BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

---------In the Matter of----------)
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PUBLIC UTILITIES COMMISSION)
)
Instituting a Proceeding to Review)
Hawaiian Electric Company, Inc.,)
Hawaii Electric Light Company, Inc.)
and Maui Electric Company, Ltd.'s)
Demand-Side Management Reports and)
Requests for Program Modifications)
)

DOCKET NO. 2007-0341

ORDER NO. 32054

POLICY STATEMENT AND ORDER
REGARDING DEMAND RESPONSE PROGRAMS

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POLICY STATEMENT AND ORDER
REGARDING DEMAND RESPONSE PROGRAMS

I. INTRODUCTION

In this Policy Statement and Order, the commission sets forth policy guidelines for the continued operation and expansion of demand response programs, and orders the HECO Companies to respond to a number of commission directives in furtherance of these guidelines.[1] The commission strongly supports the use of cost-effective and efficiently run demand response programs. Such programs have assisted electric utilities in meeting system reserve requirements, deferring the need for future capacity additions, and promoting the reliable and

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

economical operation of the electrical grid. However, demand response can - and should - also be used to provide ancillary services and to assist with the integration of additional renewable energy resources. Furthermore, given the high costs of petroleum-based fuels, demand response programs may offer a more economical alternative to the traditional creation of new generating capacity, and may also provide customers with an additional option to manage their energy costs.

Indeed, it has been observed that fundamental changes in electricity markets are creating dramatic changes in the operation of electric grids, which, in turn, provide opportunities for additional fast, flexible, and continuously responsive distributed energy resources.[2] These forces include: (1) "[a]n evolution in customer behavior and expectations, with greater demand for reliable electricity and self reliance, including becoming an energy producer or 'prosumer';" (2) "policy driven reliance on renewable, intermittent resources and a shift to more decentralized energy resources;" and (3) "[t]echnological advancement leading to alternative methods and designs for providing and integrating services to the grid that are provided by customers' responsive

[2] "DR 2.0, A Future of Customer Response," Paul De Martini, Newport Consulting, prepared for the Association for Demand Response and Smart Grid, July 2013, at 7 ("DR 2.0 Paper").

resources, including demand management, onsite generation and energy storage."[3]

The HECO Companies have operated such programs as separate pilots for many years without an overall strategic plan and roadmap. As a result, the programs demonstrate the following deficiencies: (1) unified, clearly defined common objectives and goals to which each individual program contributes are lacking; (2) there is no comprehensive overall structure that coordinates all such programs to meet those common objectives and goals; (3) there is no comprehensive method by which to demonstrate that such programs taken together provide quantifiable net benefits to ratepayers; and (4) the programs fail to recognize the changed power system requirements for flexible response (in addition to peak reduction and energy efficiency) and the technological advances that give demand response the ability to provide operating reserves.

The purpose of this Policy Statement and Order (hereinafter sometimes referred to as "Policy Statement") is to provide specific guidance concerning the standards to be met by a fully integrated demand response portfolio. Pursuant to HRS §§ 269-6, 269-7, and 269-16, the commission is requiring the HECO Companies to establish comprehensive objectives and goals

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[3]DR 2.0 Paper at 7.

for this integrated portfolio, and to clearly articulate how each of their individual current and future demand response programs contributes to the objectives and goals established for the integrated demand response portfolio. Each of the HECO Companies should establish that the integrated demand response portfolio provides demonstrable and quantifiable benefits as a whole, based on the costs and benefits attributable to individual programs within that integrated portfolio. Such benefits include, but are not limited to, demonstrable improvements in system operations, verifiable economic benefits for ratepayers, quantifiable reductions in electricity usage, and measurable assistance in integrating increased levels of renewable energy into the grid.

Nationwide, demand response programs have grown dramatically over the past several years. Initially, such programs were utilized primarily to address emergency response and peak load management. However, as time and technology have progressed, demand response programs have been used in a variety of additional ways and are now employed to, among other things, provide energy, capacity, and ancillary services, and to provide a higher level of operational flexibility so as to support, among other things, integration of additional renewable resources, such as solar and wind. Demand response should be considered and used as another essential tool in the generation tool kit.

Hawaii has long supported the use of demand response. The commission is committed to the use of such programs when they provide quantifiable benefits to ratepayers on a cost-effective basis. However, the commission has become increasingly concerned that existing programs are not coordinated, focus on peak reduction and multi-hour load shifting, and, therefore, are not producing all of the cost-effective benefits that are possible. Moreover, the commission is concerned that existing and planned programs have not been designed so as to maximize benefits, to make full use of demand response capabilities, and to avoid duplication of effort and the incurrence of unnecessary or duplicative costs.

Thus, the commission is requiring the HECO Companies to establish overall objectives and goals for an integrated demand response portfolio for each utility consistent with this Policy Statement, and to conduct a comprehensive review and evaluation of their current and planned demand response programs to ensure that they are consistent with, and substantially contribute to, these overall objectives and goals. Moreover, this comprehensive review should demonstrate that the integrated demand response program is both cost-effective and an effective use of ratepayer funds.

The commission is directing the utilities to address the benefits and costs of using demand response to (1) assist in integrating additional renewable resources into the grid; (2) provide additional ancillary services, including, but not limited to, frequency management, regulation (up and down), dispatchable resources, and contingency reserves; and (3) manage distribution system requirements. In conjunction with this directive, the HECO Companies shall identify the use of available technologies for current demand response programs to achieve greater cost effectiveness and report to the commission on these specific items within ninety (90) days from the date of this order.

The HECO Companies are also directed to demonstrate how the integrated demand response portfolio and the individual programs within it fit into the existing grid and distribution system of each utility. Similarly, the Companies should demonstrate how the integrated demand response portfolio will be used in future generation and distribution planning and operation in general, and in designing a "smart grid" in particular, as further discussed herein.

II.

DEFINING DEMAND RESPONSE

Demand response is often defined as follows:

> Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time or to incentive payments designed to induce lower electricity use....[4]

Stated somewhat differently, demand response refers to a consumer's change in electricity consumption, relative to the expected levels, in response to an inverse change in the price of electric energy or to incentive payments designed to induce a change in consumption.[5]

The commission reiterates that as demand response programs have evolved, so has their use such that these programs are no longer simply considered methods to decrease consumption during peak periods, but are also methods to assist in balancing system operations and in the integration of renewable energy resources. Hence, it is more appropriate to view demand response

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[4]See U.S. Department of Energy, Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005 (definition also includes reductions in demand due to high wholesale market prices, which are not relevant in the State of Hawaii). The commission has, in the past, referred to this definition. See, e.g., "Decision and Order," Docket No. 2010-0165, filed on November 9, 2011, at 1-2.

[5]18 C.F.R. §35.28(a)(4).

programs not only as peak reduction programs, but as programs designed to modify customer use of electricity so as to permit the most efficient and cost-effective operation of the electrical system.

Demand response programs can be further classified by describing the basic mechanisms that can be used to encourage changes in consumption patterns; that is, whether the mechanism is a (1) time-based pricing program or an (2) automated or manual control program.

There are three basic types of time-based pricing that can be used to encourage modifications in customer use of electricity. First, on-peak/off-peak pricing sets two prices: one for on-peak usage and one for off-peak usage. The on-peak/off-peak periods are established according to the load characteristics of each utility. Second, time-of-use pricing is similar to on-peak/off-peak pricing, but applies to several different time periods within a day. Time-of-use pricing can also be used to encourage the use of energy at a reduced price to customers that can increase loads at the time of a potential curtailment of certain renewable energy supply sources, such as wind and solar. Third, real time pricing reflects prices on an hourly basis, with some limited notice of the changes to the customer. The HECO Companies have established several time-of-use tariffs (although they are not widely utilized at this time), as further discussed herein.

Likewise, there are various types of automated or manual control programs where the system operator either (1) asks a customer to take a previously agreed-upon curtailment action when the operator requires such a response for either operational or economic reasons or (2) a customer is automatically curtailed by a previously agreed-upon amount by way of equipment that either permits the system operator to reduce or terminate load, and to restore the previous levels, or that operates autonomously (based on system frequency deviations, for example). These programs are sometimes described as "incentive based" programs, as they generally provide participants a credit or payment for taking the prescribed action. As described herein, the HECO Companies are currently operating a number of these types of demand response programs.

In addition to these time-of-use or manual/automatic demand response programs, there is a potential for customer-side implementation of demand response. For example, customers may provide demand-response through use of their generating and storage resources, provided that the generators and storage resources can be controlled by the system operator or by autonomous operation of on-site distributed energy equipment such as by a smart inverter.

Demand response programs can also be used to provide ancillary services. These ancillary services include, but are not limited to, the provision of spinning reserves to defer or avoid higher cost generating unit operation, frequency management (such as droop response and regulation), provision of a "bridge" for the time period between a sustained ramp down of renewable energy sources and when additional quick-start generation can be brought on line, or other system needs. Demand response can be faster and more accurate than generation response and can respond autonomously to frequency deviations as well as to system operator commands.

Finally, demand response programs are often considered in conjunction with energy efficiency programs under the general category of demand side management ("DSM") programs. Hawaii's energy efficiency programs are currently overseen by a third party administrator separate from the HECO Companies, as further discussed in herein. Although energy efficiency programs are not addressed in this Policy Statement, the commission directs the companies to coordinate closely with Hawaii Energy to assist and prepare customers to participate in demand response programs as they install energy efficiency devices or technologies on the customer side of the meter.

The types of services and programs included within the definition of demand response continue to evolve and expand. The demand response programs conducted by the HECO Companies should be structured so as to embrace these expanded services where they are proven to be cost effective. Given the high cost of energy and the high penetration of renewables in Hawaii, it is reasonable to expect that Hawaii would lead the nation in the use of advanced demand response for power system reliability services.

III.

CURRENT AND PROPOSED DEMAND RESPONSE PROGRAMS

A. HECO Programs.[6]

1. HECO's Residential Load Control Program.

HECO's Residential Direct Load Control ("RDLC") Program offers eligible residential customers the opportunity to participate in a program in which a participant's water heater and/or central air conditioning can be interrupted in return for an incentive payment. HECO uses load control receivers ("LCRs") to remotely activate load control and restore loads to these

[6]This section summarizes the basic structure of the demand response programs of each of the HECO Companies. Updated information for these programs is included in the Annual Program Modification and Evaluation ("M&E") and Annual Accomplishments and Surcharge ("A&S") reports. These reports are discussed in greater detail in Section V.D. of this Policy Statement.

appliances by sending load shed commands via a wireless radio frequency paging system. Currently, customers receive a fixed monthly credit for participating in the program of $3.00 per month for water heaters, and $5.00 per month for central air conditioners.[7]

The HECO RDLC Program is intended to provide system benefits in the form of generating unit capacity deferral. The Program also provides system reliability benefits by providing (1) dispatch capability during grid emergencies and (2) system protection capability by automated load shedding during system under-frequency events.

The RDLC program currently has approximately 36,000 participants, representing approximately 17 MW of peak load reduction.[8] However, it should be noted that since 2010, an average of 1,000 participants per year (representing approximately 400 kW per year) have left the program, usually as a result of converting electric water heaters

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[7]See "In the Matter of Public Utilities Commission Regarding Integrated Resource Planning," Docket No. 2012-0036, Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., Maui Electric Company, Limited, 2013 IRP Report ("2013 IRP Report"), Chapter 7, Demand Response Programs, at 7-19 and 7-20, filed on June 28, 2013.

[8]The HECO RDLC water heater program element has approximately 32,000 participants, representing approximately 14 MW of peak load reduction. The central air conditioning element has approximately 4,000 participants, representing approximately 3 MW of peak load reduction. 2013 IRP Report at 7-20.

to solar water heating systems. HECO is attempting to replace those participants so as to maintain the 17 MW of system peak load reduction.[9]

According to the 2013 IRP Report, HECO proposes to "further enhance the value and capabilities of its traditional load management programs by examining new program technologies, program designs, and market and operational strategies for providing ancillary services support for integrating renewable resources."[10] To accomplish this, HECO proposes to add approximately 34,000 new participants, representing an additional system peak load production of 18 MW, for a total of approximately 36 MW.[11]

2. <u>HECO's Commercial And Industrial Demand Response Programs</u>.

HECO's current commercial and industrial demand response programs consist of three elements. The Commercial and Industrial Load Control ("CIDLC") Program contains two of these

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[9]2013 IRP Report at 7-20.

[10]2013 IRP Report at 7-20.

[11]In the 2013 IRP report, HECO states that the method used to forecast the MW totals for the program expansion was based on the analyses set forth in the "Assessment Of Demand Response Potential For HECO, HELCO, And MECO," Final Report, Global Energy Partners, LLC, May, 2010 (hereinafter cited as "GEP Report"). The MW forecasts are based on 30% penetration for each of the program elements. The GEP Report is discussed in greater detail in Section V.C. of this Order.

elements: (1) the Direct Load Control ("DLC") program element, which targets large commercial and industrial ("C&I") customers and (2) the Small Business Direct Load Control ("SBDLC") program element, which targets smaller C&I customers. The third element is HECO's Fast DR pilot program element, which also targets large C&I customers.

For the DLC program, HECO targets large C&I customers who have loads that are non-critical or that are backed by other generators that can be controlled by or at the request of HECO's system operator. These "controlled loads" are curtailed to address either (1) a dispatch curtailment event, such as a real or anticipated shortfall in generation to meet a projected system peak demand period or (2) an underfrequency load curtailment event when the system frequency falls below a specified level. The program is also used to provide additional system reliability through underfrequency relay and as an emergency dispatch resource.[12]

DLC participants receive an incentive of $10.00 per kW per month for automated load shedding or $5.00 per kW per month for manually dispatched load shedding. In addition, participants receive a variable energy credit of $0.50 per kWh of reduction

[12]2013 IRP Report at 20-15.

for eligible kWh of energy reduction actually provided whenever a dispatch curtailment event occurs.[13]

HECO's SBDLC program element targets small and medium commercial customers with water heater and central air conditioner loads typically greater than 3 kW and less than 300 kW. These appliances are controlled by a one-way, radio controlled LCR device, which also includes a built-in under frequency relay which will automatically interrupt the load if the system frequency drops to a certain level.[14]

SBDLC participants receive a monthly credit of $5.00 for each water heater, $5.00 per ton for central air conditioning (CAC), and $8.00 per kW for other equipment as approved by HECO. If a participant is eligible to enroll multiple loads, they may do so and receive incentive payments for each enrolled load.[15]

The DLC and SBDLC program elements are primarily designed to be a resource option for generation capacity deferral and emergency system protection. As of the end of the 2011 program year, the CIDLC Program had an enrollment of approximately 19 MW of curtailable load (approximately 18 MW from the DLC program element and approximately 1 MW from the

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[13]2013 IRP Report at 7-22.

[14]2013 IRP Report at 20-15.

[15]2013 IRP Report at 7-22.

SBDLC program element). CIDLC participants were comprised of 42 "active" large business customers participating in the DLC program element, and 161 small business customers participating in the SBDLC program element.[16]

The third element is HECO's Fast DR pilot program, which is designed to test whether the commercial and industrial markets will accept new demand response technologies and quick response program designs that are intended to provide grid operational benefits that would support the integration of variable renewable resources. HECO states that the purpose of the pilot is to provide feedback for future modification to the program design and operations of the CIDLC program.[17]

Under the Fast DR pilot program, participant loads are either controlled on an automated or semi-automated basis, with a ten (10) minute notification by the system operator. Hawaiian Electric has enrolled 37 participants, accounting for approximately 5.7 MW, while Maui Electric has enrolled four participants, accounting for approximately 200kW.[18]

As with the RDLC program, the 2013 IRP Report notes that HECO desires to further enhance the value and capabilities

[16]2013 IRP Report at 7-21 and 7-22.

[17]2013 IRP Report at 7-22.

[18]2013 IRP Report at 7-29 and 7-30.

of traditional load management to examine new program technologies, program designs, and market and operational strategies for providing ancillary services support to integrating renewable resources.[19] At present, HECO plans to expand enrollment in the Fast DR pilot program and to modify the CIDLC program to incorporate lessons and best practices from the Fast DR pilot program.

3. Rider I.

HECO's current tariff includes "Rider I." Under this tariff provision, HECO is authorized to provide interruptible Contract Service, which can be used in similar fashion to the CIDLC program to reduce load. To be eligible for this service, the service must be supplied and metered at a single voltage and delivery point where 100 kW or greater is subject to disconnection "under the terms and conditions as set forth in the contract agreement." While this type of service may be considered to be a demand response program, it should be noted that the Rider was closed to new customers as of February 28, 2011.

[19]2013 IRP Report at 7-21.

4. <u>HECO's Proposed Commercial And Industrial Dynamic Pricing Pilot Program</u>.

On November 29, 2011, HECO filed an application to implement a Commercial and Industrial Dynamic Pricing ("CIDP") Pilot Program in 2013, dependent on the implementation of HECO's Fast DR Pilot Program.[20] Dynamic pricing allows customers to respond to the changing cost of electricity by curtailing their demand in response to changes in the retail price of electricity. By way of the CIDP pilot program, HECO proposes to:

> conduct a two-year pilot program during which commercial and industrial customers who can provide at least 50 kW, or 15% of their annual demand, in load curtailment, whichever is greater, will be given monthly demand credits in return for dramatically lowering their energy use at certain times (and sometimes on short notice) when necessary to fulfill operating reserve requirement, meet system demands, or otherwise reduce operating costs.[21]

More specifically, HECO describes the operation of the program as follows:

> Under the Company's proposed CIDP Pilot Program, a program participant will designate a firm service level ("FSL") - a level of

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[20]"In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC., For Approval of a Commercial and Industrial Dynamic Pricing Pilot Program and Recovery of Program Costs," Docket No. 2011-0392, HECO Company Application, filed December 29, 2011 ("2011 HECO Dynamic Pricing Application").

[21]2011 HECO Dynamic Pricing Application at 18.

> kW demand that is significantly lower than the normal operating use, but sufficient to safely and efficiently operate his/her facility for limited periods of time. A participant would agree to reduce facility demand to the FSL when a curtailment event is called. In return, the participant receives a reduced demand charge (i.e., a monthly $/kW credit), for each kW of demand difference between the participant's actual demand and the FSL regardless of whether or not a curtailment event is called.
>
> However, when an event is called, the participant is expected to reduce facility load to, or below, the FSL. During a curtailment event, the participant may choose to reduce load to a level above the FSL, or not reduce load at all. In these circumstances, the participant will pay a "buy-through" energy price in $/kilowatt hour (kWh), that is in effect only for the duration of the curtailment event, for all kWh consumed above the FSL. The buy-through energy price is several times higher than the otherwise applicable tariff energy price. All kWh usage up to the contracted FSL times the duration of the curtailment event will be charged at the participant's standard tariff energy rate and will not be affected by the buy-through energy price.
>
> The signal that is sent by the utility to the participant to initiate load reduction under the CIDP Pilot Program is the buy-through energy price which represents a significant increase in energy price over and above the otherwise applicable tariff.[22]

Based on the concerns expressed in this Policy Statement, the commission has not yet approved this program. However, the commission observes that, as part of the integrated

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[22]2011 HECO Dynamic Pricing Application at 6.

portfolio approach called for here, such a program may serve as a resource for a variety of ancillary service and other system operational needs.

B. MECO Programs.

MECO currently operates a Fast DR pilot program. The program is designed to be a quick response (less than ten minutes) resource, and is comprised of semi-automated and automated demand response elements. Generally, in the semi-automated demand response process, a service provider's operations center will be notified of an event via a phone call or as an auto-generated phone message. The service provider will then notify the program participants to perform according to their pre-defined curtailment plan.[23]

The automated DR process differs from the semi-automated process in that the curtailment agreed to in the customer's pre-defined curtailment plan is executed automatically by utilizing a customer's energy management system without requiring acknowledgement from the customer.[24]

Service interruptions under MECO's Fast DR pilot program cannot exceed two hours per day, with a maximum of

[23]2013 IRP Report at 7-29.

[24]2013 IRP Report at 7-29.

80 hours per year per participant. The controlled demand incentive for the Fast DR pilot program is $10 per kW per month, and the energy reduction incentive is $0.50 per kWh, but is not paid for the first fifteen hours of curtailment. Currently, there are four participants in the program with a total impact of 200 kW.[25]

The 2013 IRP Report notes that MECO intends to develop a portfolio of residential, commercial, and industrial customer loads that will allow economic operation of its grid. To that end, MECO states that it will continue to "proactively explore opportunities for flexible grid resources to absorb the growth of as-available renewable generation and defer or reduce the size of new capacity additions."[26]

C. HELCO Programs.

HELCO does not currently have any customer demand response programs. However, HELCO has utilized under-frequency load-shedding as a low-cost demand response resource.[27]

HELCO's future strategy is to develop a portfolio of residential, commercial, and industrial customer loads that will

[25]2013 IRP Report at 7-29 and 7-30.

[26]2013 IRP Report at 22-10.

[27]It should be observed that each of the HECO Companies use under-frequency load shedding as a demand response tool, some more frequently than others. 2013 IRP Report at 7-31.

enable reliable and economic operation of its electric grid. In the 2013 IRP Report, HELCO states that its future demand response actions will be framed by development of a demand response roadmap, following the steps generally laid out in the Reliability Standards Working Group, Demand Side Options Subgroup Whitepaper entitled "Demand Response as a Flexible Operating Resource."[28] This Whitepaper is discussed in depth in Section IV of this Policy Statement.

IV.

THE EVOLUTION OF OBJECTIVES ASSOCIATED WITH DEMAND RESPONSE PROGRAMS

Over the years, the commission has approved each of the currently operating demand response programs and program elements described in Section II of this order either as pilot programs, or by reauthorizing existing programs as requested by the HECO Companies. The commission's orders approving these programs illustrate the evolving role for demand response programs. While not intended to be exhaustive, the commission reviews here the history of the various demand response programs - and the orders approving them - with a particular emphasis on how demand response objectives have evolved over time.

