BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application)
Of)
)
HAWAII ELECTRIC COMPANY, INC.)
HAWAII ELECTRIC LIGHT)
COMPANY, INC.)
MAUI ELECTRIC COMPANY, LIMITED)
)
For Approval of Demand Response)
Program Portfolio Tariff)
Structure, Reporting Schedule,)
And Cost Recovery of Program)
Costs through the Demand-Side)
Management Surcharge)
)

DOCKET NO. 2015-0412

DECISION AND ORDER NO. 35238

FILED
2018 JAN 25 P 3: 18
PUBLIC UTILITIES
COMMISSION

TABLE OF CONTENTS

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application Of HAWAIIAN ELECTRIC COMPANY, INC. HAWAII ELECTRIC LIGHT COMPANY, INC. MAUI ELECTRIC COMPANY, LIMITED For Approval of Demand Response Program Portfolio Tariff Structure, Reporting Schedule, And Cost Recovery of Program Costs through the Demand-Side Management Surcharge.	)	Docket No. 2015-0412 Decision and Order No. 35238

DECISION AND ORDER

The Public Utilities Commission ("commission"),[1] by this decision and order, approves the HECO Companies' revised demand response ("DR") portfolio ("Revised DR Portfolio") tariff

[1]The parties to this docket are HAWAIIAN ELECTRIC COMPANY, INC. ("HECO"), HAWAII ELECTRIC LIGHT COMPANY, INC. ("HELCO"), MAUI ELECTRIC COMPANY, LTD. ("MECO") (collectively, the "HECO Companies" or "Companies"); the DEPARTMENT OF COMMERCE AND CONSUMER AFFAIRS, DIVISON OF CONSUMER ADVOCACY ("Consumer Advocate"), an ex officio party to this proceeding, pursuant to Hawaii Revised Statutes § 269-51 and Hawaii Administrative Rules § 6-6-62(a); DEPARTMENT OF BUSINESS, ECONOMIC DEVELOPMENT, AND TOURISM ("DBEDT"), an intervenor pursuant to In re Hawaiian Elec. Co., Inc., Hawaii Elec. Light Co., Inc., Maui Elec. Co., Ltd., Docket No. 2015-0412, Order No. 33835, filed July 28, 2016 ("Order No. 33835"), at 52; LIFE OF THE LAND ("LOL") and DISTRIBUTED ENERGY RESOURCES COUNCIL OF HAWAII ("DERC"), participants to the docket pursuant to Order No. 33835.

structure framework and directs the Companies to begin immediate implementation thereof, subject to the conditions, directives, and further orders as set forth herein.

I.

INTRODUCTION

The commission has observed on numerous occasions that Hawaii's electric grids are in a state of rapid and, at times, dramatic transition. In 2016, approximately 26% of the HECO Companies' combined electricity sales were powered by renewable sources, with higher percentages for Maui and Hawaii Island of 37% and 54%, respectively. Notably, in the aggregate, 34% of this renewable generation came from distributed generation, specifically customer-sited, grid-connected solar photovoltaic ("PV") and wind resources. The trend toward more dynamic and distributed power systems is expected to continue, given underlying economics, customer preferences, and the State's energy policy goals. This is evidenced, in part, by the HECO Companies' Power Supply Improvement Plans ("PSIPs") wherein, over the long-term, distributed solar PV within the Companies' service territories is assumed to grow from approximately 700 MW today[2] to more than 3,000 MW in 2045.

As the electric utility network continues to transform from one defined by central station generation and one-way power flow to a system in which there are thousands of distributed energy resources ("DER") and multi-directional power flows, there is an emergent and increasing need to ensure that these resources are able to play an integral role in the functioning of the network. Indeed, the commission has previously issued guidance regarding the transformation of each island's transmission and distribution grids into "modern, advanced electrical networks that are capable of integrating greater quantities of customer-sited distributed energy resources" and expanding the array of energy options for customers to manage their usage.[3]

The HECO Companies' Revised DR Portfolio creates the economic and technical means by which customers can use their own equipment and behavior to have a role in the management of the electricity grid. Ultimately, the Companies' DR initiatives will

---

[2]Hawaiian Elec. Co., Inc., News Release, January 18, 2018, available at https://www.hawaiianelectric.com/2017-saw-big-surge-in-solar-installations.

[3]In re Public Util. Comm'n, Docket No. 2012-0036, Order No. 32052 ("Order No. 32052"), Exhibit A, "Commission's Inclinations on the Future of Hawaii's Electric Utilities," filed April 28, 2014, at 3.

result in a more flexible and reliable grid while at the same time empowering customers with expanded energy options and economic opportunity.

The Companies intend to accomplish this by working with participating customers to control, either directly or indirectly, customers' equipment in a way that impacts their net demand for electricity. These changes in demand, which can be achieved in many ways, from manipulating the operation of water heaters or air conditioners or altering charge or dispatch schedules of behind-the-meter storage and electric vehicles ("EVs"), help manage the grid's supply-demand balance and improve response to contingency events.

Increasingly, the rise in levels of renewable energy resources, while contributing to the supply-side of the equation, create a more dynamic situation from a utility system operations perspective, due to the inherent variability of these resources. Leveraging flexible and manageable demand-side resources helps to manage system operations. As a result, DR is expected to play an essential role in the future of the HECO Companies and in the achievement of Hawaii's clean energy goals by creating opportunities to allow customers, and their growing populations of DER, to help increase renewable energy resources on the grid while maintaining grid stability and reliability.

The Revised DR Portfolio includes a revised request for approval that focuses on four system-level grid service tariffs and a selection of riders to allow customers to participate in the following programs:

1. Capacity programs that compensate customers for providing capacity services to the grid through time-of-use ("TOU") rates, real-time pricing ("RTP"), critical peak incentives ("CPI") and/or day-ahead load shifting ("DALS");

2. Fast Frequency Response ("FFR") programs that compensate customers on Oahu for providing a load-reducing response following a contingency scenario (e.g., a generation trip);

3. Regulating Reserve programs that help the Companies to balance their electric grids by operating DR resources in response to automatic generation control ("AGC") signals from the Energy Management System ("EMS"); and

4. Replacement Reserve programs that compensate customers for providing load-reduction in place of the Companies starting a fast-start generator.

The related tariffs and riders will be implemented using a phased approach that begins with a focus on FFR for Oahu, Replacement Reserves for Oahu, a Capacity program of CPI for Oahu and Maui, and the continuation of the interim Residential TOU rate for all islands. The remaining tariffs and riders for the various islands will be initiated in the 2018 to 2020 timeframe.

Participating customers will be empowered with increasing opportunities to simultaneously install DER and, with them, actively participate in the grid and its associated value chain. These opportunities will take the form of either rates and incentive-based programs that will compensate customers for their participation or by way of engagements with turnkey service providers that contract with the Companies to aggregate and deliver various grid services on behalf of participating customers and their distributed assets.

Leveraging these cost-effective assets will allow all customers to benefit through lower operation, fuel, and capital costs associated with managing the grid.

The Revised DR Portfolio is the result of more than two years of effort to:

- Quantify and value the grid service needs over the next 15 years;
- Describe the technical means through which these services can be delivered;
- Identify and forecast various customer assets that are capable of delivering grid services in accordance with operational requirements; and
- Develop the means and market mechanisms to allow customers to provide these services.

Making beneficial use of DR programs is a critical step along the accelerated path to 100% renewable energy. Toward that end, the Revised DR Portfolio is an integral, cost-effective component included in the Companies' December 2016 PSIP Update in Docket No. 2014-0183.

Ultimately, the Revised DR Portfolio will support the Companies' key strategic initiatives around enhancing the customer experience and modernizing the grid by gathering and presenting the status, availability, and control of DER, facilitating renewable energy resource integration, improving operational efficiency, and providing more customer options.

II.

BACKGROUND AND PROCEDURAL HISTORY

On April 28, 2014, the commission issued four Orders[4] that provided broad guidance with respect to electric utility planning and operations. In Order No. 32054, the commission addressed the Companies' DR programs and set forth "policy guidelines for the continued operation and expansion of [DR] programs, and order[ed] the Companies to respond to a number

---

[4]See Order No. 32052; In re Public Util. Comm'n, Docket No. 2011-0206, Decision and Order No. 32053, filed on April 28, 2014 ("Order No. 32053"); In re Public Util. Comm'n, Docket No. 2007-0341, Order No. 32054, Policy Statement and Order Regarding Demand Response Programs, filed April 28, 2014 ("Order No. 32054" or "DR Policy Statement"); and In re Public Util. Comm'n, Docket No. 2011-0092, Decision and Order No. 32055, filed April 28, 2014 ("Order No. 32055").

of commission directives in furtherance of these guidelines."[5] The DR Policy Statement directed the Companies to "undertake, immediately and expeditiously, an overhaul of their existing [DR] programs by (1) consolidating those programs into a single integrated [DR] portfolio, (2) establishing appropriate overall objectives and goals for the integrated portfolio, as well as each individual program within the portfolio, and (3) developing and utilizing appropriate standards to measure the performance of, and the overall benefits achieved by, the integrated portfolio and each individual program within the portfolio."[6]

On July 28, 2014, the Companies submitted their Integrated Demand Response Portfolio Plan ("IDRPP").[7] On March 31, 2015, the Companies submitted an update to that plan ("IDRPP Update").[8]

---

[5]Order No. 32054 at 1.

[6]Order No. 32054 at 84.

[7]See In re Hawaiian Elec. Co., Inc., Hawaii Elec. Light Co., Inc., Maui Electric Co., Ltd., Docket No. 2007-0341, "Submission of Integrated Demand Response Portfolio Plan," filed July 28, 2014.

[8]See In re Hawaiian Elec. Co., Inc., Hawaii Elec. Light Co., Inc., Maui Electric Co., Ltd., Docket No. 2007-0341, "Submission of Integrated Demand Response Portfolio Plan Update," filed March 31, 2015.

On July 28, 2015, the commission issued Order No. 33027, assigning a Special Advisor to guide, monitor, and review the IDRPP design and implementation.[9]

On November 6, 2015, the Companies submitted a supplement to the IDRPP ("IDRPP Supplemental"),[10] and on November 20, 2015, the Companies submitted a revised IDRPP Supplemental ("IDRPP Revised Supplemental").[11] The IDRPP proposed a broad range of potential DR programs that will deliver a wide array of grid services,[12] ranging from capacity to fast frequency response.

On December 30, 2015, the HECO Companies filed their DR Portfolio Application[13] in Docket No. 2015-0412 for approval of

---

[9]See In re Hawaiian Elec. Co., Inc., Hawaii Elec. Light Co., Inc., Maui Electric Co., Ltd., Docket No. 2007-0341, Order No. 33027, filed July 28, 2015 ("Order No. 33027").

[10]See In re Hawaiian Elec. Co., Inc., Hawaii Elec. Light Co., Inc., Maui Electric Co., Ltd., Docket No. 2007-0341, "IDRPP Supplement: System Response Requirements," filed November 6, 2015.

[11]See In re Hawaiian Elec. Co., Inc., Hawaii Elec. Light Co., Inc., Maui Electric Co., Ltd., Docket No. 2007-0341, "IDRPP Supplement: System Response Requirements (Revised)," filed November 20, 2015.

[12]Unless otherwise specified, the term "grid services" refers to the grid service definitions provided in the IDRPP Supplemental and as revised in Docket No. 2015-0412.

[13]See In re Hawaiian Elec. Co., Inc., Hawaii Elec. Light Co., Inc., Maui Electric Co., Ltd., Docket No. 2015-0412, "Application of Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc. and Maui Electric Company, Limited; Verification; Exhibits

the DR program portfolio tariff structure, reporting schedule, and program cost recovery through the demand-side management surcharge.[14] In their Application, the HECO Companies requested commission approval of the following:

> 1. The proposed tariff structure as described in the Application upon which the [DR] Program Portfolio is to be deployed. The proposed structure includes grid services-based tariffs consisting of rules that define the services, riders that define the DR programs to deliver those services, and corresponding rates;
>
> 2. The recovery of costs associated with the HECO Companies' DR programs through the Demand-Side Management ("DSM") component of the Integrated Resource Planning ("IRP") Cost Recovery Provision ("DSM Surcharge");
>
> 3. A two-year program and budget approval cycle with the initial cycle beginning on the effective date of the tariffs; and
>
> 4. The proposed reporting structure which includes an annual Accomplishments & Surcharge Report ("A&S Report") and a Modifications and Evaluation Report ("M&E Report") every other year.[15]

The HECO Companies also proposed, as a conceptual measure, four grid service tariffs, which included preliminary grid service rules and examples of the corresponding DR riders and rates.

'A'-'I'; and Certificate of Service," filed December 30, 2015 ("DR Portfolio Application").

[14]See DR Portfolio Application at 1-2.

[15]DR Portfolio Application at 85-86.

On July 28, 2016, the commission issued Order No. 33835, which among other things, granted DEBDT's motion to intervene and granted participant status to LOL and DERC.[16]

On August 31, 2016, the HECO Companies filed their revised DR program implementation timeline ("Revised DR Implementation Timeline"),[17] pursuant to Order No. 33835.

On September 1, 2016, the commission convened an informal technical conference.

On September 8, 2016, the Parties and Participants filed their comments on the Companies' Revised DR Implementation Timeline, pursuant to Order No. 33835.[18]

On September 13, 2016, the HECO Companies filed a draft of Addendum No. 1 to Request for Proposals for Provision of grid services Utilizing Demand-Side Resources RFP No. 06175-02, Issued: May 1, 2015; Appendices A and B ("RFP Addendum No. 1").[19]

---

[16]See Order No. 33835, filed July 28, 2016 ("Order No. 33835").

[17]See Docket No. 2015-0412, "Revised DR Implementation Timeline," filed August 31, 2016.

[18]See Docket No. 2015-0412, "Distributed Energy Resources Council of Hawaii's Comments on the HECO Companies' DR Application and Timeline; and Certificate of Service," filed September 8, 2016; "Comments of The Department of Business, Economic Development, and Tourism; and Certificate of Service," filed September 8, 2016; "Division of Consumer Advocacy's September 8, 2016 Comments in Response to Order No. 33835," filed September 8, 2016.

[19]Docket No. 2015-0412, "Submission of Commission Requested Information From Technical Conference," filed September 13, 2016.

On September 21, 2016, the commission issued guidance on the Companies' RFP Addendum No. 1 and noted an intention to host a follow-up technical conference.[20]

On October 21, 2016, the commission issued Order No. 34051, which established the procedural deadlines to govern this proceeding.[21]

On November 4, 2016, commission-hosted Technical Conference #2 was held, pursuant to Order No. 34051.

On December 14, 2016, pursuant to a request made during the Technical Conference #2, the HECO Companies filed its "Value of Services Methodology" document.[22]

On January 6, 2017, the Consumer Advocate filed comments on the HECO Companies' "Value of Services Methodology."[23]

On January 12, 2017, commission-hosted Technical Conference #3 was held, pursuant to Order No. 34051.

---

[20]Docket No. 2015-0412, "Addendum No. 1 to RFP for Provision of Grid Services Utilizing Demand-Side Resources," filed September 21, 2016.

