

PNNL-28956



# Hawaiian Electric Companies Demand Response Tool

August 2019

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Prepared for  
the U.S. Department of Energy  
under Contract DE-AC05-76RL01830

Pacific Northwest National Laboratory  
Richland, Washington 99354

## Executive Summary

This document introduces the Hawaiian Electric Companies (HECO) Demand Response (DR) Tool, which was developed at the Pacific Northwest National Laboratory (PNNL). The battery storage evaluation tool (BSET) by PNNL was modified to run one-year simulations that evaluate the benefits of behind-the-meter (BTM) PV and storage from the customer perspective, while optimizing use of these assets to minimize customer energy bills and improve reliability. Bill minimization is achieved by engaging BTM assets optimally to reduce demand charges, provide energy generated by PV back to the grid, and engage in DR programs. In addition, reliability statistics for each of the five islands identified in the tool (Hawaii, Lanai, Maui, Molokai, and Oahu) were used to define low, mid, and high outage rates. Outages are then randomly placed throughout the year by the model during the simulation to explore tradeoffs between reliability and DR program participation. Figure E.1 presents the graphical user interface for the HECO DR Tool.

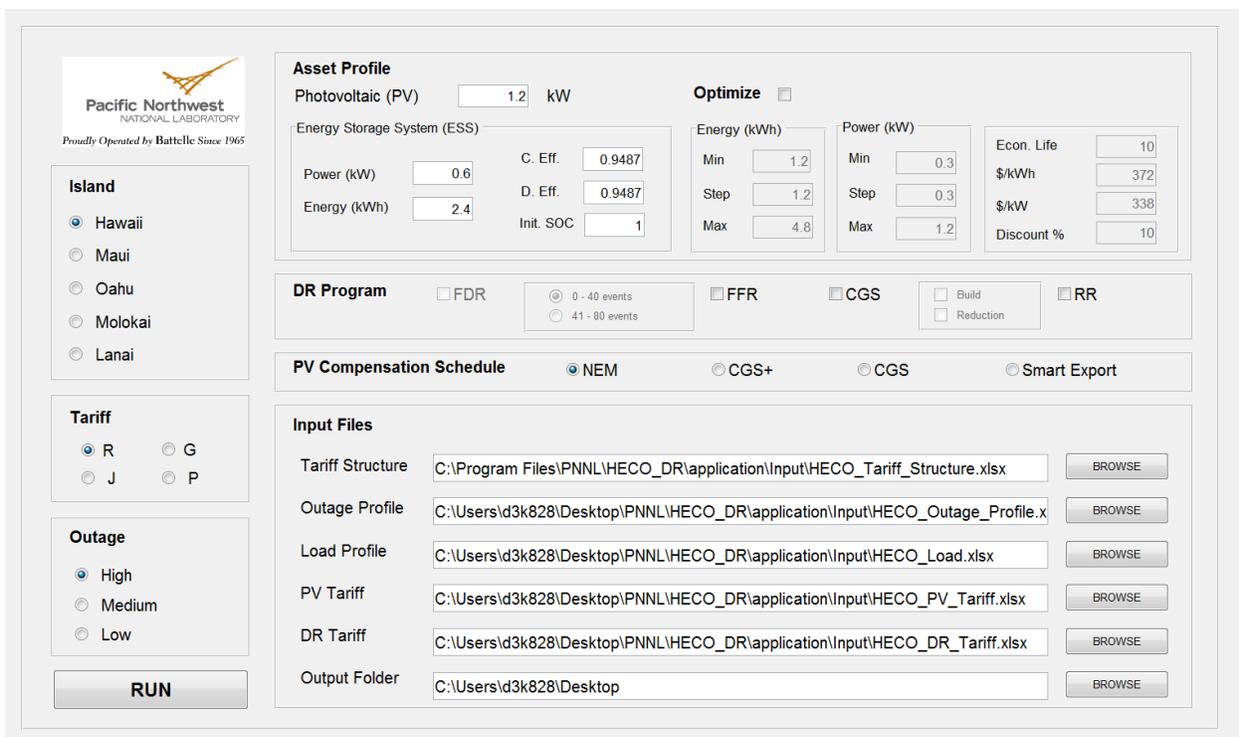


Figure E.1. HECO Demand Response Tool Graphical User Interface

The HECO DR Tool co-optimizes the benefits of the bundled use cases over a one-year simulation period. This is followed by a look-ahead optimization, which is solved to determine the battery base operating point each hour. The 24-hour look-ahead optimization is then repeated hourly, thus representing a rolling 24-hour formulation that uptakes new information in order to re-define an optimal dispatch strategy throughout the year.

PNNL has worked with HECO to define a number of customer, tariff, and reliability levels. The tool described in this document enables the customers and the utility to better understand the value to customers for DR program participation, and the incentive levels required to ensure desired participation rates. The tool will enhance HECO’s understanding of how these resources can best be operated in aggregation to provide grid services and associated value to the

customers. It also allows HECO to understand how participation in DR programs affects the value these BTM assets would otherwise provide to the customer directly through reduction in demand charges or outage mitigation.

This report provides the background and a user's guide for this tool. In addition, it explains the existing programs, the basics of the DR tool, and the optimization tool's structure and application.

## Acknowledgments

We are grateful to Dr. Imre Gyuk, who is the Energy Storage Program Manager in the Office of Electricity Delivery and Energy Reliability at the U.S. Department of Energy. Without his organization's financial support and his leadership, this project would not be possible.

## Acronyms and Abbreviations

AC	Alternating Current & Air Conditioning
AGC	Automatic Generation Control
BAU	Business as Usual
BSET	Battery Storage Evaluation Tool
BTM	Behind-the-meter
CAC	Central Air Conditioning
CAIDI	Customer Average Interruption Duration Index
C&I	Commercial and Industrial
CGS	Customer Grid Supply
CGS+	Customer Grid Supply+
CGSP	Capacity Grid Service Program
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DLC	Direct Load Control
DOE	Department of Energy
DR	Demand Response
EWHS	Electric Water Heaters
ESS	Energy Storage System
FDR	Fast Demand Response
FERC	Federal Energy Regulatory Commission
FFR	Fast Frequency Response
GS	Grid Service
GUI	Graphical User Interface
Hz	Hertz
ISONE	Independent System Operator, New England
kW	Kilo-watt
kWh	Kilo-watt hour
LP	Linear Programming
MATLAB	Matrix Laboratory
MCC	Marginal Capacity Costs
MW	Megawatts
NARUC	National Association of Regulatory Utility Commissioners
NEM	Net Energy Metering
NREL	National Renewable Energy Laboratory
PF	Performance Factor
PG&E	Pacific Gas and Electric

PNNL	Pacific Northwest National Laboratory
PUC	Public Utility Corporation
PV	Photovoltaic
SAIDI	System Average Interruption Frequency Index
SMECO	Southern Maryland Electric Cooperative
SMUD	Sacramento Municipal Utility District
SPP	Southwest Power Pool
SPU	Snohomish Public Utility
SOC	State of Charge
TOU	Time of Use
US	United States
VEN	Virtual End Node

## Contents

Executive Summary .....	ii
Acknowledgments .....	iv
Acronyms and Abbreviations.....	v
Contents .....	vii
1.0 Introduction .....	1.1
1.1 Evaluating Customer-Side Benefits.....	1.1
2.0 Instructions for Using the HECO Demand Response Tool.....	2.1
2.1 System Requirements.....	2.1
2.2 MATLAB Runtime Installation .....	2.1
2.3 DR Tool Installation.....	2.1
2.4 Running a Simulation.....	2.1
2.5 Viewing Simulation Results .....	2.4
3.0 Model Definition and Data Requirements .....	3.1
3.1 Model Definition .....	3.1
3.2 Mathematical Modelling .....	3.1
3.2.1 Without DR Program .....	3.2
3.2.2 With DR Program .....	3.4
3.2.3 Optimal Sizing .....	3.7
3.3 Data Requirements .....	3.7
3.3.1 Tariff Structures.....	3.8
3.3.2 Solar PV Compensation .....	3.12
3.4 Net Energy Metering.....	3.12
3.4.2 Demand Response Programs .....	3.15
3.4.3 Outage Profiles and Costs.....	3.24
4.0 Demand Response and Customer Behavior.....	4.1
4.1 Types of Demand Response Programs .....	4.1
4.1.1 Direct Load Control.....	4.2
4.1.2 Load Reduction & Distributed Energy Resources (DERs).....	4.4
4.2 DR Potential in Hawaii .....	4.6
4.3 Incentives, Customer Behavior, and Participation Levels .....	4.7
4.3.1 Base Incentive Rates.....	4.8
4.3.2 Compensation for Inconvenience .....	4.9
4.3.3 Customer Type.....	4.10
4.3.4 Risk .....	4.11
4.3.5 Communication .....	4.11
5.0 Conclusions and Opportunities for Additional Research .....	5.1
6.0 References.....	6.1

## Figures

Figure 1.1.	HECO Demand Response Tool Graphical User Interface .....	1.2
Figure 1.2.	24-hour Energy Storage Schedule .....	1.3
Figure 1.3.	BSET Sizing Output .....	1.4
Figure 2.1.	DR Tool Default View.....	2.2
Figure 2.2.	Contents in the Original Folder of Installation .....	2.2
Figure 2.3.	Application Folder Contents .....	2.2
Figure 2.4.	Input Folder Contents .....	2.3
Figure 2.5.	First Warning Message .....	2.3
Figure 2.6.	Second Warning Message .....	2.3
Figure 2.7.	Value Stream Results .....	2.4
Figure 2.8.	Optimal Battery Operations.....	2.5
Figure 2.9.	Output on the Hard Disk.....	2.5
Figure 3.1.	Example of NEM Customer Receiving Energy Credit.....	3.12
Figure 3.2.	HECO Regulation Signal.....	3.24
Figure 4.1.	Survey of DLC Programs Including their Incentive Values and Corresponding Participation Rates.....	4.3
Figure 4.2.	Estimates of Distributed PV Generation Penetration by Location .....	4.5
Figure 4.3.	DR Forecast for 2019 by Peak Reduction (MW) within Hawaii, by Scenario .....	4.7
Figure 4.4.	Enrolled MW by DR Program Type .....	4.9

## Tables

Table 3.1.	Residential Customer Schedule Prices by Island and Category .....	3.9
Table 3.2.	Schedule G Energy Pricing by Island .....	3.9
Table 3.3.	Schedule J Energy Pricing by Island .....	3.10
Table 3.4.	Schedule P Energy Pricing by Island.....	3.11
Table 3.6.	Customer Grid Supply Credit Rates by Island .....	3.13
Table 3.5.	Customer Grid Supply+ Credit Rates by Island .....	3.14
Table 3.7.	Smart Export Schedule and Compensation by Island.....	3.15
Table 3.8.	Fast DR Program Details.....	3.15
Table 3.9.	Fast DR Program Options .....	3.16
Table 3.10.	Fast DR Program Events.....	3.16
Table 3.11.	Under Frequency Events on Oahu in 2017 at the 59.7 Hz Threshold .....	3.19
Table 3.12.	Maximum Number of Events Called per Year for the Capacity Grid Service Program.....	3.20
Table 3.13.	Average Number of Outages and Average Outage Duration by Island .....	3.25

## 1.0 Introduction

Hawaii Electric is currently awaiting approval of its Integrated Demand Response Portfolio Filing from the Hawaii Public Utility Corporation (PUC). As a part of this filing, HECO is targeting an expansion of its demand response (DR) program from providing traditional capacity services to also providing a number of ancillary services, which HECO is calling grid services, including fast frequency response, regulating reserve, replacement reserves, and capacity. With the proliferation of customer photovoltaics (PV) and energy storage expected, HECO would benefit from a better understanding of the value that a customer will place on participation in DR programs, and the incentive levels required to ensure customer participation, while also allowing the customer to reap the benefits of a PV and battery storage system. The expected customer sizing of the battery resource goes along with this task. In addition, HECO would benefit in understanding how these resources may be best operated in aggregation to provide grid services, while ensuring customer value.

### 1.1 Evaluating Customer-Side Benefits

To address this problem statement, it is important to understand the benefits of PV and energy storage accruing to customers and the utility and, based on financial expectations, the structure that incentives could take in order to facilitate an outcome that meets the needs of both parties. With that noted, the Pacific Northwest National Laboratory (PNNL) first focused on benefits to customers only.

PNNL has worked with HECO to define a number of customers, tariff, and reliability levels in order to evaluate the benefits of behind-the-meter (BTM) PV and energy storage for these scenarios to its customers.

PNNL modified its battery storage evaluation tool (BSET) to run a one-year simulation, evaluating the benefits of PV and battery storage for customer-energy management applications. These applications or use cases were defined by PNNL in partnership with HECO. The modified tool evaluates the benefits of BTM PV and energy storage for a defined set of customer types and tariff structures, as defined by HECO in order to determine the benefits to customers when operated in an optimal manner. Figure 1.1 presents the graphical user interface designed for the evaluation of the HECO demand response program.

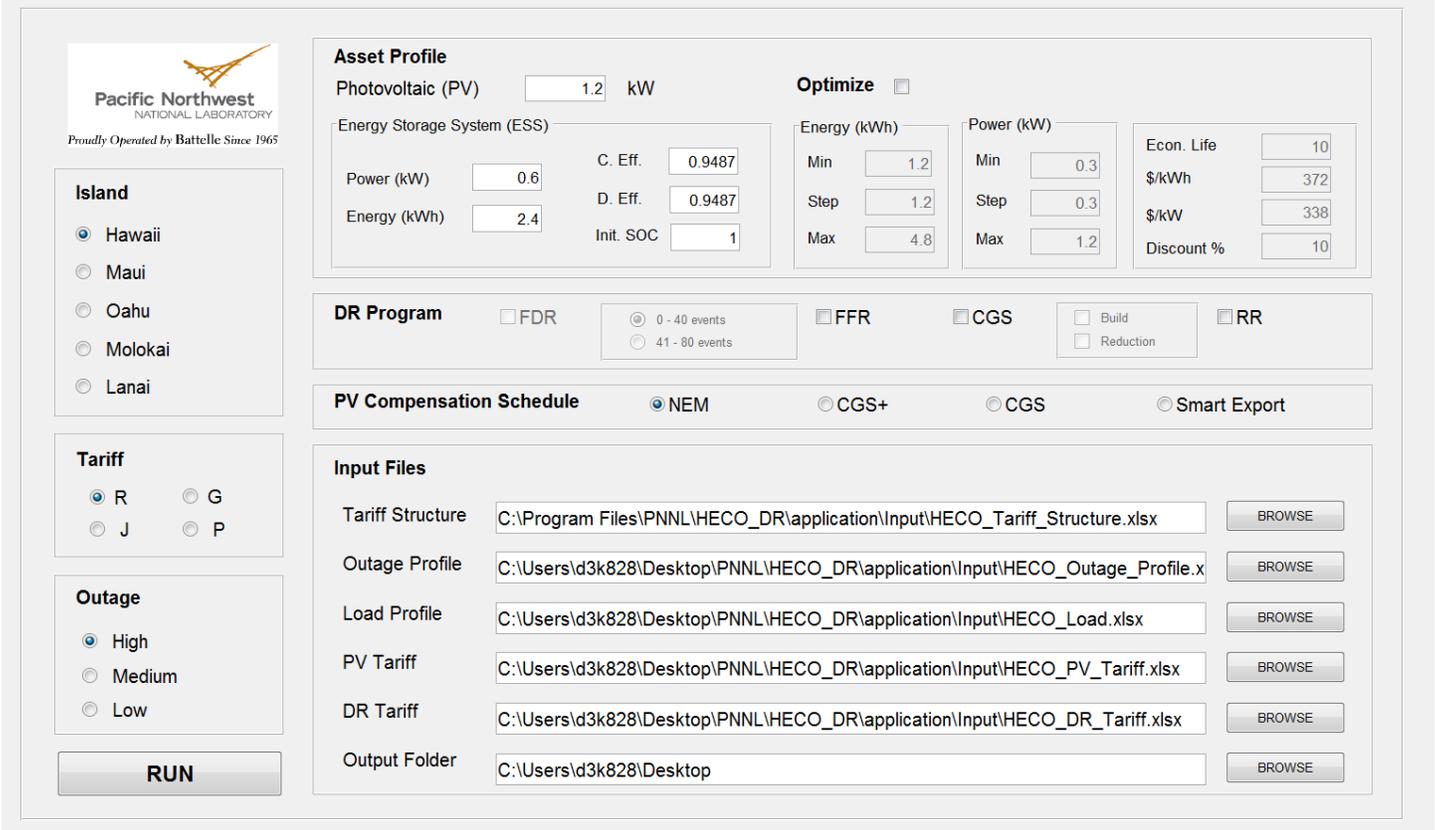


Figure 1.1. HECO Demand Response Tool Graphical User Interface

Once PNNL defined the value of each use case or service based on bill reductions or avoided costs, as well as the corresponding capacity and energy requirements, BSET was used to co-optimize the benefits among these services over a one-year simulation period. In this control strategy, at each hour, a look-ahead optimization is first formulated and then solved to determine the battery base operating point. The minute-by-minute simulation is then performed to simulate the actual battery operation.

