Evaluation of Hawaii's Renewable Energy Policy and Procurement

Final Report

January 2014 Revision

Energy+Environmental Economics

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Energy and Environmental Economics, Inc.
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
415.391.5100
www.ethree.com

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1 Executive Summary

The State of Hawaii has ambitious goals for renewable energy development with a target of 40% of the State's electricity coming from renewable generation by 2030. Under a National Association of Regulatory Commissioners (NARUC) funded grant, Energy and Environmental Economics, Inc. (E3) was retained by the Hawaii Public Utilities Commission (PUC) to develop a methodology and compare the economics of different renewable generation procurement options.

This study evaluates some of the key renewable policy and procurement options in the service territories of Hawaiian Electric Company, Inc. (HECO), Hawaii Electric Light Company, Inc. (HELCO), Maui Electric Company, Limited (MECO), and Kauai Island Utility Cooperative (KIUC). After the completion of this first phase of study, the PUC will continue to work with E3 to further refine the approach and evaluate potential changes to the existing planning and procurement of renewable energy with the goal of reducing costs of renewables to ratepayers in Hawaii and / or increasing their value. E3 will provide technical assistance to the PUC in this next phase by updating and improving the modeling and evaluation tools and running stakeholder workshops to incorporate and validate the approach.

In this phase, we develop an economic framework that can consistently compare procurement options across all the Hawaiian Islands using a transparent and industry standard approach, and we then perform an assessment of current renewable procurement options in Hawaii. The basis for comparison in this study is net cost (or value) of each renewable procurement option to ratepayers. The net cost is calculated as the difference between the cost of renewable purchases, including any associated ratepayer costs for interconnection, integration, and delivery, and the avoided costs, including displaced conventional power plants, reduced fuel consumption, and other avoided costs. We evaluate the following procurement options; utility-scale renewables purchased through competitive bidding, smaller scale renewable energy systems purchased through feed-in-tariff (FIT), and behind the meter renewables 'purchased' through net energy metering (NEM).

We find that renewable energy provides a significant opportunity for Hawaii to reduce electricity costs to customers. There are many renewable technology types that provide net value to ratepayers. These include various sizes of wind energy and solar photovoltaic generation on each island, as well as in-line hydroelectric generation. Given the high costs of purchasing petroleum fuels for energy on the islands, these approaches can lower utility costs. However, not every approach to procuring renewable energy and deploying it in Hawaii provides net value. We find that biofuel resources are more costly than conventional generation and other renewable options. We find that customer-owned generators that sell energy to the system through NEM tariffs at full retail credit impose costs that exceed the avoided costs (the value to the system). However, these findings are based upon currently available information on energy and system costs and it is expected that additional data and improvements to the methodology would further strengthen the analysis. In addition, this initial version of the analysis excludes certain externalities, equity considerations, and fuel price volatility impacts as well as other important regulatory considerations that are not easily monetized.

These findings are based on the current procurement approaches in place in Hawaii. In this report we include a review of alternative procurement approaches that could be considered as a means to further reduce ratepayer costs as the PUC reviews different resource portfolios and reviews policies such as FIT and NEM.

Beyond the net value of specific renewable energy types, we find that the portfolio of renewable energy systems is important, and there is value in a diversity of geographic locations and technology types to smooth out the production of renewable energy and reduce the volatility on the system. In the analysis completed in Phase 1, diversity generally reduces variability in the production of renewable energy over the course of the year and displaces higher cost generation and the need for conventional generation. We suspect that diversity will also decrease the costs to integrate renewable energy which could be illustrated with more detailed modeling of the operation of the island grid systems.[1]

As noted above, we recognize that there are more considerations around developing renewable energy in Hawaii than net cost and that these are not included in this study. Additional positive aspects of renewable energy that are not considered include the financial certainty of renewable purchases and reducing sensitivity to oil price fluctuations, and the positive environmental and quality of life benefits from cleaner air, water, and reduced greenhouse gas (GHG) emissions. Renewable energy also provides more intangible values of energy independence and sustainability. There are also negative aspects not considered that include increased land use and the visibility of renewable energy systems. Finally, there are other considerations such as equity in access to renewable energy and the distributional impacts amongst those who benefit and those who bear any costs associated with renewables. We believe that all of these issues should be considered in the development of renewable energy policy and the development of specific projects. To the extent possible, these important elements should be included in future regulatory proceedings in addition to the net cost approach presented here.

[1] "Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power." Ryan Wiser and Andrew Mills. LBNL. September 2010. **http://emp.lbl.gov/sites/all/files/REPORT%20lbnl-3884e.pdf**
"Operating Reserves and Variable Generation." Erik Ela, Michael Milligan, and Brendan Kirby. NREL. August 2011. **http://www.nrel.gov/docs/fy11osti/51978.pdf**

In conclusion, we believe that renewable energy continues to provide a great opportunity for Hawaii to address its existing and future energy challenges. Through careful planning and procurement of renewable generation that focuses on ratepayer value, Hawaii can both reduce costs and improve the environment.

In the report that follows, we provide a detailed description of our methodology for developing avoided costs. Then we show the results that support our conclusions above. Next, the report provides an overview of alternative renewable procurement approaches from other jurisdictions which is intended to inform future procurement decisions and policy designs in Hawaii. Finally, we provide conclusions and next steps to improve and refine the tools developed to date and engage stakeholders to consider modifications to renewable procurement that can decrease costs and increase the value of renewables. These modifications can provide greater ratepayer benefits of renewables to Hawaii.

2 Cost-Benefit Analysis Methodology

2.1 Overview

In striving to meet Hawaii's Renewable Portfolio Standards (RPS), it is necessary for the PUC to compare various renewable resources on the basis of their overall value. A resource's value can be best determined using net cost or net value analysis, which compares the *total cost of bringing the resource online* (the "procurement cost") to the *total benefits generated by the renewable resource* (the "avoided cost"). Cost-benefit analysis is a common decision-making tool in the electricity industry. E3 has built several spreadsheet models that will allow the PUC to perform such analysis to compare different channels for renewable energy procurement, as well as different renewable energy technologies.

Figure 1. Net Cost Calculation

Net Cost or Net Value allows comparison across policy and procurement options for individual projects as well as for long-term planning and portfolio comparisons. This study considers the costs of various renewable energy procurement mechanisms in place in Hawaii today, including utility-scale procurement, the FIT program, and NEM program.

The figure above illustrates the broad cost-benefit calculation performed by E3 in this study. The Net Cost or Net Value of incremental renewable energy is determined by calculating the avoided cost and comparing it to the procurement cost. Avoided costs are benefits to the system of displacing conventional generation with new renewable energy, and can include reduced marginal costs of conventional energy, capacity, transmission and distribution deferral, environmental benefits, etc. These benefits will vary based on the hour when the renewable energy is available. The procurement cost of renewable energy (i.e., the cost of adding the renewable energy to the system) varies by procurement mechanism, but is reflected in recent power purchase agreement (PPA) contract prices, FIT tariff prices, or NEM tariff retail rate credits.