[21]Docket No. 2015-0412, Order No. 34051, filed October 21, 2016.

[22]Docket No. 2015-0412, "Submission of Commission Requested Information from Technical Conference No. 2," filed December 14, 2016.

[23]Docket No. 2015-0412, "Comments on the 'Value of Services Methodology,'" filed January 6, 2017.

On February 10, 2017, the HECO Companies filed their Revised DR Portfolio, pursuant to Order No. 34051.[24]

On March 3, 2017, the Parties and Participants filed information requests ("IRs") of the Companies.[25] The HECO Companies responded on March 24, 2017.[26]

On April 21, 2017, the Consumer Advocate, DBEDT, LOL, and DERC each submitted a Statement of Position ("SOP").[27]

---

[24]Docket No. 2015-0412, "Revised Demand Response Portfolio," filed February 10, 2017.

[25]Docket No. 2015-0412, "Distributed Energy Resources Council of Hawaii Information Requests on the HECO Companies' Revised DR Portfolio Filing; and Certificate of Service," filed March 3, 2017; Docket No. 2015-0412, "Life of the Land's Information Requests; and Certificate of Service," filed March 3, 2017; Docket No. 2015-0412, "The Department of Business, Economic Development, and Tourism's First Set of Information Requests to the Hawaiian Electric Companies; and Certificate of Service," filed March 3, 2017; Docket No. 2015-0412, "Division of Consumer Advocacy's Submission of Information Requests," filed March 3, 2017.

[26]Docket No. 2015-0412, "Responses to Information Requests," filed March 24, 2017.

[27]Docket No. 2015-0412, "Distributed Energy Resources Council of Hawaii's Statement of Position on the HECO Companies' Revised DR Portfolio Filing; and Certificate of Service," filed April 21, 2017 ("DERC SOP"); Docket No. 2015-0412, "Life of the Land's Statement of Position; and Certificate of Service," filed April 21, 2017 ("LOL SOP"); Docket No. 2015-0412, "Statement of Position of The Department of Business, Economic Development, and Tourism," filed April 21, 2017 ("DBEDT SOP"); Docket No. 2015-0412, "Division of Consumer Advocacy's Statement of Position," filed April 21, 2017 ("CA SOP").

On May 5, 2017, the HECO Companies submitted a Reply SOP.[28]

On May 24, 2017, Sunrun submitted a public comment on "needed DER-focused grid service opportunities" as they relate to the Companies' Revised DR Portfolio.[29] Sunrun stated appreciation for the time and effort the Companies have placed into the current Revised DR Portfolio, but made several suggestions for refining the Revised DR Portfolio.[30]

On June 28, 2017, the commission issued separate information requests to the HECO Companies[31] and all other Parties.[32]

On July 12, 2017, the HECO Companies' submitted a status update to certain remaining key milestones in the demand response portfolio implementation timeline.[33]

---

[28]Docket No. 2015-0412, "Hawaiian Electric Companies' Reply Statement of Position; and Certificate of Service," filed May 5, 2017 ("HECO's Reply SOP").

[29]Docket No. 2015-0412, Sunrun's "Public comments on needed DER-focused grid service opportunities," filed May 24, 2017 ("Sunrun's Comments").

[30]Sunrun's Comments at 1-5.

[31]Docket No. 2015-0412, "PUC-HECO-IR-101 to PUC-HECO-IR-112," filed June 28, 2017.

[32]Docket No. 2015-0412, "PUC-NUP-IR-113 to PUC-NUP-117," filed June 28, 2017.

[33]Docket No. 2015-0412, "Status Update to the Demand Response Portfolio Implementation Timeline," filed July 12, 2017.

On July 13, 2017, the Parties filed their responses to the commission's information requests.[34]

On December 18, 2017, the HECO Companies submitted a draft Grid Service Purchase Agreement ("GSPA") and related exhibits for commission review and approval.[35] The filing further proposed follow-on procedural steps and revisions to the DR implementation timeline.[36]

---

[34]Docket No. 2015-0412, "The Department of Business, Economic Development, and Tourism's Responses to the Information Requests from the Public Utilities Commission; and Certificate of Service," filed July 13, 2017; Docket No. 2015-0412, "The Distributed Energy Resources Council of Hawaii's ('DER Council') and Life of the Land's Responses to the Commission's Information Requests on Docket No. 2015-0412," filed July 13, 2017; Docket No. 2015-0412, HECO Companies' "Responses to Commission Information Requests," filed July 13, 2017; Docket No. 2015-0412, "Division of Consumer Advocacy's Responses to the Public Utilities Commission's Information Requests," filed July 13, 2017.

[35]Docket No. 2015-0412, "Submission of Grid Service Purchase Agreement and Proposed Follow-on Procedural Steps and Revisions to the DR Implementation Timeline," filed December 18, 2017 ("Draft GSPA Filing").

[36]Draft GSPA Filing, at Exhibit 4.

III.

REVISED DR PORTFOLIO

The Companies' Revised DR Portfolio presents a revised request, which focuses on four system-level grid service tariffs and a selection of riders to allow customers to deliver the following programs:

1. Capacity programs that compensate customers for providing capacity services to the grid through TOU rates, RTP, CPI, and/or DALS;[37]

2. Fast Frequency Response ("FFR") programs that compensate customers on Oahu for providing a load-reducing response following a contingency scenario (e.g., a generation trip);[38]

3. Regulating Reserve programs that help the Companies to balance their electric grids by operating DR resources in response to AGC signals from the EMS;[39] and

4. Replacement Reserve programs that compensate customers for providing load-reduction in place of the Companies starting a fast-start generator.[40]

---

[37]Revised DR Portfolio, Exhibit 1, at 2.

[38]Revised DR Portfolio, Exhibit 1, at 2.

[39]Revised DR Portfolio, Exhibit 1, at 2.

[40]Revised DR Portfolio, Exhibit 1, at 2.

The Companies have articulated several Rate Schedules and riders upon which the DR programs are to be deployed in support of the four grid services, as outlined below.

A.

Revised Approval Request

In their Revised DR Portfolio filing, the Companies are currently requesting approval of the following:

1. Revised DR Portfolio tariffs for the following four grid service rules:

    a. Rule No. [XX] - Capacity Grid Service.

    b. Rule No. [XX] - Fast Frequency Response Grid Service.

    c. Rule No. [XX] - Regulating Reserve Grid Service.

    d. Rule No. [XX] - Replacement Reserve Grid Service.

2. Rate schedules and riders upon which the DR programs are to be deployed in support of the four grid services rules as follows:

    a. Schedule CPI-C - Commercial Peak Incentive.

    b. Rider FFR-SMB - Small and Medium Business Fast Frequency Response Grid Service for Load Resources.

    c. Rider FFR-R - Residential Fast Frequency Response Grid Service for Load Resources.

    d. Rider FFR-C - Commercial Fast Frequency Response Grid Service for Load Resources.

e. Rider NSAR-SMB - Small and Medium Business Non-Spinning Auto Response.

f. Rider NSAR-R - Residential Non-Spinning Auto Response.

g. Rider NSAR-C - Commercial Non-Spinning Auto Response.

3. Immediate implementation of rate schedules and riders for the islands of Oahu and Maui, and the staged implementation of additional rate schedules and riders by island as further described in [the Revised DR Portfolio].

4. Plan to migrate participants from currently-approved DR programs or pilot programs to otherwise applicable proposed Rider(s) under the grid services rule(s).

5. Continued use of the DSM Adjustment component of the IRP cost recovery provision for the collection of DR Portfolio variable costs until such costs are approved and reflected in the Companies' respective base rates.

6. Demand Response Adjustment Clause ("DRAC") as a new component of the Integrated Resource Planning Cost Recovery Provision for purposes of reconciling actual Revised DR Portfolio variable expenditures to Revised DR Portfolio variable expense elements embedded in the Companies' respective base rates as a result of general rate cases.

7. Treatment of Grid Services Purchase Agreement ("GSPA") contract(s) as variable program costs for purposes of cost recovery through base rates, the DSM Adjustment and/or the DRAC, as applicable.

8. Reporting structure, including annual A&S Report and M&E Report filings, and the approval of requested modifications to the DR programs in a timely manner.

9. Request to propose DR program modifications, including modifications to rules, riders, and rates outside of the M&E and or A&S Reports, as circumstances warrant.

10. Three-year Evaluation, Measurement and Evaluation ("EM&V") cycle and associated rate and rider review and refinement.

11. Request to review and approve the implementation costs of the Revised DR Portfolio and related cost recovery mechanisms in the proceeding, notwithstanding that the same requests are included in HECO's 2017 test year rate case (Docket No. 2016-0328).[41]

Furthermore, in requesting the above commission approvals in the Revised DR Portfolio filing, the Companies are no longer requesting the following, as was requested in the original Application:

1. With the filing of HECO's 2017 test year rate case (Docket No. 2016-0328), the Companies have incorporated the DR Portfolio budget into the rate case and are no longer requesting a two-year budget approval cycle.

2. The Companies are no longer requesting the Renewable Energy Infrastructure Program ("REIP") Surcharge as an alternative to the DSM Surcharge for recovery of DR program costs.

3. The Companies are no longer requesting the M&E reporting to be conducted biannually.[42]

---

[41]Revised DR Portfolio, Exhibit 1, at 4-6.

[42]Revised DR Portfolio, Exhibit 1, at 6-7.

B.

Tariff Structure

As part of the DR Portfolio, the Companies articulate their proposed grid service tariff structure and included pro-forma tariffs with rules, riders, and rates for illustrative purposes. The commission supports the tariff structure framework, which largely reflects a technology-neutral approach that allows customer-owned or third-party resources to provide services to the grid, provided that such resources meet established technical requirements.

As noted above, the Companies have functionally defined four bulk power system services to be addressed by grid service tariffs: (a) three ancillary service tariffs, which cover the response time continuum from cycles through hours (FFR, Regulating Reserve, and Replacement Reserve); and (b) a fourth tariff covering Capacity.

The rate structure for customers participating in DR programs would be composed of multiple parts, including one grid service rule, a standardized service agreement, one or more grid service riders, and in some cases one or more grid service rate schedules and or utility aggregator ("UA") contract. At a minimum, each grid service tariff will collectively define the grid services' availability, customer or aggregator eligibility, notification requirements, compensation provided for participation, and other technical and participation requirements.

The core grid service tariff elements are defined as follows:

Rule. A rule is the technology-neutral definition of one of the grid services that the Companies need in order to maintain reliability. A rule may also contain the economic value of the grid services that the Companies believe the grid service presents to the grid, which may help inform customers and aggregators about their participation. The rule will have a rider and a service agreement, and or a UA contract appended to it. The service agreement would be used to enroll customers into a rule by way of enrollment to a rider. Alternatively, a UA contract would enable aggregator participation in providing grid services to the Companies.[43]

Rider. A rider provides the specific requirements of participation that an individual customer shall abide by to provide a grid service under the applicable tariff. Each rider is associated with a particular class of customer and a particular mechanism or program by which the customer provides a grid service (participates in a rule). Participation requirements contained in the rider include requirements for technology or equipment,

---

[43]Revised DR Portfolio, Attachment D, at 1.

enrollment processes, annual limits, testing, event notification, incentive calculations, consequences of non-compliance, and other relevant DR program attributes that directly affect a customer's participation under the tariff.[44]

Service Agreement. The service agreement will be a standard agreement between a customer and the applicable Company, and will contain the general terms and conditions that each party shall abide by. The service agreement will reference the rule(s) and associated rider(s) through which the customer will participate in providing grid services to the applicable Company.[45]

Rate. The underlying rate structure that a customer takes service under for energy services supplied by the Companies, upon which DR-specific rules and riders are applied. Unlike a rider that must be appended to an existing rate schedule under which a customer is taking service, new rate schedules developed under this DR Portfolio will conform to this proposed structure and offer pricing programs such as TOU, DALS, or RTP. The respective Company's existing pricing programs will continue to operate under currently published tariffs.[46]

---

[44]Revised DR Portfolio, Attachment D, at 2.

[45]Revised DR Portfolio, Attachment D, at 2.

[46]Revised DR Portfolio, Attachment D, at 2.

UA Contract. Unlike a customer, an aggregator does not take electric service from one of the Companies, and is therefore not eligible to enroll via a rider. In order to make a grid service offering to one of the Companies, an aggregator must sign up for the grid service tariff through a UA contract. The UA contract will have requirements resembling those in the corresponding applicable riders; however, the terms and conditions will likely go through a negotiation process between the aggregator and the applicable Company. The Companies anticipate that one of these UA contracts will be a general GSPA for each Company to contract for turn-key grid services.[47]

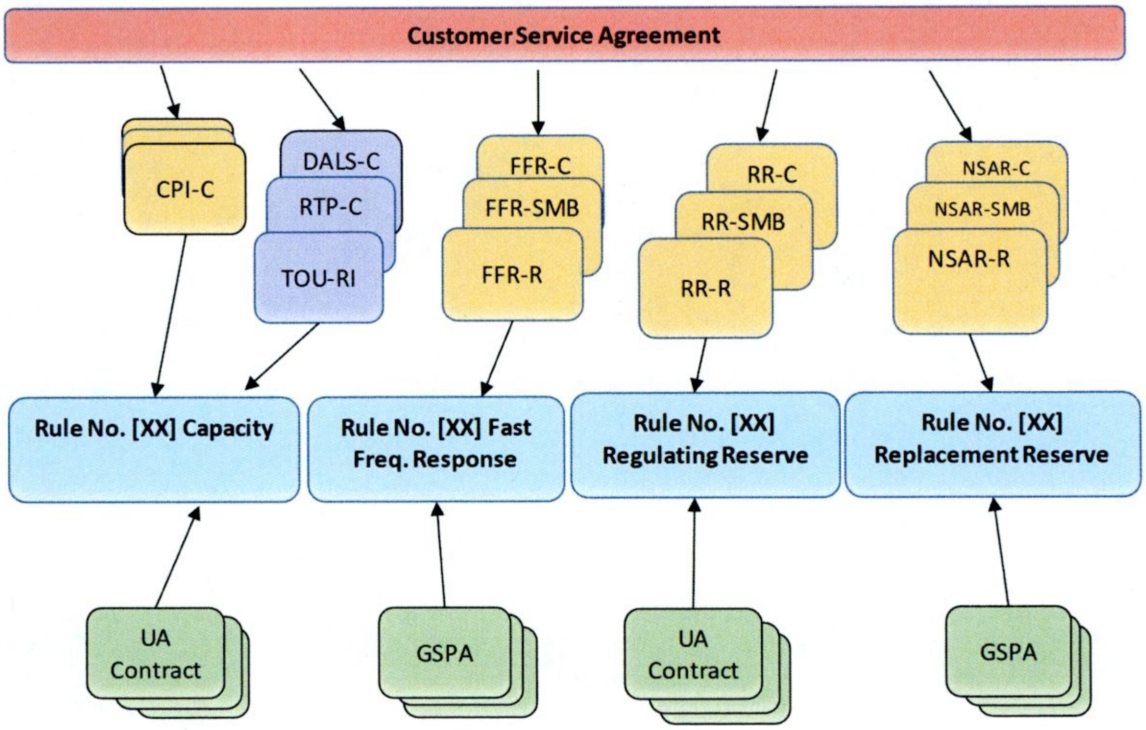
Figure 1, below, provides a high-level organization of the structure of a grid service tariff and how the elements of the tariff are related. As shown, a rule is structurally central to a grid service tariff in that it provides the definition and high-level requirements of a grid service that the Companies may acquire. The riders, rates, and UA contracts then reference and build upon the cornerstones of the rule and define (at a more granular level) the requirements that a customer or aggregator must meet in order to provide the grid service defined in the rule.[48]

---

[47]Revised DR Portfolio, Attachment D, at 2-3.

