BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

---- In the Matter of ----	
PUBLIC UTILITIES COMMISSION	DOCKET NO. 2014-0192
Instituting a Proceeding to Investigate Distributed Energy Resource Policies	

ORDER NO. 32737

GRANTING MOTIONS TO INTERVENE, CONSOLIDATING AND INCORPORATING RELATED DOCKETS, AND ESTABLISHING STATEMENT OF ISSUES AND PROCEDURAL SCHEDULE

FILED

2015 MAR 31 P 4: 11

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GRANTING MOTIONS TO INTERVENE,
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ESTABLISHING STATEMENT OF ISSUES AND PROCEDURAL SCHEDULE

By this Order, the commission (1) grants intervenor status to HAWAII SOLAR ENERGY ASSOCIATION ("HSEA"); LIFE OF THE LAND ("LOL"); RENEWABLE ENERGY ACTION COALITION OF HAWAII, INC. ("REACH"); HAWAII RENEWABLE ENERGY ALLIANCE ("HREA"); HAWAII PV COALITION ("HPVC"); THE ALLIANCE FOR SOLAR CHOICE ("TASC"); SUNPOWER CORPORATION ("SUNPOWER"); STATE OF HAWAII DEPARTMENT OF BUSINESS, ECONOMIC DEVELOPMENT, AND TOURISM ("DBEDT"); BLUE PLANET FOUNDATION ("BLUE PLANET"); and RON HOOSON (collectively, "Intervenors"); (2) consolidates Docket No. 2014-0130 with this docket; (3) incorporates by reference in this docket the evidentiary record of Docket No. 2011-0206, relating to the First and Second Stipulations of the PV Subgroup; (4) orders the

HECO Companies[1] to comply with certain directives and requirements; and (5) establishes a preliminary Statement of Issues and Procedural Schedule to govern this proceeding.

I.

Background

A.

April Orders

On April 28, 2014, the commission issued four major Orders ("April 2014 Orders")[2] addressing a range of issues related

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[1]The "HECO Companies" or the "Companies" are the Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Limited ("MECO").

[2]The April 2014 Orders include the following: (1) In the Matter of PUBLIC UTILITIES COMMISSION Regarding Integrated Resource Planning, Docket No. 2012-0036, Decision and Order No. 32052, filed April 28, 2014 ("Order No. 32052"); (2) In the Matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate the Implementation Of Reliability Standards for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited, Docket No. 2011-0206, Decision and Order No. 32053, filed on April 28, 2014 ("Order No. 32053"); (3) In the Matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Review Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc. and Maui Electric Company, Ltd.'s Demand-Side Management Reports and Requests for Program Modifications, Docket No. 2007-0341, "Order No. 32054, Policy Statement and Order Regarding Demand Response Programs," filed on April 28, 2014 ("Order No. 32054"); and (4) In the Matter of the Application of MAUI ELECTRIC COMPANY, LIMITED FOR Approval of Rate Increases and Revised Rate Schedules and Rules, Docket No. 2011-0092, Decision and Order No. 32055, filed on April 28, 2014 ("Order No. 32055").

to electric utility planning and operations in the State of Hawaii ("State"). Taken together, the April 2014 Orders provide key policy, resource planning, and operational directives to the HECO Companies and to Kauai Island Utility Cooperative ("KIUC").[3] The April 2014 Orders require the HECO Companies to improve their planning and operational practices to (1) aggressively pursue energy cost reductions; (2) proactively respond to emerging renewable energy integration challenges; (3) improve the interconnection process for customer-sited solar photovoltaic (PV) systems; and (4) embrace customer demand response programs.

Of particular relevance to this proceeding, in Order No. 32052, the commission rejected the HECO Companies' Integrated Resource Plan ("IRP"). The commission found that the Companies' analytical approach was fundamentally flawed, the plan had employed inappropriate and inadequate modeling tools and analysis techniques, and the plan failed to address or respond to many of the principal planning issues explicitly identified by the commission as requiring detailed study. In lieu of an approved plan, the commission proceeded with several other parallel initiatives to ensure adequate resource planning for the HECO Companies.

[3]While the April 2014 Orders are primarily focused on the HECO Companies, in some cases the commission has required specific responses from KIUC, and much of the policy and planning discussion is applicable statewide.

In addition, given the continuing failure of the HECO Companies to articulate a sustainable business model and adequately plan for a future with substantial quantities of renewable energy, the commission presented a white paper entitled, "Commission's Inclinations on the Future of Hawaii's Electric Utilities."[4] The white paper outlined the vision, strategies, and regulatory policy changes required to align the HECO Companies' business model with customers' expectations and state energy policy, and provided specific guidance for future energy planning and project review, including strategic direction for future capital investments.

In Order No. 32054, the commission concluded that demand response ("DR") programs benefit both customers and electric utilities in a variety of ways, and can be particularly beneficial in integrating additional renewable energy resources and improving the efficiency of the State's electric grids. The Order required the development of an integrated DR portfolio for each of the HECO Companies.

In Order No. 32053, the commission, among other things, provided an overview of several technical integration challenges facing the State's electric utilities as distributed energy resources ("DER") and renewable energy continue to be deployed

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[4]The White Paper was attached to Order No. 32052 as "Exhibit A."

more broadly throughout the State. The commission observed that, with respect to reliability concerns, the lack of transparency and a slow response to provide supporting technical information foster public distrust about utility management of distributed generation interconnection challenges.

Thus, Order No. 32053 required the HECO Companies to implement a distribution circuit monitoring program, integrate and improve the transparency of the Companies' interconnection queues, and prepare and submit a Distributed Generation Interconnection Plan ("DGIP") to demonstrate that the Companies are employing prudent business practices in an environment of accelerating change, particularly relating to the integration of substantial quantities of renewable energy onto the State's island grids. The commission required the HECO Companies to include in the DGIP a technical assessment of DER integration challenges and associated mitigation solutions, as well as detailed, actionable plans to increase distributed generation interconnection capability in major capacity increments.

Order No. 32053 further instructed the PV Subgroup of the Reliability Standards Working Group ("RSWG") to collaborate and, if possible, stipulate to any areas of agreement on their work products from the RSWG process, particularly any proposals that could be implemented quickly by way of revisions to the

HECO Companies' distributed generation interconnection policies in Tariff Rule 14H.

B.

First and Second Stipulations

On May 28, 2014, pursuant to Order No. 32053, issued in Docket No. 2011-0206, the PV Subgroup of the RSWG filed its First Stipulation.[5] The PV Subgroup held five in-person meetings to "discuss in detail. . . any proposed further modifications to Rule 14H. . . that might be required in light of the changes to circuit and system penetration levels and policy modifications that occurred since the submission of the [PV Subgroup Final Work Product]."[6] However, the PV Subgroup stated that it was not able to reach agreement on several issues. Nonetheless, the PV Subgroup reported that "these inquiries and discussion are ongoing" and that "for each of these issues, further collaborative discussion may yield additional agreement such that stipulated language may be added to [the First Stipulation]."[7]

[5]"Stipulation Regarding Work Products Submitted As A Part Of The January 18, 2013 Final Report Of The PV Sub-Group For The Reliability Standards Working Group," filed in Docket No. 2011-0206 on May 28, 2014 ("First Stipulation").

[6]First Stipulation at 4.

[7]First Stipulation at 9.

Thereafter, on June 12, 2014, the PV Subgroup filed its Second Stipulation.[8] The PV Subgroup stated it met three additional times to further discuss where there may be additional agreement to expeditiously improve interconnection rules and procedures. The PV Subgroup members stated that the proposed modifications "are mutually acceptable to each respective [Subgroup] member" and that the HECO Companies "will submit appropriate revised tariff sheets for the [c]ommission's consideration" upon approval of any of the proposed modifications to Rule 14H. The PV Subgroup also stated its "members recognize the value and productivity of its previous and current collaborative work and will aim to continue this successful collaboration on an informal basis to assist where possible in the development of other Order No. 32053 compliance items that address distributed generation and interconnection issues."[9] The commission thereafter issued information requests to clarify certain inconsistencies and other questions with the First and Second Stipulations. The PV Subgroup discussions are on-going.

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[8]"Second Stipulation Regarding Work Products Submitted As A Part Of The January 18, 2013 Final Report Of The PV Sub-Group For The Reliability Standards Working Group," filed in this docket on June 12, 2014 ("Second Stipulation").

[9]Second Stipulation at 11-12.

C.

DER Policy Docket

On August 21, 2014, the commission instituted this proceeding to investigate the technical, economic, and policy issues associated with DER as they pertain to the electric operations of HECO, HELCO, MECO, and KIUC.[10]

Thereafter, on August 26, 2014, the HECO Companies filed their Distributed Generation Interconnection Plan in Docket No. 2011-0206. By Order No. 32292 issued in Docket No. 2011-0206,[11] the commission transferred the DGIP into the instant proceeding for review.

Between August 25, 2014, and September 10, 2014, ten motions for intervention were timely filed in this docket.

On September 12, 2014, the commission issued Order No. 32293 in the instant proceeding, inviting comment from the public on the HECO Companies' DGIP. The commission has received 737 pages of comments from the public, including from several entities that have requested intervention in this proceeding.

[10]"Order No. 32269 Instituting a Proceeding to Investigate Distributed Energy Resource Policies," issued August 21, 2014 in Docket No. 2014-0192.

[11]"Order No. 32292 Transferring Distributed Generation Interconnection Plan to Docket No. 2014-0192," issued September 12, 2014.

On September 30, 2014, the commission issued information requests to the HECO Companies, to which the Companies responded on October 10, 2014. On October 31, 2014, HECO submitted "supplemental responses" to the commission's information requests, wherein the Companies stated that, as of October 22, 2014, at least 5,176 customers were waiting for interconnection approval. The Companies further stated that 4,558 customers on Oahu would be interconnected by April 2015. The Companies did not address whether or to what extent customers waiting on the islands of Maui, Lanai, Molokai, or Hawaii would receive interconnection approval.[12]

On January 20, 2015, the HECO Companies filed a motion ("January 20 Motion") for commission approval to (1) reinstitute a program capacity cap for the Net Energy Metering ("NEM") program; (2) allow customers who are currently waiting for interconnection approval and those who may apply for interconnection until March 20, 2015 to interconnect under the NEM program; (3) approve an interim Transitional Distributed Generation ("TDG") tariff; (4) approve an interconnection agreement for the TDG tariff;

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[12]In a follow-up letter filed February 23, 2015, the HECO Companies indicated that the number of applications in the interconnection queue for Oahu is 2,193, with 2 applications pending on Maui and 336 pending on Hawaii Island.

and (5) allow the Companies to modify Tariff Rule 14H[13] via a 30-day tariff filing.[14]

In response to the January 20 Motion, the Consumer Advocate filed a protest,[15] and several entities submitted comments in opposition to the HECO Companies' motion.[16]

On February 27, 2015, the Chairman of the commission and the President of the HECO Companies signed a letter agreement wherein the signatories agreed that, among other things, the sixty day timeline proposed by the HECO Companies would not provide sufficient time for commission and stakeholder review of the

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[13]Tariff Rule 14H relates to service connections to facilities on customers' premises, specifically interconnection of distributed generating facilities operating in parallel with the HECO Companies' electric systems.

[14]"Hawaiian Electric Companies' Motion For Approval Of NEM Program Modification And Establishment Of Transitional Distributed Generation Program Tariff, Appendices 1 To 5 And Certificate Of Service," filed January 20, 2015.

[15]"Division Of Consumer Advocacy's Protest Of Hawaiian Electric Companies' Motion For Approval Of NEM Program Modifications And Establishment Of Transitional Distributed Generation Program Tariff," filed January 27, 2015.

[16]See (1)Letter from Blue Planet, filed January 27, 2015; (2)"Request For Party Status And Opposition Of The Alliance For Solar Choice, Hawaii Solar Energy Association, Hawaii PV Coalition, And Sunpower Corporation To The Motion Of The Hawaiian Electric Companies, Exhibit 1, Affidavit Of R. Thomas Beach And Certificate Of Service," filed January 27, 2015 (joined by HREA on January 27, 2015); and (3)"The Department Of Business, Economic Development, And Tourism's Response To Hawaiian Electric Companies' Motion For Approval Of NEM Program Modification And Establishment Of Transitional Distributed Generation Program Tariff And Certificate Of Service," filed January 27, 2015.

Companies' motion, and that regardless of whether the commission has ruled (favorably or otherwise) on the Companies' proposal for policy changes, the Companies have an affirmative duty to interconnect customers consistent with existing policy.[17]

II.

Intervention

A.

Motions to Intervene

In Order No. 32269, the commission, sua sponte, named HECO, HELCO, MECO, KIUC, and the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs ("Consumer Advocate")[18] (collectively, the "Parties") as Parties to the instant proceeding.[19] The commission invited interested individuals, entities, agencies, and community or business organizations to file motions to

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[17]See Letter Agreement by and between Randy Iwase and Alan Oshima, dated February 27, 2015, available at puc.hawaii.gov/wp-content/uploads/2015/03/NewRelease.20150227.pdf.

[18]The Consumer Advocate is statutorily mandated to represent, protect, and advance the interests of all consumers of utility service and is an ex officio party to any proceeding before the commission. See Hawaii Revised Statutes § 269-51 and Hawaii Administrative Rules § 6-61-62

[19]Order No. 32269, at 6.

intervene or participate without intervention pursuant to Hawaii Administrative Rules ("HAR") Chapter 6-61.[20]

Ten motions to intervene were timely filed by interested stakeholders in this docket. The movants state as follows.

HSEA states that it is a non-profit professional trade association with an organizational purpose to promote the utilization and commercialization of renewable energy resources, educate consumers about solar energy technologies, and develop sound trade and technical practices among its 80 member companies.[21] HSEA states that its interest is in "ensuring that the rules governing the installation of DER will be structured in a way that will promote the utilization and commercialization of renewables in Hawaii in a sustainable, fair, and transparent fashion."[22] Furthermore, HSEA states that its members and representatives "have the timely expertise, knowledge, and experience to assist the Commission in the development of a sound record, by providing facts, fact-based opinions and conclusions regarding the present docket."[23]

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[20]Order No. 32269 at 6.

[21]"Motion to Intervene of the Hawaii Solar Energy Association and Certificate of Service," filed August 25, 2014, at 2 and 5 ("HSEA Motion").

[22]HSEA Motion at 4.

[23]HSEA Motion at 5.

LOL states that it is a non-profit Hawaii-based organization whose members live, work, and recreate in Hawaii.[24] In support of its motion, LOL states that it offers a "unique perspective" on the issues the commission may establish in this docket, including the "impacts, externalities, and unintended side-effects of energy projects and programs".[25] LOL states that its position is that DER can "significantly decrease environmental, social and cultural impacts *if* done right."[26] Finally, LOL states it intends to "present a proactive case, supported by expert witnesses and exhibits" and collaborate with other potential intervenors to "assist the Commission in developing a strong record through which reasonable solutions can be developed."[27]

REACH states that it is a "not-for-profit trade association whose members include businesses engaged in the production, manufacture, development, installation, integration, construction, marketing, sale and/or distribution of distributed energy generation systems (including advanced inverters) and distributed energy storage systems in the state of Hawaii,

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[24]"LOL Motion to Intervene, Affidavit of Henry Q Curtis, And Certificate of Service" filed September 2, 2014, at 9 ("LOL Motion").

[25]LOL Motion at 4, 9, and 13.

[26]LOL Motion at 10 (emphasis in original and footnote omitted).

[27]LOL Motion at 14-15.

on islands served by the HECO Companies and KIUC."[28] REACH further states that it is "committed to using the specific engineering, economic and policy expertise, knowledge, and experience of its officers and directors, and of technical employees of its member businesses, to assist the [c]ommission in the development of a sound record in this proceeding."[29]

HREA states that it is a "Hawaii-based, private, non- profit corporation. . . composed of developers, manufacturers, distributors, scientists, engineers, and advocates in renewable energy"[30] and that its member organizations and individuals are "companies, consultants, or agents involved in and/or considering manufacturing, marketing, selling, installing and maintaining wind and solar systems in distributed energy applications and are concerned about electric utility customers' access to distributed energy systems, and the conditions under which such access would be granted."[31] HREA further states that it will "provide, on behalf of its members, the resources and professional expertise in a timely

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[28]"Motion for Intervention of Renewable Energy Action Coalition of Hawaii, Inc., and Certificate of Service" filed September 9, 2014, at 3-4 ("REACH Motion").

[29]REACH Motion at 7.

[30]"Motion to Intervene of the Hawaii Renewable Energy Alliance and Certificate of Service," filed September 9, 2014, at 2 ("HREA Motion").

[31]HREA Motion at 4.

manner to assist in the development of a sound evidentiary [r]ecord. . . supported with technical and/or economic analysis where appropriate."[32]

HPVC states that it is a "professional trade association incorporated in the State of Hawaii. . . [whose] goals are to promote the development of sound and fair energy policies that enhance Hawaii's energy security and promote environmental and economic sustainability in the state's energy sector."[33] HPVC further states that its "member companies design, build, develop, and operate distributed PV systems in Hawaii and also sell equipment to entities that do so."[34] HPVC states that intervention can "help develop a sound record" because its member companies can contribute "detailed information about 'conditions on the ground' in Hawaii's distributed, renewable energy markets as they relate to pricing, risk, consumer sentiment, and technological innovation that is highly relevant to discussions of Hawaii's energy policy planning process."[35]

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[32]HREA Motion at 5.

[33]"Motion for Intervention of Hawaii PV Coalition; Affidavit of Mark Duda, and Certificate of Service," filed September 9, 2014, at 2 ("HPVC Motion").

[34]HPVC Motion at 4.

[35]HPVC Motion at 6-7.

TASC states that its founding members and their partners "are leading solar service providers in Hawaii, are responsible for over 10,000 residential, school, government and commercial installations in the State, and collectively employ hundreds of Hawaii residents" and that its "members' business operations in Hawaii include planning, developing, installing, selling or leasing, monitoring and maintaining solar and solar-storage energy systems that are interconnected to the Companies' distribution grid."[36] TASC has attached to its motion a paper that it states "provides a near-term plan to empower consumers to solve the technical and policy challenges required to achieve Hawaii's clean energy future."[37]

SUNPOWER states that is a "designer and manufacturer of high efficiency DER projects, principally in the form of distributed solar photovoltaic ("PV") projects, which are sold in Hawaii and worldwide. Movant also designs, finances, and builds, and operates PV projects worldwide."[38] Furthermore, SUNPOWER states that it has "designed, installed and financed over 40 MW of residential and

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[36] "Motion to Intervene of The Alliance for Solar Choice, Verification, and Certificate of Service," filed September 10, 2014, at 2 and 4 ("TASC Motion").

[37] TASC Motion at 6.

[38] "Sunpower Corporation's Motion to Intervene, Verification, and Certificate of Service," filed September 10, 2014, at 2 ("SUNPOWER Motion").

commercial systems through its distributors or self-performed at the distribution level via the Feed-in Tariff ("FIT"), Net Energy Metering, Rule 14H interconnection programs, and other power supply facilities via bilateral agreements."[39]

SUNPOWER further states that given its "unique experience and expertise with DER in Hawaii. . . it will be able to assist the [c]ommission in its investigation of the technical, economic, and policy issues associated with DER as they pertain to the HECO Companies and KIUC" and that it "is prepared, with the assistance of its technical experts, to discuss and analyze the various technical, economic, and policy issues concerning DER, and how these issues interrelate. . . ."[40]

DBEDT, through its director, in his capacity as the State's energy resources coordinator, states that it has a "clear interest in and can add value to this proceeding as the representative of the State's policy objective and public good."[41] DBEDT states the nature and extent of its interests are "mandated by statute" and that the instant proceeding will "directly affect the Department's statutory obligations" and the "execution of its

[39]SUNPOWER Motion at 4.

[40]SUNPOWER Motion at 6-7.

[41]"Department of Business, Economic Development, and Tourism's Motion to Intervene and Certificate of Service," filed September 10, 2014, at 4-5 ("DBEDT Motion").

statutory functions and the Energy Resources Coordinator's statutory role and duties."[42] Furthermore, DBEDT states that the State of Hawaii is the second largest consumer of electricity in Hawaii and that this proceeding may have a potential "impact on the state government's energy costs.[43]

DBEDT states that its "expertise in energy planning, analysis, policy development, and knowledge of the renewable energy market and technologies will assist the [c]ommission and the parties in this docket by providing relevant studies, surveys and other information related to institutional, policy, financial, and other issues related to the [c]ommission's consideration of the technical, economic, and policy issues pertaining to DER."[44] In addition, DBEDT states that it has engaged expert consultants and advisors who can assist DBEDT in providing "meaningful assistance to the [c]ommission with respect to the highly complex DER issues to be addressed in this proceeding."[45]

Blue Planet states that it is a "Hawaii public interest organization. . . dedicated to promoting Hawaii's swift transition to a clean energy economy through the rapid adoption of renewable

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[42]DBEDT Motion at 7-8.

[43]DBEDT Motion at 7-8.

[44]DBEDT Motion at 10.

[45]DBEDT Motion at 10.

energy and increased energy efficiency."[46] Blue Planet states that it has retained the services of an expert consultant with "over forty-five years of experience in the energy industry" to assist in review and analysis of technical data and information, regulatory policy matters, utility financial and revenue requirements matters, and other technical, economic, and policy issues in the instant proceeding.[47]

Mr. Hooson states that he is "active in the design, build, or inspection of a large percentage of all roof mounted PV systems of the Island of Oahu;" has been instructed in electrical theory; has held the highest electric licenses; has worked for utilities, government agencies, and private sector organizations in renewable and conventional energy conservation; has designed, supervised installation, or inspected over four thousand PV small - and medium-sized systems; has trained military plan reviewers in grid interconnection and safety; and currently serves as a licensed supervising electrician and senior PV system special electrical inspector for the Department of Planning and Permitting

[46]"Blue Planet Foundation's Motion to Intervene, Declaration of Sebastian J. Nola, and Certificate of Service," filed September 10, 2014, at 2 ("Blue Planet Motion").