Figure 1.2 shows 1-minute output of an Energy Storage System (ESS) recently modeled using PNNL’s BSET. The top panel of the figure shows the prices of the balancing-up service (blue line), balancing-down service (black dashed line), and the energy price (red line). Each price line is also identified in the figure. The balancing-up price is zero throughout the day, so the ESS does not provide any balancing-up service at any point. The optimization tool performs trade-offs between the balancing-down and energy services. The energy service bid is shown as a black dashed line in the middle panel. The actual output of the ESS is presented as the red line, and deviates from the initially scheduled pattern in order to provide balancing-down service and in mitigating an outage at around 7:00 p.m. The bottom panel shows the state of charge (SOC) of the ESS. As services are provided, the value derived from the service is logged, as is the time the ESS is engaged in providing each service. The model then determines, when optimized, the annual number of hours the EES would be optimally engaged in the provision of each service and the value derived from each service.

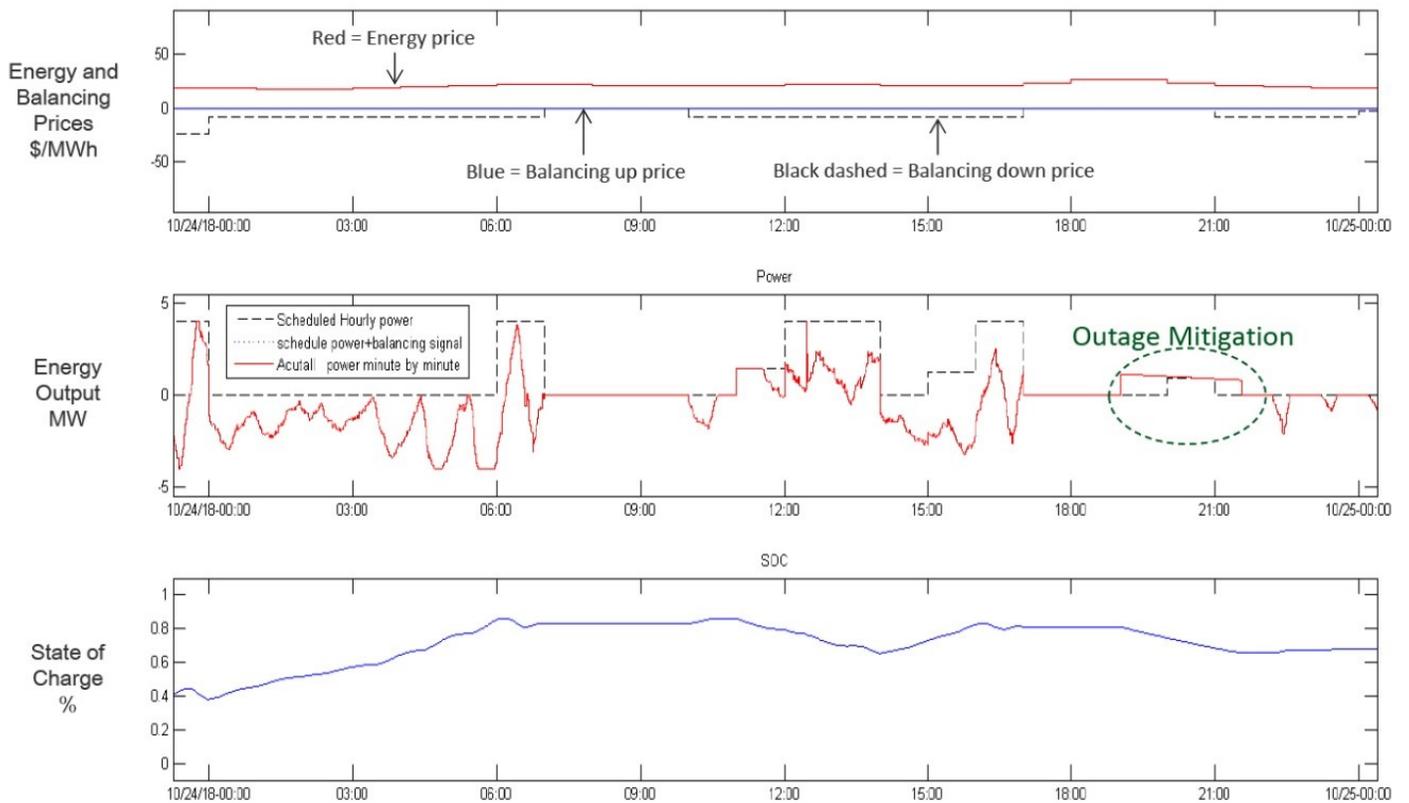


Figure 1.2. 24-hour Energy Storage Schedule

Using load data and tariff structures for five Hawaiian Islands (Hawaii, Maui, Molokai, Lanai, and Oahu), and energy storage characteristics, BSET was used to define the optimal dispatch strategy for ESSs for the simulation year along with the optimal scale of the ESS. The services evaluated within the tool focus on the benefits to customers (e.g., energy charge reduction, demand charge reduction, and outage mitigation).

Figure 1.3 demonstrates BSET’s current capacity to determine the optimal scale of an ESS given the value of services provided by storage, ESS costs, grid conditions, and local load. By defining a range of potential power and energy capacities BSET can determine the optimal power and energy capacity within the specified range.

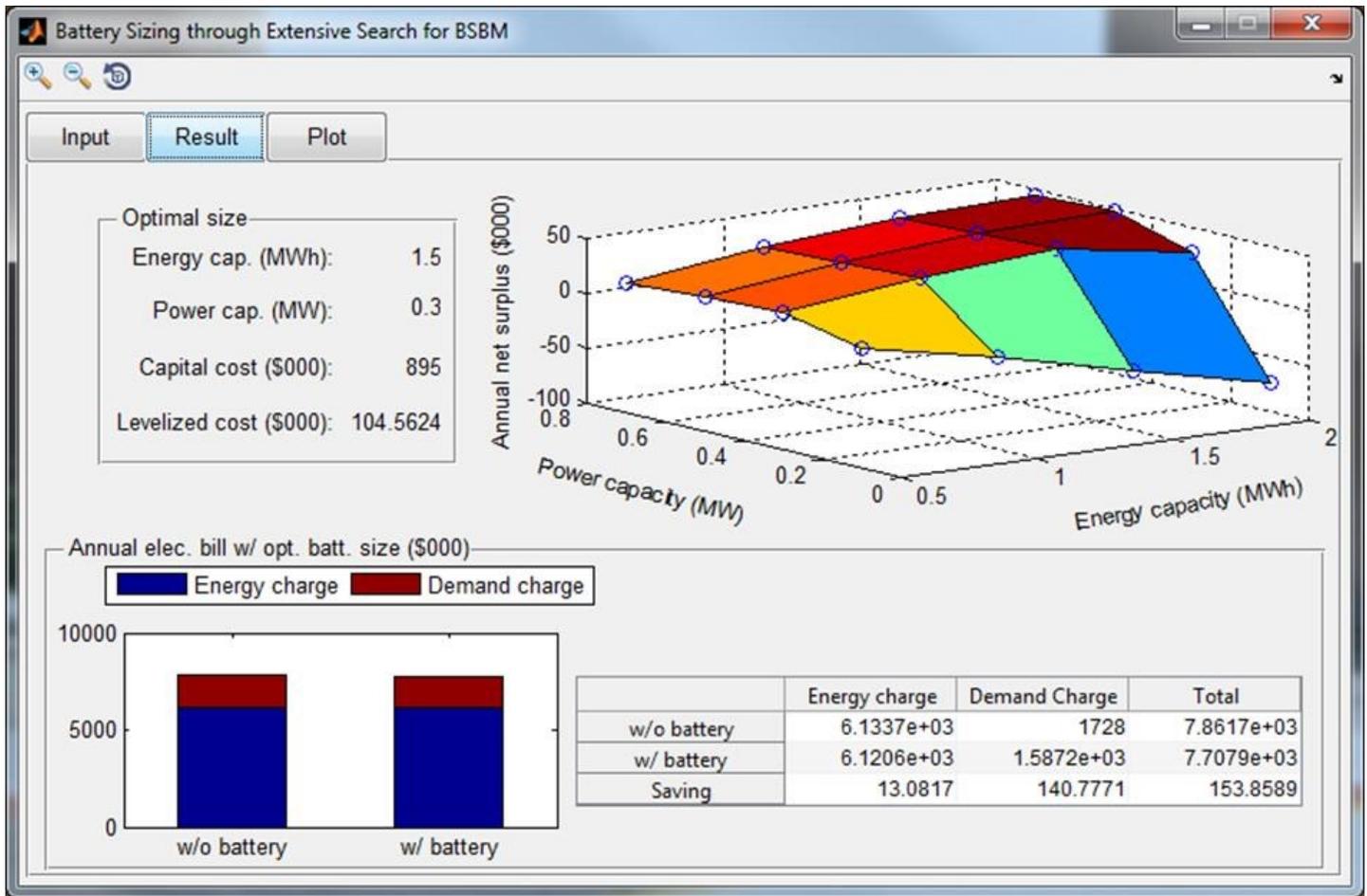


Figure 1.3. BSET Sizing Output

Recent experience with other similar BTM energy storage demand response programs (e.g., Green Mountain Power) and consumer preference studies will be evaluated in order to determine appropriate payback periods for customer participation. Those payback periods could ultimately be used to define required return rates for customers to incentivize participation.

## 2.0 Instructions for Using the HECO Demand Response Tool

### 2.1 System Requirements

The HECO Demand Response Tool operates on the Microsoft® 64-bit Windows® operating systems. It was developed using MATLAB®, and the stand-alone executable file was generated using the Deploy Tool of MATLAB version 9.4 (R2018a). Before using the tool, users must first make sure that the version 9.4 (R2018a) of the MATLAB Runtime is installed and is available on the target computer where the executable file will be run. The instructions to install MATLAB Runtime Installer are provided in section 2.2.

### 2.2 MATLAB Runtime Installation

To check if MATLAB Runtime Installer V 9.4 is running on the computer, go to the MATLAB prompt and enter “>>mcrinstaller”. Administrator rights to run MATLAB Runtime Installer will be required on the target computer. Alternatively,

1. Download the Windows version of the MATLAB Runtime (Version 9.4 64-bit) for R2018a from the following link on the MathWorks website [here](#).
2. Install the MCR\_R2018a\_win64\_installer.exe.

### 2.3 DR Tool Installation

1. Decompress HECO\_DR\_V1\_Setup.zip file.
2. Install the HECO\_DR\_V1\_Setup.exe file. Check the “add a shortcut to the desktop” option. The default installation folder is “C:\Program Files\PNNL\HECO\_DR\_V1”.
3. Once the installation is complete, you can access the tool from the shortcut on the desktop.

### 2.4 Running a Simulation

The primary function of the HECO DR tool is to formulate and solve the battery and PV compensation optimization and simulation over a 1-year period to evaluate the benefits from various demand response applications.

1. Left-double-click the HECO\_DR\_V1.exe to launch the tool. The default view is shown in Figure 2.1 and it does not automatically load the input files or the output folder.
2. Click on the browse button next to the blanks for input files to select the right files. Go to the installation folder (Default: “C:\Program Files\PNNL\HECO\_DR\_V1”) and left-double-click on the “application”, as shown in Figure 2.2. After this, left-double-click on the “Input” folder (Figure 2.3) and choose the corresponding input files for all the respective blank fields (Figure 2.4). Be careful to select the correct file for each field. If there is any mistake/ mix-up in file selection, the error shown in Figure 2.5, Figure 2.6 will pop up.

Figure 2.1. DR Tool Default View

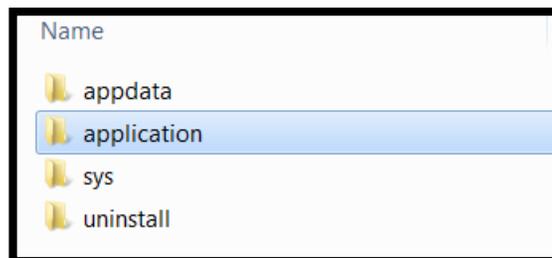


Figure 2.2. Contents in the Original Folder of Installation

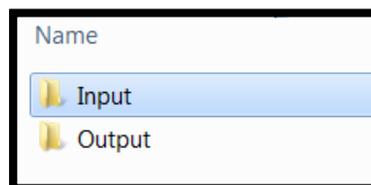


Figure 2.3. Application Folder Contents



Figure 2.4. Input Folder Contents



Figure 2.5. First Warning Message

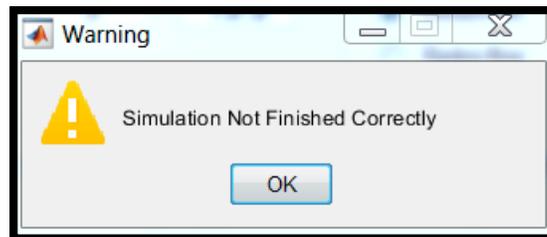


Figure 2.6. Second Warning Message

3. For the Output folder, select the "Output" folder shown in Figure 2.3 or any other folder of your choice.
4. Click the "Run" button to start a simulation with the default settings for 1) Island, 2) Asset Profile, 3) Outage, 4) Tariff, 5) DR Program, and 6) PV Compensation Schedule. There are three phases in the simulation: a) reading input files; b) running the optimization; and c) writing solutions. The second phase is the most time consuming one and take 5-15 seconds. The progress bar indicates the status of the optimization.

