so as to raise or lower the voltage at its terminals.
3) Delivery of power in four quadrants, that is, positive real power and positive reactive power; positive real power and negative reactive power; negative real power and

negative reactive power; and negative real power and positive reactive power.

4) The detection of voltage and frequency at its terminals and the ability to react autonomously to mitigate abnormal conditions: to provide reactive power if the voltage is low; to increase real power output if the frequency is low.

5) In combination with a communication link, to deliver real and reactive power and to charge and discharge storage facilities in accordance with signals from the utility. [5]

The California PUC recently noted: "If properly applied, smart inverters can improve the performance of the distribution grid and the network as a whole, or, conversely, if improperly applied, can present serious problems in terms of voltage control, the clearing of short circuits and the creation of dangerous 'islanding' conditions."[6] TASC supports this claim and agrees with APS and TEP that their utilization of advanced inverters can support grid modernization. But APS and TEP have not made an effort to properly manage and integrate already deployed smart inverters on their systems or investigate opportunities that may fulfill their research needs that already exist and could therefore be utilized at potentially little to no cost to customers. Yet the utilities' DG ownership proposals ask the Commission to approve their monopoly DG programs *based on the same capabilities* that the competitive solar market can provide.

Both TEP's and APS's current interconnection requirements specify that inverters must be set to trip PV systems offline during any abnormal grid conditions, such as a deviation from normal operating frequency or voltages.[7] This requirement means that currently deployed smart inverters in Arizona are not allowed to provide *any* of their enhanced grid stabilization functions during abnormal grid conditions.

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[5] Interim Decision Adopting Revisions to Electric Tariff Rule 21 For Pacific Gas And Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company to require "Smart" Inverters (Proposed Decision); California PUC Rulemaking No. 11-09-011, issued on November 13, 2014. (Herein after "Rule 21 Proposed Decision"). (Included as Attachment 1).

[6] Rule 21 Proposed Decision at p. 3.

[7] APS Interconnection Requirement for Distributed Generation, 8.7.1.12 (available at http://www.aps.com/library/solar%20renewables/InterconnectReq.pdf); TEP Electric Service Requirements for Small Interconnected Distributed Generation Sources, Section 4., Standards (*available at*, https://www.tep.com/doc/ESR/SR-122.pdf).

Furthermore, inverters on existing customer and third-party owned systems are fully capable of directly communicating with, and accepting instructions from, the utility. This utility coordination can be accomplished using existing internet connections and without a costly, utility-owned communication infrastructure that TEP and APS programs inherently require. The communication infrastructure that enables distribution management software to communicate with and coordinate inverters is already functioning and available in the private market and should be fully leveraged prior to additional ratepayer investment into dedicated utility communications infrastructure.

APS and TEP appear to be only willing to allow smart inverters to perform their full functionality when they can own, rate base, and vertically integrate them into their monopoly structure. The Commission should consider lower cost, more flexible and readily available alternatives before committing substantial ratepayer funds to utility ownership of DG. The Commission should instruct the utilities to work with solar developers and other owners of advanced inverters to figure out the appropriate compensation for owners of advanced inverters to perform these advanced functions and then compare those costs to that of utility ownership.

b. Regulators in Areas with the Highest Solar DG Penetrations are Taking an Open Architecture Approach To Enable Advanced Inverter Features

As explained above, both TEP and APS currently require inverters to trip offline when grid conditions deviate from normal (within a very narrow band). This is true for most utilities in the United States because most utilities craft their interconnection requirements based on the Institute for Electrical and Electronic Engineer's ("IEEE") Standard 1547, which was last issued in 2003. However, almost all of the advanced features of modern inverters have come to market since that time. Therefore IEEE's standard is out of synch with today's technology. Industry, in collaboration with IEEE, is currently working to define new smart inverter standards to bring about grid modernization.

Meanwhile, in California and Hawaii, high and rising penetrations of solar DG are forcing regulators to update interconnection policies to unlock the capabilities of smart inverters to better integrate DG and to provide cost effective support for distribution system operations through customer and third-party owned advanced inverters. These interconnection policies are directly feeding the IEEE standards work, and will eventually be integrated into the revamped standard. Furthermore, these standards are intended to facilitate the interaction between utilities and third-party owned DG and inverters.

Other regulators are increasingly investigating and supporting open architecture distribution platforms over traditional vertically integrated utility infrastructure investments when addressing rapidly raising rates of solar DG penetration. Because Arizona is similarly faced with DG growth, it is important to examine all reasonable policy options before authorizing additional utility investment.

i. The California PUC's Rule 21 Modifications

On November 13, 2014 the California Public Utilities Commission issued a Proposed Decision in its rulemaking docket to modify interconnection standards for Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas and Electric, the states three largest investor owned utilities. The proposed decision largely approves modifications developed through collaboration between utilities, the solar industry, and other stakeholders through a Smart Inverter Working Group.[8] The Commission's stated purpose of the new standards is "to capture the technological advances offered by smart inverters"[9] The Proposed Decision also explains that the purpose of advanced inverter functionality is "to allow grid operators to obtain grid support services for dispersed locations at *lower cost* than currently available."[10]

The modifications to Rule 21 will require that new inverters installed in California with third party or customer owned DG systems will comply with updated standards, which will

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[8] Rule 21 Proposed Decision at p. 4.
[9] Rule 21 Proposed Decision at p. 1.
[10] Rule 21 Proposed Decision at p. 8.

eventually be included in the updated IEEE Standard 1547.[11] Rule 21 will set forth the protective functions and equipment requirements for inverters that connect to the utilities' distribution networks.[12] These new inverter standards will "allow interconnected generating facilities to offer system support functions to distribution or transmission system operators."[13]

For example, the Proposed Decision explains that voltage on the distribution line is now controlled by shunt capacitors, voltage regulators on the line, and voltage regulators on the distribution transformer at the substation controlled by a line drop compensation algorithm.[14] Smart inverters have the potential to substitute for all of these measures with greater accuracy and lower-cost.[15] The Proposed Decision also highlights the need for establishing the appropriate level of compensation that should be paid to inverter owners for performing these functions.[16] In the next stage of the Proceeding, the Commission will focus on revising Rule 21 to include communications protocols between customer and third party owned inverters and distribution and transmission operators.[17]

California's approach does not require utility ownership of DG, nor does it require any capital investments that will go into the utility rate base. Furthermore, as Rule 21 is implemented, most major inverter manufacturers will incorporate advanced inverter capabilities into all of their products, which will drive increased availability and cost reduction of such inverters in Arizona. California is taking a common-sense approach to integration of smart inverters by utilizing existing and planned PV system installations owned by customers and third party developers.

ii. Hawaiian Electric Company ("HECO") is Working With Stakeholders to Unlock the Benefits of Customer and Third-Party Owned Inverters

[11] Rule 21 Proposed Decision at p. 2.
[12] Rule 21 Proposed Decision at p. 2.
[13] Rule 21 Proposed Decision at p. 7.
[14] Rule 21 Proposed Decision at p. 13-14.
[15] Rule 21 Proposed Decision at p. 14.
[16] Rule 21 Proposed Decision at p. 14.
[17] In California the independent operator (CAISO) manages the transmission system and the utilities manage the distribution system.

SolarCity, one of TASC's member companies, recently co-announced that it has entered into a cooperative research agreement with the Energy Department's National Renewable Energy Laboratory (NREL) to address operational issues associated with high degrees of distributed solar penetration on electrical grids.[18] The work includes collaboration with the Hawaiian Electric Companies to analyze high penetration solar scenarios using advanced modeling and inverter testing at NREL's Energy Systems Integration Facility.

The companies and NREL are collaboratively testing the dynamic of inverter-based assets on distribution circuits, advanced voltage regulation approaches including smart inverters, and the impact of bi-directional power flows on distribution circuits. Hawaiian Electric is providing technical input on testing and setup throughout the process as well as feedback on results. The initial test results have already had a major impact on HECO's backlogged interconnection queue. Applying the preliminary results of NREL and SolarCity's research with Hawaiian Electric, the utility expects that they will approve almost all customers who have been awaiting interconnection over the next five months.[19]

Instead of insisting that utility ownership is necessary to integrate more DG on its system, HECO has taken a more collaborative and less capital-intensive approach. Colton Ching, Hawaiian Electric vice president for energy delivery, says "We know how important the option of solar is for our customers. Solving these issues requires that everyone - utilities, the solar industry and other leading technical experts like NREL - work together. That's what this work is all about."[20] TASC would welcome similar collaboration with TEP and APS to unlock advanced inverter capabilities.

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[18] SolarCity Press Release. (Included as Attachment 2); *See also, Gavin Bade, How the HECO-SolarCity Partnership is Turning Rooftop Solar Into a Grid Asset*, available at http://www.utilitydive.com/news/how-the-heco-solarcity-partnership-is-turning-rooftop-solar-into-a-grid-ass/338838/ (Included as Attachment 3).
[19] SolarCity Press Release.
[20] SolarCity Press Release.

c. The Commission Should Adopt a Statewide Standard to Enable Enhanced Inverter Capabilities

APS is currently ranked the #3 state in the country for total megawatts of solar and #4 in watts per customer.[21] The ACC should therefore work with stakeholders to conduct investigations and policies that establish uniform statewide interconnection standards for solar DG, including inverter standards that enable enhanced functionality. Arizona is currently one of the few states that lack statewide interconnection standards. While APS and TEP each offer guidance to developers, they rely on the outdated IEEE 1547 standard to govern interconnection. To move Arizona towards policies that encourage open architecture grid design and third-party innovation, Arizona should follow the path of high penetration areas like California and Hawaii.

Rather than merely accepting the utilities' claims that they must own DG systems and advanced inverters to unlock their benefits, the ACC could convene an Arizona smart inverter-working group to come up with cost effective ways to integrate existing and future third-party owned smart inverters. This effort should be part of a larger effort to create uniform statewide operational and technical interconnection standards supporting the policy goals of the state.

2. Strategic Locational Deployment of DG is Being Achieved Through Collaboration Between Utilities and Solar Developers Across the Country

Both APS and TEP's utility-owned DG proposals seek to target areas of the grid where DG systems can provide the most grid benefits. However, utility ownership is not required to deliver grid benefits in these targeted areas. Rather, encouraging third-party deployment in targeted areas can deliver the desired results while leveraging the benefits of open competition and third-party innovation. In fact, in several areas of the country, utilities are offering specific

[21] See interactive map *available at*, http://www.solarelectricpower.org/discover-resources/solar-tools/utility-solar-rankings.aspx

incentives for targeted DG deployment and investigating how time of use rates can provide customer and TPO motive.

TASC members would welcome the opportunity to strategically deploy DG if APS and TEP were willing to share relevant data about optimal locations to maximize grid benefits. By knowing where to focus installations and responding to appropriate incentives to do so, APS and TEP can direct needed DG interconnections in these targeted areas. Such sharing of data is also consistent with the Residential Utility Consumer Office's ("RUCO") key policy principles to create a level playing field between utilities and third-party solar developers, which it outlined in its October 17th comments. RUCO's sixth principle states that there should be "[t]ransparent sharing of non-confidential information between the utility and third party developers." TASC welcomes the opportunity to direct installation efforts towards areas targeted for increased grid benefits.

a. The California PUC is following the lead of Southern California Edison ("SCE") in Strategic Deployment of DG

In California, SCE is administering an RFO to support its Preferred Resource Pilot, which calls for the procurement of DG-eligible renewable resources to be interconnected in <u>targeted locations</u> within central Orange County. To assist bidders in siting and interconnection location, SCE has made available an interactive "PRP Interconnection Map" on the RFO website that includes the locations of SCE distribution circuits, substations, system voltages, available capacity, and current and queued DG interconnection amounts in the relevant area.[22] This data sharing facilitates third parties that intend to provide DG installations and services in the SCE-targeted areas.

The California Public Utilities Commission is further expanding on this targeted DG deployment concept. On November 17, 2014, the California PUC issued the Assigned

[22] Southern California Edison Request for Offers for Renewable Energy from Distributed Generation Resources for the Preferred Resources Pilot ("PRP RFO") at p. 3. Available at https://sceprprfo.accionpower.com/_scedgpr_1401/documents.asp?strFolder=a.%20RFO%20Documents/ii.%20RFO%20Instructions/&filedown=&HideFiles=True

Commissioner's Ruling regarding development of rules for development of distribution resources plans ("DRP"), which will outline utility efforts to integrate and leverage distributed energy resource ("DER") installations.[23] All of California's IOUs are now required under Public Utilities Code, section 769, to file DRPs by July 1, 2015. The Commission is also authorized to modify and approve a utility's DRP "as appropriate to minimize overall system costs and maximize rate-payer benefit from investments in distributed resources."

The Assigned Commissioner's Ruling lays forth a new framework for distribution planning and specifically discusses Section 769's requirement that the Commission, utilities, consumers, and new service providers, must work cooperatively to ***revise existing incentives and tariffs to promote DG in locations that will provide the greatest net benefits to the grid.***[24] Specifically, the Ruling would require IOUs to develop an analysis of how much DG interconnection capacity is available on its grid, down to the circuit level, and then share those results via publically available online maps.[25] Furthermore, the utilities would have to specify the net benefits in a given location that DG resources could provide.[26] The process described builds upon collaborative processes while directing utilities to share technical data on their distribution system and planning efforts in order to facilitate increased penetration of DERs.[27]

b. Consolidated Edison RFI in New York Encourages Strategic Deployment of Third-Party and Customer Owned DG Resources

Consolidated Edison ("ConEd") utility in New York State is administering an RFI to defer a planned $1B substation upgrade investment via innovative DER solutions that provide transmission and distribution system load relief and reduced generation capacity requirements. ConEd has identified two substations in its Brownsville area that are forecasted to be overloaded

[23] Assigned Commissioner's Ruling RE Draft Guidance For Use In Utility AB 327 (2013) Section 769 Distribution Resource Plans,); California PUC Docket No. R-14-08-013, issued on November 17, 2014. (Herein after "Assigned Commissioner Ruling"). (Included as Attachment 4).
[24] Assigned Commissioner's Ruling, p. 5, *see also,* p. 21.
[25] Assigned Commissioner's Ruling, p. 15.
[26] Assigned Commissioner's Ruling, p. 16.
[27] Assigned Commissioner's Ruling, p. 19-20.

under normal conditions starting in 2016. The overload is expected to reach 58MW in 2018, and ConEd seeks to invest $200M in novel customer-side load management and DG programs in order to shed load from the specified areas.[28]

ConEd's RFI proactively identified targeted areas in its network where DERs may provide significant and immediate grid benefits. ConEd is looking for systems "that can be deployed rapidly, and with operational confidence," which are increasingly available in the market.[29] The creative use of DERs should allow ConEd to defer the construction of the new substation and feeder to 2024, potentially even longer.

c. Similar Policies in AZ Would Save Customers Money

While specific incentives might not be the right choice for Arizona, TASC encourages the ACC to similarly direct Arizona utilities to analyze their existing systems to identify strategic locations, where DG can provide grid benefits and avoid costly capacity upgrades prior to approving utility ownership programs. Utilities should then publicize these locations where DG would provide significant value, as well as make underlying distribution data available to third parties to assess opportunities to target these areas. Analyzing and calculating the potential benefits of DG to provide these grid services should also be considered in any future cost/benefit analyses. The Commission could consider and adopt such policies through a statewide interconnection rulemaking, as previously discussed.

3. Contribution to Peak Demand can be Encouraged Without Utility Ownership

In its responses to Staff's Open Meeting Memoranda with regard to both TEPs and APS's proposals, TASC argued that the Commission could encourage free-market installations that maximize production during peak periods through creative rate design mechanisms or incentives,

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[28] ConEd RFI: Innovative Solutions to Provide Demand Side Management to Provide Transmission and Distribution System Load Relief and Reduce Generation Capacity Requirements; July 2014 (*available at*, http://www.coned.com/energyefficiency/Documents/Demand_Management_Project_Solicitation-RFI.pdf).
[29] ConEd RFI.

such as time-of-use pricing, and do so at a far lower cost to ratepayers than installing systems themselves.