[28]2013 IRP Report at 21-7 and 21-8.

On October 14, 2004, the commission approved a settlement concerning HECO's initial application to institute a 5-year RDLC pilot program.[29] As explained by HECO, the overall objective of the program was to assist HECO in meeting its peak demand by providing HECO "with approximately seventeen (17) megawatts ("MW") of interruptible load from residential water heaters during the system peak."[30] HECO further stated that the RDLC would provide "additional planning reserve capacity, and [would] help defer the need for future capacity additions."[31] Additionally, HECO noted that the RDLC program would assist it in handling under-frequency situations.[32]

Shortly thereafter, on October 19, 2004, the commission approved HECO's application to institute a 5-year CIDLC pilot program.[33] Again, HECO described the overall objective of the program as one of assisting HECO in meeting its peak demand:

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[29]See "In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC., For Approval of a Residential Direct Load Control Program, and Recovery of Program Costs," Docket No. 03-0166, Order No. 21415 at 3-4 (October 14, 2004) ("Order No. 21415").

[30]Order No. 21415 at 4.

[31]Order No. 21415 at 4.

[32]Order No. 21415 at 4.

[33]See In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC., For Approval of a Commercial and Industrial Direct Load Control Program, and Recovery of Program Costs, Docket No. 03-0415, Order No. 21421 (October 19, 2004) ("Order No. 21421").

"The objective of this program is to provide HECO with approximately twenty-one (21) megawatts ("MW") of interruptible load, beyond that provided by the existing customers on Rider I."[34] Likewise, the CIDLC program was designed to assist HECO in handling under-frequency situations.[35]

Thus, HECO stated that the initial objectives of these two demand response programs were to assist HECO in meeting its system peak demand by shedding load and meeting system capacity requirements, and to assist in handling under frequency situations. Moreover, at this time, these programs were considered to be part of HECO's demand side management ("DSM") programs.

On March 16, 2005, the commission issued Order No. 21698, opening an "Energy Efficiency Docket" in order to consider HECO's DSM efficiency and load control programs separately from an ongoing rate case docket in which they had originally been included.[36] The new docket was designed to

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[34]Order No. 21421 at 4.

[35]Order No. 21421 at 4-5. As previously noted, program information for both the RDLC and CIDLC programs is to be included in the Annual Program Modification and Evaluation ("M&E") and Annual Accomplishments and Surcharge ("A&S") reports. These reports are discussed in greater detail in Section V.D. of this Policy Statement

[36]See "In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC., For Approval of Rate Increases and Revised Rate Schedules and Rules, and for Approval and/or Modification of

consider a number of new and ongoing DSM programs, as well as HECO's proposals to modify the cost recovery mechanism for the RLDC and CIDLC programs.[37]

On February 13, 2007, the commission issued Order No. 23258 in the Energy Efficiency Docket, in which the commission stated:

> For the purposes of this Decision and Order, consistent with the Panel Hearings, the term "Energy Efficiency" will refer to the savings of energy usage; the term "Load Management" will refer to direct control or management of the load; and the term "DSM" will refer to Energy Efficiency and Load Management collectively.[38]

Thus, at this point, the RDLC and CIDLC programs were still considered to be part of an overall DSM portfolio. However, the commission further ordered that the administration of all "energy efficiency" DSM programs would be turned over to a non-utility, third-party administrator, while load management programs would continue to be managed by HECO:

Demand-Side and Load Management Programs and Recovery of Program Costs and DSM Utility Incentives," Docket No. 04-0113, Order No. 21698 at 19 (March 16, 2005).

The new "Energy Efficiency Docket" was docketed as "In the Matter of HAWAIIAN ELECTRIC COMPANY, INC., For Approval and/or Modification of Demand-Side and Load Management Programs and Recovery of Program Costs and DSM Utility Incentives," Docket No. 05-0069. This docket did not include MECO or HELCO.

[37]Docket No. 04-0113, Order No. 21698 at 1.

[38]Docket No. 05-0069, Order No. 23258 at 8.

> At this time, utility control over Load Management programs is crucial to system stability. Therefore, in finding that the Non-Utility Market Structure is the most appropriate for the HECO Companies at this time, the commission specifically excludes Load Management programs from the third-party administrator's area of responsibility.[39]

At this point, the RDLC and CIDLC programs continued to be described as programs that could be used to reduce peak demand or to address an emergency situation.

Following the separation of energy efficiency and load management programs, on October 27, 2007, the commission opened Docket No. 2007-0341 to address issues concerning the load management programs for all three HECO Companies.[40] Again, these programs were considered to be DSM programs.

On April 30, 2009, HECO filed an application with the commission requesting authority to extend the RDLC for three years, and to substantially expand the program to provide an increase from 17 MW to 26 MW of interruptible load.[41]

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[39]Order No. 23258 at 37-38. Beginning on July 1, 2009, the energy efficiency programs of the HECO Companies were transferred to Hawaii Energy.

[40]"In the Matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Review Hawaiian Electric Company, Inc. Hawaii Electric Light Company, Inc., and Maui Electric Company, Ltd.'s Demand-Side Management Reports and Requests for Program Modifications," Docket No. 2007-0341, Order No. 23717 (October 27, 2007).

[41]See "In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC. For Approval of Extension to the Residential Direct

HECO's justifications for the proposed extension and expansion of the RDLC program were the same as those initially expressed in 2004:

> The objective of the RDLC Program is to provide interruptible load from residential water heaters and central a/c systems during a capacity shortfall, as discussed in HECO's 2009 Adequacy of Supply ("2009 ACS") Report filing dated February 27, 2009. In addition, the RDLC Program provides grid reliability if the HECO system experiences an event that reduces system frequency below a specified level.[42]

HECO also noted that load management programs, such as the RDLC Program, could be used to address fluctuations resulting from intermittent renewable energy sources, although it did not further expand on how this could or would be implemented.[43] Instead, it stated that the RDLC would be used, as it had been for the past five years, to shed load during times of peak demand or to assist in addressing emergency under-frequency situations.[44]

Load Control Program and Recovery of Program Costs," Docket No. 2009-0097, HECO Application ("2009 RDLC Application"). HECO stated that the RDLC Program had exceeded its original projection of 17 MW of interruptible load with the installation of over 36,000 load control switches on electric water heaters and 3,000 load control switches on central a/c units, for an estimated total of over 26 MW of peak interruptible load by the end of 2009. 2009 RDLC Application at 4, 12.

[42]2009 RDLC Application at 5.

[43]2009 RDLC Application at 6.

[44]2009 RDLC Application at 8-9.

The commission approved the requested three-year extension of the RDLC program, but denied the request to expand it.[45]

> In the commission's view, it would be inappropriate at this time to allow expansion of the program before completion of the impact evaluation and other evaluation necessary to determine whether the program is designed and being implemented efficiently and effectively.[46]

The commission noted that it was not clear "how effective the proposed expansion will actually be in deferring the need for future capital investment."[47]

> More importantly, HECO anticipates having a reserve capacity surplus during the 2010-2012 timeframe, even without the proposed expansion of its load control programs. HECO states that with the addition of Campbell Industrial Park Combustion Turbine-1, there is a forecasted reserve capacity surplus of 60-120 MW in 2010 and 0-60 MW in 2012. These forecasts include the existing 58 MW contributions from the RDLC and CIDLC Programs. Therefore, an expansion of HECO's load control programs at this point in time is not required to meet HECO's capacity requirements for 2010 through 2012, and would actually add to a forecasted capacity surplus.[48]

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[45]Docket No. 2009-0097, "Decision and Order" at 21, filed December 29, 2009 ("2009 RDLC Order").

[46]2009 RDLC Order at 17.

[47]2009 RDLC Order at 18.

[48]2009 RDLC Order at 19 (footnotes omitted).

On March 31, 2009, HECO filed an analogous application to both extend and expand the CIDLC program by adding 8.4 MW of contracted interruptible load for a total program interruptible load of 36 MW by the end of 2012.[49] The commission approved the request for extension of the CIDLC, but denied the request for expansion of the program. The commission's conclusions with respect to the CIDLC program were similar to those that it made with respect to the RDLC program, including the finding set forth above concerning the forecasted capacity surplus.[50]

Thus, at this time, questions began to be raised concerning one of the initial objectives of the RDLC and CIDLC programs - reduction in capacity requirements either through reductions in peak demand or by eliminating the need for new generation. However, with the implementation of the Fast DR programs by both HECO and MECO, there came an acknowledgement that demand response could be used for purposes other than reducing demand for capacity or responding to under frequency events.

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[49]See "In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC. For Approval of Extension to the Commercial and Industrial Direct Load Control Program and Recovery of Program Costs," Docket No. 2009-0073, HECO Application at 19.

[50]Docket No. 2009-0073, "Decision and Order" at 21, filed December 29, 2009.

For example, in their joint application to implement the Fast DR programs, the HECO Companies stated that the term "Fast DR" refers to customer loads that can be shed within ten minutes or less from the time the customer receives notification by the utility, and that Fast DR may provide many, but not all, of the attributes of "quick start" class of firm generation resource.[51] With respect to objectives for these programs, the HECO Companies stated:

> The EnergyScout for Business CIDLC Program is primarily designed to be a resource option for generation capacity deferral and emergency system protection. In contrast, the Fast DR Pilot Program is designed to be a "quick start" (i.e., less than 10 minutes) bridge resource primarily intended to facilitate grid operations when there are increasing levels of variable intermittent renewable energy. Under specific system event conditions resulting from a sustained ramp-down of intermittent wind resource, Fast DR could be an effective option to supplement the need for additional spinning reserve requirements.[52]
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> * * * * * * * *
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> Actual operating experience will provide a means for Hawaiian Electric and MECO system operations personnel to evaluate the reliability of the fast response customer

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[51]"In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC., HAWAII ELECTRIC LIGHT COMPANY. INC., MAUI ELECTRIC COMPANY, LIMITED, For Approval of a Fast Demand Response Pilot Program and Recovery of Program Costs," Docket No. 2010-0165, HECO Companies' Application at 1, filed on August 31, 2010 ("2010 Fast DR Application").

[52]2010 Fast DR Application at 8.

loads to function as a grid management tool capable of providing a variety of ancillary services for managing increasing levels of renewable energy penetration from wind and solar.[53]

Likewise, Exhibit G to the 2010 Fast DR Application provided a general discussion of how demand response resources could be used to provide a variety of ancillary services:

> The DR Roadmap envisions a portfolio of DR that consists of existing (CIDLC and RDLC) and future (Fast DR and Dynamic Pricing) programs that provides resources covering the spectrum of response times that the utility uses to maintain system reliability. Those DR resources, juxtaposed with supply-side resources, provide the utility with tools to improve generation efficiency, improve service reliability, accept increased renewable energy into the system, potentially defer investments in new generation resources, or otherwise lower costs.[54]

On November 9, 2011, the commission issued a "Decision and Order" in Docket No. 2010-0165 approving the HECO and MECO Fast DR pilot programs and the recovery of program costs.[55] In so doing, the commission recognized the evolving nature of the uses for demand response programs:

> In addition, the commission notes that the proposed Fast DR Program may contribute to system stability by enabling the

[53]2010 Fast DR Application at 15-16.

[54]2010 Fast DR Application at Exhibit G, p. 1 of 1.

[55]Docket No. 2010-0165, "Decision and Order," filed on November 9, 2011 ("2011 Fast DR Order").

> HECO Companies to displace the need to utilize Under Frequency Load Shed as a method of responding to demand spikes or outages. Also, the Fast DR Program pilot provides the HECO Companies the opportunity to more fully evaluate potential DR benefits, particularly as they relate to the integration of additional quantities of renewable energy resources on various island grids. The Fast DR Pilot program may also provide an opportunity to assess customer willingness to participate in such programs.[56]

The Commission further stated:

> [T]he commission shares some of the Consumer Advocate's concerns, and suggests that the HECO Companies consider developing an overall DR strategy that would set forth their long-term vision, mission, operating philosophy, goals, objectives and near-term action plans for the greater implementation of DR.[57]

This finding was echoed by HECO in its proposal to implement a commercial and industrial dynamic pricing ("CIDP") program. HECO observed that the proposed CIDP program could serve to meet a more comprehensive set of demand response objectives:

> The objective of dynamic pricing is to provide price incentives and disincentives to cause changes in customer behavior that lead to reductions in demand. These demand reductions can be of benefit to the operation of the electrical system depending on the

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[56]2011 Fast DR Order at 19-20 (footnotes omitted).

[57]2011 Fast DR Order at 20. The commission's approval of the Fast DR program was subject to the submission of detailed information concerning the program.

> configuration of utility and non-utility generation at the time of a possible event. Hawaiian Electric continues to explore the impact of integrating additional intermittent renewable energy resources into its system grid. Those studies are on-going and it is possible that not all of the issues and system needs have been identified.[58]

While such programs were initially approved primarily as a means to help the utility manage its peak demand and/or to address certain emergency situations, it is now uniformly recognized that demand response programs can provide additional benefits in the form of additional assistance to system operations and the provision of a variety of ancillary services. Through this Policy Statement, the commission directs the HECO Companies to take a more comprehensive, long-term, integrated approach to the use of demand response programs to achieve all of these purposes and objectives.

V.

PREVIOUS ANALYSES OF THE HECO COMPANIES' DEMAND RESPONSE PROGRAMS

In formulating this Policy Statement, the commission has reviewed a large number of studies and analyses of

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[58]"In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC. For Approval of a Commercial and Industrial Dynamic Pricing Pilot Program and Recovery of Program Costs," Docket No. 2011-0392, HECO Application at 8, filed December 29, 2011.

demand response programs conducted on both a national and a Hawaii-specific basis. While it is not possible to summarize all of these studies and analyses here, several are of particular relevance to the development of this Policy Statement.

A. "Demand Response As A Flexible Operating Resource," A Report Prepared By The RSWG Demand Side Options Subgroup.

In Docket No. 2011-0206, a Reliability Systems Working Group ("RSWG") was established to develop reliability standards for the HECO Companies. Several subgroups to the RSWG were created, including the RSWG Demand Side Options Subgroup ("DR Subgroup"). The DR Subgroup was created to examine and analyze the potential of demand side options.

In March of 2013, the DR Subgroup issued a white paper that addressed the use of demand response as a flexible operating resource that "could play a role in meeting Hawaii's electric system operational objectives…."[59] The Demand Side Options ("DSO") Paper states that demand response can be utilized to:

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[59]See "In re Pub. Util. Comm'n, Instituting a Proceeding to Investigate the Implementation of Reliability Standards for Hawaiian Elec. Co., Inc., Hawaii Elec. Light Co., Inc., and Maui Elec. Co., Ltd.," Docket No. 2011-0206, Reliability Standards Working Group Independent Facilitator's Submittal, Final Report, filed on March 25, 2013, Demand Response As A Flexible Operating Resource ("DSO Paper"), at 1-2. A copy of the DSO Paper is attached to this Order as Exhibit A.

1. Reduce total kilowatt hours consumed;
2. Reduce peak loads, to reduce the amount of fossil fuel generation required for contingencies and demand, or to assist in meeting photovoltaic ("PV") variability;
3. Build off-peak loads to increase consumption of minimum load generation and reduce wind curtailments;
4. Reduce the impact of variability and volatility of PV ramps by integrating PV operation with end use loads;
5. Provide utility-dispatchable and automatic, automated load control to deliver fast ancillary services (frequency management, up-regulation and down-regulation, spinning reserve) without burning fossil fuels;
6. Provide utility-dispatchable and automatic, automated load control (responding in the same frequency range as generator governor response and ahead of, but coordinated with, the utility's current under-frequency load shedding schemes), and eventually, spinning reserves to protect system frequency; and

7. Provide utility-dispatchable demand response as a bridge under contingency conditions while waiting for utility emergency diesel generators to come on-line.[60]

The DSO Paper observes that demand response options "have the potential to create value for Hawaii's ratepayers, and should, therefore, be investigated."[61]

According to the DSO Paper, there are several prerequisites that are necessary if demand response is to be utilized effectively. First, demand response programs must serve the objectives identified above, while also meeting customers' economic and/or energy management needs. Second, demand response programs must identify those loads that will respond to the relevant price and/or system conditions. Third, the utility must be able to manage, control, and coordinate the resources supplied by demand response programs using an appropriate manual or automatic method. Fourth, the contribution of demand response resources in meeting the program objectives must be measured and quantified. Fifth, the compensation to be provided to the customer participant should be based on the value of the specific capacity, energy, or ancillary services provided, or the cost

[60]See DSO Paper at 2.

[61]DSO Paper at 2.

of providing capacity, energy, or ancillary services from another source.[62]

The DSO Paper also discusses the customer side of the demand response equation. For example, with respect to load control demand response programs, the DSO Paper observes that customers who actively manage their operations are generally better candidates for the more sophisticated time-based programs as they are accustomed to scheduling their operations in a way that reduces energy costs and improves profits.[63] Automated demand response programs can be more broadly applied, including remote control of water heaters, pumps, air conditioners, and refrigeration.[64]

In addition to these more traditional types of load control, the DSO Paper observes that customers can provide "demand response through operation of on-site, behind-the-meter generating and storage resources, provided that such generators can be controlled in a manner consistent with the demand-response program parameters, and that they comply with environmental and other applicable regulations."[65] Batteries, electric vehicles, pre-heating of water heaters, and pre-cooling of buildings,

[62]DSO Paper at 2-3.

[63]DSO Paper at 7.

[64]DSO Paper at 7.

[65]DSO Paper at 7.

freezers, and refrigeration can all be utilized as forms of demand response.[66]

The DSO Paper also sets forth a specific proposal for a demand response program pertaining to county and privately-owned water companies.[67] These companies employ many horsepower of electric-powered pumps for both water and wastewater lift stations. The DSO Paper states that these should be recognized as primary loads to explore for generation load matching and the start of a smarter, more flexible grid. As these pumps have significant flexibility in terms of when they operate, and water can be stored for up to several days without operating these pumps, the operation of these pumps could be coordinated to match the generating resources that may be available at any given time (for example, to operate off peak to absorb high levels of wind generation) or to provide ancillary services to the power system (frequency regulation, load following, or spinning and non-spinning contingency reserves). The DSO Paper recommends that the commission undertake further investigation of this proposal.

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[66]DSO Paper at 7.

[67]DSO Paper at 17-20.

In sum, the DSO Paper makes the following recommendations:[68]

1. The commission should investigate pricing programs, and manual and automated demand response programs that will incentivize customers to change their consumption patterns in ways that are beneficial to stakeholders. Included in this investigation is an analysis of benefits to be achieved by increasing demand during minimum load periods.
2. The use of demand response and energy storage should be encouraged to provide ancillary services whenever technically feasible and economically justified.
3. Stakeholders should be encouraged to develop specific pricing and/or manual demand response programs and those programs should be expeditiously reviewed by the commission.
4. The commission should consider the appropriate role of third party agents and aggregators as a

[68]The DSO Paper discusses both existing and future demand-side programs offered or to be proposed by the HECO Companies.

means to operate demand response programs effectively and efficiently.

5. Demand response programs should be considered in the Integrated Resource Planning process.

6. The energy efficiency potential study contractor should be directed to perform specific load research data collection to allow a utility to better estimate the demand response potential in Hawaii.

7. The commission should require that Hawaii Energy work with the utilities to identify those customers and loads that are most promising for demand response, and to assure that Hawaii Energy and the demand response planners coordinate program plans and marketing to assure that energy efficiency does not compromise demand response opportunities and vice versa.

The commission greatly appreciates the work of the RSWG Demand Side Options Subgroup and adopts several of their recommendations in this Policy Statement.

B. "Hawaiian Electric Company Demand Response Roadmap Project," A Report Prepared By The Lawrence Berkeley National Laboratory.

In January 2013, the Lawrence Berkeley National Laboratory ("LBNL") issued a report entitled "Hawaiian Electric Company Demand Response Roadmap Project."[69] The purpose of the Project was to develop a "demand response roadmap" to provide "a high level examination of the most critical technology, resource planning, environmental, operational, customer, and regulatory factors for achieving the demand response goals."[70] The specific objectives of the LBNL Project were as follows:

- Evaluate the potential demand response needs of the HECO electricity grid;
- Outline potential demand response limitations, options, communication, and control technologies; and
- Identify research, education, policy, outreach needs, technology gaps, and best practices to guide HECO development activities.

The authors of the LBNL Project observed that a demand response roadmap does not provide an implementation action plan, and, thus, it does not define specific programs or technologies, nor does it develop detailed cost effectiveness scenarios.

[69]"Hawaiian Electric Company Demand Response Roadmap Project," by Roger Levy and Sila Kiliccote, Ernesto Orlando Lawrence Berkeley National Laboratory, Report No. LBNL-6215E, January 2013 (hereinafter referred to as the "LBNL Project").

[70]LBNL Project at 7.

However, the roadmap may recommend research or other projects that address these factors.

The LBNL Project identified five basic load-shaping objectives for demand response applications:

1. Energy efficiency, defined as programs that reduce overall electricity consumption, usually during times of peak demand;
2. Load shifting, defined as programs that move consumption from periods of high prices to periods of lower prices by way of real time pricing or time-of-use pricing;
3. Peak shaving, defined as programs that require a response during peak hours to reduce peaks on high-system load days;
4. Reliability response, defined as programs that require a fast response of short duration; and
5. Regulation response, defined as programs that continuously follow minute-to-minute commands from the grid in order to balance the aggregate system load and generation.[71]

LBNL's review of HECO's current demand response programs (RDLC, CIDLC, SBDLC, Fast DR, and CIDP) identified six

[71]LBNL Project at 17.

different load shaping objectives that were served by these programs. However, LBNL concluded that these six load shaping objectives generally serve only two of the basic demand response program objectives set forth above: (1) peak shaving and (2) reliability response (under frequency).[72] As observed by LBNL, "[a]ll of these HECO objectives focus on shaping load to either reduce existing system fuel costs or to defer future capacity additions," which is a common demand response objective throughout the industry.