**Note:** Whenever the tool does not function properly, glitches, or fails to respond, close and restart the tool.

## 2.5 Viewing Simulation Results

When the simulation is finished, the user can view:

1. Value stream from different applications, with and without DR, and a bar plot showing the same (Figure 2.7),

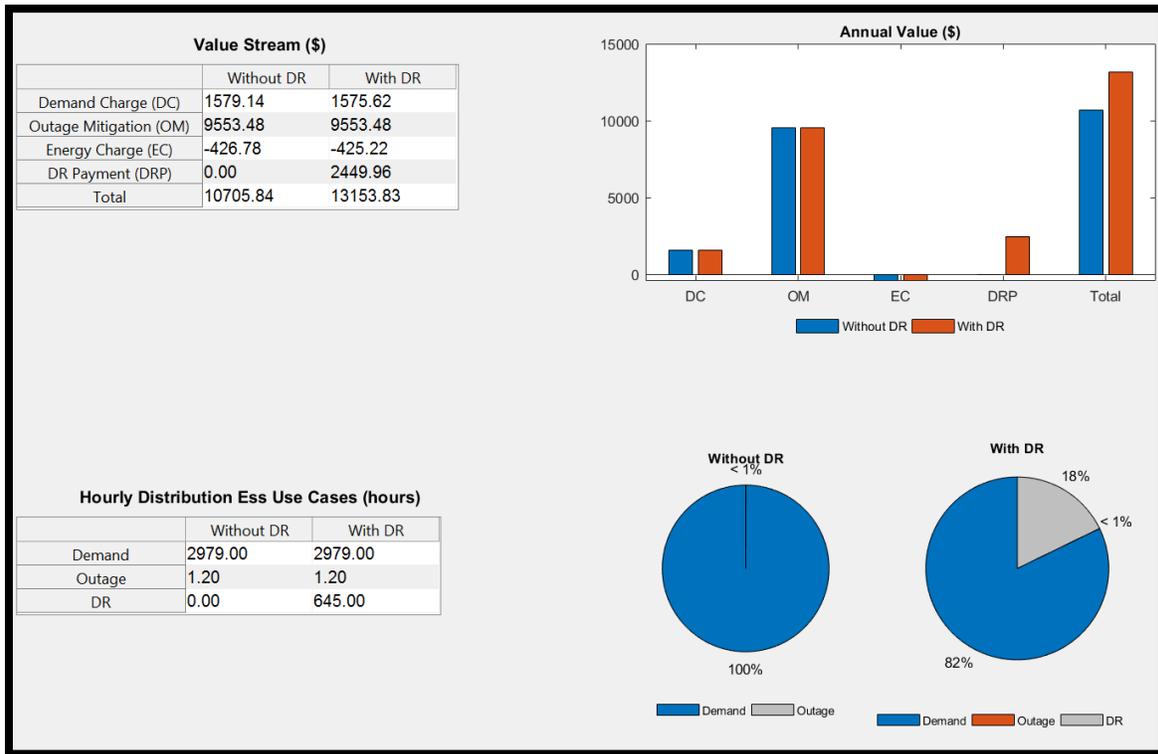


Figure 2.7. Value Stream Results

2. Hourly distribution of the ESS by use cases (Figure 2.7), and
3. Battery operations and performance (year-round) with line plots for the load, output, and SOC faced by the system in each hour (Figure 2.8). This can be zoomed into for particular hours of the year to determine the precise plot movement in the specified time-frame.

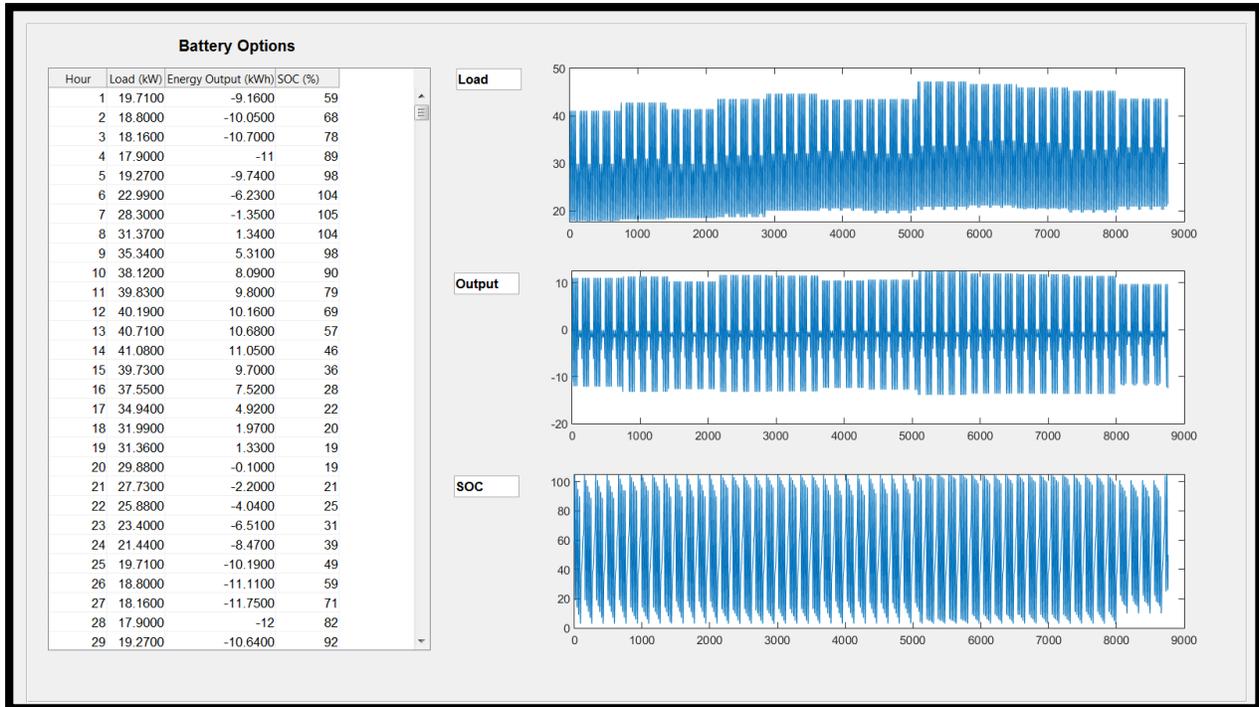


Figure 2.8. Optimal Battery Operations

The value stream from the “With DR” option only comes up when a DR program is selected, otherwise it is 0. The user can also view the results on the hard disk by accessing them in the Output folder that has been selected for that simulation (Figure 2.9).



Figure 2.9. Output on the Hard Disk

## 3.0 Model Definition and Data Requirements

### 3.1 Model Definition

HECO delivers electricity to customers located on the islands of Hawaii, Lanai, Molokai, Maui, and Oahu. HECO is interested in understanding the value of services provided to their customers from BTM storage in combination with PV systems. PNNL's task is to build a tool using the foundation laid by BSET that can evaluate the benefits of PV and ESSs, produce hourly battery activity, and optimize sizing of BTM energy storage for customers.

How much customers are charged for energy usage and how much compensation they receive for their solar production and battery storage differs between islands, rate classes, and which program they're enrolled in. For this reason, each potential combination of factors is included within the model so as to correctly capture the potential benefits each customer may receive.

Figure 1.1 presents the Graphical User Interface (GUI) for the tool. Users will select an island, a tariff structure, an outage level, and a distributed energy resource (DER) program to specify the location and type of customer that is being modeled.

In the Asset Profile Box, the size of the PV array located at the customer site as well as their installed BTM storage specifications is to be entered. If the customer does not currently have an ESS installed, an option to optimize is available at right that will calculate the optimal sizing of a potential system for that customer.

The Input Files Box will allow the user to link to the data required to perform all the calculations allowed by the tool, and include links to tariff structures, load profiles, outage information, and other information.

When the model is run, values will be generated for different use cases as applicable to the specific customer under examination; use cases will include demand charge reduction, PV production benefits, outage mitigation, and a DR benefit depending on which program in which they're enrolled. Note that the hourly values and plot below the main output could be received through files output from the model. The tables and graphs in Figures 2.7 and 2.8 are present in the GUI.

### 3.2 Mathematical Modelling

In order to evaluate potential benefits from DR programs, two categories of optimal scheduling problems are formulated to determine the annual payment with and without DR, respectively, considering different tariff structures and PV compensation programs. The optimization problems were converted to standard linear programming (LP) problems, which can be readily solved by many existing open-source and commercial solvers. By solving these LP problems, we obtain the minimum electric energy cost (with PV compensation and DR incentive included) and the corresponding battery charging/discharging operation. The benefits of using battery storage in participating DR programs can be estimated by calculating the cost difference between without and with DR cases. Detailed tariff structures PV compensation programs, and demand response programs are described in Section 4.3. Based on these information, optimal scheduling of ESS is formulated as described in this section. Notation used in these formulation are summarized as follows.

$\lambda_s^{NF}$	Non-Fuel energy charge price for monthly energy consumption at level with index $s$
$\lambda^{BF}$	Base fuel energy charge price
$\lambda^{EC}$	Energy charge price
$MCD_{s,j}$	Monthly customer demand in level with index $s$ in month $j$ .
$MCD_j$	Monthly customer demand in month $j$ .
$MPD_j$	Monthly peak demand in month $j$ .
$DCR$	Demand charge price
$p_k^+, p_k^-$	Power injection/withdrawal into/from grid during hour $k$ , respectively.
$p_{max}$	Maximum power (measured at the grid connection point) that can be injected and withdrawn into/from grid.
$p_k$	Power exchange between battery storage and grid during hour $k$ , which is positive when injecting power into grid.
$p_k^{batt}$	Rate of change of energy stored in the battery at the end of time hour $k$ , which is positive when battery is discharged.
$\eta^+, \eta^-$	Discharging and charging efficiency of the battery storage, respectively, including components such as conductor, power electronics, and battery.
$e_k$	Energy transfer between battery and grid during time hour $k$ , which is positive generation mode and negative in load mode.
$E_s$	Battery energy capacity.
$R^{PV}$	Revenue from PV compensation
$\zeta_1$	FDR event incentive rate \$0.5/kW
$\zeta_2$	FDR participation incentive rate \$5 or \$10/kW
$\kappa$	FFR incentive rate: \$5/kW
$PCB$	CGS build incentive rate: \$3/kW
$PCR$	CGS reduction incentive rate: \$2/kW
$\beta$	RR incentive rate: \$5/kW
$PFDR_m$	Capacity committed in FDR event with hour index $m$
$FFR^{annual}$	Annual average capacity committed to FFR
$CB^{annual}, CR^{annual}$	Annual average capacity committed to CGS build and reduction service
$RR^{annual}$	Annual average capacity committed to RR
$r_k^+, r_k^-$	Regulation up and down capacity during hour $k$ , respectively.
$\epsilon_k^+, \epsilon_k^-$	Energy reserve per MW regulation up and down service of hour $k$ , respectively.
$a$	Battery equivalent capital cost with respect to energy size in \$/kWh,
$b$	Battery equivalent capital cost with respect to power size in \$/kW
$\alpha = \frac{i(1+i)^n}{(1+i)^{n-1}}$	Capital recovery factor for a specified battery lifetime ( $i$ : interest or discount rate, $n$ : life of battery)

### 3.2.1 Without DR Program

Utility tariff structures vary with customer types. Therefore, different objective functions are developed accordingly in the optimal scheduling problem. Customer charge, which apply to all customer types, is a fixed value therefore is excluded from the objective function. Demand charge is only applied to medium and large commercial and industrial (C&I) customers. PV compensation is also included in the objective function.

### 3.2.1.1 Objective function

The objective function varies with tariff structures, as described below.

#### For residential customer:

The energy charge includes two parts: the non-fuel energy charge and the base fuel energy. The price of the non-fuel energy charge varies with total monthly energy consumption as described in 4.3.1.1.

To minimize the energy charge, the objective function can be expressed as:

$$\sum_{j=1}^J \left( \sum_{s=1}^3 \lambda_s^{NF} * MCD_{s,j} + \lambda^{BF} * MCD_j + R_j^{PV} \right)$$

Where  $j$  is the month index,  $J=12$  is the number of month in a year

$\lambda_s^{NF} * MCD_{s,j}$  is the Non-Fuel energy charge for electric energy at level with index  $s$  in month  $j$ ,

$\lambda^{BF} * MCD_j$  is the basic fuel energy charge in month  $j$ ,

$R_j^{PV}$  is the PV compensation, which depends on load profile, PV generation, battery charging/discharging power, and PV compensation program participated.

#### For small C & I:

There is only one energy charge rate. The objective function to be minimized is:

$$\sum_{j=1}^J \lambda^{EC} * MCD_j + R_j^{PV}$$

Where

$\lambda^{EC} * MCD_j$  is the energy charge in month  $j$ ,

#### For medium and large C & I:

As described in 4.3.1.3 and 4.3.1.4, the medium and large C & I customer's monthly bill includes customer charge, energy charge, and demand charge. The objective function to be minimized is:

$$\sum_{j=1}^J (\lambda^{BF} * MCD_j + DCR * MPD_j + R_j^{PV})$$

Where

$\lambda^{BF} * MCD_j$  is the energy charge in month  $j$ ,

$DCR * MPD_j$  is the demand charge in month  $j$ .

### 3.2.1.2 Constraints

In this case, only operational constraints from battery storage system needs to be considered.

#### Power limit:

The power transfer between the battery and grid should stay within the upper or lower bounds of power injection and withdrawal into/from grid.

$$0 \leq p_k^- \leq p_{max} \quad \forall k = 1, \dots, K$$

$$0 \leq p_k^+ \leq p_{max} \quad \forall k = 1, \dots, K$$

where  $k$  is the hour index, and  $K=8,760$  is the number of hours in a year.

#### Power transfer between battery and grid:

The power transfer between the battery and grid is the difference between the injected power and the withdrawn power.

$$p_k = p_k^+ - p_k^-, \quad \forall k = 1, \dots, K$$

#### Rate of change of energy in battery:

The rate of change of energy in the battery should include the charging and discharging efficiency.

$$p_k^{batt} = p_k^+/\eta^+ - p_k^-/\eta^-, \quad \forall k = 1, \dots, K$$

#### Dynamics of energy remained in battery:

The energy of the battery relates to the rate of change of energy as well as the energy value at last time interval

$$e_k = e_{k-1} - p_k^{batt}, \quad \forall k = 1, \dots, K$$

#### Energy limit in battery:

The energy of the battery should not exceed the battery energy limits,

$$0 \leq e_k \leq E_s/\eta^+, \quad \forall k = 1, \dots, K$$

## 3.2.2 With DR Program

Customer receive incentives by participating in DR programs which can help to reduce their monthly electricity bills. There are four DR programs available within HECO: Fast Demand Response (FDR), Fast Frequency Response (FFR), Capacity Grid Service (CGS), and Frequency Regulation (RR). The latter three are available for all customers while the FDR program is only available to C & I customers. The incentives and requirements of DR programs are added to the optimal scheduling problems. The energy charge and demand charge

components in the objective function and battery operational constraints remain the same as the case without DR.

### 3.2.2.1 Objective function

#### For residential customers:

The objective function to be minimized is:

$$\sum_{j=1}^J \left( \sum_{s=1}^3 \lambda_s^{NF} * MCD_{s,j} + \lambda_{BF} * MCD_j \right) - FFR_{Incentive} - CGS_{Incentive} - FRP_{Incentive}$$

Where

The annual incentive for participating FFR service:

$$FFR_{Incentive} = FFR^{annual} * \kappa * J$$

The annual incentive for participating CGS service

$$CGS_{Incentive} = -PCB * CB^{annual} + PCR * CR^{annual}$$

The annual incentive for participating RR service

$$RR_{Incentive} = \beta * RR^{annual} * J$$

#### For small C & I:

The objective function to be minimized is:

$$\sum_{j=1}^J \lambda^{BF} * MCD_j - FDR_{Incentive} - FFR_{Incentive} - CGS_{Incentive} - FRP_{Incentive}$$

In addition to the three DR programs available for residential customers, there is an FDR program available to C & I customers.

The annual incentive for this program is as follows:

$$FDR_{Incentive} = \zeta_2 * J * (\sum PFDR_m) / length(KFDR) + \zeta_1 * \sum PFDR_m, \forall m \in KFDR$$

#### For medium and large C & I:

The objective function to be minimized is:

$$\sum_{j=1}^J (\lambda^{BF} * MCD_j + DCR * MPL_j) - FDR_{Incentive} - FFR_{Incentive} - CGS_{Incentive} - FRP_{Incentive}$$

### 3.2.2.2 Constraints

The battery operational constraints in Section 3.2.1.2 remain the same. Additional constraints are developed based on the requirement and rules of different DR programs.