In the first step of the analysis, E3 created a spreadsheet model capable of simulating hourly energy costs island by island for the years 2013 through 2033. The model can also project other costs associated with conventional energy generation, including capacity costs and ancillary services (AS). As described below in more detail, the avoided cost model calculates the value to the system of displacing conventional generation by adding new renewable energy generation.

Next, under direction from the PUC, E3 developed a set of future scenarios where different types and amounts of renewable energy generation are added to each island system. These scenarios do not represent preferred or likely outcomes. They are designed to indicate the relative impacts of changes to key avoided cost drivers. Avoided costs are separately calculated for each scenario.

Finally, the avoided costs calculated for each scenario are compared to the marginal cost of different renewable procurement options. This produces the Net Cost or Net Value. For a given procurement mechanism (e.g, utility-scale, FIT, or NEM program), if the costs of procurement are less than the avoided costs, then the procurement mechanism produces a net value to the system. If the costs of procurement are higher than the avoided costs, then the procurement mechanism results in a net cost to the system.

The following sections describe how the avoided costs are calculated, what scenarios were analyzed, and how E3 determined the procurement costs for each renewable energy procurement mechanism.

2.2 Benefits

In order to determine the benefits of a renewable energy resource, E3 has constructed a Hawaii-specific avoided cost model. Avoided costs represent the cost to ratepayers of operating the existing electricity system that is displaced by adding renewable resources to the grid. Since electricity has a different avoided cost value depending on its time of delivery to the grid, E3's model creates hourly avoided costs for a one year period. Hourly avoided costs are a more granular way to compare renewable resources with very different output profiles, such as wind and solar photovoltaic (PV) resources; the time-dependent value of those resources is not well captured using average monthly avoided costs. E3's avoided cost model is designed to calculate a separate set of avoided costs for four of the Hawaiian islands: Oahu, Hawaii, Maui, and Kauai.

2.2.1 AVOIDED COST COMPONENTS

Avoided cost components for renewable energy projects include energy costs, capacity value, grid support services, reduced financial risk and security risk, and environmental and social benefits including improved air and water quality and economic development. This report focuses on the components which were quantifiable using existing data and studies. These were largely the grid services components – energy, capacity and grid services – which represent the bulk of the utility and ratepayer benefits and costs. E3 has developed methodology to calculate the value in every hour of six components: energy generation, energy losses, AS, system capacity, emissions costs, and transmission and distribution (T&D) deferral. The methodology for calculating each component is described at a high level below.

Figure 2 Avoided Cost Components Rocky Mountain Institute

Component	Description	Treatment in current analysis
Generation Energy	Estimate of hourly wholesale value of energy	Developed via stack models of generation resources by island.
Energy Losses	The losses associated with delivery of energy from central station generators to customers via the T&D system.	T&D losses were provided by each of the utilities.
Generation Capacity	The costs of building new generation capacity to meet system peak loads	Determined via resource adequacy reports and cost of fixed operations and

		maintenance (O&M)
Ancillary Services	The marginal costs of providing system operations and reserves for electricity grid reliability	Benefit of reduced AS assumed to be 1% of energy costs. Additional analysis required to determine integration costs specific to each island.
Environment	The cost of carbon dioxide emissions associated with the marginal generating resource	Current analysis assumes $0/ton but model is capable of using other values
T&D Deferral	Reducing load at some locations can result in reduced cost of investment for the utility for upgrades to transmission and distribution. However, with high penetrations of renewable generation additional renewables can require additional investments.	The current analysis assumes no deferral value but also no additional distribution cost as the data was unavailable to determine costs and benefits by location

Another potentially large component of grid service avoided costs, T&D deferral was not included as a more detailed study to determine how and if renewable generation reduces or increases grid related investments for each utility would be necessary. These grid based avoided costs implicitly value this cost at zero value; assuming neither a net benefit of deferred investment nor a net cost of additional investment. In addition, this version of the analysis does not attempt to quantify the financial and security risk reduction benefit or the environmental or social costs beyond carbon dioxide.

2.2.1.1 Energy Cost

The avoided cost of energy reflects the marginal cost of generation needed to meet load in each hour. E3's avoided cost model operates in two different modes to calculate the avoided cost of energy: in the first mode, production simulation data is used; in the second, a stack model is used.

Production Simulation Mode

This mode is available for Kauai only. KIUC uses production simulation software called UPLAN, which performs an hourly dispatch to meet loads over one full year and determines the hourly marginal cost of energy in that year. KIUC provided E3 with the results of production simulation runs for the years 2014 and 2025, which include the marginal generator, marginal fuel, and marginal energy cost in every hour for both of those years. These results reflect KIUC's assumptions about what Kauai's system will look like in 2014 and in 2025.

Using KIUC's fuel price forecast and the 2014 and 2025 hourly marginal energy price shapes, E3 created hourly energy prices for every year from 2013 through 2035. The 2013 prices were generated by backing out the assumed heat rate for each generator in the 2014 data using 2014 fuel costs, and then using the hourly heat rate and the 2013 fuel costs to calculate 2013 energy prices. The same methodology was used to scale to the 2025 prices for the years 2025 through 2035. The methodology described above reflects the assumption that the system modeled in 2014 is a good representation of the system in 2013, and the system modeled in 2025 is a good representation of the system through 2035. This is a simplification and could be explored further in the next phase of analysis.

In the years between 2014 and 2025, KIUC's production simulation modeling cases include increasing quantities of renewable generation. As a result, the marginal fuel and marginal generating unit are different between 2014 and 2025 for some hours. For example, KIUC's production simulation results do not show renewable generation on the margin in 2014, but that phenomenon does appear in some hours in 2025. In reality, the change within a single hour from one marginal unit to another would happen as a step function in a single year. In the absence of data to determine what year that step occurs in each hour, E3 modeled the hourly marginal energy prices for the years between 2014 and 2030 as linearly transitioning from the 2014 price to the 2025 price in each hour and then from 2025 to 2030.

Stack Model Mode

This mode is available for all four islands analyzed in this study. The production simulation software used by HECO, HELCO, and MECO calculates marginal energy prices but the calculations are done within the "black box" of the model, thus, it is impossible to determine the key drivers of the calculations or verify the pricing that is produced. In addition, the production simulation software used by HECO, HELCO, and MECO does not indicate which fuel or generator is operating on the margin in every hour, which makes it difficult to extrapolate between the planning years that are run in the model. Thus, to generate the required marginal prices, E3 used the operating characteristics of the generators on each island to build transparent dispatch models for each of the three HECO, HELCO, and MECO systems analyzed in this report. In order to allow consistent comparison between Kauai and the other islands, we also built a stack model for KIUC.