The LBNL Project also observed, however, that HECO's RDLC and CIDLC programs incorporate certain features that relax constraints and provide much greater flexibility and potential load shaping value than what is common in other industry programs, including (1) elimination of seasonal and peak hour constraints; (2) direct control options for small business consumers; and (3) under frequency response.[73] As to the latter, the LBNL Project states that HECO's receivers provide remotely configurable capability to autonomously monitor and shed load when the frequency falls below pre-set levels.[74]

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[72]LBNL Project at 18-19 and Table 1.

[73]LBNL Project at 19-20.

[74]LBNL Project at 20. LBNL observes that HECO is perhaps the only utility in the United States to offer frequency response integrated into device level control switches.

The LBNL Project summarized its observations with respect to HECO's demand response programs as follows:

> HECO has created a broad portfolio of demand response applications targeted to each of its major customer segments. HECO's small business commercial programs, in particular, target a market segment underserved by the utility industry. The features of these programs also provide operating flexibility not often found in most other utility applications. Eliminating seasonal and event/duration limitations, common to almost all other utility applications elsewhere, provides HECO with valuable operating flexibility. With the Fast DR and proposed CIDPP pilot projects, HECO is in a position to examine state-of-the-art options in communication and customer control features critical to demand response for renewable integration. HECO has also assembled detailed projections to estimate system wide potential for demand response across a range of typical load shaping objectives.[75]

The LBNL Project identified a number of projects, split into two paths, which are intended to develop revised estimates of HECO's demand response potential. A number of LBNL's specific recommendations are adopted in principle in a later section of this Policy Statement. In a nutshell, however, LBNL concluded:

> The collective end goal of all recommendations is to provide HECO with a flexible demand response framework that has the capability to address uncertainty, easily adapt to evolving requirements,

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[75]LBNL Report at 27.

and support options for achieving a range of objectives.[76]

C. <u>"Assessment Of Demand Response Potential For HECO, HELCO, And MECO," Prepared by Global Energy Partners, Inc.</u>

In May of 2010, Global Energy Partners, LLC ("GEP"), issued a Report that estimated the potential demand reductions from demand response programs for the HECO Companies.[77] The authors note that this Report was designed to address the unique operating characteristics of each of the three HECO Companies' systems.

Significantly, the study stated that because each system is currently a closed system, each system is "particularly susceptible to supply side fluctuations and constraints not typically experienced by most utilities on the mainland."[78] Thus, the GEP Report states that the demand response needs of the HECO Companies' systems differ from those of interconnected systems. Given this, the authors also included a separate assessment of the potential for a "sizeable" ancillary services program, which the Report refers to as "fast DR."[79] These fast

[76]LBNL Report at 45.

[77]"Report Title: Demand Response Potential Assessment for HECO, HELCO, and MECO," Global Energy Partners, LLC, Walnut Creek, CA, May 2010. (hereinafter cited as "GEP Report").

[78]GEP Report, Executive Summary at v.

[79]GEP Report, Executive Summary at v.

DR ancillary services are defined as resources necessary to respond to those events that require a response time of ten (10) minutes or less of event notification, such as events that are called during times of system emergency, when there is a sustained ramp down of variable renewable energy resources, or that are called to avoid starting generation units that have high variable costs.[80] The commission observes that the GEP Report does not appear to address the situation where demand response is used to shift load so as to avoid curtailment of renewable energy loads, such as shifting load to evening hours in order to avoid curtailment of wind generation.[81]

The GEP Report developed a total of nine DR options and assumed delivery mechanisms in assessing the potential for demand response for each utility.[82] These nine can be grouped into

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[80]GEP Report at 3-8.

[81]But see Docket No. 2010-0037, Hawaiian Electric Companies' Responses to Information Requests, DBEDT-HECO-IR-6, which notes that "[a]dvanced metering systems can also enable different pricing programs that are designed to modify customer behavior. However, depending on the design of the pricing program, energy usage may be shifted to different times of day for more efficient grid utilization grid stability rather than reducing overall usage. Smart grid technologies can be used to enable expanded and more intelligent load control on the grid." As further discussed in this Policy Statement, the commission views this objective as a primary one for future demand response programs.

[82]These include direct load control of central air conditioning, split system air conditioning, room air conditioning, water heating, and other end uses, as well as

five categories of demand response: direct load control, critical peak pricing, curtailment, demand bidding, and ancillary services. The four levels of potential addressed for these nine programs are: (1) a technical potential estimation, which assume 100% of customers in each class participate in one or more of the options without regard to costs and benefits; (2) an economic potential estimation, which also assumes 100% participation, but only considers options that are cost-effective; (3) a maximum achievable potential, which is the savings potential for programs that pass the economic screen; and (4) the realistic achievable percentage ("RAP"), which is the savings potential for the demand response options that pass the economic screen assuming "most likely" customer participation rates.[83]

The GEP Report included a summary of demand response potential by type of demand response program for each of the

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Critical Peak Pricing, Demand Bidding, and Ancillary Services/UF events. GEP Study at 3-1. It should be observed that while some of these options are similar to the existing RDLC and CIDLC programs, they are not identical to them. That is, the Report did not study the existing programs, it instead developed its own set of programs in order to assess the maximum potential for demand response for each of the HECO Companies.

[83]GEP Report at 1-1 to 1-2.

HECO Companies in terms of peak load reduction, as well as a summary of demand potential for fast DR ancillary services.[84]

The study stated that it took an aggressive view of the potential peak load reduction which could result from demand reduction and concluded:

> The results from this study show that there exists significant potential for peak load reduction for all three utilities through a wide variety of DR programs. The results also indicate the hierarchy of programs In the order of their contribution to the aggregate potential. The portfolio of DR programs needs to be designed carefully so that the appropriate customer segments are targeted with those programs that are likely to yield attractive results. . . . Other than pilot studies, primary market research could also be conducted for all three utilities so as to be able to better understand customer awareness of DR programs, perceived barriers, and what could be the best strategy toward program development and implementation.[85]

The Report concluded that the Realistic Achievable Potential ("RAP") peak load reduction from demand response potentially achievable by 2020 for each utility is as follows: (1) for HECO, a peak load reduction of 161 MW, or 11% of 2020 peak; (2) for HELCO, a peak load reduction of 19 MW, or 9% of

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[84]GEP Report at 3-1 to 3-8. The commission observes that these results should be viewed in light of the detailed discussion included in the Report.

[85]GEP Report at 5-40.

system peak; and (3) for MECO, a peak load reduction of 21 MW, or 11% of system peak.[86]

For fast DR (as defined by GEP), the GEP Report stated that the potential RAP load reduction for HECO grows substantially from 51 MW in 2010, to 91 MW in 2020, to 109 MW in 2040.[87] For HELCO, it grows from 1 MW in 2010, to 12 MW in 2020, to 16 MW in 2040.[88] For MECO, it grows from 1 MW in 2010, to 10 MW in 2020, to 13 MW in 2040.[89] The Report observed that all DR options considered under fast DR are cost-effective.

The Report concluded:

> Results for all three utilities show that residential dynamic pricing program has the largest share in the total potential. In our analysis, we assumed that residential customers with AMI are placed on default dynamic pricing with opt-out provision. The second highest contribution in the aggregate potential comes from residential Direct Load Control program. In the early years, this program has a high share in the total potential. But from 2020 onward, its share drops as dynamic pricing programs dominate in the total potential. The third highest contribution to the aggregate DR potential comes from C&I dynamic pricing programs. Reliability-based DR programs such as Curtailable tariffs have a high share in the early years of the analysis time frame. But as participation in dynamic pricing

[86]GEP Report at 5-1 to 5-40.

[87]GEP Report at 5-1 to 5-40.

[88]GEP Report at 5-1 to 5-40.

[89]GEP Report at 5-1 to 5-40.

programs steadily ramps up over time, their share progressively drops. Direct Load Control Programs for C&I customers have a relatively low share of less than 2% in the total potential. The C&I Demand Bidding Program also has a low contribution at 1-2% share from 2010 to 2020, with a steadily declining potential in later years.[90]

D. HECO's Annual Demand Side Management Reports.

HECO files two annual reports with the commission: (1) the Annual Program Modification and Evaluation Report ("M&E Report"), filed in November of each year; and the Annual Accomplishments and Surcharge Report ("A&S Report"), filed in March following the end of each program year.[91]

The M&E Report provides a prospective view of DSM programs operations for the next program year and includes the following:

- An updated forecast of the budgets and goals (i.e., demand savings);
- A description of the modifications to the program design that HECO proposes to implement; and
- The results of evaluation studies which can also serve as the basis for potential

[90]GEP Report, Executive Summary at xiv.

[91]Order No. 23717, filed on October 12, 2007, ordered that such reports and requests be filed in this docket. "Decision and Order," filed November 9, 2011, in Docket No. 2010-0165, ordered HECO and MECO to file their "Annual Accomplishments and Surcharge Report" for their Fast Demand Response Pilot Programs in this docket as well.

modifications to budgets, goals, and program implementation strategy.

The A&S Report includes a review of the DSM program(s) financial performance from the prior program year:

- Documenting the accomplishments of the programs, including an accounting of the demand savings impacts, equipment installations, and recorded program expenditures;
- Reconciling revenue collected from the cost recovery surcharge adjustment, and establishing new cost recovery factors for the DSM surcharge component of the Integrated Resource Planning ("IRP") Surcharge; and
- Providing an update of the cost effectiveness of the program(s) based upon recorded program expenditures and measure adoptions.

1. <u>The 2013 M&E Report</u>.

The most recent M&E Report was filed on November 29, 2013.[92] As set forth above, the M&E Report was designed to provide an updated forecast of budgets and goals, describe proposed modifications to the HECO Companies' demand response programs, and present evaluation studies which could serve as the basis for potential modifications to budgets, goals, and program implementation strategy.

[92]"Hawaiian Electric Company, Inc. Demand-Side Management Programs, Annual Program Modification And Evaluation Report," filed November 29, 2013 ("2013 M&E Report").

To begin, the 2013 M&E Report stated that the Fast DR Pilot program is "a limited scope market trial intended to test the Hawaii's C&I market acceptance of newer DR technologies, and two types of program designs: (1) a Curtailment Service Provider ("CSP") program design and (2) a Utility Managed Outsourced to Third Party program design."[93]

With respect to CSPs, the HECO Companies stated that a CSP is "a third party that serves as an intermediary between utilities and customers, aggregating groups of customers who participate DR programs.[94] HECO and MECO have contracted with Honeywell Utilities Solutions and Constellation New Energy to provide 6.0 MW of semi-automated DR.[95] In Hawaii, the participants are paid directly by HECO and MECO, rather than having the market clearing entity pay the CSPs directly for the delivery of the demand side resource, and having the CSP compensate the individual customers who are participants in the DR program.[96]

The 2013 M&E Report stated that another business model that is being utilized by some utilities is to outsource management of DR programs to third party contractors, which can

[93]2013 M&E Report at 5-6, footnotes omitted.

[94]2013 M&E Report at 5, n. 11.

[95]2013 M&E Report at 5-6, n.11.

[96]2013 M&E Report at 6, n. 11.

be done so that all program administration functions can be outsourced.[97] With respect to the Fast DR program, HECO has contracted with Honeywell International, Inc., and Akuacom (a subsidiary of Honeywell) to provide customer recruitment, customer program enrollment and load provisioning services, while HECO has overall responsibilities for program administration, including program design, customer relationship management, DR event scheduling and operations, measurement and verification (M&V), and financial settlement payments to participants.[98]

The 2013 M&E Report noted that on October 21, 2013, the commission approved the continuation of the RDLC and CIDLC Programs, with approval to replace participants who drop out through December 31, 2014.[99] HECO did not request any modifications for the RDLC or CIDLC Programs in the 2013 M&E report.[100]

Nevertheless, HECO discussed a number of changes to both Programs that it will propose in the near future. With respect to the RDLC program, HECO stated that, as its system moves to a grid comprised of more as-available renewable

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[97]2013 M&E Report at 6, n. 12.

[98]2013 M&E Report at 6, n. 12.

[99]2013 M&E Report at 12 and 18.

[100]2013 M&E Report at 13 and 19.

generation, "the ability for DR programs to provide ancillary services (i.e., additional dispatchable resources for spinning reserve and regulation services) will likely require operational changes to the current RDLC Program."[101]

> Hawaiian Electric anticipates future modifications to program rules, incentive structure, and load management equipment - replacement of one-way Load Control Receiver ("LCR") technology with newer two-way communication devices - will be necessary. These changes will support new DR technical and operational capabilities that must be developed such as: (1) establishing automatic load shed schemes which balance participants' tolerance for the number and duration of interruptions with the array of operational needs of the system operator, (2) developing infrastructure to provide reliable, real-time, high fidelity data on the available aggregate load from participants, and (3) having a portfolio of available load reduction resources which aggregate across all load management programs.
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> To this end, in 2014 Hawaiian Electric will pursue the development of new technical and operational strategies, the evaluation of new DR management systems, and the evaluation of new DR load management equipment technologies as further described herein. Hawaiian Electric will also pursue a "community based model" enrollment methodology to replace participants who have exited the program. The model will focus on the demographic community that would benefit from an energy efficient device that also provides incentives through a DR program.[102]

[101]2013 M&E Report at 15.

[102]2013 M&E Report at 15-16.

The 2013 M&E Report also stated that HECO and Silver Spring Networks ("SSN") have teamed to begin the initial build out of SSN's modernized grid solution during the first quarter of 2014.[103] This phase is focused on the deployment of advance metering to a group of approximately 5,100 residential households, and will include both upgraded switches and a limited field trial of ZigBee enabled load management equipment such as programmable communicating thermostats and other load control devices.[104] The DR objectives for Phase 0 are:

> (1) Market Test - Validate the current RDLC Program participants' willingness to continue their participation in DR programs; (2) Technology Adoption - Identify customer barriers to the adoption of newer load control devices; (3) Operational Experience - Conduct a limited evaluation of residential DR loads to act as a flexible resource for renewable integration and; (4) Cost-Effectiveness - Collect and analyze customer and utility cost and benefit information to validate key assumptions for the Hawaiian Electric Companies' residential DR program design.[105]

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[103] 2013 M&E Report at 17.

[104] 2013 M&E Report at 17. Zigbee's website describes Zigbee Smart Energy as the "world's leading standard for interoperable products that monitor, control, inform and automate the delivery and use of energy and water" that "create greener homes by giving consumers the information and automation needed to easily reduce their consumption and save money, too." See www.zigbee.org/Products/ByStandard/ZigBeeSmartEnergy.aspx

[105] 2013 M&E Report at 17.

It should also be noted that, following the filing of its 2013 M&E Report, on January 10, 2014, HECO filed for approval to modify the RDLC by adding a new classification of grid interactive electric resistance water heaters to the residential water heating program element so as to conduct a "proof of concept deployment" in program year 2014.[106]

With respect to the CIDLC Program, HECO stated that it will, in the near future, be requesting certain operational changes in the Program which, among other things, will improve the use of the CIDLC program as a "flexible operating tool for system operators" and will "better align the CIDLC Program with the new Environmental Protection Agency ("EPA") regulations, new system requirements, and Fast DR Pilot Program."[107] As to the latter, according to HECO, these changes to the CIDLC program will result in the termination of its Fast DR pilot program:

> The Fast DR Pilot Program began in 2012 and will close at the end of 2014. Hawaiian Electric plans to request closure of the pilot in the third quarter of 2014, and transition the Fast DR customers to the CIDLC Program. Therefore the intent of the three "new options" under the CIDLC program is twofold: (1) to create a smooth transition for Fast DR customers, and (2) to apply the

[106]Docket No. 2007-0341, Letter Requesting RDLC Program Modifications, filed January 10, 2014, at 1. The Letter also proposes other modifications to budgeting and reporting requirements. Id.

[107]2013 M&E Report at 23.

> lessons learned from the Fast DR pilot to the current CIDLC program.[108]

The three new DLC options referenced in the above quote are (1) a ten minute notice emergency option; (2) a ten minute notice emergency and economic option; and (3) a ten minute notice emergency and economic, "no generators" option.[109] For the SBDLC program element, HECO notes that:

> As Hawaiian Electric's system moves to a grid comprised of more as-available renewable generation, the ability of the SBDLC Program element to provide ancillary services (i.e., additional dispatchable resources for spinning reserve and regulation services) will require changes to the current SBDLC program including, modifications to program rules, incentive structure, and load management equipment (i.e., replacement of LCR technology with newer IP based two-way devices) in order to fully realize the opportunity for significant economic and reliability benefits at times when the system experiences a sustained ramp down of intermittent renewable generation. In 2014, the Company will pursue the development of new technical and operational strategies, evaluation of new DR management systems, and the evaluation of new DR load management equipment technologies as further described herein.[110]

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[108] 2013 M&E Report at 23.

[109] 2013 M&E Report at 25.

[110] 2013 M&E Report at 26.

The 2013 M&E Report also addressed such issues as forecasted impacts and cost-effectiveness of the demand side programs.

2. The 2014 A&S Report.

The most recent A&S Report was filed on March 31, 2014.[111] In it, HECO described the following as its overall objective for its demand response programs (RDLC, CIDLC, and Fast DR):

> The Companies' Demand Response ("DR") strategy is to develop portfolios of residential, commercial and industrial customer loads that will enable the reliable planning and economic operations of Hawaii's electric grid. Hawaiian Electric's DR programs were traditionally deployed as load management (or direct load control) resource options for generation capacity deferral. Generation capacity deferral load management programs are designed to primarily respond to events for reliability reasons (such as generation system emergencies) by disconnecting the customer's use of utility supplied power for a pre-defined period of time. These traditional uses of load management programs continue to benefit customers by allowing Hawaiian Electric to defer and/or reduce the size of future capital investments to build new power plants, and are still used today by Hawaiian

[111]Docket No. 2007-0341, Hawaiian Electric Company, Inc., "Demand-Side Management Programs Annual Accomplishments and Surcharge Report," March 31, 2014 ("2014 A&S Report").

Electric's system operators to respond to system emergencies.[112]

The 2014 A&S Report stated that HECO's RDLC, CIDLC, and Fast DR Pilot programs provided a cumulative load impact at the customer level of approximately 29.9 MW.[113] The RDLC Program achieved approximately 14.8 MW of load reduction (a drop of -0.2 MW from 2012 levels), the CIDLC Program achieved approximately 12.8 MW of load reduction (a decline of -3.8 MW

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[112]2014 A&S Report at 4. The HECO Companies state that the RDLC and CIDLC Programs are collectively referred to as the "EnergyScout Programs." Id. The Companies further state that this Report does not include information concerning the SolarSaver Pilot Program. The commission observes that a separate report on that program, entitled "SolarSaver Pilot Program Report," was filed on March 28, 2014, in Docket No. 2006-0425.

[113]The HECO Companies state that program impacts were previously reported at the gross generation level, and that an 11.17% loss factor was used to convert impacts from gross generation to the customer level. 2014 A&S Report at 6, n. 8. The Companies further state that on a going forward basis, program impacts will be reported at the customer level because that is the common reference point used for other relevant filings, such as the Adequacy of Supply filing. Id.

Thus, the 2013 A&S Report stated that there was 36.0 MW of gross generation (32.0 MW of customer generation assuming an 11.17% loss factor), based on impact assumptions for RDLC and CIDLC from the 2011 EnergyScout Impact Evaluation Report and the enabled load under the Fast DR Pilot Program. 2013 A&S Report at 6-7. The 2013 A&S Report further noted that in 2012, there was decline of 0.3 MW in the RDLC program and 0.6 MW in the CIDLC program. Id. This was due to the fact that approximately 500 water heaters and 100 air conditioning participants in the RDLC Program either opted-out from further participation or converted to solar water heating. Id. The reduction in the CIDLC program was due to the fact due that a participant removed one of its facilities from the CIDLC Program because the facility closed and no longer receives electric service. Id.

from 2012 levels), and the Fast DR Pilot Program for HECO and MECO provided 2.25 MW of load reduction (an increase of 1.85 MW from 2012 levels).[114] In 2013, the HECO Companies utilized the DR Programs 165 times for a cumulative duration of 129 hours, 28 minutes, a small decline from 2012 levels.[115]

As noted above, there were declines in the load reduction attributable to the EnergyScout programs. The HECO Companies described the reasons for this decline as follows:

> In 2013, approximately 350 water heater ("WH"), and 50 air conditioning ("A/C") participants in the RDLC Program either opted-out from further participation or converted to solar water heating which resulted in a reduction of 0.2 MW (customer level). In 2013, the CIDLC program load impact was reduced by 3.8 MW (customer level) due to two customers who opted out of the program due to changes in their operational requirements, one customer that changed facilities and did not want to enroll the new facility equipment, and one customer that closed its facility and no longer receives electric service.[116]

The 2014 A&S Report also summarized the expenses for the demand response programs. In 2013, HECO spent approximately (1) $4.9 million for the RDLC and CIDLC programs; 77% of those expenses (approximately $3.8 million) were incentives paid to

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[114]2013 A&S Report at 6-7.

[115]2014 A&S Report at 8; 2013 A&S Report at 8.

[116]2014 A&S Report at 6 (footnote omitted).

customers; (2) $1.2 million for HECO's Fast DR program; and (3) $43,744 for MECO's Fast DR program.[117]

The benefits and costs of the EnergyScout Programs are determined using the following four tests, which are set forth in the 2001 California Standard Practice Manual ("SPM"):[118]

- Program Administrator Cost Test ("PAC"): The PAC test compares capacity and fuel savings with utility program costs. A value greater than one (1) indicates that the net present value of revenue requirements will be reduced.