#### FDR

Power requirement: FDR capacity is limited by available battery power and energy during FDR events.

$$PFDR_m \leq p_m$$

$$PFDR_m \leq p_{max} * FDR_m^{duration} / 60 \quad \forall m \in KFDR$$

#### FFR

Power requirement: the battery should meet the power output requirements when called.

$$FFR^{annual} \leq P_{max}$$

Energy reserve requirement: The battery should reserve a certain amount of energy all the time.

$$FFR^{annual} * 0.15 \leq E_s$$

Energy output requirement: the battery should provide enough energy output when called.

$$\text{and } FFR^{annual} * FFR_n^{duration} \leq p_n \quad \forall n \in KFFR$$

#### CGS

During CGS build/reduction service, the charging/discharging should be limited so that the battery can provide 4-hour continuous service.

$$p_{kb} \geq -\min\left(p_{max}, \frac{ES}{4}\right)$$

$$p_{kr} \leq \min\left(p_{max}, \frac{ES}{4}\right)$$

$$CB^{annual} = (\sum p_{kb}) / \text{length}(KCB), \forall kb \in KCB$$

$$CR^{annual} = (\sum p_{kr}) / \text{length}(KCR), \forall kr \in KCR$$

#### RR

##### Regulation up/down capacity:

The battery should reserve enough regulation up/down capacity to ensure it can fulfill the service requirements,

$$r_k^+ \leq p_{max} - p_k,$$

$$r_k^- \leq p_{max} + p_k$$

### SOC limits with regulation up/down energy:

The battery should ensure enough energy be reserved to provide regulation services.

$$0 \leq e_k - \frac{\epsilon_k^+ r_k^+}{\eta^+} \leq E_s$$

$$0 \leq e_k + \epsilon_k^- r_k^- \eta^- \leq E_s$$

### Aggregation requirements:

Average regulation up and regulation down power throughout a year are used in the incentive calculation in order to accommodate aggregation requirement.

$$RR^{annual} \leq \frac{\text{sum}(r_k^+ + r_k^-)}{\frac{K}{2}}, \forall k = 1, \dots, K$$

### Capacity limit:

The capacity committed to RR service should be within the battery limit.

$$RR^{annual} \leq p_{max}$$

### 3.2.3 Optimal Sizing

As described in previous sections, the battery size is given and the battery capital cost is not included in the optimization. For optimal sizing, battery power  $P_{max}$  and energy capacity  $E_s$  are added to decision variables. The levelized annual battery cost can be expressed as

$$-\alpha(a * E_s + b * P_{max})$$

which is added into the objective function to determine the optimal battery size.

This method only outputs one optimal battery size and corresponding economic performance, without providing the evaluation results for other battery sizes. To overcome this shortcoming, in the DR tool, users can select an array of battery sizes in the input panel for evaluation. A 3-D plot is provided for exploring economic benefits as a function of battery power and energy capacity.

## 3.3 Data Requirements

Data underlying the DR tool will be addressed throughout the remainder of this section.

### 3.3.1 Tariff Structures

The tool includes four of HECO’s tariff schedules that a majority of their customers fall under. These schedules each appear on all five of the islands, but their components and individual prices differ across each island. The included schedules (R, G, J, and P), will each be described in detail next.

#### 3.3.1.1 Schedule R – Residential

This tariff schedule is for any residential customer on any of the five islands. There are three charges within this category that make up a customer’s bill. They are: the customer charge, the non-fuel energy charge, and the base fuel energy charge. The prices for each of these charges as well as the kWh levels within the non-fuel energy charge are different for each island.

Below is an example of the monthly bill components and prices from the island of Hawaii:

<b>Customer Charge</b>		
Single-Phase Service	\$9.00	/month
<b>OR</b>		
Three-Phase Service	\$18.00	/month
<b>Non-Fuel Energy Charge</b> (added to Customer Charge)		
First 350 kWh	\$0.081034	/kWh-month
Next 850 kWh	\$0.092569	/kWh-month
Everything over 1,200 kWh	\$0.111343	/kWh-month
<b>Base Fuel Energy Charge</b> (added to Customer Charge and Non-Fuel Energy Charge)		
All kWh usage	\$0.136062	/kWh-month

The total cost is calculated for the residential schedule using the following formula:

$$\text{Total cost} = \text{Customer Charge} + \text{Non-Fuel Energy Charge} + \text{Base Fuel Energy Charge} - \text{Incentives from DR Programs for residential customers (FFR, Capacity, and Regulation)}$$

As stated previously, each of these values changes by island. The values for each island are shown in the Table 3.1. Note the numbers to the left of the boxes within the Non-Fuel Energy Charge, these are the kWh demand ranges that each price applies to on that island. For example, a residential customer on Lanai with 300 kWh of demand in a given month is charged the first 250 kW of that at \$0.09124/kWh and the rest at \$0.11624/kWh.

Table 3.1. Residential Customer Schedule Prices by Island and Category

Schedule		Oahu	Hawaii	Lanai	Maui	Molokai
R	<b>Customer Charge</b>					
	Single-Phase Service	\$9.00	\$10.50	\$8.50	\$8.50	\$8.50
	Three-Phase Service	\$18.00	\$15.00	\$13.00	\$13.00	\$13.00
	<b>Non-Fuel Energy Charge</b>					
	kWh ranges (\$/kWh)					
	<350	\$0.081034	300 \$0.112019	250 \$0.0912400	350 \$0.0933930	250 \$0.114278
	350-1200	\$0.092569	300-1000 \$0.145537	250-750 \$0.116240	350-1200 \$0.115993	250-750 \$0.140778
>1200	\$0.111343	1000 \$0.156529	750 \$0.123240	1200 \$0.122393	750 \$0.152278	
<b>Base Fuel Energy Charge</b>						
All kWh usage (\$/kWh)	\$0.136062	\$0.162487	\$0.322668	\$0.230016	\$0.263468	

Single-Phase service is for residential customers that have 320 continuous amps or less and Three-Phase service customers are those with 200 continuous amps or less. Customers are one or the other and face the single, appropriate customer charge, not both.

Example monthly bill:

For a single-phase residential customer that lives on the island of Molokai and their kWh demand for the month is 600 kWh, their bill for that month would be:

$$\text{Customer Charge} + \text{Non-Fuel Energy Charge} + \text{Base Fuel Energy Charge}$$

$$\$8.50 + \{[250 * \$0.114278] + [(600 - 250) * \$0.140778]\} + (\$0.263468 * 600) = \$86.34$$

All HECO customers face a minimum charge each month that is not dependent on energy usage. For residential customers this value is either the single-phase service charge or the three-phase service charge, whichever applies for that customer.

### 3.3.1.2 Schedule G – General Service Non-Demand (Small C&I)

This tariff schedule is for non-residential customers with loads <5,000 kWh a month. There are two charges within this category that make up a customer’s bill. They are the customer charge and the energy charge.

Below is the breakdown of prices customers in this category face across each island.

Table 3.2. Schedule G Energy Pricing by Island

Schedule		Oahu	Hawaii	Lanai	Maui	Molokai
G	<b>Customer Charge</b>					
	Single-Phase Service	\$33.00	\$31.50	\$30.00	\$26.00	\$27.00
	Three-Phase Service	\$61.00	\$54.50	\$45.00	\$44.00	\$38.00
<b>Energy Charge</b>						
All kWh usage	\$0.213317	\$0.315858	\$0.448726	\$0.345890	\$0.448344	

The total cost is calculated for the small C&I customer using the following formula:

$$\text{Total cost} = \text{Customer Charge} + \text{Energy Charge} - \text{Incentive from DR Programs for Schedule G (FDR, FFR, Capacity, Regulation)}$$

Only the residential customers face different pricing levels based on their levels of energy consumption. All other tariff schedules, like this one, merely have a flat rate that all energy will be charged at each month.

As shown so far, neither the residential customer nor the small C&I customer receive demand charges as part of their bill. This will, however, be a component of the next two rate structures: J & P.

### 3.3.1.3 Schedule J – General Service Demand (Medium C&I)

This tariff schedule is for non-residential customers with loads >5,000 kWh a month. There are three charges within this category that make up a customer’s bill: the customer charge, the demand charge, and the energy charge.

Below is the breakdown of prices customers in this category face across each island.

Table 3.3. Schedule J Energy Pricing by Island

Schedule		Oahu	Hawaii	Lanai	Maui	Molokai
J	<b>Customer Charge</b>					
	Single-Phase Service	\$60.00	\$38.00	\$50.00	\$60.00	\$37.00
	Three-Phase Service	\$82.00	\$64.00	\$70.00	\$75.00	\$47.00
	<b>Demand Charge</b>					
	Billing Demand kW* \$/kW	\$11.69	\$10.25	\$11.50	\$10.00	\$10.00
	<b>Energy Charge</b>					
All kWh usage*\$/kWh	\$0.169734	\$0.248033	\$0.425860	\$0.304163	\$0.369705	

#### Billing Demand:

The demand charge is a portion of the customer’s bill that is linked to their peak energy usage for the month. For every single island, the minimum billing demand (i.e. the amount that gets charged at the demand charge rate) is 25 kW under this schedule. That is, no matter what, each of these customers will be charged at least 25 kW\* the appropriate \$/kW demand rate in the table above for their demand charge.

Assuming their peak demand for the month is higher than 25 kW, the actual billing demand is the higher of two options:

1. The peak kW demand in a given month, or
2. The average of the current month’s peak demand and the highest peak demand of the past 11 months.

The total bill for this rate schedule is the sum of the customer charge, the demand charge, and the energy charge. The minimum a customer will be billed is the sum of the customer and demand charge.

Example:

If a single-phase, medium C&I customer on the island of Hawaii had a demand of 6,500 kWh in a given month and their peak kW in the month was 50 kW, their bill would be:

$$\text{Customer Charge} + \text{Demand Charge} + \text{Energy Charge}$$

$$\$38.00 + (50 \text{ kW} * \$10.25) + (\$0.248033 * 6500 \text{ kWh}) = \$2,162.71$$

### 3.3.1.4 Schedule P – Large Power Service (Large C&I)

This tariff schedule is for non-residential customers with a high-power load demand. The level of power load for customers to qualify changes by island. There are three charges within this schedule that make up a customer’s bill: the customer charge, the demand charge, and the energy charge.

Below is the breakdown of prices customers in this category face across each island. Note the numbers directly beneath each island name. These are the minimum kW power load demands for customer to qualify for the P rate class on each island, customers that don’t meet this requirement fall into Schedule J.

Table 3.4. Schedule P Energy Pricing by Island

Schedule		Oahu	Hawaii	Lanai	Maui	Molokai
		>300 kW	>200 kW	>200 kW	>200 kW	>100 kw
P	Customer Charge	\$350.00	\$400.00	\$250.00	\$300.00	\$150.00
	Demand Charge					
	Billing Demand kW	\$24.34	\$19.50	\$22.00	\$20.00	\$18.00
	Energy Charge					
	All kWh usage	\$0.149013	\$0.218184	\$0.402141	\$0.277504	\$0.295392

#### Billing Demand:

For every island, the minimum billing demand that will be charged to make up their demand charge for Schedule P is the power load qualification for that island. For example, on the island of Lanai, customers must have a power load of >200 kW to be counted as a Schedule P customer and, consequently, their minimum demand billing amount is 200 kW as well. So, Lanai customers in this class will face a \$22\*200 = \$4,400 demand charge at minimum even if their peak is <200 kW.

Assuming their peak demand for the month is higher than the minimum, the actual billing demand is the higher of two options

1. The peak kW demand in the given month, or
2. The average of the current month’s peak demand and the highest peak demand in the past 11 months.

The total bill for this rate schedule is the sum of the customer charge, the demand charge, and the energy charge in the same format as Schedule J above.

The minimum a customer will be billed under this tariff schedule is the sum of the customer and demand charge.

### 3.3.2 Solar PV Compensation

There are four different solar compensation programs that HECO customers can enroll in to realize PV production benefits. They are: Net Energy Metering (NEM), Customer Grid Supply (CGS), Customer Grid Supply+ (CGS+), and Smart Export. Each of these are described in the remainder of this report.

## 3.4 Net Energy Metering

The NEM program works to incentivize customers with solar production by reducing their bill directly for all kWh of energy generated and crediting them on a future bill if they generate more than they demand in a given month. HECO is not currently accepting additional applicants for the NEM program.

Note that no amount of PV generation will affect their minimum charge amount and it can only be applied towards the variable charges on their bill. Customers can connect PV systems up to 100 kW. The credits they can receive per kWh of generation differ by island and are equivalent to the full retail rate, not including the fixed customer charge, as shown in the tariffs described in the previous section.

Example:

A residential customer on Oahu has 150 kWh delivered to their home during times that PV production falls short of load. Further, the same customer has an excess of 240 kWh of energy received from the utility from the PV system resulting from times when PV production exceeds load at the home. In this case, it would mean that the customer had a net export of 90 kWh of energy onto the grid and would receive a credit for that amount. In this case, the customer would eliminate the energy component of the bill and would be credited for 90 kWh at 8.10¢/kWh. That amount would be applied to the next bill when their demand is greater than their generation. If their PV generation continues to be greater than their demand then the credit is cumulative and is eventually applied when their generation < demand, most likely in winter when there is less PV generation.

The diagram in Figure 3.1 shows a month in which more generation was received than demanded by a customer.

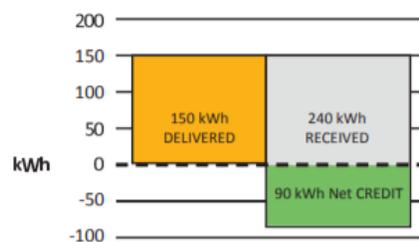


Figure 3.1. Example of NEM Customer Receiving Energy Credit

In months where the customer generates less energy than they demand, they are charged for their net demand at the appropriate prices outlined under the tariff structure. For example, say a residential customer on Oahu had 100 kWh of demand but only generated 60 kWh from their PV in a given month. Their net energy demand, 40 kWh, would be charged at \$0.081034/kWh since that is still within the <350 kWh range as specified for that island in Table 3.1.

Any credits that are built up at the end of the year will be refunded towards any eligible charges within the 12-month billing cycle, i.e. charges that may have accrued in months prior to the excess PV generation. If there is any credit leftover after this process and at the end of the 12-month billing cycle it is forfeited. Credits do not roll over into the next year of billing.

### 3.4.1.1 Customer Grid Supply

This program is the same as CGS+ but customers face a different credit rate. Under the customer grid supply compensation structure, energy generated by the PV system is used first to power the home. Any energy exceeding onsite loads during each hour is exported onto the HECO grid. A bidirectional meter is used to determine the energy taken from the grid to meet onsite load requirements and the amount of energy exported onto the grid. The lesser of those two values is credited at the rates presented in Table 3.5. If the bill amount is less than the monthly minimum after all credits are applied, a monthly minimum is used. The monthly minimums are \$26.42 per month (\$25 plus \$1.42 Green Infrastructure Fee) for residential customers and \$51.42 per month for commercial customers.

Table 3.5. Customer Grid Supply Credit Rates by Island

Island	CGS Plus Credit Rate (¢/kWh)
Oahu	15.07
Maui	17.16
Lanai	27.88
Molokai	24.07
Hawaii Island	15.14

The following examples demonstrate how PV energy production is compensated under this program.

#### Example 1: Bill that Exceeds the Minimum Bill

Steps to Calculate Bill:

1. Determine lesser of Utility Supplied kWh vs. Utility Received kWh - Example: Utility Supplied: 350 kWh, Utility Received: 412 kWh, Credit is based on lesser amount: 350 kWh.
2. Calculate your Customer Grid Supply credit (\$0.1507, Oahu Rate) (350 \* \$0.1507) = \$52.75
3. Apply credit to bill (\$97.92 Bill No Credit) – (\$52.75 CGS Credit) = \$45.17 Customer Bill

#### Example 2: Minimum Bill

Steps to Calculate Bill Resulting in a Minimum Bill:

1. Determine lesser of Utility Supplied kWh vs. Utility Received kWh: Utility Supplied: 150 kWh, Utility Received: 250 kWh, Credit is based on lesser amount of 150 kWh
2. Calculate your Customer Grid Supply credit (\$0.1507, Oahu Rate)  $(150 * \$0.1507) = \$22.61$
3. Apply credit to bill – (\$47.92 Bill No Credit) – (\$22.61 Customer Grid Supply Credit) = \$25.31  
\$25.31 < Minimum Bill = \$26.42 Customer Bill

This program is not actively enrolling additional customers.