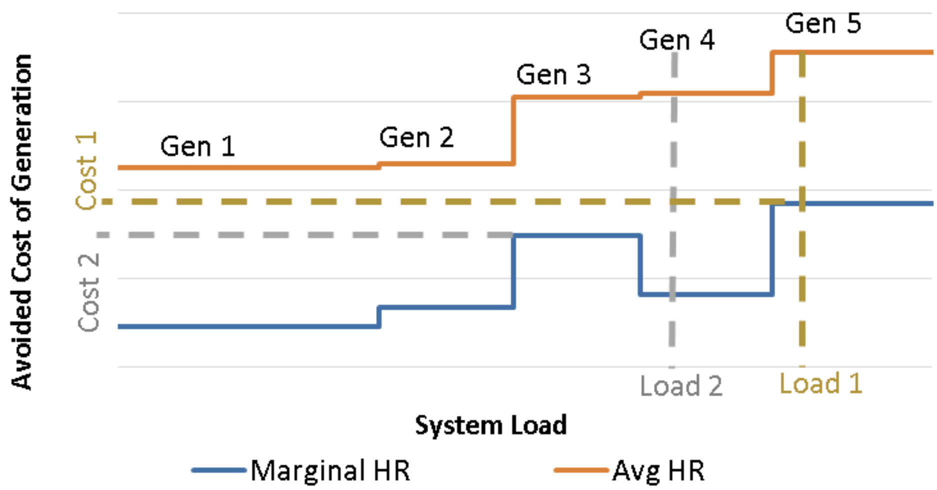
Stack Model Dispatch Methodology: HECO, HELCO, and MECO

Each stack model begins with a list of dispatchable generators on the island being modeled. In order to rank an island's generators to create a dispatch order, E3 calculates each resource's variable cost of generation. That cost is calculated using the generator's heat rate, the cost of the generator's fuel in that year, and the cost of variable O&M activities. We assume that the generator's heat rate is equal to its *average* heat rate at maximum power output. We use average heat rate for generator ranking purposes because average heat rate reflects a generator's startup fuel cost, which should be taken into account when setting the dispatch order. Using annual fuel forecasts supplied by the utilities, we calculate the cost of generation in each year from 2013 through 2035, and then rank the generators from lowest to highest generation cost in each year.

After creating a dispatch order, E3 creates hourly marginal energy costs. We first determine the net system load in each hour, and then use the dispatch stack to assess which generators must be running in order to serve load. As will be noted below, E3 incorporated assumptions regarding must run and other reliability requirements such as reserve requirements in the logic for the dispatch stack. Next, we look at the marginal cost of generation of each resource operating in that hour. While E3 uses a generator's average heat rate to set the stack (dispatch) order, we use the generator's *marginal* heat rate to determine the hourly marginal cost of generation in this step. The reason for this is because once several generators have been dispatched to meet load, if additional renewable generation is added to the system, the operating generator with the highest cost of generation, excluding startup cost, is the one that should be backed down. The HECO utilities supplied E3 with marginal heat rates for each generator at maximum output (Pmax) and minimum output (Pmin), and we used the average of the two values as a representative marginal heat rate in all hours.

Figure 3 below illustrates this approach using an example dispatch stack of five generators. The orange line represents each generator's energy cost calculated using average heat rate, and it shows that the generators are ranked by that value in ascending order. The blue line shows the avoided cost of generation for each generator calculated using the marginal heat rate. The gold and silver dotted lines represent two example load and avoided cost scenarios. In the first example, the system net load is equal to Load 1. All five generators must be operating to serve load, and Generator 5 has the highest marginal cost of the five generators, so its marginal cost represents the avoided cost, Cost 1, in that hour. In the second example, the system net load is Load 2. Generators 1 through 4 must operate to meet that load level. Of those four generators, Generator 4 is last in the stack because of its relatively high startup cost, but Generator 3 has the highest marginal cost of generation. So, the avoided cost of energy in that hour is equal to Generator 3's marginal energy cost — Generator 3 is the resource that would be ramped down were additional renewable generation available in that hour.

Figure 3 Example Dispatch Stack



Since E3's stack includes dispatchable generation only, the hourly system load used is the hourly gross system load net of all hourly non-dispatchable generation. Non-dispatchable generation includes variable resources, such as wind and solar generators, as well as contracted resources with fixed shapes such as HELCO's Puna Geothermal Venture resource on HELCO's system and the HPower waste-to-energy facility on HECO's system. Each utility provided E3 with its 2012 gross hourly load data, which is scaled up in each year in proportion with the load growth predicted in the utilities' 2013 integrated resource planning (IRP) (for HECO, MECO, and HELCO only) and Adequacy of Supply statements.

Stack Model Dispatch Methodology: KIUC

Although KIUC supplied E3 with hourly marginal energy costs from their production simulation runs, we built a stack model for the Kauai system in order to compare analysis of the other islands to KIUC. We used the same methodology for KIUC as for the other islands, with one exception: we did not use average heat rates to create our stack ranking. KIUC uses marginal heat rates in their production simulation modeling, so we used those heat rates to both create our stack order and determine the avoided energy cost in each hour. As for the other utilities, we averaged each generator's marginal heat rates at Pmax and Pmin to create a representative marginal heat rate. This methodology allowed us to very closely match KIUC's production simulation results while also examining the impact of different renewable build scenarios on KIUC's avoided costs. The flexibility to compare different avoided cost scenarios is not available when using existing production simulation results.

Modeling Operations with a Stack Approach

One key limitation of a stack model approach is that it is difficult to account for operational restrictions, such as operating reserve requirements, minimum generation levels, and generator ramp rates. Without correctly modeling operations, stack models typically generate an overly idealized dispatch. In order to improve our stack model's approximation of real system operations, E3 added a reserve requirement to the model. Each utility supplied information regarding the amount of reserve capacity typically modeled on each system, which is an approximation of real operating reserve capacity that typically varies hourly with load level and renewable generation. The utilities also provided E3 information about which generators typically supply reserves. E3 then modeled reserves by holding back a constant amount of each reserve-supplying generator's capacity from the stack in every hour. The following table shows the quantity of reserves modeled for each island in every hour, as well as a list of generators assumed to supply that reserve capacity.

Table 1 Reserves Modeled by Utility

Utility	Reserves (MW)	Generators Used
HECO	180	Kahe 1-4, Waiau 7-8
HELCO	16	Hill 5&6, Keahole Dual Train
MECO	40	M14/15/16, M17/18/19
KIUC	4	CT1, D7

E3 also assumed that generators providing spinning reserves must be operating at an output greater than their Pmin capacities in all hours. The stack model calculates the sum of the various Pmin amounts for each reserve generator on each island, and places that block of capacity at the front of the stack. We then include in the stack only the capacity above Pmin and below the reserve capacity for each generator supplying reserves. In any hour when net system load is below the cumulative Pmin of the reserve generators, additional renewable energy in that hour does not earn any energy avoided cost value; this is analogous to the additional renewable generation being curtailed in that hour. The table below shows the total Pmin of system reserves modeled for each island.