[47]Blue Planet Motion at 3-4, 7.

for the City and County of Honolulu.[48] Mr. Hooson states that his "experience and analytical skills would both support Hawaii's goals of sustainability and help to ground the proceeding in the facts based on the laws of physics, the National Electrical Code safety specifications and established electrical circuit design criteria."[49]

As stated above, all ten intervention motions were timely filed and no Party opposed any of the motions.

B.

Ruling on Intervention

HAR § 6-61-55 provides the requirements for intervention in commission proceedings. It states, in pertinent part:

> (a) A person may make an application to intervene and become a party by filing a timely written motion in accordance with sections 6-61-15 to 6-61-24, section 6-61-41, and section 6-61-57, stating the facts and reasons for the proposed intervention and the position and interest of the applicant.
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> (b) The motion shall make reference to:
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> (1) The nature of the applicant's statutory or other right to participate in the hearing;

[48]"Motion to Intervene of Ron Hooson (Applicant) and Certificate of Service," filed September 10, 2014, at 2-4 ("Ron Hooson Motion").

[49]Ron Hooson Motion at 5.

> (2) The nature and extent of the applicant's property, financial, and other interest in the pending matter;
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> (3) The effect of the pending order as to the applicant's interest;
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> (4) The other means available whereby the applicant's interest may be protected;
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> (5) The extent to which the applicant's interest will not be represented by existing parties;
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> (6) The extent to which the applicant's participation can assist in the development of a sound record;
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> (7) The extent to which the applicant's participation will broaden the issues or delay the proceeding;
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> (8) The extent to which the applicant's interest in the proceeding differs from that of the general public; and
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> (9) Whether the applicant's position is in support of or in opposition to the relief sought.[50]

Furthermore, in Order No. 32269, the commission advised potential movants that:

> [T]he investigation to be conducted in this docket will require detailed analysis and discussion of various technical, economic, and policy issues concerning DER. Potential intervenors or participants must be prepared to address these issues in depth and to meaningfully participate in the discussion and resolution of same.
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> . . .

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[50]HAR § 6-61-55(a) and (b).

> [I]n this proceeding, potential intervenors and participants are required to present detailed information in their motions which demonstrates either that they possess expertise with respect to DER issues, or that they will retain consultants that have such expertise. Thus, potential intervenors should demonstrate engineering, economic, and policy expertise commensurate with the highly complex and technical nature of these interrelated issues. This requirement is necessary so that the issues can be addressed in both a comprehensive and timely fashion.[51]

HAR § 6-61-55(d) further states that "[i]ntervention shall not be granted except on allegations which are reasonably pertinent to and do not unreasonably broaden the issues already presented." The general rule concerning the granting of intervention is well settled: intervention is not a guaranteed right of a movant, but is "a matter resting within the sound discretion of the commission," so long as that discretion is not exercised arbitrarily or capriciously.[52]

The commission has, in the past, granted intervention in investigatory and policy proceedings, such as this docket.[53]

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[51]Order No. 32269 at 7-8.

[52]In re Application of Hawaiian Elec. Co., Inc., 56 Haw. 260, 262-263, 535 P.2d 1102, 1104 (1975).

[53]See In the Matter of Public Utilities Commission Regarding Integrated Resource Planning, Docket No. 2012-0036, "Order No. 31443 Addressing Filed Motions to Intervene and Motion to Participate Without Intervention, and Providing Guidance on Integrated Resource Planning Matters," filed September 9, 2013; In the Matter of Public Utilities Commission Instituting a Proceeding to Investigate the Implementation of Reliability

The commission finds it appropriate to adopt such an approach in this docket as well. Each potential intervenor has addressed the requirements of HAR § 6-61-55, and, importantly, has categorically stated it has expertise with respect to DER issues, or that it will retain consultants that have such expertise. Based on these assertions and the commission's review of the each of the motions to intervene, the commission grants intervention to HSEA, LOL, REACH, HREA, HPVC, TASC, SUNPOWER, DBEDT, Blue Planet, and Mr. Hooson.[54]

The commission cautions the Intervenors permitted herein that their participation will be limited to the issues established by the commission in this docket. Moreover, the commission reminds all Parties[55] that it is imperative that participation in this docket reflect a high standard of quality, relevance, and timeliness. Finally, the commission observes that it will preclude any attempts to broaden the issues or to unduly delay the

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Standards for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited, Docket No. 2011-0206, "Order Granting Intervention, Approving RSWG Purpose, Scope of Work and Work Plan, and Clarifying Role of Commission's Consultant," filed October 12, 2011.

[54]However, the commission will continue to evaluate motions to intervene or participate without intervention in future proceedings on a case-by-case basis.

[55]Unless otherwise indicated, the term "Parties," as used in this Order, means the HECO Companies, KIUC, the Consumer Advocate, and the Intervenors.

proceeding, and will reconsider any Intervenor's participation in this docket if, at any time during the course of this proceeding, the commission determines that any Intervenor is attempting to unreasonably broaden the pertinent issues established by the commission in this docket, is unduly delaying the proceeding, or is failing to meaningfully participate and assist the commission in the development of the record in this docket.

III.

CONSOLIDATION OF DOCKET NO. 2014-0130 WITH THIS DOCKET

Docket No. 2014-0130 concerns the HECO Companies' application to modify Tariff Rule 14H in several ways. According to the HECO Companies, the intent of the proposed modifications is "limited to those issues specifically raised by the Commission in Decision and Order No. 31901 relating to the interconnection review of distributed generating facilities with energy storage systems."[56]

After review, the commission finds that there is significant overlap among the issues in Docket No. 2014-0130 and those under consideration in the instant proceeding. The commission further finds that these overlapping issues should be considered

[56]"Application of Hawaiian Electric Company, Inc., Hawai'i Electric Light Company, Inc., and Maui Electric Company, Limited," Docket No. 2014-0130, filed June 2, 2014, at 7.

together, rather than separately in individual dockets. Accordingly, the commission consolidates Docket No. 2014-0130 with this docket and incorporates by reference the record in Docket No. 2014-0130 in order to further develop appropriate interconnection requirements and screening processes for energy storage systems.

IV.

INCORPORATION BY REFERENCE OF CERTAIN PORTIONS OF DOCKET NO. 2011-0206

As discussed above, by Order No. 32053, the commission requested that the PV Subgroup of the RSWG collaborate and, if possible, stipulate to any areas of agreement on their work products, particularly any proposals that could be implemented quickly by revisions to the HECO Companies' distributed generation interconnection policies in Tariff Rule 14H.

The commission is appreciative of the PV Subgroup members' efforts to expeditiously come to agreement on unresolved aspects of their work products. Over the past several months, the members of the PV Subgroup have significantly advanced the technical discussion of DER integration challenges in Hawaii and, based on the commission staff's observations of their discussions, have significantly improved the HECO Companies' understanding of the capabilities of DER and the benefits they provide to the Companies' power systems.

However, given the significant overlap between the issues under discussion by the PV Subgroup and the issues under consideration in the DER policy docket the commission finds it appropriate to conduct further PV Subgroup activities in the instant proceeding. Accordingly, the commission hereby incorporates by reference in this docket the record in Docket No. 2011-0206 pertaining to the First and Second Stipulations of the PV Subgroup.[57] The commission expects the Parties to the DER docket will adopt the constructive and pragmatic approach taken by the PV Subgroup as the Parties consider the critical issues in this docket.

V.

DISCUSSION

A.

The HECO Companies' Distributed Generation Interconnection Plan

In Order No. 32053, the commission directed the HECO Companies to prepare and submit a Distributed Generation

[57]This includes the comments filed by other Parties to Docket No. 2011-0206, and the responses of the HECO Companies and other members of the PV Subgroup to the commission's information requests.

Interconnection Plan ("DGIP"), which must include, at a minimum, the following components:

1. A **Distributed Generation Interconnection Capacity Analysis** to proactively identify distribution circuit capacity to safely and reliably interconnect distributed generation resources and the system upgrades requirements necessary to increase circuit interconnection capability in major capacity increments, including:

   - Analyses of technical impacts and challenges associated with export of energy from distributed generation at levels that result in sustained backfeed of power from distribution circuits into the distribution substation during day-time hours;

   - Development of recommended circuit upgrade requirements, including associated costs and ratepayer impacts, to enable circuit penetration limits to be raised in a logical, step-wise manner;

   - Identification of circuit penetration limits (expressed as a percent of gross DML) that would represent a sound, technical-based progression to increase circuit penetrations in a step-wise manner as experience is gained, and technical feedback is acquired with higher penetration levels, including timelines to propose when those increasing limits would be implemented; and

   - Impact of system level limitations on aggregate amount of variable renewable energy and how it relates to potential limits on interconnection of distributed generation incorporating analysis and conclusions from the Power Supply Improvement Plans.

2. An **Advanced DER Technology Utilization Plan** to provide the near, medium and long-term plans by which customers would install, and utilities would utilize, advanced inverters, distributed energy storage, demand response and EVs to mitigate adverse grid

impacts starting at the distribution level and up to the system level, including:

- Plans to utilize grid support functionality embedded in advanced inverters, including autonomous controls and two-way communication to provide, among other capabilities, real-time PV output visibility to the system operator and also the ability to limit export of excess solar PV energy;

- Proposed requirements for new DER inverters to utilize state-of-the-art technical capabilities such that these system can provide autonomous grid support functions, enable active utility control of DER and provide ancillary services as grid conditions require;

- Stakeholder input in the tariff development process by which standards for advanced inverters are adopted for inclusion in Rule 14H, prior to filing with the commission;

- Plans to enable two-way communications with all customer installed DER equipment using proposed AMI communications infrastructure or other suitable communications networks;

- Plans to utilize distributed energy storage, sited either on utility distribution infrastructure or on the customer side of meter, to mitigate impacts of high penetration solar PV systems; and

- Plans to utilize the technical capabilities of advanced inverters, energy management control systems and customer energy storage systems to develop non-export options for distributed generators as well as options to provide ancillary and other grid support services, and appropriate tariff provisions to accommodate this.

3. A **Distribution Circuit Improvement Implementation Plan** which shall summarize the specific strategies and action plans, including associated costs and schedule, to implement circuit upgrades and other

mitigation measures to increase capacity of electrical grids to interconnect additional distributed generation, including:

- Prioritization of proposed mitigation actions to focus on the immediate binding constraints for interconnection of additional distributed generation, whether on high penetration distribution circuits or at the system level, depending upon the situation on each island grid;

- Analysis of the cost and benefits of proposed mitigation strategies and action plans;

- Discussion of how distribution system design criteria, and operational practices, could be modified to enable greater interconnection of distributed generation systems; and

- Proposals for addressing the cost allocation issues associated with who bears responsibility for system upgrade costs.[58]

The HECO Companies submitted their DGIP on August 26, 2014. Commission staff reviewed the DGIP and prepared a Staff Report and Proposal ("Staff Report"), which is attached to this Order. The Staff Report is a document prepared by the staff of the commission and is intended to serve as a framework to facilitate collaboration among the Parties and Intervenors (collectively referred to as the "Parties"). However, the Staff Report does not represent the policy of the commission except as specifically incorporated into this or other Orders issued by the commission. That said, the commission views

[58]Order No. 32053 at 51-55.

the Staff Report as a useful summary of technical and economic challenges facing the State in deploying cost-effective distributed energy resources and in achieving its energy goals.

The Staff Report, among other things, provides a preliminary review of the HECO Companies' DGIP and suggests that the DGIP is not sufficiently responsive to the requirements set out in Order No. 32053.[59] The commission provided a clear directive to the HECO Companies to submit "information and analysis. . . in order to analyze potential constraints that exist due to high penetration of solar PV systems, and as a result, develop strategies and plans to mitigate these constraints."[60] The Staff Report notes that the HECO Companies compiled a list of potential technical interconnection and integration challenges but did not prioritize mitigation solutions to be implemented, such that DER deployment can continue in a timely manner. Furthermore, the Staff Report observes that the DGIP filing did not define and establish plans to implement a non-export option for new DG systems, as specifically directed in the Order requiring the development of the DGIP.[61]

At this time, the commission takes no action with respect to the DGIP. Any remedial actions to bring the DGIP into compliance

[59] Staff Report at 11 - 14.

[60] Order No. 32053 at 50.

[61] Staff Report at 11-12.

with the commission's directives will be considered in a later phase of this proceeding, or in appropriate related proceedings, as determined by the commission.

The Staff Proposal states that the initial phase of this docket should be focused on resolving the immediate impediments limiting customer choice and continued deployment of cost effective DER systems. In this regard, the commission acknowledges that the HECO Companies have subsequently provided some clarity regarding customers currently waiting in the interconnection queue. In a letter to the commission filed in this docket on October 31, 2014 (the "October 31 Letter"), the HECO Companies stated:

> For customers who live on heavily penetrated circuits above the DML [Daytime Minimum Load] threshold, based on recent preliminary test results of inverters, the Companies have developed a plan. . . to interconnect the majority of these customers by April 2015, and all remaining customers in this grouping by December 2015.[62]

However, in the commission's view, HECO's proposed timeline does not reflect the urgency of this situation. While the rate of new interconnection applications has slowed over the past several months, customers continue to submit nearly one thousand

[62] *See* October 31 Letter at 1.

interconnection requests each month across the HECO Companies' service territories.[63]

In their January 20 Motion, the HECO Companies proposed that customers who have applied for interconnection after October 31, 2014 (as well as customers who will continue to apply in the future), may be permitted interconnection up to a higher circuit penetration threshold. This proposal was based on recent inverter testing performed by the U.S. Department of Energy National Renewable Energy Laboratory ("NREL"), which indicated that certain reliability concerns previously alleged by the HECO Companies are unlikely to present undue risks to the power system.[64] Accordingly, the HECO Companies state:

> [T]he Companies plan to increase the circuit penetration threshold for transient overvoltage on their systems from 120% of Gross Daytime Minimum Load ("GMDL") to 250% of GDML. This will allow additional DG interconnection while the Companies continuously monitor both circuit and system-level impacts to maintain reliability and safety and to determine whether further expansion of penetration thresholds is prudent.[65]

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[63]See Letter from D. Brown to commission, filed February 27, 2015 in Docket No. 2014-0192.

[64]The risk of transient over-voltage has been cited by the HECO Companies as the justification for the existing limits on interconnecting new solar PV systems. The NREL study found that modern inverters do not exacerbate transient over-voltage risks.

[65]January 20 Motion at 2.

However, in the January 20 Motion the Companies imply that increasing the circuit-level interconnection limit to 250% of GDML is contingent upon commission approval of the Companies' requests to cap the NEM program and to establish a "transitional" program that compensates customers for exported generation that may not reflect the Companies' avoided cost.

The commission has reviewed the HECO Companies' January 20 Motion and finds the proposals therein to be insufficiently supported at this phase of the proceeding. Moreover, the Parties have not been given an opportunity to fully respond to the Motion. Accordingly, the commission will not rule on the January 20 Motion at this time.[66]

Rather, as discussed further below, this Order directs the HECO Companies to collaborate with the Parties to this docket to resolve the distributed energy resources issues identified herein through a two phase schedule. The issues established for the first phase of this proceeding are considered by the commission to be of the highest priority, based on the urgent need to clear the existing interconnection queue backlog, assist in providing needed grid-supportive capabilities, enable customer choice, and allow

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[66]See also the letter agreement signed by the Chairman of the commission and the President of the HECO Companies.

DER to continue to grow cost-effectively in the future without adversely affecting non-participating customers.

The commission recognizes there are substantial technical and economic challenges associated with the integration of significant amounts of variable renewable energy resources, including distributed solar PV. The commission has devoted substantial resources over the past several years to assist the HECO Companies in addressing these issues, and will continue to do so. However, it is ultimately the responsibility of the HECO Companies to squarely confront the challenges of this rapidly changing business environment and provide their customers with safe, reliable, and affordable electricity service.

B.

Statement of Phase 1 Issues
And Further Directives to the Parties

At the outset, the commission acknowledges that there are numerous overlapping technical, economic, and policy issues associated with DER as they pertain the electric operations of HECO, HELCO, MECO, and KIUC.[67] Moreover, these issues are inextricably

[67]As noted in Order No. 32269, the commission recognizes that KIUC has not been directed to prepare either a Power Supply Improvement Plan or a DGIP. The commission did not require KIUC to conduct or file either plan by way of that Order, but did require KIUC to actively participate as a party to this docket as it may be subject to any applicable commission decision issued herein.

linked to many other parallel proceedings before the commission, including review of the HECO Companies' Integrated Demand Response Portfolio Plan and Power Supply Improvement Plans, the Feed-in-Tariff Re-examination, and various power purchase agreements and capital expenditure requests for utility-scale resources. In fact, given the rapid technological advances associated with various forms of DER, consideration of DER is essential in nearly every other aspect of planning and operations of the State's electric utilities. Furthermore, several issues, as discussed herein, have become more urgent due to growth in distributed PV and require immediate resolution.

Therefore, the commission finds it appropriate to address several high priority issues in an initial phase of this proceeding (Phase 1). The issues identified herein are based on the conceptual framework for categorizing DER-related issues provided in Table 6 of the Staff Report.

The Staff Report proposes a two-phase process by which the Parties can expeditiously discuss and design solutions to address these issues. The Staff Report further suggests that, within each phase of the process, there should be two separate tracks -- system integration and economics and pricing -- to better facilitate discussion and resolution of issues.[68] The commission

[68] Staff Report at 40-41.

will adopt this two-phase, two-track approach here (see Section VI, below). As set forth therein, the Parties may file initial comments (including proposed additions and/or modifications) on the Statement of Issues within twenty (20) days of the date of this Order. Following the commission's review of any such filings and developments in this and other parallel proceedings, the commission may modify the Statement of Issues for consideration in this docket.

1.

Statement of Issues

The commission identifies the following issues for resolution in Phase 1 of this proceeding:

1. Have the HECO Companies met their commitments and responsibilities to clear the interconnection backlog and enable continued DER growth?

   a. What options to improve the HECO Companies' performance with respect to processing customer interconnection applications should be considered in Phase 1 of this docket?

2. What near-term revisions to applicable interconnection-related tariffs[69] should be made expedite the interconnection process, mitigate DER integration challenges, and enable beneficial DER investment, deployment, and customer choice?

[69] Applicable interconnection-related tariffs include Rule 14H for the HECO Companies and Tariff No. 2 for KIUC.

a. What high priority revisions under consideration by the PV Subgroup of the RSWG should be made to Rule 14H?

b. What additional revisions previously under consideration by the Parties to Docket No. 2014-0130 should be incorporated into Rule 14H, if any?

c. How should a customer self-supply option be technically specified, such that a customer opting to self-supply with minimal grid impact may be permitted to interconnect immediately without need for lengthy review or study?

d. What revisions to applicable interconnection-related tariffs should be made to accommodate a customer self-supply option?

e. What other high priority revisions should be made to applicable interconnection-related tariffs to enable customer choice and continued DER deployment, including mandatory requirements for advanced inverter functionality?

f. Whether it is necessary or appropriate to include screening criteria for system-level grid integration issues in the interconnection review process?

3. How should existing HECO Companies and KIUC DER policies and programs be modified to create new DER market choices while a longer-term DER market structure is established?

a. How should a tariff to enable a customer self-supply option be specified?

b. How should a tariff to enable a customer grid-supply option be specified?

c. What other tariff(s) should be developed to create new DER market choices while a longer-term DER market structure is established? How should any proposed tariff(s) be specified?

d. What modifications should be made, if any, to the Net Energy Metering Program to ensure DER will be acquired cost-effectively until a longer-term DER market structure can be established?

e. To what extent, if any, are non-participating customers detrimentally or positively impacted from customer DER deployment options discussed in Issues 2 and 3.

Further commission directives pertaining to these issues are discussed in the following sections.

2.

Evaluation of Progress in Clearing the Interconnection Backlog

According to the HECO Companies, more than 7,200 electric utility customers sit waiting in the interconnection queue, including more than 3,600 who have been waiting for more than six months, and more than 1,700 customers who have not been permitted to interconnect for over a year.[70]

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[70]See Letter from D. Brown to the commission, filed February 27, 2015.

In public comments filed in this docket, customers report receiving little or no information from the HECO Companies as to the status of their interconnection applications. Furthermore, the commission is aware of numerous complaints from customers describing their confusion and frustration with the interconnection process and their treatment at the hands of their electric utility. This situation is unacceptable and represents a significant failure by the Companies to respond to customer needs and to the commission's Orders.

As noted above, in the October 31 Letter, the HECO Companies provided a 4-page supplement to the DGIP in which the Companies commit to interconnect the remainder of the current interconnection backlog by the end of 2015. However, as discussed above, the Companies' proposed timeline does not reflect the urgency of the situation.

Therefore, an initial focus of this docket, among other Phase 1 priorities, shall be to closely monitor the progress of the HECO Companies in meeting their interconnection commitments and responsibilities to rapidly clear the current interconnection backlog. The commission will require regular reporting by the HECO Companies as to their progress. Continued failures or delays will be addressed directly by the commission in this docket or in other proceedings, as determined by the commission.

3.