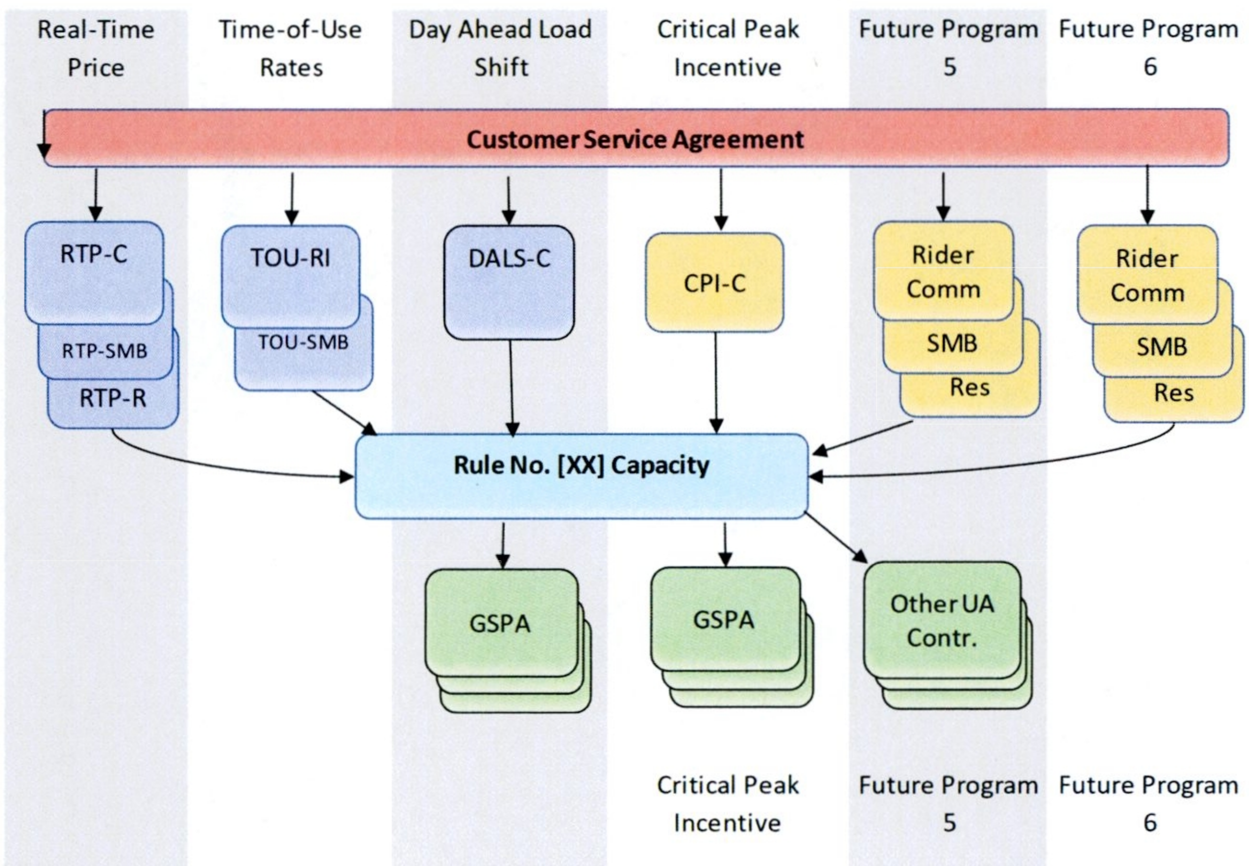
[48]Revised DR Portfolio, Attachment D, at 3.

Figure 1. Grid Service Tariffs



A single grid service rule can be tied to multiple DR programs providing the grid service to meet the requirements of the rule. A DR program will be the mechanism used by the Companies to subscribe customers to a grid service tariff through subscription in a rider, UA contract, or rate, to provide a grid service. For programs deployed by the Company, a customer would sign a service agreement that would enroll them into the program by subscription to a rider or rate. A program, as depicted under the Capacity grid service tariff in Figure 2, below, can consist of just a rider, just a UA contract, a multiple of riders and UA contracts, or a rate. Although the riders and UA contracts are different mechanisms to enroll grid service capacity under a rule, they can be grouped together and defined as a program with each offering a subset of grid services to the total grid service requirement. By constructing the grid service tariffs in this manner, the Companies can allow both customers and aggregators to simultaneously participate and offer grid services using any resources that meet applicable technical requirements.[49]

Figure 2. Grid Service Tariff Structure



49Revised DR Portfolio, Attachment D, at 4.

C.

DR Programs

The following section presents the DR programs envisioned by the Companies as part of this Revised DR Portfolio. Pursuant to the Revised DR Portfolio, the table below maps the DR programs to the riders and rules that govern their design and operation. For example, the Commercial FFR program is governed by the FFR-C Rider, which is under the FFR rule. Riders are applicable to customers who directly participate with the Companies in providing grid services. Customers can also choose to participate with aggregators, in which case a UA contract and a contract between an aggregator and customer replaces the rider as the mechanism by which a customer provides grid services under a rule.[50]

Table 1. Map of Rules, Riders/Rates and Programs

Rules	Rider or Rate Schedule	Program	Customer Class
Capacity	TOU-RI, TOU-SMB, CPI-C,	Time-of-Use Rate	R, SMB
	RTP-R, RTP-SMB, RTP-C,	Real Time Price	R, SMB, C
	CPI-C	Critical Peak Incentive	C
	DALS-C	Day-Ahead Load Shift	C
FFR	FFR-R, FFR-SMB, FFR-C	Fast Frequency Response	R, SMB, C
Regulating Reserve (RR)	RR-R, RR-SMB, RR-C	Regulating Reserve	R, SMB, C
Replacement Reserve	NSAR-R, NSAR-SMB, NSAR-C	Non-Spin Auto Response	R, SMB, C

The Programs are discussed above by customer class: Residential ("R"), Small and Medium Business ("SMB"), and

---

[50]Revised DR Portfolio, Exhibit 1, at 20-21.

Commercial ("C"). The set of programs for each customer class represents the Companies' envisioned DR Portfolio to allow customers to provide grid services and receive appropriate compensation.[51]

Table 2, below, identifies the compatible riders and rates, and as a result, programs, that customers can participate in simultaneously using a single resource. According to the HECO Companies, for example, a single resource may provide FFR and Non-Spin Automatic Response ("NSAR"); however, that resource cannot also provide Regulating Reserve simultaneously due to the conflicting demand on the resource from the different services. A customer may, however, use multiple resources to provide all three services simultaneously, given that there are different resources providing FFR and Regulating Reserve and that each is metered individually.[52]

---

[51]Revised DR Portfolio, Exhibit 1, at 21.

[52]Revised DR Portfolio, Exhibit 1, at 21-22.

Table 2. Compatible Riders/Programs

	FFR	RR	NSAR	CPI	RTP	TOU	DALS
FFR	○	○	●	●	●	●	●
RR	○	○	○	○	●	●	●
NSAR	●	○	○	○	●	●	●
CPI	●	○	○	○	●	●	●
RTP	●	●	●	●	○	○	○
TOU	●	●	●	●	○	○	○
DALS	●	●	●	●	○	○	○

●	Nominated Resource is eligible to provide simultaneous service
○	Nominated Resource is not eligible to provide simultaneous service

Table 3, below, identifies the implementation timeline of the DR programs discussed here and their associated riders, and the islands on which these programs will be offered. Correspondingly, aggregator UA contracts will be established in the same timeframe for the same programs. The Companies currently offer TOU-RI across all islands and will offer FFR and NSAR programs for all customer classes on Oahu and a CPI program for commercial customers on Oahu and Maui. In 2018, the Companies have plans to offer a TOU program for SMB customers, a DALS program for commercial customers, and a Regulating Reserve program for all customer classes across all islands.[53]

---

[53]Revised DR Portfolio, Exhibit 1, at 22.

Table 3. Implementation Timeline for Riders/Programs

	Program/Rider	Oahu	Hawai'i	Maui	Lana'i	Moloka'i
2017	**Time-of-Use**					
	TOU-RI	X	X	X	X	X
	FFR					
	FFR-R	X				
	FFR-SMB	X				
	FFR-C	X				
	NSAR					
	NSAR-R					
	NSAR-SMB					
	NSAR-C					
	CPI					
	CPI-C	X		X		
2018	**TOU**					
	TOU-SMB	X	X	X	X	X
	DALS					
	DALS-C	X	X	X	X	X
	RR					
	RR-R	X	X	X	X	X
	RR-SMB	X	X	X	X	X
	RR-C	X	X	X	X	X
2020	**RTP**					
	RTP-R	X	X	X	X	X
	RTP-C	X	X	X	X	X
	RTP-SMB	X	X	X	X	X

1.

Capacity Grid Services

With respect to Capacity grid service, the Companies will offer programs for each of the Residential, SMB and Commercial customer classes. The programs will be rate schedule programs that present different rates to customers at different times of the day depending on the system needs during those time periods.[54] For Residential and SMB customers, the Capacity grid service program will be a TOU program offer with a long-term target of offering RTP programs on all islands. Residential customers will have the opportunity to participate in the Companies' existing TOU-RI rate schedule. An opt-in TOU program and rate for SMB customers will be filed with the commission for review and approval before implementation in 2018. Under the opt-in TOU program, customers will pay different electric rates for different time periods during the day.[55]

Commercial customers will be offered a CPI (Critical Peak Incentive) program on Oahu and Maui and a DALS (Day-Ahead Load Shift) program on all islands. In the CPI program, customers will receive a dispatch command for their nominated loads and will have to respond within ten minutes.[56]

In the DALS program, the Companies will provide a load response request in the form of a TOU price signal the day before the event, allowing commercial customers appropriate notification to schedule their operations and provide their nominated response during the following day. The Companies will forecast weather and

---

[54]Revised DR Portfolio, Exhibit 1, at 23.

[55]Revised DR Portfolio, Exhibit 1, at 24.

[56]The CPI program replaces the existing CIDLC program. See Revised DR Portfolio, Exhibit 1, at 24 n.13.

system conditions to identify load shift events the day before and generate and dispatch this signal to customers. The specific methodology used to generate this signal will be filed for review and approval by the commission with the DALS-C Rate Schedule in the timeframe identified in Table 3 above.[57]

The Companies aspire to replace the TOU and DALS programs with an opt-in RTP program for all customer classes on all islands. Targeted for 2020, this program would publish a day-ahead, hourly price for electric service. The Companies would set this hourly price on a daily basis based on forecasted weather and system conditions to optimize customer load to meet the available generation resource. A price signal would then be dispatched to customers and, depending on their interest and sophistication, they could manually follow the price signal or install enabling technology that allows their load to respond automatically to the price signal. The methodology and mechanism used to generate the hourly price will be filed for review and approval to the commission with the RTP Rate Schedules in the timeframe identified in Table 3.[58]

---

[57]Revised DR Portfolio, Exhibit 1, at 24.

[58]Revised DR Portfolio, Exhibit 1, at 24-25.

2.

FFR Programs

With respect to FFR grid service, the Companies will make available an FFR program for each of the Residential, SMB, and Commercial classes on Oahu. At present, the Companies have not identified an option to provide FFR on other islands. Each type of customer will have an opportunity to subscribe their loads to provide FFR service. The Companies will require the customers to respond automatically to frequency set points that establish a load response to system under frequency, helping the system to recover following contingencies and displace alternative resources in providing FFR service. The customers will receive participation incentives in accordance with the incentives identified in the Revised DR Portfolio, Attachment E.[59]

3.

Regulating Reserve Programs

With respect to Regulating Reserve grid service, the Companies will make available a Regulating Reserve program for each of the Residential, SMB, and Commercial customer classes across all islands in 2018. Each type of customer will have an opportunity to subscribe their loads to provide Regulating Reserve

[59]Revised DR Portfolio, Exhibit E, at 25.

service. The Companies will require customer resources to respond automatically to the Companies' AGC signal, helping the Companies to balance the electric grids on each island. Customers will receive participation and performance incentives in accordance with the incentives identified in the riders that will be submitted to the commission for review and approval before program implementation in 2018.[60]

4.

Replacement Reserve Programs

With respect to Replacement Reserve grid service, the Companies will make available a NSAR Reserves program for each of the Residential, SMB, and Commercial customer classes on Oahu.[61] At present, the Companies have not identified an option to provide Replacement Reserves on the other islands. Each type of customer will have an opportunity to subscribe their loads to provide Replacement Reserve service. The Companies will require customer resources to respond within 10 or 30 minutes to a Company dispatch signal. This will help the Companies to address longer-term contingency requirements that are not otherwise addressed by the

[60]Revised DR Portfolio, Exhibit 1, at 25-26.

[61]The NSAR program replaces the existing FastDR, RDLC, and SBDLC programs; any new FastDR expansion customers on Maui will migrate to CPI. See Revised DR Portfolio, Exhibit 1, at 26 n.14.

other grid services. Customers will receive participation incentives in accordance with the incentives identified in the applicable riders included in the Revised DR Portfolio, Attachment E.[62]

D.

Customer Enrollment in Grid Service Tariffs

The Companies plan to acquire grid services through two methods: (1) self-administered programs, where the Companies engage with customers directly; and (2) via third-party aggregators. The Companies also plan to engage directly with eligible large commercial customers, or self-aggregators, who will contract directly with the Companies for the delivery of services, while relying on the support of technical service providers.[63]

Under the first option, customers will enroll in a Company offered program to provide a grid service. The customer would fill out an enrollment form or Service Agreement, that provides customers with information needed to enroll and participate in the grid service tariff.[64] Under the second option, the aggregator will contract with the Companies to provide a

---

[62]Revised DR Portfolio, Exhibit 1, at 26.

[63]See Revised DR Portfolio, Exhibit 1, at 27-28.

[64]Revised DR Portfolio, Exhibit 1, at 27.

specific amount of grid service or combination of services at a negotiated price, and will subscribe customers to provide the services. The aggregator will be the point of contact for the DR program and all associated issues, including meeting the Companies' requirements and passing on the Companies' pricing signals to its customers.[65] The initial DR programs are proposed to launch under the aggregator model, with the Companies' deferring implementation of self-administered programs for at least a year in order to provide space for a third-party market to develop.

E.

Grid Service Performance Requirements

The Companies have identified specific grid service requirements for the DR programs offered within the Revised DR Portfolio.