- Total Resource Cost Test ("TRC"): The TRC test compares the capacity and fuel savings with the program costs plus customer costs (excluding incentives paid to customers). Since customer incentives are considered a transfer payment in the TRC test, incentives are not included in the calculation (i.e., the customer incentive benefit to the participant is offset by the increased revenue requirement for the utility). Thus the results of the TRC Test will be greater than the results of the PAC Test. A value greater than one (1) for the TRC Test indicates that the program is a cost effective resource option.

- Participant Test ("PT"): The PT test quantifies the benefit a participant may derive from a DR program. This test measures whether the DR measure/equipment is economically attractive to the participant. A value greater than one (1) indicates

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[117]2014 A&S Report at 7.

[118]California Standard Practice Manual, "Economic Analysis of Demand Side Management Programs and Projects" (October 2001). <u>See also</u> "2010 Demand Response Cost Effectiveness Protocols," California Public Utilities Commission, R.07-01-041.

that the program is cost-effective for the participant.

- Rate Impact Measure Test ("RIM"): The RIM test assesses the average rate impact to non-participants over the life of the program. The costs included in the RIM Test include costs to administer the program, incentives paid to participants, and lost revenue from long term reduced electricity sales that result from conservation and energy efficiency programs. A value greater than one (1) indicates the program has a positive impact to the average rate, while a value less than one (1) indicates a negative impact to the average rate.[119]

Utilizing these tests, the 2013 A&S Report concluded that, for 2012, the benefits to all customers, both participants and non-participants, outweighed the costs of the program.[120] While the 2014 A&S Report states that HECO analyzed costs and benefits pursuant to these tests, HECO applied the tests to two of the scenarios described in the 2013 IRP Report: (1) the "Blazing a Bold Frontier" scenario and (2) the "Stuck in the Middle" scenario.

The "Blazing a Bold Frontier" scenario envisions very high oil prices and a community "sentiment" to expand clean energy goals; this sentiment, in turn, is presumed to motivate policy makers to progress "briskly and boldly" towards integrating more renewable energy to mitigate the high cost

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[119]2014 A&S Report at 8-9.

[120]2013 A&S Report at 12.

of fossil fuel generation on electricity rates.[121] The 2014 A&S Report states that, under this scenario, "system demand is declining in future years which decreases the urgent need to install future firm capacity generation" and that "[a]s a result program benefits are significantly reduced."[122] Thus, the 2014 A&S Report concludes that "the EnergyScout Program is not cost-effective under this scenario because the benefits do not outweigh the costs of the program."[123]

It should be observed, however, that the IRP analysis does not take into account use of demand response for ancillary and other services:

> Currently the IRP analysis is unable to account for possible electric grid services that DR could provide to support further integration of as-available renewable resources. In the meantime the Companies' continue to assess if DR can be used as an operational tool to provide such services by mitigating impacts of as-available renewable resources (i.e. unpredictable ramping-up and ramping-down of this type of generation.) In this vein, Hawaiian Electric has proposed program modifications and has taken initial steps to evaluate such electric grid support benefits provided by the existing EnergyScout Programs.[124]

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[121]2014 A&S Report at 10 (footnote omitted).

[122]2014 A&S Report at 10.

[123]2014 A&S Report at 10-11.

[124]2014 A&S Report at 11.

Results are more favorable from a cost/benefit standpoint under the "Stuck in the Middle" scenario. This scenario is described as one in which oil prices grow from 2012 levels and where interest in meeting clean energy goals continues, but remains mired in indecision, leading to continuing debate on solutions and little policy changes.[125] The 2014 A&S Report states that "[t]he Stuck in the Middle scenario reflects a relatively static system demand in future years which presents an opportunity for the EnergyScout Programs to defer installation of future firm capacity generation."[126] Thus, the 2014 A&S report concludes that "the benefits to all customers, both participants and non-participants, outweigh the program costs" under this scenario.[127] Again, however, it should be observed that this analysis focuses on deferring future firm capacity generation and not on the use of demand response to provide ancillary and other services.

The forecasted cumulative load impacts for the RDLC and CIDLC Programs for 2014 are 15.0 MW and 16.6 MW, respectively.[128]

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[125]2014 A&S Report at 11 (footnote omitted).

[126]2014 A&S Report at 11.

[127]2014 A&S Report at 12.

[128]2014 A&S Report at 12. Again, these estimates are provided at the customer level.

These estimates assume that customers who exit the EnergyScout Programs will be replaced through year-end 2012.[129]

> The replacement of customers on the RDLC Program may result from: (1) load reductions associated with participants who exit the program, and (2) participants who convert from electric resistance water heating to solar water heating. For the CIDLC Program, replacement of customers may result from: (1) customers who do not complete commissioning and have expired program contracts, (2) participants who exit the program for unforeseen reasons (e.g., shutting down a facility and no longer receiving electric service), and (3) any potential modifications in contract interruptible loads for the existing CIDLC Program participants.[130]
>
> For the Fast DR programs, the Report states:
>
> In 2014, Hawaiian Electric expects to enable an additional five (5) customers in the Fast DR Pilot for a cumulative load impact of approximately 6.9 MW (customer level). Maui Electric has met its Fast DR Pilot goal of enrolling four (4) customers for a total of 0.2 MW (customer level), and will enable their fourth final customer for a cumulative load of 0.2 MW (customer level).[131]

In addition to capacity reductions, there are other system benefits resulting from the programs. For the RDLC, these include system protection operations, reliability dispatch operations, economic dispatch operations, and test events.

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[129]2014 A&S Report at 12.

[130]2014 A&S Report at 12.

[131]2014 A&S Report at 12.

System protection (or under-frequency) capabilities are utilized when unforeseen situations arise, such as the loss of a major generating unit or some other event that causes system frequency to decrease rapidly.[132] The residential participant's load control receiver ("LCR") senses the drop in frequency and removes that participant's contract interruptible load ("CIL") from the grid. Once the system frequency has stabilized, power is restored to the LCR and the participant's load is returned in a smooth ramped return. In 2013, the RDLC controllable load operated automatically in response to under-frequency events 11 times for cumulative duration of 37 minutes.[133]

With respect to reliability dispatch operations, in 2013, system operators dispatched the controllable loads in the RDLC Program 18 times for a cumulative duration of 16 hours, 1 minute, in anticipation of, or in response to, emergency conditions on the system.[134]

With respect to economic dispatch operations, the 2014 A&S Report stated:

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[132] 2014 A&S Report at 19.

[133] 2014 A&S Report at 19.

[134] 2014 A&S Report at 20.

> In 2013, Hawaiian Electric's system operators dispatched the controllable loads for the RDLC WH program and A/C program elements 29 times for a cumulative duration of 28 hours, 19 minutes in order to assist in serving the loads which would otherwise have been served by the normal operations of Hawaiian Electric's generating units. The 2013 economic dispatch events enabled system operators to lower total system operating costs by dispatching RDLC Program loads. For limited periods of time, where the load and the rate of change in load can be predicted with some certainly, system operators used the RDLC Program to avoid start-up costs and emissions associated with starting and running generating units for short periods of time to maintain balance between system demand and generation supply.[135]

Finally, with respect to Test Events, the Report states that in the summer of 2013, HECO installed 50 programmable communicating thermostats ("PCT") in the RDLC Program as part of a field trial to analyze PCT load impact from increasing the participants' thermostat set-point by four degrees, and running the event for three hours.[136] According to the 2014 A&S Report:

> The purpose of the 2013 PCT field trail was to test and collect data on the PCT load impact as well as customer acceptance of the device. Unlike a (sic) LCR which is controlled using a 50 percent cycling algorithm, PCT control can be performed by changing the temperature set-point of the thermostat. The PCT also provides more customer value because it has device features that allow customers to pre-schedule and

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[135]2014 A&S Report at 20.

[136]2014 A&S Report at 20.

> monitor the energy usage of their air conditioner. The PCT field trial indicated that the individual PCT load impact was comparable to the LCR impact, and that Hawaiian Electric could run a three (3) hour event with a PCT in comparison to the typical one (1) hour event with a LCR, and still maintain the customer acceptance of the longer DR events.[137]

On April 26, 2013, HECO issued a Request for Information ("RFI") to evaluate DR technologies for residential and small commercial business markets.[138] The Report states:

> Over 40 responses to the RFI were received, which was higher than the company anticipated and a positive indication that the market for DR technologies is dynamically growing. Of the 40 responses, 12 submissions were end device technologies (i.e. load control switch, PCT), eight (8) submissions focused on solutions for the back-end system to control an end device, 14 submissions proposed a solution from the end device to their back-end system, and six (6) submissions specialized in gateway devices that provided a link between the end device and the backend system.
>
> For all 40 submissions Hawaiian Electric analyzed product features such as preferred two-way communication protocol and market penetration of the product on a national level. The overall assessment of the responses also indicated that the market is still in its infancy due to a substantial number of proposed products that did not provide a complete DR solution, or were not flexible enough to work interchangeably with other products or on Hawaiian Electric's

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[137]2014 A&S Report at 20-21.

[138]2014 A&S Report at 21.

> current back-end system. As Hawaiian Electric continues to evolve its DR programs the results of this RFI provide a snapshot of what new technologies are currently available and an exhaustive list of vendors that the Companies' can work with in future DR program development.[139]

HECO concludes that the RDLC program is beneficial to the continued reliable operation of the electric grid and, thus, states that it will continue to utilize the residential water heater and air conditioning loads for system protection, reliability, and economic dispatch purposes.[140] HECO further observes that, as it moves to integrate more as-available, renewable resources, "the ability of the RDLC Program to serve as an additional dispatchable resource to reduce system demand can provide a significant reliability benefit at times when the system experiences a sustained ramp down of intermittent generation."[141] Thus, HECO states that in 2014, it will "continue to develop new load control schemes for its system operators to execute" and "will introduce the operation of GIWH to the system operation team to coordinate events focused on more integration of as-available renewable resources."[142]

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[139]2014 A&S Report at 21.

[140]2014 A&S Report at 23.

[141]2014 A&S Report at 23.

[142]2014 A&S Report at 23. The Report further states that additional details on the activities for the RDLC Program for 2014 are set forth in section II of the 2013 M&E Report.

Similar additional benefits are listed for the CIDLC program. The CIDLC Program is utilized for under-frequency capabilities when unforeseen situations arise that cause the system frequency to decrease rapidly; in 2013, the CIDLC controllable load operated automatically in response to three different under-frequency events for a cumulative duration of 13 minutes.[143] The CIDLC Program can also be used to address reliability issues, but the Program was not used in 2013 in response to, or anticipation of, any emergency conditions.[144]

HECO further states that as it continues to modernize its grid, demand response can be used for additional purposes, including: "(1) integrating as-available renewable resources (i.e. mitigating unpredictable ramping-up and ramping-down of this type of generation), (2) economic benefits by peak shaving and avoiding the start-up of Hawaiian Electric generators, and (3) system reliability with under-frequency."[145] HECO has also proposed several modifications to the CIDLC Program, including: (1) adding a Technical Assessment and Technical Incentive ("TA/TI") customer installation allowance; (2) adding a new "Monthly Nominated Load" incentive calculation method; and

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[143]2014 A&S Report at 27.

[144]2014 A&S Report at 27.

[145]2014 A&S Report at 27.

(3) adding a new classification of grid interactive electric resistance water heater technology.[146]

With respect to the HECO/MECO Fast DR Programs, during 2013, HECO recruited technical coordinators ("TC") to perform the installation and enablement process through the Commission-approved TA/TI installation allowance; these activities were designed to meet the four Fast DR Pilot objectives which are: (1) market test, (2) technology evaluation, (3) operational experience, and (4) cost-effectiveness.[147]

With respect to the market test, the Report states that the initial market segments targeted in 2012 included hospitality, condominium, and office building segments due to their sophisticated EMS systems, but that with the introduction of the TA/TI incentive, recruitment increased by ten customers with varying types of building controls.[148] Because recruitment exceeded expectations, HECO decreased its enrollment efforts in mid-2013.[149]

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[146]2014 A&S Report at 30-31.

[147]2014 A&S Report at 34.

[148]2014 A&S Report at 34.

[149]2014 A&S Report at 34.

With respect to technology evaluation, the Report states:

> The diversity of the market has brought a variety of engineers and technologies capable of integrating any device onto the program using an Open Automated Demand Response ("OpenADR") signal. The OpenADR signal is sent from Hawaiian Electric's DRAS to multiple OpenADR gateways. The OpenADR gateways and OpenADR cloud services have proven to be reliable. One TC also offers EE devices that can perform demand limiting and DR through their cloud service. This TC is providing customers with an EE/DR solution by using the TA/TI to help decrease project costs to the customer.[150]

With respect to operational experience, HECO reports that the TCs started recruiting Fast DR customers in June, 2013, and the addition of more TCs has helped enable customers and has spurred competition among the TCs.[151] The Report further states that:

> In latter half of 2013, Hawaiian Electric's system operation engineers created various scenarios for potential use of the Fast DR resource for system benefits. One such scenario tests cost savings related to deferral of starting up generators by forecasting the increasing amount of intermittent distributed power during the mid-morning period (e.g., increasing solar PV generation due to increasing solar irradiance), against the anticipated rate of system load growth over the same period, and

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[150]2014 A&S Report at 35.

[151]2014 A&S Report at 35.

using DR to manage the system load to avoid a generator start up.[152]

With respect to cost effectiveness, HECO states that its consultants are establishing a multi-attribute framework to analyze how successful the Fast DR Program is in meeting the goals and objectives of the program.[153] The Report states that the results will be presented in the final evaluation report to be submitted by the end of the third quarter of 2014.[154]

For 2014, HECO states that expects to enable "an additional six (6) customers for a cumulative load impact of 6.9 MW (customer level)" and observes that MECO "has met its goal of enrolling 0.2 MW (customer level) and will enable its fourth and final customer for a cumulative load impact of 0.2 MW (customer level)."[155] In addition, HECO plans to (a) train and evaluate system operators; (b) commission additional customers; (c) modify and test new Fast DR program rules; (d) enable and analyze customers with water and wastewater loads capable of performing load following; and (e) submit a final Fast DR Pilot evaluation report.[156]

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[152]2014 A&S Report at 35.

[153]2014 A&S Report at 36.

[154]2014 A&S Report at 36.

[155]2014 A&S Report at 37.

[156]2014 A&S Report at 38.

Finally, the 2014 A&S Report addresses the Commission's Decision and Order filed November 9, 2011, approving the establishment of a Fast DR Pilot Program. In that Order, the Commission directed the HECO Companies to submit, in their annual M&E Report, A&S Report, and final pilot program report, information concerning seven specific issues.[157] In summary form, the 2014 A&S Report addressed these issues as follows:[158]

1. Impact of Fast DR Pilot on the CIDLC Program:

   Response Lessons learned thus far from the Fast DR Pilot Program have positively impacted the design of the CIDLC Program.

2. Load impact evaluation:

   Response HECO's evaluation consultant tested nine alternative day-of adjustments, and found that a day-of adjustment period two (2) hours prior to the event performed best. "Using this method, the consultant estimates an average curtailment of 148 kW per customer, five (5) percent more than the average kilowatts of load curtailment than these customers committed to and 29 percent more than the average kilowatts of load curtailment estimated using the Hawaiian Electric's settlement methodology."

3. Cost effectiveness of Fast DR Pilot:

   Response A determination of cost-effectiveness cannot be prior to completion of the pilot and HECO has data on enrollment and administrative costs,

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[157]Docket No. 2010-0165, "Decision and Order," filed on November 9, 2011, at 21-22.

[158]2014 A&S Report at 39-41.

enablement costs, load curtailment, persistence of participation and load reductions, and the avoided costs from calling Fast DR events.

4. <u>Fast DR Pilot Program Costs</u>:

Actual program costs cannot be compared to budgeted program costs until the pilot is complete and data on actual program costs is collected.

5. <u>Risk Management and Action Plan</u>:

<u>Response</u> The 2014 A&S Report states that there are no additional updates to the Risk Management and Action Plan that was attached to the Navigant Report.[159]

6. <u>Evaluation of the Pilot based on the Risk MAP</u>.

<u>Response</u> The Report identifies the three current risks as: "(1) delayed customer enablement, resulting in inadequate data to analyze and evaluate pilot objectives; (2) lack of maturity of technologies and protocol/security standards which are still under development and not available in time for deployment; and (3) delays in modification to certain program parameters." These issues will be addressed in the final evaluation report to be filed at the end of the Fast DR Pilot.

7. <u>Potential for Fast DR at HELCO</u>.

Navigant Consulting, Inc., was retained to assist in analyzing the potential for Fast DR on the HELCO system. The applicability of Fast DR for HELCO's system is discussed in Navigant's separate report entitled "Fast Demand Response at Hawaii Electric Light:

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[159]A copy of Navigant's "Risk Management Plan Project: Fast DR Pilot Program" is attached to the 2012 M&E Report.

Initial Findings in Response to the Hawai'i Public Utilities Commission's D&O Reporting Requirements," November 2012. The HECO Companies anticipate filing an update to this report with the 2014 M&E report or at the time that they file the final Fast DR pilot evaluation report.

E. 2011 EnergyScout Impact Evaluation: Hawaiian Electric Company's Direct Load Control Programs.

On March 31, 2013, in Docket No. 2007-0341, HECO filed its "2011 EnergyScout Impact Evaluation: Hawaiian Electric Company's Direct Load Control Programs," prepared by KEMA, Inc. (hereinafter referred to as the "KEMA Report").[160] The KEMA Report provides the impact evaluation results for three of HECO's Direct Load Control ("DLC") programs: Residential Water Heater ("RDLC-WH"), Residential Central Air-Conditioner ("RDLC-CAC"), and the Commercial and Industrial DLC Program ("CIDLC"). These programs use load control relay switches ("LCRs"), whereby either HECO can interrupt the power by radio on demand, or the units are programmed to respond by disengaging automatically during under-frequency ("UF") events.

In the report, KEMA develops new load shapes for each DLC program, concludes that the new load shapes for RDLC-WH are

[160]HECO's cover letter stated that this Report was filed in accordance with Order No. 23717 and that it is the second and final impact assessment planned for RDLC and CIDLC programs. These programs are sometimes collectively referred to as the "EnergyScout" Programs. KEMA Report, Cover Letter, p. 1.

more accurate than the existing load shapes for forecasting load reduction, and finds that the model used to predict the RDLC-CAC load produces very accurate results.

F. MECO System Improvement And Curtailment Reduction Plan Review.

In Docket No. 2011-0092, addressing MECO's most recent rate case, the commission ordered MECO to file a "System Improvement and Curtailment Reduction Plan" ("SICR").[161] Among other things, the SICR was required to address the "[u]tilization of demand response programs and energy storage technologies to reduce the need for on-line fossil generation to provide operating reserves and other ancillary services."[162]

MECO filed its SICR on September 3, 2013. Thereafter, the commission retained a consultant, Brendan Kirby, to review the SICR as filed.[163] With respect to MECO's current demand response programs, Mr. Kirby concluded:

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[161]"In the Matter of the Application of MAUI ELECTRIC COMPANY, LIMITED, For Approval of Rate Increases and Revised Rate Schedules and Rules," Docket No. 2011-0092, Decision and Order No. 31288 at 135 (May 31, 2013) ("Order No. 31288").

[162]Order No. 31288 at 136.

[163]"MECO System Improvement and Curtailment Reduction Plan Review," prepared by Brendan Kirby, dated February 24, 2014, and filed in Docket No. 2011-0092 on February 26, 2014 ("Kirby Report"). The Kirby Report, and MECO's response, are discussed in greater detail in Decision and Order being issued in Docket No. 2011-0092 simultaneously with this Policy Statement.

> The demand response program described in the SICR Plan appears both slow and misdirected. With wholesale energy costs an order of magnitude higher than on the mainland one would think that Hawaii would be leading in the deployment of demand response. On the contrary, while the Electric Reliability Council of Texas (ERCOT) must limit market-supplied demand response of contingency reserves (too much demand response is offered and at prices below generation response), MECO finds demand response ineffective and expensive. **This may be because MECO's focus has been on traditional peak reduction and load shifting rather than on flexibility and fast response.** With curtailment expected during all hours (Figure 6) it is up and down reserves that are required, especially reserves that can bridge until fast-start generation can respond. In the case of new ICE generation this can be under five minutes. The island's small electrical size, compared with mainland interconnections, can be an advantage for demand response utilization with power system frequency providing a very fast deployment signal.[164]

Mr. Kirby emphasizes that MECO has focused exclusively on shifting consumption rather than on short duration rapid response and the provision of ancillary services.[165] "The focus on prescheduled operations of thermal generation, energy storage, and demand response are all misguided" because MECO failed to recognize that "[b]oth operations and analysis need to focus on

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[164]Kirby Report at 2 (emphasis added).

[165]Kirby Report at 3.

response to the dynamically changing aggregation of load and variable renewable resources (both central and distributed)."[166]

In his analysis, Mr. Kirby states that the modeling conducted in response to Order No. 31288 was not able to determine when to dispatch demand response resources for optimal curtailment reduction because those resources are modeled as scheduled programs rather than as flexible tools to help mitigate curtailment of renewable generation.[167] MECO's failure to model correctly is problematic for a number of reasons, including: (1) it focuses on using demand response to eliminate the need for cycling generation, but does not show whether demand response could help to eliminate the need for baseload generation and (2) as noted above, MECO appears to have modeled demand response on a fixed schedule, negating its flexibility and response benefits.[168]

Moreover, the Kirby Report states that "[i]t is especially troubling to base recommendations and decisions on modeling tools and analysis that fall materially short of accurately reflecting the capabilities and limitations of the power system and the resources being analyzed."[169] The Report

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[166]Kirby Report at 3.

[167]Kirby Report at 17.

[168]Kirby Report at 17.

[169]Kirby Report at 17-18.

observes that "[r]atepayers cannot afford to compensate MECO for increased operating costs that result from inadequate modeling techniques and tools."