Table 2 System Pmin by Utility

Utility	HECO	HELCO	MECO	KIUC
System Pmin (MW)	175.8	37.3	51.5	13.4

In reality, all conventional generators have Pmin values which impose restrictions on system operations. We include some Pmin considerations in order to best model operating reserves within the stack model framework; this approach makes the model's dispatch less idealized and more constrained, but does not fully account for the limitations created by minimum operating levels. The final operational considerations included in the stack model are forced and maintenance outage rates. The utilities provided E3 with annual outage rates for each individual generator, and we derated the maximum capacity of each generator in every hour by its combined outage rate. For example, a 100 MW generator with a 10% combined outage rate would be modeled in the stack as a 90 MW generator. These operational modeling approaches improve our stack model's approximation of real dispatch patterns, but the model still cannot fully recreate actual system operations and represents an overly idealized and flexible generator dispatch.

2.2.1.2 Emissions

Avoided emissions costs reflect the avoided carbon dioxide emissions that accompany the avoided energy generation in each hour. As with the energy costs, emissions costs can be determined using KIUC's production simulation data, or they can be calculated using the stack models for each island.

Production Simulation Mode

The production simulation data provided by KIUC shows which fuel is on the margin in every hour in 2014 and 2025. E3 uses the carbon content of different fuel types published by EIA[2] to determine the amount of CO_2, in tons, emitted by the marginal generator in each hour in 2014 and 2025. As in the energy price calculation, we use the 2014 shape for 2013, and we use the 2025 shape for the years 2025 through 2035. In the years between 2014 and 2025, we assume a linear transition from the marginal 2014 CO_2 emissions content to the marginal 2025 content in each hour, because we cannot anticipate the exact year when the marginal fuel changes.

Stack Model Mode

In stack model mode, the stack predicts which generator will be on the margin in every hour. E3 then determines the marginal CO_2 emissions quantity in each hour based on the marginal fuel. Since the generator stack is reconfigured in every year, an individual CO_2 emissions shape is created in each year.

2.2.1.3 CO_2 Price

The actual avoided emissions cost is based not only on the amount of CO_2 emitted on the margin in every hour, but also the price of CO_2 emissions in each year. E3 has included three different carbon price forecasts in the model: a base forecast, mid forecast, and high forecast. These forecasts are originally derived from the HECO, MECO, and HELCO 2013 IRP. The base case assumes no carbon price; the mid case assumes a $25/ton carbon price in 2013 and the high case assumes a $100/ton carbon price in 2013. E3 escalates the carbon price in every year by the

[2] EIA carbon content data available at http://www.eia.gov/oiaf/1605/coefficients.html

rate of inflation, assumed to be 2% per year. All the initial scenarios modeled use a cost of $0/ton.

2.2.1.4 Losses

E3 models system transmission losses as a percent of energy cost to account for losses between the points of generation and delivery. Each utility (HECO, HELCO, MECO, and KIUC) provided E3 with a flat system loss factor, as shown in Table 3 below.

Table 3 Loss Factor by Utility

Utility	Loss Factor
HECO	5.3%
HELCO	6.7%
MECO	6.3%
KIUC	4.13%

2.2.1.5 Ancillary Services

Besides displacing the cost of energy generation, new renewable resources may also result in additional value from reductions in AS requirements. It is difficult to quantify the AS benefit of a renewable resource in Hawaii, especially as the islands approach very high levels of renewable penetration. Due to this uncertainty, E3 includes avoided AS costs as a sensitivity. AS costs are modeled as 1% of the total energy generation cost in each hour. That value is based on the California Independent System Operator's *2009 Annual Report on Market Issues* *and Performance*, which determined that total spending on reserves in California in 2009 amounted to 1.0% of the value of total wholesale purchases. Alternately, AS can be modeled to have zero cost. In the results presented, E3 models AS costs at 1%.

2.2.1.6 Capacity

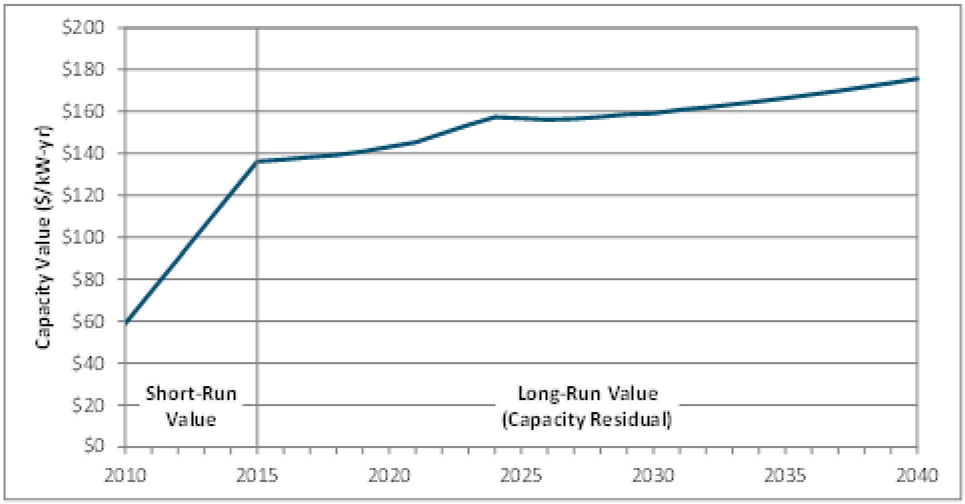
The capacity value captures the reliability-related cost of maintaining a generator fleet with enough capacity to meet each year's peak load and planning reserve margin. E3 distinguishes between a short-term and long-term capacity value. In the short-term, the system has adequate capacity to meet its planning reserve margin, so no new capacity needs to be constructed. The short-term value of capacity is equivalent to the fixed O&M of a combustion turbine. Fixed O&M represents the cost to the utility of keeping generators in operation so that they will be available to meet peak loads. In the absence of historic fixed O&M cost data in Hawaii, E3 uses forecasts for the fixed O&M costs of future combustion turbines (CT) and combined cycle gas turbines (CCGT). Expected future fixed O&M cost values were supplied by HECO and the PUC.

In the long-term, new capacity resources must be added to the system to meet load growth. The long-term value of capacity represents the cost of building a new CT or CCGT, less the value of the energy generated by the new resource. E3 calculates the total annualized fixed cost of a new capacity resource using a pro forma model. To determine the resource's energy value, we determine the "strike price" of the new generator: the minimum hourly value of energy that is enough to cover the generator's variable cost, thus justifying its operation. E3 then compares the strike price to the hourly energy costs in use in the model, costs which are generated either by production simulation data or a stack model. For example, a new capacity resource could have a strike price of $200/MWh. In an hour when the marginal cost of energy is greater than $200/MWh, for example $250/MWh, it would be economic for the new capacity resource to operate in that hour. The $50/MWh difference between the strike price and the marginal energy cost is then attributed as value to the new capacity resource. This calculation is performed in every hour of the year, and the total annual energy value assigned to the new CT or CCGT is subtracted from the annualized fixed cost of the resource. The difference represents the long-term capacity value of the resource: the cost of constructing the resource that cannot be recovered from its operational value.