### 3.4.1.2 Customer Grid Supply+

This program is nearly identical to the NEM program described above, except that customers can still apply to this one as the other program is closed. Under this program customers receive a monthly bill credit for energy delivered to the grid on their bills through the same method as the first program. The export credit is fixed through Oct. 20, 2022 and is outlined in the table below for each island. This program does require controllability such that HECO could disconnect your PV system from the grid in the event of an emergency. The eligible system size is up to 100 kW. Under this program, the minimum residential bill is \$25.

Table 3.6. Customer Grid Supply+ Credit Rates by Island

Island	CGS Plus Credit Rate (¢/kWh)
Oahu	10.08
Maui	12.17
Lanai	20.80
Molokai	16.77
Hawaii Island	10.55

### 3.4.1.3 Smart Export

The Smart Export Program is for customers who have both PV and BTM storage. Customers are expected to charge their battery with the solar production during daylight hours (9am – 4pm) and then use the battery in the evening to fulfill their energy demand. If they have stored more than they demand in an evening, customers receive credit for any energy they export onto the grid. The eligible system size is up to 100 kW.

Energy exported onto the grid during the daytime (between 9am-4pm) is not compensated; however, customers are able to receive a credit for any energy exported to the grid during all other hours.

Customers under this program receive a monthly bill credit for any energy they inject into the grid, which helps to offset their energy cost when their demand is greater than their generation. The prices per island are fixed through October 22, 2022 and are shown in the table below.

Table 3.7. Smart Export Schedule and Compensation by Island

Island	12 a.m. to 9 a.m. (¢/kWh)	9 a.m. to 4 p.m. (¢/kWh)	4 p.m. to 12 a.m. (¢/kWh)
Oahu	14.97	No Credit	14.97
Maui	14.41	No Credit	14.41
Lanai	20.79	No Credit	20.79
Molokai	16.64	No Credit	16.64
Hawaii Island	11.00	No Credit	11.00

Example:

Say a residential customer located on Oahu used their PV to charge their battery up to 50 kWh in an afternoon but their demand that evening was only 10 kWh. They could inject the remaining 40 kWh onto the grid and receive a bill credit of  $40 \text{ kWh} * 14.97 \text{ cents/kWh} = \$5.99$  as long as they injected between 4pm and 9am.

### 3.4.2 Demand Response Programs

The tool has been equipped to evaluate three existing DR programs and one, the regulation reserve program, currently under consideration by HECO. These DR programs are highlighted in the remainder of this section.

#### 3.4.2.1 Fast Demand Response

The Fast Demand Response (FDR) Program is for commercial and industrial HECO customers who agree to be called upon for temporary energy reduction. Events are triggered by unexpected demand increases or supply drops from variable renewable resources. To mitigate the effects of these events, participants reduce their energy consumption through a strategy that has been agreed upon between them and HECO (equipment shutdown, lighting shutdown, etc.). For the DR tool, we consider the use of energy storage to satisfy this requirement. For their participation customers receive a monthly bill credit. Table 3.8 outlines the rules of the program.

Table 3.8. Fast DR Program Details

Parameter	
Time to reduce load following call	10 minutes
Availability requirements	7am-9pm M-F, non-holidays
Maximum event time	1 hour
Maximum opt outs of event without penalty per year	3
Minimum Load Reduction Offer	50 kW

As highlighted in Table 3.8, the maximum opt outs of events without penalty per year is three. The penalty for opting out is a two-month suspension from the program.

The frequency of times a customer nominates themselves to be called upon for an event per year determines the compensation they receive. Customers receive this benefit each month regardless of whether events are called.

Table 3.9. Fast DR Program Options

Frequency of Events Volunteered For	Incentive
0-40 events/year	\$5/kW-month
41-80 events/year	\$10/kW-month

Both incentive structures also receive an additional \$0.50/kWh credit during actual events based on event performance. These values are multiplied by a performance factor which is based on average performance during events in a month. The calculation for the payment each month is outlined below:

$$\text{Event Incentive} = (\text{capacity reduced}) \times (\text{event duration}) \times (\$0.50/\text{kWh}) \times (\text{performance})$$

$$\text{Participation Incentive} = (\$5/\text{kW} \text{ or } \$10/\text{kW}) \times (\text{capacity reduced}) \times (\text{performance})$$

Performance is calculated as (actual duration)/(expected duration) per event and averaged over all events in the month.

For modeling purposes, we added an option in the GUI to allow the user to select between the two options outlined in Table 3.9. If the first option is selected, the number of events cannot surpass 40.

We allowed the energy storage system to be bid into this program while also using it for other bill reduction operations. When the system fails to perform, the participation incentive is reduced. The performance rate will be measured to ensure it meets minimum program standards. Using historic data on fast frequency response events, we defined an average statistical year for these events as defined in Table 3.10. Between 2006 and 2017, HECO made 134 calls for FDR with an average call duration of .82 hours. Events between 2006 and 2017 were randomly selected to construct a statistically average year for simulation purposes.

Table 3.10. Fast DR Program Events

Event#	Date	State Time	Ending Time	Duration
1	12-Feb	6:00:00 PM	7:00:00 PM	60
2	14-Jun	7:00:00 PM	8:02:00 PM	62
3	10-Jul	7:00:00 PM	8:00:00 PM	60
4	7-Aug	8:00:00 AM	8:30:00 AM	30
5	22-Aug	8:00:00 AM	9:00:00 AM	60
6	22-Aug	7:00:00 PM	8:00:00 PM	60
7	8-Sep	7:12:00 PM	8:12:00 PM	60
8	27-Oct	6:30:00 PM	7:30:00 PM	60
9	6-Nov	8:00:00 AM	9:00:00 AM	60
10	10-Dec	6:00:00 PM	7:00:00 PM	60
11	29-Dec	6:11:00 PM	7:11:00 PM	60

### 3.4.2.2 Fast Frequency Response (FFR) Grid Service Program

Fast Frequency Response (FFR) is a local discrete response at a specified frequency trigger. FFR acts to limit the frequency drop or over-frequency resulting from a frequency disturbance,

such as loss of a generator or load. It assists in arresting the decline in frequency as a result of a contingency event. Updates to this grid service may be informed by any future updates to the Power Supply Improvement Plan or other appropriate company filings.

The following parameters guide the program:

- Underfrequency response to 59.7 Hz deviation
- All resources that can meet the standard are able to participate (expecting mostly water heaters and batteries)
- Availability: 24 hours per day
- Return to normal: 30 minutes
- Participation incentive: \$5/kW-month

### Description and Requirements

#### 1. Additional Definitions.

- a. Non-Event Days – Any day in which load is not manipulated by a GS Event.
- b. Not Applicable

#### 2. Service Requirements.

- a. Resource. The resource offering FFR must have the following operating characteristics and technical capabilities:
  - i. The resource must be capable of the full range of the amount of FFR capability offered without manual resource operator intervention of any kind.
  - ii. Supplier must ensure that its control and monitoring or related Supervisory Control and Data Acquisition (SCADA) equipment for its enrolled resources are operational throughout the time period during which FFR is required to be provided. Polling rate of monitored equipment must occur at a more frequent periodicity than the poll rate specified in the communications and control section below.
- b. The resource must return to its normal operating state at a rate not to exceed ten percent (10 percent) of supplier's forecasted capability per minute until an aggregate of 50 MW or more is enrolled in the FFR grid service across all supplier resources. When 50 MW or more of FFR is available, the companies will assign a ramp rate to a supplier's resource such that the maximum ramp rate across all supplier resources does not exceed five (5) MW per minute.
- c. Response Timing and Accuracy. When the measured frequency is less than or equal to the frequency trigger (as specified in Section H), the supplier enrolled resources must be fully deployed within 12 cycles including the operating time of the disconnecting device. A deviation of +/- 0.02 Hz of the frequency trigger as specified in Section H will be permitted.
- d. Availability requirement. FFR grid service is subject to event trigger as specified in Section H 24 hours per day.
- e. Periods of No Availability. If supplier is temporarily unable to provide FFR service, the supplier shall update its operational forecast to identify the period(s) during which FFR service will be unavailable.

- f. Non-export provision. Supplier shall not be allowed to export energy into the company system (i.e., no back feed capability), unless otherwise permitted under an interconnection agreement or supplemental screening and review for each specific resource.
- g. Operational Requirements.
  - i. Return to normal operation. Supplier shall ensure that no snap back, i.e. a demand peak because of holding off participant load, occurs upon return to normal operation. The return ramp rate of the resource shall adhere to defined resource return ramp rate requirements.
  - h. Trigger. Supplier shall provide FFR service when the system reaches the trip frequency trigger
    - i. Trigger set point shall be configurable remotely by the supplier.
    - ii. This setting may be changed upon HECO's written request as necessary for grid response coordination, up to twice annually.
    - iii. Trip frequency requirement set point shall be 59.7 Hz or lower.
  - i. Event Duration. Supplier may commence normal operation in accordance with Section G. Operational Requirements specified above.
    - i. Supplier shall provide service for a total of thirty (30) minutes after detection of the FFR trigger described above or (at the Company's discretion) after detecting frequency holding between 59.95 and 60 Hz for one (1) minute.
- 3. Performance Factor (PF) Calculations.
  - a. The PF for each event will be the percentage of delivered capability compared to the forecasted capability, not to exceed 100%.
  - b. Performance Factor Calculation:
 
$$PF_e = \left[ 1 - \left| 1 - \frac{D_e}{F_e} \right| \right]^2$$

$$D_e = M_{interval_p} - \left( \frac{\sum_{i=1}^n M_{interval_i}}{n} \right)$$
    - $PF_e$  = Event Performance Factor
    - $D_e$  = Delivered capability (kW) during event e
    - $M_{interval_p}$  = Meter reading in interval prior to deployment of FFR service as specified in Section H, Trigger
    - $M_{interval_i}$  = Meter reading(s) in interval(s) following deployment of FFR service as specified in Section H, Trigger. Intervals which contain FFR event trigger and Resource return to normal operation will not be counted for the purposes of Performance Factor Calculation.
    - $n$  = Number of metering intervals in event
    - $F_e$  = Forecasted capability (kW) for time of event e
- 4. Communications and Control. Reserved.

- a. Protocol/Specification. Supplier GSDS shall use OpenADR 2.0b to communicate with the Distributed Energy Resource Management System (DERMS). One OpenADR 2.0b certified Virtual End Node (VEN) will be required for FFR communications and control.
  - b. Data. Capability in kW shall be made available for polling by the DERMS every one (1) minute using the OpenADR 2.0b Data Reports TELEMETRY\_USAGE. Company may also require the TELEMETRY\_STATUS report. During a GS Event, TELEMETRY\_USAGE shall reflect Capability
5. Testing.
- a. Manual Dispatch Test. The Resource must be able to be triggered by the Company manually. This manual trigger will serve as the resource test. Specific OpenADR signal level will depend on the finalization of the design and implementation of the DERMS.
  - b. Annual Testing. Refer to Exhibit I – Service Level Agreements for information regarding testing requirements in the FFR GS agreement.
6. Maximum Events Called Per Year: Not Applicable.

To replicate the calls for under frequency events, we obtained data for Oahu in 2017. During these events, the ESS would need to supply the rated power for the event duration. With the longest duration of any under frequency event at the 59.5 or 59.7 Hz thresholds registering 9 minutes, approximately 15 percent of any storage system’s energy must be reserved at all times because there is no event foreknowledge.

**Table 3.11. Under Frequency Events on Oahu in 2017 at the 59.7 Hz Threshold**

Date	Start Time	Ending Time	Event Duration
2/11/2017	4:22:00 PM	4:24:00 PM	0:02:00
2/13/2017	2:10:00 AM	2:14:00 AM	0:04:00
3/24/2017	5:00:00 PM	5:02:00 PM	0:02:00
3/25/2017	12:36:00 PM	12:38:00 PM	0:02:00
4/9/2017	5:00:00 PM	5:02:00 PM	0:02:00
4/10/2017	4:52:00 PM	4:54:00 PM	0:02:00
4/23/2017	7:21:00 PM	7:23:00 PM	0:02:00
8/21/2017	3:36:00 PM	3:41:00 PM	0:05:00
8/30/2017	3:46:00 PM	3:51:00 PM	0:05:00
9/12/2017	7:08:00 PM	7:15:00 PM	0:07:00
11/28/2017	4:50:00 PM	4:53:00 PM	0:03:00
12/6/2017	8:44:00 PM	8:48:00 PM	0:04:00
12/21/2017	3:32:00 PM	3:36:00 PM	0:04:00
<b>TOTAL</b>		<b>13</b>	<b>0:44:00</b>

### 3.4.2.3 Capacity Grid Service Program

Capacity resources can be derived from generation resources or controlled load. Capacity for dispatchable generation is defined as the power (MW) rating of the unit. Capacity for variable generation is defined as the amount of capacity (MW) that can be assured in the next four (4) hours of the resource. Capacity of controlled load is defined as the minimum of load under control during the 24-hour day.

- Build (Charging of ESS): Provide build service for a four (4) hour block during the system mid-day renewable generation peak.
- Reduction (Discharging of ESS): Provide Reduction service for a four (4) hour block during evening peaking periods, as specified under Section E.
- Build: The Company will dispatch a build command at least eight (8) hours, but no longer than 24 hours prior to the build event. The supplier’s resource portfolio shall ramp up to its forecasted build capability in the thirty (30) minutes preceding the event
- Reduction: The Company will dispatch a Reduction command at least ten (10) minutes but no longer than 24 hours prior to the Reduction event. The Supplier’s Resource portfolio must meet its Forecasted Reduction Capability within two (2) minutes from the event start time.
- Event duration: 4 hours for each. With a 4-hour requirement, the ESS can bid in an amount of power that can be provided constantly over four hours. Thus, an ESS with an E/P ratio of 1.0 could bid in one-fourth of its power capacity while an ESS with an E/P ratio of 4.0 could bid in 100 percent of its power capacity.
- Build: 10:00AM – 2:00PM
- Reduction: 5:00PM – 9:00PM
- All resources that can meet the standard are able to participate
- Availability: 24 hours per day
- Participation incentive: (Build - \$3/kW-month; Reduction \$2/kW-month). A participant can sign up for one or both build and reduction programs.
- Maximum events called per year are presented in Table 3.12. We assume that the maximum events are called each year and that the lowest load hours within the build and highest load hours during the reduction time periods serve as the call hours. We split the call events evenly between build and reduction. Events can occur on the same day.