Further, TASC noted in its earlier responses that both APS and TEP have traditionally incented south facing solar systems. APS's standard application form states, "[i]deally, solar units should face south to collect the most solar energy throughout the year. The further east or west the system faces the lower the yearly output will be."[30]

APS's claim that utility ownership is necessary to face PV systems to the west and southwest is misleading and disingenuous. Instead of allowing APS to invest millions of customer dollars to install west-facing PV, the Commission should develop policies, like those described below, to incent customers to coordinate PV system output with peak system demand through innovative TOU rate design or other incentives. Hudson Light & Power ("HLPD") offers a program to encourage west and southwest facing systems. Under its Photovoltaic Incentive Program, HLPD offers two ranges of incentives. South facing systems between 170° and 220° fall into the Range 1 category and receive a $1.00 per watt. West and southwest facing systems >220° and 300° are considered Range 2 and receive an additional $0.25 per watt. The stated purpose for the program is the reduction of the late afternoon HLPD summer system peak. HLPD also acknowledges that the resulting peak reduction benefits all HLPD customers who fund the PV rebate program. [31]

While the above program is a direct incentive to incent customers to install west-facing PV, a similar end result is possible through multiple approaches including a TOU program. Designing TOU rates that compensate DG owners for contribution to reducing peak demand would utilize Arizona's investment in smart meters and provide benefits to all customers. With both utilities receiving ARRA funding to install smart meters in 2009, such a program would leverage a valuable asset already available in the state. Other states have used additional measures to incent west-facing PV, including incentives to promote west-facing installations,

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[30] APS Residential Reservation Application Form, p. 4. (Included as Attachment 5).
[31] Hudson Light & Power, Photovoltaic Incentive Program, accessed on 11/21/14. http://www.hudsonlight.com/Library/HLPD_PV_Rebate.pdf (Included as Attachment 6).

though this end result can be accomplished through properly constructed TOU rate design where peak coincident generation is appropriately compensated.

4. SolarCity, TASC Member, No-Cost Proposal

TASC encourages ACC staff, Commission and RUCO to require further investigatation of alternatives prior to supporting utility owned DG. TASC further encourages TEP and APS to conduct competitive solicitations for inverter owners that would be willing to partner with the utilities to test integration of smart inverters. As a demonstration of our willingness to participate and belief that there are absolutely lower cost alternatives to providing the ancillary benefits research needs that TEP and APS seek, TASC members hereby offer to work with the utilities to demonstrate the technical benefits sought in their proposal via a collaborative demonstration pilot at little to no cost to customers. As mentioned earlier, TASC members have advanced inverters already installed on PV installation in AZ. Specifically, TASC members propose a demonstration pilot to:

1. Demonstrate enhanced inverter features
2. Demonstrate use of existing communications networks to enable utility communication and coordination of smart inverters
3. Demonstrate advanced grid benefits, such as voltage regulation and frequency regulation, via smart inverters.

These benefits result from leveraging existing and future DER installations, and can be deployed at a fraction of the cost to ratepayers as the proposed utility efforts. By leveraging existing assets owned by customers and third parties, APS and TEP can demonstrate the technical benefits of DERs without investing significant ratepayer funds.

5. Conclusion

The ACC should not be swayed by the APS and TEP arguments that utility ownership is necessary and prudent when it comes to accessing operational benefits of distributed generation. Rather, utility ownership of DG is not necessary to unlock benefits, adds costs to deployment, sidelines third parties that are an engine of innovation, and unnecessarily prevents competition.

TASC believes that the Commission should carefully examine, learn from others states experiencing similar DG penetration, and weigh additional options before committing ratepayer funds to a utility-owned program. The decision to vertically integrate is simply premature.

Respectfully submitted this 5th day of December, 2014.

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Attachment 1

STATE OF CALIFORNIA EDMUND Governor

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Agenda ID #13460
Quasi-Legislative

TO PARTIES OF RECORD IN RULEMAKING 11-09-011:

This is the proposed decision of Commissioner Michael Picker. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's December 18, 2014 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

/s/ TIMOTHY J. SULLIVAN
Timothy J. Sullivan
Chief Administrative Law Judge (Acting)

TJS:lil

Attachment

Decision **PROPOSED DECISION OF COMMISSIONER PICKER**
(Mailed 11/13/2014)

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)

INTERIM DECISION ADOPTING REVISIONS TO ELECTRIC TARIFF RULE 21 FOR PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY TO REQUIRE "SMART" INVERTERS

1. Summary

Today's decision adopts modifications to Electric Tariff Rule 21 to capture the technological advances offered by smart inverters. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are authorized to file Advice Letters with revisions to Electric Tariff Rule 21.

2. Background

The Commission initiated Rulemaking (R.) 11-09-011 on September 22, 2011 to review and, if necessary, revise the rules and regulations governing

[1] Pursuant to Commissioner Picker's May 13, 2014, Scoping Memo this portion of the proceeding is categorized as Quasi-Legislative and the remainder of the proceedings as ratesetting.

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.

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 separate Generator Interconnection Agreement 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.

3. Revising Technical Specifications for Inverters

Electric Tariff Rule 21 also sets forth the protective functions and equipment requirements for connection to the utilities' distribution networks. These requirements are based on the Institute of Electrical and Electronics Engineers' 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 local (small scale) renewable generation is connected to the distribution grid through inverters. Fostering deployment of this type of generation is one of the goals of the California Solar Initiative, among other important policy objectives of this Commission.

Since 2003, the technical capabilities of inverters have advanced substantially. Today's "smart inverters" have many capabilities, including:

- The delivery of DC power into an AC system, such as photovoltaic power to the AC grid; and the delivery of AC power to a DC load, as in charging a battery from the grid.
- The generation or absorption of reactive power so as to raise or lower the voltage at its terminals.
- Delivery of power in four quadrants, that is, positive real power and positive reactive power; positive real power and negative reactive power; negative real power and negative reactive power; and negative real power and positive reactive power.
- The detection of voltage and frequency at its terminals and the ability to react autonomously to mitigate abnormal conditions: to provide reactive power if the voltage is low; to increase real power output if the frequency is low.
- In combination with a communication link, to deliver real and reactive power and to charge and discharge storage facilities in accordance with signals from the utility.

If properly applied, smart inverters can improve the performance of the distribution grid and the network as a whole, or, conversely, if improperly applied, can present serious problems in terms of voltage control, the clearing of short circuits and the creation of dangerous "islanding" conditions. As greater numbers of renewable generating resources interconnect with the grid, the influence of the smart inverter will grow.

To develop proposals to take advantage of these new capabilities, the parties to this proceeding created the Smart Inverter Working Group (Working Group). In January 2014, Working Group issued its "Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources." The Recommendations were circulated to the parties via a February 7, 2014 assigned Administrative Law Judge (ALJ) ruling and were the subject of the February 19, 2014 prehearing conference.

The Working Group recommended the following revisions to Electric Tariff Rule 21 in what it categorizes as "Phase 1":

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 sub-section 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 May 13, 2014, the assigned Commissioner issued his scoping memo directing the electric utilities to analyze these recommendations and propose specific modifications to Electric Tariff Rule 21.

On July 18, 2014, PG&E, SCE and SDG&E filed and served in this docket a draft Advice Letter filing setting forth revisions to Electric Tariff Rule 21 to conform to the seven recommendations made by the Working Group, and any other revisions needed to Electric Tariff Rule 21 to facilitate deployment of smart inverter capabilities.

On August 18, 2014, parties filed and served comments in this docket on the draft Advice Letter filings. Comments were filed by: Fronius USA LLC, Power-One, Schneider Electric, California Energy Storage Alliance, Empower Micro, CleanCoalition, Enphase Energy, and Apparent Energy.

All commenters praised the consensus built by the diligent hard work of the Working Group.

Several parties recommended delaying the effective date of the requirement for improved inverters, and explained that time was needed to research and develop technology to meet the new requirements, as well as obtain certification from Underwriters Laboratory. Specifically, these parties would extend the mandatory implementation date from the later of December 31, 2015, or the date of approval by Underwriter's Laboratory, to the later of:
(1) eighteen months after publication of revised Electric Tariff Rule 21, or
(2) twelve months after the Underwriter's Laboratory approval.

Several parties also supported adopting definitions for two specific types of voltage, reference and offset, and refining the definitions of "mandatory operation" and "voltage excursion." Several parties suggested that adding greater than or equal to and less than or equal to arrows to the voltage ride-through and frequency ride-through tables would improve precision.

Power-One and California Solar Energy Industries Association (CALSEIA) proposed allowing existing inverters to be replaced with a similar quality inverter; that is, an inverter that did not meet the definition of smart inverter. Power-One argued that the objective of the revisions was to encourage new installations to incorporate smart inverters, and not to require that existing inverters, which may still be under warranty, to be replaced with smart inverters.

Power-One and Fronius noted that the draft Advice Letters did not have exemptions from the voltage and frequency ride-through requirements for stand-by systems, and advocated for such exemptions. Power-One also suggested that the connect/reconnect ramp-up rate should be mutually agreed upon by the producer and distribution system manager.

CALSEIA reiterated its request that the Commission require the utilities to provide financial assurances that revenue to producer systems will not be diminished by Advanced Grid Functionalities. CALSEIA claimed that "new rate structures are needed that more accurately represent the value of [Advanced Grid Functionalities] on the grid." CALSEIA stated that until new rate structures are adopted, producers should not be required to operate in a manner that yields lower revenue.[2]

Discussion

Pursuant to Public Utilities Code Section 451 each public utility in California must:

> Furnish and maintain such adequate, efficient, just and reasonable service, instrumentalities, equipment and facilities, ...as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public.

The duty to furnish and maintain safe equipment and facilities falls squarely on California public utilities, including electric utilities.

The burden of proving that particular facilities are safe also rests with the utility. The purpose of Electric Tariff Rule 21 is to ensure that generating facilities interconnect with California electric distribution or transmission systems subject to requirements that they maintain safe operating conditions for utility customers, personnel, and the general public, as well as to retain electric system integrity.

In today's decision, we adopt revisions to Electric Tariff Rule 21, developed largely through consensus, that require new inverters used by interconnecting generating facilities to have enhanced technical capabilities. These new inverter standards will allow interconnected generating facilities to offer system support functions to distribution or transmission system operators. As set forth below, we resolve three remaining but relatively minor issues and authorize the electric utilities to file Advice Letters with revisions to their

[2] CALSEIA comments at 3 – 4.

respective Electric Tariff Rule 21 conforming to today's decision and to be effective on filing.

Also in today's decision, we set the course for bringing to fruition the promise of these new inverter standards. The purpose of the new inverter functionalities is to allow grid operators to obtain grid support services for dispersed locations and at a lower cost than currently available. To achieve this objective, generating facility operators must install the smart inverters, capable of communications, and then must also have a convenient and economical means to make these services available to the transmission or distribution system operator. This step will be the next objective of this proceeding and contained within the third investigatory Phase of the Working Group work.

Issues for Resolution

The effective mandatory date of the requirements adopted today shall be the later of December 31, 2015, or 12 months after the date the Underwriters Laboratory approves the applicable standards. This effective mandatory date should not be construed as a gating factor for the installation of inverters with the applicable standards. With the revision of Electric Tariff Rule 21, we permit and encourage the utilities to work with installers to deploy smart inverters as quickly as possible. To achieve our goal of having enhanced inverters deployed expeditiously while not causing market disruptions, smart inverter requirement shall be permitted and encouraged to be used, but not mandated, on all new inverter installations up until the date that these new standards become mandatory. These new standards do not apply to inverters installed prior to the revision of Electric Tariff Rule 21.

Further, the soft-start connect ramp-up rate and the soft disconnect ramp-down rate should be set as requested.

We also accept the consensus from the parties on the following revisions: (1) Section Hh.2.f.i.; (2) the Frequency Ride-Through Table, Hh-2; (3)Voltage Ride-Through Table Hh-1; and (4) the Definitions VRef, VRefOfs, Mandatory Operation and Voltage Excursion. These consensus revisions are set forth in Attachment A.

1. Effective Mandatory Date of Enhanced Inverter Requirements

In their draft revisions to Electric Tariff Rule 21, the utilities recommended that inverters that can perform functions which autonomously contribute to grid support during excursions from normal operating conditions – "smart inverters" – be required mandatory effective the later of December 31, 2015 or the date Underwriter Laboratory approves the new standards.[3] Smart inverter requirement shall be permitted and encouraged to be used, but not mandated, on all new inverter installations up until the date that these new standards become mandatory. These new standards do not apply to inverters installed prior to the revision of Electric Tariff Rule 21.

As described above, some commenters requested a date certain, i.e., December 31, 2015, or June 2016, and others sought to extend the effective date of the new standards to the later of: (1) eighteen months after publication of revised Electric Tariff Rule 21, or (2) twelve months after the Underwriter's Laboratory updated standard approval.

A date certain is not practical because the Underwriter's Laboratory standard revision process does not offer a date certain for completion. In adopting these new standards for Electric Tariff Rule 21 today, we would like to

[3] Specifically, the date the Supplement SA of UL-1741 (with California requirements) is approved by the full UL-1741 Standards Technical Panel.

see them implemented at the earliest practicable date, while still allowing inverter manufacturers adequate time to seek necessary certifications.

In an effort to find the right balance between the utilities' proposal and Power-one and Schneider's proposal, we adopt the effective date of the new inverter requirements as the later of either (1) December 31, 2015 or (2) twelve months after the date the Supplement SA of UL-1741 (with CA requirements) is approved by the full UL-1741 Standards Technical Panel.

2. Replacement Inverters

In their draft Electric Tariff Rule 21, the utilities propose that, after the effective date for the new standards, traditional inverters currently in operation, which fail, should be replaced with inverters that meet the new standards. Commenters proposed allowing installed inverters to be replaced with an inverter not classified as a Smart Inverter. One party argued that the objective of the revisions to Electric Tariff Rule 21 was to encourage new installations to incorporate smart inverters, and not to require that existing inverters, which may still be under warranty, to be replaced with smart inverters.

At this point in time, we are convinced by Power-One's arguments that requiring already installed inverters to be replaced by smart inverters may affect manufacturer warranties. As a result, we find that allowing existing inverters to be replaced with an existing inverter not classified as a Smart Inverter should be allowed. Given that the body of knowledge relating to Smart Inverters is growing quickly, we invite the utilities and consensus builders to develop proposals that encourage the replacement of existing inverters with smart inverters at time of failure.

Therefore, we reject the replacement requirements set forth in draft Electric Tariff Rule 21, Section H.d.ii, as proposed by the utilities, and instead adopt Enphase's recommended language for Section H.d.ii:

> The replacement of an existing inverter to an inverter that is not classified as a Smart Inverter is allowed per Section H. Section H may be used in all or in part, for replacement inverter based technologies by mutual agreement of the Distribution Provider and the Applicant.

3. Provisions for UPSs, Critical Loads, and Microgrids

In their comments, Schneider, Enphase and Power-one all reference the need to make a special allowance in the Electric Tariff Rule 21 revisions for inverters that serve on-site back-up power needs. In their reply comments, the utilities oppose these allowances, but do not provide supporting evidence for their position. Given the important reliability and resilience function that distributed generation coupled with an inverter can provide to a customer, we find that the Electric Tariff Rule 21 revisions should be revised to reflect Power-One and Enphase's recommendation in Section H.2.b.ii):

> **Load Shedding or Transfer**
> The voltage and frequency ride-through requirements of H. 2. b. ii) shall not apply if either: a) The real power across the Point of Common Coupling is continuously maintained at a value less than 10% of the aggregate rating of the Smart Inverters connected to the Local EPS prior to any voltage disturbance, and the Local EPS disconnects from the Area EPS, along with Local EPS load, such that the net change in real power flow from or to the Area EPS is less than 10% of the aggregate Smart Inverter capacity; or b) Local EPS load real power demand equal to 90% to 120% of the predisturbance aggregate Smart Inverter real power output is shed within 0.1 seconds of Smart Inverter disconnection.

We also find that Schneider's recommendation to organize discussions with utilities to find better ways to accommodate back-up power systems that grid-interconnect has merit. We therefore recommend that the utilities begin such a process, and when the one year after the adoption of Revised Electric Tariff Rule 21, bring proposed modifications to Electric Tariff Rule 21 back to the Commission for consideration.