Following a discussion of these issues, the Kirby Report makes the following recommendations with respect to MECO's demand response programs:

1. MECO's demand response programs should be examined to determine if they are fully addressing the actual system flexibility needs necessary to facilitate integration of renewable resources.[170]

2. MECO should analyze utilizing DR to provide ancillary services and operating reserves to reduce the amount of required must run generation and curtailment of renewable resources. If MECO is currently unable to model the full range of demand response resources, MECO should rectify this shortcoming by improving its modeling capability before performing the analysis.[171]

3. The Commission could consider again asking MECO to analyze demand response programs and energy storage technologies to reduce the need for on-line fossil generation to provide operating reserves and other ancillary services. However, given the amount of effort MECO has invested in current ineffective demand response efforts, a complete redesign of the current demand response effort may be in order.[172]

4. For water and wastewater facilities, commercial aggregators that enable these

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[170]Kirby Report at 22.

[171]Kirby Report at 18.

[172]Kirby Report at 22.

> facilities to provide ancillary services already exist. Thus, the Commission could consider asking MECO to invite an appropriate commercial aggregator to analyze the facilities and to recommend a solution for possible immediate implementation.[173]

Finally, Mr. Kirby recommends that the commission conduct a review of MECO's demand response programs to determine, among other things, the types of demand response that are best suited to reducing curtailment of renewable resources and that fully consider ancillary services.[174] Further, he recommends that MECO consider retaining outside experts and demand response providers that currently supply regulation and contingency reserves from aggregations of responsive load.[175]

VI.

POLICY STATEMENT

The commission strongly supports and encourages the continuation and implementation of existing and new demand response programs, provided that these programs result in quantifiable benefits to all ratepayers, whether or not they participate directly in those programs. Both the DSO Paper and LBNL Project present detailed lists of overall objectives for

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[173]Kirby Report at 22.

[174]Kirby Report at 22-23.

[175]Kirby Report at 22-23.

such programs, which the commission has, to a large extent, incorporated into its findings here.

In this Policy Statement, the commission establishes the following as the stated objectives for current and future demand response programs to be developed and implemented by the HECO Companies.

1. Demand response programs should provide quantifiable benefits to ratepayers.

2. Demand response programs should provide at least one and, in most cases, more than one, of the following:

a. A reduction in total kilowatts consumed or a change in how kilowatts are consumed that is beneficial to overall system operations;[176]

b. A reduction in peak loads and, thus, the deferral of new generation capacity;

c. Assistance in meeting photovoltaic and wind variability;

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[176]Energy efficiency programs provide energy savings, and demand response programs provide reductions in demand at critical times, ancillary services, and other benefits as discussed herein. However, there is some overlap: energy efficiency can reduce demand, and demand response, with proper control strategies, can produce some energy savings. See National Action Plan for Energy Efficiency, "Coordination of Energy Efficiency and Demand Response," Prepared by Charles Goldman (Lawrence Berkeley National Laboratory), Michael Reid (E Source), Roger Levy, and Alison Silverstein (2010).

d. A shift of a portion of system load to off-peak times (which may be mid-day in the near future for systems with high PV penetration) to, among other things, increase consumption of minimum load generation and to reduce curtailments of renewable generation;

e. Assistance in assuring the reliability of the system through, among other things, programs that permit fast response of short duration to meet contingency conditions prior to utility emergency diesel generators coming on line;[177]

f. A non-fossil fuel source of ancillary services, such as frequency management, up-regulation and down-regulation, and dispatchable energy;

g. Customer benefits such as greater control over energy use and opportunities to lower electricity bills; and

h. A potential means for addressing greenhouse gas emissions standards established by the state of Hawaii and the federal government.

The HECO Companies' current demand response programs primarily act so as to reduce usage during peak periods and to assist in addressing system reliability in under-frequency situations, although there are certain features of these programs

[177]Demand response which increases load during times of high wind and solar generation may also be available to provide spinning reserve and regulation during the exact times when wind and solar increase their need.

that provide HECO with additional operational flexibility. However, as discussed above, demand response programs can and should be structured to assist the system in various ways, from shifting on-peak load to off-peak times, to providing ancillary services, to assisting in the integration of renewable energy resources into the grid.

By way of this Policy Statement, the commission directs the HECO Companies to undertake, immediately and expeditiously, an overhaul of their existing demand response programs by (1) consolidating those programs into a single integrated demand response 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.

The commission also observes that, currently, HECO is further along in its implementation of demand response programs than either MECO or HELCO. Thus, the integrated demand response portfolio evaluation conducted by the latter two companies should avoid unnecessary duplication and delay by utilizing the practices and lessons learned from HECO's implementation. The commission finds that a more aggressive approach to demand response is appropriate for HELCO and MECO where there are significant amounts of variable renewable energy resources already installed and there is a need to reduce curtailment of renewable energy resources.

VII.

REQUIREMENTS TO BE COMPLETED WITHIN NINETY (90) DAYS OF THE DATE OF THIS POLICY STATEMENT AND ORDER

A. Consolidation Of Demand Response Programs.

By way of this Policy Statement, the commission is directing each of the HECO Companies to consolidate into a single integrated portfolio - for planning, operational, administrative, and cost recovery purposes - their currently existing and/or future planned demand response programs. As discussed in the next section, each Company should establish a well-defined set of overall objectives and goals to be achieved by the portfolio as a whole and how each of the various demand response programs that make up the portfolio specifically contribute to those objectives and goals.

The HECO Companies have repeatedly stated that they view their various individual demand response programs (such as CIDLC, RDLC, and Fast DR) as a means of developing a portfolio of residential, commercial, and industrial loads that will enable them to operate the grid in a reliable and economic fashion. For example, HECO has stated:

> Hawaiian Electric's DR strategy is to develop a portfolio of residential, commercial and industrial participant loads that will collectively enable reliable and economic operation of the modern grid [reference omitted]. Hawaiian Electric has taken steps to implement its DR strategy incrementally, over time, through a combination of shorter-term initiatives including, pilot programs, participation in grant-funded research, development and demonstration projects, and market studies.[178]

The HECO Companies' current approach focuses primarily on the levels of interruptible capacity that can be attained from each individual program. Thus, while a "total" amount of interruptible capacity for all programs can be calculated by adding together the individual capacity numbers, there is no unified plan to achieve an overall goal. Essentially, each demand response program operates on a fragmented, stand-alone basis.

For example, HECO currently reports the expenses and demand savings for RLDC and CIDLC programs separately.[179] Quarterly reports are not currently provided for the HECO and

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[178] "Application For Expansion Of The Commercial And Industrial Direct Load Control Program" at 5, filed on May 17, 2012, in Docket No. 2012-0118.

[179] See Quarterly Report for RDLC and CIDLC Programs, filed by HECO on August 14, 2013, in Docket No. 2007-0341.

MECO Fast DR programs. Requests for expansion of existing programs are made only with respect to a particular program, with little or no discussion of how an expansion of one program works in conjunction with - or in opposition to - an expansion of another program, other than to state that each particular program is one of a variety of programs designed to address demand response.

The HECO Companies present forecasts of the growth - positive or negative - for each program on a yearly basis. Again, however, these forecasts to a large degree are based on how a particular program is performing with respect to the goals established for that program, which goals are usually stated in terms of amount of interruptible capacity achieved. There is little emphasis on what the most economical and beneficial overall use of demand response programs is desirable given the current and future generating mix of each of the HECO Companies.

Over the past few years, the currently-effective demand response programs have been proposed on a fragmented and ad hoc program-by-program basis. The commission finds that the time is long overdue for each of the HECO Companies to aggressively plan, develop, implement, and operate a fully integrated portfolio of demand response programs that will collectively serve all of the objectives identified above. Moreover, rather than approaching demand response on a piecemeal basis, the Companies must demonstrate how their demand response portfolio and programs fit into both current and future planning and operation of the generation and distribution system, as well as how they fit into any future plans for "smart grid" implementation, including whether or not individual programs will benefit from the implementation of a smart grid.

There are several reasons supporting such consolidation. First, by treating all demand response programs together, the utility can determine if certain types of demand response programs are a better fit for one group of customers as opposed to another. For example, it may prove to be more beneficial to utilize commercial and industrial programs, as opposed to residential programs, to provide ancillary services both because these customers are generally more sophisticated in managing their loads and because they are large enough to provide meaningful levels of ancillary services. Likewise, residential programs may be better suited to providing more traditional demand response services, such as reductions in peak demand and frequency control. These inquiries and determinations, among others, should be addressed in an integrated approach to demand response.

Second, utilization of an integrated program will include defined objectives and goals to be achieved by the entire portfolio. It can then be determined how much each individual program does - and, as importantly, should - contribute to the overall objectives and goals for demand response.

Third, the consolidation of all demand response programs (currently, RDLC, CIDLC, and Fast DR) should serve to streamline the program, reduce the potential for duplicative expenses, and assist in achieving a unified set of objectives and goals.

Fourth, technology considerations are closely aligned with an overall portfolio approach. While discussed in more detail below, suffice it to say at this point that the various uses for demand response programs are, to a great degree, dependent on the technology that is available. Obviously, such technology comes at a cost. Part of the overall analysis to be conducted by the HECO Companies pursuant to this Policy Statement is to identify what level of benefits can be provided at different cost levels, whether the benefits outweigh the costs in each program mix, and which programs and customer classes would benefit most - and are most likely to utilize or accept - advanced technology. These analyses and decisions should not be made on a program by program basis, but for all programs in the portfolio.

For these reasons, the HECO Companies are hereby directed to consolidate their existing demand response programs into a single integrated demand response portfolio. While implementation of this integrated portfolio may involve many departments within each Company, the commission expects the HECO Companies to designate a single individual as having primary overall responsibility for the program administration and management of the integrated demand response portfolio.

B. Comprehensive Evaluation Of Demand Response.

By way of this Policy Statement and Order, the commission is directing each of the HECO Companies to conduct a comprehensive evaluation of its grid (both existing and future as further discussed below) and generation resources to identify and quantify the types of cost-effective demand response programs necessary to achieve one or more of the objectives established above for the next five, ten, and twenty years. Once that determination is made, the utility should evaluate whether existing demand response programs are sufficient to achieve each objective, or whether modification of those programs (including discontinuance) or the implementation of additional programs is necessary.

The studies discussed in this Policy Statement and Order provide a framework for this comprehensive evaluation. Based on a consideration of these and other studies, the commission directs that, at a minimum, each utility's integrated portfolio evaluation should address the following issues:[180]

- An analysis of detailed estimates of demand response potential for each of the HECO Companies;

- The role of individual demand response programs in achieving the overall objectives of the integrated demand response portfolio;

- The role of demand response in reducing curtailment of renewables, eliminating the need for baseload generation, and achieving renewable portfolio standards;

- Technology considerations with respect to designing and implementing demand response programs;

- Potential limitations on the design and implementation of demand response programs;

- The use of customer provided demand response;

- The use of third parties with respect to demand response programs;

- The impact of demand response on greenhouse gas emissions; and

- Additional issues relevant to the implementation of demand response programs.

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[180]These requirements are, in part, developed from the recommendations and conclusions contained in the various studies that are reviewed in this Policy Statement. See, Section V, supra.

The commission urges the companies not to "reinvent the wheel" by producing studies that are duplicative of the numerous previous and existing studies. Rather, the commission is directing the HECO Companies to thoroughly and carefully review their demand response programs and studies with an emphasis on how to achieve maximum results in terms of the objectives outlined herein and to identify actions for implementation to accomplish such objectives in a timely and cost-effective manner.

1. Detailed Estimates Of Demand Response Potential.

Each of the HECO Companies should develop and present a detailed estimate of demand response potential for the next five, ten, and twenty year periods. While detailed estimates of potential load reduction from the use of demand response programs are set forth in the GEP Report, that Report does not address estimates of the potential amounts of spinning reserve, regulation, load shifting, or inter-hour variability that could be addressed through use of demand response programs. Obviously, this is essential to integrating increased levels of renewables into the grid.

Similarly, the GEP Report assumed that price responsive demand is feasible for the HECO Companies, but did not address detailed estimates of price response demand potential. In producing this estimate, each Company's system operational costs, both direct and potential opportunity costs of foregone low priced as-available energy, should be evaluated to determine if there is sufficient cost variation to support development of effective, dispatchable dynamic rates and price responsive demand response options.

The integrated portfolio evaluation required by this Policy Statement should provide detailed estimates for all categories of potential demand response with respect to each of the objectives established in this Policy Statement. As noted by the LBNL Project, these estimates should be at a level of detail that supports market segmentation, customer and load targeting, and the development of specific load shaping applications.[181]

2. <u>The Role Of Individual Demand Response Programs In Achieving The Overall Objectives Of The Integrated Demand Response Portfolio</u>.

The HECO Companies should present an analysis concerning what portion of the estimated demand response potential ***for each objective*** set forth in this Policy Statement each existing and future program is expected to provide over the same five, ten, and twenty year timeframe. This task necessarily includes a determination as to which programs are best suited to achieve which objective(s). In conjunction with

[181]LBNL Project at 49.

that determination, the HECO Companies should establish priorities for each of the objectives established here. This task requires a thorough review of existing and potential programs to determine the best mix of programs to achieve the overall integrated portfolio objectives, as further discussed below.

Specifically, each of the HECO Companies shall, at a minimum, address each of the following issues with respect to its current RDLC, CIDLC, Fast DR, and/or Rider I programs, as well as the proposed CIDP program and any future programs identified during the comprehensive review discussed above. For each such program, HECO should:

a. address the impact of each program in terms of whether it duplicates any features and results of any other program in the portfolio, or whether it results in any negative consequences to any other program in the program;

b. provide a detailed explanation of how demand reduction or other benefits (such as assistance in under-frequency situations or achievement of expected renewable implementation targets) are measured with respect to each program, along with all assumptions and calculations;

c. provide a detailed explanation of the development of the criteria used, or proposed to be used, to evaluate each program;

d. provide a detailed explanation of why each program in the portfolio is a cost-effective means by which to achieve one or more of the portfolio goals;

e. include a recommendation as to whether each program should be continued without modification, modified, expanded, or discontinued;

f. where applicable, provide a detailed report comparing the costs and benefits of ancillary and other grid support services provided by each program as compared to using conventional fossil-fuel generation; and

g. address whether, and, if so, to what extent, the individual program would benefit from the implementation of a smart grid.

3. <u>The Role Of Demand Response In Reducing Curtailment Of Renewables, Eliminating The Need For Baseload Generation, And Achieving Renewable Portfolio Standards</u>.

As discussed above with respect to MECO, the Kirby Report notes that any demand response analysis should determine whether demand response can help to eliminate the need for baseload generation, and not focus solely on cycling generation, because it is the baseload generation that forces the curtailment of renewable resources. Baseload generation should be a power system function or requirement, "not a convenience for a power plant."[182] Mr. Kirby further observes that baseload units should only be dispatched out of economic order if they are required for purposes of reliability.[183] Thus, if a generator is unable to cycle off when not required, that is an undesirable characteristic of that generator, and MECO should consider eliminating that characteristic so as to pass on resulting cost savings to ratepayers.[184]

These points are directly related to the reduced curtailment of renewable generation. Thus, the HECO Companies shall address these points for each Company in the evaluation required here. Moreover, as previously discussed, there are issues with how MECO models its use of demand response. According to the Kirby Report, the MECO model is not able to determine when to dispatch demand response resources for optimal curtailment reduction since they are modeled as scheduled programs.

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[182]Kirby Report at 17.

[183]Kirby Report at 17.

[184]Kirby Report at 17.

> MECO appears to have modeled demand response on a fixed schedule, negating its flexibility and response benefits. It makes no sense to install demand response to help mitigate renewables curtailment and then operate that demand response at times when it increases curtailment. Any sensible operator would simply stop using a resource that was harming the power system.[185]

One of the objectives of this Policy Statement is to utilize demand response to provide ancillary services and operating reserves with the goal of reducing the amount of required must run generation and renewables curtailment. If MECO or the other HECO Companies are currently unable to model the full range of demand response resources, modeling capability must be improved prior to performing the analysis.

The Kirby Report also observes that, for MECO, it is not clear whether demand response efforts are addressing the flexibility required to increase renewables integration or whether they are instead still focused on peak reduction and generation capacity deferral.[186]

> For example, the discussion of Maui Electric's Existing Fast DR Pilot Program (Exhibit H, pg 7) discusses the addition of an Automated DR option. Scheduled or manual response can be useful for traditional peak reduction but is not as helpful for integrating renewables where the need to keep thermal generation online to supply up and

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[185]Kirby Report at 17.

[186]Kirby Report at 19.

> down reserves to respond to unscheduled wind and solar variability is typically the limiting factor.
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> A focus on real-time flexibility and response as opposed to scheduled peak reduction is especially important because the required real-time response is typically much shorter (minutes) than the scheduled peak reduction (hours). Response is required to cover the time from when the event starts to the time that other generation resources can be brought on line or taken off line. This reserves function does require faster communications and control but the fast response is typically easier for the load itself to provide because the shorter response duration translates into less stored energy in terms of temperature shifts, water volumes pumped, or processes disturbed. It is critical that the demand response programs be designed to focus on the actual responses that will benefit the power system under current and future high renewables penetration conditions rather than on the traditional schedule-based peak reduction demand response programs.[187]

These points shall also be addressed for each of the HECO Companies in the evaluation.

Finally, these considerations are integral to a determination of whether and to what extent demand response programs, in conjunction with other measures adopted by the HECO Companies, can assist in meeting the State of Hawaii's

[187]Kirby Report at 19.

renewable portfolio standards ("RPS").[188] As discussed herein, one of the major objectives established by this Policy Statement is to utilize demand response so as to accommodate increased levels of renewable energy into the grid. To the extent that objective can be accomplished, it will obviously have an impact on the RPS standards.

4. Technology Considerations.

As part of the evaluation, each of the HECO Companies should identify any new technologies that would assist in meeting the objectives for a particular demand response program. Chief among these is an assessment of advanced metering infrastructure ("AMI"). However, there should be an assessment of other technological initiatives that would support increased demand response, including, but not limited to, the implementation of dynamic rates and price responsive demand options. Obviously, part of this evaluation requirement is to determine whether any new technology is necessary or cost effective.

With respect to this task, the commission takes judicial notice of HECO's recent proposal to implement significant changes in order to develop a "smart grid." A preliminary report on this project, dated November 7, 2013,

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[188]See HRS §269-92.

states that the HECO Companies plan to use a network platform that enables multiple applications on a single network, including AMI, demand response, energy efficiency, and distribution automation.[189] The HECO Companies further state that a range of devices can be connected to this platform, allowing a range of choices to all customers.

Pursuant to the commission's Decision and Order filed on July 26, 2010, in Docket No. 2008-0303, on March 17, 2014, the HECO Companies filed a copy of the HECO Companies' "Smart Grid Roadmap & Business Case." According to the cover letter, this document "outlines the Hawaiian Electric Companies' plan for a smart grid program, the applications available within a smart grid and the benefits they bring to customers and the State." The HECO Companies further state that they "plan to file an application with the Commission in the fourth quarter of 2014" concerning smart grid implementation.

While the smart grid proposal is obviously germane to the issues presented here, the commission cautions that it is not a reason to delay either the evaluation required here or to avoid aggressive pursuance of cost-effective demand response to serve the objectives identified here. The commission notes that full

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[189]"Hawaiian Electric's Smart Grid Program (Preliminary)" at 8, dated November 7, 2013. See also "Smart Grid Roadmap & Business Case" at 78.

deployment of the AMI infrastructure would not take place on the neighbor islands until 2017, and on Oahu, until 2018.[190] The commission reiterates that further development of demand response programs should not be delayed until these dates.

Demand response programs can be and are being implemented now and do not necessarily depend on the development of a smart grid. Some programs can certainly be enhanced by such improvements, but this is not necessarily true in all instances. The task here is for the HECO Companies to identify the technology necessary for demand response programs to provide benefits both immediately and in the future, and to ensure that any technical improvements made now can be implemented seamlessly into a smart grid proposal should one be proposed and implemented.

5. Potential Demand Response Limitations.

The evaluation should also outline potential demand response limitations, including any current limitations in technology. Likewise, the evaluation should analyze any relevant equipment or technologies that do not effectively assist in meeting the demand response objectives.

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[190] Id. at 16.

6. Customer Provided Demand Response.

Utility customers today have many options for managing their electricity use and cost. Customers not only generate some of their electricity requirements through on site distributed generation, but, in some cases, they can sell their excess energy back to the utility. On site customer capability is evolving, with storage options becoming available to individual customers.

Other emerging demand response concepts include use of demand response resources as a "virtual power plant." This involves the aggregation of distributed energy and demand response resources into the functional equivalent of a generator that can be controlled by the utility. Obviously, a well-designed smart grid could assist in implementing this concept.[191]

Demand response may also have a role in the development of microgrids. A microgrid is a defined electric system that contains designated loads and demand energy resources, including distributed generators, storage devices, or controllable loads "that can be operated in a controlled,

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[191]The concept can be integrated "through the use of power electronics (e.g., inverters/converters), demand management, or energy storage resources to offset variability. . . [i]n the U.S., the most prevalent version of [virtual power plants]. . . is the aggregation of demand response by firms like EnerNOC, Comverge and C-power." See DR 2.0 Paper at 20-21.

coordinated way either while connected to the main power network or while islanded."[192]

In their evaluations, the HECO Companies should identify and explore the potential for customer-provided demand response through either behind-the-meter generating resources, storage resources or other resources provided through demand response, provided that such resources can be controlled in a manner consistent with demand response program parameters. The evaluation should identify any current use of customer-provided demand response as well as any future plans to encourage and implement any such programs. Similarly, there may be opportunities to develop demand response programs associated with electric vehicle charging.