Revisions to Interconnection-related Tariffs to Enable DER Market Growth

As has been discussed above, revisions to applicable interconnection rules may be necessary to support the efforts of the HECO Companies to clear the interconnection backlog and to allow continued DER interconnection in the future. Thus, within ninety (90) days of the date of this Order, the HECO Companies shall jointly file with the Parties a stipulation setting forth proposed revisions to Rule 14H designed to (1) finalize the work of the PV Subgroup of the RSWG (relating to high priority revisions to Rule 14H); (2) finalize the work of the Parties to Docket No. 2014-0130 to develop new interconnection standards and processes that accommodate the potential benefits of distributed energy storage; (3) enable a customer opting to self-supply with minimal adverse grid impact to immediately interconnect without undergoing lengthy technical review or study; (4) incorporate high priority autonomous advanced inverter functions into applicable interconnection requirements; and (5) incorporate screening criteria for system level grid integration issues, if deemed necessary.

The stipulation shall include a technical specification of how a customer self-supply system should be configured, so that there is transparency and standardization of what system configurations will be permitted to interconnect under the customer self-supply option. The stipulation should also include proposed revisions to interconnection standards to enable DER systems to automatically provide essential advanced grid-supportive functionality (e.g., high/low frequency and voltage ride through and trip settings, etc.), and other proposed revisions considered highest priority to enable DER policies under consideration in the first phase of this proceeding.[71]

Should the HECO Companies and the other Parties be unable to agree to a stipulation, the HECO Companies shall file their proposed revisions consistent with the directives stated above, including an explanation as to why the Companies were unable to stipulate with the other Parties. In addition, the other Parties shall jointly or separately file their own proposed revisions and explanations to the same effect. The commission will consider the stipulation or proposal(s) filed by the Parties consistent with the directives herein, and will issue an order instructing the HECO Companies to file revised Tariff Sheets reflecting any revisions to applicable interconnection rules approved by the commission.[72]

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[71]The proposed revisions should be consistent with guidance previously provided by the commission to the PV Subgroup in Docket No. 2011-0206.

[72]As discussed above, the initial focus of this proceeding is on the urgent needs in the HECO Companies' service territories;

The commission emphasizes that the proposed revisions to interconnection tariffs considered in Phase 1 should be focused on the system integration track issues suggested in the Staff Report that allow for expedited interconnection of customer self-supply systems and will assist in mitigation of technical challenges associated with interconnection. Following the resolution of the issues identified by the commission for immediate review in this docket, the commission will consider further revisions to interconnection tariffs in Phase 2 of this docket.

4.

Creation of New DER Market Choices

The establishment of a re-designed policy framework for distributed energy resources is a central objective of this proceeding. As the commission stated in Order No. 32053,

> The commission believes it is unrealistic to expect that the high growth in distributed solar PV capacity additions experienced in the 2010 - 2013 time period can be sustained, in the same technical, economic and policy manner in which it occurred, particularly when electric energy usage is declining, distribution circuit penetration levels are increasing, system level challenges are emerging and grid fixed costs are increasingly being shifted to non-solar PV customers.
>
> The commission submits that the distributed solar PV industry in Hawaii will, out of

however, the commission may determine KIUC should be subject to any applicable commission decisions issued herein.

> necessity due to their accomplishments thus far, have to migrate to a new business model, not unlike what is expected for the HECO Companies as a result of disruptive technologies. The distributed solar business model will need to shift from a customer-value proposition predicated upon customers avoiding the grid financially - but relying upon it physically and thereby creating circuit and system technical challenges - to a new model where the customer-value proposition is predicated upon how distributed solar PV benefits both individual customers and the overall electric system....[73]

The commission acknowledges there are many difficult issues that must be resolved in order to ensure a re-designed regulatory approach achieves a flexible, efficient, fair, and cost-effective DER market structure. The commission is confident that the Parties will continue the collaborative, solutions-focused approach established in the Reliability Standards Working Group ("RSWG") process and that has extended into recent efforts by the PV-Subgroup to update Rule 14H. In short, because of the importance of these issues to the State's energy sector and economy, the commission believes it is imperative that the standard of conduct in this docket and the technical conferences described further below is productive collaboration based on reasonable dialogue.

Thus, through good-faith discussion in the technical conferences described below, the Parties are directed to stipulate,

[73]Order No. 32053 at 49-50.

to the extent possible, to a "path forward" that transitions from existing DER policies (including the Net Energy Metering program) to a longer-term DER market structure. The Phase 1 work products should include new tariffs enabling customer self-supply and grid-supply options consistent with the technical specifications to be developed by the Parties in Phase 1 of this docket.

In addition, the Parties shall collaborate to develop a transition plan to a future DER market-based procurement program that will be developed in Phase 2 of this proceeding ("DER 2.0 Transition Plan"). The DER 2.0 Transition Plan, to be developed in Phase 1 and remain in effect until DER 2.0 is finalized, should be developed after considering the proposal submitted by HECO in its January 20, 2015 Motion, as well as any alternatives proposed by the Parties, and should include a stipulation as to what modifications, if any, should be made to the NEM Program at the conclusion of Phase 1 of this proceeding.

VI.

Procedural Schedule

As discussed above, the Staff Report and Proposal attached to this Order provides a framework to consider the major issues in this docket. As set forth in the schedule below, the commission expects the Parties to participate in bi-weekly technical conferences to address the issues set forth above.

These discussions will necessarily be expedited, as the timely resolution of these issues is of great importance to the State. The technical conferences are intended to facilitate discussion and collaboration among the Parties, with the goal of enabling Parties to stipulate to a proposed resolution of Phase 1 issues within the expedited timeframe established herein. In order to allow sufficient commission oversight of this process and to help ensure productive discussions, the technical conferences will be chaired by commission staff or its designee.

At this time, the commission adopts the following Procedural Schedule to expeditiously resolve the highest priority (Phase 1) issues in this docket (including both System Integration and Economics/Pricing tracks).

Phase 1 Procedural Steps	**Timing**
Technical Conferences on Phase 1 issues, including the Parties and commission staff	Bi-weekly unless otherwise specified by the commission
Parties file Initial Comments on Statement of Issues	Within twenty (20) days of the date of this Order
Parties file Preliminary Statements of Position on Phase 1 Issues	Within sixty (60) days of the date of this Order
Parties file Stipulated Resolution of Phase 1 Issues (or Final Statements of Position)	Within ninety (90) days of the date of this Order
Commission Decision and Order on Phase 1 Issues and Guidance on Phase 2	Subsequent to Parties' Stipulation

The commission will provide notice to the service list as to the time and location of the first technical conference. The commission may modify the procedural schedule based on its review of developments in this docket or in other parallel proceedings.

VII.

Orders

THE COMMISSION ORDERS:

1. The motions to intervene of HSEA, LOL, REACH, HREA, HPVC, TASC, SUNPOWER, DBEDT, Blue Planet, and Mr. Hooson are granted.

2. Docket No. 2014-0130 is consolidated with this docket and the record in Docket No. 2014-0130 is incorporated by reference into the instant proceeding.

3. The record pertaining to the First and Second Stipulations of the PV Subgroup in Docket No. 2011-0206 is incorporated by reference into the instant proceeding.

4. The HECO Companies shall submit weekly reports in this docket documenting progress clearing the interconnection backlog. The HECO Companies shall consult with commission staff to determine the format and content of these reports.

5. The HECO Companies and KIUC shall submit monthly reports on key technical developments to enable DER market growth.

The reports shall discuss efforts to utilize advanced technologies and grid-supportive DER functions to allow further integration of DER systems. The HECO Companies shall consult with staff to determine the format of these reports but to the extent feasible, data in the reports should be submitted in electronic format. At a minimum, the reports shall list the following:

a. Energy storage systems deployed by island, including but not limited to customer-sited storage options such as battery storage, thermal storage, and dispatchable thermal water heaters;

b. Customer non-export systems with additional breakdown for those systems identified for congested circuits;

c. DER customers subscribed and participating in existing demand response programs; and

d. Utility utilization of advanced inverter capabilities.

6. The Parties may file Initial Comments on the Statement of Issues, within twenty (20) days of the date of this Order.

7. The Parties shall file Preliminary Statements of Position on the Phase 1 Issues as set forth herein, and as may be modified by the commission, within sixty (60) days of the date of this Order.

8. The Parties shall jointly file stipulated resolution of the Phase 1 issues, within ninety (90) days of the date of this Order. At a minimum, the stipulation shall include the following

items noted as "Anticipated Work Products 3-5" in Table 6 of the Staff Report and Proposal attached to this Order:

a. Proposed revisions to applicable interconnection-related tariffs to mitigate near-term DER technical integration challenges, expedite interconnection process, and standardize technical specifications for fast-track approval of customer self-supply systems;

b. New tariff for customer self-supply systems; and

c. Proposed DER 2.0 Transition Plan, including tariff for grid-supply systems.

If the Parties are unable to agree to a stipulated resolution of the issues, the Parties shall file joint or individual final statements of position, including comments describing why they were not able to reach agreement.

DONE at Honolulu, Hawaii MAR 3 1 2015.

PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

By
Randall Y. Iwase, Chair

By Michael E. Champley
Michael E. Champley, Commissioner

By Lorraine H. Akiba
Lorraine H. Akiba, Commissioner

APPROVED AS TO FORM:

Thomas C. Gorak
Thomas C. Gorak
Commission Counsel

2014-0192.sr

Staff Report and Proposal

DOCKET NO. 2014-0192

MARCH 31, 2015

Contents

Executive Summary

This Staff Report and Proposal describes several high priority technical and economic challenges associated with continued growth in distributed energy resources ("DER"),[1] and offers policy suggestions for consideration by the Parties to the DER docket before the Hawai'i Public Utilities Commission (Docket No. 2014-0192). This document outlines a roadmap for quickly but thoroughly addressing these challenges and designing new policies to facilitate the next wave of DER deployment in Hawai'i (referred to as "DER 2.0").

DER 2.0 will provide new ways for customers to manage and control their energy use, incorporate many new grid supportive technical capabilities, and offer new ways to create value throughout the electricity system supply chain, from power generation down to the energy services provided to meet customer needs. However, thoughtfully designing and implementing DER 2.0 will require collaborative efforts on the part of many stakeholders, including the state's electric utilities, customers, DER developers, manufacturers, and policymakers. To assist the Parties, the staff of the Public Utilities Commission has prepared this Staff Report and Proposal, with the following goals:

- Clear the Interconnection Backlog: ensure timely processing of requests to interconnect distributed generation ("DG") in the HECO Companies' service territories;
- Enable DER Market Growth: update key technical interconnection requirements to utilize advanced technologies and enable grid-supportive functions and services; and
- Create New DER Market Choices: establish new market options for the next significant growth stage of DER technologies.

Hawai'i has reached unprecedented levels of distributed renewable energy, particularly for a state with multiple islanded power systems. This Staff Report and Proposal offers a solutions-oriented, detailed roadmap and work scope to push through the current interconnection bottleneck and accelerate cost-effective deployment of DER throughout Hawai'i.

[1] In this Staff Report and Proposal, the term "distributed energy resources" refers to technologies and other resources typically located at customer premises, which may be designed to serve all or part of a customer's load, supply power to the distribution system, provide grid-supportive functions, or a combination of these or other services. Distributed energy resources include distributed generation, demand response, energy storage, electric vehicles, and energy efficiency.

Introduction

In the *Commission's Inclinations on the Future of Hawaii's Electric Utilities* ("Commission's Inclinations"),[2] the Commission provided guidance that Hawai'i's electric utilities will need to harness distributed energy resources ("DER") to benefit individual customers and the utility system. More specifically, the Commission stated:

> "In recent years, Hawaii has seen exponential growth in rooftop photovoltaic (PV) systems. Coupled with continued innovation in other distributed energy resources, such as electric vehicles and distributed energy storage, the utilities will need to plan proactively for future additions of DER. The rapid adoption of these technologies will require the utilities to design programs and develop distribution system infrastructure to optimize the system and maximize customer benefits."[3]

The State of Hawai'i is poised to become a national and world leader in creative solutions to integrate significant levels of DER. The state's commitment to clean energy was central in establishing the ambitious goal of reaching at least 70% clean energy statewide by 2030 – 40% renewable energy generation and 30% through energy efficiency.[4] Several key state energy policy directives support this commitment, such as the state's policy to "maximize the deployment of cost effective investments in clean energy production and management for the purpose of promoting Hawaii's energy security."[5]

Beyond state policy goals, the fundamental long-term economics of DER technologies indicate a prominent role in Hawai'i's energy future. With projections of continued cost declines in DER coupled with Hawaii's high retail electricity rates, Hawai'i's market trends have supported early adoption of these technologies, followed by sustained demand for widespread use.

Despite these supporting policy and economic factors, the market for DER in Hawai'i appears to be at an inflection point. The continued, frustrating delays and lingering cloud of uncertainty with the current interconnection process is leading the HECO Companies'[6] customers, and the companies that supply and install DER technologies, to seek alternatives to grid-connected DER systems. This is an understandable response given customers' overriding concerns to assert greater control and certainty over their high electricity bills, but is counterproductive to the State's interests to promote a vibrant, clean energy economy that supports all residents and businesses. Furthermore, for most customers, an off-grid DER system is likely to be an inferior alternative to a grid-connected option that recognizes, and compensates for, the potential grid value that can be supplied by customer-sited DER systems that are configured to provide circuit- and system-level benefits.

[2] The Commission's Inclinations were attached as Exhibit A to Decision and Order No. 32052 issued in Docket No. 2012-0036.

[3] Commission's Inclinations at 15.

[4] See Hawaii Revised Statutes ("HRS") § 269-92.

[5] See "State of Hawaii – Energy Policy Directives" available at http://energy.hawaii.gov/energypolicy.

[6] The HECO Companies are Hawaiian Electric Co., Inc., Hawaii Electric Light Co., Inc., and Maui Electric Co., Ltd. The HECO Companies serve the islands of O'ahu, Hawai'i, Maui, Moloka'i, and Lana'i.

In addition, the recent disruption in the distributed solar PV industry sends the wrong market and policy signals to current and future innovative companies that are helping transform the state's energy system. A key state energy policy directive is to launch an energy innovation cluster, and several initiatives have been cultivating energy innovators within the Hawaiian Islands. To sustain these efforts and attract the best innovators to our market, the State should send a clear message that it welcomes DER technological advances and is willing to address the concomitant disruptive forces that these technologies pose to the utility's existing business model and regulatory regime.

With this forward-looking perspective, future growth of the DER market will necessitate new technical and operational capabilities for grid-connected DER systems and will require a migration to new industry business models with multiple product offerings for customers. In the final decision and order issued in the Reliability Standards Working Group ("RSWG") docket, the Commission noted:

> "The Commission submits that the distributed solar PV industry in Hawaii will, out of necessity due to their accomplishments thus far, have to migrate to a new business model, not unlike what is expected for the HECO Companies as a result of disruptive technologies. The distributed solar business model will need to shift from a customer-value proposition predicated upon customers avoiding the grid financially – but relying upon it physically and thereby creating circuit and system technical challenges – to a new model where the customer-value proposition is predicated upon how distributed solar PV benefits both individual customers and the overall electric system...."[7]

The Commission's Inclinations and many recent orders have also discussed the critical importance of aggressively pursuing strategies to lower utility fuel and purchased power costs, which comprise a significant portion of today's customer energy bills.[8] With the proposed additions of new utility-scale solar projects on several Hawaiian islands, most notably O'ahu and Kaua'i, it is likely that in the near future, utility-scale solar will become the marginal generating resource during many days of the year, rather than conventional oil-fired generation.[9] In other words, substantial growth in distributed solar may result in curtailment of other renewable resources due to decreasing daytime net demand. Furthermore, continued substantial growth in solar PV, whether distributed or utility-scale, may result in new technical integration challenges that would require additional mitigation measures. Therefore, new additions of distributed PV will increasingly need to be

[7] Decision and Order No. 32053, Docket No. 2011-0206, at 49.

[8] "New generation resources should lower system costs and maximize use of cost-effective renewable resources." Commission's Inclinations at 4.

[9] The marginal generating resource refers to the generating unit that will increase or decrease output in response to an increase or decrease in demand. Each island grid has unique characteristics that determine the marginal generating unit at any given time. For example, on Maui, due to many factors including a greater proportion of renewable resources relative to daytime electricity demand, the marginal generating unit is often utility-scale wind, which is routinely curtailed during the daytime period.

competitively priced compared with utility-scale solar (including integration costs), while accounting for locational and other benefits these systems can provide to the grid.

This policy proposal ("Staff Report and Proposal"), drafted by the staff of the Hawai'i Public Utilities Commission,[10] is intended to facilitate productive discussion among the Parties to the Distributed Energy Resources docket ("DER Docket"). The roadmap includes a solutions-oriented, detailed proposed work scope, with associated timelines for decision-making. It outlines a roadmap to achieve state energy policy goals by:

- Clearing the Interconnection Backlog: ensure timely resolution of the customer applications waiting to be processed through the HECO Companies' interconnection queues (beyond those HECO has committed to processing by April 2015);
- Enabling DER Market Growth: update interconnection standards to utilize advanced technologies and enable grid-supportive functions and behaviors; and
- Creating New DER Market Choices: develop interim market pathways (e.g., self-supply and grid-supply) for continued DER deployment until a comprehensive DER 2.0 market structure can be established.

Section 1 provides an overview of trends in Hawai'i's solar PV market including the recent disruption experienced since 2012, regulatory proceedings addressing DER in Hawai'i, and the HECO Companies' efforts to address distributed energy resources in response to the Commission's orders.

Section 2 outlines a series of potential near-term solutions to technical and economic DER integration challenges. Potential solutions include two interim market pathways—customer self-supply and customer grid-supply—that are intended to address both of these types of challenges. With proper design, these new development options can address near-term technical concerns with further interconnection of DER systems, institute a more certain and timely interconnection process for systems that utilize advanced technologies to mitigate grid-integration challenges, and establish pricing for future grid-supply energy systems that is more aligned with the economic value these resources provide to the electric grid.

Section 3 describes a detailed proposed scope for the DER docket separated into two tracks—*system integration* and *economics/pricing*—with timelines for near-term (Phase 1) and mid-term (Phase 2) decision-making on these tracks.

[10] This document was prepared by Commission staff and is intended to serve as a summary of the immediate challenges facing the state in DER deployment and as a proposal to facilitate collaboration among the Parties to Docket No. 2014-0192. As such, it does not represent the views or policies of the Hawaii Public Utilities Commission. See Order No. 32737, filed March 31, 2015 in Docket No. 2014-0192, at 29-30.

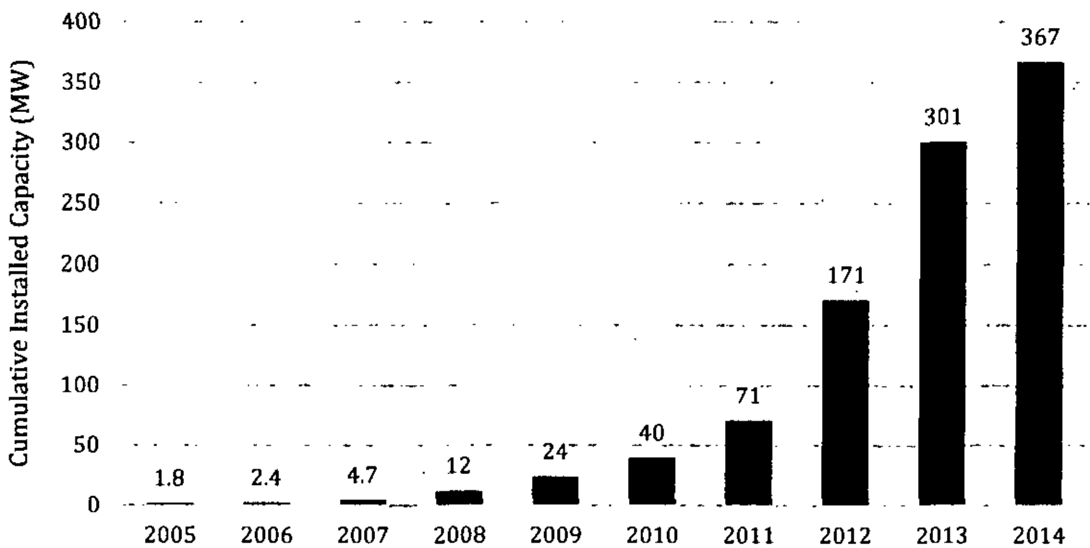
Section 1 – Overview of Recent Trends in Hawai'i Solar PV Market

This section summarizes recent trends in the Hawai'i DER market, separated before and after the interconnection policy changes HECO announced on September 6, 2013.[11]

Pre-September 2013 Market Trend

Figure 1, below, shows the growth trend for distributed solar PV systems in the HECO Companies' service territories. The chart depicts the exponential growth of distributed PV solar installations that started in 2005 and lasted until late 2013. Of note, installed capacity nearly doubled every year since 2006 and the growth rates in 2012 and 2013 moved Hawai'i into a position of national prominence in the amount of installed solar PV per capita.[12]

Figure 1. Hawaiian Electric Companies Distributed Solar PV Installed Capacity[13]



During this period, high electric rates, declining solar costs, innovative solar financing products, and generous state tax policy drove the growth trend, and the Net Energy Metering ("NEM") program size caps were removed to accommodate customer demand and solar

[11] See HECO Press Release "Hawaiian Electric Companies implement changes to help more customers add solar photovoltaic systems" Available at: http://www.hawaiianelectric.com/heco/_hidden_Hidden/CorpComm/Hawaiian-Electric-Companies-implement-changes-to-help-more-customers-add-solar-photovoltaic-systems?cpsextcurrchannel=1

[12] See *Top 10 Solar States Infographic.* Solar Energy Industries Association. Available at http://www.seia.org/sites/default/files/resources/Top-10-Solar-States-Infographic.pdf. See also *2013 Solar Leaders* available at http://www.solarelectricpower.org/discover-resources/solar-tools/utility-solar-rankings.aspx

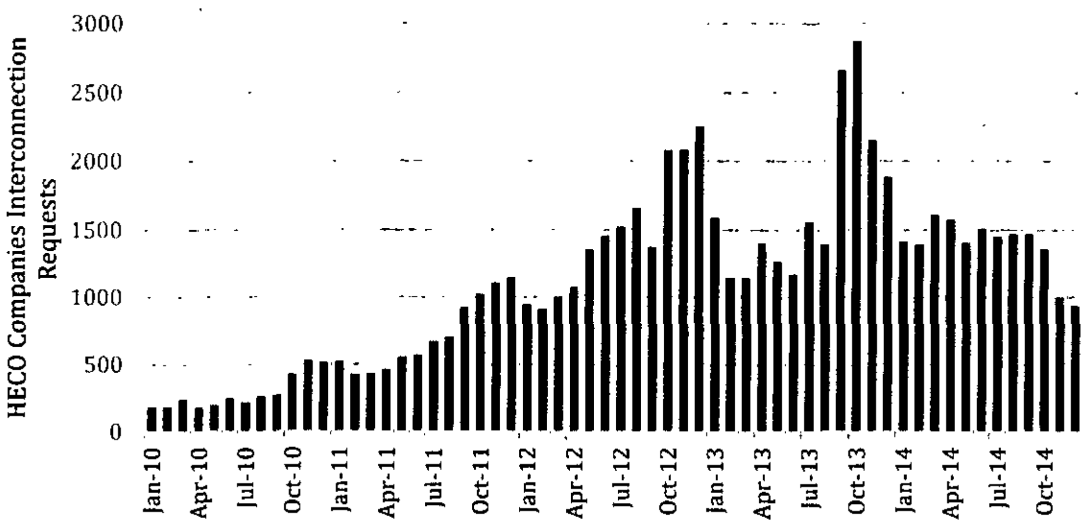
[13] See Hawaiian Electric News Release dated January 2, 2014, accessible at http://www.hawaiianelectric.com/heco/_hidden_Hidden/CorpComm/Rooftop-PV-enjoys-another-strong-year-in-Hawaii?cpsextcurrchannel=1. Additional data provided by HECO at the request of Commission staff.

industry growth. The growth of distributed PV reached significant levels relative to each isolated grid throughout the HECO Companies' service territories,[14] and the exponential growth that occurred during this period appears to have outpaced both the utility's understanding of the range of potential integration issues and the utility's ability to effectively manage the customer interconnection queue.[15]

Post-September 2013 Market Trend

After the utility announced a series of changes to the interconnection process in September 2013, customers requesting interconnection of their PV systems faced significant delays. Agrowing backlog of requests have entered the queue since late 2013. The last column in Figure 1 (above) shows that the incremental growth of distributed solar PV installed capacity declined significantly in 2014 compared to previous years. Figure 2 shows this trend for net energy metering (NEM) customers in the HECO Companies' service territory.