Finally, E3 models a gradual transition from the short-term to the long-term capacity value. We use the capacity surplus or shortage predicted in each year in the utilities' Adequacy of Supply statements. When the capacity surplus is large, the capacity value equals the short-term value. As the capacity surplus shrinks, the capacity value approaches the long-term value. When the capacity surplus shrinks to zero, and in years beyond that point when there is a capacity shortage, the capacity value equals the long-term value. Figure 4 below shows an example of the transition in capacity value over time.[3]

[3] Note this example is from California's experience, and not Hawaii, but it shows the same conceptual methodology.

Figure 4 Example Short-Run and Long-Run Capacity Values from California

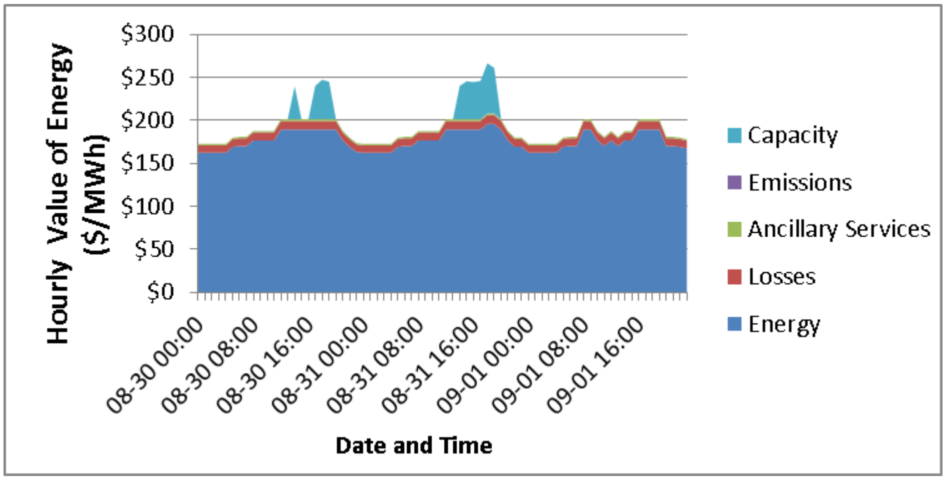


After the total annual capacity value is calculated (in dollars per kW-year), it must be allocated to specific hours when capacity need is greatest. We allocate capacity to the top 500 load hours for each utility modeled, which represents the top ten to fifteen percent of load hours in the year. In each hour, the size of the capacity allocation is proportional to the difference between the load in the hour and the maximum annual load. For example, if the system peak is 1000 MW, an hour with a 950 MW load will receive a smaller capacity allocation than an hour with a 980 MW load.

2.2.1.7 Total Avoided Costs

Once hourly components have been calculated, they are summed to determine the full avoided cost value. E3's avoided cost model can calculate costs for a single year from 2013 to 2035, or the model can produce levelized costs over a 15 or 20 year period beginning in any start year, so long as the end year is not later than 2035. The following figure shows an example three-day avoided cost snapshot, illustrating how each cost component is summed up to calculate the total hourly value. As seen the graph, capacity cost is included in total avoided cost only for some hours of the year.

Figure 5 Three-Day Avoided Cost Snapshot



2.2.2 AVOIDED COST SCENARIO ANALYSIS

The hourly avoided cost of each of the elements described above is summed to generate the total avoided cost in each hour, and those total avoided costs are used to determine the benefits of new renewable projects over their lifetimes of 20 years or more. During the lifetime of resources that are added to the system in the near future, the electricity system on each island will change dramatically as Hawaii reaches its RPS targets and adapts to emissions requirements. The value of a new resource to the system depends on how the system changes in the future. When the avoided cost model is run in production simulation mode, those changes are fixed, as they are inputs to the original production simulation runs that inform the model results. However when the model is in stack model mode, the system is initially modeled as it currently exists in 2013, and then different assumptions can be applied to create a future scenario.

E3's avoided cost model allows selection from several variables. Table 4 lists each variable and describes the choices available.

Table 4 Avoided Cost Scenario Variables

Variable	Options for Selection
Fuel Forecast	Reference, low, and high fuel forecasts are available for each fuel type, including biodiesel. They are derived from HECO's 2013 IRP and KIUC's production simulation data.
Fuel Infrastructure Strategic Plan (FISP)	There is potential for the Hawaiian islands to introduce natural gas as a replacement fuel in the future. There are two fuel strategy scenarios available in the model: the first is business as usual, including switching some units to lower emissions fuels in 2017 and again in 2022 to comply with environmental regulations, as detailed in the current Fuel Infrastructure Strategic Plan; the second option is a large-scale switch to natural gas in existing generators in 2022.
Carbon Forecast	Scenarios select either a $0/ton, $25/ton, or $100/ton carbon price in 2013. The selected price is escalated at the rate of inflation. These options are based on HECO's 2013 IRP. Note the previous IRP did not escalate the carbon price.
New Capacity Resource	A variety of resource types could fill each island's future capacity needs. The model includes diesel CTs, as well as natural gas CTs and CCGTs. Resource costs are sourced from HECO's IRP, as well as from EIA data supplied by the PUC. The selection of fuel type is made in conjunction with the FISP assumptions.
RPS Buildout	Different renewable resources are available on each island. The model allows scenarios to select from the following resource types: PV, wind, biofuels, geothermal, biomass, waste-to-energy, and hydroelectric. Each resource type is assigned a 2030 total installed capacity value. The model then installs the resource gradually in each year following a linear trajectory until it reaches the total scenario capacity in 2030.

These various modeling options can be combined to generate cohesive scenarios that represent likely outcomes for each island. Scenario analysis shows how the benefit of a renewable resource changes depending on the future system.

2.3 PUC Scenarios Developed

To show the impact of different portfolios on the avoided costs of specific technologies, the PUC developed different long-term scenarios for each island. These scenarios do not represent preferred or likely outcomes. They are designed to utilize the range of the avoided cost model's capabilities and to indicate the relative impacts of changes to key marginal cost drivers. The following figures show the inputs to each scenario by island.