The purpose of this requirement is to have the HECO Companies engage in active (and ongoing) consideration of potential future uses for demand response as these and other concepts are further developed and refined. As discussed herein, demand response has progressed from a tool to simply reduce use of capacity at peak and other times, to a tool to provide a variety of services. As part of overall transmission and generation planning and operation, the HECO Companies should

[192]DR 2.0 Paper at 21, quoting CIGRE Distribution Systems and Dispersed Generation Working Group, http://c6.cigre.org/WG-Area/WGc6.22-Microgrids.

evaluate future demand response trends on an ongoing basis, before rather than after the fact.

7. Third Party Providers Of Demand Response.

Third parties have been utilized by electric utilities, including the HECO Companies, to market and manage some of their demand response portfolio. For example, Southern California Edison Company ("SCE") uses EnerNOC as a third-party demand response provider. According to EnerNOC's website, EnerNOC has contracted to supply SCE with up to 110 megawatts (MW) of demand response capacity.[193] EnerNOC focuses on commercial and industrial sites capable of reducing their demand by 100 kilowatts (kW) or more on demand. Ultimately, the incentives these customers can earn from participating in EnerNOC's demand response program help their bottom line by providing a valuable financial boost during a difficult business climate.

Likewise, Pacific Gas and Electric Company ("PGE") utilizes a third party to administer its automated and semi-automated demand response programs. The third party encourages customers to participate in the programs, thereby expanding their energy management capabilities through

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[193]See: www.enernoc.com/our-resources/case-studies/enernoc-provides-key-demand-response-resources-to-southern-california-edison.

the use of semi-automated and automated electric controls and management strategies.

Similarly, water, wastewater, and irrigation pumping loads can provide ancillary services including regulation and spinning reserve. For example, Enbala Power Networks provides automated control capability for Pennsylvania American Water so that it can provide regulation, spinning reserve, and energy management without impacting water and wastewater operations.

As discussed above, HECO has contracted with third parties to provide assistance with the Fast DR Program in the areas of customer recruitment, customer program enrollment and load provisioning services, while HECO has overall responsibilities for program administration, including program design, customer relationship management, DR event scheduling and operations, measurement and verification), and financial settlement payments to participants.[194]

There are opportunities for third parties in the residential market as well. For example, if the grid is modernized, through the use of smart meters, third parties may be able to control thermostats or hot water heaters for a group of residential homeowners. Moreover, as the Staff of the Federal Energy Regulatory Commission ("FERC") has observed,

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[194]See, also, 2013 A&S Report at 34-36.

smart metering may lead to increased demand response by residential customers as more data becomes available to them:

> The wealth of information produced by advanced meters has spurred the increased development of customer services and products, such as home energy reports, home energy management software, and mobile software applications (e.g., notifications, outage/restoration mapping, usage profiles, billing, and service requests). Certain utilities have partnered with third-party software providers to develop interface applications that simplify and deliver energy consumption data directly to retail customers. For example, monthly energy consumption data reports can alert customers to potential cost-savings from energy efficiency measures, behavioral changes or alternative rate programs.[195]

FERC Staff also noted that "[San Diego Gas & Electric] launched Green Button Connect My Data, which allows customers to automatically send their energy usage data to third-party providers, giving customers additional options to view their previous day's usage data using a smartphone application."[196] Customers could be provided with the choice to "sell" their demand response to a third party aggregator, who would, in turn, "sell" to the utility.

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[195] "Assessment Of Demand Response And Advanced Metering Pursuant to Energy Policy Act of 2005, Section 1252(e)(3)," FERC Staff Report at 4-5 (footnote omitted) (October 2013). The footnote to this section of the Report states that examples include Florida Power & Light, Southern California Edison, and San Diego Gas & Electric ("2013 FERC Staff DR Report").

[196] 2013 FERC Staff DR Report at 4.

The commission is aware that there are issues with these approaches, including access to utility data and customer privacy issues. While such issues can and must be addressed, it is clear that there is an increasing potential for demand response from residential customers, and that third party providers can assist in developing this source of demand response.

The evaluation should address whether and, if so, to what extent third party agents and aggregators could or should be used as a means to design, market, and manage one or more of the demand response programs effectively and efficiently. The commission recognizes that, from the HECO Companies' perspective, fundamental system operation decisions regarding when to initiate load reductions, change dynamic pricing, etc., would remain with the utilities. However, working with a third party that markets and aggregates demand response loads removes those functions from the utility, and allows the utility to focus on how to best utilize available demand response resources at any particular time. Thus, the evaluation should also address whether marketing and aggregation of the integrated demand response portfolio and each of its elements should be managed by a third party. With respect to this issue, each of the HECO Companies should compare the internal costs of marketing to and aggregating demand response customers versus the costs of outsourcing these tasks to a firm specializing in them.

8. Impact Of Demand Response On Greenhouse Gas Emissions.

The Environmental Protection Agency ("EPA") has recently begun to seek input from state agencies and others to develop guidelines concerning its implementation of regulations under Section 111(d) of the Clean Air Act.[197] Under that provision, EPA is to establish a procedure whereby states are to submit plans to the EPA concerning emissions standards for existing generation facilities (as opposed to new generation facilities). Section 111(d) is written broadly, and allows EPA flexibility in implementing its guidelines.

EPA is currently soliciting comments from various entities prior to establishing the guidelines. While it is not the purpose of this Policy Statement to engage in a detailed discussion of these issues, a brief summary is in order as there can be a role for demand response to play in meeting the EPA emissions standards. Generally, there are two basic approaches to addressing carbon pollution from existing plants: a "source based" approach and a "systems" approach. A source based approach assesses emission reduction measures that could be

[197] 42 U.S.C. §7411(d).

taken directly at each power plant. A systems approach evaluates a broader source of measures that could be taken beyond simply focusing on individual power plants. This means that there could be credits against the standards for prior emission reduction projects and investments, including demand response programs.

For the state of Hawaii, the commission and others have encouraged EPA to adopt a systems approach. Such an approach would recognize the following factors. First, since Hawaii has a greenhouse gas law and energy objectives in place, the federal guidelines adopted by the EPA would accept those as the state plan, provided that the State would report annually on progress of the plan and track emissions on a statewide basis using reporting mechanisms already in place.[198]

Second, and directly relevant to this Policy Statement, the guidelines to be issued by the EPA should permit demand response, as well as other reduction strategies, to be included as a source of emissions reductions.

For purposes of the evaluation required in this Policy Statement, the HECO Companies are directed to identify and quantify how the various demand side management programs

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[198]Relevant statutes and regulations include: (1) Act 234, Session Laws of Hawaii 2007, Relating to Greenhouse Gas Emissions, codified at HRS §§ 342B-71 to 342B-73; (2) the Hawaii State Planning Act, as amended, codified at HRS §§ 226-1 to 226-109; and (3)Renewable Portfolio Standards and Energy Efficient Portfolio Standards, HRS §269-91, et seq.

(as opposed to the energy efficiency programs discussed in Section IV of this Order) addressed in the evaluation could be used as system wide reduction credits with respect to a systems approach to reductions in emissions. Stated somewhat differently, assuming that a systems approach is adopted for Hawaii in the EPA guidelines, each utility must ensure that they are collecting the data necessary from their demand response portfolio and programs to quantify and justify systemwide reduction credits should those be adopted by the EPA in their guidelines under Section 111(d).

9. Additional Issues.

This discussion is not intended to suggest that the tasks discussed above are the only ones that should be undertaken in the evaluation of the integrated demand response portfolio. Indeed, the studies addressed in the Policy Statement include a number of specific recommendations concerning issues that should be analyzed and addressed. To the extent these are not covered by the list of tasks above, they should be considered and addressed as appropriate.

C. <u>Composition And Cost Effectiveness Of An Integrated Demand Response Portfolio</u>.

Based on the evaluation required by this Policy Statement, each of the HECO Companies should develop several alternative "mixes" of demand response programs that could achieve one or more of the overall integrated portfolio objectives. More particularly, each utility shall develop three alternative, detailed, integrated demand response mixes that include cost-effective demand response programs that address reductions in capacity, shifting of load to accommodate increased levels of renewables, services designed to assist normal and emergency operation of the system, prioritized load shaping objectives, revised control strategies, dispatch criteria, estimates of interruptible price response, and under frequency response potential.

Thus, for example, one mix might utilize residential load control programs as the primary means to achieve reductions in total kilowatts and commercial and industrial load control programs for load shifting purposes. Likewise, it may prove more cost-effective to use load control programs for all customer classes to achieve kilowatt reductions, and time-based programs to encourage commercial and industrial customers to shift their loads as well as reducing them.

For each mix of programs that is developed to achieve the overall objectives of the integrated demand response portfolio, the HECO Companies must assess - for both the integrated portfolio taken as a whole and each program in each mix - whether the objective(s) to be achieved for that program can be achieved in a cost effective manner. To accomplish this task, the HECO Companies may continue to use, as a starting point, the four SPM Tests from the 2001 California Standard Practice Manual[199] to determine if the program benefits outweigh the programs costs. However, the HECO Companies are cautioned that the SPM Tests focus on the customer, and, thus, are only part of the assessment called for in this Policy Statement. As discussed herein, demand response also provides a number of benefits that are not "customer specific," including ancillary services and dynamic load adjustment.

The California Public Utility Commission ("CPUC") tests focus primarily on load reduction, and do not adequately capture the benefits of shifting load so as to accommodate more renewables on the system, providing ancillary services, etc. In fact, the CPUC has recognized this limitation in developing the protocols discussed above, noting that its protocols "may not be fully applicable to permanent load shifting programs,

[199]California Standard Practice Manual, "Economic Analysis of Demand Side Management Programs and Projects" (October 2001).

especially if those programs are non-dispatchable."[200] Nevertheless, CPUC authorized the continued use of these protocols for load shifting until such time as a better method of measuring such benefits is developed.

The Commission directs the HECO Companies to explore and propose additional methods to address, measure and quantify these concerns. The results of this analysis should be presented in the evaluation required by this Policy Statement, along with any specific recommendations for adoption of one or more of these alternatives.

D. Portfolio Reporting Requirements.

The commission directs the HECO Companies to continue to file the A&S and M&E Reports, as discussed above, once the integrated demand response portfolio has been approved. However, those reports should be tailored so as to specifically address the objectives and directives included in this Policy Statement as detailed above. Moreover, the reports should analyze the operation, benefits, and costs of the integrated demand response portfolio taken as a whole, as well as the

[200]"2010 Demand Response Cost Effectiveness Protocols," California Public Utilities Commission, R.07-01-041, at 5 ("CPUC Protocols").

operation, benefits, and costs of each individual demand response program in the integrated demand response portfolio.

E. Program Budgets.

In the past, the commission has reviewed and generally approved - sometimes with modifications - proposed budgets for each of the demand response programs. In several instances, the commission has treated the programs as pilot programs. By this Policy Statement, the commission is modifying its past practice in two related respects.

First, for those demand response programs proposed to be included in the integrated portfolio that are being implemented and/or operated on an ongoing basis (as opposed to a pilot program with a defined end date), the HECO Companies should submit a pro forma tariff (that is, a proposed tariff that is not subject to the strictures of HRS §269-16) that sets forth the terms, conditions, and benefits that a participating customer may receive, including, but not limited to, eligibility requirements, required customer equipment, other technical and engineering requirements, notification requirements (if any), and compensation provided by the utility for participation.

Once accepted, review of revenues and expenses associated with each tariffed demand response program would be conducted in rate case dockets, rather than in separate dockets for each of the demand response programs. For example, any incentive payments to program participants, or revenues received by one of the HECO Companies (for example, as a result of a participant's decision not to curtail when directed to do so) could be included in the revenue requirement and reconciled through the Revenue Balancing Account.[201] Likewise, expenses associated with the demand response program could be included as operation and maintenance expenses to be reviewed during rate case proceedings.

Second, for any pilot program or other program that is not ripe for treatment as discussed above, the HECO Companies should present an annual budget. However, in authorizing these pilot programs, the commission will no longer approve or deny these budgets. Issues concerning cost recovery will be addressed in a rate case or other appropriate forum.

F. Coordination With Water Companies.

Finally, the commission directs the HECO Companies to actively pursue and implement a demand response program

[201]See "In the Matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate Implementing a Decoupling Mechanism for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc. and Maui Electric Company, Limited," Docket No. 2008-0274, which is the initial order addressing decoupling for the HECO Companies.

pertaining to county and privately-owned water companies.[202] With respect to this proposal, the DR Subgroup stated:

> At times there may be arbitrage opportunities between the value of renewable resources being curtailed and an incentive to customers for shifting load into hours when curtailment would otherwise occur. Taking advantage of this arbitrage opportunity could increase renewable energy generation and provide a source of funding to pay customers for the value of shifting load.[203]

The DSO Paper states that water systems may comprise up to 5%-15% of each island's load, and should thus be considered as primary loads to explore for generation load matching, and as a potential starting point of a smarter, more flexible grid.

These pumps may have significant flexibility in terms of when they operate. For example, the operation of these pumps could be coordinated to match the generating resources that may be available at any given time. The DSO Paper goes on to state that while such a program is conceptually feasible and may provide benefits to the grid or local area, each load and respective water usage need, as well as any management rights or issues, need to be further investigated.

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[202]DSO Paper at 17-20.

[203]DSO Paper at 17.

This proposal merits serious consideration from each of the HECO Companies. The commission observes that MECO stated that it would offer to partner with the County of Maui ("COM") "to conduct a water and wastewater DR potential and technical feasibility studies (sic) to model, determine and demonstrate the potential DR" and further explained:

> The COM water and wastewater facilities are potentially positioned to provide real-time DR resources to Maui Electric's grid by supplying generation and non-generation ancillary services and to potentially shift water pumping loads in order to accept renewable generation that might otherwise be curtailed.[204]

Likewise, HELCO has indicated that it is exploring with the County of Hawaii Department of Water Supply the demonstration of a water pumping load that could be interrupted for demand response purposes.[205]

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[204]"In the Matter of the Application of MAUI ELECTRIC COMPANY, LIMITED, For Approval of Rate Increases and Revised Rate Schedules and Rules," Maui Electric System Improvement and Curtailment Reduction Plan, dated September 3, 2013, Exhibit H at 8. The commission notes that MECO has engaged Brown & Caldwell to perform an initial assessment of demand response potential and technical feasibility of asset classes within the County of Maui's Division of Water Supply and Wastewater Reclamation Division. The results of this study may or may not be responsive to the issues addressed here.

[205]2013 A&S Report at 42.

The investigation and implementation of such a program can and should begin immediately. Accordingly, each of the HECO Companies should, within ninety (90) days of the date of this order, provide (1) a list of water and wastewater companies that could participate in such a program; (2) an estimate, in terms of amounts of controllable load, dollars and system benefits, that could be derived from such a program, including an estimate of how such a program could affect curtailment of renewable loads and to what extent such a program could provide ancillary services; (3) an estimate of the costs associated with installing the appropriate equipment and other measures to operate such a program, as well as a detailed explanation concerning any additional equipment or system upgrades necessary to operate the program; and (4) a detailed list and discussion of any operational constraints or barriers to implementation and/or operation of such a program.

VIII.

CONCLUSION AND ORDER

By way of this Policy Statement, and the directives set forth herein, the commission reaffirms its commitment to utilizing demand response as a primary means of providing a variety of benefits to the HECO Companies' systems. Demand response programs are an important part of the overall planning and operation of the generation and distribution functions of the electric utility. The HECO Companies should, in response to the specific directives set forth above, develop an integrated demand response portfolio that is cost-effective and that provides the variety of benefits discussed herein. Likewise, the portfolio should be flexible so as to incorporate new technologies that can assist in achieving the various objectives, and eliminate programs that no longer contribute substantially to the achievement of these objectives.

THE COMMISSION ORDERS:

1. The Policy Statement set forth herein is hereby adopted as of the date set forth below.

2. Each of the HECO Companies shall respond by way of written report with all relevant supporting analyses, studies, and other documents, to the directives set forth in this Policy Statement and Order within ninety (90) days of the effective date of this order.

DONE at Honolulu, Hawaii APR 2 8 2014.

PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

By Hermina Morita
Hermina Morita, Chair

By Michael E. Champley
Michael E. Champley, Commissioner

By Lorraine H. Akiba
Lorraine H. Akiba, Commissioner

APPROVED AS TO FORM:

Thomas C. Gorak
Thomas C. Gorak
Commission Counsel

2007-0341.rs

Reliability Standards Working Group
Hawaii PUC Docket No. 2011-0206

DEMAND RESPONSE AS A FLEXIBLE OPERATING RESOURCE

By: The RSWG Demand Side Options Subgroup [1]

I. Introduction

This white paper reviews the opportunity for Hawai`i's utilities to obtain additional operating flexibility via the use of flexible demand-side programs. The use of loads to provide electric utility market products (e.g. capacity, energy, and ancillary services) is known as "demand response." The capital cost associated with demand response is typically much less than the capital cost associated with constructing new generating plant. For Hawai`i in particular, where construction costs for new capacity are very high relative to the U.S. mainland, demand response resources' capital costs may be an order of magnitude less expensive than new generation (i.e. 100's of dollars per kilowatt for demand response, versus 1000's of dollars per kilowatt for incremental generation additions). The cost to use the reserves (dominated by the energy opportunity cost) may be much lower as well, especially for ancillary services. Further, demand response resources can provide a high level of operating flexibility, which when combined with the existing generation mix, can allow greater penetration of intermittent renewable energy resources. Thus, a thorough and aggressive investigation of the potential for all types of demand-response should be a priority for all stakeholders.

> **The capital cost associated with demand response is typically much less than the capital cost associated with constructing new generating plant.**

This white paper provides a potential path that would allow a rollout of demand-side programs with increasing complexity as time goes on. One possible next step for the Commission would be to open another investigatory docket that is designed to make specific recommendations regarding demand response as discussed herein. However, there may also be opportunities for stakeholders to jointly present to the Commission demand-side type programs that could be implemented quickly.[2]

II. Goals for Demand Response in Hawai`i

The Hawai`i utilities and third party providers seek to significantly increase the amount of renewable energy produced in the state, reduce renewable energy curtailments, and maintain a

[1] The Demand-Side Options Working Group consists of Hugh Baker (HDBaker & Company), Alan Hee (HECO), Carlos Perez (HECO), Brendan Kirby (Hawaii PUC Consultant), Bash Nola (Blue Planet Consultant), Jose Dizon (HECO), Will Rolston (County of Hawai`i), and Alison Silverstein (RSWG Independent Facilitator). Notable contributions to this effort have been made by Lisa Dangelmaier (HELCO), Dora Nakafuji (HECO), and Curtis Beck (HELCO).

[2] This could also include the upgrading of existing demand response programs to enhance the speed of communication and bandwidth for 2-way control.

EXHIBIT A

high level of system reliability at affordable prices. To this end, they need to use all available energy options to manage supply, demand, system operations and energy costs effectively. Demand response could play a role in meeting Hawai`i's electric system operational objectives:

1) Reduce total kWh consumed to reduce oil imports (e.g., through efficiency including always-on building commissioning and more efficient, rationalized end-use operation with flatter load factors);
2) Reduce peak loads (in 5-9 pm period) to reduce the amount of fossil generation required for contingencies and demand or PV variability (e.g. through lower on-peak AC, water heater, refrigeration and pool pump usage);
3) Build off-peak loads to increase consumption of minimum load generation and reduce wind curtailments (e.g., through building and device pre-cooling or pre-heating);
4) As distributed PV generation and penetration increases on many feeders and expands across the HI island grids, reduce the impact of variability and volatility of PV ramps by integrating PV operation with end use loads, offsetting and absorbing much of the fast ramps against host building or same-feeder loads and distributed storage (possibly including end uses as storage media), so the bulk power system sees slower net ramps with less magnitude and speed;
5) Use utility-dispatchable and automatic (e.g., demand-side equivalent of Automatic Generator Control and frequency droop response), automated load control to deliver fast ancillary services (frequency management, up-regulation and down-regulation, spinning reserve) without burning fossil fuels in a boiler;
6) Use utility-dispatchable and automatic, automated load control (responding in the same frequency range as generator governor response and ahead of, but coordinated with, the utility's current under-frequency load shedding schemes), and eventually, spinning reserve to protect system frequency;
7) Use utility-dispatchable demand response as a bridge under contingency conditions while waiting for utility emergency diesel generators to come on-line.

Keep in mind that demand response is only a tool and does not always lower cost or increase renewable energy usage. However, demand response options have the potential to create value for Hawai`i's ratepayers and therefore should be investigated to meet the objectives listed above.

III. Pre-Requisites for Demand Response Programs

There are several prerequisites for tapping demand response:

1) *Define the Objectives*: The demand response program resource must serve the utility system objectives (as reviewed above) and customers' energy management and/or economic needs.
2) *Identify Responsive Loads*: the ability of demand side programs to deliver the reliability products required in Hawai`i will depend upon the types of customer end-use loads and customer-owned generators in Hawai`i and whether those can

The prerequisites for accessing demand response as a resource include a clear system objective and need, loads that are responsive, a control scheme, measurement and verification (and baseline) methodology, and adequate customer/program participant compensation.

feasibly be used to respond to relevant price and/or system conditions.

3) *Control Scheme*: There must be an ability to use these resources in the manner required to achieve the desired objectives (i.e., manage, control, and coordinate). The level of technical sophistication required to achieve a specific objective can vary from very simple (e.g. phone call, text message, email) to very complex (e.g. under-frequency relays, full supervisory control and data acquisition ("SCADA") or SCADA-like control and communication functionality). It is also possible to achieve automation of demand response via installation of a control interface between the utility demand-response automation system and the customer's existing Building Management System ("BMS").
4) *Measurement and Verification ("M&V")*: It is necessary to quantify or measure the contribution of the demand-side resources in meeting the program objectives. Required solutions may range in complexity from interval meters that can record 15-minute consumption and store the data for later analysis, to near-real time, two-way communication between the resources and the system operator via utility-grade telemetry. The M&V scheme also needs to identify a "baseline" load profile for the customer, against which the customer's actual demand during a demand response "event" can be compared in order to determine performance. Statistical sampling may be appropriate for some types if demand response verification.[3]
5) *Compensation to the Customer/Program Participant*: Finally, demand response program design and compensation should be based on the value of specific capacity, energy and ancillary service products, or the cost of providing such capacity, energy or ancillary services by other means. Many demand response options can be competitive – including both program implementation and customer compensation costs – when compared to the costs of generation or storage options for capacity or ancillary services.