Figure 2. HECO Companies Interconnection Requests[16]



The graph shows a decline in new interconnection requests in late 2013 and late 2014 when market demand has typically increased at the end of the year.[17] Numerous articles in the local media have commented on the rapid decline in the solar market and significant delays for interconnection.[18]

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[14] See Order No. 32053, filed on April 28, 2014, in Docket No. 2011-0206 at 25.

[15] See Order No. 32053 at 32 and 90.

[16] See HECO Response to PUC-HECO-IR-7, Docket No. 2014-0192. Commission staff does note a less volatile pattern of interconnection requests for MECO and HELCO compared to HECO.

[17] Order No. 32053 at 28. See also Honolulu PV Weekly available at http://files.hawaii.gov/dbedt/economic/honolulu-pv-weekly.pdf

[18] See, e.g., *PV System Permits Plummet on Oahu.* Honolulu Star-Advertiser. September 10, 2014, accessible at http://www.staradvertiser.com/s?action=login&f=y&id=274577681&id=274577681. See also *Oahu's Solar Industry Continues to Cool Down.* Pacific Business News. October 14, 2014,

Collectively, the data show a volatile and disruptive business cycle for distributed solar PV in Hawai'i's largest market. Interconnection delays have become a significant source of frustration for waiting customers, the distributed solar PV industry, and the broader public.[19]

Furthermore, boom and bust cycles are disruptive and economically inefficient. This situation is counterproductive to the state's energy policies, hinders business planning, reduces the efficiency of the industry, and ultimately leads to higher prices for the end consumer. While the boom of recent years may not return in the same form, the policies proposed in this document and to be developed in this proceeding are intended to create a thriving DER market going forward.[20]

Tariff Rule 14H and Interconnection of DER

The HECO Companies' Tariff Rule 14H establishes the technical requirements and process to interconnect distributed generation facilities to the electric utility grid. The following summary highlights several of the key recent utility and regulatory efforts to update these rules and analyze technical requirements for higher levels of DER.

Table 1. Summary of Regulatory Proceedings Addressing DER Interconnection

Docket	Summary
Docket No. 2002-0051	In January, 2002, Hawaiian Electric Company, Maui Electric Company, and Hawaii Electric Light Company each filed a request for authorization to "modify its Rule 14 to establish Interconnection Standards and to require an interconnection agreement for distributed generating facilities operating in parallel to the Company's electric electric (sic) system." On November 15, 2002, the Commission conditionally approved the request, which added to Rule 14 a new paragraph H and three appendices (interconnection standards; interconnection agreement, and interconnection procedures). In the Decision and Order, the Commission stated: "The utilities are urged to continuously review and monitor the customer interconnection requirements set forth in the joint submission, to determine whether it is technically feasible to deploy less stringent customer requirements. As an example, pursuant to Appendix III, section 3 (a), the need for additional technical study may be triggered by feeder penetration of greater than 10 per cent. By contrast, other jurisdictions set the penetration threshold at 15 per cent. Furthermore, the technical review/screening process in other jurisdictions appears less restrictive. The commission is optimistic that, in the future, a more streamlined interconnection process will result."[21]

accessible at http://www.bizjournals.com/pacific/news/2014/10/13/oahus-solar-industry-continues-to-cool-down.html.

[19] See legislative informational briefing on interconnection from September 19, 2014, available at http://olelo.granicus.com/MediaPlayer.php?view_id=13&clip_id=43316. See also legislative informational briefing on interconnection from October 14, 2013, available at http://olelo.granicus.com/MediaPlayer.php?view_id=13&clip_id=36947

[20] Customers do not have unlimited demand for energy, so exponential growth of solar PV systems was unlikely to occur indefinitely as the market evolves. However, the severe reduction in industry growth was likely exacerbated by the significant delays in interconnection approvals and interconnection charges imposed on customers by the HECO Companies.

[21] See Decision and Order No. 19773 filed November 15, 2002 in Docket No. 2002-0051, at 10.

Docket No. 2003-0371	In October of 2003, the Commission opened a new docket to investigate and establish guidelines for distributed generation development,[22] stating that: "It is anticipated that the use of distributed generation ... will grow substantially in the coming years throughout the nation including Hawaii." Issues raised in the docket included: (1) addressing interconnection matters; (2) determining who should own and operate distributed generation projects; (3) identifying what impacts, if any, distributed generation will have on Hawaii's electric distribution systems and market; (4) defining the role of regulated electric utility distribution companies ("UDCs") and the commission in the deployment of distributed generation in Hawaii; (5) identifying the rate design and cost allocation issues associated with the deployment of distributed generation facilities; and (6) developing the necessary revisions to the integrated resource planning process, if necessary. In January of 2006, the Commission set forth "certain policies and principles for the deployment of distributed generation in Hawaii and certain guidelines and requirements for distributed generation, some of which will be further defined by tariff as approved by the Commission" and stated: "While it is feasible for distributed generation to operate solely for its customer-generator disconnected from the utility's distribution system, many of the benefits of distributed generation previously discussed can be realized only if distributed generation is connected to the distribution system. The complexity of a distributed generation unit's interconnection with the distribution system varies, depending upon (a) the type of technology, (b) the fuel source, either fossil or renewable, (c) the power system interface, (d) the extent of interaction required between the customer-generator and the utility, and (e) the architecture of the distribution system into which the distributed generation is interconnected. Requiring each customer-generator to negotiate a complex interconnection agreement anew may create an unnecessary barrier to entry and may discourage the interconnection of small, cost-effective distributed generation projects. Accordingly, the commission hereby requires that each utility establish a non-discriminatory interconnection policy by proposed tariff for approval by the commission, that entitles distributed generation to interconnect when it can be done safely, reliably and economically."[23]
Docket No. 2010-0015	On January 7 and 8, 2010, the Hawaiian Electric Companies applied for approval to modify Rule 14H and its three appendices, and to add a fourth appendix.[24] The changes were proposed to take effect on February 8, 2010. However, over the next two weeks, several entities filed formal protest and opposition documents with the Commission. On January 27, 2010, the Commission suspended the HECO transmittals and opened a proceeding (Docket No. 2015-0015) to investigate the proposed changes. Over the next twenty months the Parties negotiated an agreement on stipulated revisions to Rule 14H to (1) facilitate the higher

[22] See Order No. 20582 filed October 21, 2003 in Docket No. 2003-0371.

[23] See Decision and Order No. 22248, filed January 27, 2006 in Docket No. 2003-0371.

[24] See Transmittals No. 10-01, 10-01H, and 10-01M, filed January 7 and 8, 2010, and subsequently reviewed in Docket No. 2010-0015.

	penetration and interconnection of renewable distributed generating facilities that operate in parallel with the electric utility's distribution system; (2) represent best practices in the area of interconnection; and (3) result from a fair and consensus-based, collaborative process among the Parties.[25] On December 20, 2011, the Commission issued a Decision and Order on the remaining issues related to the HECO Companies' Tariff Rule 14H, governing the interconnection of distributed generating facilities operating in parallel with the utilities' electrical systems. However, the Commission "decline[d] to adopt the HECO Companies' proposals to provide them with the absolute authority to defer the interconnection of a generating facility under certain conditions."[26]
Docket No. 2011-0206	Docket 2011-0206 was established to facilitate the efforts of the Reliability Standards Working Group ("RSWG"), which ultimately included twenty-five entities, plus technical consultants and observers. The purpose of the RSWG was to recommend fact-based standards, metrics, rules, criteria and processes to "help determine how we can interconnect the maximum amount of renewable generation to the grid while preserving grid reliability" and to define the circumstances under which renewable energy projects of all sizes, technologies and procurement mechanisms could or could not be incorporated into each of the Hawaiian Electric Companies' island grids. The standards, rules, criteria and processes were to be clear, fair, transparent and unambiguous. Sub-groups met frequently, often in all-day meetings. In the three-year period following opening of the docket, 239 documents (5,560 pages) were filed under the docket.[27] Recommendations of the PV-DG Subgroup included: • Revisions to Rule 14H with a new, transparent interconnection screening process to allow more projects to interconnect expeditiously without sacrificing safety, reliability and power quality. • A proposal to manage all distribution-level interconnection requests with a new queuing proposal that would give the utility and all developers "a window into the interconnection procedures and the status of projects" within the queue for each area of the queue. This could be integrated with the Hawaiian Electric Companies' Feed-in Tariff queue process. • A proposal to enhance the monitoring and controllability of PV production, including sharing PV developers' data on PV production with the utility and plans to expand the HECO Companies' PV monitoring network across the distribution grid. • A proactive approach for the HECO Companies to plan for higher penetrations of DG, which may require additional tariff modifications.[28]

[25] See Decision and Order filed Nov. 29, 2011 in Docket No. 2010-0015.

[26] See Decision and Order No. 30027, filed December 20, 2011 in Docket No. 2010-0015.

[27] Key RSWG documents included the Final Report of the Independent Facilitator, filed March 25, 2013, and the Report of the Technical Review Committee, filed May 29, 2013, in Docket No. 2011-0206.

[28] See Order No. 32053, filed on April 28, 2014, in Docket No. 2011-0206 at 18.

	In April of 2014, via Order No. 32053 ("RSWG Order"), the Commission ruled on the RSWG Work Product. In the RSWG Order, the Commission made a number of observations that indicated the utility was slow to anticipate and recognize the consequences of this sustained level of growth.[29] Furthermore, the Commission observed that the "HECO Companies have not provided... long-term plans to interconnect increasing amounts of solar PV capacity on already high penetration distribution circuits [or] the technical basis [for] *de facto* circuit interconnection limits..." and that the "... lack of transparency and slow response to provide supporting technical information on reliability concerns foster public distrust about utility management of the distributed generation interconnection challenges."[30] To address these and other issues, the Commission further ordered the HECO Companies to develop and file several plans, including a proposal for an integrated interconnection queue consistent with the recommendations of the RSWG and a Distributed Generation Interconnection Plan ("DGIP") that will utilize forward-looking planning consistent with the "Proactive Approach" recommended by the PV-DG Subgroup of the RSWG, among other requirements.
Docket No. 2014-0130	Docket 2014-0130 was established as a result of Decision and Order No. 31901, wherein the Commission instructed the HECO Companies to file an application to modify Tariff Rule 14 "for the purpose of clarifying the following matters: 1. A customer that installs a battery back-up system must also obtain an interconnection review by the electric utility to ensure the proper interconnection of the customer's generating facility with the electric utility's system; and 2. The interconnection requirements for a customer's battery back-up system and the screening process to review such a request for interconnection."[31] The HECO Companies filed their proposed modifications on June 2, 2014. The Parties' continued their discussions and filed Reply Statements of Position for the Commission's consideration on February 19, 2015.

Distributed Generation Interconnection Plan

The RSWG Order included explicit instructions to the HECO Companies to address these critical issues in the Distributed Generation Interconnection Plan (DGIP). The DGIP is required to include the following three major components:

1. A **Distributed Generation Interconnection Capacity Analysis** to proactively identify distribution circuit capacity to safely and reliably interconnect distributed generation resources and the system upgrades requirements necessary to increase circuit interconnection capability in major capacity increments.[32]
2. An **Advanced DER Technology Utilization Plan** to provide the near, medium and long-term plans by which customers would install, and utilities would utilize, advanced inverters, distributed energy storage, demand response and EVs to

[29] Order No. 32053 at 33.

[30] Order No. 32053 at 31-50.

[31] Decision and Order No. 31901

[32] Order No. 32053 at 51.

mitigate adverse grid impacts starting at the distribution level and up to the system level.[33]

3. A **Distribution Circuit Improvement Implementation Plan** which shall summarize the specific strategies and action plans, including associated costs and schedule, to implement circuit upgrades and other mitigation measures to increase capacity of electrical grids to interconnect additional distributed generation.[34]

Preliminary DGIP Review

The DGIP contains 283 pages of material, with 843 pages of additional documents and reports. The Commission provided explicit instructions as to the requirements of the DGIP that do not appear to have been adequately addressed.[35] For example, the DGIP did not articulate a clear, timely plan to resolve the substantial interconnection queue and plan for future integration of DER, including distributed energy storage systems and electric vehicles.[36] Due to this and other fundamental deficiencies, on September 30, 2014, the Commission issued a set of initial information requests to the HECO Companies in the DER docket.[37]

According to the HECO Companies' responses to these information requests (filed October 10, 2014), at the very best under the plans in the DGIP filing, existing customers would need to wait until April 2015 (eight additional months after the DGIP filing) before the Companies would finish clearing the backlog on high penetration circuits. The mitigation measures identified would accommodate only a fraction of the then pending interconnection requests (20% of waiting customers on O'ahu, 50% on Maui, and 12% on Hawai'i Island).[38]

In response to an information request on interconnecting new DG customers beyond the existing backlog, the HECO Companies stated, "the Companies do not have visibility at this time as to the timing of further increases in allowed penetration levels."[39]

Despite the Commission's admonition in the RSWG Order that, "the HECO Companies have been quick to identify interconnection technical challenges but slow to offer solutions to

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[33] Order No. 32053 at 52.

[34] Order No. 32053 at 54.

[35] The discussion of the DGIP herein is not, nor is it intended to be, a definitive or exhaustive assessment of the HECO Companies' filing. This document is primarily forward-looking and focused on solutions to the current situation in Hawai'i.

[36] See Figure ES-8 in DGIP at ES-22 where DESS/CESS deployments are listed in the "Long Term" category. See also Decision and Order No. 32316.

[37] See Letter from Commission to J. Viola, dated September 30, 2014, filed in Docket No. 2014-0192.

[38] See HECO Response to PUC-IR-2d, Letter from J. Viola to Commission dated October 10, 2014, filed in Docket No. 2014-0192.

[39] See HECO Response to PUC-IR-1d, Letter from J. Viola to Commission dated October 10, 2014, filed in Docket No. 2014-0192. In a subsequent filing with the Commission, the HECO Companies have made new commitments to address the interconnection queue, which are discussed further below. See Letter from J. Viola to Commission dated October 31, 2014, filed in Docket No. 2014-0192 at 1.

these problems," [40] the DGIP filing contains numerous technical studies, often with inconsistent findings, resulting in an expanding list of technical concerns raised with interconnection of DG. In addition, the filing does not prioritize how the Companies propose to address these concerns with timely solutions. In several cases, particularly with circuit-level technical concerns, the basis for the concerns raised in the DGIP, and the mitigations proposed by the HECO Companies, are not clearly defined or well founded by the supporting technical material. The filing is also clearly deficient in defining and establishing plans to implement a non-export option for new DG systems.

Furthermore, the DGIP (and the Power Supply Improvement Plans filed concurrently with the DGIP) prominently feature a proposal to replace the net energy metering (NEM) program with a new "DG 2.0" program. The "DG 2.0" proposal has significant flaws that have been extensively discussed in public comments filed in Docket No. 2014-0192. For example, the proposal would significantly increase fixed charges for all residential customers (to $55/month) and add a new charge of $16/month for DG customers. The proposal has drawn substantial negative feedback in the public comments filed with the Commission, and Commission staff is concerned with numerous aspects of the proposal.[41]

The proposed fixed-variable rate design would result in substantial increases in costs to low usage customers and customers who have already invested in DER. These fixed fees would also limit the economic attractiveness of new DER investments, including energy efficiency (regardless of whether DER investments would lower overall utility costs), and may further encourage existing HECO customers to opt-out of utility service and meet their energy services needs through off-grid and natural gas-based systems.[42] Finally, it is not clear how the proposal would incent new DER systems with the advanced, grid supportive features that are required to integrate additional renewable generation in Hawai'i. In staff's view, the utility's proposed plans do not adequately address the immediate or long-term issues associated with integrating distributed energy resources and achieving the state's energy goals.

Many respondents to the DGIP filing have noted similar concerns [43] and have offered alternative proposals for consideration. For instance, The Alliance for Solar Choice, Hawaii

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[40] See Order No. 32053 at 33.

[41] The Commission received hundreds pages of public comments in response to its invitation for public comment. The vast majority of these comments stated opposition to HECO's filings. See *Hawaii PUC Invites Public Comment on the HECO Companies' Action Plans.* September 15, 2014. Available at http://puc.hawaii.gov/wp-content/uploads/2014/09/2014.09.15_HAWAII_PUC_INVITES_PUBLIC_COMMENT_ON_HECO_ACTION_PLANS.pdf.

[42] Commission staff views utility customer defection as undesirable due to the excessive capital expenditure this would require at scale and the adverse impact customer exit would have on remaining customers that may not have the ability to opt-out of utility service (such as low-income customers, customers in condominiums and apartment buildings, renters, etc.).

[43] See "Customer-Based Solutions for the Hawaii Electric System" at 8, "Rate designs that rely heavily on fixed charges and demand charges offer a weak financial motive for customers to reduce electric consumption, fail to reduce peak demand, and discourage economically efficient decision-making. Such charges are inconsistent with customer choice and empowerment, and penalize energy-

PV Coalition, and Hawaii Solar Association have proposed increasing minimum bill levels and introducing a time-of-use rate (including opt-in use of smart meters) as an option in the short term. They suggest these alternatives will incent customers to better match load and generation using non-export systems and DER systems that only export during peak demand periods.[44] Staff believes that these suggestions align with the Commission's Inclinations and have been included for consideration in the proposed work scope shown in Table 6 of this paper.

Despite the significant flaws in the DGIP filing, Commission staff does not believe ordering a complete redo of the plans at this time would promote a speedy resolution of the near-term technical and economic issues associated with further interconnection of distributed generation. Instead, the proposed docket work scope described in Section 3 is intended to help focus the efforts of the Parties to resolve the current interconnection queue and establish new pathways for further DER development.

Efforts to Address the Interconnection Queue Since Filing the DGIP

The HECO Companies filed a follow-up letter to the Commission dated October 31, 2014 (the "October 31 Letter"), which included "supplemental" responses to the IR responses filed on October 10, 2014. In the October 31 Letter, the HECO Companies stated:

> "For customers who live on heavily penetrated circuits above the [Daytime Minimum Load] DML threshold, based on recent preliminary test results of inverters, the Companies have developed a plan . . . to interconnect the majority of these customers by April 2015, and all remaining customers in this grouping by December 2015."[45]

The October 31 Letter stated that at the time of the filing 4,807 customers on O'ahu were in the interconnection queue. Of this total, 2,058 were in the process of approval because they are on lower penetration circuits (at or below 120% DML), or integration solutions were implemented or were in progress. Another 2,749 customers remained in the queue waiting for solutions to allow interconnection. In the letter, the HECO Companies committed to interconnecting 2,500 of these remaining customers by April 2015 and the other 249 customers by December 2015. The letter also noted that 333 MECO customers were waiting for interconnection approval and Hawai'i Island had 336 customers waiting in the queue. The letter did not provide any indication of the Companies' plans for interconnecting the customers waiting on Maui and Hawai'i Island.