1. Capacity Grid Service - The Companies will require Capacity grid service(s) to have a minimum response duration of four consecutive hours.[66]

2. Fast Frequency Response Grid Service - The Companies will require Fast Frequency Response grid service(s) to provide service for up to 30 minutes, and must be available to respond in all 24 hours of the day, unless specified otherwise. The resource must also respond to a frequency deviation of within + or - 0.02 Hz of the trip frequency within

---

[65]Revised DR Portfolio, Exhibit 1, at 28.

[66]Revised DR Portfolio, Attachment D, at 12.

+/- 0.0167 seconds of the 12 or 30 cycles requirements.[67]

3. Regulating Reserve Grid Service - The Companies will require Regulating Reserve grid service(s) to have a sustained minimum response duration of 30 minutes. The Regulating Reserve service must be controllable to a resolution of 0.1 MW by the AGC system.[68]

4. Replacement Reserve Grid Service - The Companies have identified two types of Replacement Reserves: (1) 10 minute reserves; and (2) 30 minute reserves. For the 10 minute reserves, the Companies will require the grid service to have a minimum response duration of one hour. For the 30 minute reserves, the Companies will require the grid service to have a minimum response duration of two hours. The resource must also be capable of being controlled and monitored by the Companies' energy management system.[69]

F.

Establishment of Grid Services Market

The HECO Companies acknowledge the commission's interest in taking a market-based approach to the delivery of grid services. At this time, the Companies view the Request for Proposal ("RFP") process as the most viable form of competition in light of uncertainty related to interest and capability for delivering these services. As such, the Companies plan to procure as much as

---

[67]Revised DR Portfolio, Attachment D, at 16-17.

[68]Revised DR Portfolio, Attachment D, at 20-21.

[69]Revised DR Portfolio, Attachment D, at 25-26.

possible of the targeted DR-delivered grid services via third-party aggregators, procured through the RFP process. The intent is for this to be an ongoing process whereby the Companies will issue rolling RFPs for unfulfilled grid services for up to five-year terms. In this fashion, existing aggregators would have the opportunity to expand their offerings and new aggregators may enter the market.[70]

Initial RFP awards will have a maximum five-year term, while each subsequent RFP award will have a shorter maximum term as the process approaches its five-year terminus. At that time, the Companies will assess the depth of the market and implicit market competitiveness to determine if the RFP process should be continued or transitioned into an alternative procurement method.[71]

Each RFP awardee will execute a GSPA. While the shorter contracts offer less business model and revenue certainty to the awardees, the Companies believe that increasing amounts of risk will also be correspondingly removed from the equation. For example, operational risk, technology risk, and market risk - both in terms of customer adoption and in terms of cost structures - will be reduced, thus balancing the risk-reward equation. Hard-to-reach customer segments, end-use

---

[70]Revised DR Portfolio, Exhibit 1, at 40-41.

[71]Revised DR Portfolio, Exhibit 1, at 40.

diversification of unsatisfied grid service needs will likely be explicitly addressed via self-administered programs.[72]

IV.

STATEMENTS OF POSITION

A.

Consumer Advocate

1.

Proposed Grid Services

The Consumer Advocate states that, based on its review, "it appears that the Companies have defined the proposed grid service tariff in a technology-neutral manner."[73] That said, the Consumer Advocate indicates that "the other Parties and Participants, especially DERC, may provide additional information in this area."[74]

2.

Proposed DR Tariff Structure

Based on its review, the Consumer Advocate "does not object to the DR tariff structure as proposed by the Companies,

---

[72]Revised DR Portfolio, Exhibit 1, at 41.

[73]CA SOP at 8.

[74]CA SOP at 8.

which include the use of rules, riders, schedules, and agreements (i.e., standardized service agreements and utility aggregator contracts) to deploy the DR programs."[75] The Consumer Advocate further states its belief that "there are benefits to having the individual service and programs in different tariff documents as compared to having only one tariff for all of the services and programs."[76] By utilizing separate tariffs, the Companies "will hopefully avoid confusion and minimize the need for significant revisions in the future."[77]

The Consumer Advocate, in citing to the new and novel nature of the DR tariff structure and programs, recommends that the Companies, when more details are available, develop educational materials that will be made available in hard copy and online, to help customers and possible participants better understand the proposed programs.[78]

Notwithstanding the above, the Consumer Advocate "objects to the Companies' current request to approve the proposed DR tariffs and immediate implementation of those tariffs," contending that "the Revised DR Portfolio would benefit

---

[75]CA SOP at 9.

[76]CA SOP at 9.

[77]CA SOP at 9.

[78]CA SOP at 9.

from additional review and comment in several areas before implementation."[79]

The Consumer Advocate identifies the following areas that it asserts merit additional review and comment:

1. There is a need to review the language of the rules, riders, schedules, and agreements to ensure that each of the components are consistent and provide clear and transparent information to the potential participant;

2. More thought should be given to assess the frequency at which "course correction" (i.e., when adjustments to the incentive levels) should be done;

3. Additional thought should be given to the incentive levels themselves; and

4. Questions remain as to whether the proposed incentives reflect a reasonable pricing for the services that may be obtained.[80]

3.

Proposed Cost Recovery

The Consumer Advocate states a number of concerns with the proposed cost recovery requests, which, it asserts, appear "only partially developed."[81] The Consumer Advocate is not clear how the proposed reconciliation processes would work, nor is it

[79]CA SOP at 10.

[80]CA SOP at 10-12.

[81]CA SOP at 14.

clear whether the value and benefits associated with DR will be fully realized and flowed through to customers.

More specifically, the Consumer Advocate states that the proposed use of the DRAC (combined with the other cost recovery proposals) is potentially problematic in that it creates an additional recovery mechanism for which costs would need to be tracked to ensure that the same costs are not recovered between the three cost recovery mechanisms (i.e., rate proceeding, DSM Surcharge, DRAC).[82]

4.

Proposed Monitoring and Reporting

The Consumer Advocate also questions how adequate monitoring and reporting associated with the proposed programs will allow informed review of the programs that will facilitate reasonable modifications, if needed, as well as proper coordination of the DR programs with other ongoing efforts, some of which are the subject of ongoing regulatory proceedings.[83] "The Consumer Advocate recognizes that DR is a tool that could be a cost-effective means by which to utilize to help balance system needs as Hawaii moves forward with its clean energy transition,

[82]CA SOP at 15.

[83]CA SOP at 15.

but it is not the only tool and should not be confused with the most important tool."[84]

B.

DBEDT

Overall, "DBEDT supports the expeditious rollout of DR programs" and notes that "[i]mplementation of DR programs hastens Hawaii's transition to a clean energy economy."[85]

In addition, DBEDT supports the general framework of the proposed DR program, which separates pricing of services from the grid with compensation for services provided to the grid. The separation of pricing for services to and from the grid allows for an expedient means by which to transition pricing to a structure that supports the transition to a clean energy economy.[86]

1.

DR Tariff Structure

DBEDT states that the general, overarching structure of the DR program is reasonable. It allows for DR programs and rate design to be effectively integrated while addressing the

---

[84]CA SOP at 15.

[85]DBEDT SOP at 13.

[86]DBEDT SOP at 15.

transformation of each pricing sector separately. This separation eases the transition towards a market in which customers pay for the services they receive from the grid and are compensated for the services they provide to the grid.[87]

DBEDT does express some concerns with the transparency of the Companies' activities to align and validate the principal pricing framework in which DR exists; in particular, how the pricing methodology is aligned across the interrelated utility-scale resource planning and procurement.[88]

2.

Cost Recovery

DBEDT does not object to the cost recovery mechanism at this time given the relative size of the DR resources in magnitude and costs; however, DBEDT believes that additional information is required and should be included in the Companies' recurring reporting.[89] DBEDT stresses that its concerns should not be construed as indicating a need to "hold up the rollout of the program."[90]

---

[87]DBEDT SOP at 5.

[88]DBEDT SOP at 5-6.

[89]DBEDT SOP at 10.

[90]DBEDT SOP at 10.

Specifically, DBEDT requests that the Companies track and report on the costs incurred by each individual DR program. In addition, DBEDT would like the Companies to develop a methodology to allocate the costs of an individual program to the specific grid services that comprise that individual program, and include this in the Companies' proposed recurring reporting activities.[91]

C.

DER Council

1.

Market Risk Allocation

DERC wishes to ensure that the final GSPA balances both the industry's and the Companies' needs regarding market risk and a sufficient level of program development and protection. Specifically, DERC states that "a 5-year contract should be the absolute minimum to ensure that aggregators can balance the risk of the investment costs and various unknowns regarding performance and program management with these new DR tariffs."[92]

---

[91]DBEDT SOP at 12.

[92]DERC SOP at 7.

2.

Fair and Competitive Procurement

While understanding that the success of the DR program will be a joint effort between the Companies and the aggregators as the individual DR tariffs get tested and confirmed, DERC seeks to ensure that the Companies' participation in the DR tariff does not provide the Companies with an unfair advantage vis-à-vis third-party aggregators.[93] Should the Companies decide to compete with third-party aggregators, DERC states that "the commission must ensure that all parties receive equal treatment and opportunity, and that the Companies would not have an unfair advantage.[94] DERC further asserts that, "in order to ensure that aggregators have a fair chance to compete and to arrive at the most realistic price . . . the Companies should not provide an individual enrollment option, at least for the first year of the program, and instead serve as a back-stop to cover any gaps in the program that the aggregators have not been able to cover."[95]

---

[93]DERC SOP at 9.

[94]DERC SOP at 10.

[95]DERC SOP at 11.

3.

Measurement and Verification

DERC generally supports the HECO Companies' proposal to implement a two-pronged approach to evaluation, measurement, and verification, which provides data on both individual and aggregated resources and which also tackles the question of system-level DR value assessment. That said, DERC has concerns "that a fixed effects regression model could not be adequately replicated by multiple participants in the market, as compared to calculating a 10-day baseline for example, which both the utility and multiple industry parties should be able to separately verify."[96]

DERC proposes that the Companies allow device-level telemetry to be qualified and individual device types to be certified to allow for settlement. DERC suggests that such devices can be qualified in a similar manner to the Companies' established practice of publishing a list of prequalified inverters for customer-sited PV systems.

Ultimately, DERC views EM&V as an important topic for ongoing discussion and demonstration, and recommends that the Companies strive for maximum flexibility at this early stage of

[96]DERC SOP at 12.

market development and allow for various options to be explored in the preliminary stages of the DR program.[97]

4.

Program and Budget Approval Cycle

DERC states several concerns regarding whether a two-year budget and program cycle is the best approach to provide sufficient flexibility to provide DR program course correction. DERC's primary concern relates to having a sufficient payment runway by which to recoup necessary upfront hardware and installation costs.[98]

DERC proposes that the Companies be permitted to revise programs and tariffs on a 2-year budget cycle, in order to keep up with technology developments and thereby protect ratepayer interest but at the same time provide a 5-year program payment runway that will allow the industry to finance the upfront costs of enrolling and equipping customers.[99] "As new programs evolve, or existing tariffs and programs are modified, providers may choose to keep individual customers on their 5-year runway to recoup

[97]DERC SOP at 13.

[98]DERC SOP at 14.

[99]DERC SOP at 14-15.

costs, or move them to other programs that may be better suited to the participating customer's capabilities."[100]

D.

Life of the Land

LOL does not oppose the Revised DR Portfolio, but "cannot endorse the program" due to concerns related to the Avoided Cost Study and a lack of sufficient infrastructure to enable all customers to participate.[101]

With respect to the proposed DR tariff structure, LOL states that the successful deployment of a robust, cost-effective DR program portfolio will necessarily depend upon the number of participants, the impact to frequency and voltage, and the ability of all communities on all islands to participate.[102] LOL indicates that success cannot be determined until after the program is launched, highlighting the need for monthly updates and future discussions.

With respect to whether the DSM Surcharge is an appropriate cost recovery mechanism, LOL states that the nomenclature associated with traditional utility customers' needs

---

[100]DERC SOP at 15.

[101]LOL SOP at 6-7.

[102]LOL SOP at 13.

to expand and that "[a]t a minimum, the DR expenses should be recovered through a Prosumer Surcharge."[103]

LOL further states that there is a need to merge the DR and DER proceedings and that, going forward, monthly updates on the DR program implementation "to the DR/DER stakeholder group" will be important.[104]

E.

HECO Companies' Reply

The HECO Companies observe that, based upon the Parties' SOPs, there do not appear to be any general objections to the proposed tariff structure.[105] The sections that follow summarize the Companies' response to particular issues of the proposed DR tariff structure as raised by the Parties.

---

[103]LOL SOP at 13-14.

[104]LOL SOP at 14-15.

[105]HECO's Reply SOP at 13.

1.

Grid Services Purchase Agreement

The Companies seek to respond to several of DERC's concerns regarding the GSPA. First, DERC recommends contracts with a minimum of five-year terms (preferring ten-year terms) and first rights of refusal upon contract renewal to aggregators. First rights of refusal allow aggregators to be the first in line to provide DR programs to customers, even before the Companies.[106]

Because the Companies need to balance not only their own and vendors' risks, but also risks to customers, the Companies appreciate DERC's understanding of the Companies' position concerning shorter contract terms associated with the first round of GSPAs to reflect the preliminary nature of the programs.[107] In addition, the HECO Companies state that they "are amenable in concept to the inclusion of a first right of refusal term in the GSPA," but note that discussion of such issues at this time is premature and would be better addressed when the GSPA is reviewed in its entirety with short-listed vendors.[108]

With respect to DERC's concern regarding a potential unfair advantage by the Companies over third-party aggregators in

---

[106]HECO's Reply SOP at 13.

[107]HECO's Reply SOP at 13-14.

[108]HECO's Reply SOP at 14.

subscribing DR customers, the Companies "reiterate that they do not have any plans to bid against third-party providers to provide specific DR products or services at this time."[109] The Companies commitment does not apply to engagement with self-aggregators, however.[110]

In response to DERC's concern that individual enrollment might hinder or interfere with third-party aggregator efforts to recruit new customers, the Companies are amenable to DERC's proposal that they not provide a direct enrollment option in the first year of the program, and that the Companies intend for third-party aggregators to be the primary mechanism by which to enroll customers in DR programs at this time.[111] That said, the Companies also intend to ensure that deployment targets for all market segments are met. Accordingly, the Companies may direct-enroll customers for specific market segments, where the Companies "do not receive acceptable or sufficient aggregator proposals to provide grid services, or are not able to come to terms with an aggregator on a contract."[112] As suggested by DERC, the Companies intend to serve as a backstop for any market segments

---

[109]HECO's Reply SOP at 15.

[110]HECO's Reply SOP at 15.

[111]HECO's Reply SOP at 15.

[112]HECO's Reply SOP at 15.

where third-party aggregators have recruited customers but where gaps remain in procurement targets.[113]

In terms of the envisioned market structure, the Companies reiterate that third-party aggregators will not directly subscribe to the tariffs (rules, rates or riders) filed in connection with the Revised DR Portfolio.[114] Aggregators will have the opportunity to engage in a GSPA, which are contracts that are subject to the rules of the grid service tariffs and other technical requirements, but not the riders or rates themselves. The rates and riders are designed only for direct Company-administered DR programs, wherein the Companies directly market, recruit, enroll, enable, and manage customers' devices to deliver the specific services.[115] The values published in the riders are indicative of the incentive levels that customers will receive for services. This does not reflect the entirety of value to be paid to aggregators for the delivery of services, but rather reflects in some form the portion of that value that is expected to be paid to customers.[116]

---

[113]HECO's Reply SOP at 15.