While not a prerequisite per se, the adoption of advanced meters, communications systems, and smart grid technologies can facilitate real-time demand-side options for Hawai`i. Large and small loads offer different load profiles and flexibility options and should be tapped to provide differing demand response services; these possibilities could be unlocked with smart meter systems.

IV. <u>Implementation of Demand Response</u>

There are several mechanisms for implementing a change in customer loads in a way that provides value within a power system. Three will be discussed here: pricing, manual demand response, and automated demand response.

a. Time-Based Pricing Programs

Time-based pricing programs can influence customer behavior.

One of the easiest ways to induce the behavior of customer demand is through electricity pricing. If the utility wants the customer to use less during a certain time period, the utility would charge more for electricity during that period; to encourage higher consumption in other periods, the electricity rate would be lower in those periods. These retail rates are tailored for different classes of customers.

[3] DR resources used to provide ancillary services may not need the baseline if the events are fast and short.

There are three basic types of pricing models[4] that can be used to incentivize customer behavior:

1) *On-Peak / Off-Peak Pricing*: In this model, the customer sees two prices, one price for "on-peak" time periods and another price for "off-peak" time periods. The time periods vary depending on the system load characteristics. Another variation of on-peak / off-peak pricing is "critical peak pricing" ("CPP"), in which the "on-peak" period is very short (usually temperature-driven) and the Critical Peak price is very high. These prices can vary according to system conditions, with day-ahead or hour-ahead warnings of extreme peak conditions and prices.
2) *Time of Use Pricing ("TOU")*: TOU pricing is similar to on-peak/off-peak pricing, but with several time periods across the day. TOU pricing applies to fixed periods with fixed prices that do not change (other than by season). TOU pricing may also be used to encourage the use of curtailed energy at a reduced price to customers who are willing to increase loads at the time of potential curtailment.
3) *Dynamic or Real-Time Pricing ("RTP")*: In an RTP program, energy prices change hourly as a function of power system load and generation conditions, with some limited notice of price levels to the customer. RTP programs vary in terms of notice provided to the customer, but a typical program might determine the day-ahead price schedule as the system operator plans unit commitments for the following day, and send that price schedule to the customer before the start of the day when it applies. Other programs allow prices to vary hourly or every ten minutes in near-immediate response to current operating conditions with hour-ahead or ten-minute-ahead notice.

If Hawai`i chooses to use pricing programs as one method to drive its demand response programs, those price patterns should be tailored to each island's load and generation patterns and the incremental costs of utility-owned and purchased generation. Interval metering ("smart-meters") is the tool that is almost always used to measure the customer's electricity usage during the various pricing periods in time-based pricing programs, with the usage in appropriate pricing period applied to the time-based rate for that same time period to compute the bill. And while it is proven that customers modify their electricity usage in response to well-designed time-of-use and dynamic rates, it may take some time to determine the most appropriate rates for Hawai`i. Details of production costing, generation contracting, and retail price design complicate developing economically efficient pricing programs. Note also that time-based rates do not give system operators any direct control over customers' energy usage.

If Hawaii chooses to use pricing programs as one method to drive its demand response programs, those price patterns should be tailored to each island's load and generation patterns and the incremental costs of utility-owned and purchased generation.

[4] In a presentation to the RSWG group on October 23, 2012, time based pricing was divided into dynamic and static TOU pricing. The category "on-peak/off-peak pricing" (e.g., CPP) may be confused with TOU pricing which is also on-peak/off-peak pricing. However, CPP is dynamic, meaning that the price and timing during the day are dependent upon system conditions and not set daily periods, as is TOU pricing.

There is typically no penalty associated with a customer's failure to reduce loads in the desired time periods, other than the higher price that the customer incurs for having demand during the higher priced time periods.

b. Manual Demand Response Programs

In a manual demand response program, the system operator asks the customer to take a specific, pre-agreed curtailment action via some kind of communication (e.g. phone call, text message, email, fax, etc.) when the system operator requires the response for reliability or economic reasons. Based on the scheduled demand response "event", it is then up to the customer to take action necessary to comply with the system operator request. The advance notice for a program of this type can range from day-ahead, hours, or minutes. In this instance, the utility does not have any direct control over the customer's actions.

In a manual demand response program, the system operator asks the customer to take a specific, pre-agreed curtailment action. It is up to the customer to take action necessary to comply with the system operator request.

In a program of this type, there is typically an after-the-fact verification that the load responded as desired (using interval metering with remote communication capabilities). There is typically a baseline of some type established for the customer, against which the actual load is compared for purposes of determining the customer's performance during an event. This type of program can be designed to include penalties for non-compliance, which might range from reduced compensation all the way to making the customer ineligible for continued participation in the program.

An important consideration of a manual demand response program is customer compensation. The amount of compensation is a balance between the value of the customer's response during an event, versus an amount of compensation that will make it worth the customer's time and effort to participate and implement curtailment during called events. In some areas, the customer is paid a reservation fee (essentially a capacity charge) whether an event is called or not, with additional compensation for responding adequately to an actual event. Few demand response programs pay customers only for responding to events.

c. Automated Demand Response Programs

In an automated demand response program, the particular load that is participating in the demand response program is outfitted with communications and control equipment that allows the utility system operator to signal the load to automatically cut back or turn off (and later, to turn on again). In an automated demand response program, manual action on the part of the customer is not required. The load curtailment can also be automated to respond directly to price signals, frequency or voltage levels.[5] The above measures could be tied to an Interruptible Rate schedule to promote participation.

[5] Manual and automated demand response programs can exist in the same program. For example, the Fast DR pilot program currently being implemented at HECO and MECO has both an auto DR and a semi-auto DR phase. The semi-auto DR phase involves sending a DR signal via phone, text, or e-mail message to the facility manager who

In an automated demand response program, the particular load that is participating in the demand response program is outfitted with communications and control equipment that allows the utility system operator to signal the load to automatically cut back or turn off (and later, to turn on again).

Direct load control of retail loads such as air conditioners, water heaters and pool pumps are the long-standing examples of simple automated demand response; more sophisticated programs have been developed to exploit commercial and industrial customers' energy management systems. Simple direct load control programs do not require interval meters nor extensive measurement and verification programs, and customer compensation could be as simple as a standing discount to the participant's monthly electric bill.

HECO has successfully implemented several automated demand response programs, including a residential hot water heater program that has under-frequency responsive capabilities. Further, as was reported to the RSWG in its meeting on September 18-19, 2012, HECO is actively working with Honeywell to put into place the architecture to implement additional automated demand response capabilities.[6] HECO and MECO programs are pilot project efforts.

The logical rollout sequence for demand-side programs is to first go after customers who offer the largest amount of flexible load. However, a comprehensive smart grid deployment strategy should also consider the potential for the aggregation of smaller flexible loads (this speaks only to the *ability* to aggregate those loads, not *who* aggregates those loads). Smaller flexible loads, aggregated into demand-side programs may actually offer greater flexibility than do larger loads. The opportunity cost for many small loads to provide spinning reserve is very low so they often are a very attractive source for aggregation to provide spinning reserve.

V. <u>Customer-Side Implementation of Demand-Response</u>

a. Load Control

Industrial customers (most of which in Hawaii would be located in the HECO system) and municipal and agricultural pumping loads (located throughout the islands) may have extensive DR capabilities.

The types of demand response best suited to a system depend on the system objectives for demand response, the types of customer loads, and the customers' level of sophistication about energy costs and management options. Customers who actively manage their operations are usually better candidates for more sophisticated time-based programs because these customers are accustomed to scheduling their operations in a way that

manually activates the building automation system (BAS), which automatically initiates load reductions via a Schema programmed into the BAS.

[6] As of the date of this white paper, HECO has signed contracts with 13 Fast DR Pilot program participants. MECO has 4 semi-auto DR participants. Total = 17.

reduces their energy costs and improves their profit margins. Industrial customers (most of which in Hawai`i would be located in the HECO system) and municipal and agricultural pumping loads (located throughout the islands) may have extensive DR capabilities. More simplified time based pricing programs may or may not be effective among residential customers and can't be offered until advanced meters have been deployed. Fully automated programs can be effective for residential customers, especially for providing ancillary service where the required response duration is typically relatively short.

As one moves into manual programs, again the level of sophistication is correlated to the sophistication of the customer. In Hawai`i, candidates for manual demand response might include water pumping customers and perhaps resorts and hotels, to the extent that they have some degree of flexibility with their loads (e.g. laundry operations).

Automated programs can be more broadly applied, provided that there are end-uses embedded in the load curve that can be modified using active control by the system operator. Water heaters, pumps, air conditioners, refrigeration and those types of loads may be candidates for active control in Hawai`i. Automated response to frequency events can be especially attractive since the response can be very rapid and yet the required response duration is typically shorter (minutes rather than hours). Because Hawai`i's electric systems are isolated and all imbalance results in frequency error, reconnection or restoration of frequency-responsive demand should be coordinated by the system operator to ensure reserve generation is on-line and available to serve it, (which cannot be determined solely by the system frequency measurement). If reconnection occurs before generation is available to serve it, there could be additional low-frequency events.

b. On-Site Generation and Energy Storage

Customers can also provide demand response through operation of on-site, behind-the-meter generating and storage resources, provided that such generators can be controlled in a manner consistent with the demand-response program parameters, and that they comply with environmental and other applicable regulations. For example, some customers may operate fleets of standby generators that could operate within a demand response program as part of the standby generator's periodic testing program. Energy storage technologies such as batteries can also provide demand response. Eventually electric vehicles may provide significant opportunities for storage, demand response, and/or price response. Automatic or scheduled demand response can be used for thermal energy storage by pre-heating water heaters, pre-cooling buildings, or pre-cooling freezers and refrigeration units, to shift load to off-peak periods and absorb a portion of minimum load generation. An additional emerging customer-side resource option is the microgrid. In a microgrid, the customer load, energy generating resources and storage resources are operated as a contained system (in effect by creating a mini balancing area). A microgrid operated in parallel with the larger utility system can in certain circumstances, in addition to allowing for scheduled interchange between the utility and the customer microgrid, provide demand response and ancillary services.

VI. Use of Demand Response and Storage to Provide Ancillary Services

The RSWG Ancillary Services study being performed by General Electric ("GE") through Hawaii Natural Energy Institute ("HNEI") points out the potential for using demand response and energy storage to provide ancillary services. According to the November 20, 2012 draft GE report: "... GE identified and summarized in a table which generation, transmission, ***storage and demand-side*** technologies are able to provide each ancillary service given current technology capabilities and fuel availability, without screening or limiting the options with respect to economic cost-effectiveness. As requested, GE generally limited technologies to those that are available in commercial or pilot applications today ..."[7] (emphasis supplied). Table A.3-3[8] of the GE draft report identifies commercially available demand response technologies that can provide the following ancillary services: frequency response, regulation, spinning reserves, non-spinning reserves and replacement reserves. The same table shows emerging energy storage technologies that can provide multiple types of ancillary services as well.

The RSWG Ancillary Services study being performed by GE points out the potential for using demand response and energy storage to provide ancillary services.

Specific points and recommendations from the November 17, 2012 draft of the GE report include:

1) Many [system] operators such as ERCOT allow storage to participate in arresting the frequency decline (ERCOT FRRS). Many [system] operators including PJM and ERCOT allow demand response (ERCOT LAaR) to participate in frequency response." [9]
2) "... storage as well as DR should be allowed to provide primary frequency response and spinning reserve."[10]
3) "Operators (for example, PJM) allow Curtailment Service Providers (CSP's) that bid demand reductions into the Regulation Market. Demand response also provides regulation in MISO. Enbala Power Networks enables large electricity user to participate in the regulation market." [11]
4) "[..] a recommendation is to allow LESRs [Limited Energy Storage Resources] and DRs [demand response] to provide frequency regulation service."[12]
5) "If the existing capacity is insufficient or uneconomic [to provide spinning reserves], then other means of obtaining spinning reserves (for example, from battery storage and DR) should be explored."[13]

GE: "Storage as well as DR should be allowed to provide primary frequency response and spinning reserve."

[7] *Ancillary Services Definitions and Capability Study*, Draft Final Report For Hawaii Natural Energy Institute, GE Energy Consulting, November 20, 2012, p 12.
[8] Ibid. p 13.
[9] Ibid p 19.
[10] Ibid p 20.
[11] Ibid p 21.
[12] Ibid p 21.
[13] Ibid p 27.

6) "If the ancillary service requirements were not successfully achieved, or it appears that excess ancillary capability is available, consider potential solutions that could alleviate the deficiency or allow the system to operate in a more efficient manner. Solutions may include ... New resources ... storage, demand response ..."[14]
7) "Consider potential solutions to alleviate deficiencies and improve system efficiency [...] Adjustments to operating procedures: Activation thresholds for DR, [...] New resources: [...] storage, demand response ..."[15]
8) "In addition to the economic viability, consider the risks associated with pursuing the respective path. Consider items such as: [...] Challenges associated with monitoring / controlling DR participation on a centralized basis." [16]
9) "Demand-side participation and programs can be used to provide certain ancillary services, like operating reserves, but the grid operator needs to have control over those resources on a centralized basis. Preferably [this is accomplished] via physical control such as demand response switches." [17]
10) "Load shaping programs such as electric vehicle charging schedules, may be implemented to help shape the system load and thereby make planning for ancillary service deployment easier."[18]
11) The GE report references a presentation entitled "Opportunities for Mass Market Demand Response to Provide Ancillary Services, October 2011, by Robb Pratt (Pacific Northwest National Laboratory) and Dave Najewicz (GE Appliances). [19]

Frequency responsive demand response can be faster and more reliable that obtaining reserves from generation and does not necessarily require high-speed communications. Obtaining ancillary services from demand response can also reduce renewable generation curtailment by allowing conventional generators to operate at lower loads or to be turned off during low net-load periods.

VII. Demand Response Program Components

There are several business components common to all demand response programs. These affect the business models available to deliver DR.

The design of a demand response program is driven by the system's need for resources (e.g. energy, capacity, and/or ancillary services) and the potential of the system's customers and end use loads to provide demand response of differing types.

1) *Program Design*: Prior to designing a program, there should be a clear understanding of the system objectives. Therefore, the program proposal should include an assessment of the potential ability of the demand response program to meet these objectives, and if program

[14] Ibid p 31.
[15] Ibid p 31.
[16] Ibid p 32.
[17] Ibid p 36.
[18] Ibid p 37.
[19] Ibid Appendix H, Reference No. 20. This presentation can be found at: http://www1.eere.energy.gov/analysis/pdfs/opportunities_for_mass_market_dr_for_as_rob_pratt_pnnl_and_dave_najewicz_ge.pdf

costs can be reasonably estimated (e.g., based on the results of a pilot program), program cost-effectiveness should also be presented. The design of a demand response program is driven by the system's need for resources (e.g. energy, capacity, and/or ancillary services) and the potential of the system's customers and end use loads to provide demand response of differing types. This is a decision that is best made involving as many stakeholders as possible and is one that ultimately must receive regulatory approval. One of the tasks of the ongoing Reliability Standards Working Group is to develop recommendations to the Public Utilities Commission regarding the type of resources that are needed in Hawai`i power markets in order to meet the State's energy policy goals of larger penetration of renewables.

2) *Customer recruiting*: Once a demand response program is designed and approved, customers must be recruited to participate in the program. This is largely a marketing function that could be performed by the utility, by third party curtailment service providers, or possibly by a third party administrator. For maximum participation, it is important that this role be filled by someone with both the understanding of the benefits and obligations associated with a demand response program *and* the requisite marketing and sales skills.

Almost all of the demand response program components could be outsourced to third parties.

3) *Customer program enrollment and customer relationship management*: When a customer agrees to sign up for a demand response program, there must be a way to register the customer into the program, to register the responsive load that the customer is providing and to record the details that will be required to ensure timely settlement with the customer for successful participation. Further, after enrollment the customer needs a point of contact with respect to the demand response program. Several types of parties can perform these tasks. To the extent that the utility performs this task, then appropriate changes must be made to the utility's Customer Information System ("CIS"), Customer Relationship Management ("CRM") and billing systems. To the extent that a third party performs this function, if the third party brings its own CIS and CRM platforms into play, then there must be appropriate integration between the third party systems and the utility systems. There are a number of third party providers that provide these capabilities.

4) *Load Provisioning*: After the customer is enrolled, the customer's load must be provisioned to participate in the demand response program. For a time-based pricing program or a manual demand response program, provisioning might be as simple as providing the customer a web-based platform for monitoring its own performance. In the case of an automated program, provisioning consists of installation of hardware (e.g. relays, load shedding equipment, interfaces with customer-owned building management systems, under-frequency relays) and communications capabilities at the customer site. Provided that the technology specifications and communications protocols are open

Because demand response is an active, operational resource, the operator of the balancing area must be the entity that performs the scheduling and control of demand response events.

and non-proprietary, there are a number of third parties that perform these provisioning tasks as a service to utilities and load-side aggregators.

5) *Scheduling / Operations*: Because demand response is an active, operational resource, there must be centralized control and coordination of the operation of demand response programs to ensure their coordination with grid needs. The operator of the balancing area typically calls demand response events to meet specific system needs, particularly with respect to use of the loads to provide ancillary services. Thus, the scheduling and operation of demand response programs must remain with the system operator – although third-party intermediaries can receive that curtailment signal and deliver aggregated customer curtailments consistent with the parameters of the program. Indeed, in demand response programs that provide real-time products (e.g. ancillary services like operating reserves, frequency response, etc.) a decision must be made to as the minimum size load that can participate in the program, or if smaller loads can be aggregated into larger groups that can participate. To a large extent, the minimum load size is a function of the technical provisioning requirements for the load and the cost of meeting those requirements.
6) *Measurement and Verification ("M&V")*: After a demand response event has been called, there must be a way to measure and verify that the customer did actually provide the desired response. In the case of real-time demand response products, the M&V may be provided via telemetry and the system operator has the ability to see the performance of a customer in real time.[20] In the case of time-based pricing programs and manual demand response programs, the M&V function will most likely be performed after the fact. This function can be performed by the utility, using its meter data management ("MDM") system to automate the collection, validation, and analysis of the metered data. However, the M&V function can also be performed by qualified third party "meter data management agents." In fact, it is quite common (especially in energy efficiency performance contracts) to have a third party perform the M&V function. In some cases, the M&V function may be based on a simulation using actual after-the-fact data but applied to the class or type of load to determine customers' DR responses.
7) *Settlement*: The final function in a typical demand response program is settlement with the customer. In some cases, the settlement with the customer may be in the form of a credit against a power bill. In other situations, settlement may require an actual separate payment to the customer. For most DR programs, the utility can perform all DR settlement calculations. Ultimately, there must be a central clearing authority for these settlements. In Hawai`i, that function best resides with the system operator. However, in some circumstance, it may be acceptable to have intermediaries between the central clearing agent and the participating customer.

All of these DR program components can, in principal, be outsourced with the exception of the Scheduling/Operations component.

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[20] In the case of a program with multiple participants, it is unlikely that the system operator would want to see anything other than the aggregate response from the demand side resource. Statistical or other aggregate monitoring techniques may prove to be the most reliable and cost effective means to monitor the aggregate response. There would also likely be a need to audit, after the fact, the actual response of the individual loads.

VIII. Demand Response Business Model Options

It follows from the inherent flexibility in the delivery of demand response functions, that there are a number of different business models that can be utilized. Business models are not mutually exclusive. It is a matter of policy and efficiency as to the appropriate business model for a program and/or service territory. Several business models are discussed here.

1) *Utility Managed*: Under this model the utility provides all program functions and roles internally.
2) *Utility Managed – Outsourced to Third Party:* Some utilities are outsourcing the management of demand response programs to a third party contractor – for instance, curtailment services providers deliver direct load control and diverse energy management services across much of the Northeast, Southwest and California. The Hawaiian Electric Companies currently outsource much of the recruiting, enrollment, and provisioning elements of its existing programs. The exception is the Direct Load Control ("DLC") program element of the Commercial and Industrial Direct Load Control ("CIDLC") Program for which Hawaiian Electric currently performs all of the functions itself.

Demand response business models are not mutually exclusive. It is a matter of policy and efficiency as to the appropriate business model for a program and/or service territory.

3) *Curtailment Administrator*: Hawai`i has separated energy efficiency programs and utility operations, creating a third party Energy Efficiency Administrator. A similar model could conceivably be deployed for demand response programs, although the costs of doing so and effectiveness of real-time coordination would require further investigation because the functions required to deliver demand response are quite different from the functions that are being provided by the existing Public Benefits Fund Administrator (PBFA).
4) *Curtailment Service Providers ("CSP's)*: A completely new class of load aggregators has arisen over the past ten years or so in response to the expansion of demand response programs across various power markets both in the US and internationally. These aggregators, known as Curtailment Service Providers or CSP's, perform most of the functions identified above. Typically, the CSP enters into a contract with the system operator (a utility or independent system operator) to deliver a block of demand response resource that meets the specific program criteria. The CSP is required to meet all of the technical requirements of the specific program. The market-clearing entity pays the CSP directly for the delivery of the demand-side resource, and in turn the CSP is responsible for compensating the individual customers who are participants in the program. A CSP shares its compensation with participating customers. Typical splits are in the range of 60% to 80% of the payment going to the customer, with the balance going to the CSP. CSPs are not necessarily regulated entities although they would be subject to general contract law and consumer protection

A Curtailment Service Provider ("CSP") enters into a contract with the utility to deliver a resource in accordance with the DR program. The CSP must meet all of the technical requirements of the specific DR program. The utility pays the CSP, which in turns compensates the customer.

regulations that apply to any other business. If the CSP model is utilized, a set of consumer protection rules many be desirable; however this would be a legislative issue, not a Commission issue.