4. Volt/Var

Commenting parties, like Power-One and Fronius, noted further revision to Section Hh.2.j.regarding increased information within the Volt/Var definitions. The utilities replied that this level of detail need not be included in the tariff since such detailed specifications are not yet ripe for inclusion. We request that the utilities investigate this level of detail and make a proposal as to the details based on experience in one year's time from the passage of this revision of Electric Tariff Rule 21.

5. Ramp-Down Specification

In their draft Electric Tariff Rule 21 revisions, the utilities proposed that the soft-start connect ramp-up rate <u>and</u> the soft disconnect ramp-down rate be set at 2% of maximum current output per second. Commenters opposed including a soft disconnect ramp-down rate and proposed that the rate should be mutually agreed upon by the distribution or transmission system operator and the generating facility. In particular, Schneider states that the proposed ramp-down rate would preclude the ability of inverters to provide maximum power point tracking, which it states is a critical functionality of an inverter.

Given the nascent nature of smart inverter deployment, we are convinced by Schneider's concerns, which are echoed by Power-One and Enphase, that a ramp-down requirement may have un-intended consequences. As a result, we will adopt the ramp rate specifications proposed by Schneider, which would replace the utilities proposed Section Hh.k.2 with.

> **Connect/Reconnect Ramp-up rate:** Upon starting to inject power into the grid, following a period of inactivity or a disconnection, the inverter shall be able to control its rate of increase of power from 1 to 100% maximum current per second, with specific settings as mutually agreed upon by the Distributor Provider and the Producer.

We invite this topic to be reconsidered either by the utilities proposing subsequent modifications that include ramp-down requirements or by the Working Group via a filing in this proceeding or in a subsequent phase after this revision of Electric Tariff Rule 21.

6. Adjusted Ride-Through Tables

Parties included updated Voltage and Frequency Ride Through tables in their comments. In reply comments, utilities supported this recommendation. Therefore, we support the updated frequency and voltage ride through tables as included by Fronius in their comments.

Harmonizing Rule 21 Revisions with Federal Wholesale Tariffs

Consistent with our past practice, we will direct the utilities to seek such approval from the Federal Energy Regulatory Commission as may be needed for conforming changes to their federal wholesale Tariffs interconnection specifications.[4]

Realizing the Value of Smart Inverters

The voltage on a distribution line is now controlled by shunt capacitors, voltage regulators on the line, and a voltage regulator in the distribution

[4] *See*, e.g., D.12-09-018 at 32, and D.14-04-003.

transformer at the substation controlled by a line drop compensation algorithm. The smart inverter has the potential to substitute for all of these measures with greater accuracy and at lower cost. To capture the potential for improved voltage control along with the cost savings, the owners of smart inverters connected to the grid must to provide this support as needed by the distribution provider, on terms and conditions acceptable to the inverter owner. Establishing the appropriate level of compensation for inverter owners under the different circumstances that will arise in the real world of transmission and distribution system operation is a complex undertaking. Such an undertaking is necessary, however, if California is to benefit from the investments being made in smart inverters.

Collaboration and consensus have been the hallmark of this proceeding to date, and we are hopeful that this will continue as we move toward bringing the value of smart inverters to day-to-day grid operations. To initiate this next part of the proceeding, our Energy Division Staff will sponsor a workshop to receive proposals from all interested parties, including the distribution providers, equipment vendors, trade associations and other interveners. Subsequent workshops will be held as needed until consensus among the parties is reached or divergent opinions are well defined. At that point, the Energy Division will make recommendations for a Commission decision or further proceedings.

Among the issues to be addressed are: should voltage support be measured in kilovolt-amperes reactive and kilovolt-ampere reactive-hours, the equivalent of real power and energy? Should dollar values be assigned to each, either through bidding by the producers or in negotiations between the producers and the distribution providers? Should frequency support be measured by power injected into the grid or absorbed from it (the charging of a storage device) in kilowatts and kilowatt-hours? How should this be priced, either through bidding by the producers or in negotiations between the producers and the distribution provider? How would the ancillary services be controlled? Options include active control by the distribution provider, which through a communication system would control the real and reactive output of the producer's generator or smart inverter; by contract: the generator provides real and reactive power at certain times of the day; or in response to predetermined grid conditions: e.g., when the voltage at the Point of Common Coupling falls to a certain value, the inverter produces reactive power. Such other parameters for measuring ancillary services and other contractual issues as may be brought up by the parties.

4. Comments on Proposed Decision

The proposed decision of Commissioner Picker 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 _______, and reply comments were filed on _______ by _______.

5. Assignment of Proceeding

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

Findings of Fact

1. The parties to this proceeding created the Working Group which issued in January 2014 its "Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources."

2. The Working Group recommended the following revisions to Electric Tariff Rule 21:

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 sub-section 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 methods.

3. On May 13, 2014, the assigned Commissioner issued his scoping memo directing the electric utilities to analyze the Working Group's recommendations and propose specific modifications to Electric Tariff Rule 21.

4. On July 18, 2014, PG&E, SCE and SDG&E filed and served a draft Advice Letter filing setting forth revisions to Electric Tariff Rule 21 to conform to the seven recommendations made by the Working Group.

5. On August 18, 2014, parties filed and served comments on the draft Advice Letter filings, with relies on September 8, 2014.

6. After the utilities' filing and the comments, three issues remained and required resolution in today's decision.

7. Setting a reasonable mandatory effective date of the requirements adopted herein of the later of December 31, 2015, or 12 months after the date the Underwriters Laboratory approves the applicable standards strikes a reasonable balance between the utilities and the inverter manufacturer commenters' recommendations.

8. Our goal of having enhanced inverters deployed expeditiously while minimizing market disruption is best achieved by allowing existing inverters installed prior to the revision of Electric Tariff Rule 21 to be replaced with an inverter that may or may not be classified as a Smart Inverter.

9. Inverters serving back-up power systems shall be given an exemption from these requirements if they meet the specifications recommended by Enphase and Power-One in their comments.

10. The soft-start connect ramp-up rate should be set as recommended by the Schneider at 1 to 100% of maximum current per second, with the potential for specific settings to be set upon mutual agreement by provider and grid operator.

Conclusions of Law

1. Inverters installed after the effective date of the requirements adopted in today's decision should comply with the updated standards applicable to all inverters, with the exception of inverters that are installed to replace inverters that were in place prior to the effective dates in this Decision and inverters that serve back-up power systems, as defined herein.

2. The ramp-up rate should be set as requested by Schneider at 1 to 100% of maximum current per second, with the potential for specific settings to be set upon mutual agreement by provider and grid operator.

3. The proposed effective mandatory date of the requirements adopted herein should be the later of December 31, 2015, or 12 months from the date the Underwriters Laboratory approves the applicable standards.

4. PG&E, SCE and SDG&E should be authorized to file and serve a Tier 1 Advice Letter, effective on five day notice, which revises Electric Tariff Rule 21 as proposed in the July 18, 2014, filing and is consistent with today's decision.

5. Consistent with our past practice, we should direct the utilities to seek such approval from the Federal Energy Regulatory Commission as may be needed for conforming changes to their federal wholesale Tariffs interconnection specifications.

6. The next stage of this proceeding will focus on revising Electric Tariff Rule 21 to include communications protocols, as that recommendation process based on building consensus is currently underway. The next focus of investigation in this proceeding should be on establishing the appropriate level of compensation for inverter owners providing grid support functions.

7. The consensus modifications to the utilities' proposal set forth in Attachment A to today's decision should be adopted.

8. The Joint Motion of Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company Regarding Implementation of Smart Inverter Functionalities filed on July 18, 2014, should be granted consistent with today's decision.

9. This proceeding should remain open to bring the value of smart inverters to day-to-day grid operations and ratepayers.

10. This decision should be effective immediately.

INTERIM ORDER

Therefore, **IT IS ORDERED** that:

1. The motion Joint Motion of Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company Regarding Implementation of Smart Inverter Functionalities filed on July 18, 2014, is granted, subject to the modifications set forth in today's decision.

2. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company are authorized to file and serve a Tier 1 Advice Letter, effective on five day notice, which revises Electric Tariff Rule 21 as proposed in the July 18, 2014, filing and are consistent with today's decision.

3. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall seek such approval from the Federal Energy Regulatory Commission as may be needed for conforming changes to harmonize their federal wholesale Tariffs interconnection specifications with the revisions to Electric Tariff Rule 21.

4. The utilities are ordered to file a Tier 1 Advice Letter updating Electric Tariff Rule 21 indicated the date of the approval of Supplemental SA of UL 1741 (with CA requirements) within five days of its approval.

5. One year after the adoption of Revised Electric Tariff Rule 21, the utilities will make a proposal regarding: the provisions for Uninterruptible Power Supplies, Critical Loads, and Microgrids; enhanced Volt/Var specifications based on detailed analysis gathered from utilizing these functions; inclusion of a consensus-based ramp-down specification.

6. Rulemaking 11-09-011 remains open.

This order is effective today.

Dated ____________________________, at San Francisco, California.

Attachment A

Agreed Upon Revisions to Definitions

1. VRef: The reference voltage or nominal voltage.

2. VRefOfs: The offset from the reference voltage due to the location of the Smart Inverter system on a distribution feeder. This may be a setting or may be calculated dynamically from local voltage measurements.

3. Mandatory Operation: The Smart Inverter operates at maximum available current without tripping during Distribution Provider's Transmission or Distribution System excursions outside the region of continuous operation. Any functions that protect the Smart Inverter from damage may operate as needed.

4. Voltage Excursion: Beginning when Distribution Provider's Transmission or Distribution System voltage at the PCC exits the Near Nominal magnitude range and ending when voltage re-enters the Near Nominal magnitude range.

Table Hh-1: Voltage Ride-Through Table

Region	Voltage at Point of Common Coupling (% Nominal Voltage)	Ride-Through Until	Operating Mode	Maximum Trip Time
High Voltage 2 (HV2)	$V \geq 120$			0.16 sec.
High Voltage 1 (HV1)	$110 < V < 120$	12 sec.	Momentary Cessation	13 sec.
Near Nominal (NN)	$88 \leq V \leq 110$	~~Continuous Operation~~ Indefinite	Continuous Operation	~~Continuous Operation~~ Not Applicable
Low Voltage 1 (LV1)	$70 \leq V < 88$	20 sec.	Mandatory Operation	21 sec.
Low Voltage 2 (LV2)	$50 \leq V < 70$	10 sec.	Mandatory Operation	11 sec.
Low Voltage 3 (LV3)	$V < 50$	1 sec.	Momentary Cessation	1.5 sec.

Table Hh-2: Frequency Ride-Through Table

System Frequency Default Settings	~~Minimum~~ Range of Adjustability (Hz)	Ride-Through Until (s)	Ride-Through Operational Mode	~~Default~~ ~~Clearing~~ Trip Time (s)
f > 62	62 - 64	No Ride Through	Not Applicable	0.16
60.5 < f ≤ 62	60.1 - 62	299	Mandatory Operation	300
58.5 ≤ f ≤ 60.5	Not Applicable	Indefinite	Continuous Operation	Not Applicable
57.0 ≤ f < 58.5	57 – ~~60~~ 59.9	299	Mandatory Operation	300
f < 57.0	53 – 57	No Ride Through	Not Applicable	0.16

(End of Attachment A)

Attachment 2

Press releases

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SolarCity and Hawaiian Electric Join Forces with NREL to Advance Distributed Solar

Nov 20, 2014

San Mateo, Calif. and Honolulu – SolarCity has entered into a cooperative research agreement with the Energy Department's National Renewable Energy Laboratory (NREL) to address operational issues associated with high degrees of distributed solar penetration on electrical grids. The work includes collaboration with the Hawaiian Electric Companies to analyze high penetration solar scenarios using advanced modeling and inverter testing at the Energy Systems Integration Facility (ESIF).

Testing with SolarCity and Hawaiian Electric at ESIF is covering the dynamic of inverter-based assets on a grid system, voltage regulation, and bi-directional power flows. Engineers from SolarCity and Hawaiian Electric were at NREL's campus in September to kick off the research project, and in October for a follow up meeting.

"This is an excellent opportunity to utilize ESIF's unique capability to evaluate system-level issues such as anti-islanding, and help reduce risk and minimize the R&D challenges a power distributor or producer may face," NREL's Director of Partnerships for Energy Systems Integration Martha Symko-Davies said.

Hawaiian Electric is providing technical input on testing and setup throughout the process as well as feedback on results.

"We know how important the option of solar is for our customers. Solving these issues requires that everyone - utilities, the solar industry and other leading technical experts like NREL - work together. That's what this work is all about," said Colton Ching, Hawaiian Electric vice president for energy delivery. "With the highest amount of solar in the nation, our utilities are facing potential reliability and safety issues before anywhere else."

Hawaiian Electric has already seen such promising initial test results that they recently announced a plan for approving net-metered customers waiting to interconnect their rooftop solar systems in neighborhoods with high amounts of solar already installed. Applying the preliminary results of NREL and SolarCity's research with Hawaiian Electric, the utility expects that they will approve over the next five months almost all customers who have been awaiting interconnection.

"SolarCity is committed to ensuring that solar is an asset to grid operators, and this partnership will take us further towards that goal," said Peter Rive, SolarCity's co-founder and chief technology officer.

NREL will also evaluate SolarCity's PV generation curtailment hardware and software based on the potential need for PV power curtailment, or the use of less solar power than is potentially available at a specific time, through a remote signal.

"We're pleased that Hawaiian Electric agreed to partner on these important tests and commend them for taking early test results and instituting policy changes that will help Hawai'i's solar industry.Our collaboration has been fruitful and we look forward to continuing our work together," said Jon Yoshimura, SolarCity's Director of Policy and Electricity Markets.

The research was supported by the Office of Energy Efficiency and Renewable Energy. Funding was equally shared between SolarCity and the Energy Department's SunShot Initiative.

About Hawaiian Electric Company

Hawaiian Electric and its subsidiaries, Maui Electric and Hawai'i Electric Light, serve the islands of Oahu, Maui, Lanai, Molokai and Hawai'i Island, home to 95 percent of the people of Hawai'i. Hawaiian Electric's parent company is Hawaiian Electric Industries (NYSE: HE). In a changing world, the Hawaiian Electric Companies are taking the lead in adding renewable energy and developing energy solutions for its customers to achieve a lower cost, clean energy future for Hawai'i. For more information, visit www.hawaiianelectric.com.

About SolarCity

SolarCity® (NASDAQ: SCTY) provides clean energy. The company has disrupted the century-old energy industry by providing renewable electricity directly to homeowners, businesses and government organizations for less than they spend on utility bills. SolarCity gives customers control of their energy costs to protect them from rising rates. The company makes solar energy easy by taking care of everything from design and permitting to monitoring and maintenance. SolarCity currently serves 15 states and signs up approximately one new customer every minute of the work day. Visit the company online at www.solarcity.com and follow the company on Facebook & Twitter.

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Attachment 3

Utility Dive

How the HECO-SolarCity partnership is turning rooftop solar into a grid asset

Can the partnership change how we think about solar interconnection and utility-installer relations?

By Gavin Bade | December 2, 2014

Conventional wisdom tells us that electric utilities and solar installers are supposed to be rivals. From the utility's perspective, the more rooftop solar, the less electricity that customers will purchase from the grid. For installers, the more skeptical utilities are about the advantages of distributed energy, the more likely they are to support policies that curtail it. It's a narrative played out across the nation, from Wisconsin (http://www.utilitydive.com/news/activists-say-we-energies-rate-plan-would-effectively-demolish-rooftop-s/326492/) to Arizona (http://www.utilitydive.com/news/arizona-regulatory-staff-rejects-aps-bid-to-own-rooftop-solar/330168/) and beyond.

But one new partnership hopes to change that paradigm by combining the grid knowledge of a major electric utility with the technology of the nation's largest solar installer and the resources of a top energy lab. Last month, SolarCity and Hawaiian Electric Co. (HECO) announced (http://www.utilitydive.com/news/solarcity-partners-with-heco-to-study-solutions-to-solar-problems/335221/) they were teaming up with the National Renewable Energy Laboratory (NREL) in Colorado to study how to better integrate rooftop solar onto the grid.