Table 3.12. Maximum Number of Events Called per Year for the Capacity Grid Service Program

Island	2018	2019	2020	2021	2022	2023
<b>Oahu</b>						
• Build	52	80	104	104	104	104
• Reduction	52	80	104	104	104	104
<b>Hawaii</b>						
• Build	33	81	134	186	206	216
• Reduction	33	81	134	186	206	216
<b>Maui</b>						
• Build	104	124	144	144	144	144
• Reduction	104	124	144	144	144	144
<b>Molokai</b>						
• Build	0	0	186	188	190	195
• Reduction	0	0	186	188	190	195
<b>Lanai</b>						
• Build	3	7	199	205	207	215
• Reduction	3	7	199	205	207	215

## Description and Requirements

1. Additional Definitions.
  - a. Non-Event Days – Any day in which participant facility demand is not manipulated by a grid service event
  - b. Similar Usage Days – Days that have the same usage characteristics, i.e., weekdays with other weekdays, non-holidays with other non-holidays, and non-event days with other non-event days
2. Service Requirements.
  - a. Resource. A Resource enrolled by supplier offering capacity service must have the following operating characteristics and technical capabilities:
    - i. Build: Provide build service for a four (4) hour block during the system mid-day renewable generation peak, as specified under Section E. Availability Requirement, below.
    - ii. Reduction: Provide reduction service for a four (4) hour block during evening peaking periods, as specified under Section E.
    - iii. Supplier must ensure that its control and monitoring or related SCADA equipment for its enrolled resources are operational throughout the time period during which capacity service is required to be provided. The polling rate of monitored equipment may not exceed specified rates.
  - b. Resource Ramp Rate. Preceding a capacity event, the supplier's enrolled resource must ramp to its forecasted capability at the ramp rate (increase and decrease in MW/minute) specified below. Immediately following a capacity event, the supplier's resource must return to its normal operating state at the ramp rate specified below.
    - i. HECO Company Requirement:
      - (1) The Resource must ramp to its forecasted capability at a rate not to exceed ten percent (10%) of supplier's forecasted capability per minute until an aggregate of 50 MW or more is enrolled in the capacity grid service across all supplier resources. When 50 MW of capacity is available, the companies will assign a ramp rate to a supplier's resource such that the maximum ramp rate across all supplier resources does not exceed five (5) MW per minute.
      - (2) The resource must return to its normal operating state at a rate not to exceed ten percent (10%) of supplier's forecasted capability per minute until an aggregate of 50 MW or more is enrolled in the capacity grid service across all supplier resources. When 50 MW or more of capacity is available, the companies will assign a ramp rate to a supplier's resource such that the maximum ramp rate across all supplier resources does not exceed five (5) MW per minute.
    - ii. Maui Electric Company Requirement:
      - (1) The resource must ramp to its forecasted capability at a rate not to exceed ten percent (10%) of supplier's forecasted capability per minute until an aggregate of 20 MW or more is enrolled in the capacity grid service across all supplier resources. When 20 MW or more of capacity is available, the companies will assign a ramp rate to a supplier's resource such that the maximum ramp rate across all supplier resources does not exceed two (2) MW per minute.

- (2) The resource must return to its normal operating state at a rate not to exceed ten percent (10%) of supplier's forecasted capability per minute until an aggregate of 20 MW or more is enrolled in the capacity grid service across all supplier resources. When 20 MW or more of capacity is available, the companies will assign a ramp rate to a supplier's resource such that the maximum ramp rate across all supplier resources does not exceed (2) MW per minute.
- c. Response Timeline: Supplier's enrolled resources must take action in response to a dispatch command sent by the Company as specified below.
- i. Build: The Company will dispatch a build command at least eight (8) hours, but no longer than 24 hours prior to the build event. The supplier's resource portfolio shall ramp up to its forecasted build capability in the thirty (30) minutes preceding the event at the ramp rate specified in Section 2.B Resource Ramp Rate and must achieve the capacity capability provided in the operational forecast by the start of the build event. Following the event, the supplier may return to its normal operating state in the thirty (30) minutes after the end of the build event at the ramp rate specified in Section 2.B Resource Ramp Rate, or after receiving a command from the Company's system operations department at the ramp rate specified in Section 2.B Resource Ramp Rate.
  - ii. Reduction: The Company will dispatch a Reduction command at least ten (10) minutes but no longer than 24 hours prior to the reduction event. The supplier's resource portfolio must meet its forecasted reduction capability within two (2) minutes from the event start time. Following the event, the supplier may return to its normal operating state in the thirty (30) minutes after the end of the build event at the ramp rate specified in Section 2.B Resource Ramp Rate, or after receiving a command from the Company's system operations department at the ramp rate specified in Section 2.B Resource Ramp Rate.
- d. Event Duration.
- i. Build: Supplier shall provide service for four (4) hours during specified timeframes.
  - ii. Reduction: Supplier shall provide service for up to four (4) hours for reduction during specified timeframes. Event duration will be at the discretion of the companies' system operations department at the time of event trigger.
- e. Availability Requirement: Supplier's resource portfolio must be available to provide capacity service for specified build and reduction periods. These periods should be reflected in the Supplier's operational forecast.
- i. Build: 10:00AM – 2:00PM
  - ii. Reduction: 5:00PM – 9:00PM
- f. Periods of no Availability: If supplier is temporarily unable to provide capacity service, supplier shall update its operational forecast to identify the period(s) during which capacity service will be unavailable.
- g. Non-export Provision: Supplier shall not be allowed to export energy into the Company System (i.e., no backfeed capability), unless otherwise permitted under an interconnection agreement or supplemental screening and review for each specific Resource.
- h. Operational Requirements: If there is an interruption due to a system contingency event, for up to one (1) hour duration of interruption, the Supplier's Resources will be allowed to

provide Build service after the contingency event for the same amount of time as the interruption event beyond the Build period specified in 3.E Availability Requirement.

3. Dispatch/Control Requirements.
  - a. Trigger. Supplier shall receive a signal from the DERMS
4. Forecasting Requirements. Reserved.
  - a. A separate forecast file will be required for capacity build and capacity reduction.
  - b. Refer to Exhibit F in the GSP agreement – Operational forecast, for information regarding forecasting requirements.
5. Baseline.
  - a. Estimated Baseline Calculation. The estimated baseline calculation shall take the average demand of the ten (10) previous similar usage days, using five (5) minute interval data for the same period as the event. This establishes the average normal demand for the participating facility during the event period based on the corresponding interval points from the previous ten (10) similar usage days.
6. Performance Factor Calculation.
  - a. The performance factor for each event will be the percentage of delivered capability compared to the forecasted capability.
  - b. The ramp-in and ramp-out periods of any event will not affect the Performance Factor calculation of the event.
  - c. Performance Factor Calculation:
 
$$PF_e = \frac{\sum_{i=1}^n \left( 1 - \left| 1 - \frac{D_{interval_i}}{F_{interval_i}} \right| \right)}{n}$$
    - $PF_e$  = Performance Factor during Build period
    - $D_{interval_i}$  = Delivered capability (kW) during interval  $i$
    - $F_{interval_i}$  = Forecasted capability (kW) for time of interval  $i$
    - $i$  = 15 minute interval
    - $n$  = number of 15 minute intervals in an event
7. Communications and Control. Reserved
  - a. Protocol/Specification. Supplier GSDS shall use OpenADR 2.0b to communicate with DERMS. One OpenADR 2.0b certified Virtual End Node (VEN) will be required for capacity build communications and control and capacity reduction communications and control. Data and signal requirements apply to each VEN.
  - b. Data. Capability in kW shall be made available for polling by the DERMS every five (5) minutes using the OpenADR 2.0b Data Reports TELEMETRY\_USAGE. Company may require the TELEMETRY\_STATUS report. During a GS Event, TELEMETRY\_USAGE shall reflect Capability
  - c. Signal. Signal may be a direct control signal activating Capacity Grid Services or may be a request to reserve Capacity Grid Services. Specific OpenADR signal level will depend on the finalization of the design and implementation of the DERMS.

8. Testing.

a. Annual Testing. Annual testing requirements are specified in the terms of agreement.

9. Maximum events called per year are identified in Table 3.12.

**3.4.2.4 Regulation Reserve Program**

HECO is developing a frequency regulation-focused demand response program. The bullets below highlight the basic parameters defined for the program thus far.

- To participate, customers must bid in assets to follow an automatic resource response to automatic generation control (AGC) signal
- All resources that can meet the standard are able to participate; HECO is expecting mostly water heaters and batteries)
- Availability: 24 hours per day
- Expected to be dispatched in 30 minute to 1 hour increments, though those increments can be consecutive
- Participation incentive: \$5/kW
- Frequency of the call is twice each day. Regulating reserve cost data provided by HECO was used to define the hours when calls would be made under this program. We assume the call will be made when the most cost would be avoided.

HECO provided a Raw AGC file to PNNL, as presented in Figure 3.2.

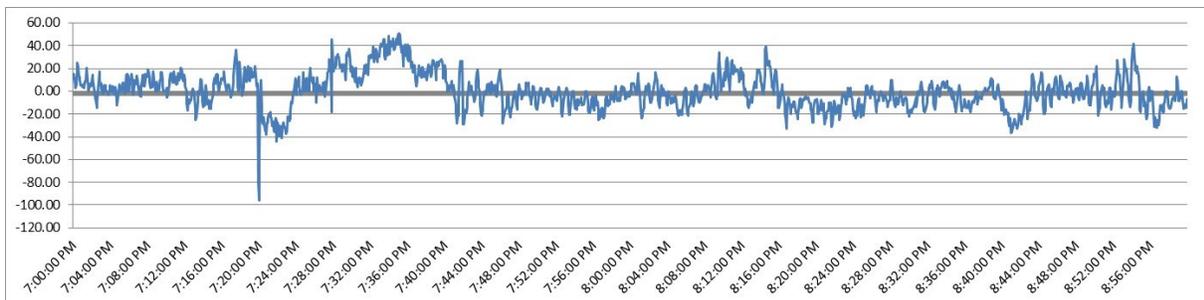


Figure 3.2. HECO Regulation Signal

**3.4.3 Outage Profiles and Costs**

Outage data was obtained from HECO for all five islands from 2011 through 2016. Table 3.13 presents the customer average interruption duration index (CAIDI) and system average interruption frequency index (SAIFI) values for each island for each year plus the average, high, and low values experienced. CAIDI represents the average interruption duration and is the sum of all customer outage durations divided by the total number of customer interruption. SAIFI is the average number of outages that customers experience.

By using the above values for each island to randomly model outages and outage duration, we can obtain benefits for the customer if they have the capability to withstand the outage at the time it strikes.

Table 3.13. Average Number of Outages and Average Outage Duration by Island

Island	2011	2012	2013	2014	2015	2016	Average	High	Low
<b>Maui</b>									
CAIDI	74.8	66.1	102.5	69.2	147.2	87.3	91.2	147.2	66.1
SAIFI	1.7	1.4	1.4	1.5	2.1	1.5	1.6	2.1	1.4
<b>Molokai</b>									
CAIDI	52.6	234.0	79.8	101.6	76.2	129.7	112.3	234.0	52.6
SAIFI	2.5	3.8	10.4	6.6	5.7	5.5	5.8	10.4	2.5
<b>Lanai</b>									
CAIDI	82.6	38.5	67.1	74.8	54.0	46.9	60.6	82.6	38.5
SAIFI	3.8	1.3	2.9	7.6	3.5	3.4	3.8	7.6	1.3
<b>Oahu</b>									
CAIDI	150.2	83.1	88.8	72.7	71.9	72.4	89.8	150.2	71.9
SAIFI	1.7	1.4	1.4	1.5	2.1	1.5	1.6	2.1	1.4
<b>Hawai'i</b>									
CAIDI	50.9	50.2	44.0	195.4	92.7	56.9	81.7	195.4	44.0
SAIFI	3.6	2.8	4.6	4.9	5.2	3.1	4.0	5.2	2.8

In order to assign monetary values to reducing or eliminating potential outages, the findings of Sullivan et al. (2015) from Lawrence Berkeley National Laboratory are used. This process estimates costs based on customer group (residential, commercial, or industrial), the duration of the outage, the time of year the outage occurred, and the time of day the outage began. A scenario was run in which the average historic outage data in Table 3.13 was used, with outages occurring randomly throughout the year. Thus, savings to customers is based on the Sullivan et al. (2015) cost assumptions and average customer load and outage profiles for each island.

Interruption cost data presented in Sullivan et al. (2015) were used to construct cost curves for small commercial and industrial (C&I) customers, medium and large C&I customers, and residential customers. In Sullivan et al (2015), the cutoff point between small and medium/large C&I customers is 50,000 kWh annual C&I. For HECO, Schedule G customers have a maximum annual load of 60,000 kWh. Schedule J and P customer load exceeds 60,000 kWh. Thus, we have assigned the small C&I designation to Schedule G customers and are treating Schedule J and P customers as medium/large C&I customers for assigning outage costs. The rates applied to each customer class are presented in the equations below.

$$OC_{m\&lci} = 117.5d^2 + 7,831.5d + 10,588$$

$$OC_{sci} = 3.9964d^2 + 491.16d + 221$$

$$OC_r = .0186d^2 + 1.5035d + 3.642$$

Where:

$OC_{m\&lci}$  = Outage cost for medium and large C&I customers

$OC_{sci}$  = Outage cost for small C&I customers

$OC_r$  = Outage cost for residential customers

D = Duration of outages.

## 4.0 Demand Response and Customer Behavior

DR is typically defined as shifts in demand-side electrical use from ordinary consumption levels in response to price signals or incentives designed to encourage energy reduction behavior. This typically occurs at peak hours or when reliability of the system is in question (FERC 2018). Traditionally, utilities would seek to meet peaking high energy demand by providing additional power supply from peaking generation sources. These resources, however, are often expensive to maintain and are only fully utilized during short bursts of peaking energy demand. This cost inefficiency makes the process non-optimal for both the producers to match supply to demand and for the consumers, who see these costs transferring onto them. This inefficiency has led to solutions involving DR programs in which utilities instead call upon their customers to close the load-generation gap through load reduction actions and utilizing available resources to drive down demand at peak hours to meet the available supply.

Three ways to classify the benefits of DR are: participant, market wide, and market efficiency. The participant incentives are targeted towards the actual enrollees and work to compensate them directly for their time, energy, and load-reduction actions. The market-wide incentives benefit all the consumers, participants, and non-participants alike in terms of reduced power fluctuation and energy shortage, along with reduced costs. Market efficiency benefits are related to improving performance in the energy market as a whole. This happens when participants and consumers have better knowledge and control over their consumption, allowing them to facilitate the market equilibrium (Albadi & El-Saadany 2008). This report will focus primarily on participant incentives and the behavior of the individual consumer.

There are a variety of DR programs that are applicable to different customers and different assets and combinations therein. Further to that effect, the variety of incentives that each of these programs offers can vary based on a multitude of factors upon which a customer's willingness to accept a program can be highly dependent. The subsections that follow will provide a brief overview of common types of DR programs, the DR potential for Hawaii, and finally a discussion regarding the basis of incentive values and the factors that influence customer participation and behavior.

### 4.1 Types of Demand Response Programs

DR is generally broken into two types: incentive-based and price/time-based. Time-based involves utilities relaying price information to the participants for specific time segments who are then able to adjust their demand in real time towards lower-cost hours. Incentive-based DR, on the other hand, involves a direct compensation (typically a bill credit), for shifting consumption patterns in a pre-determined manner during peak periods (Khajavi et al. 2011). Within either program, during peak load hours of energy consumption, the price of energy increases giving rise to a disincentive for the participants to consume more energy and vice versa. Time-based DR is typically built into the tariff structure and is commonly referred to TOU pricing. This form of DR is not closely aligned with utility DR programs such as the one we are exploring here. This report will focus on the incentive-based structure to be in line with the objectives of the DR tool and the programs it will evaluate.

Incentive-based demand response programs can be broken down into different areas that can include direct load control (DLC) programs such as air conditioning (AC) cycling, water heater control, and other assets or customer-side control programs involving DERs such as solar or

diesel generators, and storage. Each of these programs are described briefly in the subsections that follow, along with examples of existing programs.

#### 4.1.1 Direct Load Control

DLC is a DR structure in which utilities have the ability to remotely dictate the relevant loads of customers without any active customer participation at the time of reduction. The compensation for DLC programs typically involves a recurring financial incentive, either at a flat rate or per unit rate whenever the program calls upon the customer's asset.

DLC programs were started in the 1970s and to date remain one of the most popular DR programs. These programs enable utilities to control demand during peaks with minimum customer involvement. DLC, though widely present in literature and practically tested, still poses some technical problems. Since it is only used in specific duration of peak load energy demand periods, there is occasionally wasted potential regarding the controllable-technology that could be captured through more refined programs (Chen et al. 2014).