Regardless of which business model is used to administer demand response programs, since DR is so intimately responsive to system operational needs, DR programs should be designed to meet the system's operational needs, and DR events should be initiated by the system operator rather than any third party.

IX. RSWG & RSWG Demand Side Options Subgroup Discussions to Date

In early 2012, the RSWG Demand Side Options (DSO) subgroup identified a process to determine if demand side options (including but not limited to demand response and energy storage) could be viable resources for the HECO Companies in terms of providing additional system flexibility and allowing greater penetration of renewable resources. The DSO working group's process included:

1) Identification of existing demand response programs in the HECO Companies' service areas;
2) Determination of loads available in the system that are flexible or which have characteristics conducive to dispatch (on or off) in some manner;
3) Determination of ancillary services products required in the HECO Companies' systems;
4) Match potential demand response programs with required products, including each of the ancillary services.

As part of the HECO Companies' participation in the RSWG docket, the HECO Companies produced a "Roadmap" for demand response programs prepared by Lawrence Berkeley National Laboratory. This roadmap document laid out a process for determining programs and technologies conducive to demand response. The roadmap process, if implemented, will take several years to complete.

The DSO subgroup has determined that there has been no load research studies performed in some time that would help determine the types and levels of penetrations of particular end-use loads that would be candidates for demand response.[21] HECO is however working with the Commission's Public Benefits Fund Administrator (PBFA) evaluation consultant to conduct on-site and mail/telephone surveys to obtain end-use data that will be used for energy efficiency and demand response potential studies.

There have been no load research studies performed in some time to determine end-use loads that are candidates for DR in Hawaii. HECO is working with the Commission's consultant to obtain end-use data that would provide this information.

[21] However, a Global Energy Partners DR potential study conducted on behalf of the Hawaiian Electric Companies in 2010 did identify DR potential categorized by control mechanism (e.g., direct load control, dynamic pricing), but not by end-use.

On April 13, 2012, the HECO Companies filed an application (Docket No. 2012-0079) for expansion of the Residential Direct Load Control ("RDLC") program for the HECO service area (i.e. Oahu only). The application summarized the demand response programs in place in the HECO systems. MECO participates in the Fast DR Pilot Program.[22] There are no demand response programs in the HELCO service area at the present time (although in PUC Docket 2010-0165 and PUC Docket 2007-0341 HELCO pledged to undertake a study of the potential for such programs). HECO included in its application in Docket No. 2012-0079 a plan for expanding and/or extending demand response programs and a dynamic pricing program. HECO's timeframes with respect to rollout of these programs on a permanent basis range from 2013 to 2017.[23]

General Electric, working through the Hawaii Natural Energy Institute ("HNEI") at the direction of the RSWG, is delivering a report on ancillary services requirements in Hawai`i. The report identifies the specific ancillary services that are required in each of the HECO company systems, the report clearly identifies demand response and energy storage as potential resources for providing certain ancillary services.

HECO has contracted with Honeywell to implement automated demand response programs in the HECO service territory over the next 2 to 3 years.

In September 2012, in a conference call meeting of the DSO subgroup, the HECO Companies stated that the Commission is now contracting for end-use load research studies that can be used to identify loads that are capable of responding to dispatch signals (manual, automatic or otherwise). The HECO Companies indicated that information of this type would be available in 2013, after which the load research data can be used for demand response and energy efficiency EE potential studies.

At the September 19, 2012 RSWG meeting, Honeywell presented an overview of the technology that they are deploying with HECO to implement automated demand response programs in the HECO service territory. The deployment of this system is to take place over the next two to three years.

On October 3, 2012 a call was held among some members of the DSO working group and HELCO. In that call we learned that the utilities currently have a pricing program in place through a tariff known as "Rider M." Rider M is available only to certain customers who are subject to demand charges. The purpose of Rider M is to incentivize loads to shift their demands from on-peak to off-peak periods. Thus, the "product" that this delivers is peaking power and perhaps a modest level of minimum load mitigation. Under Rider M, the customer is compensated through an elimination of the demand charge; if the customer does not shift the load, then it is penalized by a demand charge that is the tariffed demand charge plus $1.00 per kilowatt-month per unit of billing demand. Using the HELCO version of Rider M, a low load factor customer who complies with the Rider M terms and conditions receives at most a benefit that is approximately 2 – 3 cents per KWH (spread over all of its energy usage in a month) for a savings of, at most, approximately 5 – 10% of its total energy.

[22] MECO will also be testing DR in the Wailea Smart Grid project – residential water heaters and PCTs.
[23] See HECO's Application in Docket No. 2012-0079, Exhibit B, page 3 of 3 (pdf page 62).

X. Status of Demand-Side Initiatives in the HECO Companies' Systems

Demand-side resources can play a role as an operational resource and should therefore be considered as a resource option in the HECO Companies' systems. A fundamental task of a system operator is to match aggregate generation and aggregate load on an instantaneous and continuous basis. Inside RSWG, and elsewhere, much discussion has gone into determining the "right" generation resource mix to fulfill this task. Permanent reductions on the load side of the equation are being carried out by the PBFA in its energy efficiency work. In addition, there have been HECO Company initiatives with respect to modifying load behavior in operating time frames (e.g. less than one day and/or providing ancillary services) in response to power system needs. Table 1 shows the existing HECO demand response programs as of September 2012. MECO has a pilot demand response program. There are currently no demand response programs offered in the HELCO service territory. The objective of the Fast DR Pilot program is to obtain DR resources available within 10 minutes to provide a "bridge" between when the need for a generating unit to be started is identified and when the unit is available on-line. In addition, the RDLC and CIDLC programs, which have been in place since 2005, provide under-frequency protection via their under-frequency relays (UFRs) embedded in the load control receivers provided by HECO and installed at customer premises. The UFRs respond nearly instantaneously when the frequency thresholds are attained.

Table 1

Hawaiian Electric Existing and Proposed Demand Response Programs

Program Name	Existing or Proposed?	Customer Segment*	MW Nov. 2012	Customers Nov. 2012
Fast DR Pilot **	Existing	C&I>50 kW	2	17
CIDLC (DLC) #	Existing	C&I>50 kW	18	42
CIDLC (SBDLC) #	Existing	C&I > 3 kW	1	161
RDLC #	Existing	Res	17	≈36,000
Rider I #	Existing	C&I	3	4
CIDP Pilot @	Proposed	C&I > 50 kW	0	0

* C&I = Commercial and Industrial, Res = Residential

** Includes Fast DR Pilot on Maui. Cumulative MW program goal is 7 MW (total on Maui + Oahu) in 2013.

Program currently not expanding.

@ Cumulative MW program goal is 2 MW within two years.

The HECO Companies are working on new demand-side programs such as the Fast DR Pilot Program, the Commercial and Industrial Dynamic Pricing (CIDP) Pilot Program, and are seeking approval from the Commission to expand the RDLC and CIDLC programs. However, as presented to the RSWG on September 18, 2012, the timeframe for some of these initiatives are relatively long, i.e., well beyond the current Integrated Resource Planning (IRP) process. Notwithstanding some of the longer term program initiatives, the CIDP pilot and the RDLC and

CIDP program expansions are awaiting Commission approval and could be in place and available for customer enrollment in 2013, i.e., possibly before the completion of the IRP process. In the meantime, there may be additional loads in the HECO Companies' systems that could provide meaningful capacity, energy and ancillary service resources via demand response resources that are not being accessed. As noted above, there are pricing programs and manual demand response programs that could be put into place without waiting on the automated technology and those programs should be further explored.

This paper proposes that the Commission consider allowing the HECO Companies, end users and possibly curtailment service providers, to explore and develop demand response programs that can be implemented in the near term. In particular, the DSO subgroup believes that it may be possible to launch new demand response programs that would precede the automated programs by as much as two years.[24] These programs, which would initially be aimed at commercial customers, would allow customers to become accustomed to the benefits that would accrue to them for changing their operation, while getting comfortable enough over time to allow the automated control over some of their operations when the automated systems are ready. These programs would also allow the utility operators to get comfortable with the use of demand response for reliability requirements.

The DSO subgroup recommends that the Commission consider allowing the utilities and other market participants to develop DR programs that can be implemented in the near term. It may be possible to launch new DR programs that would precede the automated programs by as much as 2 years.

Additionally, with the concerns expressed repeatedly in the RSWG (and particularly the MLC working group) regarding the curtailment of non-firm renewable energy resources from time to time, we recommend that the utilities and non-firm renewable generators develop demand-side programs that build load in periods when curtailment would otherwise occur or to provide reserves that are currently required to be supplied by thermal generation. This of course is not a zero sum proposition. In order to provide the incentive for the customer to move its load to off-peak periods or to provide reserves, there must be a source of funding to pay the customer for doing so. One possible mechanism for doing this would be for the non-firm generator to take less compensation during periods when it would otherwise be curtailed (during which time periods it currently receives nothing). The arbitrage between the existing contractual price and the reduced price would allow for a pool of funds to be collected which would then be used to pay customers to shift their demands. In such a scenario, everyone wins. The renewable generators would get paid when otherwise they would be curtailed.

[24] Note that the CIDP pilot program that is awaiting PUC approval is a pricing program and it also has a semi-auto (i.e., manual) DR component, in addition to an auto DR component.

XI. Specific Proposal for a Demand Response Program

There are at least several water pumping loads in each of the HECO Companies' service areas worth evaluating and exploring. Domestic water providers such as County and privately-owned water utilities employ many horsepower worth of electric-powered pumps. Also, any demand-response program developed for water pumps would be repeatable to other water systems – which may comprise 5-15% of each Island's load. These should be considered the primary loads to explore for generation-load matching and the start of a smarter and more flexible grid. Agricultural water users routinely operate their own water systems for irrigation and livestock operations. Both private and public entities operate electric-powered wastewater lift stations. From an operational perspective, these pumps have significant flexibility in terms of when they operate, and in a significant number of cases, water storage facilities are available that can store several days' worth of water without operating these electric powered pumps. At the current time, there is no coordination of the operation of these pumps to match generating resources that may be available at any given time (e.g. to operate off-peak to absorb high levels of wind generation) or to provide ancillary services to the power system (regulation, load-following, or contingency reserves). Though conceptually feasible and while each type of load may provide benefits to the grid or local area, each load and respective water usage need as well as any water management rights or issues need to be further investigated for appropriateness and fit.[25]

At times there may be arbitrage opportunities between the value of renewable resources being curtailed and an incentive to customers for shifting load into hours when curtailment would otherwise occur. Taking advantage of this arbitrage opportunity could increase renewable energy generation and provide a source of funding to pay customers for the value of shifting load.

a. Concept

To illustrate how these loads could immediately be utilized, consider the curtailment of available wind generation. Let's call the wind generator "Wind 1" and a generic pumping load called "Pump A". Let's call the hypothetical utility "Utility." Pump A is a 1 MW pumping load and it has a choice to pump water today at noon, or tonight at midnight. Pump A is on a general service rate schedule with a rate of $0.35 per KWH, regardless of the time it runs. The utility's marginal cost is $0.25 per KWH regardless of the time of day (a simplifying assumption for purposes of this "thought experiment") and its marginal cost is based on burning oil to generate electricity. Let's assume that Wind 1 is compensated at $0.20 per KWH.[26] From a water operations perspective, Pump A is ambivalent as to which time it runs. Utility is operating its system and through its daily and hourly load forecasting processes, it determines

[25] Several investigative studies were conducted in California as part of linking the state water irrigation management and large pumping loads with electric utility and renewable integration. However, in light of real-time operations and water management needs, recreational use and fish management constraints, overall energy value and demand response opportunities and value were not as significant as originally expected. Proper tailoring of program with appropriate and available loads will need to be further investigated.

[26] This assumes that Wind energy cost is lower than the utility's marginal cost. While this is generally true, it may not always be true. E.g., during certain times of the day, HELCO's and Maui's wind energy costs are sometimes higher than HELCO's and Maui's marginal cost of generation.

that a system low load condition will occur at midnight. Wind 1 is forecasting strong trade winds overnight and expects to be available to produce its full output. Because of constraints around thermal unit commitment, the Utility expects that it may need to curtail Wind 1's generation overnight.

In the current situation, the operating decisions made by the owner of Pump A are totally divorced from the operating decisions of the Utility. Therefore if the pump chooses to run at noon, the following economic outcome occurs (cash outflows for the relevant entity are shown as negative, cash inflows are shown as positive):

Cost of power for Pump A:	$0.35 per KWH * 1 MW * 1 hour =	($350.00)
Utility Marginal Cost to Supply Pump A:	$0.25 per KWH * 1 MW * 1 hour =	($250.00)
Wind 1 Revenue at Midnight (curtailed)		$ 0.00

However, if the pump chooses to run at midnight, the following economic outcome occurs:

Cost of power for Pump A:	$0.35 per KWH * 1 MW * 1 hour =	($350.00)
PUMP A INCREMENTAL SAVINGS		$0.00
Utility Marginal Cost to Supply Pump A:	$0.20 per KWH * 1 MW * 1 hour =	($200.00)
RATEPAYER INCREMENTAL SAVINGS[27]		$50.00
Wind 1 Revenue at Midnight (not curtailed)	$0.20 per KWH * 1 MW * 1 hour =	$200.00
WIND 1 INCREMENTAL REVENUE		$200.00

In the example above, Pump A is not compensated for the option value of running at midnight rather than at noon; rather the example assumes that Pump A simply made a choice to run and it happened to coincide when wind curtailment would have otherwise occurred. However, if the optionality of Pump A is recognized by all parties, Pump A would receive a payment in recognition of its willingness to coordinate its operations with Utility's operations. Assume that that policy is for the ratepayer to split the benefits with the individual customer on a 50-50 basis. Now the economics would look like this:

Cost of power for Pump A (per tariff):	$0.35 per KWH * 1 MW * 1 hour =	($350.00)
Split system fuel cost with ratepayers		$25.00
PUMP A INCREMENTAL Power Cost		(325.00)
Utility Marginal Cost to Supply Pump A:	$0.20 per KWH * 1 MW * 1 hour =	($200.00)
Split fuel savings with Pump A		($25.00)
RATEPAYER INCREMENTAL SAVINGS		$25.00
Wind 1 Revenue at Midnight (not curtailed)	$0.20 per KWH * 1 MW * 1 hour =	$200.00
WIND 1 INCREMENTAL REVENUE		$200.00

In this example, all parties would benefit from the arrangement. By shifting its operation from noon until midnight, with no adverse consequences on its operations, Pump A reduces its power cost by $25, ratepayers benefit by $25, and the Wind A gains $200 in revenue that it would not otherwise have realized. *Of note, the utility is not harmed in this arrangement*.

[27] These savings accrue to all Utility's ratepayers since fuel is a pass-through.

Since the need for thermal units to meet on-peak loads in the 5 pm to 9 pm time period contributes to the need for off-peak minimum load generator operation, it is useful to consider whether and how to modify water and waste water pumping loads to minimize their operation during electric system peak hours; again, if these loads pay a flat rate per KWH regardless of the utility's cost to generate or acquire each KWH, there may be significant cost savings and net benefit to all parties by paying pumping loads to not operate during system peak hours (or providing reduced energy rates for pumping loads that operate off-peak).

Another way to do this that could provide a more meaningful level of compensation to incentivize customers would be for the wind generator (in this example) to share some of its revenue with the customer. The situation might look something like this:

Cost of power for Pump A (per tariff):	$0.35 per KWH * 1 MW * 1 hour =	($350.00)
Split system fuel cost with ratepayers		$25.00
Split 25% of wind plants windfall with ratepayer		$50.00
PUMP A INCREMENTAL Power Cost		(275.00)
Utility Marginal Cost to Supply Pump A:	$0.20 per KWH * 1 MW * 1 hour =	($200.00)
Split fuel savings with Pump A		($25.00)
RATEPAYER INCREMENTAL SAVINGS		$25.00
Wind 1 Revenue at Midnight (not curtailed)	$0.15 per KWH * 1 MW * 1 hour =	$150.00
WIND 1 INCREMENTAL REVENUE		$150.00

Again, the utility is not harmed and the wind plant still receives revenues from that it would not have otherwise received but for the customer's willingness to change its behavior. Within the confines of existing contracts and regulation, this last example may or may not be achievable, however, the point is that a substantial arbitrage opportunity exists that would allow more renewable energy, avoid burning oil, and that would result in economic benefit (or no harm) to all parties except the oil suppliers, assuming there are no limitations/constraints to the water pumping and management needs.

b. Implementation

The implementation of an arrangement described above would be straightforward and relatively simple. The components of such a program would consist of the following:

1) *Scheduling notifications to loads*: The utility control operator should be able to provide, on a daily basis, a schedule for the operation of the flexible loads. This schedule could be communicated to the owner of the load via a phone call, fax, text message, email or other means. No additional technology is required to provide these notices.
2) *Ability of the load to implement the schedule*: a load that participates in this program must have the operational wherewithal to execute the schedule, i.e. operate its loads according to the schedule. With less sophisticated customers, this might require a manual operation, but with sufficient advance notice (e.g. an hour or longer) this does not necessarily represent an obstacle. More sophisticated customers (e.g. county water systems) may have already implemented SCADA systems that would allow scheduling of multiple loads from a central remote location.

3) *Interval metering with communications*: The measurement and verification of performance of the loads is an important consideration. For purposes of starting such a program, the only M&V technology that would be required is interval metering with recording capability. The verification of the load's performance could be established after the fact and settlement with the load could take place based on the load's actual performance against a baseline (in this case a simple baseline is all that is required – was the load on when the utility scheduled it on, and was it off when it was scheduled off). The metering preferably has remote data collection capabilities via a POTS line or (even better a cellular IP addressable modem) installed with the meter. This would allow access to the customer's performance on a next day basis.
4) *Payment mechanism*: the customer would presumably earn a credit on their electric bill, or a separate fee, in return for agreeing to this flexibility. The amount of compensation needs to be a balance between a level that will incentivize the load to participate and a level that will provide benefits to ratepayers and other ratepayers.

This relatively simple program could immediately result in less curtailment of renewable loads and provide additional operating flexibility with respect to commitment of other utility generating assets and dispatchable contracts. After refinement of this program and education of participating customers, and interest by non-participating customers, the program could then be refined and upgraded to include controls and telemetry on loads that would be dispatched directly by the utility. Such a program would offer real-time M&V. Such a program might also provide numerous ancillary services including regulation, load following, spinning reserve and non-spinning reserve. Provision of ancillary services requires much less water or energy storage capabilities (tens of minutes versus hours or days) than rescheduling operations and many more MW of response are potentially available.

This relatively simple program of shifting flexible loads into hours when curtailment is forecasted to occur, could immediately result in less curtailment of renewable loads and provide additional operating flexibility with respect to commitment of other utility generating assets and dispatchable contracts.

Since there are only a few water and waste-water pumping loads per island, and their characteristics are already well-known, it should be feasible to estimate the operational and cost impacts of the changes proposed above and develop appropriate incentive offerings relatively quickly without waiting until 2014 for completion of a DR potential study. What may be less well-known is whether the existing pumping loads have other operational constraints due to permits, water flow rate, seasonal concerns, technology limits or other use concerns which may limit their ability to participate in aspects of demand response as envisioned. Upgrades to technology, communication and other un-intended consequence risks of coupling two critical infrastructures such as water and electricity delivery infrastructures for islanded grids may also need to be considered (though coordination of two critical infrastructures should lead to greater reliability if it is done correctly). It may also be feasible for the Commission to adopt these proposed changes through a tariff rather than going through a fully-litigated rate case.

XII. Conclusions and Recommendations

In conclusion, there are very real opportunities to affect the demand side of the supply-demand balance in a way that will produce economic benefit for ratepayers, and that will allow greater penetration of renewable energy. Further, there are loads today that could, with incentives, shift their demand patterns in ways that would be beneficial to many if not all of the stakeholders represented in the RSWG process. Accordingly, this paper recommends to the RSWG and to the Commission the following proactive steps to move on a quicker pace towards implementing demand-side programs:

In conclusion, there are very real opportunities to affect the demand side of the supply-demand balance in a way that will produce economic benefit for ratepayers, and that will allow greater penetration of renewable energy.

1) Investigate pricing programs and manual and automated demand response programs that will incentivize customers to change their consumption patterns in ways that are beneficial for stakeholders. Included in this investigation would be an analysis of the benefits of increasing demand during minimum load periods (i.e., examining the cost reductions that could be incurred and the impact on renewable energy purchases during the entire 24-hour day);
2) Encourage the use of demand response and energy storage to provide ancillary services whenever technically possible and economically justified;
3) Allow the utilities and other interested stakeholders to develop specific pricing and/or manual demand response programs, with expedited regulatory review and approval to get these programs in place as soon as possible;
4) As the Commission reviews new DR programs, it should consider the appropriate role of third party agents and aggregators (i.e. curtailment service providers) to deliver demand response programs effectively and efficiently;
5) Ensure that demand response programs are considered in the Integrated Resource Planning process;
6) Direct the energy efficiency potential study contractor to perform specific load research data collection that will allow the utility to better estimate the demand response potential in Hawai`i.
7) Require Hawaii Energy work with the utilities to identify those customers and loads that are most promising for demand response, and assure that Hawaii Energy and the DR planners coordinate program plans and marketing to assure that energy efficiency does not compromise promising DR opportunities (and vice versa).

CERTIFICATE OF SERVICE

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

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