It's a unique type of research partnership, one that both the utility and industry-leading solar provider hope can change how the entire sector looks at distributed resources.

The roots of the partnership

HECO is a utility with a solar challenge. How can it integrate the nation's highest penetrations of rooftop PV—providing nearly 20% of generation (http://www.utilitydive.com/news/hawaiis-utilities-plan-for-67-renewables-by-2030/303926/) —onto the grid without reliability issues? It's a question that troubled Hawaii's largest utility so much it had to hit pause (http://www.utilitydive.com/news/hawaii-utilities-solar-installers-feud-over-lengthy-interconnection-delays/306040/) on solar interconnections on some circuits earlier this year, creating a backlog of thousands of customers and prompting many panel installers to flee the island state (http://www.utilitydive.com/news/solar-installers-flee-hawaii-as-interconnection-queue-backs-up/314160/) .

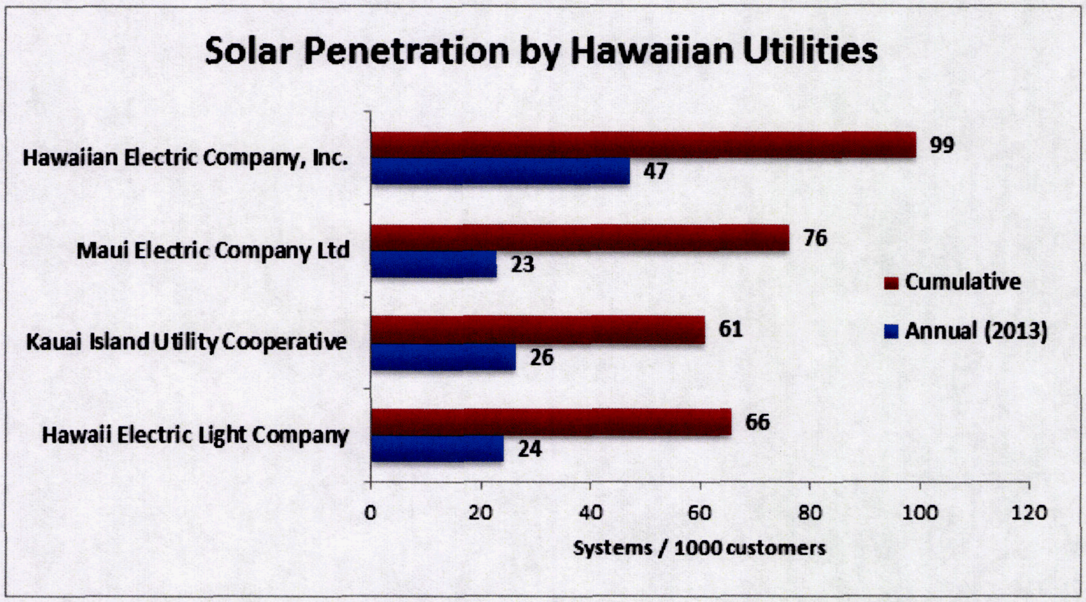
SolarCity, meanwhile, has a related issue. How can it convince utilities everywhere—often the biggest skeptics to solar integration—that distributed energy is not a liability for reliability, and can actually be an asset on the grid?

It was those complementary challenges that brought the two companies together with NREL, according to Colton Ching, vice president of energy delivery for HECO. He says the utility's own modeling for what could happen on circuits with high solar penetration had "hit a wall," and that they needed real-world experience in a lab environment to ensure they could connect more solar safely and without reliability issues. Once the companies connected, they decided to use the NREL facility because it had all the resources to test a number of different grid configurations, solar penetrations, and inverter technologies in a safe environment.

"We thought it would be the perfect place to take different kinds of inverters and actually subject them to the kind of things you would never want to subject an actual grid and actual components to," Ching said.

For SolarCity, the partnership had obvious advantages from the start, Peter Rive, co-founder and CFO of SolarCity, said in an interview with Utility Dive.

"The impetus for this was basically that if there are any operations concerns in regards to interconnecting solar we want to address them," he said. "[HECO] had a very specific overvoltage concern so we got together with NREL and they have a great lab that gives you the ability to simulate these edge grid conditions that HECO was concerned about."



Credit: SEPA

HECO's technical problem

Ching and Rive said HECO had immediate concerns about a specific problem with solar integration: Transient overvoltage. What would happen on high-solar circuits when the grid connection for the solar units is suddenly interrupted, like if a tree fell on a power line?

When grid connection is interrupted, Ching explained, "the breaker in the substation suddenly opens up ... and now you have these homes with their PV systems and a circuit that's no longer connected to the grid."

"What happens to that power that was going back to the grid, what happens when it has nowhere to go?"

HECO feared that the fractions of a second when the switch was open could cause voltage on the circuit to spike dangerously. If that was the case, Ching said, such interruptions could cause safety and reliability issues, potentially damaging utility and customer equipment.

“What our testing set-up in NREL did was literally test that phenomenon,” he said.

Encouraging preliminary results

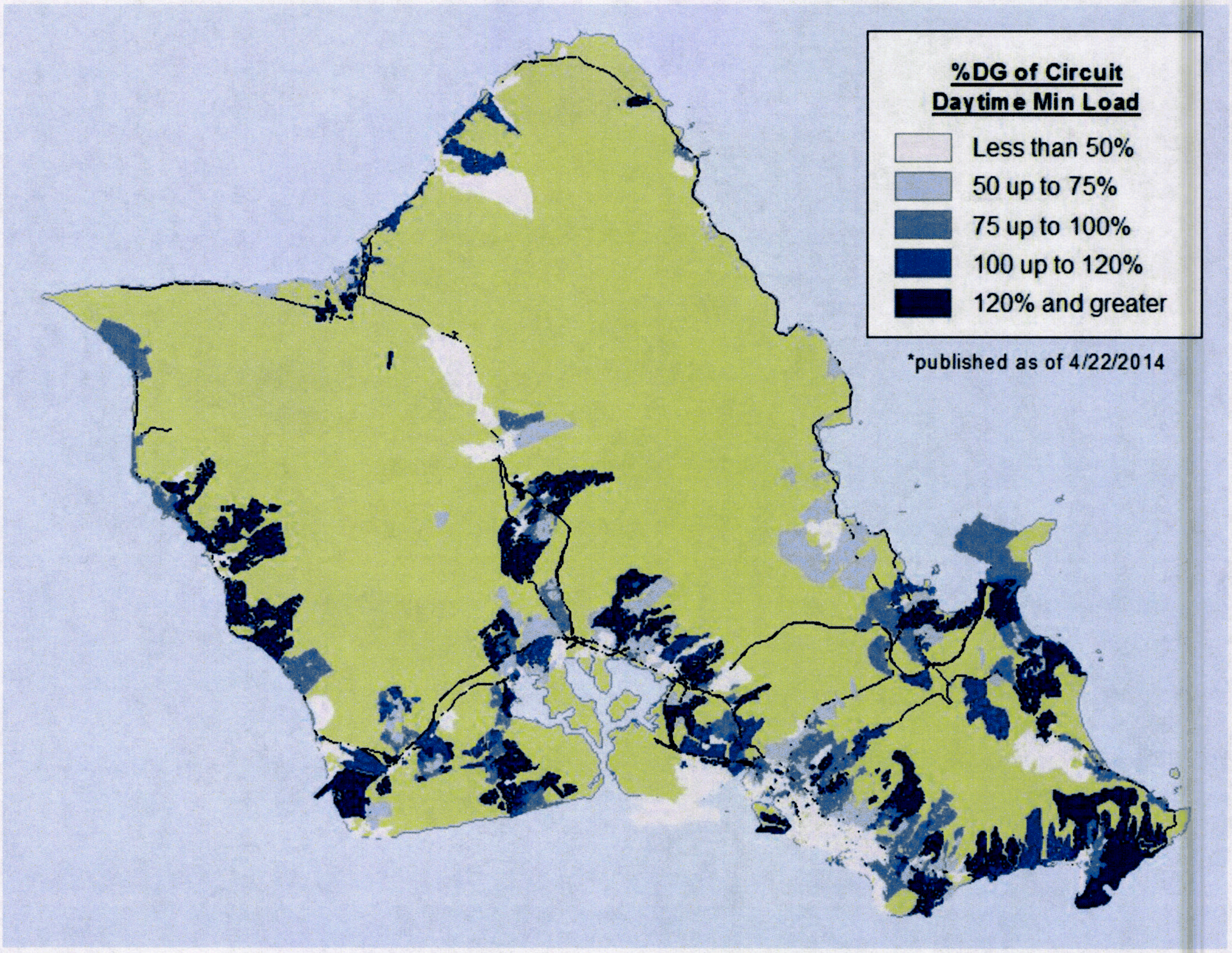
Testing the impacts of sudden grid disconnection comes down to the performance of inverters on the circuit. The engineers needed to know if they would react fast enough to turn solar systems off in time to avoid harmful voltage levels.

The answer, according to Rive and Ching, is a resounding ‘Yes.’

Whether it was “inverters built for larger commercial systems or smaller residential systems, we saw a consistent pattern where inverters turned themselves off very, very quick—much quicker than we thought,” Ching said.

Engineers from the companies tested a number of typical inverters without special modifications or treatment. The results were so encouraging for HECO that it recently announced a new plan to interconnect the more than 3,000 backlogged solar customers. Rive said the decision came directly from the results of the inverter studies.

“The primary liability concern they had has been addressed,” he said. “Therefore it’s giving them the confidence to increase the amount of solar power systems that they have on certain circuits.”



HECO overgeneration hotspots on Oahu

Credit: [HECO (http://www.hawaiianelectric.com/portal/site/heco/lvmsearch)](http://www.hawaiianelectric.com/portal/site/heco/lvmsearch)

Further testing and long-term goals

While the testing so far has aimed to prove that high solar penetrations need not do harm to the grid, further research will aim at proving it can enhance reliability and act as a grid resource, Rive said.

“Our goal is to show in the long run—and by the long run, I mean next year—how smart inverters can be a massive asset for the utility operations by providing frequency supports by providing VARs and by providing voltage support,” he said.

Rive also indicated the NREL testing would include research on SolarCity curtailment systems and storage technology. Curtailment would come from automated software deployed in the substation that stems the flow of power coming from rooftop systems if the generation to load ratio gets too high.

By 2020, SolarCity [aims to bundle energy storage "by default" (http://www.greentechmedia.com/articles/read/solarcity-nest-to-energy-regulators-open-the-grid)](http://www.greentechmedia.com/articles/read/solarcity-nest-to-energy-regulators-open-the-grid) with every rooftop solar system it sells, and Rive said the impetus behind that push is the same as what predicated the partnership.

"In general, the big thing is that we want to make these distributed resources a tool for the grid operators and that's the plan with the battery systems as well," he said. "There's a lot of value to distributed resources and it's our goal to show all of the utility operators how they can take advantage of it to lower their prices and increase reliability."

Both Rive and Ching have high expectations for the partnership between the companies and NREL, and hope their model of cooperation can be replicated elsewhere.

"I do see it as a paradigm shift for sure," Rive said, "and I think we'll be seeing that shift be happening over the next couple of years, where first we'll address any reliability issues, and then transition to grid operators saying 'Hey [solar] is great. I like it and I can use it to make the grid more resilient.'"

Ching says his goal for the project is for it to become "a shining example for Hawaii and also for the industry in general." He hopes to leverage the partnership so it can be expanded, and more utilities can cooperate with more installers to ensure that solar is an asset, not a liability.

"The best results, the best work, comes from working together," he said.

Top Image Credit: Flickr; h080 (https://www.flickr.com/photos/7718908@N04/5916938946)

Filed Under:

Generation Business News Solar Technology

Attachment 4

MP6/jt2 11/17/2014

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)

ASSIGNED COMMISSIONER'S RULING RE DRAFT GUIDANCE FOR USE IN UTILITY AB 327 (2013) SECTION 769 DISTRIBUTION RESOURCE PLANS

On August 14, 2014, the Commission issued Rulemaking 14-08-013 Regarding Policies, Procedures and Rules for the Development of Distribution Resource Plans. This Rulemaking included a draft Scoping Memo that put forward 16 questions for parties to comment upon. Attached to the draft Scoping Memo, and included in the questions for parties, was a paper entitled, "More Than Smart: A Framework to Make the Distribution Grid More Open, Efficient and Resilient." Over 30 parties responded with comments or replies. On September 17, 2014, Energy Division held a workshop to discuss party comments to the Draft Scoping Memo and the "More Than Smart" paper.

In comments, parties provided a wide variety of recommendations for the types of Distribution Resource Plan guidance the Commission should provide the Utilities. After careful consideration of these comments, review of similar proceedings in states like New York and Hawaii, and discussions with a wide variety of stakeholders, I have, in collaboration with Energy Division, developed the attached draft Distribution Resource Plan Guidance (Draft Guidance) document.

Parties may file comments on the attached Draft Guidance by December 5, 2014. Subsequent to the submission and review of comments, I will issue a Ruling with a Final Distribution Resource Plan Guidance document that will serve as the basis for utility Applications. My intention is to consolidate these forthcoming Applications with this Rulemaking.

The following is a summary of the attached Draft Guidance:

1. In Part 1, the Draft Guidance suggests a "New Framework for Distribution Planning" driven by the imperative of deep greenhouse gas emissions reductions, and enabled by the mass adoption of Distributed Energy Resources.

2. In Part 2, the Draft Guidance suggests that the jurisdictional scope of the proceeding should be the low-voltage distribution, while also identifying where this proceeding overlaps with other Commission proceedings.

3. In Part 3, the Draft Guidance identifies the need for on-going coordination between the Utilities, State Agencies and the Independent System Operators. The Draft Guidance also suggests that the Demand Response Providers (DRP) filings be submitted as Applications. Finally, the Draft Guidance addresses the applicability of the Guidance to Small and Multi-Jurisdictional Utilities.

4. In Part 4, the Draft Guidance lays out the requirements for the DRP filings, including: a) the development of Integration Capacity and Locational Value Analysis tools; b) the development of Demonstration projects; c) the provision of data access; d) an assessment of tariff and contract implications; e) the identification of safety considerations; f) the description of barriers to Distributed Energy Resources deployment; g) an explanation of how the DRP filings will be coordinated with the Utility general rate cases; and h) a description of proposed next steps.

IT IS RULED that that parties may submit comments on the draft Distribution Resource Plan Guidance attached to this Ruling no later than December 5, 2014.

Dated November 17, 2014, at San Francisco, California.

/s/ MICHAEL PICKER
Michael Picker
Assigned Commissioner

ATTACHMENT

Draft Guidance Document for R. 14-08-013

Table of Contents

Part One: Introduction

On August 14, 2014, the California Public Utilities Commission initiated Rulemaking (R.14-08-013) to establish policies, procedures, and rules to guide California investor-owned electric utilities (Utilities) in developing their Distribution Resources Plan Proposals, which they are required by Public Utilities Code Section 769 to file by July 1, 2015. This rulemaking also will evaluate the Utilities' existing and future electric distribution infrastructure and planning procedures with respect to incorporating Distributed Energy Resources (DER) into the planning and operations of their electric distribution systems.

Subsequent to the Rulemaking, the Staff of the Energy Division conducted a workshop on September 17, 2014, to provide a forum for Investor-Owned Utilities (IOUs) and stakeholders to explore issues raised by § 769. The workshop also previewed positions subsequently raised in Comments on the Order Instituting Rulemaking (OIR) that were filed and served on September 22 and Replies that were filed and served October 6, 2014.

This DRAFT document provides additional clarification of several issues raised by Parties and sets out preliminary guidance for content and structure of the Distribution Resources Plans (DRPs) that will be filed by July 1, 2015. The DRPs filed by July 1, 2015 should be consistent with each other in structure and content so they may be more easily compared and analyzed. While each Utility's application will be expected to provide information and proposals that best reflect its own circumstances and operational needs, it is in the Public Interest to ensure some level of standardization in approach and methodology for achieving the goals of § 769.