Figure 6 HECO RPS Scenarios

	Baseline	Scenario 1 (High Wind)	Scenario 2 (High Solar)	Scenario 3 (LNG)
Wind	Existing ~100 MW	Add 440 MW	Same as baseline	Same as baseline
Solar	Add 280 MW	Same as baseline	Add 680 MW	Same as baseline
Biofuel	As required to meet RPS	Same as baseline	Same as baseline	Same as baseline
Fuel Switch	Base Case (switches in 2017 and 2022 as required to meet federal standards)	Same as baseline	Same as baseline	HSD 2017; LNG 2022
Carbon Pricing	None	Same as baseline	Same as baseline	Same as baseline
Capacity Resource	Small Diesel (IRP)	Same as baseline	Same as baseline	Natural Gas CT (IRP)

In all scenarios, non-dispatchable renewables (wind, PV, geothermal, hydroelectric, biofuels, and waste-to-energy) are added to the system gradually beginning in 2013 until reaching their full designated capacity in 2030. Each resource type on each island has a shape and capacity factor based on existing resource data. Hawaii has state RPS targets that utilities must meet in 2015, 2020, and 2030, and the stack model adds the renewables designated in each scenario in a piece-wise linear fashion in order to prevent any RPS shortages in those target years. For example, if a utility has a 500 GWh need in 2015 beyond what has already been installed, and the scenario specifies both PV and wind capacities to be added to the system, PV and wind are added linearly from 2013 to 2015 in order to reach the 2015 RPS target, even if that results in an RPS surplus prior to 2015. This approach is repeated for the years from 2015 to 2020 and from 2020 to 2030; the full RPS build in each scenario is achieved in 2030. In some scenarios, biofuel is used to meet any RPS requirement beyond the specified RPS additions of other technology types. We use a similar method, adding biofuel linearly to meet requirements in 2015, 2020, and 2030, and we then added biofuel as needed beyond 2030.

Figure 7 MECO RPS Scenarios

	Baseline	**Scenario 1 (Waste to Energy)**
Wind	Existing ~72 MW	Same as baseline
Solar	Add 50 MW	Same as baseline
Waste-to-Energy	None	Add 10MW Waste-to-Energy Facility
Biofuel	As required to meet RPS	Same as baseline
Fuel Switch	Base Case (switches in 2017 and 2022 as required to meet federal standards)	Same as baseline
Carbon Pricing	None	Same as baseline
Capacity Resource	Small Diesel (IRP)	Same as baseline

Figure 8 HELCO RPS Scenarios

	Baseline	Scenario 1 Keahole Fuel Switch	Scenario 2 New Geothermal
Wind	Existing ~30 MW	Same as baseline	Same as baseline
Solar	Add 50 MW	Same as baseline	Same as baseline
Biofuel	None	Fuel switch Keahole to biodiesel (53.5 MW baseload)	None
Geothermal	Existing 38 MW	Same as baseline	Add 50 MW, deactivate Hill and Puna
Fuel Switch	Base Case (switches in 2017 and 2022 as required to meet federal standards)	Same as baseline	Same as baseline
Carbon Pricing	None	Same as baseline	Same as baseline
Capacity Resource	Small Diesel (IRP)	Same as baseline	Same as baseline

HELCO's scenarios include two generator-specific changes. The first is switching Keahole's fuel from high sulfur diesel to biodiesel. To model this switch, we remove Keahole from the HELCO dispatch stack, and add 40 MW of non-dispatchable biodiesel to the system representing the capacity of the Keahole facility. We assume an 80% capacity factor after the switch, and a baseload shape based on constant output in every hour of the year. The switch takes place in the model in 2020. The second generator-specific change is the deactiviation of the Hill and Puna generators in Scenario 2. We model that change by simply zeroing out the available capacity of those two generators immediately in 2020.

KIUC's scenarios include a baseline scenario where an additional 15 MW of hydro resource is developed in addition to the 24 MW of planned solar expansion and 6.7 MW of biomass. That is compared to another scenario where no new hydro is developed.

Figure 9 KIUC RPS Scenarios

	Baseline	Scenario 1 No new Hydro
Solar	Add 24 MW	Same as baseline
Biomass	Add 6.7 MW	Same as baseline
Hydro	Add 15 MW	None
Biofuel	As required to meet RPS	Same as baseline
Fuel Switch	None	Same as baseline
Carbon Pricing	None	Same as baseline
Capacity Resource	Small Diesel (IRP)	Same as baseline

2.4 Costs

In performing cost-benefit analysis, avoided cost benefits of a renewable resource are compared to the cost of the resource. E3's analysis compares three different channels of renewable energy resources currently available in Hawaii, each with its own set of costs: utility-scale resources, FIT resources, and NEM resources.

2.4.1 UTILITY-SCALE PROCUREMENT COSTS

The cost of utility-procured renewable generation is equivalent to the power purchase agreement (PPA) price at which the utility purchases power from the generator owner. However, only approved PPA prices are available, which results in a delay in the publicly available pricing for renewable projects. However, the PUC reviews these contract terms and can use the avoided cost tool to compare the benefits to the costs of procurement of a specific project. Different renewable technologies can then be compared side by side on a net cost or net value basis. E3 has performed some sample technology comparisons using publicly available representative PPA costs.

2.4.2 FEED IN TARIFF COSTS

Hawaii's FIT program awards pre-established energy purchase rates to eligible PV, concentrated solar power (CSP), hydroelectric, and wind generators. The payment rate varies depending on the technology type and size. The cost of a FIT resource to the utility is equivalent to the FIT rate that applies to that specific project. For each different resource category, a cost-benefit analysis can be performed by comparing the appropriate FIT rate to the avoided costs.

2.4.3 NET ENERGY METERING COSTS

The cost to utilities of a NEM resource is equivalent to the NEM participant's bill savings which is the payment they no longer send to the utility. E3 uses a detailed bill savings calculator to determine that cost, originally developed as part of the California Public Utility Commission's (CPUC) 2012 NEM Cost-Benefit Study. The bill savings calculator determines the cost of an individual NEM installation based on the customer's gross electricity usage pattern, utility rate, and renewable generation profile. This analysis does not include the administrative costs of the implementing the NEM program as this information was not collected but this component is small compared to the other costs. The NEM renewable generation profile can then be compared to the system's hourly avoided costs to determine the total benefit of the NEM installation, and the installation's net cost can then be determined. The methodology used to determine the cost of a NEM system is described below.

2.4.3.1 Electricity Usage

The NEM bill calculator's starting input is a customer's hourly electricity usage shape spanning one year. HECO supplied load shapes for different customer types on Oahu, Maui, and Hawaii islands via the utilities' 2008 and 2009 class load studies. In the absence of actual Kauai loads, E3 used Maui load shapes to represent KIUC customers. After a specific usage shape is selected, the model converts it into billing determinants — inputs that are used by a utility to calculate bills. Billing determinants include monthly energy usage (measured in kWh), monthly maximum demand (measured in kW), number of days in the month (this is included because some service charges are applied on a daily basis), as well as other rate-specific parameters such as the customer's electricity delivery voltage and phase. For customers on tiered rates, billing determinants are calculated separately for each tier.

2.4.3.2 Utility Rate

Next, the customer's rate is selected, and charges specific to the rate are applied to the customer's billing determinants. For example, if a customer uses 100 kWh of electricity in the month of June and is on a rate with a summer energy charge of $0.35/kWh, the customer's June energy charge is $35. This process is repeated for each month of the year and for each type of charge included in the customer's rate. For customers on tiered rates, separate charges are calculated for each tier. The total annual electricity bill is the sum of all of these components. Each utility supplied E3 with information regarding which rate schedules were most common among NEM participants, and the values for those rates effective 12/1/2012 were included in the calculator. Rates were entered into the calculator with a high level of detail, allowing very accurate bill calculation. The rates included in our NEM analysis are shown in the table below.