DLC programs typically receive incentives on an annual rate that is strictly independent of the number or length of events called in a peak season. Incentive values differ depending on whether the asset enrolled is a thermostat, central AC, or another device the utility can tap into. Furthermore, the incentive value is typically much higher for commercial and industrial (C&I) customers than for residential customers due to the discrepancy in load amount. For residential thermostat programs, the incentive ranges from \$85 upfront + \$25/year with Austin Energy who successfully enrolled 7,000 customers under their program up to a single \$125 payment for Hydro One with no annual benefit (Hledik et al. 2016). Residential space heating, on the other hand, is estimated at only \$30 annually and central air conditioning at \$15 (Haeri et al. 2017).

Looking at DLC programs for larger, non-residential customers, PacifiCorp's central air conditioning DLC program offers only \$38 a year for small C&I customers but up to \$128 for large C&I; however, other utilities such as Duke Energy place the value closer to \$85 annually. It is estimated that program participation for small C&I customers under the Central Air Conditioning (CAC) DLC programs is in the range of 10-40% of eligible customers. Typically, however, participation is in the range of 2-15% with an event participation of 95% (Haeri et al. 2017).

A comparison of a variety of different DLC programs, their incentive values, and the associated participation of residential customers is provided in Figure 4.1. Looking at the values such as those of SMECO, which offered the highest annual incentive of surveyed utilities and the highest residential participation, it would be reasonable to assume that the high incentive is driving high participation. However, looking at programs such as Dominion with a similarly high incentive but very low participation suggests that other factors are impacting customers' willingness to accept that should be considered (State of Michigan 2017).

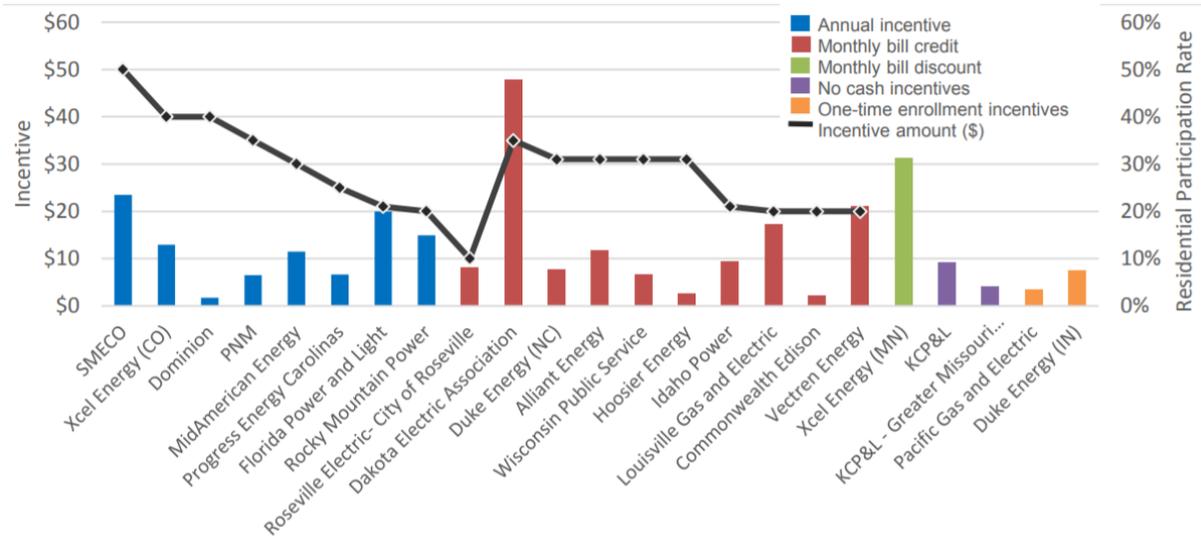


Figure 4.1. Survey of DLC Programs Including their Incentive Values and Corresponding Participation Rates (Source: State of Michigan 2017)

Electrical water heaters (EWHs) and heat pumps are a common way for residential customers to involve themselves in DR and is often a subcategory of DLC. If controlled remotely by the utility, energy consumption is reduced on the side of the consumer without a great loss in comfort or disruption. Water can be heated during off-peak hours and stored, remaining warm even if the energy supply to the water heater is stopped during peak hours. Technological advances involving smart devices can expand this program so that all thermostatically controlled devices could not only be controlled in a binary fashion, that is if energy supply should be provided or not, but can also be used to control the thermostat set-point. This can provide a better dynamic control to the utility and lesser discomfort for the customer (Pourmousavi et al. 2014)

A large proportion of household demand for energy is driven by the EWHs in the US as these systems have a relatively high power consumption. Given that EWHs involve a resistor, which invalidates the need for a reactive power supply, there is a lower opportunity cost for the consumer to give up energy supply. This makes it low-cost on the behalf of the utility to use EWH systems for DR programs (Diao et al. 2012; Saele and Grande 2011).

HECO’s own residential Direct Load Control Water Heater program is a fully subscribed program with 34,000 participating customers. Customers are offered a \$3 bill credit every month (\$48/year) whether or not an event is triggered in which the utility draws upon energy from their system. Portland General Electric in Portland, Oregon launched a pilot study in 2017 in which participating customers receive an initial \$50 incentive for participating, a \$100 incentive at the conclusion of the 12-month pilot, and \$100 for allowing the utility to collect water heater data throughout the pilot (PGE 2017). Appalachian Power Company offers a load management water heating provision in which customers are capable of earning a bill credit of between \$9.68 and \$12.70 each month by installing a water heater capable of consuming energy only during non-peak hours (State of Michigan 2017).

### 4.1.2 Load Reduction & Distributed Energy Resources (DERs)

DERs are typically small-scale distribution-level local units that are connected to the power grid. They can consist of technologies such as wind turbines and customer-sited solar arrays but ultimately cover a wide variety of assets including non-renewables such as small-scale generators or battery storage technology (Arenawire 2018). Emergency backup power systems or other types of DERs can be valuable assets for DR programs due to their ability to be aggregated and/or their quick response times during event hours.

There is a wide variety of programs that DERs can be eligible for or are best suited. During events, when the energy supply begins to fall short of demand, participants are offered an incentive to allow their backup energy generation to be called upon with short notice. Other assets, typically renewables, can work to obtain a levelized load reduction across all hours through energy efficiency measures or power generation and are oftentimes compensated under different structures that more closely resemble a DLC program. Peaking generation units, as discussed previously, are expensive to maintain and are sometimes limited in usage to short bursts of time. DER's can cumulatively or individually offer a solution to this problem by impacting customer demand either when directly called upon, or in a consistent manner as with solar. Examples of each of these program types will be described in the next subsections.

#### 4.1.2.1 Photovoltaics

Solar PV and other customer-sited assets offer a new innovative way for customers to have greater control over their electricity usage. HECO, as shown in the Figure 4.2, is expected to experience a large surge in distributed PV, with above a 20 percent penetration estimate forecast by 3<sup>rd</sup> parties. That permeation of customer generated power and load reduction offers a large opportunity for DR programs, especially if paired with energy storage, and a need for more dynamic solutions as the grid changes to take advantage of the available benefits (Trabish 2018). Understanding and accurately predicting the establishment of these customer-owned resources can allow utilities to more accurately and optimally place their investments to meet future demand.

There are often demand response programs for distributed energy resources that act as TOU programs in which customers receive incentives for shifting their load away from peak hours. Kauai Island Utility Cooperative, for example, launched a Time of Use (TOU) solar pilot program that offered a 25 percent discount on electricity rates to customers who were able to shift load to hours when solar was not overloading the grid (NARUC 2016). Alternatively, resources like solar PV can gain a DR incentive in a less active manner than traditional DR assets. ISO-New England, for example, while not a utility, offers a passive DR program in which customers with solar or energy efficient resources that can offer a continuous reduction in load receive a benefit (ISONE 2018).

Other assets that fall under the category of DERs such as combined heat and power generation can also be used as a source for peak reduction and DR given that their purpose is not to reduce energy consumption overall for a customer in the way that solar PV might but rather reduces the requirement for utility-owned resources (Haeri et al. 2017).

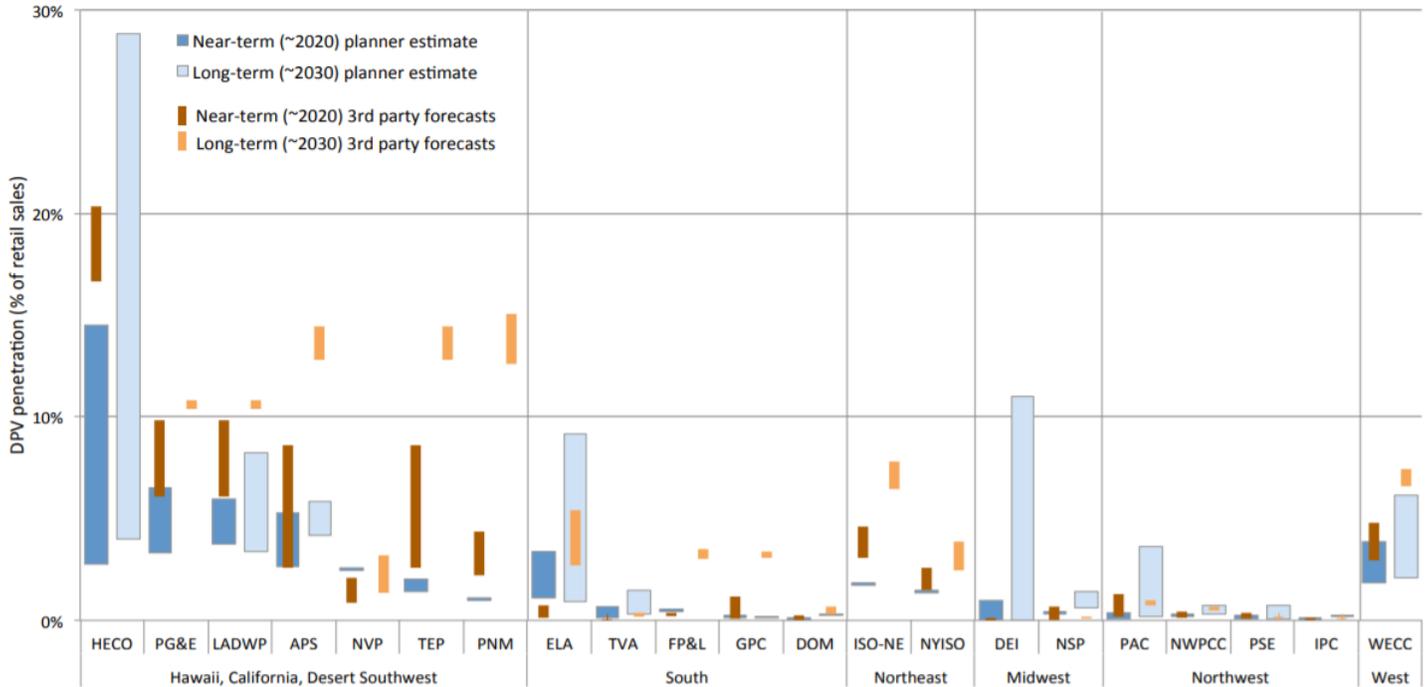


Figure 4.2. Estimates of Distributed PV Generation Penetration by Location (Source: Trabbish 2018)

#### 4.1.2.2 Energy Storage

Storage is a DER that works to shift energy consumption from one time period to another and can take advantage of price differentials across hours. Specifically, storage focuses on shifting demand from peak to non-peak energy demand periods, offering an opportunity for demand response strategies. The technology differs from the traditional DR strategy in that DR is inherently tied to the end use whereas storage is bidirectional in nature.

Storage systems are often used in sectors requiring uninterruptible power. With enhanced sophistication of battery management systems, the utility can depend on the participants to increase feasibility for shedding load at peak times and meeting their own energy needs. Nonetheless, there are certain pitfalls in the storage systems which prevents them from optimal use. Once the energy is stored and made available for the utilities through enrollment in a DR program, it cannot be used for other purposes, which introduces a loss of availability and opportunity costs for the participating customer (NREL 2015; DOE 2016).

Backup power is the main reason a customer will install a storage system BTM. Batteries represent cleaner, despite the fact that they often come with a higher price tag (John 2015). Significant potential also exists for programs that combine distributed resources such as solar with BTM storage. Combining the two resources can allow a utility to take advantage of the benefits that each resource can offer and optimize cost-reduction and revenue generation for both the customer and the utility. The dispatch capabilities of energy storage offer integration value for non-dispatchable resources which may generate energy during periods of low load.

Regarding incentive programs, storage would typically be expected to enroll in programs in which it could follow a load reduction strategy and be compensated on a \$/kW basis as opposed

to a flat incentive rate as with DLC. These demand curtailment programs are typically most valuable to large C&I customers that would be capable of reducing their loads by 100 kW at a time or higher and could include hospitals, large retail, data centers, and a variety of industrial customers. For some programs, customers do not necessarily receive a direct compensation for their activity during called-upon events but rather, they receive an incentive based on their pledged reduction each month regardless of whether an event occurs.

Haeri et al. (2017) estimates the average value for a large C&I demand reduction program at approximately \$10/kW for demand response events. These values can range considerably, however, going from \$4/kW for Sacramento Municipal Utility District (SMUD) and as high as \$35/kW for both Snohomish Public Utility and National Grid's Connected Solutions Program on the East Coast of the US (National Grid 2018). As mentioned previously, however, incentive value doesn't necessarily correlate perfectly with higher participation. Pacific Gas & Electric (PG&E), which offered an incentive in the range between \$4 and \$12/kW annually, found their participation to be only 2.1 percent of eligible customers in their 2016 annual report, indicating that there were potentially other factors making the program unattractive to potential enrollees (Haeri et al. 2017).

As with other programs, residential customer incentives are typically lower than C&I customers. Baltimore Gas and Electric's Smart Energy Rewards program, for example, began offering a program in 2012 of \$1.25/kWh during events and on average customers would earn \$6.67 during a peak event overall. This program, however, was able to obtain enrollment by over a million of their customers within four years (NARUC 2016).

## 4.2 DR Potential in Hawaii

According to the Federal Energy Regulatory Commission's (FERC) National Assessment of Demand Response Potential, Hawaii's large C&I customer base has a larger than average share of the overall peak at 35 percent. Given that large C&I customers often have the largest benefit potential from participating in DR programs due to their ability to reduce their demand charge through large load reductions, this share indicates a high potential for a successful interruptible tariff or peak reduction program. Interruptible tariff programs involve customers reducing their load by an agreed upon amount during situations in which the utility is experiencing system reliability problems in exchange for an incentive. Large C&I customers who have behind the meter storage would likely be those most able to participate successfully.

Figure 4.3 demonstrates the results of the FERC analysis and shows the potential for the Business as Usual (BAU), the Expanded BAU, Achievable Participation, and Full Participation cases. These are each defined as follows, reproduced verbatim from the FERC report:

- Business-as-Usual Scenario: What will demand response and peak demand be in five and ten years?
- Expanded BAU Scenario: What will demand response and peak demand be in five and ten years if the current mix of demand response programs is expanded to all states and achieves "best practices" levels of participation, and there are modest amounts of pricing programs and advanced metering infrastructure deployment?
- Achievable Participation Scenario: What is the potential for demand response and peak demand in five and ten years if advanced metering infrastructure is universally deployed, dynamic pricing is the default tariff, and other programs are available to those who decide to opt out of dynamic pricing?

- **Full Participation Scenario:** What is the total potential amount of cost-effective demand response that could be achieved in five and ten years?”

As shown, there is a high potential peak MW reduction for large C&I customers both in all cases beyond BAU for interruptible tariffs and other DR programs (FERC 2017).