[114]HECO's Reply SOP at 15.

[115]HECO's Reply SOP at 15-16.

[116]HECO's Reply SOP at 16.

The Companies further clarify that successfully executed GSPAs may be subject to tariff modifications during the life of the contract.[117] The Companies state that "[t]he Tariff and its associated rules are anchor tenets of the Companies' Revised DR Portfolio and serve as the mechanism by which the Companies ensure DR program effectiveness, particularly in the interest of the customers."[118] Accordingly, any substantive changes made to the grid service tariff rules, and, consequently, the Riders, may impact GSPAs in place between the Companies and aggregators. That said, the Companies state an intention that the GSPA will be "crafted in a manner that contemplates and accommodates potential modifications to the Tariff, affording aggregators a greater sense of how Tariff modification may impact performance under the contract."[119]

Finally, in response to DERC's assertion that the Companies should not reduce DR tariff rates if customers or aggregators receive rebates or renewable energy tax credits, the Companies state that they do not intend to reduce the value of services or the associated incentives or payments made to customers or aggregators in response to external rebates or credits.

---

[117]HECO's Reply SOP at 16.

[118]HECO's Reply SOP at 16.

[119]HECO's Reply SOP at 16.

2. Evaluation, Measurement, and Verification

In response to some concerns expressed by DERC, the Companies state a need to clarify the difference between EM&V and measurement and verification ("M&V"), as "DERC appears to be conflating evaluation of the DR portfolio for program impact, implementation, and effectiveness review, with M&V for aggregator performance and settlement."[120]

The Companies intend to engage an EM&V consultant to help define a detailed plan to both perform impact and program evaluation on the entire portfolio, and M&V for aggregator performance and settlement.[121] This plan will identify the processes, data requirements, and analysis methodologies necessary to conduct both DR portfolio evaluation and M&V for aggregator performance and settlement.[122] Based on the plan, the Companies intend to hire an independent third-party evaluation expert to conduct an overall DR portfolio evaluation, grid service by grid service. This is intended to be a post-program deployment

[120]HECO's Reply SOP at 18.

[121]HECO's Reply SOP at 18.

[122]HECO's Reply SOP at 18.

exercise, and potentially could start as early as six to eight months after initial deployment.[123]

With respect to M&V for aggregator performance and settlement, the Companies intend to establish standards for settlement that will be consistent among the Companies and aggregators and will help to address DERC's concern about possible market friction if the Companies and aggregators come to different conclusions on M&V.[124]

In response to LOL's critique that, absent full smart meter deployment, the DR programs will only be available to those customers already participating in the energy transition, the Companies clarify that all proposed DR programs will launch within the next three years as proposed in Revised DR Portfolio and are expected to be advanced absent an island-wide blanket Advanced Metering Infrastructure ("AMI") deployment.[125]

3.

Benefits and Costs

The Consumer Advocate recommends reconsideration of the frequency by which "course correction" for incentive changes

[123]HECO's Reply SOP at 18.

[124]HECO's Reply SOP at 18.

[125]HECO's Reply SOP at 19.

occurs, given its concern that the Companies may be focused solely on customer uptake rather than cost-effectiveness.[126] The Consumer Advocate also reiterated its assertion that the commission should not make a decision based on partially-developed support.[127] The Companies indicate that while it is possible to modify the incentives, the Companies will continually assess the cost-effectiveness of its DR programs. The Companies also outline an illustrative list of events that necessitate programmatic course correction:

- PSIP Update Report: December 2016 - Remove programs if programs are no longer cost-effective, or add programs if new service needs are identified and/or cost-effective substitution is available.

- New Grid Service Requirements - Update tariffs with new requirements or establish new tariffs as new services emerge.

- Enrollment Rate - In a cost-effective manner, increase or decrease incentives to meet targeted DR potential.

- EM&V Results - If achievement does not meet planning goals, portfolio sizing would need to be adjusted and cost-effectiveness reassessed.

- Actual Costs - Budget will increase or decrease depending on actual costs.[128]

---

[126]HECO's Reply SOP at 20.

[127]HECO's Reply SOP at 20.

[128]HECO's Reply SOP at 20

The Companies indicate that any "course corrections" to incentive levels could be made even as the DR program is being administered, and will always be subject to the Companies' evaluation and commission approval of the cost-effectiveness of the DR programs. Therefore, it is not necessary, and would be counter-productive, to delay implementation of the DR programs as suggested by the Consumer Advocate.[129]

With respect to the alteration of incentive levels, the Companies state that such alterations would most likely occur within the first three years of the DR Portfolio. The Companies submit that customer uptake is still an important metric in the incentive levels and that the Companies' current DR programs, which have demonstrated that targeted capacity goals can be met with the proposed incentive levels, are a good proxy for their future programs.[130]

The Companies further state that they are committed to executing the best grid service resource that is beneficial to all customers. In order to fully realize the benefits, the Companies maintain that an EM&V must be performed against the implemented

---

[129]HECO's Reply SOP at 21.

[130]HECO's Reply SOP at 22.

DR Portfolio. The Companies will use a three-step cyclical process to assist in the realization of benefits.[131]

First, the Companies will operationalize DR-provided services by delivering the services (in amounts consistent with planning assumptions) to system operators in a manner that is familiar and useful relative to conventional practices.[132]

Second, the Companies will measure and verify that these services were actually delivered to operators and utilized. In other words, the EM&V process will determine if targeted levels of services were achieved.[133]

Third, the Companies will provide the planning team with the actual achieved levels of service such that this information can be used to refine and modify ongoing planning efforts.[134]

Once this three-step process is verified through iteration, the Companies will be able to verify the benefits realization of DR that flow back to customers.[135]

---

[131]HECO's Reply SOP at 23.

[132]HECO's Reply SOP at 23.

[133]HECO's Reply SOP at 24.

[134]HECO's Reply SOP at 24.

[135]HECO's Reply SOP at 24.

4.

DR Portfolio Implementation

The Companies express agreement with several of the Parties in that the interrelation, of rule, rider, and any contract agreement associated will have to be clearly articulated for enrollment. The Companies state that they will be putting additional effort into customer outreach and education to help support marketing and recruitment. Furthermore, this is assumed to be within the scope of aggregator contracts; the Companies will support this activity as well.[136]

V.

DISCUSSION

A.

Overview and Context

As the electric utility network continues to transform from one defined by central station generation and one-way power flow to a system in which there are thousands of DERs and multi-directional power flows, there is an emergent and increasing need to ensure that these new resources are able to play an integral role in the functioning of the network. Indeed, the commission has previously issued guidance regarding the

[136]HECO's Reply SOP at 25.

transformation of each island's transmission and distribution grids into "modern, advanced electrical networks that are capable of integrating greater quantities of customer-sited distributed energy resources" and expanding the array of energy options for customers to manage their usage.[137]

The commission observes that the overall strategic and conceptual direction of the Revised DR Portfolio is aligned with past commission guidance and is consistent with an approach that embraces the utility's increasing role as an energy network systems integrator and operator. Historically, DR has been confined to applications related to load shifting or system peak reduction. The industry has increasingly recognized that advanced DR can also provide emergency grid services and help to facilitate further integration of variable, renewable resources. The grid service tariff structure developed by the Companies in the Revised DR Portfolio provides a foundational, extensible market structure tied to system costs and requirements. This approach advances the Companies' efforts beyond traditional notions of DR to the provision of grid services more broadly, representing a significant next phase in the development of a participatory electric grid. Permitting customer-sited and non-traditional resources to become folded into energy network operations through

[137]Order No. 32052, Exhibit A, at 3.

the provision of grid services can cost-effectively increase system reliability, while enabling further integration of DER and other renewable resources, marking a critical step towards achieving the State's energy policy and goals.

B.

Tariff Structure

Upon review of the tariff structure framework, the commission is supportive of the Companies' approach. The tariff structure appears to be sufficiently comprehensive and flexible to enable the successful deployment of a robust, cost-effective DR program portfolio. The commission observes that there are benefits to having the individual service and programs in different tariff documents as compared to having only one tariff for all of the services and programs. The separate tariffs should avoid confusion and mitigate the need for significant revisions in the future.

In sum, as proposed, the tariff structure framework should provide an extensible foundation that can be expanded to include the creation of additional grid service tariffs, for instance, distribution-level services, as well as for the development of additional riders where necessary and appropriate.

C.

Grid Service Rules

The HECO Companies propose four grid service tariffs that are delineated by the grid services defined in the Companies' IDRPP Supplemental Report. The grid service tariffs include the Capacity Tariff, the FFR Tariff, the Regulating Reserve Tariff, and the Replacement Reserve Tariff. As discussed above, each grid service tariff will have a published rule. The rules are articulated in the Revised DR Portfolio and illustrated, at a summary level, in Figure 1 above. Each rule defines the grid service, identifies the value of the grid service, and includes service agreements to be used for the standard enrollment process of customers.

Although some questions persist, particularly for those aspects of the rules that the Companies have acknowledged require further refinement and finalization, the commission finds that the proposed grid service rules appear reasonably defined in a technology-neutral manner. That said, regular monitoring and review of the DR Portfolio implementation will be critical to the success of the program and may well reveal the need for modifications to the grid service rules.

1.

<u>Riders and Rates</u>

The riders and rates that pertain to the grid services outlined above provide the specific rules of participation that an individual customer shall abide by to provide a grid service under the applicable tariff in order to either receive an incentive payment from the Companies or pay varying energy prices depending on time of day and system conditions. As mentioned above, each rider is associated with a particular class of customer and mechanism, or program, by which the customer participates in a grid service tariff.

It is possible for multiple riders to reference the same grid services rule, and it is possible for a rider or rate to be used in conjunction with other riders as specified in each applicable rider. Rates, however, cannot be combined with other rates, but can be combined with other riders. Practically, this will allow a customer to participate in multiple programs to provide multiple grid services to the Companies. Table 2, above, identifies the compatible riders and rates that can be utilized by customers simultaneously to provide multiple grid services to the Companies using a single resource. According to the Companies, a customer can provide non-compatible service simultaneously using different resources given that each resource is metered individually.

The commission notes that such an approach to grid service provision may be suboptimal or overly restrictive in some cases, in that the restrictions may not necessarily reflect the capability of the resource, but rather reflect product definition, contracting, settlement, or programmatic design limitations. Nonetheless, the commission acknowledges that such restrictions may be reasonable, for purposes of administrative simplicity, at the outset of program implementation. Over time, the commission expects that grid service definitions and the overall DR Portfolio will be designed to make the best and highest use of resources and capabilities, while at the same time ensuring that customers do not pay for resources that are not available or will not materialize when needed.

The Revised DR Portfolio, Attachment E, contains riders specific to the DR programs proposed by the Companies and intended for immediate implementation. The Companies have indicated that a future filing will request approval of DR Programs and their associated riders and rates prior to their implementation.

The Companies state that for resources other than those stipulated in the DR Portfolio, such as solar PV resources with advanced inverters, other riders may be formulated in the future to permit customers to provide grid services to the Companies under the grid service tariffs presented in the instant application. The commission stresses the importance of developing additional riders in the near-term to permit resources to provide grid services through means other than solely load redactor to the Companies under the grid service tariffs currently articulated, as well as additional grid service tariffs that may be developed in the future.

2.

Aggregation and Third-Party Procurement Process

For aggregator provided programs, riders do not apply, as the Companies will directly contract with aggregators through UA contracts (the GSPA being the primary turn-key contract) to provision the various grid services under the grid service tariffs. These contracts will reference and comply with the rules associated with each tariff and are likely to include many of the requirements for each customer class as specified in the applicable rider.

For resources other than those stipulated in the DR Portfolio, for example, for solar PV resources with advanced inverters, aggregators would sign separate UA contracts to provide grid services using other resources. Alternatively, an aggregator could use multiple types of resources to provide grid services under the same contract. The details, such as pricing and capacity of grid service would be subject to a procurement and negotiation between the Companies and the aggregator.

The Companies' proposal is commendable for its intent to establish, consistent with past commission guidance, a new market for aggregated DR services and to take advantage of the ability of innovative third-parties to deploy new customer-sited solutions. The commission notes that both the HECO Companies and third-party service providers have expressed interest in getting programs underway and improving over time, rather than delaying implementation to develop more formal market structures. The commission supports this approach and emphasizes the need to continue implementation in order to gain invaluable experiential learning for iterative program improvement.

With respect to longer-term programmatic refinements, the commission observes that formal market structures for procurement of resource commitments, as compared to limited RFP processes and bilateral contract negotiation, can offer potential for more cost-effective resource procurement, ensure adequate resources in times of scarcity, and create opportunity for new market entrants to offer value through innovative services. Recognizing that market development will take time, the commission issues the following guidance for future development of more formal market structures.

Formalized market structures. The Companies have already short-listed vendors based on their 2015 RFP for grid services, and intend to execute bilateral contracts with vendors to acquire a portfolio of aggregated resources to meet program targets. Many features of these contracts (e.g., contract term, milestone payments, performance factor calculations) will be standardized through the grid services purchase agreement (GSPA), but others will be subject to bilateral negotiations (e.g., pricing, relative availability by time of day). The commission acknowledges that sufficient market participation is a prerequisite to the establishment of formalized market structures, but observes that wholesale markets in other jurisdictions, characterized by uniform price auctions with demand and offer curves, support more efficient price discovery than bilateral negotiation. Setting a transparent clearing price also communicates a value signal to other vendors, encouraging them to develop new solutions whose cost is below the market clearing price.

Time-period differentiation. The Companies' proposed approach is for aggregators to individually supply a grid service availability forecast for every hour, implying that the Companies will need to compile a portfolio of aggregated resources that add up to the total system requirement at different times of day. Recognizing that most resources have varying ability to respond to DR events throughout the day, this approach risks oversubscribing resources during periods of abundance, or undersubscribing resources during periods of scarcity. Contracting separately for resource commitment at different periods of day and seasons, with clearing prices specific to each time period, again allows more efficient and precise price discovery. During periods of resource scarcity, prices can be higher, encouraging greater resource participation and providing a market signal for new entrants capable of providing grid services during those times. In turn, during periods of resource abundance, prices can be lower, ensuring a more cost-effective program.

Procurement frequency and openness to new entrants. The Companies intend to launch proposed programs with aggregators from among the vendors short-listed in the 2015 RFP, then release rolling RFPs as needed to fulfill capacity targets. The Companies proposed contract duration is five years. While this approach may be effective in providing vendors with the certainty needed to launch a new market, in the long-term the market may be better served by a regular schedule of recurring RFPs for predetermined capacity volumes. As proposed, if grid service targets are fulfilled from among the short-listed vendors, new vendor entry may be effectively restricted for five years. Future evolution could include a predictable and recurring procurement volume and frequency (e.g., 20% of program capacity procured every year for five-year contracts). This maintains the certainty associated with long-term contracts while creating flexibility for innovative new entrants to join the market.