Table 5 NEM Customer Rates by Utility

Utility	Residential Rates	Commercial Rates	Industrial Rates
HECO	R	G, J	P
HELCO	R	G, J	P
MECO	R	G, J	P
KIUC	D	G, J	P, L

2.4.3.3 Renewable Generation

In addition to the customer's hourly gross electricity usage data, the bill savings results depend on the hourly profile of the renewable generation at the customer site. Renewable generation both offsets the customer's electricity purchases from the utility and earns credits during periods when surplus generation is exported to the grid. E3 uses the National Renewable Energy Laboratory's (NREL) System Advisor Model (SAM) to simulate hourly PV generation shapes for each island. SAM uses typical meteorological year solar insolation data from NREL's Solar Prospector database, which has a spatial resolution of 10 km^2. That hourly insolation input is converted into an hourly energy output shape. E3 generated two shapes for each of the four islands under study: one shape was selected to represent a drier, sunnier portion of each island, while the second shape was selected to represent the wetter regions of each island. Either shape can be selected and scaled up to the full PV system size. E3 assumes that systems are sized to displace 50% of a customer's annual gross load while remaining below the NEM system size cap for each island. [4]

2.4.3.4 Bill Savings Calculation

Using the three inputs above – gross usage data, rate information, and PV generation data – the model calculates a NEM participant's bill savings. The cost-effectiveness of NEM is a comparison of the benefits provided by NEM generators to the system (avoided cost) to the costs paid by the system to the NEM generators (bill savings) and the costs to administer the NEM program (program costs). As previously stated, this comparison can be made considering

[4] E3 assumes 50% of gross load based upon studies for the California NEM which show decreasing marginal benefits beyond 50% load. Our initial look at Hawaii rates showed decreasing returns or no impact to the per kWh bill benefits, thus we maintained this assumption for all rate types as a simplification. Additional analysis could provide optimal system sizes by rate class.

the entirety of NEM generation, or only the exported piece of NEM generation. As such, we calculate two cost-effectiveness metrics:

1. Export Only cost-effectiveness = Bill Savings of Export Only + Program Costs - Avoided Cost of Export Only

2. All Generation cost-effectiveness = Bill Savings of All Generation + Program Costs - Avoided Cost of All Generation

Note that by this definition of cost-effectiveness, which quantifies costs to ratepayers as positive values, positive values will indicate a cost shift from NEM participants to other ratepayers. After calculating the 2012 costs using either method, E3 uses a rate escalation forecast to estimate the bill savings in every year of the PV system's 20-year lifetime. The PUC created retail rate forecasts for each island and customer class (residential, commercial, and industrial) based on the utilities' assumptions regarding future growth in fuel and O&M expenses as well as grid upgrades. E3's analysis assumes that all PV systems are installed in 2013. Using the 2012 bill savings and the 20 year retail rate escalation, E3 calculates the total levelized cost of generation over the lifetime of the system on a $/MWh basis.

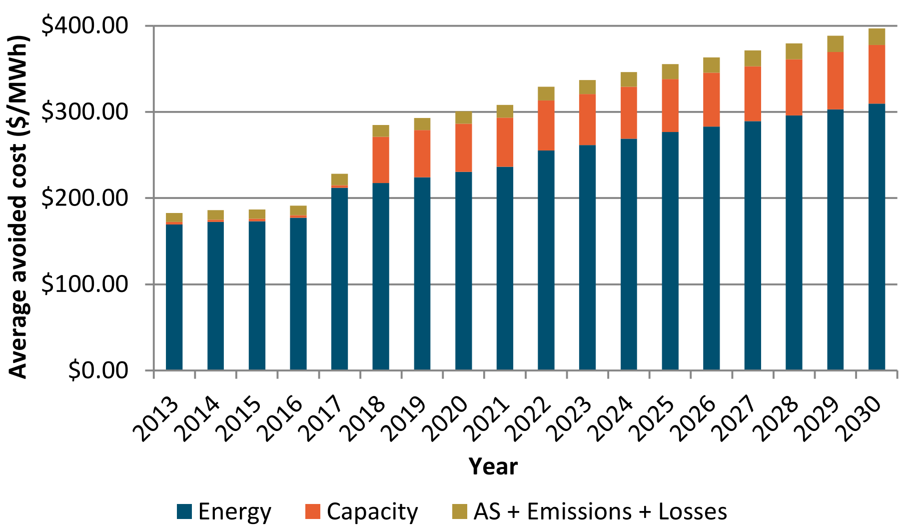
3 Results

This section will first outline the avoided cost results by island and scenario and then E3 will show how those avoided costs can be used to evaluate renewable procurement options.

3.1 Avoided Cost Components

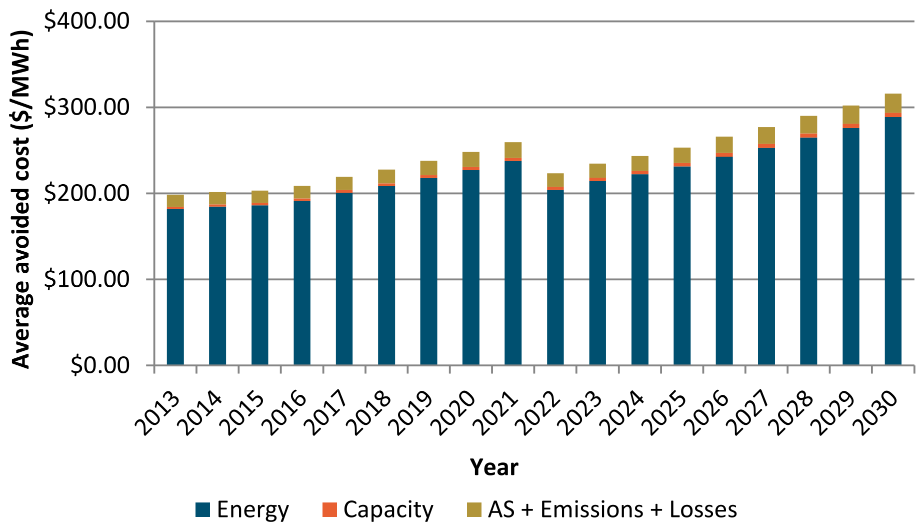
The following charts show the average avoided cost components in the base case scenario by island to demonstrate how the components vary.

Figure 10 HECO Avoided Cost Components by Year



HECO Adequacy of Supply filings show that they will need added capacity starting in 2018, thus, starting in that year E3's methodology accounts for the cost of new capacity resources and allocates that capacity need to the top 500 hours. This results in substantially higher avoided costs starting in 2018. The second driver of the avoided cost is the expected fuel price escalation over time which is seen in the increasing energy component of the avoided cost.