The October 31 Letter also proposed new requirements to approve interconnection of systems on high penetration circuits and listed a number of additional solutions that the Companies are pursuing to address interconnection of customers in the queue. The letter also notes inverter testing is ongoing at the US Department of Energy National Renewable

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conscious customers who have neither a short- nor long-term ability to respond to fixed, demand, or NEM-Specific charges." This white paper was an attachment by The Alliance for Solar Choice, Hawaii PV Coalition, and Hawaii Solar Energy Association ("the solar industry") to the their motions to intervene in this docket.

[44] See "Customer-Based Solutions for the Hawaii Electric System" at 6.

[45] See Letter from J. Viola to Commission dated October 31, 2014, filed in Docket No. 2014-0192 at 1.

Energy Laboratory ("NREL") to evaluate the operational performance of inverters during certain challenging conditions. However, the October 31 Letter offered no definitive timelines for implementation of these solutions, and some of these solutions, such as options for non-export PV systems, were required elements of the DGIP that were clearly deficient or entirely absent.

The October 31 letter and subsequent progress in addressing technical integration challenges are a welcome improvement over the deficient DGIP submission, and suggest a more concerted effort by the HECO Companies to address the interconnection queue than in the period following the September 2013 announcement. However, the timelines in the October 31 letter still indicate some customers will be waiting for more than another entire *year* for interconnection approval, and the plan provides little detail on the pathway for future interconnection beyond the current queue. Commission staff expects the HECO Companies will devote sufficient attention to these issues to compress the timeline commitments in the October 31 letter. Failure to aggressively pursue actions to address these issues should be reviewed in a later phase of the DER docket or in other appropriate proceedings as part of an overall assessment of utility performance.

HECO Motion to Cap the NEM Program

On January 20, 2015, the HECO Companies filed a motion for Commission approval, within sixty days, to:

1) Re-establish a system-wide cap on the Net Energy Metering ("NEM") program for each island service territory, effectively ending the program for new customers;
2) Create a "transitional distributed generation program" that would compensate new solar customers at the cost of fuel used for generation (about half the current retail electric rate currently used in the NEM program), as well as other make changes to the terms and conditions of interconnection; and
3) Allow HECO to modify interconnection standards and rules in the future through a tariff-filing process, rather than through a formal application to the Commission as is currently required.[46]

If the Commission approves these requests, HECO claimed it will increase the de facto circuit penetration limit of 120% of daytime minimum load ("DML") to 250% of DML, based on the results of the first phase of inverter testing underway at NREL.[47]

According to HECO's January 20 Motion, the test results "indicated that the tested inverters could trip off extremely quickly to mitigate the extent to which overvoltage occurred" and

[46] See Hawaiian Electric Companies' Motion for Approval of NEM Program Modification and Establishment of Transitional Distributed Generation Program Tariff; Appendices 1 to 5; filed January 20, 2015 in Docket No. 2014-0192.

[47] In February 2015, NREL released its report on the first phase of this testing, which found that, among other things, "the maximum over-voltage measured in any test did not exceed 200% of nominal, and typical over-voltage levels were significantly lower" and that "no inverters exceeded a trip time of two seconds, which is the maximum time an IEEE 1547 compliant inverter can remain connected to an islanded system." See A. Nelson et al. "Inverter Load Rejection Over-Voltage Testing SolarCity CRADA Task 1a Final Report" NREL: Golden CO, February 2015.

"the Companies' evaluation of the test results...indicated that circuit penetration levels greater than 120% of [gross DML] but less than some upper bound can be allowed...." However, HECO has not said how much additional distribution circuit DER hosting capacity this would free up nor how many customers would be able to interconnect at the higher penetration limit. Commission staff also observes that the inverter testing did not address potential system-level challenges that have been noted in prior Commission orders and which are described further in Section 2 of this Staff Report.[48]

HECO also made reference to several pilot projects that it claimed are underway to provide data and experience with load management and non-exporting PV systems. While this appears to be a positive development, as noted above, establishment of a non-export interconnection option for customers was ordered by the Commission in April 2014, and required to be included in the DGIP. Nearly a year later, HECO has provided no details on the scope or anticipated timelines for these pilot projects, nor any indication when a non-export option would actually be made available to customers.

Subsequent to the Companies' motion to cap the NEM program, the Consumer Advocate[49] filed a formal protest and several entities submitted comments opposing the HECO Companies' proposal, noting that HECO's motion has several significant shortcomings, including a lack of supporting evidence that 1) demonstrates the need for such drastic policy changes on such a short timeframe, 2) justifies the proposed compensation rates in the "Transitional Distributed Generation" program, and 3) justifies withholding interconnection approval for otherwise technically sound PV systems on circuits above 120% of GDML but below 250% pending Commission consideration of policy issues associated with DER.

On February 27, 2015, the Chairman of the Commission and the President of HECO signed a letter agreement wherein the signatories agreed that, among other things, the sixty day timeline proposed by the HECO Companies would not provide sufficient time for Commission and stakeholder review of the Companies' motion, and that regardless of whether the Commission has ruled (favorably or otherwise) on the Companies' proposal for policy changes, the Companies have an affirmative duty to interconnect customers consistent with existing policy.

Summary of Remaining Sections of this Staff Report and Proposal

Section 2 of this document examines a number of important technical, economic, and policy issues in the future evolution of DER and describes two new proposed models for customer systems that appear promising to mitigate many of the near-term technical concerns raised by the utility.

[48] See Decision and Order No. 32053, Docket No. 2011-0206, at 39-40. The commission stated, "notwithstanding expansion of distribution circuit capacity to accommodate more solar PV systems, system level reliability, curtailment, and operational challenges on each island grid, not individual, distribution circuit penetration levels, will ultimately become the binding constraint, and thus limit the cumulative amount of customer solar PV capacity that can be interconnected to, and the amount of energy that can be exported onto the grid."

[49] The Division of Consumer Advocacy ("Consumer Advocate") of the State Department of Commerce and Consumer Affairs is a Party to all proceedings before the Commission.

Section 3 of this proposal outlines a number of recommendations for immediate remedial actions to avoid further uncertainty and disruption in the electricity market in Hawai'i. Staff recommends this should include:

- Clearing the Interconnection Backlog: timely resolution of the customer applications waiting to be processed through the HECO Companies' interconnection queues (beyond those HECO has committed to processing by April 2015);
- Enabling DER Market Growth: updates to interconnection standards to enable grid-supportive functions and behaviors utilizing advanced technologies; and
- Creating New DER Market Choices: development of interim market pathways (e.g., self-supply and grid-supply) for continued DER deployment until a comprehensive DER 2.0 market structure can be established.

Section 2 – Near Term Technical and Economic Challenges and Proposed Solutions for the Evolution of Hawai'i's DER Market

The following discussion of the future evolution of DER in Hawai'i begins with the premise that DER systems can and must positively contribute both technically and economically to the utility grid, and the economic structure of the programs that enable DER systems can and must provide a compelling value proposition to customers.

The rapid growth in DER and future adoption of new DER technologies are diversifying the characteristics of customer electricity supply and service requirements in Hawai'i. At a high level, DER customers may contemporaneously self-supply either all, or a portion, of their electricity requirements, while potentially offering many distinct and valuable services to the grid. "Non-participant" customers (those who do not invest in DER systems) continue to rely upon the electric utility for their full electricity supply requirements.

These diverse supply and service requirements must be harmonized in a manner that enables the electric utility to fulfill its obligation to serve non-participant customers at reasonable rates and at the same time, enable customers to adopt DER technologies to manage their electricity consumption.

Commission staff is optimistic that with reasonable adjustments to policy, pricing, and programs, the growing marketplace of DER providers will continue to respond with products that are attractive to customers and can be cost-effectively integrated into Hawai'i's electricity systems to provide benefits for all customers.

Purpose

As discussed above, the purpose of this Staff Report and Proposal is to facilitate productive discussion among the Parties to Docket No. 2014-0192.

The purpose of Section 2 is to:

- Describe several near-term technical challenges that have been raised, with the goal of assisting the Parties in addressing existing technical issues, and ensuring the Parties remain aware of emerging challenges that are expected to arise as DER deployments continue to grow, and
- Provide suggestions for consideration among the Parties regarding policy design to address economic challenges associated with continued DER deployment.

Guiding Principles

Staff adopted following guiding principles in preparation of this Staff Report and Proposal:

1. Enable continued, cost-effective deployment of DER throughout the State;
2. Enhance customer choice in energy production and consumption;
3. Maintain safety and reliability of the State's power systems;
4. Maximize the efficiency and improve the transparency of the interconnection process;
5. Ensure customers are fairly compensated for value provided and are fairly charged for services obtained from the system;

6. Limit unnecessary disruption and volatility in the State's energy markets;
7. Non-participant customers are not detrimentally impacted, or benefit, from DER deployment; and
8. Participating and non-participating customers have comparable access to the grid.

Staff has endeavored to ensure that the policy proposals described herein are consistent with the guiding principles above, and suggests that any alternatives developed as part of this docket similarly adhere to these guiding principles.

Solving Four Near-Term DER Technical Integration Challenges

In the RSWG Order, the Commission noted a number of potential safety, reliability or operational issues that were less evident at lower DER penetration levels but were expected to emerge as distributed resources continued to increase over time. These challenges were less evident at lower penetration levels due to the fact that the growth in distributed solar PV involved mostly smaller, single-phase residential systems and that electric grids contain an inherent "integration capacity" to incorporate variable renewable generation.

This document provides an update to a number of technical and operational concerns discussed in the RSWG Order that have also been noted in some of the utility's technical studies included in the DGIP and PSIP filings, responses to the Commission's information requests, and in comments filed by Parties and the public. The focus of the discussion, similar to the RSWG Order, is on the O'ahu grid where customers currently face the largest backlog of interconnection requests; [50] and a significant amount of new variable renewable generation is planned in the next two years. However, the policy proposals are generally applicable to all the islands.

The following discussion identifies and describes four near-term DER integration challenges and suggests customer-based solutions that can help address these potential problems. While the focus of this Staff Report and Proposal is on DER-specific policies and *customer-based* mitigations, there are numerous additional integration solutions that do not necessarily involve customer-based mitigations and are most appropriately the responsibility of the utility to design and implement (or procure from third-parties). These utility-based options should be considered in appropriate parallel proceedings, such as Docket No. 2014-0183, as determined by the Commission.

The matrix in Table 2 (below) summarizes one way to categorize DER technical integration challenges. During both "steady state operations" [51] and "contingency events," technical challenges may arise at either the overall system-level or at the distribution circuit-level. These challenges are discussed in more detail below. The discussion of each challenge starts with a "Problem Statement" summarizing the technical integration issues and then offers one or more "DER-Based Technical Integration Solutions". These DER-based solutions provide the basis for the two proposed development models for future DER systems (customer "self-supply" and "grid-supply") and the "DER Advanced Technology Roadmap" in Table 3. The

[50] See HECO Response to PUC-HECO-IR-7, filed February 27, 2015 in Docket No. 2014-0192.

[51] "Steady state operations" refers to normal or typical grid conditions, whereas "contingency events" refers to grid conditions characterized by unexpected or unplanned events, including emergency conditions.

discussion of technical challenges and the DER Advanced Technology Roadmap are intended to inform the work scope and prioritization of near-term items outlined in Section 3.

Table 2. Framework for Categorizing Near-term Technical Integration Challenges

	Examples of Technical Integration Challenges	
	Steady State Operations	**Contingency Events**
System-level	Over-generation and increasing variability in generation resulting in: • Curtailment of other renewable generation • Frequency regulation and ramping challenges for central generation	Behavior of aggregate DER fleet may exacerbate grid instability during emergencies: • Need grid-supportive frequency and voltage trip and ride through settings
Circuit-level	Over-generation resulting in: • Approaching or exceeding distribution system equipment capacity limitations	Behavior of DER systems during circuit-level contingencies may result in: • Unintentional islanding • Temporary load rejection overvoltage

System-Level Technical Integration Challenges

System-Level Integration Challenge #1: Over-Generation and the "Duck Curve"

Problem Statement

In 2013, the California Independent System Operator ("CAISO") began simulating grid operations under scenarios with significant additions of solar PV (both utility-scale and distributed generation) that were anticipated to occur by 2020. The large additions of customer-sited distributed generation significantly reduce the net demand ("load") that the utility needs to serve in the middle of the day. Graphical depictions of these changes in the net load profile became known as the "duck curve."[52] This pattern has already appeared on several islands in Hawai'i and is expected to become a routine occurrence on the O'ahu grid with the planned addition of nearly 300 MW of new utility-scale and feed-in tariff ("FIT") solar PV proposed to come online by 2017.[53]

Under today's paradigm for distributed generation, customers typically size the capacity of their PV systems to meet most or all of their *annual* energy demand, which results in a PV system that often produces more power than their home or business needs during the middle of the day. When this occurs, the PV system exports power onto the utility grid and essentially uses the grid to store excess energy during the daytime. Later in the day, as the PV system's output declines and eventually produces no power when the sun sets, the customer draws

[52] See http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf for further description and discussion of mitigation strategies.

[53] See HECO Application filed October 10, 2014 in Docket No. 2014-0308, Exhibit 3 at 2.

power back from the grid to meet their evening and nighttime electricity needs. At low levels of DER, this mode of operation results in a small reduction in load on the overall utility system, and the aggregate impact on the grid is minimal. With significantly higher levels solar PV expected in the next two years, integrating additional customer-sited PV that operates in this mode becomes more challenging.

At a basic level, the overall electricity system currently has a finite capacity to integrate variable renewable energy sources that may be defined by the total gross load on the system and the minimum amount of conventional generation needed to maintain a stable grid through potential contingency events, and provide reserves to accommodate load and generation forecast errors. The O'ahu grid currently includes about 270 MW of solar PV, and with the future addition of proposed utility-scale PV described above, the total amount of solar PV capacity during the peak solar hours of the day (typically between 10am and 2pm) may be at or above 500 MW. In addition, O'ahu currently has another 99 MW of variable wind capacity. During these peak solar hours, the O'ahu grid typically has an aggregate gross demand (customer load) of between approximately 1,000 to 1,100 MW.[54]

The net effect of solar generation under today's operational characteristics is to reduce daytime system demand on the grid. Today, generation from PV systems typically displaces power that would be produced from oil-burning power plants. However, with the significant new additions of solar PV, the O'ahu grid is expected to frequently encounter days where the daytime supply of solar energy exceeds the current capacity to integrate variable renewable energy.

Under these conditions of "over generation" of power during the midday hours, utility system operators anticipate having to reduce output ("curtail") of solar PV plants.[55] Thus, with no change in the current situation, the O'ahu grid will likely encounter periods where generation from rooftop PV systems will force curtailment of power from utility-scale PV plants.[56] It may also challenge central generation in its ability to meet moment to moment variations in load, or ramp generation up and down throughout the day. This situation is counterproductive to the state's policy goals to reduce fossil fuel consumption (primarily oil) with renewable energy sources and concurrently reduce the higher energy costs of oil-fueled generation units.

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[54] See HECO Power Supply Improvement Plan, Docket No. 2014-0183, at 1-3 (noting that a review of load profiles from recent years shows daytime peak loads on the O'ahu grid at 850 MW net of distributed solar in 2014).

[55] Over generation could also be reduced if conventional power plants can minimize their output to accommodate more renewable energy. HECO claims in the PSIP that many existing generators can substantially reduce their minimum output levels (to < 5 MW gross, or about 1 MW net output) at modest cost. However, because Docket No. 2014-0192 is primarily focused on DER policies, Commission staff recommend the implementation of utility-based mitigations be evaluated in the PSIP review docket (Docket No. 2014-0183), or other appropriate proceedings.

[56] Under today's operating characteristics, utility-scale PV plants are the only PV systems with communications and control capabilities to reduce output after receiving a signal from the system operator.

The solutions to daytime over generation will require a number of operational changes by the utility on the "supply-side" of the equation, such as modifications to improve the flexibility and responsiveness of existing generators, and many of these options will be the subject of evaluation in the review of the HECO Companies' Power Supply Improvement Plans (PSIPs).[57] However, the solution set to this challenge also should include options on the "demand-side" of the grid, especially demand response and utilizing advanced functionality and capabilities of distributed resources.[58]

Near-Term DER-Based Technical Integration Solutions

There are a number of customer-based strategies available to address the potential for system-level over-generation; however, some approaches may require significant changes to the way utilities and customers interact. For example, demand reduction and load control programs which are typically triggered only during peak hours or contingencies may need to be used to supplement the ramping capability of existing generators during anticipated major morning and evening ramp events.

Demand response and/or distributed energy storage systems coupled with conventional PV designs offers a promising opportunity to minimize and possibly improve the "grid footprint" of PV systems. Under a customer "self-supply" option (further described later in Section 2), the DER system would prevent or limit exports of energy onto the grid. However, the incorporation of a storage system (such as a controllable water heater, building cooling, battery system, etc.) could shift daytime generation to serve customer demand later in the day. In addition to autonomous or programmed functions, these systems can receive commands from the grid operator, enabling supply of power, reserves, and other services to the grid during high value periods like peak demand or during grid emergencies when power is needed immediately. With the introduction of a suitable pricing mechanism to signal the relative supply and demand for energy on the grid (such as real-time pricing or time-of-use rates), the value of "self-supply" options can be greatly enhanced. With this type of pricing, customers will be encouraged to increase energy consumption during the daytime periods with high solar output (low daytime energy prices) and self-supply energy during periods of high costs (high peak pricing), flattening the grid's overall load profile. Commission staff believes this new DER development option can help mitigate the system-level challenge described above as well as others described below, and should assist projects in receiving expedited approvals for interconnection when they are correctly configured and installed.[59]

A second alternative could be scheduled "curtailment" or reduction in power from DER systems during periods of high solar output. Curtailment is currently one method used by the HECO Companies to control output of utility-scale renewable plants to balance the supply and demand of energy on the grid. Because this requires reducing output from clean, renewable energy sources, it is clearly a less preferred option. However, Commission staff

[57] It should be noted that utility-based or "supply-side" solutions often require long lead-times in order to procure equipment and implement modifications to existing infrastructure.

[58] For additional discussion of many strategies to address these issues see J. Lazar "Teaching the Duck to Fly," Regulatory Assistance Project, January 2014.

[59] Customers should be given the opportunity to opt-in to receiving an advanced meter to facilitate customer energy management and new pricing structures.

notes Hawai'i is reaching levels of solar power that far exceed power systems on the mainland. Substantial additional growth of solar PV systems will require new solutions to emerging integration challenges. Furthermore, DER systems should be able to automatically provide grid-supportive functions (such as frequency response) that can reduce the need for curtailment. These advanced capabilities should also reduce the need to carry reserves tied to online variable renewable capacity. If renewable resources must be curtailed, the curtailed generation should be used to provide reserves to further support the system as needed.

System-Level Integration Challenge #2 – "Restore Grid's Resiliency During Contingency Events"

Problem Statement

In the technical studies attached to the utilities' DGIP filing, the HECO Companies raise a number of significant concerns with the performance of DER systems during emergency (or "contingency") events, and have implied that further additions of DER would require new mitigation measures.

By way of background, power systems are typically planned to sustain operations through a number of pre-defined major contingency events by employing protective measures that are designed to prevent total collapse of the system. These contingency events include unplanned outages at the largest power plants and unplanned problems, or "faults", with major transmission lines. Both of these types of contingencies can destabilize the electrical system, and if not resolved in extremely short time frames (generally on a millisecond timescale), the instability can result in a prolonged island-wide blackout.

For unplanned outages at major power plants (referred to as "unit trips"), the primary challenge is to immediately respond to a significant undersupply of energy with a reduction in load and/or increase in generation to restore the relative balance of energy supply and demand on the grid. On O'ahu, the primary protective measure for this contingency is the use of spinning reserves (generators online and ready to immediately increase output as needed).[60] As a last resort, the power system automatically disconnects pre-programmed segments of the utilities' distribution system (i.e., automatically shuts off power to preselected neighborhoods) to immediately decrease the demand on the system (known as under frequency load shedding or "UFLS").[61] On O'ahu, the largest power plant, the AES coal plant, has tripped offline at least once in each of the past two years, and post-event analysis indicates that the power system was less resilient to this contingency than in prior similar events, suggesting that new measures may be needed to maintain system stability such as revisions to the existing UFLS scheme and DER-based solutions to support system stability.[62]

[60] Neighbor island power systems typically do not carry spinning reserves to mitigate the loss of the largest generating unit and are more reliant on the under frequency load shedding protection scheme to prevent system collapse during contingency events.

[61] Demand response can also provide contingency reserves. HECO's overall demand response portfolio is the subject of Docket No. 2007-0341.

[62] AES Generating Unit Trip Event Reports, dated August 19, 2013 and August 25, 2014, filed under confidential seal pursuant to Protective Order 2014-PO-03.

With respect to faults on major transmission lines, a fault condition can force the grid's frequency and voltage (key operational parameters) outside of the operational ranges of equipment connected to the utility system, including DER systems. DER systems are required to operate within a specified range of frequency and voltage values, and modeling studies and limited event data suggest that, absent changes to current practices, large numbers of DER systems could trip offline as a result of a severe unit trip or transmission fault, exacerbating the original disturbance to the grid's stability.