D.

Grid Services Purchase Agreement

The commission notes that it has only had the benefit of a preliminary review of the Companies' proposed GSPA at this time. That said, at a high level, the commission stresses the importance of an equitable and competitive marketplace for grid services and echoes Parties' concerns related to the Companies potentially having an unfair advantage over third-party aggregators in subscribing DR customers. The commission underscores that the preference is for third-party aggregators to be the primary mechanism by which to enroll customers in DR programs at this time. To that end, the GSPA represents the foundational market structure for procurement of grid services from third-party aggregators.

The Companies' have articulated a timeline whereby the Companies receive feedback from stakeholders and submit a, presumably revised, standard GSPA for commission review in March 2018.[138] The Companies do not propose moving forward with final selections from the short-listed vendors from RFP # 06175-02 until eight weeks after commission approval of the GSPA.[139] Realistically, this would place final selections made for RFP # 06175-02 no earlier than August 2018.

---

[138]Draft GSPA Filing, Exhibit 4, at 2.

[139]Draft GSPA Filing, Exhibit 4, at 3.

After an initial review, the commission has some questions and concerns related to the Companies' proposed GSPA. In particular, there is concern that the GSPA may be overly restrictive and burdensome for many market participants. The commission observes that California has designed and implemented a Demand Response Auction Mechanism ("DRAM"), which is a pay-as-bid auction where California investor-owned utilities ("IOUs") seek monthly DR system capacity, local capacity, and flexible capacity. The attendant DRAM Purchase Agreement is a standard form contract, akin to the Companies' proposed GSPA, between DR aggregators or providers and the IOUs. The commission notes that the DRAM Purchase Agreement would appear to embody a less burdensome, more streamlined approach.

The commission strongly supports the need to meaningfully engage stakeholders and market participants and to incorporate their feedback with respect to necessary modifications to the proposed GSPA. That said, the commission does not find it necessary, at this time, to delay moving toward the Best and Final Offer ("BAFO") stage with the short-listed vendors until after commission approval of the GSPA. To the contrary, the commission expects that there will be material value in moving forward and leveraging experiential learning in these early stages to inform requisite changes to the proposed GSPA. Thus, the Companies are directed to move forward with conducting a robust stakeholder engagement and review process as articulated in milestones 23 through 25 in Exhibit 4 of the GSPA filing.[140] Informed by stakeholder and market participant comment and feedback, the commission expects the Companies will revise the GSPA as necessary and appropriate before soliciting the BAFO from the short-listed vendors.

The commission determines that in the interest of expeditiously advancing this nascent market and achieving early learnings through implementation, commission approval of the proposed GSPA is not required before the Companies make final selections for RFP # 06175-02, with contract execution completed no later than June 2018. This should permit vendors to conduct customer acquisition in the third quarter of 2018.

The commission strongly suggests that the Companies file a second, revised GSPA, sometime in the March 2019 time frame, informed by feedback from stakeholders, prospective market participants, and the experiential learning gained from executing agreements with short-listed vendors from RFP # 06175-02. A more formal, deliberative process would commence at that time, consistent with the proposed approach outlined in milestones 26 through 31 in Exhibit 4 of the GSPA filing, with the clear objective of having an approved GSPA in place by the end of 2019

[140]Draft GSPA Filing, Exhibit 4, at 2.

in advance of the Companies' second RFP issuance, which is expected to begin within 18 months of the initial awards.

E.

Cost-Effectiveness

The HECO Companies analyzed the costs and benefits for the DR Portfolio using the Portfolio Administrator Cost ("PAC") test, which compares capacity and fuel savings with utility portfolio costs.[141] A value greater than one indicates that the life-cycle fuel and capacity savings exceed the life-cycle portfolio costs. A value greater than one also indicates that the net present value of revenue requirements will be reduced.[142]

The Companies' analysis demonstrates that the DR Portfolio for all island programs is expected to be cost-effective with PAC test results greater than one, which indicates that the benefits to all customers, both participants and non-participants, outweigh program costs. The total Demand Response Management System ("DRMS") cost is allocated to Oahu's total cost within the analysis and yet still yields a benefit-cost ratio well above one.[143]

---

[141]Revised DR Portfolio, Attachment F, at 21.

[142]Revised DR Portfolio, Attachment F, at 21.

[143]Revised DR Portfolio, Attachment F, at 21.

The commission commends the efforts to date and instructs the Companies to continue moving toward deployment of the DR programs consistent with the Revised DR Portfolio. As demonstrated by the cost-benefit analysis included in the Revised DR Portfolio, a robust DR Portfolio should provide net benefits to all customers. Given the expected value to both participating and non-participating customers, as well as the potential for DR to enable DER to assist in the reliable operation of the energy network to help facilitate further renewables integration, the commission continues to support expeditious DR program implementation.

F.

Cost Recovery

The HECO Companies include several requests in their Revised DR Portfolio pertaining to cost recovery. These requests include the following:

1. Continued use of the DSM Adjustment component of the IRP cost recovery provision for the collection of DR Portfolio variable costs until such costs are approved and reflected in the Companies' respective base rates;

2. Establishment of the DRAC as a new component of the IRP cost recovery provision for purposes of reconciling actual Revised DR Portfolio variable expenditures to Revised DR Portfolio variable expense elements embedded in the Companies' respective base rates as a result of general rate cases;

3. Treatment of [GSPA] contract(s) as variable program costs for purposes of cost recovery through base rates, the DSM Adjustment, and/or the DRAC, as applicable; and

4. Request to review and approve the implementation costs of the Revised DR Portfolio and related cost recovery mechanisms in the instant docket, notwithstanding that the same requests are included in HECO's 2017 test year rate case in Docket No. 2016-0328.

The following sections address each of the above requests in turn.

1.

Continued Use of DSM Surcharge

The HECO Companies request to continue using the DSM Surcharge to recover prudently incurred costs until the commission approves the DR Portfolio budget in base rates during the next set of respective rate cases. The Companies have rescinded their original request to recover incremental costs through the REIP Surcharge.

The recovery process for variable DR program costs would be akin to the existing recovery in the DSM Adjustment for MECO and HELCO. Approved variable program costs will determine the rate for the DSM Adjustment and will be reconciled against the actuals.

The following are other specifications outlined in the Revised DR Application:

- All program costs will be separated into two DSM adjustments: (1) residential and (2) commercial and industrial;

- Interest expense will be attributed to the cumulative net difference between revenues and costs each month at the rate of return on rate base approved in each Company's respective most recent rate case; and

- MECO and HELCO propose to increase the frequency of reconciliation under the DSM Adjustment to quarterly.

The commission agrees, in principle, with the Companies' need to recover prudently incurred DR program costs, consistent with established regulatory ratemaking principles, that are required to stand up, expand, and maintain the proposed DR programs. More specifically, the commission acknowledges that there is value in the use of a surcharge to account for variations with respect to customer incentives depending on the frequency of "dispatch" of DR resources, and insofar as the utilization of a surcharge can help place DR resources on equal footing with traditional resources from an accounting perspective. This is particularly true during the enrollment and expansion phase of DR Portfolio implementation, since DR program costs could vary substantially as program costs will depend upon the actual customer participation levels, which will be somewhat unpredictable at the outset.

For these reasons, the commission approves the use of the DSM Adjustment to recover prudently incurred DR program variable costs prior to commission approval of base rates that include the proposed total DR program costs. As the Companies indicate, it is expected that implementation of the DSM Adjustment mechanism will vary by Company.

The commission further approves of a quarterly DSM Adjustment reconciliation due to the expected magnitude of the variable DR program costs.

The Companies shall modify the DSM Adjustment section of the IRP Cost Recovery Provision and submit revised tariffs, consistent with the Companies' request in the Revised DR Application, for commission review and approval.

2.

Establishment of Demand Response Adjustment Clause

As stated previously, during the enrollment and expansion phase of DR portfolio implementation, DR program costs may vary substantially because program costs depend upon customer participation levels, which is unpredictable, especially given that the Companies' DR programs will be new to the market. Specifically, program cost variability is driven by the rate of enrollment of, enablement of, and ongoing incentive payments to program participants.

In recognition of this inherent variability and in the interest of conformity with the spirit of the commission's recommendation to utilize the Revenue Balancing Account ("RBA"), the Companies have proposed the creation of a DRAC. The DRAC is proposed to accommodate the uncertainty of variable costs incurred to launch and grow the DR programs. The DRAC defines variable costs to include expenses incurred to procure and install participant devices, expenses to provide grid services, incentives to program participants, and advertising and marketing expenses as specified in Attachment F of the Revised DR Application. Specifically, the DRAC would enable the reconciliation of the level of variable costs for DR programs established in an approved rate case's revenue requirements against those variable costs actually incurred in the operation of DR programs. Ultimately, the objective is to operate within the overall variable cost budget, relying on the DRAC as a means to true-up and accommodate a non-static incurrence of variable costs.

Notwithstanding this objective, the commission is cognizant of the importance of controlling costs within each budget cycle. With respect to a DRAC mechanism, the commission will review the prudency of any costs included in the DRAC that increase significantly from test-year estimates in base rates. As greater experience is gained and sufficient data exists, the commission expects to explore establishing a specified percentage threshold, above which a prudency review would be automatically triggered.

The DRAC mechanism is proposed to be included as a new section in the IRP cost recovery provision in order to avoid adding a new line item to the customer's bill, which is how the DSM Adjustment is also reflected in the tariff and on the customer bill. The Companies will modify the IRP cost recovery provision to include a DRAC section.

The commission approves, in principle, the creation of a DRAC mechanism to reconcile and pass through the difference between actual DR variable costs and the amount of DR variable costs included in base rates. As proposed, the Companies shall establish separate DRACs for residential programs and for commercial programs for each utility division, and also propose quarterly reconciliations of actual variable program costs versus the prorated rate case variable cost amount, across all programs. Interest expense will be attributed to the cumulative net difference each month at the rate of return on the rate base approved in each Companies' respective most recent rate case, which is the same method of interest calculation that the DSM Adjustment reconciliation employs.

The commission directs the Companies to submit revised tariffs detailing the design and operation of the proposed DRAC mechanism for commission review and approval. At the outset, the frequency of reconciliation shall be quarterly, as proposed; however, the commission intends to review the true up frequency as the DR Portfolio expands and matures as a program and as the Companies' costs become more predictable.

The commission expects the Companies to track and report through the reconciliations the overall variable spending to ensure transparency regarding DRAC operation. In addition, as discussed below, the commission stresses the importance of transparently accounting for benefits realization. The commission directs the Companies to provide a plan for benefits realization for commission review, in the 2018 M&E Report.

3.

Request to Review and Approve Implementation Costs

The Companies categorize the allowable incremental costs for which they request recovery into three types: (1) incentives, (2) materials, and (3) outside services.[144] The Companies further define the relevant cost categories to include, but not limited to, the following:

a. amounts which are directly paid to customers;

[144]Revised DR Portfolio, Exhibit 1, at 45.

b. aggregators or outside service providers;

c. costs for customer equipment;

d. customer installation;

e. customer incentive payments;

f. costs for the procurement of grid services provided by third-parties to customers;

g. costs for advertising and marketing.

The HECO Companies state their belief that these cost categories are required to launch, grow, and maintain the proposed DR programs. The Companies express concern regarding the variability of incurred program costs because customer participation levels are unpredictable and time is required to adequately evaluate DR program execution to refine program budget accuracy until sufficient experience has been gained through implementation of the DR Portfolio.

The commission is inclined to approve cost recovery for reasonable and prudently incurred costs associated with the DR Portfolio, including, as noted above, the use of appropriate surcharges and reconciliation adjustments to provide for timely recovery of such DR Portfolio costs. At this stage, however, it is premature to grant any cost recovery beyond the use of specific cost recovery mechanisms.

With respect to costs the Companies propose are eligible for reconciliation through the DRAC mechanism, the Companies need to provide more information regarding the cost categories they decided to include in the Revised DR Application. The Companies state that variable costs are deemed to be expenses incurred to procure and install participant devices, expenses to provide grid services, incentives to program participants, and advertising and marketing expenses, but the commission still lacks sufficient clarity pertaining to these expense categories, including which of these categories fall into their three major groups of costs: incentives, materials, and outside services.

Although the Companies correctly note that in Order No. 32054 the commission suggested the use of the RBA mechanism as a possible and appropriate form of cost recovery reconciliation, the commission made it clear at that time that the "review of revenues and expenses associated with each tariffed demand response program" would be addressed after the tariffs had been finalized and approved. By this decision and order, the commission directs the Companies to submit DR tariffs for review and approval. Because the commission has not yet approved such tariffs, and given that the magnitude and characterization of future costs remains somewhat uncertain, granting broader cost recovery is inappropriate at this time.

4.

Benefits Realization

The commission notes there is a need to provide further analysis on the realization of benefits to customers as a result of DR program implementation. The benefits to customers are expected to fall into one of the following categories: (1) fuel; (2) operations and maintenance ("O&M"); and (3) capital savings. As the Consumer Advocate has observed, the Companies do not provide a detailed explanation of these prospective savings and how they will flow through to customers. The Companies do mention the potential for fuel savings to be realized through the energy cost adjustment clause ("ECAC"); however, understanding all the potential benefits to customers and through which mechanisms they will flow is essential to ensuring the success of the DR program.

In the Revised DR Portfolio, the HECO Companies state that they will provide a methodology and plan for benefits realization in a future M&E Report, which is filed in or around November of each year. The commission directs the Companies, in the 2018 M&E Report, to provide a thorough outline or accounting of all potential benefits and how the Companies plan to ensure those benefits flow through to customers.

G.

Evaluation, Measurement, and Verification

The HECO Companies appropriately recognize that the DR programs will require ongoing evaluation and refinement based on the experience gained after program launch. To support this program evolution, the Companies request approval of a reporting structure that includes an annual Company-sponsored M&E Report, and a three-year EM&V cycle. Internal review and reporting by the Companies will be essential and, generally, the commission finds that the proposed reporting structure is reasonable and provides sufficient transparency and timely updates to inform the relative success of the DR program.

That said, the commission notes the importance of independent program evaluation and, in particular, an objective accounting of DR program benefits and how/whether they are realized by customers. To that end, in the future, the commission may consider the use of independent oversight and monitoring to evaluate program design and results with attention to market competitiveness and consumer interests, among other objectives.

In addition, in response to concerns raised by DERC, the commission supports an expansion of the M&E Report to include, when appropriate, a forward-looking review of the DR capacity analysis for all islands, beginning with the 2019 M&E Report.

H.

DR Portfolio Implementation and Further Guidance

The HECO Companies' proposed DR Portfolio presents a promising opportunity to unlock new value from customer-sited resources, share value with customers, and encourage the evolution of a flexible energy system necessary to achieve the State's energy goals. The proposed DR programs are trailblazing for their breadth and attention to advanced services from DER, including ancillary service products and an evolution toward real-time pricing. The commission recognizes the need to move forward with cost-effective program implementation, but fully expects that, given the nature of this industry-leading effort, adjustments and refinements will need to be made as hands-on experience is gained by the Companies, aggregators, and participants.