Therefore, as per the Assigned Commissioner's Ruling that releases this Draft Guidance document, Parties are asked to file and serve comments on this Draft Guidance by December 5, 2014. Reply comments are not specifically requested. A subsequent Assigned Commissioner's Ruling will be issued on approximately February 1, 2015 that includes the Final Guidance on the DRPs in advance of the Utilities' July 1, 2015 DRP filing deadline.

A New Framework for Distribution Planning

Since 2001, the Public Utilities Code has provided that "[e]ach electrical corporation, as part of its distribution planning process, shall consider nonutility owned distributed energy resources as a possible alternative to investments in its distribution system in order to ensure reliable electric service at the lowest possible cost."

In addition, between 2001 and the present, the Commission has developed policies that engaged and promoted ever greater quantities of DERs located within the Utilities' distribution system. In recognition that traditional distribution system planning is limited in its ability to support State policies on DERs and emerging technologies, the Legislature passed Assembly Bill (AB) 327 in 2013

Public Utilities Code Section (§) 769 (established by AB 327) requires Utilities to submit DRPs that recognize, among other things, the need for investment to integrate cost-effective DERs and for actively identifying barriers to the deployment of DERs such as safety standards related to technology or operation of the distribution circuit. Notably, the Commission is authorized to modify and approve a Utility's DRP "as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources."

The goal of § 769 must be understood in the context of both the five explicit requirements that must be addressed in the DRPs, as well as a broader context of California's energy and climate goals. The primacy of AB 32 and Executive Order S-21-09 mean that, in order to deliver benefits, major energy policies initiatives must necessarily support the achievement of 2020 and 2050 greenhouse gas (GHG) reduction targets. The DRPs are no different. This also recognizes the fact that the underlying rationale for promoting increased deployment of the DERs specified by statute is that they have a critical role to play in meeting California's policy of significantly reducing GHG emissions from the State's electricity and transportation systems.

Additionally, because they provide a platform for future investments in energy delivery infrastructure, primarily but not limited to, the electric distribution networks owned and operated by the IOUs, these DRPs should also reflect these parallel goals:

1) to modernize the electric distribution system to accommodate two-way flows of energy and energy services throughout the IOUs' networks;

2) to enable customer choice of new technologies and services that reduce emissions and improve reliability in a cost efficient manner; and

3) to animate opportunities for DERs to realize benefits through the provision of grid services.

An inevitable consequence of these rapidly evolving changes to utility distribution will be the need to add new infrastructure, enhance existing networks and adopt new analytical tools to allow consumers to be active managers of their electricity consumption through the adoption of DERs. The goal is to create a distribution grid that is "plug-and-play" for DERs.

One integral step in this process is the need to dramatically streamline and simplify processes for interconnecting to the distribution grid to create a system where high penetrations of DER can be integrated seamlessly.

Additionally, as recognized by § 769, the Commission, the Utilities, consumers and new service providers, must work cooperatively to revise existing incentives and tariffs to promote DER in locations that will provide the greatest net benefits to the grid. These benefits include enhanced reliability of delivery and the opportunity to introduce innovation - whether driven by the Utilities or by non-traditional parties - into the utility of the future.

A significant component of the net benefit calculation will be whether deeper penetration of DER in a particular location or on a specific feeder will be able to provide an alternative to the most costly upgrades of distribution (or eventually transmission) facilities that might otherwise be necessary to meet load. The deferral or avoidance of network upgrades may, in fact, offset much of the expected costs of accommodating new customer-side resources. So the DRPs must recognize a balance between promoting grid modernization technologies and minimizing the total expected investment in this system while allowing for deeper penetration of DER throughout utility grids. This is, indeed, a daunting challenge, but one that the Utilities and the Commission must face head on in this proceeding.

This locational optimization aspect of § 769 represents an especially difficult challenge to those engaged in this Rulemaking, and this document provides some initial guidance to Parties on how to define optimal locations, and what tools are available to conduct technical analysis of existing circuits to allow for far deeper penetration of DER, while minimizing necessary system upgrades.

Finally, although § 769 appears to call for a one-time exercise in this new method of Distribution Planning, there appears to be general agreement that this should really be an on-going, cyclical process that will repeat over time to incorporate how technologies and market policies are evolving and to take advantage of lessons learned in previous cycles. In addition, it is important that these DRPs reflect not only the prospect of an iterative process going forward, but also recognize and map how each Utility's Smart Grid Deployment Plan will support the DRP initiative.

For this reason, one of the most important recommendations of this guidance document is for the Commission and Utilities to adopt a biennial DRP filing cycle. Each iteration of the process will move California further down a path toward deeper penetration of DER, more effective analysis of where DER provides the most value to customers and to the electric distribution system, and a greater understanding of the policy framework that is necessary to achieve these goals.

Some Parties would like this proceeding, and the DRPs, to serve as platforms for reinventing the existing utility distribution services model - perhaps along the lines being investigated in New York State's "Reforming the Energy Vision" (REV) process. That is not the focus of this proceeding. The OIR decision correctly stated, "The goal of these plans is to begin the process of moving the IOUs towards a more full integration of DERs into their distribution system planning, operations and investment."

Given the significant change this will represent to traditional distribution planning processes - which are mainly focused on meeting expected load growth and potential peak consumption without much regard to customer-side interactions - even this relatively narrow focus may be considered revolutionary.

While it is logical to conclude that effective integration of DERs at the level envisioned by this Rulemaking may well trigger necessary changes to business models and utility service platforms, that is a longer term prospect, and beyond the scope of this current proceeding and this Guidance document. Nonetheless, there may be opportunities in the context of this proceeding to begin exploring ideas for the future - this can only benefit the Commission, Utilities and Parties in understanding the long-term implications of the actions that we begin today. This is why the Commission has recognized and continues to align this proceeding with the *More Than Smart* initiative (described in more detail below).

It is the intent of this Guidance document to incorporate the most relevant outcomes from that initiative while focusing the first proposed DRPs on meeting the directives of § 769. It is my intent that in 2-3 years, we will move beyond questions like how to quantify and operationalize the locational value of DERs, towards a focus on the relationship between the Utilities, consumers, third-party DERs providers and the California Independent Systems Operator (CAISO). What we learn from this round of DRPs will help frame these discussions and provide a critical foundation to evaluate questions related to future business models and market designs.

An addendum to the structural guidance section of this document provides a proposed schedule for phasing future planning developments and activities over a longer term time horizon.

The More Than Smart Vision

Over the course of the last two years, The More Than Smart initiative has sought to bring together leading thinkers at the Grid Edge to develop a framework for integrating DERs into the fabric of distribution planning and operations. More Than Smart started as a collaboration between Caltech's Resnick Institute, the Greentech Leadership Group and the Governor's Office of Planning and Research to organize a set of conferences to discuss how to institute the changes necessary to enable a DER friendly grid. As the More Than Smart initiative progressed, it coalesced around the development of a white paper, *More Than Smart: A Framework to Make the Distribution Grid More Open, Efficient and Resilient,* that was appended to the OIR for this proceeding. This paper presented a set of four key principles around distribution planning, design build, operations and integrating DER into operations that it posits are critical to creating a more open, efficient and resilient grid.

- **Distribution planning should start with a comprehensive, scenario driven, multi stakeholder planning process that standardizes data and methodologies to address locational benefits and costs of distributed resources.** Distribution planning is becoming more complex. An integrated planning and analysis framework is needed to properly identify opportunities to maximize locational benefits and minimize incremental costs of distributed resources. This is enabled by a standardized set of analytical models and techniques based on a combination of utility grid operational data and DER market development information to achieve repeatable and comparable results.

- **California's distribution system planning, design and investments should move towards an open, flexible, and *node-friendly network system* (rather than a centralized, linear, closed one) that enables seamless DER integration.** California's vision for significant DER contribution to resource adequacy and safe, reliable operation of the grid requires a move to a network system. The evolution to an open platform will involve foundational investments in information, communication and operational systems not seen in existing utility smart grid plans. These investments should be based on solid architectural grid principles while ensuring the timing and pace align with customer needs and policy objectives. In the future, the state should strive toward converging electric utility designs with other distribution systems for gas, water and other services.

- **California's electric distribution system operators (DSO) should have an expanded role in electric system operations (with CAISO) by acting as a technology-neutral marketplace coordinator and situational awareness and operational information exchange facilitator while avoiding any operational conflicts of interest.** Today, bulk power systems and distribution systems are largely operated independently. DSOs can help play an integrating role with CAISO. California is already at the point at which integrated and coordinated operations based on better situational information is essential. This integration requires both an expansion of the minimal functions of utility distribution operations and clear delineation of roles and responsibilities between the CAISO and utility distribution system operators. Finally, as with transmission, distribution operations will need standards of conduct to ensure neutral operational coordination.

- **Flexible DER can provide value today to optimize markets, grid operations and investments. California should expedite DER participation in wholesale markets and resource adequacy, unbundle distribution grid operations services, create a transparent process to monetize DER services and reduce unnecessary barriers for DER integration.** Flexible DER can provide a wide range of value across the bulk power and distribution systems. The issue is not if or when, but rather how do

> we enable integration of flexible DER into these systems. This will be enabled by the expansion of CAISO services and new distribution operational services. As such, new capabilities and performance criteria should be identified as part of the distribution planning process. These new services should be coordinated with existing programs knowing some existing demand response programs may be surpassed in their relevance and value in the context of AB 327 objectives. Finally, barriers to broad participation involving complex and expensive measurement and verification schemes and related settlement processes should be simplified for DER.

The More Than Smart paper, and party comments thereof, helped to build the foundation for this guidance. The More Than Smart initiative did not stop at the development of the white paper. It has subsequently continued to convene interested stakeholders to discuss many of the key questions that are raised in this guidance document. In this way, the More Than Smart initiative has served as a way for a diverse group of interested parties, from the Utilities to DER technologist to ratepayer advocates, to engage in open discussion of complex technical questions, which can then to brought forward to this proceeding.

Part Two: Description of Purpose and Scope of the Guidance

The following guidance to the Utilities is intended to describe the structure and contents of the Distribution Resources Plans the Utilities are required to file in July, 2015, pursuant to § 769. This guidance defines certain terms that are used in § 769, as they are to be applied in the plans. Finally, the guidance will clearly describe what is in the scope of the plans, what is being handled in other proceedings and potential overlap and necessary coordination, and existing statutes, standards and requirements that will also govern the plans.

Jurisdictional Scope

The scope of this guidance encompasses the "distribution system," which is the portion of the electric supply system that operates at voltages lower than the transmission level on the "customer side" of the distribution substation. Although "distributed energy resources" are not specified in § 769 in terms of interconnection voltage level or maximum nameplate capacity, it is assumed in this proceeding that DER will mostly be interconnected at the distribution voltage levels (4kV - 16kV or lower) and at sizes of 20 MW or less. This definition puts all DER within the jurisdiction of the Commission, except to the extent that distribution-connected or interoperating DER may participate in the wholesale market.

Identification of Related Proceedings and Processes that Overlap R.14-08-013

These are several Commission proceedings in which subjects such as interconnection, rates, incentives and goals for certain classes of DER are already under active consideration. The following list includes most of the active proceedings that have been identified that directly relate to areas that are potentially encompassed by the DRPs. This is not a complete list, but is meant as a placeholder as more areas of overlap are identified.

- Alternative Fueled Vehicles (R.13-11-007);
- Demand Response (R.13-09-011);
- Distributed Generation (R.12-11-005);
- Energy Efficiency (R.13-11-005);
- Energy Storage (R.10-12-007, now closed, but which is expected to have a successor rulemaking in 2015-16);

- Integrated Demand-Side Management (R.14-10-003);
- Net Energy Metering Successor Tariff (R.14-07-002);
- Residential Rate Reform (R.12-06-013);
- Smart Grid (R.08-12-009, pending closure);
- Water-Energy Nexus (R.13-12-011);
- Energy Upgrade California Marketing Education & Outreach (currently without an open proceeding).
- Rule 21 Interconnection (R.11-09-011)
- Renewable Portfolio Standard (R.11-05-005)

This Rulemaking, and the DRPs that will be filed in 2015, do not intend to supersede policy determinations or programmatic decisions that rightly fall to the above proceedings. For example, this Rulemaking should not establish new procurement targets for the various DERs identified by 769 , but if new information about resource need is developed in this proceeding, the Utilities should make every effort to align this information with what is being determined in the relevant policy proceeding.

Similarly, the DRPs should not be the forum to adopt new tariffs that are instrumental for certain technologies, a task that is rightly relegated to the appropriate rulemaking. For example, while this Rulemaking might recommend that a locational benefit component would be valuable addition to Net Energy Metering, the development of such a tariff is best conducted in the NEM Successor Tariff rulemaking.

In the long run, it may be expected that the changes to infrastructure investment and DER penetration that are enabled via the DRP process will inevitably have impact on Long-Term Planning and Procurement activities currently conducted by the Commission, as well as other procurement mechanisms, ranging from Renewable Portfolio Standard solicitations to Energy Storage procurements.

For this reason, it is essential that Commission Staff and the Utilities make every effort to maintain close coordination among all of these proceedings in order to prevent duplication of effort, conflicting priorities and wasted economic investments.

To the extent that activities in the DRP can or should impact the existing proceedings, the DRPs should identify areas in which the Commission needs to incorporate findings or activities from or into these related proceedings.

Identification of other relevant statutory requirements that DRPs must address

Besides the underlying Legislative mandates that guide Commission responsibilities to ensure safe, reliable and affordable electric services, and the terms of § 769 (and other provisions of AB 327 that impact distributed generation and rates), there is always a potential that new Legislative measures will be enacted into law that could impact DER policies.

One such bill, Senate Bill 1414 (Wolk, 2014), has been recently signed into law to amend Public Utilities Code Sections 380 and 380.5 to establish policies to incorporate demand response (DR) within the Resource Adequacy requirements that Utilities are required meet. While at this point it is uncertain how this new law would impact Utility or third-party DR programs, the Utilities in their planning efforts must assess and accommodate this new directive.

Just as with current regulatory initiatives, the DRPs must explicitly recognize any existing or new Legislative mandates which may have a direct bearing on DER deployment.

Part Three: Commission Oversight

Coordination among Utilities, State Agencies and ISO

Going forward, it is critical that DRP activities be coordinated among the three Utilities, the CAISO, and the California Energy Commission (CEC), as well as the CPUC. Increasing penetrations of DER connected at the distribution level pose operational, planning and policy development challenges for the CAISO and the CEC that must be accounted for in processes that are outside the scope of the DRP. Coordination with the Transmission Planning Process, the Long Term Procurement Planning Process and the Integrated Energy Policy Report is essential, both as the DRPs are developed, and as they are executed.

There is a tension between the desires of DER technology providers and enablers to fully participate in energy service markets beyond provision of energy to residential and commercial customers or utilities, and limits on the current structures to allow full participation in such markets (or those that can be developed in the future). This Rulemaking, and the DRPs that result, cannot resolve these issues at this time, but may represent the first steps toward creation of a new industry model for full and interactive integration of DERs at a level previously unimagined. Coordination among agencies and industry players will be key to success.

CPUC Process

The general schedule of this proceeding was outlined in R.14-08-013 to include the issuance of this Guidance document for public comment and a Commission determination or ruling in early 2015 to allow for Utilities to incorporate both a broad vision and principle, and specific Commission recommendations in their DRPs filings.

While that process proceeds, there will be a period of four or five months in which it may be useful for Commission Staff to actively engage parties and non-Party industry participants in further refining aspects of Distribution Plans, market forecasts, locational benefits analysis, cost-effectiveness methodologies, or the bigger questions of how these may influence regulatory policies and Utility business structures in the future. As part of the final Guidance document, Staff may propose a schedule or menu of workshops or activities to this end.

Categorization of Utility DRP Filings

Given that the DRPs may necessitate cost recovery to be fully implemented, the Utilities are directed to file the DRPs as Applications which the Commission may then consolidate with this Rulemaking into a single proceeding.

Applicability to Small and Multi-Jurisdictional Utilities

In comments to the OIR for this proceeding, the California Association of Small and Multi-Jurisdictional Utilities (CASMU) requested that they be allowed to submit more simplified versions of the DRPs than the three large investor owned utilities. For the purposes of DRP guidance, the CASMU members are directed to file DRPs that, at minimum, address the five statutory requirements in § 769 as it relates to their distribution systems. They are not required to follow the detailed guidance herein.