Near-Term DER-Based Technical Integration Solutions

In the utilities' filings, they have asserted that significant reliability risks exist on each island grid that could be increased with further additions of DER systems. Commission staff recommends that the system stability simulations submitted in the utilities' filings and the overall set of proposed mitigations should be investigated thoroughly in the PSIP review docket, and that the Parties to the DER docket should focus on feasible, near-term DER-based technical solutions that can help stabilize the grid during contingency events. Staff observes that the Commission's Inclinations stated that, "All generation resources should contribute to system stability... consistent with their resource characteristics and state-of-art technical capabilities."[63]

The PV Subgroup of the RSWG (which includes the HECO Companies, solar industry representative, and other stakeholders) has been discussing some of these solutions in an attempt to develop a stipulation to modifications to the HECO Companies' interconnection rules, as requested by the Commission.[64] These modifications should include expanding the operational range of inverters and requiring them to stay connected to the utility grid during the contingency events noted above (i.e., expanded voltage and frequency "ride through" settings). Commission staff has been tracking discussions on this issue and believes that workable solutions exist, consistent with the technical capabilities of DER systems and the legitimate needs of the grid. These discussions should be concluded as soon as practicable, and the work of the PV Subgroup should be finalized and submitted to the Commission for review and approval.

As discussed in Section 3, interconnection standards for new DER systems should be updated to incorporate revised frequency and voltage ride through and trip settings and other high-priority revisions. Retrofits of existing DER systems should be evaluated later in Phase 2 of the DER docket.

Commission staff also notes that several potential DER-based solutions appear to be in the near-term product development plans of DER system providers. In California's Smart Inverter Working Group (SIWG) discussions on advanced inverter functions, the working group has noted the importance of adding advanced functions into inverters to respond autonomously to grid disturbances (such as the frequency-watt function). These can be

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[63] Commission's Inclinations at 7.

[64] See First and Second Stipulations of the PV Subgroup, filed May 28 and June 12, 2014, in Docket No. 2011-0206. However, after reviewing the First and Second Stipulations and responses to subsequent information requests issued by the Commission, it became clear the Stipulations could not be accepted as submitted. Commission staff is aware the PV Subgroup continues their collaboration to resolve key questions raised in the Commission's information requests issued in that docket.

programmed into PV inverters and energy storage systems to respond automatically and instantaneously to the types of contingency events noted above that affect the grid's stability. Given Hawai'i's frontrunner status in seeing these issues before other jurisdictions, Commission staff notes the importance of aligning Hawai'i's efforts to revise the operational characteristics DER systems with the ongoing efforts in California, which are likely more influential to the near-term product development plans of major DER manufacturers. In short, the ongoing discussions in Hawai'i to quickly adopt new inverter settings and standards should as a general principle stay aligned with California's effort and also seek opportunities to more quickly implement the advanced functions under development that will provide significant grid value in Hawai'i's market, considering the unique characteristics of Hawai'i's island grids.

Distribution-Level Integration Challenges

Distribution-Level Integration Challenge #1 – "Reduce Contingency Risks on Circuits with High Levels of Solar PV"

Problem Statement

When the HECO Companies announced changes to interconnection rules in September 2013, the Companies highlighted the risk of transient overvoltage ("TOV") (or more precisely "load rejection overvoltage") potentially occurring on distribution circuits with high levels of PV as the primary safety concern that required further study before adding new systems on these circuits. This potential issue has been presented as the primary basis for the HECO Companies' de facto distribution circuit-level interconnection limits.

This situation could potentially occur when the level of PV generation exceeds the load on the circuit and the circuit is backfeeding power to the utility substation. If during these conditions, the utility isolates the circuit or distribution transformer from the rest of the system (either for routine or emergency switching operations), then voltages on the distribution circuit could spike and possibly damage customer or utility equipment.

Commission staff first observes that despite the significant concerns raised about this potential occurrence, to date, the utility has provided no evidence, either actual event data or merely anecdotal, that demonstrates this outcome has occurred or establishes the likelihood of occurrence on high penetration circuits. That said, the utility is required to engage in prudent practices to manage safety and reliability risks in operating the power system, so legitimate concerns raised by the HECO Companies should be thoroughly evaluated.

However, it should be noted that electric utilities have extensive experience with transient over-voltage caused by system switching operations and transients triggered or excited by lightning discharges. Actual circuit-level operational performance data would allow for comparative analysis between TOV conditions caused by routine utility operations and potential risks associated with DER on high penetration circuits. Without circuit-level data to establish appropriate benchmarks, the resolution of this issue has languished and further underscores the need for the distribution circuit monitoring program.[65]

Moreover, and most importantly, despite having raised this concern in September 2013, the HECO Companies did not develop a pragmatic, timely plan to address this issue in the DGIP, submitted a year later. The prolonged and uncertain treatment of this issue demonstrates a lack of urgency and resolve to meet customer needs, despite clear guidance by the Commission in the April 2014 Orders and the Commission's Inclinations.

DER-Based Technical Integration Solutions

A key missing ingredient to resolving this issue is actual circuit-level data on power quality during the types of "transient" events described here. In the RSWG Order, the Commission ordered HECO to address this shortcoming of its distribution system, and once this data is available, the potential risk and magnitude of a TOV event can be compared to the occurrence and magnitudes of routine overvoltages caused by today's utility operations. Generally speaking, absent compelling evidence, customer-sited PV should not be held to a higher standard than the utility's existing operations. In the absence of this data, the judgments about an acceptable level of risk are not firmly grounded in today's operational reality.[66]

While duly stating these broader concerns and system needs for circuit-level data, Commission staff notes that based on recent report on inverter testing at NREL ("NREL LROV Report"), it appears that modern inverters demonstrate acceptable performance even at high penetration levels.[67] As discussed above, the solar industry, inverter manufacturers, and other stakeholders have been working together to clarify that modern inverters demonstrate acceptable operational behavior during overvoltage conditions. The NREL LROV Report found that even at extremely high generation to load ratios (up to a 10 to 1 ratio – analogous to an interconnection limit of 1000% of gross daytime minimum load), "measured over-voltage magnitudes were all under 200% of nominal peak voltage, and the over-voltage durations were on the order of microseconds to milliseconds."[68] As a result of these findings, the HECO Companies have stated they plan to increase the interconnection penetration limit from 120% of gross daytime minimum load ("GDML") to 250% of GDML, and acknowledged this is not an upper limit to interconnection capacity on distribution circuits.[69]

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[65] To address this shortcoming, in April 2014 the Commission directed HECO to design and implement a circuit monitoring program throughout its service territories.

[66] Commission staff further reiterates the guidance in the RSWG Order that theoretical technical issues and suppositions based on modeling studies should no longer suffice as the only basis to support significant delays and disruptions to further interconnection of DER systems.

[67] See A. Nelson et al. "Inverter Load Rejection Over-Voltage Testing SolarCity CRADA Task 1a Final Report" NREL: Golden CO, February 2015 ("NREL LROV Report")

[68] NREL LROV Report, at 47. With respect to the test results, NREL states that it intentionally "did not attempt to impose pass-fail criteria" because "th[e] test plan is not finalized; a much simpler test may be possible" and "any pass-fail criteria should be developed through a consensus-based process including various industry stakeholders and taking into account the best available information on distribution system requirements."

[69] See Motion for Approval of NEM Program Modification and Establishment of Transitional Distributed Generation Program Tariff; filed January 20, 2015 in Docket No. 2014-0192 at 2.

Because the TOV issue has been one of the primary holdups for further interconnection on high penetration circuits, finalizing new inverter trip and ride through settings (including requirements for addressing TOV) is one of the key near-term, high priority items in the work scope defined in Section 3.

Finally, because this risk becomes apparent during periods of high PV generation on distribution circuits, other mitigation measures to similarly reduce the relative oversupply of PV generation to load can also reduce the risk of temporary load rejection overvoltage. Therefore, economic incentives such as dynamic pricing can be designed to encourage greater demand during the middle of the day (or whenever there is abundant renewable generation), particularly if these incentives can be targeted to circuits with high levels of solar. Furthermore, the development of customer PV-storage options that minimize exports of excess generation minimize the impact of new system, and can actually mitigate this risk, if customers can by encouraged to "sink" energy demand into storage systems during the middle of the day.[70]

Distribution-Level Integration Challenge #2 – Minimize Oversupply of Solar Energy During Midday Hours

Problem Statement

The discussion above noted the pending over generation challenge on O'ahu expected with the large addition of new solar PV generation proposed to enter service by 2017. An analog to this challenge exists at the distribution feeder level when the increasing amount of PV systems added to local distribution circuits begins to exceed the demand for energy on an individual distribution circuit. Under these conditions, power flow reverses direction towards the utility's substation, and possibly into adjacent distribution circuits or into the sub-transmission or transmission system (also known as a "backfeed" or reverse current condition).

Separate from the potential contingency issue known as transient or temporary overvoltage described above, the HECO Companies identify a number of other potential operational issues that could occur under reverse current conditions. Looking slightly over the time horizon of today's integration challenges, proposed circuit-level capacity limits on backfeed appear to be the next major hurdle (and cause of potential delays) under the HECO Companies' proposed set of actions.

In the DGIP, the HECO Companies propose a limit on backfeed at 50% of the capacity ratings for the distribution circuit's conductors and substation transformers. It appears that the 50% limit is primarily based on providing an adequate safety margin to accommodate a contingency where the load from adjacent circuits is transferred during equipment failures or during routine maintenance. As a preliminary matter, the Companies' proposed limits should be subjected to further scrutiny as to the appropriate threshold and associated risks.

[70] It should be noted that while energy storage technologies may assist customers in shifting energy demand in response to price signals, the underlying economic incentives to shift customer demand (such as through real-time pricing or a time-of-use rate design) can be implemented without the need for energy storage, and have been used throughout the country.

Furthermore, the DGIP proposes upgrades to the capacity of the circuit equipment, which are likely to be costly, time-consuming solutions to implement. Commission staff is concerned that with the long lead times to plan the redesign of each circuit, receive regulatory approvals, and complete the proposed construction projects that these proposed limits and preferred solutions will become another significant barrier to further development of DER systems in Hawai'i.

Near-Term DER-Based Technical Integration Solutions

In reviewing the scope of actions required today, Commission staff propose a number of DER-based solutions that will better optimize the use of today's infrastructure and facilitate further integration of DER before reaching this threshold.[71] A customer self-supply option that can use a combination of energy storage systems, energy management software, and demand response technologies to limit and minimize the export of power onto the circuit during critical periods can reduce the "grid footprint" of DER systems and allow more customers to interconnect within existing circuit-level hosting capacity. Combining these system designs with an attractive demand response portfolio and pricing signal to encourage more energy demand during the daytime hours with high solar output will provide the correct economic incentives to energy customers.

Potential scheduled curtailment of new DER systems during peak solar production hours can also mitigate some of the same concerns; however, Commission staff view this as a second best option to the alternative described above. Scheduled curtailment only addresses the "supply-side" of this energy balance equation. Scheduled curtailment also limits future opportunities to utilize the advanced systems described above to provide further grid value through participation in demand response programs and shift energy exports into peak demand hours. However, this measure does provide an option to reduce the periods with oversupply of solar energy and allow more customers to participate in DER programs. Therefore, Commission staff suggest it should be an option that customers can choose if they are not interested, or unable to afford, the more technically advanced self-supply option described above.

DER Advanced Technology Roadmap

The following table ("DER Advanced Technology Roadmap") summarizes the potential technical challenges and mitigation solutions discussed above, categorized based on whether the challenges may occur during steady-state operations or contingency events, and whether they are primarily a system-level or circuit-level concern.

The DER Advanced Technology Roadmap identifies mitigation solutions that can be implemented today using modern inverter technology, as well as other, more advanced mitigation solutions that would require communications and control capability over the DER inverter fleet. Finally, the Roadmap links the mitigation solutions to near-term DER docket actions, corresponding to the proposed Issues and Work Scope, outlined in Section 3 of this document.

[71] As stated above, there are many utility-based mitigations and the HECO Companies' progress implementing them should receive detailed attention in the PSIP review docket.

The DER Advanced Technology Roadmap and the supporting discussion in Section 2 have been prepared based on Commission staff's judgment of the highest priority technical challenges associated with continued DER deployment in Hawai'i. Staff anticipates that the Parties to the DER docket will engage in further discussion of these issues, and additional challenges and cost-effective mitigation options may be identified as DER continues to grow. This proposal includes the Roadmap to facilitate and focus dialogue on customer-based solutions to the challenges described above.

Table 3. DER Advanced Technology Roadmap (Phase 1)

	Steady State Operations			Contingency Events		
	Potential Technical Challenges	**Known DER-based Mitigations**	**Phase 1 DER Docket Actions***	**Potential Technical Challenges**	**Known DER-based Mitigations**	**Phase 1 DER Docket Actions***
System level	*Over-generation*	Customer demand response to increase load Reduce exports during high solar hours: - Daytime use of storage[A] (store excess PV and potentially add load) - DER provide reserves to reduce conventional generation minimums - Scheduled curtailment - Coordinated dispatch of fleets of DER systems with storage[AB] - Curtailment commands to PV-only systems[B]	<u>Enable DER Market Growth</u>: - Revisions to applicable interconnection standards for fast track approval for self-supply systems (enable new systems without exacerbating over-generation) <u>Create New DER Market Choices</u>: - Customer self-supply and other options - DER 2.0 Transition Plan	*Aggregated DER response to unit trip*	Underfrequency response[A] (synthetic inertia, frequency-watt) Reduce number of "legacy" PV systems with 59.3 Hz trip setting Emergency control of DER fleet by system operator[B] Update inverter settings as system conditions evolve	<u>Enable DER Market Growth</u>: - Expand ride through and trip settings - Require autonomous grid support functionality (freq.-watt)
System level	*Additional system variability requiring higher reserves*	Enable advanced inverter functions: - Provide frequency response (frequency-watt, regulation reserve[A]) - Provide autonomous ramp rate control - Coordinated dispatch fleets of PV-only systems to manage variability[B] - Utilize DER systems as DR resource to provide up and down reserves[AB]	<u>Enable DER Market Growth</u>: - Fast track approval for self-supply systems (enable new systems that do not exacerbate system variability) - Configure systems to provide reserves - Autonomous grid support functionality (freq.-watt, autonomous ramp rate control)	*Aggregated DER response to transmission fault*	Enable advanced inverter functions: - Wider ride through setting for over-frequency and under-voltage - Provide frequency response (frequency-watt) - Emergency control of DER fleet by system operator[B] - Update inverter settings as system conditions evolve	<u>Enable DER Market Growth</u>: - Expand ride through and trip settings - Require autonomous grid support functionality (freq.-watt for over-frequency)
Circuit level	*Reverse current at substation transformer*	Customer demand response to increase load If needed, reduce exports during high solar hours (as for system-level over-generation)	<u>Enable DER Market Growth</u>: - Fast track approval for self-supply systems (enable new systems that avoid triggering circuit capacity constraints) - Autonomous grid support functionality (voltage regulation) <u>Create New DER Market Choices</u>: - Customer self-supply and other options - DER 2.0 Transition Plan	*Load rejection overvoltage*	Require inverters with fast-response trip capability Emergency control of DER fleet by system operator[B] Update inverter settings as system conditions evolve	<u>Enable DER Market Growth</u>: - Fast track approval for self-supply systems (do not contribute to over-voltage risk) - Require autonomous grid support functionality (anti-islanding, fast trip in response to over-voltage) <u>Create New DER Market Choices</u>: - Customer self-supply
Circuit level	*Coordinate with existing protection and voltage regulation schemes (including secondary)*	Anti-islanding functions Emergency control of DER fleet by system operator[B] Advanced inverter functions (volt-watt, volt-vAR, power factor control) DER coordinated with voltage regulation and switching functions[B]				

* See Section 3 (Table 6) of this Staff Report and Proposal.
[A] Mitigation requires energy storage system
[B] Mitigation requires communications and control of inverters (Phase 2)

Economic Integration Challenges

While the four technical challenges described above have been raised as near-term *technical* limitations to distributed solar PV growth, Commission staff believes that the current market structure presents equally important economic and policy challenges to longer-term distributed PV deployment. These challenges are fundamental to the dominant distributed PV enabling mechanism in Hawai'i – the Net Energy Metering ("NEM") Program.[72]

Commission staff recommend the Parties to Docket No. 2014-0192 consider the structural incentives inherent in the NEM program, which encourage system designs with a significant "grid footprint." In addition, the NEM program, as currently designed, may not provide sufficient flexibility to:

1) incorporate pricing that appropriately reflects the value of energy exported to the grid, particularly during periods of over generation;
2) incent advanced grid-supportive functionality that modern DER systems can provide, and are increasingly valuable given the high costs of alternatives to meet grid needs; or
3) allocate responsibility for applicable grid integration costs.

Distributed PV penetration has now reached nontrivial levels, and while it is clear that distributed PV may provide significant benefits to both participating and non-participating customers, the NEM program was not originally designed for distributed PV deployment at scale. The NEM program was established to incent early adoption of customer-sited distributed generation by employing a straightforward and administratively simple approach designed to be easy for most customers to understand. By most measures, the NEM program has been extremely successful. However, circumstances have changed dramatically since the NEM program was established in 2001.

Compensation at Retail Rates

Under the NEM program, the electric utility is obligated to accept energy exported by a customer's system and compensate the customer at the retail electric rate, which in 2014 averaged between $0.35/kWh and $0.47/kWh, depending on the island. Given the significant declines in the installed cost of distributed PV over the last several years, it is unlikely that compensation at the retail rate accurately reflects the costs of installation.[73] Furthermore, and more importantly, given the substantial difference between the utility's avoided costs

[72] The Commission has been clear that Docket No. 2014-0192 will be encompass a comprehensive investigation of DER policies. However, given that a substantial portion of DER have been deployed in Hawai'i under the Net Energy Metering ("NEM") program, Commission staff has focused attention on this aspect of DER policy for purposes of this Staff Report and Proposal.

[73] In 2010, based on discussion among stakeholders, including members of the solar industry, the Commission established cost-based compensation rates (including a reasonable profit margin) for Schedule Feed-in-Tariff Tier 1 and Tier 2 (under 500 kW) at $0.189 - $0.274/kWh, depending on project size and technology type.

and the retail rate, it is also unlikely that retail rates provide accurate signals regarding the value to the grid of exported energy from distributed PV systems.[74]

While customer-sited solar PV can provide substantial benefits, the value of energy exports changes over time based primarily on the marginal cost of generation, which can vary significantly over time and throughout the year.[75] The current NEM arrangement is not flexible enough to adapt to changes in economic value because the basis for the rate is determined solely by the retail electric rate, which is an average, bundled price that does not necessarily reflect the marginal cost of generation at any given moment. In addition, the value of energy may change significantly in the future due to additional low-cost renewables or other changes in power supply costs.

Moreover, the longer term price signal that the NEM program conveys may be misleading. Customers have a significant incentive to oversize their PV system relative to daytime load in order to export sufficient energy to offset nighttime energy use, thereby significantly increasing the "grid-footprint" of these systems. Furthermore, NEM participants may actually increase their peak demand under the current arrangement as the economic cost to them can be neutralized through built up NEM credits.

In addition, the continued deployment of distributed PV may impose integration costs on the electric utilities in order to redesign and upgrade the transmission and distribution system (or take other mitigation actions, see above in Section 2) to accommodate distributed generation. As mentioned, the current state of bundled, average pricing does not separate out different components and services of the utility system nor does it differentiate between energy and demand-related cost drivers. When there were only a small number of PV systems interconnected, there was little need for anything more complex. However, at scale, this legacy pricing system can lead to the underpricing of some grid services and overvaluing of others. Accounting for these costs and recovering them appropriately is unnecessarily difficult and complex under the NEM program where compensation is solely at the retail rate. In a rapidly growing PV market, the effect of near term cost shifts may be much more pronounced and create noticeable distortions in pricing and cost allocation.

Distributed PV in the Renewable Energy Resource Portfolio

Looking to the future, large amounts of utility-scale renewable energy are expected to be brought online within the next several years. Absent technological advances that have not yet materialized, there is a finite amount of grid capacity in the interim for unscheduled or uncontrolled solar PV energy export. Under high penetrations, distributed PV will force the curtailment of utility-scale PV or other renewable resources.

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[74] See Evaluation of Hawaii's Renewable Energy Policy and Procurement. Energy+Environmental Economics. January 2014. Accessible at http://puc.hawaii.gov/wp-content/uploads/2013/04/HIPUC-Final-Report-January-2014-Revision.pdf.

[75] There are many other benefits of DG-PV in addition to avoided energy costs. This explanation excludes those benefits for simplicity. However, it is expected that the Parties will consider these additional benefits when establishing the appropriate compensation rate for the customer grid-supply option and the longer-term DER 2.0 market structure (see below for additional discussion).

It is economically suboptimal to curtail other renewable projects if they can deliver equivalent energy at a substantially lower price point.[76] Not only would curtailment of lower-cost utility-scale renewable energy penalize non-participating customers by effectively increasing rates, it could also undermine the future of utility-scale installations by creating economic uncertainty (due to unknown levels of curtailment) for project developers.

For the reasons discussed herein, the Parties to Docket No. 2014-0192 should consider what modifications, if any, should be made in the short-term to the NEM program to support a future with DG-PV penetration that is likely to be far higher than most stakeholders originally anticipated.

Over the medium-term (Phase 2 of the DER docket), as Hawai'i continues to lead the nation in distributed PV deployment, Commission staff expects the Parties will assist in developing a re-designed market structure to accelerate deployment of DER, aligned with least-cost procurement strategies that realize a balanced portfolio of renewable energy resources, consistent with the Commission's Inclinations and the discussion of "DER 2.0" in this document.