It is in this spirit of continuous improvement and "learning-by-doing" that the commission highlights the following areas for further consideration and potential course corrections going forward.

1.

Program Strategy

Implementation on Neighbor Islands. The commission notes that, as proposed, the DR Portfolio is not expected to be meaningfully rolled out for islands other than Oahu until the second year of the program. The commission emphasizes the need to prudently and expeditiously achieve DR program roll out on all islands, particularly given that the Companies' analysis has shown that the DR Portfolio is cost-effective across all islands. The failure to do so will continue to result in missed cost savings opportunities for customers.

Short-lived programs. Specific aspects of the Companies' DR Portfolio strategy raise concerns that may require clarification as part of the ongoing DR program evolution. More specifically, NSAR, DALS, CPI-C, and TOU are all planned to end after 2019 and migrate to RTP. Such an approach presents the risk that valuable grid services will be discontinued without sufficient replacement, to the detriment of the customer value proposition and the overall energy system. Many customers enrolled in these programs may choose not to transition to RTP, and even to the extent they do, RTP may not offer the same grid service as the discontinued program. For example, NSAR provides a 10- and 30-minute reserve and can be called in response to a contingency event; RTP prices would be set on a day-ahead basis and thus be incapable of serving a contingency reserve function. Clarification from the Companies is needed to illuminate how the contingency service provided by NSAR will be provided following that program's retirement in 2020.

Similarly, TOU rates provide an important option for customers to shift load out of the evening peak and into the mid-day period. It is likely that some customers willing to enroll in TOU would choose to revert to Schedule R rather than transition to the more complex and dynamic RTP rate, so if TOU retires in 2020, the number of customers on time-varying rates could well decline.

In sum, the Companies' proposal to retire three programs, particularly, NSAR, DALS, and TOU, after 2019, may leave the Companies' energy systems lacking valuable resources, while targeted impacts for RTP would appear ambitious. The commission directs the Companies to closely evaluate their strategic approach with respect to these programs and to make modifications as conditions require.

Programs closed to new enrollment. The commission observes that NSAR and CPI will not be available for new participants, but rather limited to migration of customers on existing DR programs. Existing DR programs have sufficient enrolled capacity to meet NSAR and CPI targets if migrated, so if programs are indeed retiring after 2019, this may be appropriate. Closing these programs to new enrollments, however, lowers the potential value for customers who may enroll in both FFR and NSAR concurrently, and would make the customer economics less attractive. Should the Companies determine there is a need to extend the lifetime of NSAR and CPI, the commission suggests that such programs also be opened to new customer enrollment.

Real-time Pricing (RTP) targets. The Companies state ambitious "targeted impacts" for RTP programs, including forecasted Oahu residential RTP capacity of 42 MW in 2020 and 75 MW in 2025.[145] At an estimated 0.79 kW reduction potential per customer, this implies 53,000 residential customers enrolled in 2020, or approximately 20% of Oahu households, and 95,000 in 2025, or approximately 35% of Oahu households. The commission firmly supports the value an RTP rate can provide in sending time-varying price signals to shift load. That said, such aggressive targets require further detailed plans from the Companies as to how customers will be encouraged to enroll in new rates, and in particular, what role default or opt-out may play in the future of rate design.

Market Structure and Procurement Considerations. Over the longer-term, the commission observes that more formalized market structures for procurement of resource commitments, as compared to more limited RFP processes and bilateral contract negotiation, may provide opportunity for more cost-effective resource procurement. The commission acknowledges that sufficient market participation is a prerequisite to the establishment of

---

[145]Revised DR Portfolio, Attachment J, at 2.

formalized market structures, but observes that wholesale markets in other jurisdictions, characterized by uniform price auctions with demand and offer curves, support more efficient price discovery, transparency, and perceived fairness than bilateral negotiation. Also of interest is whether contracting separately for resource commitment at different periods of day and seasons, with clearing prices specific to each time period, may also permit more efficient and precise price discovery.

2.

Technical and Operational Design of Programs

Overall, the Companies' proposed program rules appear to be feasible for customer participation and system operation, to be delivered via the DRMS software platform approved in Docket No. 2015-0411.[146] Several rules are unclear, however, and will need to be reviewed in the course of future program evolution.

No export provision. The Companies propose to prohibit export of energy from a customer facility, unless that customer is permitted to export through an existing interconnection agreement. Furthermore, the DR Portfolio does not yet allow for customers to provide grid services to the Companies through the export of

[146]See In re Hawaiian Elec. Co., Inc., Hawaii Elec. Light Co., Inc., Maui Elec. Co., Ltd., Docket No. 2015-0411, Decision and Order No. 34884, filed October 18, 2017.

energy. The Companies recognize the potential and value associated with the delivery of grid services via export[147] and note that "[n]ot permitting export could result in limitations in the ability of DER customers to deliver needed grid services, particularly customers with behind the meter storage capabilities, including EV customers."[148] The commission agrees that a prohibition on grid service delivery via export would significantly limit the grid service value available from customer-sited energy storage during DR events. As a reference, a Tesla Powerwall 2 battery is capable of 5 kW power output, well above the typical average customer load of approximately 2.8 kW. If this customer's resource were called to provide a grid service such as FFR, Regulating Reserve, or NSAR, its actual response would be limited to serving the local facility load at any given instant (i.e., 2.8 kW on average) rather than the full 5 kW capability of the device. The Companies identify the need for additional work to identify potential challenges, technical requirements, and value associated with export functions.

The commission directs the Companies to develop the capability to allow export during DR events as a near-term program improvement. While acknowledging the outstanding uncertainty

[147]HECO Companies' Response to PUC-IR-105(a), at 1.

[148]HECO Companies' Response to PUC-IR-105(a)(iv), at 3.

around technical requirements associated with DR resources providing export, the commission highlights this issue as a near-term need to gain maximum cost-effective benefit from DR resources.

Other proposed technical requirements. Given other proposed technical requirements, including: the requirement that each resource be separately metered should a customer wish to provide non-compatible service simultaneously using different resources; the 6-hour redeployment period for FFR, NSAR and CPI-C; and, 30-minute participation requirement for FFR, the commission is concerned with the relative need for service availability in balance with potential limitations or value erosion that these requirements could impose on customers. The commission observes that uncertainty persists for the relative need and consequences of these rules, and that there may be opportunities to revise rules in some cases to improve customer value and resource participation without significant loss of resource performance. The commission acknowledges the Companies stated intention to make limited revisions and clarifications to some rules, while monitoring other issues for possible future updates.

There is a need to identify technical resource requirements for ongoing evaluation and program improvement. Performance requirements such as 6-hour redeployment following DR events and 30-minute FFR participation may offer opportunity for future improvement, and should be reevaluated with the benefit of program experience.

VI.

STRATEGIC ALIGNMENT

The Revised DR Portfolio as envisioned by the HECO Companies is critical to the State's renewable energy future, as it will play a central role in fostering economic and technical means by which customers can use their own equipment and behavior to have a role in the management of the electricity grid. The Revised DR Portfolio will simultaneously promote grid flexibility and reliability while offering customers increased choice and economic benefit.

Given the importance of these efforts, the Companies state their support for the continued coordination and alignment of the DR Portfolio across various interrelated and overlapping proceedings. These include, inter alia: (a) Market Track of the DER proceeding (Docket No. 2014-0192); (b) integrated grid planning; (c) grid modernization (Docket No. 2017-0226); and, (d) other interrelated matters.

The commission agrees that the continued coordination and alignment of the DR Portfolio across interrelated and overlapping proceedings is critical to the success of each. To that end, in the interest of harmonizing and adequately aligning these important proceedings, the commission stresses the importance of the Companies' DR team's continued involvement in each of these efforts in order to ensure that the grid services tariff platform is sufficiently leveraged and utilized where appropriate.

A.

DER Market Track

The commission anticipates continued development of the DR Portfolio, provided that the various DR tariffs demonstrate that delivery of grid services from customer-sited resources is an efficient and reliable alternative to traditional grid management. The commission expects that the number of riders and/or grid service tariffs may well expand in the months and years ahead as the Companies extend the proposed grid service framework outlined herein. The commission also expects that the proposed DR tariffs, which currently focus solely on bulk system services, will evolve to include distribution-level services specifically tailored to contend with localized grid issues. Given this expected merging of bulk system-level and distribution-level demand response, the commission concludes there is a need to leverage the work done on the DR Portfolio to date and to integrate the grid services tariff structure into the Market Track discussion of the DER docket. The commission emphasizes the importance of the DR team in the

Companies' DER transformation initiative and stresses the need for coordination between DER programs and the grid service tariff structure to ensure proper market signals and help avoid customer and vendor confusion.

B.

Integrated Grid Planning

1.

DR-PSIP Alignment

The HECO Companies have expressed a recognition that the DR initiative, which encompasses both the DRMS and the DR Portfolio of programs, must be aligned with the PSIPs, as well as ongoing power system planning efforts in the near- and long-term. In terms of near-term alignment, the Companies' Revised DR Portfolio filing[149] has been developed in a coordinated manner with the December 2016 update to the PSIPs.[150] The portfolio optimization, avoided cost, and value of services aspects of DR Portfolio development have been completed using the myriad resource plans developed in the context of the PSIPs as the reference case.[151]

---

[149]See In re Hawaiian Elec. Co., Inc., Hawaii Elec. Light Co., Inc., Maui Elec. Co., Ltd., Docket No. 2015-0412, "Revised Demand Response Portfolio," filed February 10, 2017 ("Revised DR Portfolio").

[150]Revised DR Portfolio, Attachment K, at 2.

[151]Revised DR Portfolio, Attachment K, at 2.

The quantity and value of the underlying services that DR programs deliver, the DR programs' potential and associated costs and incentives underlying them, as well as the cost-effective levels of these programs, have been examined in accordance with the December 2016 update to the PSIPs.[152]

Specifically, the DR initiative has received, based on the DER optimization steps, a more refined target for the DER populations used in the DR Potential Study.[153] In particular, the DER populations have been determined while assuming economic impacts of TOU rates as the baseline for the DER deployments, most notably distributed storage populations.[154] Additionally, assuming these populations are in place due to pre-existing economic value, there is a cost reduction implication to the DR Portfolio, as well as the likelihood of higher acceptability rates, since the equipment is expected to already be in place.[155] These new data points have been incorporated into the Potential Study, which was re-run during the December 2016 update to the PSIPs.[156]

---

[152]Revised DR Portfolio, Attachment K, at 2.

[153]Revised DR Portfolio, Attachment K, at 2.

[154]Revised DR Portfolio, Attachment K, at 2.

[155]Revised DR Portfolio, Attachment K, at 2.

[156]Revised DR Portfolio, Attachment K, at 2.

By Decision and Order No. 34696, filed July 14, 2017, the commission, subject to the conditions set forth therein, accepted the HECO Companies' PSIP Update Report and provided guidance regarding implementation and future planning activities.[157]

Moving forward beyond the PSIP Update Report, the Companies expect to incorporate the DR Portfolio as an integrated resource within regular power system planning efforts.[158] Similar to the near-term integration with the PSIPs effort, the HECO Companies will begin with the refinement of the system needs over time as the guiding principle in defining the value for the services to be delivered.[159] With this as a foundation, the Companies intend to examine the existing DR Portfolio and modifications made during the years between planning efforts, and adjust accordingly.[160] Stated simply, the Companies expect an optimal DR Portfolio to remain an intrinsic component of future integrated planning efforts.[161] The HECO Companies further anticipate that, as a result of the cyclical planning efforts and

[157]See In re Public Util. Comm'n, Docket No. 2014-0183, Decision and Order No. 34696, filed July 14, 2017.

[158]Revised DR Portfolio, Attachment K, at 3.

[159]Revised DR Portfolio, Attachment K, at 3.

[160]Revised DR Portfolio, Attachment K, at 3.

[161]Revised DR Portfolio, Attachment K, at 3.

the impacts on the underlying system needs, the tariff rules upon which the DR programs are built may require periodic updating, either in terms of value or quantity.[162]

2.

Value of Services Methodology

A critical, animating principle of the Companies' DR Portfolio and tariff framework is the Value of Service ("VoS") approach. Stated simply, VoS is a means by which diverse resources can be assessed relative to one another. It allows for the establishment of a competitive market structure across multiple competing resources. Because no two resources are the same and each resource has different capability, as well as collections of resources having different collective capability, VoS allows for an apples-to-apples comparison of relative value to the energy system. The absence of such unified valuation has the real potential to create market inefficiencies and inconsistent assessment of resource selection.

Understanding to what degree different services will provide value to the grid over time enables a better understanding of how "unbundled" service from the HECO Companies, independent power producers, or customer assets should be valued. To this

[162]Revised DR Portfolio, Attachment K, at 3.

end, the VoS methodology is calculated by isolating a single grid service, adjusting the resource availability for that service, and identifying the change in value (avoided cost) that results. Where possible, VoS is performed independent of technology selection to minimize biases that favor one technology over another. The VoS approach provides insights as to the value of individual services to the grid, over time, for each island.

Importantly, VoS places the focus on services and not on technologies or particular types of resources. VoS can be particularly valuable in: (1) allowing planning teams to assure that near-term differences between plans will not materially impact value or composition of resources to be delivered via DR programs; and (2) assessing changes caused by broader adoption of DER such as solar PV, storage, EVs, and other flexible loads.

The commission supports the Companies' plan to further evolve and mature the VoS methodology, improve transparency of the process to stakeholders, and develop an approach such that the methodology can more broadly be applied and adopted by cross-functional departments at the Companies.

The commission agrees that, going forward, the VoS approach is a natural component or output of an iterative, integrated planning process. Accordingly, the commission directs the Companies to continue to embrace VoS as a foundational component of the Companies' future planning and procurement efforts. For the reasons stated above, application and adoption of the VoS methodology across the Companies' relevant business units should facilitate an efficient and cost-effective resource selection process.

C.

Grid Modernization

The future implementation of the DRMS, i.e., the primary delivery architecture for DR Portfolio grid services, is expected to include integration with other systems to be developed as part of the Companies' ongoing grid modernization efforts.

The commission observes that it was anticipated that the DRMS Application would interface with Smart Grid Foundation ("SGF") Project infrastructure, which was the subject of Docket No. 2016-0087. In January 2017, citing questions pertaining to renewables integration and concerns related to cost-effectiveness, the commission dismissed the SGF Project Application without prejudice and directed the Companies to develop a Grid Modernization Strategy ("Grid Modernization Strategy" or "GMS") outlining a deployment of modern grid investments pursuant to an appropriate priority and sequence, and at an optimal pace.[163]

---

[163]See In re Hawaiian Elec. Co., Inc., Hawaii Electric Light Co., Inc., Maui Electric Co., Ltd., Docket No. 2016-0087, Order No. 34281 "Dismissing Application Without Prejudice and Providing

In response, the HECO Companies have developed a GMS, the final version of which was filed on August 29, 2017.[164] The GMS highlights, inter alia, the importance of managing DR resources and other DER through a single, integrated system and notes that the functionality of the DRMS will evolve to a full DER management system ("DERMS") to facilitate the utilization of the Companies' DR programs and aggregated DER from others to manage the power system.[165]

The Companies state that the DR Portfolio will benefit from, if not rely on, key elements outlined in the GMS. In fact, the GMS effort to date has taken into account the DR Portfolio, "with a full and clear understanding of the implications of the technology roadmap to ensure synergistic alignment."[166] Thus, the Companies' GMS vision is expected to enable the DR approach described in the Companies' applications.[167]

Guidance for Developing a Grid Modernization Strategy," filed January 4, 2017.