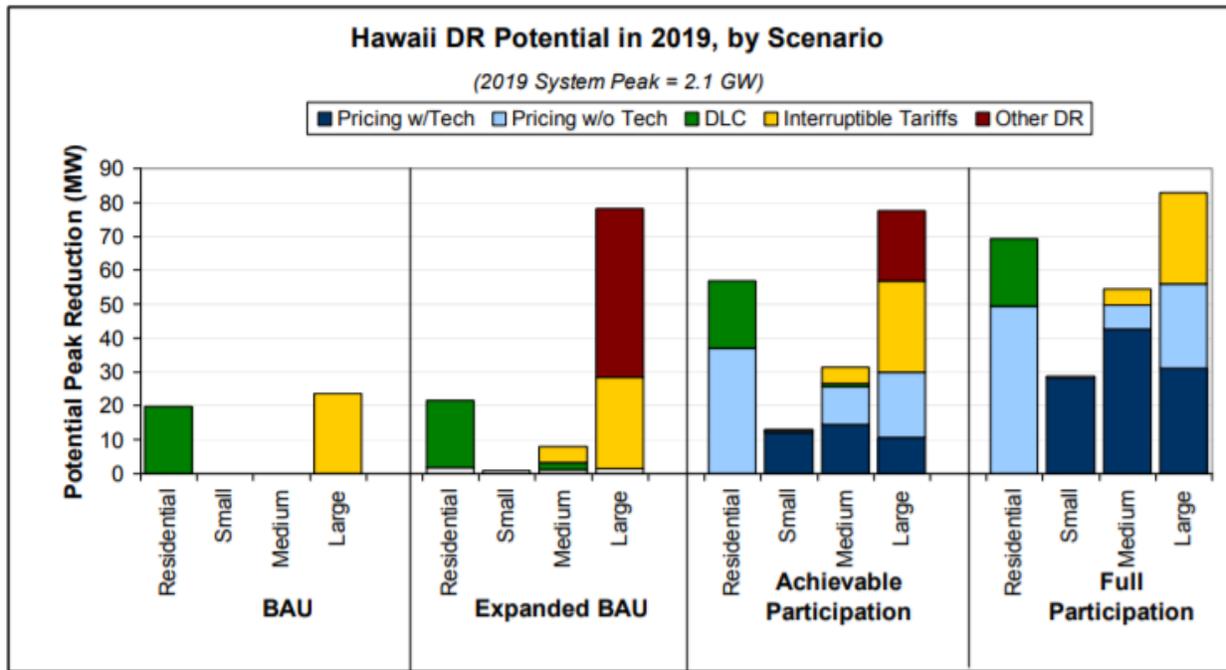


Figure 4.3. DR Forecast for 2019 by Peak Reduction (MW) within Hawaii, by Scenario (Source: FERC 2017)

### 4.3 Incentives, Customer Behavior, and Participation Levels

There are multiple aspects that can impact a customer’s participation and willingness to deviate from their baseline energy consumption. How customers change their behavior in response to changes in incentives and other program attributes can provide a reasonable indication of their willingness to participate. While direct compensation is an important driving factor, it has been shown that customers must oftentimes be compensated for factors other than the pure value of their energy to be willing to participate. Some of these other factors could include the level of discomfort or inconvenience a customer may face by decreasing their energy usage, the risks they take on by giving up their assets, or communication between the utility and the customer. These factors can relate to, and impact, the incentive value necessary to meet the customer’s willingness and overcome discomfort or other externalities they might face and could dictate the success of a program.

The subsections that follow provide an overview of the basis of incentive rates for DR programs and offer a selection of other factors that might prove influential towards customer participation and willingness to enroll.

### 4.3.1 Base Incentive Rates

The supply elasticity or how the supply of demand response assets might change in response to demand response payout rates is important to consider when establishing a DR program. Gagne et al. (2018) lists the following as important questions to consider when determining the appropriate compensation for customers:

1. What is the asset worth to the system? This estimate should include capacity cost, energy cost at peak hours, avoided carrying costs, and avoided externalities.
2. At the set price, how many consumers will participate?
3. Is there sufficient participation for the program to be effective?
4. Does the utility or the participant face the cost of implementation?

Regulatory context can dictate the base level of compensation enrollees receive for a DR program. Given that an incentive level may require approval from the public utility commission, the cost the utility would expect to avoid from obtaining energy to meet peak demand is a common source for the compensation baseline. In theory, utilities should be willing to match up to their willingness to pay for the cost of equivalent services necessary to obtain the demanded energy during peak hours. Other externalities might also be included, however, that are specific to location or utility. An assumption can be made from this, therefore, that a successful DR program will set an incentive value at or below the cost of acquiring adequate energy supply to meet peak demand, yet high enough to entice enough customers to deviate from their ordinary energy consumption behavior.

Lawrence Berkeley National Laboratory conducted a survey of the Southwest Power Pool (SPP) in 2009 that found that the compensation structure differed across cooperatives and independently operated utilities as well as across states. They found that for DLC programs, a flat monthly incentive was common and relied upon a set control strategy. Large customers, on the other hand, were typically offered programs in which they might obtain large discounts on their bill through the demand charge directly. Responding utilities also reported that, for setting their incentive values, they typically looked at more than one factor to determine compensation. Marginal capacity costs (MCC) and the cost of a natural gas-fired combustion turbine were typically used as the basis, especially for DLC programs. The details of the different factors considered are shown in the Figure 4.4, reproduced from the report. As shown, DLC programs typically rely upon marginal capacity costs or proxies for peaking units whereas interruptible programs cover a wider variety of sources for compensation basis (k et al. 2009).<sup>1</sup>

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<sup>1</sup> DLC programs provide utilities with control over end-user appliances or devices subject to pre-set limits governing frequency and duration. These end-users are often residential or small commercial customers. Interruptible rate programs are typically offered to larger industrial and commercial customers in the form of a bill credit to the customer for shedding load upon request. Customers face penalties if they fail to respond to a curtailment order.

<b>Cost/Compensation Basis</b>	<b>DLC (MW)</b>	<b>Economic (MW)</b>	<b>Interruptible (MW)</b>	<b>TOTAL (MW)</b>
Marginal Capacity Costs (MCC)	39	74	128	241
MCC & Peaking Unit Proxy	16		563	579
MCC & Customer-owned generation			60	60
Peaking unit proxy			63	63
Value of Service			27	27
Cost of customer-owned generation			239	239
Negotiated			8	8
Not Applicable (no incentive)	20			20
Unknown			5	5
Varies for each member coop	110			110
<b>TOTAL</b>	185 MW	74 MW	1,093 MW	1,352 MW

Figure 4.4. Enrolled MW by DR Program Type

Despite the opportunity to provide a range of benefits to enrollees, participation rates in DR programs throughout the country are reported as low. FERC provided a survey in 2012 that stated that for DLC programs specifically, a participation range of only 0.11 percent to 14.54 percent of eligible customers was found based on a sample of programs within the country, the former being for the Texas Reliability Entity and the latter for the Florida Reliability Coordinating Council region (Stenner et al. 2016). Proper incentive structures that match more customers' willingness to pay could work to lift these low rates.

#### 4.3.2 Compensation for Inconvenience

As the grid evolves and deviation from traditional means to match supply to demand change to bring customer response in as a solution, understanding how consumptive patterns are altered by these changes can be fundamental to a successful DR program. As customers are asked to change their behavior, the disruption to their routine often introduces factors of inconvenience or discomfort if the demand shift is high enough to cause an impact. This is especially true for DLC programs on air conditioning units or water heaters which can directly have an effect on a customer's baseline comfort level. This, in turn, can lead to an overall unwillingness to participate or a higher willingness to accept compensation for participation. Incentives must adapt to match this to guarantee adequate participation. Overall, if high program penetration itself is the goal, incentives typically need to rise in order to meet the level customers are willing to accept in order to part with their energy at the hours during which it is likely most valuable to them.

The range of compensation found for different DR programs throughout the country is oftentimes tied to factors such as:

- Minimum energy curtailment amounts;
- The amount of notification time prior to an event customers receive; and,
- Minimum length of time customers must be willing to respond.

Each of these can contribute to the amount of inconvenience a customer faces to participate. Shorter notification times don't allow as much time for customers to prepare for the loss of energy and make adequate arrangements which, in the case of C&I customers, may impact

their production more heavily. Likewise, long event times that push customers to have lower energy usage for multiple consecutive hours may have a heavy impact, especially if events are called with high frequency. While C&I customers often have the most to gain from demand response programs, they also are likely to have the highest rate of inconvenience from energy reduction and must be adequately compensated to engage in the program due to lack of productivity.

Green Mountain Power, an electric utility in Vermont, was one of the first to launch a program in 2015 that allowed customers to receive backup power in their homes by financing and installing Tesla Powerwalls that the utility could use for peak reduction. For \$37.50 a month, customers would receive a Powerwall and the reliability benefits that came with it so long as the utility obtained the ability to use it as well. Alternatively, customers could purchase the Powerwall outright for \$6,400, and GMP would then offer them a \$31.76 bill credit each month. Building on top of the results from the pilot study, the utility decided to lower the monthly cost for customers substantially and expanded the program to 2,000 participants who could now receive the same benefit for only \$1,500 upfront and then \$15 per month thereafter. The remainder of the \$5,500 Tesla Powerwall cost was absorbed by the utility based on the assumption that it would earn the loss back in long-term benefits if they could get enough participants due to the lower monthly cost. Their decision to shift to a low-cost and more lucrative option is an indicator that the pilot study suggested that they were overestimating the customer's willingness to participate and also suggests that customers are more willing to engage if benefits are more immediate (Hanley 2018).

An empirical study on residential customer's willingness to engage in DR programs found that the willingness to shift energy consumption was dependent on the usage of appliance that was being shifted. Appliances such as laptops and microwaves were found to be the assets tied to the lowest willingness to shift with more than half of respondents being unwilling to change their energy consumptive behavior at all. All other appliances such as washing machines, dishwashers, and air conditioners had lower non-compliance values. It was also found that one-fifth of all respondents stated they would require a \$2/cycle or higher incentive to shift their usage of water heaters, air conditioners, and a selection of other appliances to non-peak hours (Annala 2015).

### 4.3.3 Customer Type

Research by O'Connell et al. (2013) shows that non-residential customers oftentimes exhibit behavior that is more in line with what is considered to be economically rational and aimed towards maximizing their profits compared to residential customers. Smaller customers, and especially residential ones, have a higher mix of priorities and the act of minimizing their energy expenses may not necessarily be at the top of their list of concerns and they may need to be alternatively motivated and incentivized.

The demand curve of residential customers can be very difficult to estimate due to the higher variety of these external factors. These factors can range from the weather to the types of appliances the customer has or even how "green" a customer is. It has been demonstrated through empirical analysis that residential customer demand does not fit a conventional economic model. For this reason, offering multiple types of programs in order to capture customer variety has been shown to be beneficial (Naeem et al. 2015).

#### 4.3.4 Risk

Along with the inconvenience of a reduction of energy usage during peak events, there is also the consideration of risk. Large industrial customers typically rely on having consistent power to maintain operation, power loss can lead to large financial losses if the outages continue for a prolonged period of time. To combat this, many C&I customers install backup generators or storage and rely on those assets to mitigate their risk. These assets can offer a potentially large benefit through the participation in DR programs, using the energy available during peak hours and capturing a value for every kW they are able to reduce on their measurable load. Enrolling their storage assets in a DR program, however, could introduce risk if a DR event concludes and there is no energy remaining for the customer to rely upon for backup in time period that immediately follows.

Analysis surrounding power outage events within the US have shown that the expected loss for medium and large industrial customers is upwards of \$15,000 for a 30-minute outage. For interruptions that stretch to eight hours, this loss grows to \$94,000 (Hodge 2018). While these values are likely to be different for each commercial or industrial customer, they nevertheless are likely to have a strong impact on a customer's willingness to participate and willingness to accept. These customers would be forced to endure the probability of an outage striking with no available energy to ride through it. Their expected willingness to accept an incentive for a DR program, therefore, is expected to be at least as high as the expected losses from a power outages with no backup.

#### 4.3.5 Communication

Proper communication with customers has proven to be an important aspect of ensuring successful program enrollment and participation. Common problems and challenges DR programs face include customers dropping off programs when called upon too frequently. Customer engagement is oftentimes reported as being a key component towards optimization participation and effectiveness (Gagne et al. 2018). A survey of the SPP found that proper promotion of initiatives and giving customers a common understanding of the definitions and concepts involved in DR programs play an important role in program success. Facilitating conversation with customers can provide a stronger understanding of their potential benefits (Bharvirkar et al. 2009).

Proper education on the benefits and expectations involved in a DR program is also important for a successful program. It has been shown that not only does proper education through effective marketing lead to more efficient demand reduction, customer satisfaction also improves. Reliable tools of communication regarding optimal behavior and the incentives available during peak events are large motivators to participate. Communicating the savings or credits a customer has received immediately following an event builds positive engagement and can lead to higher rates of participation (State of Michigan 2017).

Naeem et al. (2015) notes that a major deterrent regarding participation is prompted by the lack of clarity regarding both the incentive structure and the amount of inconvenience they are expected to face. The same researchers also note that altering the parameters of a program that is being offered will change the collection of customers that enroll as the value surrounding different inconveniences and incentives changes. For example, structuring and communicating a program that offers low inconvenience to customers during certain hours will, unsurprisingly, attract a pool of enrollees who have a higher willingness to accept at those hours (Naeem et al. 2015).

## 5.0 Conclusions and Opportunities for Additional Research

In order to evaluate the various value streams generated by BTM PV and battery storage systems, the HECO DR Tool was developed to simulate PV and battery operations and benefits. The scheduling (hourly) and actual operation (minute by minute) of a battery was simulated for a one-year period and an optimal dispatch strategy was defined for combinations of assets engaged in a variety of different PV and DR programs on all five islands in the HECO service territory. An executable file was developed with a user-friendly interface where the user can choose between different islands, tariff structures, PV compensation rates, and DR programs. The battery and PV parameters can be modified according to the user's needs. The executable file is accompanied by a series of Excel®-based input files. It generates Excel®-based output files. The model takes approximately one minute to run. The output includes annual values by service and the number of hours the system would optimally be used for each service.

With knowledge of the benefits of DR programs to HECO, PNNL could expand the HECO DR tool capabilities. HECO has already worked with Black and Veatch to define the value of various ancillary services on several of its islands. With knowledge of customer responsiveness to varying DR compensation rates, the value of PV and storage to customers, and the value of DR to HECO, the foundation is now laid for a more comprehensive assessment of DR program impacts.

PNNL could evaluate optimal tradeoffs between customers and HECO with consideration of payback periods required for customers. PNNL has developed a methodology and formulation to maximize the economic benefit for individual stakeholders considering trade-offs between different applications. PV and storage have the potential to yield benefits to both the utility and the customer, but there is no single solution that can simultaneously optimize benefits to multiple parties. If, for example, an operational strategy was defined based solely on the customer's best interests, the benefits to the utility would be lower. The reverse is also true.

While the interests of multiple parties can be in conflict, there exist a number of Pareto-optimal solutions. A solution is called non-dominated or Pareto-optimal if none of the parties' interests can be improved in value without degrading the value accruing to another party. Without additional subjective preference information, all Pareto-optimal solutions are considered equally good. Often, solving a multi-objective optimization problem means finding a representative set of Pareto-optimal solutions and/or quantifying the trade-offs in satisfying the different objectives to assist in the decision making process. Exploring this solution space would yield valuable lessons to HECO as it defines goals and explores options for expanding its DR programs.

PNNL could also expand the tool to include other forms of DER, including water heaters and smart grid-enabled appliances. It could also evaluate the financial impact to customers of varying program requirements and penalties for under performance.

The goal of the additional research would be to define the benefits of participation in a demand response program to HECO and to its customers. Benefits could be compared against expectations in order to determine a space within which demand response participation can yield positive results to both parties.

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