Near-term DER Market Pathways

DER deployment in Hawai'i will continue to evolve over time. The early adopter stage with generous incentives will need to come to a conclusion. This should be viewed as a positive development that marks theentrance of DER into the mainstream. This maturation process should continue, supported by a longer-term, sustainable market framework further described below.

Commission staff suggests the solutions to the technical and economic challenges discussed herein will require new customer DER development models that provide clear market signals corresponding to the value of DER systems to the grid. As noted, re-designed pricing programs, such as optional dynamic pricing and unbundled rate structures, can enhance the value of DER systems to customers and encourage individual system designs that will provide greater value to the overall utility grid.

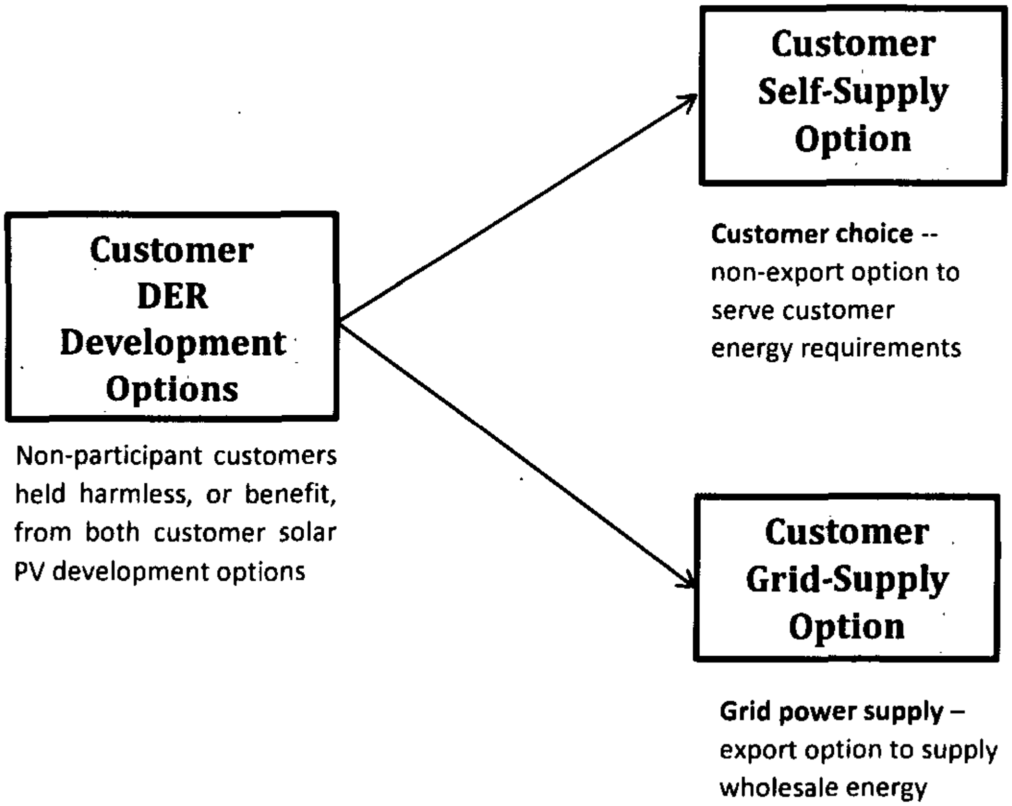
Finally, Commission staff observes that absent solutions such as the new products and offerings suggested herein, the utility's submitted plans (i.e., the PSIPs and the DGIP) suggest extremely costly, time-consuming upgrades to grid infrastructure and customer equipment will be required to integrate new DER systems on distribution circuits with high levels of existing PV.

[76] See Decision and Order No. 32053 in Docket No. 2011-0206 at 42. It should be noted that both wind and solar PV (distributed and utility-scale) are actually near-zero marginal cost resources. A truly optimized power system would treat these resources accordingly. Contract and tariff pricing would then be adjusted to reflect the true economics of these resources. As discussed herein, dynamic pricing and demand response programs can help to signal to customers the cost and value of these resources.

Customer Self-Supply and Customer Grid-Supply Options

This Staff Report and Proposal suggests two new market-based development pathways—*customer self-supply* and *customer grid-supply*—that are intended to provide customer choice, enable continued interconnection of DER systems, and offer value to the electric systems of the State. These market-based development pathways represent two fundamental value propositions of distributed resources. With proper design, these new development options can address many near-term technical concerns with further interconnection of DER systems, institute a more certain and timely interconnection process for systems that utilize advanced technologies to mitigate grid-integration challenges, and establish pricing for future grid-supply energy systems that is more aligned with the economic value these resources supply to the electric grid.

Figure 3. Near-term DER Market Pathways



In the near-term (next 90 days), the HECO Companies, with the assistance of the Parties to this docket, should develop these near-term development options in order to allow customers to choose DER system designs that can be interconnected without unreasonable cost and delay, thereby reducing the interconnection backlog as soon as possible.

These near-term market pathways are also intended to enable a smooth transition from the current interconnection and pricing policies in effect today, to a longer-term future deployment approach sustainable under high penetration solar PV scenarios. Staff recommends the longer-term DER deployment approach be developed in Phase 2 of the DER Policy docket, as discussed below in Section 3 of this document.

Customer Self-Supply Option

Customer self-supply should be designed as an option to manage or offset customer electricity demand with DER technologies, while remaining connected to the grid and offering grid support when necessary. The self-supply option should enable customer choice in energy production and consumption, using a limited- or non-export DER system that can also provide value-added grid service capabilities. This option should be responsive to market signals such as time-of-use rates and demand response programs.

The customer self-supply option acknowledges customers' clear desire and ability to control their energy consumption using a variety of cost-effective technologies available today. From a regulatory and economic perspective, the customer self-supply option is similar to energy efficiency investments, with the potential for even greater benefits by utilizing the grid-supportive technical capabilities of advanced DER systems. With proper technical design, the customer self-supply option can provide grid support, and these systems should be accorded a fast-track interconnection process under applicable interconnection rules, including on heavily saturated distribution circuits that otherwise would not permit interconnection under the HECO Companies' current rules. Fast-track interconnection is a key aspect of the customer self-supply option.

To be clear, this should not represent an off-grid or primarily non-parallel mode of operation. While isolating loads or otherwise avoiding parallel operation is certainly an option for customers, Commission staff believes that this approach would result in suboptimal outcomes both for customers and the State's electric grids. Overall, customer self-supply systems should be designed to minimize or eliminate negative grid impact, but these systems should operate in parallel with the grid in order to be capable of providing significant benefits to the grid should customers choose to do so, now or in the future. This will allow customers to invest in value-added grid service capability based on customer choice.

A key aspect of this effort will be defining the technical and operational requirements and configurations to enable interconnection of customer self-supply systems on heavily saturated distribution circuits (which should then be incorporated into applicable interconnection rules at the conclusion of Phase 1).

There are at least two alternative variations on the customer self-supply option that should be considered. First, customers could simply be given a strong economic incentive to avoid oversizing a DER system, such that the system is designed to always generate less power than is consumed on-site. Furthermore, systems can be engineered to immediately shut down or curtail output if there is an unexpected drop in customer load such that exports would be likely to occur. This economic incentive approach would be similar to the existing Standard Interconnection Agreement ("SIA") option offered by the HECO Companies, where customers are not compensated for any energy export and thus have no incentive to invest additional capital in generation capacity that cannot be economically utilized. If necessary, the customer self-supply option could be supplemented with tariff provisions that go further and actually *penalize* violations of non-export requirements. This approach would probably not require installation of a storage system.

The second main customer self-supply option that should be considered is a technical configuration that actually prevents energy export when generation exceeds local load, and directs excess generation into a storage system.[77] If the storage system is fully charged and there is still more generation than load, the system would be designed to curtail output from the system to prevent export to the grid. Because this option would require a storage system, and perhaps additional equipment and engineering design to prevent energy exports, it will likely be a more expensive approach. However, the incorporation of a storage system offers an opportunity for additional value creation through provision of grid-supportive services and functions, as well as backup services that provide greater energy independence and security for the customer. Many of the Parties to the DER docket have been discussing proposed modifications to Rule 14H that would enable interconnection and facilitate utilization of battery storage systems. These discussions should be continued in the DER docket, and any further agreement among the Parties should be finalized and submitted to the Commission for review and approval, consistent with the procedural schedule established in the docket.

As stated above, since the customer self-supply option is designed for minimal grid impact (if any), either version of the customer self-supply option should be accorded fast-track interconnection approval under applicable interconnection rules.

Despite the Commission's instruction to the HECO Companies to develop a non-export option for customers in the DGIP, staff believes the plan was not sufficiently responsive to this directive. Pilot programs for "non-export/smart-export" systems, such as those proposed by the HECO Companies, while welcome, are not adequate. In staff's view, technical specifications and a new tariff for the customer self-supply option is a high priority outcome for Phase 1 of this docket (see Section 3 for staff's recommended docket issues and work scope).

Customer Grid-Supply Option

The *customer grid-supply* option should be designed to provide customers with the option to export excess energy onto the grid at a new (possibly time-varying) rate. The rate should be reasonable and should approximate the economic value of the energy supplied by the customer to the system. Options for establishing the compensation rate could include modifications to methodologies currently in use (such as the Schedule Q, Avoided Cost filings, Feed-in Tariff rates, etc.).[78] Commission staff encourages the Parties to propose creative, well-reasoned solutions to estimate a reasonable wholesale rate. Proper price signals around system exports will help reduce over-generation and provide a bridge to a longer-term DER procurement program ("DER 2.0" – further discussed below). Price signals should also reflect grid integration costs to the extent they are applicable.

There are numerous details to such an approach, which should be expeditiously discussed by the Parties and not become barriers to development of this interim market option. Commission staff recommends that, in contrast to the customer self-supply option, which

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[77] The self-supply option could be configured many types of storage, such as a battery system or thermal storage in a hot water heater. It could also utilize an energy management system to adjust local loads to match output of the generation system.

[78] The HECO Companies' January 20, 2015 motion to cap the NEM program included another alternative: compensation for a Transitional Distributed Generation tariff based on the utilities' costs of fuel and purchased power.

should be retained in the future to enable customer choice, the customer grid-supply option described herein should be designed as an interim DER development option until the Parties have sufficient time to fully develop DER 2.0. At that point, the interim customer grid-supply option should transition to DER 2.0.

As with the customer self-supply option, this market pathway should be flexible in design so that customers can respond to market developments, such as expected demand response programs, to further add value in the future. In addition, it is appropriate to establish reasonable constraints on the capacity allocated to the customer grid-supply option in order meet renewable development targets in the utilities' overall supply portfolios. These constraints could be specified in terms of energy or capacity (e.g., based on renewable energy needs under the state's Renewable Portfolio Standards) or could be market-based using pricing to signal the value of and need for *grid-supply* system exports.

Table 4. Key Attributes of Near-term DER Market Pathways

Customer Self-Supply	**Enable customer choice** – non-export option to manage/offset customer energy needs • Similar to energy efficiency investment by customer from regulatory and economic perspective • Customer remains connected to grid and offers grid support as necessary • Responsive to time-varying rates and DR options • Allows for backup power supply to provide increased energy independence and security for customers • Avoids near-term distributed solar PV integration challenges; fast-track interconnection requests • Does not preclude providing value-added services (including energy export) at later date
Customer Grid-Supply	**Grid power supply** – export option to supply wholesale energy • Energy export driven by customer response to utility wholesale needs and pricing • Compensation rate approximates market value of energy and services provided by DER systems • Bridge to longer-term sustainable DER market structure (DER 2.0) • Capacity dedicated to grid-supply option determined by RPS needs or through market pricing that signals value of and need for wholesale energy • Cost-competitive compared to utility-scale projects adjusted for DG premiums/penalties (e.g., reduced system losses) • New products and services (e.g., virtual power plants) enabled with PV aggregation.

Alternative Customer Mitigation Options

Staff would like to offer preliminary comments on another possible near-term solution that aligns with the Commission's Inclinations: deploying storage at the circuit level.[79] While this could take several different forms, staff believes the concept of deploying distributed energy storage systems was not sufficiently evaluated by the HECO Companies in the DGIP. If, as the Company explains in their DGIP, storage could solve a large portion of the interconnection challenges, both at the circuit- and system-level, it remains unclear why the Companies have not explored models around deployment.[80] Moreover, staff is aware that the technology exists for HECO to communicate to and control distributed storage in order to alleviate grid concerns.[81]

As HECO notes, distributed storage can be "implemented faster than grid-scale systems."[82] Given the flexibility distributed storage offers and the fact that customers are likely to invest their own capital in the technology as it matures, staff recommends this approach be expeditiously evaluated. Distributed storage systems could also be installed without being connected to customer loads or generation. However, these systems could operate in parallel with the grid and could charge and discharge as needed, responding to price signals and autonomously to grid conditions (or programmed for scheduled operations). This method may save on system installation costs, compared to a more standard battery back-up or non-export system.

Distributed energy storage can have many possible configurations and business models, such as community energy storage. Staff is also interested in storage models that could allow investment by customers, and that avoid the need to oversize storage systems for individual DER deployments. This approach could be significantly more capital-efficient since customers can avoid over-purchasing a residential-scale custom battery based system themselves. This approach could also closely align with developing microgrids for improving the resiliency, reliability, flexibility, and efficiency of the state's power systems.

These kinds of innovative products, services, and business models should be seriously considered by the HECO Companies and Parties to this docket. Staff suggests that the Parties collaborate in this docket to develop market structures that can allow third-party DER providers to offer alternative products and services that provide value to all customers, as discussed further in Section 3 of this Staff Proposal.

Developing the Longer-term DER Market Structure – DER 2.0

The new market pathways (customer self-supply and grid-supply) suggested in this Staff Report and Proposal should be viewed as interim policy solutions to address near-term technical and economic challenges in DER deployment. Longer-term, this Staff Report and Proposal suggests Hawai'i should transition to a comprehensively re-designed market

[79] See Commission's Inclinations at 16.

[80] "Energy storage is potentially the most impactful technology that could allow higher levels of penetration by solar PV generation in the near- and mid-term timeframes." HECO DGIP at 4-30.

[81] HECO is currently conducting a pilot project with a provider of aggregated distributed energy storage resources.

[82] HECO PSIP at 5-36.

structure for acquiring beneficial DER systems and enabling DER to provide value to all customers ("DER 2.0"). This should include a forward-looking set of policy adjustments for cost-effective DER deployment throughout Hawai'i. These policies should support and enable various forms of DER, including distributed storage and robust demand response options, to provide benefits both to participating customers and the overall electric system.

DER systems can provide a range of values that can be measured in terms of avoided fuel and generation costs, avoided costs for provision of ancillary services, avoided new investments in power plants and grid infrastructure, improved power system reliability, improved energy and financial security, and improved environmental and public health, among others. Pricing and compensation established for DER 2.0 should be aligned to provide market signals that allow DER systems to offer the greatest value possible (recognizing that a variety or resources and technologies can be employed to serve the many needs of the power system). The overall market structure should be designed for long-term sustainability, equity, and to increase market certainty for cost-effective DER deployment.

DER 2.0

In Phase 2 of the proposed work scope described herein, Commission staff recommends that the Parties to the DER Policy docket collaborate to develop a new DER market structure for Hawai'i for Commission review. Each component of DER value can vary by technology and specific application, giving the Parties a broad range of options for developing DER pricing that provides appropriate signals for desirable technical and performance attributes.

Overall, the approach should be to craft a suite of polices and pricing structures that enable a cost-effective, market-based future for DER. This should include innovative approaches such as combining various technologies and exploration of market structures to enable aggregation and virtual power plants. The Parties should strive to ensure flexibility and longevity to the adopted polices to provide market certainty for the private sector.

Above all, DER 2.0 should fairly compensate DER system owners for value provided to the grid, should fairly charge customers for value received by the grid, and avoid potential adverse economic or reliability impacts on non-participating customers.

The options and suggested policies outlined in this Staff Report and Proposal are designed to alleviate the existing uncertainty and interconnection backlog and enable a smooth transition to a market-based DER deployment trajectory. This goal, as articulated in the Commission's Inclinations, would provide a more stable marketplace with an evolving suite of products that offer value to both the direct user and the utility systems in general.

Price Signals and Rate Design

Getting clear and accurate pricing signals to consumers (both those with DER systems and those willing to adjust consumption) is crucial to encourage adoption of technologies that possess the most valuable attributes and to optimize the power system, thereby lowering overall system costs.

Staff recommends the Commission direct the Parties to develop a market structure that is flexible to accommodate a broad range products and services that provide value to utility customers and meet customers' needs. This should include accurate price signals that evolve as the penetration levels and attributes of particular technologies change. Finally, this should include creating regulatory mechanisms that can be more responsive to the marketplace and help customers take advantage of DER technologies in a strategic manner. All of these aims should come together to spur private investment into technology configurations that maximize benefits to the electric system, environment, and all utility customers.

The Parties' collaboration in this docket should include providing recommendations on future utility rate structures, such as unbundling some amount of transmission and distribution costs from current energy charges, establishment of sensible dynamic pricing structures (such as real time pricing or time of use rates), adjustments to minimum bills, or other optional rate structures that can maximize the value of DER systems to the utility and all customers.[83] These rates should be straightforward to understand while more accurately reflecting the true value of the resource provided or consumed at the time of production or consumption. Re-designed rates should establish transparent price signals that enable DER developers to create beneficial product offerings to encourage customer participation in providing value to the grid.

While proper rate design and pricing may be sufficient to incent most grid services, there may be other services that require additional promotion, either through incentives or requirements, provided to the electric utilities and other market participants. There may also be certain demographics or customer classes that require programmatic support to enable participation in DER market opportunities. Programs such as Hawaii Energy, the Bill $aver Program (On-bill Financing and Repayment), and Green Energy Market Securitization have elements designed to address this need.

Feed-in-Tariff Re-examination

The Feed-in-Tariff ("FIT") re-examination offers the Parties an opportunity to consider whether to re-design the FIT to incent grid-supportive technologies, how to incorporate flexibility to compensate for energy and other services based on either cost or value, and whether emerging or undervalued technologies should be supported through a differentiated FIT rate.

If the FIT program should be continued, the Parties should identify near-term modifications to FIT rates to align pricing with grid economics, incent deployment of advanced DER technologies, and fund needed grid upgrades. Furthermore, the Parties should consider developing new FIT compensation structures to improve the procurement mechanism and provide market certainty and stability for DER deployment in Hawai'i, consistent with renewable energy development targets in a utility's overall supply portfolio.

Transitioning to DER 2.0 and Treatment of Existing NEM Customers

As discussed herein, this Staff Report and Proposal suggests the Parties to Docket No. 2014-0192 consider how to transition current DER policies to achieve DER 2.0, consistent with the Commission's Inclinations and applicable orders. Any modifications to existing DER policies should take effect once interim market pathways (e.g., customer self-supply and customer grid-supply) are developed.

[83] See "Customer-Based Solutions for the Hawaii Electric System" at 6 and 12 for further discussion of some of these options.

Customers with existing agreements with the utilities should be grandfathered for a reasonable transition period, which should be further discussed by the Parties. The Parties should also consider whether customers in the interconnection queue, and those who will apply for interconnection in the coming months, should be permitted to interconnect under the existing policies. New applicants and those waiting in the queue should be allowed to opt-in to the customer self-supply or grid-supply options (and DER 2.0, once it is established) should they desire, either to better monetize the capabilities of their investments or to get fast-track interconnection approval (this option should be afforded to existing NEM and FIT customers as well).

Section 3 – Proposed DER Policy Docket Issues and Work Scope

Overview

Commission staff suggests that, given the urgency of resolution of the current untenable interconnection backlog, there should be two overall timeframes for collaboration among the Parties and resolution of the many DER issues identified in the April Orders, the Commission's Inclinations, the DGIP submission, and the discussion above.

- Phase 1 (near-term) should be focused on resolving the immediate impediments limiting customer choice and the continued deployment of cost-effective DER systems. The issues proposed to be addressed in Phase 1 have been selected to focus the efforts of the Parties to the DER Docket on actions that can be taken rapidly to avoid further uncertainty and disruption in the electricity market in Hawai'i. This includes:
    - Clear Interconnection Backlog: ensure timely resolution of the customer applications waiting to be processed through the HECO Companies' interconnection queues (beyond those HECO has committed to processing by April 2015);
    - Enable DER Market Growth: update to interconnection standards to enable grid-supportive functions and behaviors utilizing advanced technologies; and
    - Create New DER Market Choices: develop interim market pathways (e.g., self-supply and grid-supply) for continued DER deployment until a comprehensive DER 2.0 market structure can be established.
- Phase 2 (mid-term) should be focused on developing a forward-looking set of policy adjustments for cost-effective DER deployment throughout Hawai'i. These policies should support and enable various forms of DER, including distributed storage and robust demand response options, to provide benefits to participating customers and the overall electric system. DER pricing established in Phase 2 should be aligned to provide market signals that allow DER systems to offer the greatest value possible, incorporating time-, location-, and attribute-varying components, if determined by the Commission to be appropriate for Hawai'i. Furthermore, interconnection standards should be revised to include additional mandatory advanced inverter functions to support the widespread adoption of beneficial DER systems.

Within each Phase, Commission staff propose dividing the issues to be addressed into two separate Tracks to facilitate efficient discussion and assist the Commission in resolving the issues.

- System Integration Track should focus on the technical challenges and solutions that can mitigate any adverse impacts DER systems may have on the existing electric grids. Much of Track 1 should concentrate on designing customer-based mitigation solutions and finalizing appropriate revisions to interconnection standards under consideration by the Parties. The technical solutions developed in the System Integration Track should be incorporated into the policies developed in the Economics and Pricing Track.