Part Four: Guidance Distribution Resource Plan Requirements and Definitions

This guidance ruling is intended to define a framework for DRPs that has three major sections: 1) the Definitions section which defines certain terms in PUC §769 and how the Utilities will interpret these terms in the DRPs; 2) the Framework section that describes the structure and intended content of the DRPs; and 3) the description of phasing of next steps.

DRP Content Guidance

1. Integration Capacity and Locational Value Analysis Section

This section directs the Utilities to develop three analytical frameworks related to the grid integration capacity of DER, the quantification of DER locational value, and the future growth of DERs. The intent being to create a set of mutually supportive tools that at once detail how much DER can be deployed under a business as usual grid investment trajectory, while building the capabilities to compare portfolios of DERs as alternatives to traditional grid infrastructure. In recognition of the fact that the Utilities have started elements of this work already, they are directed to take into account work they have previously conducted, or are currently working on, through their Smart Grid Deployment Plans and their EPIC Investment Plans.

a. Integration Capacity Analysis:

This analysis will specify how much capacity may be available on the Distribution network. Worksheets should be provided by the Utilities that show evaluation of available capacity down to the circuit level. To implement this analysis, the IOUs shall include the following in their DRP filings:

i. Perform an Integration Capacity Analysis of their distribution system to the circuit level based on the capability of the system to integrate some quantity of DER within thermal ratings, protection system limits and power quality and safety standards. Results of analysis to be published via online circuit level maps maintained by Utilities and available to the public. Initial Integration Capacity Analysis to be completed by each Utility by July 1, 2015.

ii. Perform analysis to assess current system capability and any planned investments within 2 year period and clearly articulated assumptions for any changes in load and DER growth over the 2-year period.

iii. Perform analysis using dynamic modeling methods while avoiding of heuristic approaches.

iv. Assess the state of DER deployment and DER deployment projections. For each of the identified DERs, the Utilities should provide current levels of deployment territory wide, plus assessment of geographic dispersion and identify circuits that exhibit high levels of penetration.

b. Specify a process for regularly updating the Integration Capacity Analysis to reflect current conditions. The current process in place for updating the Reverse Auction Mechanism that requires monthly updates is a good starting point. Optimal Location Benefit Analysis:

This analysis will specify the net benefit in a given location that DERs can provide. To implement this analysis, the Utilities shall develop, and file as part of their DRPs:

i. A unified locational net benefits methodology consistent across all three Utilities that shall include, at minimum, the following criteria:

1. Avoided capital costs for distribution upgrades
2. Avoided O&M
3. Avoided electricity purchases -- quantified in terms of both retail rates and nodal wholesale prices
4. Avoided Resource Adequacy (RA) purchases -- to include system, local and flexible RA (where applicable)
5. Avoided energy losses for distribution system and transmission
6. Improved distribution system reliability and resiliency. Within the this criteria, the Utilities shall identify specific reliability and resiliency metrics that

DERs could improve (ex: distributed storage reducing SAIFI and SAIDI)
7. Additional Safety-related criteria
8. Definition for each of the benefit and cost criteria included in the locational benefits analysis
9. Description of how a locational benefits methodology can be integrated into distribution infrastructure planning and investment decisions, as well as long-term planning initiatives like the ISO's TPP, the Commission's LTPP, and the CEC's IEPR.

ii. Maintenance and Updates to Locations Analysis:

1. Specify a process for maintaining on-going updates to the DER Integration Capacity Analysis and the Optimal Location Benefits Analysis

c. DER Growth Scenarios:

As part of the DRPs, the Utilities shall develop three ten-year scenarios that project expected growth of DERs through 2025, including expected geographic dispersion at the distribution substation level and impacts on distribution planning. The three scenarios shall be based on the following criteria:

i. Scenario 1: Adapts the IEPR "Trajectory" case for DER deployment for distribution planning,

ii. Scenario 2: Adapts the IEPR "High Growth" case for DER adoption, and

iii. Scenario 3: Based on very high potential growth in the use of DERs to meet transmission system needs and resource adequacy, with key inputs drawn from achieving goals like those articulated in Zero Net Energy targets and the Governor's Zero Emission Vehicle Action Plan.

2. Demonstration and Deployment

As new analytical methods are being developed, it is critical that the Utilities develop proof points that demonstrate the capabilities of DERs to meet grid planning and operational requirements. With this in mind, the Utilities are directed to develop proposals for DER-focused demonstration and deployment projects that seek to demonstrate integration of locational benefits analysis into Utility distribution planning and operations. Where feasible, these demonstration projects should be coordinated with on-going efforts associated with each Utility's smart grid deployment plan and EPIC investment plan. To implement this guidance, the IOUs shall include the following in their DRP filings:

a. Demonstrate the Optimal Locations Benefits Analysis Methodology:

i. Perform a Locational Benefits Analysis for one Distribution Planning Area ("Study") that is linked to a known transmission system benefit for the purpose of demonstrating the analysis methodology and stakeholder engagement process. Study shall be completed by July 1, 2015.

b. Demonstrate DER Locational Benefits:

i. Develop a specification for a demonstration project where at least three DER use-cases (ex: resources adequacy, distribution capacity deferral, voltage/reactive power regulation) can validate the operational effectiveness of DER to achieve net benefits consistent with Locational Benefits Analysis. Such a DER demonstration project will either, a) displace, or b) operate in concert with existing infrastructure, to provide the defined functions. This demonstration shall also explicitly seek to demonstrate the operations of multiple DERs in concert, and as part of this component of the project shall explain how DER portfolios were constructed. This Demonstration project shall be scoped to commence within 1 year of Commission approval of the DRP. Use cases shall employ services obtained from customer and/or 3rd party DER. Each Utility shall specify services for each use case and related transaction method (e.g, contract, tariff, marginal price) by which customer and/or 3rd party DER will provide services under the demonstrations.

c. **Demonstrate Distribution Operations at High Penetrations of DER:**

i. Develop a specification for a distribution planning level area level demonstration of high DER penetrations that integrate into the IOUs distribution system operations, planning and investment for implementation. This analysis of potential benefits and locational values associated with high-DER penetration should be conducted at the Substation level and involving up to 4 or 5 circuits may serve as a prototype model which upon completion and refinement could be applied on a wider scale. This demonstration shall also explicitly seek to demonstrate the operations of multiple DERs in concert, and as part of this component of the project shall explain how DER portfolios were constructed. This Demonstration project shall be scoped to commence within 1 year of Commission approval of the DRP.

d. **Demonstrate Distribution Marginal Pricing:**

i. A specification for a demonstration project that seeks to quantify distribution marginal pricing for a distribution planning area over the course of a normal distribution infrastructure planning horizon. Included as part of this project will be a process for making public the distribution marginal prices that are derived from the project. This Demonstration project shall be scoped to commence within 1 year of Commission approval of the DRP.

3. Data Access

Many of the above sections require various amounts and types of data to be transferred between the utilities and third parties. In some cases, the Utilities may "own" (generate or acquire) the data and in some cases the data may be owned or generated by either the customer or the third party. Data sharing involves a mechanism for communicating the data among the Utilities, customers and DER owners/operators. The type of data that will be shared depends necessarily on the proposed use of the data, and what the use of the data enables, by customers, the market, and the Utility. The following types of data have been mentioned by various parties as important to furthering the goals of the DRP process:

Distribution system characteristics

- Existing distribution characteristics at substation and feeder-level – coincident & non-coincident peaks/ capacity levels/ outage data/ projected investment needs
- Electric Vehicle and charging station populations
- Existing DG population characteristics
- Backup Generator population
- Generation production characteristics, associated with intermittent resources
- Existing combined heat and power installations

Distribution Planning Data

- Demographics: household income levels, CARE customers
- Customer DG adoption forecasts
- Other customer DER adoption forecasts
- Distribution Planning load forecasts, based on forecasting scenarios proposed elsewhere in the plan.

Given that issues related to accessing customer data have been recently litigated in Commission Decision (D.) 14-05-016, it is prudent for the DRPs to instead focus on addressing data access relating to data not subject to D.14-05-016. With this in mind, the Utilities should include the following in their DRPs related to data access:

a, Proposed policy on data sharing:

i. Types of data that will be shared, including, but not limited to, all data fields referenced herein.

ii. Requirements for receiving data from DER owners (DER owners/operators)

b Procedures for data sharing:

i. Proposed process for sharing data with customers and DER owners/operators. Where data is deemed to be confidential, an explanation of why data cannot be shared and a proposed alternative to sharing data that still supports goals of DRPs.

ii. Proposed method for making this data available in as near real time as possible, subject to existing privacy constraints, with explicit consideration for how third parties can access this data directly, using the ESPI Customer Data Access system.

c. Grid Conditions Data and Smart Meters

i. Description of Utilities current plans for obtaining data from smart meters, beyond interval billing data, that reflect power quality and other factors. These data potentially include voltage, frequency, reactive power/power factor.

4. Tariffs and contracts

The DRPs may "propose or identify standard tariffs, contracts or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives." For the purposes of these DRPs, discussion of new or modified tariffs and contracts should be limited to their applicability in demonstration projects. To implement this guidance, the Utilities shall include the following in their DRP filings:

a. Outline all relevant existing tariffs that govern/incent DERs (ex: NEM, EV-TOU, Rule 21).

b. Develop recommendations for how locational values could be integrated into the above existing tariffs for DERs.

c. Develop recommendations for new services, tariff structures or incentives for DER that could be implemented as part of the above referenced demonstration programs.

d. Develop recommendations for further refinements to Interconnection policies that account for locational values.

5. Safety Considerations

Although the utilities must comply with applicable safety and reliability standards in the Public Utilities Code and General Orders, it may be necessary to propose new or modify existing standards in order to accommodate high levels of DER. For the purposes of these DRPs, the Utilities shall include the following in their filings:

a. Identify potential reliability and safety standards that DERs must meet and suggest a process for facilitating compliance with these standards. Are there differing requirements or standards that should be considered for different types of DER?

b. Delineate how DERs can support higher levels of system reliability and safety (e.g. improved SAIDI/SAIFI, resiliency, improved cybersecurity).

c. Describe major considerations for owners/operators of DER equipment, and for first-responders (fire, police and health professionals).

d. To the extent possible, describe Utility efforts to inform and engage relevant local authorities that may bear the responsibility for local permitting of DER equipment.

6. Barriers to Deployment

The DRPs shall identify any barriers to deployment of DER as specified in §769 and outlined in Definitions herein. The DRPs shall focus on three categories of barriers: i) Barriers to integration/interconnection of DERs onto the distribution grid, ii) Barriers to limit the ability of a DER to provide benefits; iii) Barriers related to distribution system operational and infrastructure capability to enable DER provision of benefits. For each of these categories of barriers, the DRPs should identify the top three barriers for each type of DER.

a. Barriers to integration/interconnection of DERs onto the distribution grid

b. Barriers that limit the ability of a DER to provide benefits

c. Barriers related to distribution system operational and infrastructure capability to enable DER provided value related to needed investment in advanced technology such as advanced protection and control systems, telecommunications and sensing.

Within each of the identified types of barriers, the DRPs shall categorize the barriers as follows:

-Statutory: statutory prohibitions (ex: inability of large campus with single master meter to deploy more than 1 MW of NEM);

-Regulatory: regulatory rules or processes that increase cost of DER deployment or limit DER functionalities (ex: prohibition on using customer smart meter data for settlement in CAISO market);

-Grid Insight: lack of visibility into distribution system conditions, Bulk Electric System conditions, or actual performance of DER that limit DER deployment of operations

-Standards: inadequate or undefined standards (ex: IEEE 1547 currently does not allow smart inverter functions to be enabled);

-Safety: safety standards related to technology or operation of the distribution circuit (ex: local fire codes that have not been updated to reflect best in class understanding of fire risks associated with rooftop PV;

-Benefits Monetization: lack of mechanism to monetize DER benefits (ex: CAISO market currently does not allow DERs to bid into market to provide certain services like spinning reserve);

-Communications: lack of communications link between DER and utilities grid operator limits deployment or benefits monetization of DER (ex: inability to sub-meter EVs in the absence of a smart meter increases cost of providing an EV owner a time-of-use rate for their EV consumption).

7. DRP Coordination with Utility General Rate Cases

One of the most critical components of the DRP process will be its interface with the Utilities General Rate Cases. As the analytical tools and demonstration projects required of the DRPs come to fruition, the interface with each Utility's GRC should become clearer. That said, it is currently too early to direct the Utilities to integrate any given piece of the DRP in their next GRC filing. Instead, the Utilities shall include a section in their DRPs where they describe what specific actions or investments may be included in their next GRCs as a result of the DRP process.

8. Phasing of Next Steps

As discussed already, the DRPs are likely only to be effective if they serve as the starting point in an on-going effort to integrate DERs into distribution planning, operations and investment. With this in mind, the DRP process should be a living one, where the Commission, the Utilities and stakeholders engage continuously to refine the activities and goals that are central to the DRPs themselves.

Although §769 appears to call for a one-time exercise in this new method of Distribution Planning, there appears to be general agreement that this should really be an on-going, cyclical process that will repeat over time to incorporate how technologies and market policies are evolving and to take advantage of lessons learned in previous cycles. For this reason, the Utilities shall include in their DRPs a plan for how their DRPs can be updated on a biennial filing cycle. Included in this component of the DRPs shall be the following:

a. A proposal for rolling updates to the DRPs occurring at least every two years for the next ten years, including a clear mapping of how these subsequent DRP phases will interact with each Utility's GRC.

As part of the Commission's consideration of these DRPs, the Commission will consider, and potentially approve, a scope for subsequent DRPs. In addition to the requirement of the Utilities to include in their DRPs a "Phasing of Next Steps", Staff has developed the following recommendations for the content of the DRP process should be phased over the next 10 years. As part of their DRP filings, the Utilities shall include:

b. A proposal that either adopts, or adopts with amendments, the following set of recommendations:

   i. 10-year time horizon, synchronized with GRC, LTPP and TPP processes.

1. Phase 1: 2 years (2016-17)

This phase will primarily focus on the evaluation of the capacity of the distribution system to support DER under the current load forecasting scenarios. The evaluation granularity should ideally be at the substation level. Utilities will need to develop or acquire tools to support this effort. Models of DER should be developed during this phase that will enable testing of scenarios. The tool development should include analysis and design of system instrumentation (sensors) required to provide input data to distribution system models.

The deliverables of this phase should include GIS maps and powerflow models of the entire distribution system to the substation level that are available in a standard format that is tool independent. In order to support third party participation in determination of optimal locations, there should be the necessary policy support for third party access to maps and models. This phase will also include planning and design of communications infrastructure to support interconnection of DER for monitoring and control.

2. Phase 2a - 2 years (2018-19)

During this phase, the methodology defined in Phase 1 will be employed to determine impacts on distribution system at the substation or feeder level. The process will be executed across the distribution system using DER models developed in Phase 1. This will provide information that can be used to identify both optimal locations and combinations of DER that can provide services in those locations. As possible, given funding constraints, continue to deploy sensors and communications infrastructure designed in Ph. 1 and continue data collection and analysis. Simulation of portfolios of DER using models developed in Ph. 1 should be completed using data acquired using monitoring and communications systems to determine impacts on distribution system.

Output of this phase will be "Distributed Energy Resource Development Zones" (could be Distribution Planning Areas) that can be associated with locational values. In these zones, additional DER portfolios would be defined using the process of value optimization. The value optimization methodology will specify tools and processes to compare DER as an alternative to traditional Distribution infrastructure investments, including both operations and economic factors

Specify tools and process to compare DER as an alternative provider of distribution reliability functions, including voltage regulation (etc.).

Specify process for utilizing above tools, including stakeholder input and feedback into analytical methods

3. Phase 2b - Ongoing (2018 and Beyond)

This phase will entail stakeholder-driven development of DER procurement policy and mechanisms for the IOUs. The procurement policy will be competitively neutral and will accommodate development of non-utility-owned distribution systems such as islandable microgrids and parallel DC and thermal distribution systems.

These activities will also include the development of Distribution System Market that can support grid service transactions. On an ongoing basis, the IOUs will update distribution system status in terms of DER deployment and associated system impacts.