[164]See In re Public Util. Comm'n, Docket No. 2017-0226, "Grid Modernization Strategy Report," filed August 29, 2017.

[165]Grid Modernization Strategy at 70-71.

[166]In re Hawaiian Elec. Co., Inc., Hawaii Elec. Light Co., Inc., Maui Elec. Co., Ltd., Docket No. 2015-0412, Response to PUC-HECO-IR-112, at 1, filed July 13, 2017 ("Response to PUC-HECO-IR-112").

[167]Response to PUC-HECO-IR-112, at 1.

The HECO Companies have outlined the elements of the DR Portfolio that may rely on the GMS:

- HECO's DR program devices may rely on the use of the neighborhood area network (NAN) with which to interface.
    - o These devices are controlled by OMNETRIC's Distributed Energy Management Systems (DEMS), designed to manage customer-sited distributed resources to perform both supply and demand functions.
- GMS DR portfolio management will also utilize advanced meters for DR measurement and verification of DR performance.
- Finally, as situational awareness is increasingly made available to HECO Distribution Operators, the currently procured DEMS will rely on that awareness to maximize the locational value of DERs through targeted dispatch.[168]

The Companies further state that the DR programs are being developed in coordination with the GMS and that the timing of associated applications and related decisions for both DR and GMS includes some inherent uncertainty, but that "the intent is to identify and deploy DR technologies and solutions that are in alignment with a focus on customer empowerment and choice, a safe, secure, reliable and resilient grid, integrative planning and the creation of efficient, cost-effective, accessible grid

---

[168]Response to PUC-HECO-IR-112 at 2.

platforms."[169] Moreover, critical to consideration of the DRMS Application, the Companies indicate that "if the DR portfolio were to proceed in advance of a decision on the GMS, the Companies will ensure, to the degree possible, that investments made with respect to demand monitoring will be made in accordance with the preliminary specifications and requirements as set forth within the GMS," in order to "simultaneously improve the chances of extensibility of these investments while limiting the risk of stranded assets."[170]

D.

Other Key Strategic Alignments

Electrification of Transportation ("EoT"). Electric vehicles ("EVs") play an important role as a potential DR resource. As the Companies move forward with an increasingly diverse set of sub-initiatives that constitute a comprehensive EoT initiative, the commission supports the Companies stated intent to continue assessing those sub-initiatives for alignment with ongoing DR efforts.[171]

---

[169]Response to PUC-HECO-IR-112 at 3.

[170]Response to PUC-HECO-IR-112 at 3-4.

[171]See Revised DR Portfolio, Attachment K, at 8-9.

In general, the Companies view the DR Portfolio as the mechanism through which EV charging patterns can be adjusted in order to deliver valuable grid services. The Companies' DR efforts will remain tightly coordinated with EoT efforts to ensure that these initiatives are as fully inclusive as possible.

The commission stresses the importance of aligning relevant components of the EoT initiative with the DR Portfolio and supports an approach that views the DR Portfolio as the mechanism through which EV charging patterns can be adjusted to deliver valuable grid services.

Hawaii Energy. The commission notes that the Companies have continued to formalize the strategic and tactical alignment with Hawaii Energy.[172] Although broad in scope, the Companies have initiated work specifically on the Integrated Demand-Side Management concept, whereby technologies that can provide both energy efficiency and demand response are considered. Competing technologies are assessed relative to their ability to deliver not only energy efficiency, but targeted efficiency aligned with system needs. Furthermore, these technologies are to be examined more holistically across a wide array of grid services. Trade-offs

[172]Hawaii Energy is the name given to the Public Benefits Fund Administrator. This entity, as established by the commission, is responsible for the development and administration of energy efficiency programs throughout Hawaii, and is funded via the Public Benefits Fund.

can be assessed by comparing the services each can or cannot provide.

The commission encourages continued engagement and coordination between Hawaii Energy and the Companies' DR team. As technology advances and system needs become more pronounced, the convergence between energy efficiency and demand response will increase. The Companies and Hawaii Energy should continue to explore synergistic opportunities to leverage and enhance existing and ongoing efforts.

VII.

NEAR-TERM GUIDANCE AND EXPECTATIONS

A.

DR Portfolio Launch and Implementation

The commission underscores the importance of successfully launching the DR Portfolio over the next 12 to 18 months. Pursuant to the Companies' cost-effectiveness analysis, further delay in launching the DR Portfolio would result in missed savings opportunities for all customers. In the commission's view, the critical near-term milestones are: (1) commencing programs via short-listed third-party aggregators; and (2) successfully scaling the DR Portfolio through the subsequent, open round of third-party aggregator bidding.

As previously noted, in the interest of expeditiously advancing this nascent market and achieving early learnings through implementation, the commission determines that approval of the proposed GSPA is not required before the Companies make final selections from the initial RFP, with contract execution completed no later than June 2018, which should permit vendors to conduct customer acquisition in the third quarter of 2018.

B.

Performance Incentive Mechanism

Given the importance of a successful DR Portfolio launch, the commission, over time, intends to develop performance incentive mechanisms to reward positive outcomes achieved by the HECO Companies.

At the outset, the commission intends to establish an initial, one-time performance incentive related to the timely acquisition of cost-effective DR[173] from the short-listed RFP respondents. For cost-effective MWs acquired, enrolled, and operational by December 31, 2018, the Companies shall receive a one-time performance incentive equivalent to up to 5% of the

[173]The commission defines cost-effective DR as those MWs acquired at below the Companies' avoided cost calculation on a per MW basis and/or meets the Companies' VoS methodology criteria (Cost effective MW = $/MW < Avoided Cost/MW).

aggregate annual contract value, subject to a cap of $500,000. Given that the Companies expect the DR Portfolio to be cost-effective, an incentive of this magnitude to share in the expected savings is a reasonable mechanism to reward the Companies' for successfully launching the DR Portfolio.

Longer term, the commission will consider different performance incentive(s) to inform and reward DR Portfolio outcomes. The commission intends to establish such a mechanism(s) prior to the Companies' issuance of its second RFP, which is excepted to begin within 18 months of the initial awards.

VIII.

FINDINGS AND CONCLUSIONS

Based on the above, and upon review of the record, the commission finds and concludes as follows:

A.

Tariff Structure

1. Upon review of the grid services tariff structure framework, the commission observes that there are benefits to having the individual services and programs in different tariff documents as compared to having only one tariff for all of the services and programs. The separate tariffs should avoid confusion and mitigate the need for significant revisions in the future.

2. The commission finds that the tariff structure framework should provide an extensible foundation that can be expanded to include the creation of additional grid service tariffs in the future, including, but not limited to, distribution-level system services.

3. The commission further finds that the proposed grid service rules appear accurately defined in a technology-neutral manner.

4. Thus, the commission concludes that the grid service tariff structure as proposed by the Companies, to include rate schedules and riders upon which the DR programs are to be deployed in support of the four grid service rules, is sufficiently comprehensive and flexible to enable the successful deployment of a robust, cost-effective DR program portfolio.

B.

Immediate Implementation

5. The commission finds that, by the Companies own analysis, the DR Portfolio for all island programs is expected to be cost-effective with PAC test results greater than one, which indicates that the benefits to all customers, both participants and non-participants, outweigh program costs.

6. Given the expected cost-effectiveness of the DR Portfolio, and consistent with the commission's findings above,

the commission directs the Companies to move forward with immediate implementation of rate schedules and riders for the islands of Oahu and Maui, and the staged implementation of additional rate schedules and riders by island as described in the Revised DR Portfolio.

7. Because the DR Portfolio appears to be cost-effective across all islands, the commission strongly encourages the Companies to explore how DR Portfolio implementation can be expanded and expedited for all islands.

8. The commission further approves the Companies' request to migrate participants from currently-approved DR programs or pilot programs to otherwise applicable proposed rider(s) under the grid service rule(s).

C.

Cost Recovery

9. The commission finds that there is value in the use of a surcharge to account for variations with respect to customer incentives and other variable costs, and insofar as the utilization of a surcharge can help place DR resources on equal footing with traditional resources from an accounting perspective.

10. This is particularly true during the enrollment and expansion phase of DR Portfolio implementation, since DR program costs could materially vary depending upon customer participation,

which are inherently unpredictable in the early stages of deployment.

11. For these reasons, the commission approves the use of the DSM Adjustment to recover prudently incurred DR program variable costs prior to commission approval of base rates that include the proposed total DR program costs.

12. The commission further approves of a quarterly DSM Adjustment reconciliation for the HECO Companies due to the expected magnitude of the variable DR program costs.

13. The commission also finds that it is reasonable to permit the use of a cost recovery mechanism to reconcile and pass through the difference between actual DR variable costs and the amount of DR variable costs included in base rates.

14. Accordingly, the commission approves the establishment of the DRAC as a new component of the IRP Cost Recovery Provision for purposes of quarterly reconciliation of actual DR Portfolio variable expenditures to Revised DR Portfolio variable expense elements embedded in the Companies' respective base rates as a result of general rate cases.

15. That said, the commission determines that such a cost recovery mechanism must employ safeguards and cost control measures, including a prudency review of any costs included in the DRAC that increase significantly from test-year estimates in base rates.

16. Finally, the commission finds it reasonable for the Companies to treat GSPA contract(s) as variable program costs for purposes of cost recovery through base rates, the DSM Adjustment and/or the DRAC, as applicable.

17. Notwithstanding the findings and conclusions outlined above, the commission finds that it is premature to grant blanket recovery of the implementation costs of the Revised DR Portfolio. The commission intends to address revenues and expenses associated with each tariffed demand response program after the tariffs are ultimately approved.

18. By this decision and order, the commission directs the Companies to submit grid service tariffs for commission review. Because the commission has not yet approved such tariffs, granting broader recovery for implementation costs of the Revised DR Portfolio is premature at this time.

D.

Reporting Structure

19. The commission finds that the Revised DR Portfolio will require ongoing evaluation and refinement based on the experience gained after program launch.

20. Thus, to support this program evolution, the commission approves the Companies' proposed reporting structure, including annual A&S Report and M&E Report filings.

21. The commission further approves the Companies' request to propose DR program modifications, including modifications to rules, riders, and rates outside of the M&E and/or A&S Reports, as circumstances warrant.

22. In addition, the commission finds that a three-year EM&V cycle and associated rate and rider review and refinement is reasonable and therefore approves the Companies' adoption thereof.

IX.

ORDERS

THE COMMISSION ORDERS:

1. The commission approves the HECO Companies' Revised DR Portfolio tariff structure framework, which includes the four grid service rules and the attendant rate schedules and riders upon which the DR programs are to be deployed in support of the grid service rules.

2. The commission orders the HECO Companies to begin immediate implementation of rate schedules and riders for the islands of Oahu and Maui, and staged implementation of additional rate schedules and riders by island, consistent with the guidance set forth in Section V.H.1 of this decision and order.

3. The HECO Companies shall submit the four grid service tariffs as well as any rate schedules and riders for commission review prior to implementation.

4. The commission approves the use of the DSM component of the IRP cost recovery provision for the collection of DR Portfolio variable costs until such costs are approved and reflected in the Companies' respective base rates.

5. The commission approves, in principle, the establishment of the DRAC as a new component of the IRP Cost Recovery Provision for purposes of reconciling actual Revised DR Portfolio variable expenditures to Revised DR Portfolio variable expense elements embedded in the Companies' respective base rates as the result of general rate cases.

6. Within thirty (30) days from the date of this decision and order, the commission orders the Companies to file DRAC and revised RBA tariff sheets, consistent with the guidance articulated herein.

7. Within sixty (60) days from the date of this decision and order, Parties may file comments on the Companies' filing made pursuant to Ordering Paragraph 6, above.

8. The commission will issue an order resolving any matters related to proposed tariff language following the filing of the Parties' comments described in Paragraph 7, above, and will direct the Companies to file final tariffs consistent with that order to implement the DRAC.

9. The commission approves, in principle, the treatment of variable program costs for purposes of cost recovery

through base rates, the DSM Adjustment, and/or the DRAC, as applicable.

10. The commission approves the Companies' proposed reporting structure, including A&S Report and M&E Report filings.

11. The commission approves the Companies' request to propose DR program modifications, including modifications to rules, riders, and rates outside of the M&E and/or A&S Reports, as circumstances warrant.

12. The commission orders the Companies, in the 2018 M&E Report, to provide a thorough outline or accounting of all potential program benefits and how the Companies plan to ensure those benefits flow through to customers.

13. The commission approves the Companies' proposed three-year EM&V cycle and associated rate and rider review and refinement.

14. The commission declines to approve the implementation costs of the Revised DR Portfolio, as such review is premature at this time.

15. Within thirty (30) days from the date of this decision and order, the commission orders the Companies to file the performance incentive mechanism ("PIM") and related tariff sheets to implement the initial, one-time incentive described in Section VII.B.

16. Within sixty (60) days of the date of this decision and order, Parties may file comments on the Companies' filing made pursuant to Ordering Paragraph 15, above.

17. The commission will issue an order resolving any matters related to proposed tariff language following the filing of the Parties' comments described in Paragraph 16, above, and will direct the Companies to file final tariffs consistent with that order to implement the initial, one-time PIM.

DONE at Honolulu, Hawaii JAN 25 2018.

PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

By ______________________
Randall Y. Iwase, Chair

By ______________________
Lorraine H. Akiba, Commissioner

By ______________________
James P. Griffin, Commissioner

APPROVED AS TO FORM:

____
Matthew T. McDonnell
Commission Counsel

2015-0412.ncm

<u>CERTIFICATE OF SERVICE</u>

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

DEAN NISHINA
EXECUTIVE DIRECTOR
DEPARTMENT OF COMMERCE AND CONSUMER AFFAIRS
DIVISION OF CONSUMER ADVOCACY
P.O. Box 541
Honolulu, HI 96809

DEAN K. MATSUURA
MANAGER, REGULATORY RATE PROCEEDINGS
HAWAIIAN ELECTRIC COMPANY, INC.
P.O. Box 2750
Honolulu, HI 96840-0001

DOUGLAS S. CHIN
ATTORNEY GENERAL
BRYAN C. YEE
GREGG J. KINKLEY
DEPUTY ATTORNEYS GENERAL
DEPARTMENT OF THE ATTORNEY GENERAL
STATE OF HAWAII
425 Queen Street
Honolulu, HI 96813

Attorneys for the Department of Business, Economic Development, and Tourism

LESLIE COLE-BROOKS
EXECUTIVE DIRECTOR
DISTRIBUTED ENERGY RESOURCES COUNCIL OF HAWAII
P.O. Box 2553
Honolulu, HI 96813

HENRY Q. CURTIS
VICE PRESIDENT FOR CONSUMER ISSUES
LIFE OF THE LAND
P.O. Box 37158
Honolulu, HI 96837