- Economics and Pricing Track should focus the policies that will enable a rapid transition in the DER market to a viable long-term trajectory. This should encompass re-design of the overall market structure, including development of the two interim market pathways described above (customer self-supply and customer grid-supply), and appropriate rate designs to enable the DER market to function properly. This Track should also harmonize the various DER procurement mechanisms to maximize the flexibility and value DER systems can provide. It should also fully integrate demand response,[84] especially for ancillary services, frequency response, reserves, and real-time energy pricing to facilitate increased load to mitigate minimum net-load conditions. Finally, this Track will ensure fair allocation of integration costs and fair compensation for DER-based value provided to the grid.

Table 6 (at the end of this section) provides a summary of the proposed Issues and Work Scope described herein.

Proposed Process and Timeline

Commission staff are keenly aware of the need for urgent resolution of the interconnection backlog and re-establishment of clarity and certainty in the DER market in Hawai'i. Accordingly, staff recommend the Commission adopt the following timeline for resolution of the issues in this docket.

Table 5. DER Policy Docket Proposed Timeline

Phase 1	**Timing**
Technical Conferences on Phase 1 issues, including the Parties and Commission Staff	Bi-weekly unless otherwise specified by the Commission
Parties may file Initial Comments on Statement of Issues	Within 20 days of Order
Parties file Preliminary Statements of Position on Phase 1 Issues	Within 60 days of Order
Parties file Stipulated Resolution of Phase 1 Issues (or Final Statements of Position)	Within 90 days of Order
Commission Decision and Order on Phase 1 Issues and Guidance on Phase 2	Subsequent to Parties' Stipulation
Phase 2	**Timing**
Technical Conferences on Phase 2 issues, including the Parties and Commission Staff	Monthly after Commission Guidance on Phase 2, unless otherwise specified by the Commission

[84] The HECO Companies' integrated demand response portfolio is the subject of Docket No. 2007-0341. Commission staff suggest the DR portfolio should remain under review in its own proceeding at this time. At a later date, the Commission could consider consolidating the DR portfolio into the DER docket, if appropriate.

Additional Procedural Steps	To be Determined by Commission Guidance on Phase 2

Commission staff acknowledges that the above proposed timeline is aggressive and contemplates several overlapping procedural steps. This approach is recommended given the need for resolution of the interconnection queue and development of near-term solutions to enable customer choice and provide market signals to encourage optimal investment decisions.

In order to provide sufficient oversight of this process and to help ensure productive discussions, the bi-weekly technical conferences suggested above should be chaired by Commission staff or its designee. The technical conferences are intended to facilitate discussion and collaboration among the Parties, with the goal of enabling Parties to stipulate to proposed resolution of Phase 1 issues (in both System Integration and Economics/Pricing tracks) within the expedited timeframe suggested herein.

However, should the Parties be unable to reach agreement and stipulate to resolution of some or all of the Phase 1 issues, the HECO Companies should file their statement of position separately or jointly with any willing Parties. Other Parties should file joint or individual statements of position, as specified in the procedural schedule suggested above. This proposed process is intended to provide flexibility and space for productive collaboration among the Parties, while also affording all Parties the opportunity to express their positions before the Commission prior to any Commission decision-making on these issues. As such, the Parties are encouraged to continue their collaboration outside of the technical conferences.

Phase 1 – Resolving Highest Priority Near-term DER Issues

In the near-term, Commission staff suggests the Parties should focus on the highest priority issues currently preventing continued deployment of cost-effective DER systems throughout Hawai'i. This should include:

1. Clearing the Interconnection Backlog: timely resolution of the customer applications waiting to be processed through the HECO Companies' interconnection queues (beyond those HECO has committed to processing by April 2015);
2. Enabling DER Market Growth: updates to interconnection standards to enable grid-supportive functions and behaviors utilizing advanced technologies; and
3. Creating New DER Market Options: development of interim market pathways (e.g., self-supply and grid-supply) for continued DER deployment until a comprehensive DER 2.0 market structure can be established.

System Integration Track – Phase 1 Priority Issues

In Phase 1, the System Integration Track should include finalizing proposed revisions to applicable interconnection rules to address immediate technical challenges and to support the economic and pricing policies to be developed in the Economics and Pricing Track.

Revisions to Applicable Interconnection Standards to Enable DER Market Growth
Revisions to applicable interconnection rules (such the HECO Companies' Tariff Rule 14H and KIUC's Tariff No. 2) should be stipulated to and proposed by the Parties which will enable fast-track approval for self-supply systems with standardized technical designs that mitigate immediate technical integration challenges, implement low/high frequency/voltage ride through and trip settings, and should include other revisions to enable near-term customer choice in DER deployment (aligned with Economics/Pricing Track Phase 1 priorities).

Other revisions that should be considered by the Parties include required autonomous functionality (such as frequency response), start-up/return-to-service requirements, process efficiency and transparency improvements to reduce the costs of the interconnection process (both to the utility and to customers), standardization of the calculation methodology for establishing gross daytime minimum load for a distribution circuit, and requirements for software or remote update capabilities for inverters so that Hawai'i can avoid costly retrofits (as occurred in Germany) as advanced inverter functionality becomes commonplace and is increasingly required for safe and reliable operation of the power system.[85] In addition, the parties should consider if system-level criteria are necessary and appropriate to incorporate into the interconnection review process. If so, this should include safeguards to ensure that system-level review will not unnecessarily slow or stop interconnection of DER.

Should the Parties be unable to stipulate to high-priority revisions to applicable interconnection rules within the timeframe specified by the Commission, the Parties should submit joint or separate proposals for the Commission's consideration.

Economics and Pricing Track – Phase 1 Priority Issues

Create New DER Market Choices
In Phase 1, efforts under the Economics and Pricing Track should focus on developing, under an aggressive timeline, interim market pathways to enable continued deployment of cost-effective DER systems. As discussed in Section 2 above, Commission staff suggests these pathways should include two interim options: *customer self-supply* and *customer grid-supply*. The primary focus of this track should be the consideration of appropriate tariff designs and rate structures that enable DER systems to maximize grid value under either customer self-supply or grid-supply options. All customers should have the option to opt-in to a time-varying rate design that more accurately reflects the value of energy production and consumption.

For the customer self-supply option, the Parties should collaborate to define pricing terms and conditions for DER systems that supply part or all of a customer's energy needs while minimizing customer grid "footprint" (non-export), unless energy export is needed by the grid.

[85] Advanced inverter functionality is already available in most modern inverters and can incorporate autonomous response behaviors, communications and monitoring capabilities, and eventually aggregation and control by the utility (or third-parties) in response to grid conditions, system operator commands, market price signals, etc.

For the customer grid-supply option, the Parties should collaborate to define service offerings and a pricing structure for DER to supply cost-competitive wholesale energy, ancillary services and demand response as required by grid. While there are many important details to consider in developing these new rate structures and market pathways, the complexities must not be permitted to delay the timely resolution of these issues.

As with issues to be addressed in the System Integration Track, should the Parties be unable to stipulate to reasonable pricing terms for the customer self-supply and grid-supply options, then the Parties should submit joint or separate proposals for the Commission's consideration.

Transitioning to DER 2.0

In addition, consideration should be given in the Economics and Pricing Track to reasonable approaches to transition from existing DER policies to DER 2.0, including consideration of the future of the NEM program. Staff suggests the Parties should focus on the mechanics of ensuring a smooth transition to the customer self-supply and grid-supply options described herein, followed by detailed consideration of the longer-term DER market structure in Phase 2.

Overall, Commission staff believes the longer-term approach should be to transition to least-cost procurement strategies that realize a balanced portfolio of renewable energy resources, consistent with the discussion of DER 2.0 in this document.

Phase 2 – Establishing Longer-Term DER Policies and Market Structure

The new market pathways and associated revisions to interconnection processes suggested in this Staff Proposal for Phase 1 should be viewed as interim policy solutions to address near-term challenges in DER deployment. Longer-term, staff believes Hawai'i should transition to a comprehensively re-designed market structure for acquiring beneficial DER systems and enabling DER to provide value to all customers ("DER 2.0"). This proposal suggests the development of DER 2.0 should proceed subsequently to resolution of the Phase 1 issues in this docket.

As with Phase 1, Commission staff recommends that Phase 2 be divided into two parallel Tracks to facilitate collaboration among the Parties and decision-making by the Commission.

System Integration Track – Phase 2 Priority Issues

In Phase 2, the System Integration Track should include further revisions to applicable interconnection standards, consideration of the costs and benefits of retrofits to existing (legacy) DER systems,[86] evaluation of the HECO Companies' circuit capacity analysis and integrated interconnection queue proposal, and review of other longer-term planning aspects of the DGIP.

[86] The costs of and benefits of retrofitting legacy equipment has not yet been demonstrated. However, once the Commission rules on updates to interconnection standards after Phase 1, any legacy equipment that can be remotely updated should be promptly adjusted to match the updated frequency and voltage interconnection standards.

The System Integration Track should also include forward-looking evaluation of technical integration challenges expected to arise as DER deployment continues. This could be accomplished with a series of technical workshops to present current data and analysis on DER integration issues, followed by solutions-oriented discussions. Any conclusions reached by the Parties should be brought to the Commission for consideration.

Evaluation of Technical Integration Challenges

This task should continue the forward-looking efforts of the Parties (already underway) to identify, confirm, and validate high priority near-term technical integration concerns and develop various customer-based mitigation solutions.[87] Evaluation of technical integration challenges should include both distribution- and system-level concerns and solutions. Any issues identified should specify the conditions under which the particular concern is relevant, and should assess the risk associated with the concern (i.e., include a quantitative or qualitative evaluation of the likelihood of occurrence and the expected outcome should it actually occur). Furthermore, each issue should be placed into context of existing system design criteria or standards, existing system tolerances and protection schemes, and known best practices in risk mitigation. All Parties should be permitted to raise technical issues for discussion; however, given the expedited timeframe needed for addressing these issues, the Parties should quickly prioritize any identified issues based on assessment of risk and other appropriate considerations. Commission staff and consultants should be participants in this process to assist the Parties in expeditious evaluation of technical challenges.

It is expected that this task will be ongoing and continue throughout Phase 2 of this docket, in parallel with the other activities suggested herein.

Interconnection Process Revisions under Phase 2

In Phase 2, Commission staff recommends the primary focus of the System Integration Track should be on a comprehensive re-examination of interconnection rules and the overall DER interconnection process. Best practices in interconnection policies have been well-documented in other jurisdictions and should be studied for any practices that are appropriate for Hawai'i. The overall goal of the re-examination should be to reduce the cost of DER deployment while ensuring safety and reliability of the power system. Specific questions to be addressed should include consideration of (1) further improving the efficiency of the interconnection process to facilitate cost-effective DER, and (2) inexpensive technical solutions that can be incorporated into applicable interconnection rules to obviate need for costly studies and grid upgrades.

In addition, staff suggests that interconnection standards requiring autonomous grid support functionality should be evaluated (beyond what may be incorporated into interconnection rules as a result of Phase 1). In addition, communications protocols between DER systems (or

[87] As stated above, there are a number of technical solutions that do not necessarily involve customer-based mitigations (e.g., to address over generation during daytime hours, large-scale power plants can be modified to enable lower output levels or cycling capability). These solutions should be noted during the evaluation of technical integration challenges, and the Commission should consider their suitability in appropriate parallel proceedings (such as the PSIP review docket), but the discussion of solutions in this docket should be focused on customer-based mitigations.

aggregated DER) and the utility system operator should be established and mandated. The California Rule 21 update process includes a collaborative effort of the members of the Smart Inverter Working Group ("SIWG") and provides a valuable model for specifying and incorporating these critical features into the DER fleet. Lessons learned from the activities of the SIWG should be incorporated into the stakeholder process in the DER docket. Finally, as with Phase 1, the efforts in the System Integration Track should be flexible to enable other revisions to interconnection standards that may emerge from discussion in Economics and Pricing Track.

Retrofits to Existing Equipment

Legacy DER technology will be a growing issue until revised interconnection standards are established. While many existing systems can be remotely reprogrammed with revised settings, the System Integration should also encompass a critical evaluation of the technical and economic costs and benefits of retrofitting the existing fleet of DER systems to bring their capabilities in line with those of modern, advanced systems. In the System Integration Track, the focus should be on (1) identifying the technical characteristics of the concern (number of legacy systems, their specific limitations, aggregate reliability impact on the power system, etc.), and (2) developing and performing the technical cost-benefit analysis, including comparison of the benefits of retrofits to alternative approaches to achieve similar goals.

DER Capacity Analysis and Integrated Queue

HECO's circuit capacity analysis and the integrated queue should be evaluated by the Parties in the context of the Proactive Approach to distribution system planning developed in the Reliability Standards Working Group. The circuit capacity analysis should be supplemented to include system level constraints as well. The HECO Companies should update the Parties on their progress implementing the Proactive Approach since they committed to it nearly two years ago in January 2013. Modifications to the methodology or approach should be suggested by the Parties and adopted by the HECO Companies. The Circuit Capacity Analysis should be updated regularly by the HECO Companies and should be publicly available alongside the Integrated Queue.

Economics and Pricing Track

In Phase 2, the Economics and Pricing Track should be focused on developing a forward-looking set of policy adjustments for sustainable DER deployment throughout Hawai'i. These policies should support and enable various forms of DER, including distributed storage and robust demand response options, to provide benefits to participating customers and the overall electric system. DER pricing established in Phase 2 should be aligned to provide market signals that allow DER systems to offer the greatest value possible, which could take many forms, such as a value-based Feed-in-Tariff, incorporating time-, location-, and attribute-varying components, if appropriate.

Any unresolved longer-term questions from Phase 1 should be also considered among the Phase 2 issues. Finally, as the DER market matures and DER providers offer more integrated services, some minimum level of standards should be put in place to ensure that customers fully understand the value proposition offered and any future obligations or risk with various DER system configurations.

DER 2.0

The DER Policy docket offers a venue for the Parties to collaborate to develop a new DER market structure for long-term sustainability, equity, and market certainty for DER deployment.

In Phase 2, the Parties should be instructed to develop of a Hawai'i-specific valuation methodology for DER. This methodology should be developed and reviewed by stakeholders before being submitted to the Commission. Each component of DER value can vary by technology and specific application, giving the Parties a broad range of options for developing DER pricing that provides incentives for desirable technical and performance attributes.

Overall, the approach should be to craft a suite of polices and pricing structures that enable a sustainable, market-based future for DER. This should include identifying synergies in combining various beneficial technologies and exploration of market structures to enable aggregation and virtual power plants. The Parties should strive to ensure flexibility and longevity to the adopted polices to provide market certainty for the private sector.

Above all, DER 2.0 should fairly compensate DER system owners for value provided to the grid, should fairly charge customers for value received by the grid, and avoid potential adverse economic or reliability impacts on non-participant customers.

Rate Design

Properly designed rates are critical to establishing sustainable and equitable cost-recovery for all customers as DER deployments continue. In Phase 2, the Parties should provide recommendations on future utility rate structures so rates appropriately recover infrastructure costs associated with the ongoing clean energy transformation. Re-designed rates should establish transparent price signals that enable DER developers to create beneficial product offerings to encourage customer participation in providing value to the grid, including desirable real-time behavior supply of desirable capabilities such as frequency response and fast reserves. Alternative optional rate designs may involve unbundling some amount of transmission and distribution costs from current energy charges, establishment of sensible dynamic pricing structures (such as real-time pricing time of use rates), adjustments to minimum bills, or other rate structures that can maximize the value of DER systems to the utility and all customers.

Feed-in-Tariff Re-examination

The Feed-in-Tariff ("FIT") re-examination is currently underway; however given the significant overlap between the FIT re-examination docket and all other aspects of the Commission's DER evaluation, this docket should be integrated effectively into the overall process in order to allow for a comprehensive evaluation of all DER procurement mechanisms. Commission staff suggests the primary issues to be addressed should be (1) why the FIT program did not perform as expected, and (2) what the optimal path forward is for the program, if any.

Staff recommends the Parties discuss what accounts for the lack of success of the FIT program (as evidenced by the discrepancy between FIT program capacity and capacity of actual FIT installations, this despite the full active queues for most tiers on most islands). This should include consideration of how queue administration and FIT interconnection request processing and management may be improved, as well as the overall implementation of the FIT program by the HECO Companies. The intention should be to identify lessons learned from the FIT program design and implementation to inform the development of DER 2.0 and the consideration of the optimal path forward for the FIT program.

The Parties should also consider whether to re-design the FIT to incent grid-supportive technologies, how to incorporate flexibility to compensate for energy and other services based on either cost or value, and whether emerging or undervalued technologies should be supported through a differentiated FIT rate. If the FIT program should be continued, the Parties should identify near-term modifications to FIT rates to align pricing with grid economics, incent deployment of advanced DER technologies, and fund needed grid upgrades. Furthermore, the Parties should develop new FIT compensation structures to improve the procurement mechanism and provide market certainty and stability for DER deployment in Hawai'i.

Summary of Proposed Issues and Work Scope

The following table summarizes the Issues and Work Scope proposed by Commission staff in this document. The table includes both near-term (Phase 1) and mid-term (Phase 2) issues, as well as a division of the issues in each phase into parallel Tracks, according to a general categorization (System Integration and Economics/Pricing).

Table 6. Proposed Issues and Work Scope for Docket No. 2014-0192

Tracks	Phase 1: Near-Term (next 3 months)	Phase 2: Mid-Term (next 6-18 months)

<u>System Integration</u>
• Forward-looking identification of technical challenges and recommended solutions for DER integration
• Implement proactive distribution planning approaches
• Enable timely and low-cost interconnection of DER
• Promote advanced DER functionality
	1. **Clear Interconnection Backlog:** regular monitoring and reporting on HECO Companies progress meeting interconnection commitments and responsibilities
	
	2. **Enable DER Market Growth:** Phase 1 revisions to interconnection standards to enable customer choice
	• Technical and operational specifications for customer self-supply systems standardized for inclusion in applicable interconnection rules (e.g., Tariff Rule 14H and Tariff No. 2)
	  • Enable fast-track approval for specified self-supply designs that minimize DER integration challenges
	  • Consider AMI-enabled designs for KIUC and opt-in AMI deployment for HECO Companies
	• Finalize work of RSWG PV Subgroup on frequency/voltage ride through and trip settings, return to service, and other high priority revisions to Rule 14H
	• Finalize work of Parties to Docket No. 2014-0130 on distributed storage interconnection requirements
	• Other revisions to enable near-term customer choice in DER deployment (aligned with Economics/Pricing Track Phase 1 priorities)
	  o Autonomous grid support functionality (e.g., frequency-watt)
	  o Consideration of remote/software update capability
	  o Process efficiency and transparency improvements to reduce interconnection costs (both utility and customer)
	  o GDML calculation methodology
	
	Anticipated Work Product: (1) Progress reports on clearing interconnection backlog, (2) options for improving HECO Companies' performance processing interconnection applications, and (3) stipulated proposed revisions to interconnection standards to enable interim customer choice options and other aspects of DER 2.0 Transition.
		4. **Forward-looking evaluation of technical integration challenges and mitigations** with targeted focus on DER design and operations specifications, including both circuit- and system-level issues
		
		5. **Phase 2 revisions to interconnection standards (communications and control)**:
		• Communications protocols and infrastructure
		• Enable advanced inverter functions
		• Cybersecurity requirements
		• Clean slate revisions to improve process and efficiency
		• Other revisions to reduce DER deployment costs (aligned with Economics/Pricing Track Phase 2 priorities)
		
		6. **Retrofits of Existing Equipment**
		• Technical and economic benefit-cost analysis relative to alternatives
		• Cost-allocation (Economics and Pricing Track)
		
		7. **DER capacity analysis** (including both circuit and system level constraints)
		
		8. **Integrated Queue**

<u>Economics and Pricing</u>
• Identify near term modifications/additions to DER tariffs and programs
• Enable customer choice to acquire and deploy DER
• Align pricing with grid economics
• Incent advanced DER technologies
• Fairly and reasonably allocate DER integration costs
	3. **Create New DER Market Choices**
	• Fast-Track Customer Self-Supply Option
	  • Enable customer choice
	  • Design for maximum grid benefit
	  • Parallel operation that enables value-added grid services based on customer choice
	• DER 2.0 Transition Plan
	  • Transition to future DER market-based procurement program ("DER 2.0")
	  • Consider HECO "Transitional Distributed Generation" proposal and alternatives
	    • Customer grid-supply option: exports compensated at fair and reasonable wholesale rate (possibly time-of-use)
	    • Opt-in to receive advanced meter
	    • Consider customer DR participation options
	    • Other options to enable value-added grid services based on customer choice
	    • Modifications, if any, to NEM program during transition
	  • Customer choice for current NEM applicants to opt-in to self-supply interconnection fast track
	
	Anticipated Work Products: (4) new tariff(s) specifying customer self-supply and, and (5) stipulated agreement on DER 2.0 Transition Plan, including any new tariff(s) specifying grid-supply options.
		9. **DER 2.0**
		• Enable long-term cost-effective DER deployment
		• Utilize variety of DER technologies and configurations, including DR
		• Fairly compensate/charge DER-owners for value provided/realized to/from grid
		
		10. **Rate Design**
		• Opt-in time of use or other dynamic pricing
		• Other rate structures to maximize value of DER
		• Minimum bills
		
		11. **FIT Re-examination**
		• Explain failure of the program
		• Identify lessons learned
		• Redesign FIT to incent grid-supportive technologies
		• Incorporate flexibility to compensate for energy and other services based on either cost or value

CERTIFICATE OF SERVICE

The foregoing order was served on the date of filing by mail, postage prepaid, and properly addressed to the following parties:

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