Based on these ongoing activities, a stakeholder-driven process will develop an analytical plan for how these deployment scenarios would impact distribution planning and identify what gaps exist in current plans to support achieving each of the scenarios. Specify plan for developing a rolling 5 year DER forecast to be included in distribution infrastructure planning, including how forecast will influence distribution expenditures.

Definitions

§ 769 uses several key terms with regard to specifying the content of the DRPs, but does not define them. This Rulemaking will offer definitions based on the record, industry practice and interviews with stakeholders. These definitions are intended to provide the basis for methodologies that will be described in the plans. The terms defined here are: a) optimal locations; b) locational value; c) cost effectiveness.

Distributed Energy Resources

For the purposes of the DRPs, §769 defines 'distributed resources as, "distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies". Given that these are somewhat broad categories, the DRPs should, at minimum, consider the following categories of DERs, with a particular focus on instances where multiple DERs are operating in concert:

Distributed Renewable Generation

- Distributed Generation – PV
- Distributed Generation – Wind
- Distributed Generation – Stationary Fuel-Cell*
- Distributed Generation – CHP*
- Distributed Generation – Stationary I-C Engine*

Energy Efficiency

- Energy Efficiency -- Residential
- Energy Efficiency – Small Commercial
- Energy Efficiency – Large Commercial
- Energy Efficiency -- Industrial

Energy Storage

- Energy Storage – Customer Side
- Energy Storage – Utility Side

Electric Vehicles

- Electric Vehicles – Residential Charging
- Electric Vehicles – Workplace/Public Charging
- Electric Vehicles – Managed Charging (VG1)

- Electric Vehicles – Bi-Directional Power Flow (VG2)

Demand Response

- Demand Response – Residential/Small Commercial
- Demand Response – Large Customer

Other DER

These three categories of DG have the potential to be fueled by renewables, but to date most deployments have been natural gas fueled. Given that the statute defines distributed resources as having to be "renewable," the DRPs must first focus on the analysis of Fuel Cells, CHP and Internal Combustion engines that are fueled by renewables. That said, natural gas fueled stationary Fuel Cells, CHP and stationary I-C engines have the potential to reduce GHG emissions, and so the utilities are encouraged to expand the scope of their DRPs to include any distributed generation that can produce GHG emissions reductions over its lifecycle.

Optimal Locations

Optimality is usually defined as a minimum or a maximum of some function or set of functions. In the case of DER, a location is optimal if:

- Some quantity of DER can be interconnected without grid upgrade or with low or no interconnection cost, i.e., minimum distribution grid impact;
- DER can serve as a solution, e.g., in Distribution Substation areas where DER can serve as a solution to defer distribution upgrades or reduce operations and maintenance expenses;
- The deployment of DER in a specific location, particularly Resource Adequacy Local Capacity Areas, can demonstrated to defer new generation or transmission;
- A DER can ensure the provision of safe and reliable operations of the grid in a specific location
- A DER can enhance the reliability of service and resiliency against service interruptions at a specific location;
- A deployment of DER can provide other benefits such as economic, environmental or social equity at a specific location.

Determination of optimality using the above definitions should also include consideration of whether the DER deployment utilizes customer side (behind the meter) or utility side (in front of the meter) interconnection.

Locational Values and Benefits

"Locational Value" is defined here as monetary value that accrues to customer and/or the utility associated with the provision of a specific service at some defined location.

"Benefits" is defined here can either be economic, operational (from the utility perspective) or societal, and locational benefits are generally defined as a monetary value that can be assigned to some location, using a set of criteria.

The method for assessment of "Benefits" should be based on considerations of how to flow locational benefits through to customers, either in terms of rates or incentives, or other mechanisms.

Cost Effectiveness

Cost-effectiveness standards are already applied to customer side distributed generation. It is not the goal of this proceeding to redefine how these cost-effectiveness standards are calculated or applied. Instead, this proceeding will utilize and build upon existing cost-effectiveness standards so they are congruent with the locational value orientation of § 769. That said, the DRPs seek to go beyond existing models of DER deployment, and as such current cost-effectiveness may be insufficient to fully characterize the value of DERs. For example, distributed generation (DG) programs utilize the E3 avoided cost calculator, yet the tool does not have the capacity to account for the potential of DG to provide differential avoided distribution infrastructure costs based on the location of the DG. This type of analysis is central to the DRPs, and so the DRPs must be able to go beyond the current cost-effectiveness protocols where needed

Attachment 5

APS Renewable Energy

PHOTOVOLTAIC GRID TIED ELECTRIC SYSTEM
RESIDENTIAL RESERVATION APPLICATION

Thank you for your support of solar technology. APS is proud to welcome you to our APS Renewable Energy Incentive Program (the "Program"). Please fill out and submit this Reservation Application along with a proposal from your equipment dealer to ensure that we receive the required information to process your reservation application. If you have any questions, please call 602-328-1924.

IT IS IMPORTANT TO NOTE THAT SUBMITTING YOUR RESERVATION APPLICATION DOES NOT GUARANTEE PROJECT FUNDING. APS will provide you with written acceptance of your reservation application. Please also note that a spending cap is set each year for the Program. After the cap has been reached, customers applying for funding will be placed on a wait list. Incentive applications are reviewed on a first com, first served basis.

1. **Complete and submit a completed and signed Reservation Application and a quote which includes an itemized list of system components including the model number and manufacturer for the generator and, if applicable, the inverter.**

2. **Receive reservation confirmation. Review, sign and return agreement**
   When your reservation has been reviewed, you will receive written notification that you were approved or that you were denied. Along with your approved written notification you will also receive an agreement that covers the terms and conditions for the interconnection of your system to the APS distribution system, credit purchase and, if applicable, purchase supply.

3. **Complete and submit an APS Interconnection Application** (Either you or your equipment dealer can complete this step).

4. **Receive Preliminary Approval Confirming System Design Appears to Meet APS Interconnection Requirements**
   APS will send written notification that the equipment submitted appears to be in conformance with APS' Interconnection Requirements.

5. **Proceed with Installation and Obtain Necessary Municipal Clearances.** (Typically your equipment dealer will assist you in obtaining any necessary clearances).

6. **Schedule APS Interconnection Inspection**
   Contact APS to request an interconnection inspection. APS will send you an authorization letter confirming that the PV System has passed inspection and that permission has been provided for the PV System to operate in parallel to the APS grid. **It is critically important to note that only an authorized APS representative can provide permission for your system to operate in parallel to the APS distribution system.**

7. **Request Incentive Payment**
   Please submit the following so that an incentive payment can be issued:
   - Installation Certification form signed by both the dealer and the installer
   - Receipt confirming the system purchase price, payment, and installation by an Arizona licensed contractor

<u>Submittal address for all program documents</u>:
APS Renewable Energy Incentive Program
PO Box 53933, MS 3161
Phoenix, AZ 85072-3933

NOTE: ALL FORMS ARE AVAILABLE VIA APS.COM OR BY CALLING 602-328-1924.

APS Renewable Energy

PHOTOVOLTAIC GRID TIED ELECTRIC SYSTEM RESIDENTIAL RESERVATION APPLICATION

How did you hear about the APS Renewable Energy Incentive Program?

☐ Brochure at Event ☐ Annual Use Letter ☐ Print Ad ☐ TV ☐ Website ☐ Radio ☒ Other [redacted]

CUSTOMER NAME AND MAILING ADDRESS INFORMATION

Primary Customer Contact Name

First Name [redacted] Last Name [redacted]

Secondary Customer Contact Name

First Name ____________ Last Name ____________

Mailing Address

Street Name [redacted]

City [redacted] State [redacted] Zip [redacted]

Will Customer own the PV System? ☐ Yes ☒ No

CUSTOMER CONTACT INFORMATION

Home Phone [redacted] Business Phone ____________

Email Address [redacted] Cell Phone ____________

INSTALLATION SITE INFORMATION

APS Account Number [redacted] Meter Number [redacted]

It there is currently no electrical service at the installation site, please leave the APS account number and meter number blank and check here.☐

Installation Address (If same as mailing address, check here ☒)

Street Name ____________

City ____________ State ____________ Zip ____________

ACCESS INFORMATION

Is your electric meter located behind a fence or gate?	☐ Yes	☒ No
If yes, do you have or plan to have a dog at this location?	☐ Yes	☒ No
Do you plan to install the Utility Disconnect at the service entrance?	☒ Yes	☐ No

MISCELLANEOUS INFORMATION

Are you a manufacturer, dealer or installer of PV Systems, or one of its employees?	☐ Yes	☒ No
Are you a developer or homebuilder?	☐ Yes	☒ No
Are you the primary occupant at the site location?	☒ Yes	☐ No
If not, are you a landlord or owner?	☐ Yes	☐ No

NOTE: If you answered yes to any of the miscellaneous questions above, you may be required to submit additional information.

EQUIPMENT DEALER INFORMATION

Dealer Name (please supply full legal name) American Solar Electric, Inc.

Contact Name Renee Guillory Telephone 480-994-1440

Fax 480-994-1438 E-mail renee.guillory@americanpv.com

Mailing Address 1475 N. Scottsdale Road Suite 410, Scottsdale, AZ 85257

INSTALLER INFORMATION (If same as equipment dealer, check here ☒)

Installer Name (please supply full legal name) ____________________

Contact Name ____________________ Telephone ____________________

Fax ____________________ Email ____________________

Mailing Address ____________________

Arizona Registrar of Contractors (AZROC) License Information

Number 168657/236520 Class k-11/k-42 Expiration 09/2009

ASSIGNMENT OF PAYMENT

Will payment be assigned to an installer, dealer or manufacturer of the qualifying system? ☒ Yes ☐ No

If yes, please complete and sign the information below:

> I authorize APS to issue Credit Purchase funds to the following third party, on my behalf, as payment toward the cost and/or installation of my PV System. I acknowledge and agree that payment made by APS to the third party below shall satisfy APS' payment obligation to me in connection with the Agreement and that, once made, APS shall have no further obligation whatsoever to me.

Dealer/Company Name (assignee) [redacted]

Address [redacted]

Customer Signature [redacted] Date [redacted]

NET BILLING AND NET METERING RATES

Please indicate your rate plan choice for compensation received from APS for the power generated by your PV System that will be delivered to the APS distribution system.

☐ EPR-2 (Energy sent back to the APS grid will be purchased by APS at wholesale price, often called "net billing")

☒ EPR-5 (Energy sent back to the APS grid will appear as a kWh credit on your bill, **often called "net metering"**)

Rate schedules are posted @ www.aps.com/ or call 602-328-1924.

INCENTIVE REQUEST (Typically your installer or equipment dealer will help you with this section).

Available residential incentive is a one-time payment of $3.00/Watt DC-STC **up to a maximum incentive of 50% of the System Cost.** Incentive payments for dealers or manufacturers of PV systems or employees of dealers or manufacturers of PV systems are capped at 50% of the system cost basis. The maximum up front incentive is $75,000 per Customer.

Total Proposed Installed System Cost: $34,020.00
(Note that incentive payment is capped at 50% of total installed system cost)

$3.00 x 5,400 (Watts DC-STC) = $16,200.00 (Total Maximum Incentive)

The minimum PV array size shall be 1,000 watts DC-STC

DE-RATING INFORMATION (Typically your installer or equipment dealer will help you with this section).

The productivity of PV Systems is sensitive to the specifics of the installation method and location, including shading, PV panel tilt angle, and azimuth. Incentives may be de-rated in accordance with the **PV Off Angle and Shading Incentive Adjustment Chart ("Adjustment Chart"). The Adjustment Chart is attached hereto as Appendix A to the Agreement. An on-line calculator is also available on aps.com or by calling 602-328-1924.**

Proposed Array Azimuth Angle from Due South 2°/88° (True)

Proposed Angle Above Horizontal (tilt angle) 18°

The azimuth is the compass direction your solar system faces. Ideally, solar units should face south to collect the most solar energy throughout the year. The further east or west the system faces the lower the yearly output will be.

The tilt angle is the tilt of the solar panel in relation to horizontal. For maximum yearly energy product, this tilt should be at approximately 30 degrees for fixed systems installed in Arizona. Furthermore, the flatter the solar panels are the more summer energy production, but the lower the winter production.

Is there a tree, building or overhang that is in proximity to the PV array? ☐ **Yes** ☒ **No**

If you answered yes, please indicate the estimated percentage impact this will have on system production:

☐ **Less than 10 %** ☐ **11% - 25%** ☐ **26% - 40%**

Based on the survey of your installation site and the installation plan, does your dealer or installer anticipate that the incentive will be de-rated? ☐ Yes ☒ No

If yes, by what percentage will the above incentive be de-rated? ____________

Attach a quote from your installer that includes an itemized list of system components including model and manufacturer of both the PV module(s) and the inverter(s).

NOTE THAT ANY MATERIAL CHANGES TO THE INFORMATION PROVIDED IN THE RESERVATION APPLICATION MUST BE PROVIDED TO APS THROUGH AN AMENDED SPIP APPLICATION AND AGREEMENT. FAILURE TO SUBMIT AN AMENDED SPIP APPLICATION AND AGREEMENT AS REQUIRED MAY JEOPARDIZE CUSTOMER'S ELIGIBILITY TO RECEIVE THE INCENTIVE PAYMENT FROM APS.

CUSTOMER **APS**

[redacted]

Name (Please Print)

Signature

Date

By (Please Print)

Signature

Date

IF MORE THERE IS MORE THAN ONE ACCOUNTHOLDER ON RECORD WITH APS, PLEASE HAVE NON PRIMARY ACCOUNTHOLDER(S) ALSO SIGN BELOW:

CUSTOMER

Name (Please Print)

Signature

Date

CUSTOMER

By (Please Print)

Signature

Date

This confirmation information will be completed by APS:

Reservation # ______________________________

Reserved Incentive Amount ______________________

Attachment 6

Hudson Light & Power Department

Photovoltaic Incentive Program

Incentive type: Utility Rebate Program
Eligible Technologies: Photovoltaic (PV)
Applicable Sector: Residential/Commercial/Industrial/Municipal
System Maximum capacity: 100 kW DC
Incentive Amounts: $1.00/watt – for Range 1 panel orientation
$1.25/watt – for Range 2 panel orientation
Maximum Incentive:
Range 1 - $5,000 per residential customer, per installation, per 12-months period
$10,000 commercial/industrial/municipal customer, per installation, per 12-months period
Range 2 - $6,000 per residential customer, per installation, per 12-months period
$12,000 commercial/industrial/municipal customer, per installation, per 12-months period

Program Budget: Limited and capped
Restrictions: Only HLPD customers in good standing qualify. Subject to applicable restrictions in the HLPD Rate Schedules and prior agreements. Good standing will be determined at the time of application and is defined as no more than one unpaid balance at the end of the billing period and before the next bill is issued for the prior 24 consecutive months.
Ownership of Renewable: Grid connected HLPD customer

Summary:

HLPD offers rebates to HLPD customers who install photovoltaic systems on their property. Project eligibility for a rebate is dependent on the orientation of the panels and the lack of shading during the summer months.

Customers will be required to have an inverter that automatically disconnects the PV system from the grid in the event of a power failure and must install a separate safety disconnect switch.

Contact: HLPD Engineer, 49 Forest Avenue, Hudson, MA 01749.

Phone: (978) 568-8736

Website: www.hudsonlight.com

Two websites where further information on local products and contractors can be found are www.sebane.org and www.nesea.org

HLPD reserves the right to modify or terminate this program without prior notice.
Check with HLPD on the program status and availability of funds.

Hudson Light & Power Department

Photovoltaic Incentive Program Overview

Thank you for your interest in the HLPD Photovoltaic (PV) Incentive Program. The information you need to apply for PV rebate is attached. Additionally, you may also want to reference www.sebane.org and www.nesea.org to find renewable products and services. Installing a PV electric system requires an advanced understanding of proper electricity and building practices. HLPD and your local building officials (where necessary) will need to approve the installation before you can receive the rebate.

Here are the basic steps to help you determine if a PV system is right for you and to apply for rebate:

1. HLPD recommends having an energy audit prior to installing a solar electric system.
Energy efficiency and conservation are the first steps in any successful energy improvement plan. The less energy you use, the further your solar generation will go. Installing a PV system is a comprehensive endeavor. To make best use of the energy you produce it is wise to first find ways to reduce your consumption. Customers may contact Energy Hotline (888-772-4242) to request an energy audit. Energy audits are free for HLPD's residential customers and are partially reimbursable for commercial/industrial customers (call HLPD for details or visit www.hudsonlight.com).

2. Complete a site assessment.
The best way to find out whether you have a good location for a PV system is to have a professional site assessment. A site assessment will provide information about the suitability of your site for solar, and the best place to locate and orient your system. This is a critical step for anyone considering solar electricity, solar water heating or other system. Please note that it is customary for solar contractors to charge a fee to perform a site assessment. You should only need one, even if soliciting two bids. Once the site has been evaluated please plan to contact HLPD to discuss the details of interconnecting, etc.

3. Choose an installer.
Choosing an installer who provides comprehensive design, equipment, and installation services is an important step. It is best to obtain two or three estimates before hiring an installer. An estimate should include the cost of hardware, shipping, installation, connection to the utility grid, and travel. It is customary for installers to offer bids that are good for a period of two weeks due to volatility in solar panel availability and pricing. A good contractor will acquire permits, assist with rebate forms, and obtain an approved utility interconnection agreement for you. Be sure to verify that the installer you choose is eligible to participate in this program.

4. Apply for a rebate.
Make sure your installer is working with HLPD on the interconnection agreement and with local officials on any applicable building and installation codes and permits. The interconnection agreement can be obtained at HLPD. To apply for a rebate fill out and submit a Request for Rebate Confirmation form to:

HLPD Engineer, 49 Forest Avenue, Hudson, MA 01749

You have 12 months from the date of Rebate Confirmation to complete the installation of the system. When the installation is done and you have completed HLPD's interconnection requirements and forms, you may request a rebate.

5. Follow up.
HLPD will perform a routine follow up inspection and field test of the facility to see that all construction went as planned. If the customer has any questions at anytime they can always feel free to contact us.

Hudson Light & Power Department

Photovoltaic Incentive Program Details

HLPD administers an incentive program for grid-connected PV electric installations. The program offers a rebate of $1.00 or $1.25 per installed watt, depending on panel orientation. The maximum rebate amount per installation is $5,000/$6,000 per residential customer and $10,000/$12,000 per commercial/industrial customer, per 12-months period, depending on panel orientation.

Eligible Participants
Any grid connected HLPD customer in good standing, subject to applicable restrictions in the HLPD Rate Schedules and prior agreements, are eligible for the rebate.

All rebates are subject to HLPD approval, whether it is a new installation or an addition to an existing PV installation. Existing PV installations do not qualify for a rebate. One-for-one replacements do not qualify for a rebate. Home based businesses qualify for residential PV rebate.

HLPD reserves the right to modify or terminate this program without prior notice. Check with HLPD on the program status and availability of funds.

Eligible Equipment
1. All of the major system components including panels and inverter must be new.

2. Photovoltaic panels must come with a 20-year or greater manufacturer's warranty and must be certified as meeting the most current edition of Underwriters Laboratory standard 1703 (UL1703).

3. All grid-tied, sine-wave inverters must be certified as meeting the current edition of Underwriters Laboratory Standard 1741 (UL1741).

Installation Requirements
1. Installations are subject to the requirements and provisions of Massachusetts's building codes, the National Electrical Code, and HLPD's Distributed Generation Installation requirements.

2. Participants are responsible for ensuring an accurate representation of the site.

3. Installers must work directly with the HLPD for new metering application, installations and locations.

4. Fixed and manual-tilt installations should have an azimuth range (direction the solar panels are facing) between 170° and 220° (**Range 1**) or >220° and 300° (**Range 2**). The purpose for such orientation range is the reduction of the late afternoon HLPD summer system peak. The peak reduction benefits all HLPD customers who fund this rebate program.

5. Fixed-tilt installations shall have a solar panel tilt angle between 20 and 60 degrees from the horizontal.

6. Installations should be completely free of shading during the hours of 13:00 to 17:00 from June 1st until August 31st. HLPD requires that a shading analysis be provided from the points chosen by HLPD on the proposed panel layout drawing. For shading analysis purposes all sections of proposed array must be included.

7. Installations must be performed by professional installers in order to qualify for a rebate. A licensed electrician must perform all electrical work.

8. The installer must provide information to the owner about operation and performance considerations relating to shading, snow cover, and maintenance of the system.

9. Provide to HLPD a site diagram. A site diagram is a drawing of your PV installation's location and nearby objects that might shade the system.

10. An AC safety disconnect switch must be installed at a location approved by HLPD between the inverter and the electrical panel. A second (check) meter may be required and located in an accessible location to measure the output of the PV system

11. PV system owner will be responsible for all grid interconnection costs incurred by HLPD.

Hudson Light & Power Department

Request for Photovoltaic Rebate Confirmation

1. *I have read and understand HLPD's PV Rebate Program documents.*

2. *I understand if I proceed with a PV installation, I am responsible to contact HLPD prior to final commitment to project to be eligible for rebate.*

3. *I agree to provide HLPD access to the proposed installation site.*

4. *I have read, understand and agree to HLPD's Terms & Conditions.*

To obtain an estimated PV rebate amount, which may be granted if all requirements are met, please provide:

PV System kW DC rating: ______________________________

Installer: ______________________________

A licensed electrician must perform all electrical work.

Electrician: ______________________________

Electrician's License #: ______________________________

The undersigned warrants, certifies and represents that:

(1) *I have spoken with HLPD's Engineer;*
(2) *The information provided in this form is true and correct to the best of my knowledge;*
(3) *The installation will meet all HLPD PV Rebate Program requirements.*

Applicant's Name (*print*): ______________________________

Title (*if applicable*): ______________________________

Company Name (*if applicable*): ______________________________

Address: ______________________________

Site Address (*if different*): ______________________________

Phone #: ____________________ Fax #: ____________________

Email: ____________________ HLPD Account #: ____________________

Signature: ____________________ Date: ____________________

(For HLPD use only)

Date Application Received: ____________________ Application Ref. #: ____________________

Date of Approval: ____________________ Estimated Rebate Amount $ ____________________

Taxable ________ Non-Taxable ________

Hudson Light & Power Department

Interconnection Application & Service Agreement

(For PV system with Inverter Capacity of 100 kW and under)

Contact Information
(*Name and address of interconnecting customer applicant*)

HLPD Customer (*print*): ____________________

Company Name: ____________________

Address of Interconnection Facility: ____________________

City: ____________________ State ____________________ Zip Code: ____________________

Telephone (*daytime*): ____________________ (*evening*): ____________________

Fax Number: ____________________ E-Mail Address: ____________________

Account Number (*required – on bill*): ____________________

Meter Number (*required – on bill*): ____________________

Additional Contact Information (*e.g., system installation contractor or coordinating company*)

Name: ____________________

Company Name:

Mailing Address:

City: ____________________ State: ____________________ Zip Code:

Telephone (*daytime*): ____________________ (*evening*): ____________________

Fax Number: ____________________ E-Mail Address: ____________________

PV System Information

Inverter Manufacturer: ____________________ Model Name & #: ____________________
Nameplate DC Rating: ________ (kW) ________ (kVA) ________ (Volts).
Single _____ Phase, or Three ______ Phase. Quantity Used: ________
System DC Design Capacity: __________ (kW) __________ (kVA)

Electrical Contractor (*contact name, company name, address, phone #*):

____

____

____

PV System UL1741 Listed: Yes _____ No _______
Estimated Installation Date: ____________________ Estimated In-Service Date: ____________________

Customer Signature

I hereby certify that, to the best of my knowledge, all of the information provided in this application is true and I agree to HLPD's Terms & Conditions for Interconnections:

Interconnecting Customer Signature ____________________ Date ____________________

Please attach manufacturer's document showing UL1741 listing to this document and mail to:

HLPD Engineer, 49 Forest Avenue, Hudson, MA 01749

Approval to Install PV System (*for HLPD use only*)

Installation of the PV System is approved contingent upon the terms and conditions of this Agreement and agreement to any system modifications, if required. System modifications required: Yes ___ No ____ TBD ____
HLPD Ref. Number: ____________________

HLPD Signature: ____________________ Title: ____________________ Date: ____________________

Hudson Light & Power Department

HLPD Terms & Conditions for Interconnections

1. **Construction of the PV system.** The interconnecting Customer may proceed to construct the PV system once the initial review by the HLPD Engineer has been completed.
2. **Interconnection and Operation.** The interconnecting Customer may operate the PV system and interconnect with HLPD's system once the following has occurred:
    - 2.1. **Municipal Inspection.** Upon completing construction, the Interconnecting Customer will cause the system to be inspected or otherwise certified by the local electrical wiring inspector with jurisdiction.
    - 2.2. **Certificate of Completion.** The Interconnecting Customer returns the Certificate of Completion to HLPD.
    - 2.3. HLPD has completed or waived the right to inspection and field test.
3. **HLPD's Right to Inspection.** Within ten (10) business days after receipt of the Certificate of Completion, HLPD may, upon reasonable notice, and at a mutually convenient time, conduct an inspection of the system to ensure that all equipment has been appropriately installed, and that all electric connections have been made in accordance with HLPD's requirements. HLPD has the right to disconnect the system in the event of improper installation or failure to return Certificate of Completion.
4. **Safe Operations and Maintenance.** The interconnecting Customer shall be fully responsible for operation, maintenance, and repair the system.
5. **Access.** HLPD shall have access to the disconnect switch (if required) of the system at all times.
6. **Disconnection.** HLPD may temporarily disconnect the system to facilitate planned or emergency HLPD work.
7. **Metering and Billing.** The following is necessary to implement the metering provisions.
    - 7.1. **Interconnecting Customer Provides Meter Sockets.** The Interconnecting Customer shall furnish and have installed, if not already in place, the necessary manual bypass meter socket and wiring in accordance with accepted electrical standards. The Interconnecting Customer shall have installed a second (check) meter socket, if required by HLPD, and the necessary wiring between the output of the system and the customer's main electrical service. This meter socket shall be located outside in an approved location.
    - 7.2. **HLPD Installs Meter.** HLPD shall furnish and install a meter within ten (10) business days after receipt of the Certificate of Completion, or within 10 business days after the inspection if completed, if such meter is not already in place.
    - 7.3. **HLPD Installs Check Meter.** The HLPD will install a second meter, if so chooses, to record the output of PV system. There will be no customer charge associated with this meter.
8. **Indemnification.** The Town of Hudson Light & Power Department (HLPD) and all of their respective agents and employees shall be afforded the maximum exemption of limitations of liability available under applicable laws and regulations arising on account of their actions or omissions relating directly or indirectly to any provision of electrical service. Without limiting the generality of the foregoing, and except to the extent otherwise expressly provided in M.G.L. Chapter 258: Neither the Town of Hudson, nor the HLPD, nor any of their respective agents or employees shall be liable to any person or agent: all liabilities, damages, losses, penalties, claims, demands, suits and proceedings of any nature whatsoever for personal injury (including death) or property damages to unaffiliated third parties that arise out of, or are in any manner connected with, the performance of this Agreement by that party, except to the extent that such injury or damages to unaffiliated third parties may be attributable to the negligence of willful misconduct of the party seeking indemnification.
9. **Limitation of Liability.** Each party's liability to the other party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omissions in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either party be liable to the other party for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever.
10. **Termination.** This Agreement may be terminated under the following conditions.
    - 10.1. **By Interconnecting Customer.** The Interconnecting Customer may terminate this Agreement by providing written notice to HLPD.
    - 10.2. **By HLPD.** The HLPD may terminate this Agreement: (1) if the PV system fails to operate for any consecutive 12-month period, or (2) in the event that the PV system impairs the operation of the electric distribution system or service to other customers or material impairs the local circuit and the Interconnecting Customer does not cure the impairment in a timely manner.
11. **Assignment/Transfer of Ownership of the PV system.** This Agreement shall survive the transfer of ownership of the system to a new residential owner when the new owner agrees in writing to comply with the terms of this Agreement and so notifies the HLPD.
12. **Interconnection Rate.** These Terms and Conditions are pursuant to HLPD's Standard Terms and Conditions for electric service and Schedules of Rates, as approved by the Hudson Municipal Light Board and as the same may be amended from time to time. All defined Terms and Rates are available at the HLPD office or online at www.hudsonlight.com.

HLPD Terms & Conditions for Interconnections (cont'd)

Definitions:

AC – *alternating electrical current (grid electricity).*
Anti-islanding test – *a utility engineer will test your completed system for safety before your interconnection contract is processed.*
Azimuth – *the direction in degrees your solar panels will face (due south is 180 degrees). For the purpose of this rebate, this angle must be between 135° and 225°.*
Building code – *check with your city and/or county offices to see if a permit for the solar installation is necessary.*
DC – *direct electrical current (solar panel or battery electricity).*
DC rating – *solar panel capacity, measured in watts.*
Evidence of Intent – *evidence that you are serious about participating in the solar rebate program; signed Interconnection Agreement.*
Grid connected – *you purchase electricity from HLPD.*
Interconnection guidelines – *safety and technical requirements for your solar installation*
Inverter – *converts DC electricity from the solar panels into AC electricity that is compatible with the electricity grid.*
Kilowatt (kW) – *1000 watts (ten 100 watt solar panels = 1 kilowatt).*
National Electrical Code Article 690 – *national electrical safety standards for photovoltaic systems established by the National Fire Protection Association (www.nfpa.org).*
Solar panel warranty – *solar panels in the rebate program must have a 20-year or greater warranty.*
Photovoltaic (PV) – *technical term for solar electricity.*
Rebate Confirmation Form – *the form you receive once you are approved for a rebate; work must not begin until you receive this form.*
Rebate queue – *the order in which approved rebates are reserved and distributed on a first-come, first-served basis if funds become limited.*
Site diagram – *diagram sent with the Rebate Application Form that shows objects that might cast a shadow on your solar panels; diagram should include distances.*
Site pictures – *pictures of the place you intend to install the solar panels AND panoramic images from East to West.*
Solar electric system – *the complete PV system capable of producing grid compatible electricity.*
Solar panel rating – *see DC rating.*
Shading Analysis Tool – *a device used to accurately chart the total shading at a specific location. (Pathfinder, Suneye, ASSET or other comparable brands are acceptable.)*
System rating – *the sum of all of the solar panels to be used in the system (# of solar panels x DC rating of solar panels) usually expressed in kilowatts (kW).*
Tilt angle – *the angle from horizontal at which the solar panels are positioned if they do not have tracking capabilities.*
Tracking – *an additional solar system component that actively moves the solar panels to face the sun as it moves across the sky during the day and/or season.*

Hudson Light & Power Department

PV System Certificate of Completion

Installation Information:

Interconnecting Customer (*print*): ______________________________

Company Name: ______________________________

Mailing Address: ______________________________

Location of Facility (*if different from above*): ______________________________

Town: ____________________ State: __________ Zip Code: __________

Telephone (*daytime*): ____________________ (*evening*): ____________________

Fax Number: ____________________ E-Mail Address: ____________________

Account # (*on bill*) ______________________________

Meter # (*on bill*) ______________________________

Electrician or Electrical Installation Contractor:

Company Name: ______________________________

Contact Name (*print*) ______________________________

Mailing Address: ______________________________

City: ____________________ State: __________ Zip Code: __________

Telephone (*daytime*): ____________________ (*evening*): ____________________

Fax Number: ____________________ E-Mail Address: ____________________

License number: ____________________ HLPD Date of Installation Approval: ____________________

Signature: ______________________________ Date: ____________________

HLPD Ref. Number: ______________________________

Wiring Inspector:

The system has been installed and inspected in compliance with the local Building/Electrical Code of

____

(*Town*)

Signed (*local Electrical Wiring Inspector*): ______________________________

Name (*print*): ______________________________

Date: ______________________________

As a condition of interconnection you are required to provide this form along with a copy of the signed electrical permit to:

HLPD Engineer
49 Forest Avenue
Hudson, MA 01749

Received by HLPD: ______________________________
Date & Initial