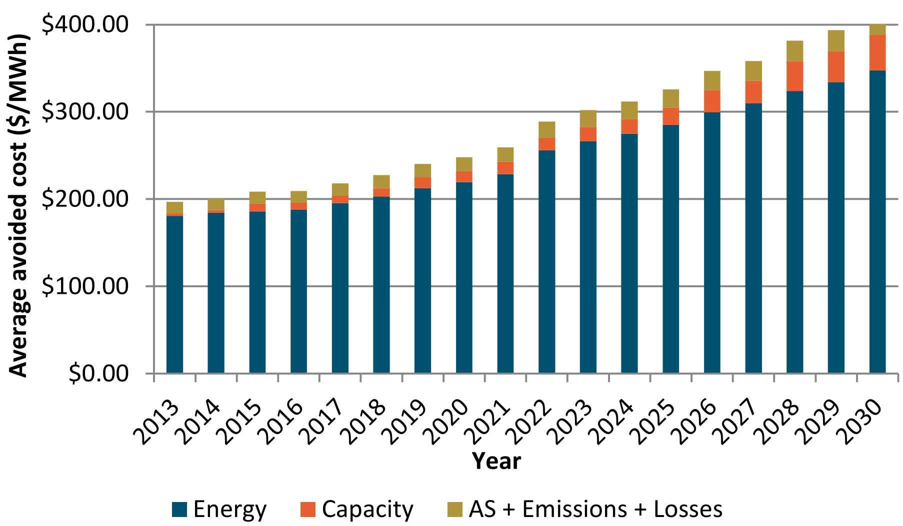
Figure 11 HELCO Avoided Cost Components by Year



HELCO's average avoided cost drops in 2022. This is due to the implementation of the 2022 fuel switch. In 2022, Hill 6 switches from medium sulfur fuel oil (MSFO) to low sulfur industrial fuel oil (LSIFO), a higher cost fuel, which changes its position in the stack. As a result, lower cost generators end up on the margin more often in 2022, and the average avoided cost drops.[5]

HELCO does not need new capacity resources until 2035. The small amount of capacity value is equal to the fixed capacity cost of the existing resource or the proxy cost of what is needed to maintain the fleet, as described in the methodology section of this report as the short-term capacity value. These costs are escalated with inflation.

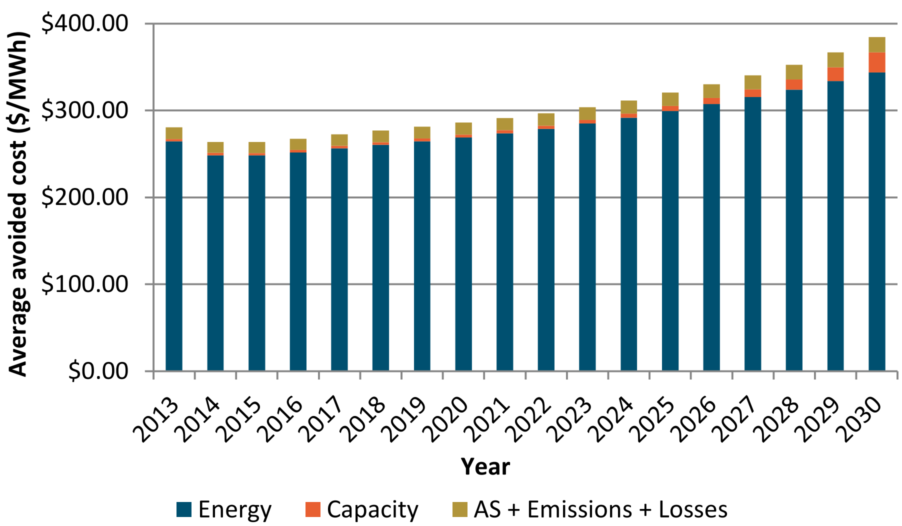
Figure 12 MECO Avoided Cost Components by Year



[5] Hill 6 has a low average heat rate with low startup costs, so it is early in the HELCO dispatch order. However Hill 6 has a higher *marginal* heat rate than other generators that come later in the stack. We assume that the highest marginal cost generator that is required to serve load in any hour is the displaced generator if a new resource comes online, and so it represents the avoided cost in that hour. Since Hill 6 is early in the dispatch order but has a higher marginal cost than generators that follow it in the stack, it is often on the margin, making HELCO's average avoided cost higher than it would be if the lower marginal cost, higher start cost generators came earlier in the stack. See Figure 3 in this report for an illustration of this principle.

The avoided cost components for MECO show a strong correlation with fuel prices. MECO also does not have any new capacity need through 2035, and so, similar to HELCO, the capacity costs are modeled as the fixed O&M of the existing fleet escalating with inflation.

Figure 13 KIUC Avoided Cost Components by Year



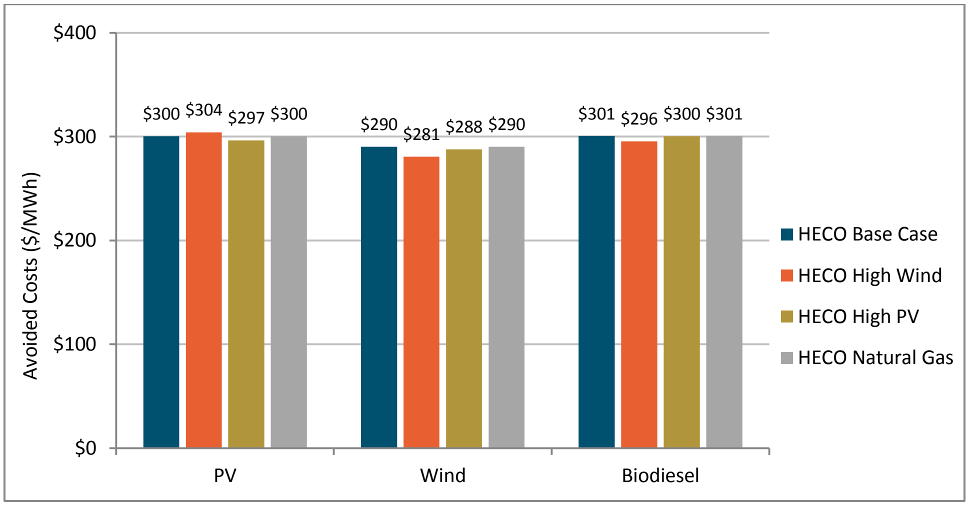
KIUC has no capacity need until 2031, so through 2030 capacity cost just increases with inflation, as in the case of MECO and HELCO.

3.2 HECO Avoided Cost Results

E3 calculated avoided costs for the base case and the high wind, high solar, and natural gas scenarios for Oahu. E3 provides a comparison of the average avoided cost by scenario and technology type in 2020, 2030, and then the 20-year levelized avoided costs.

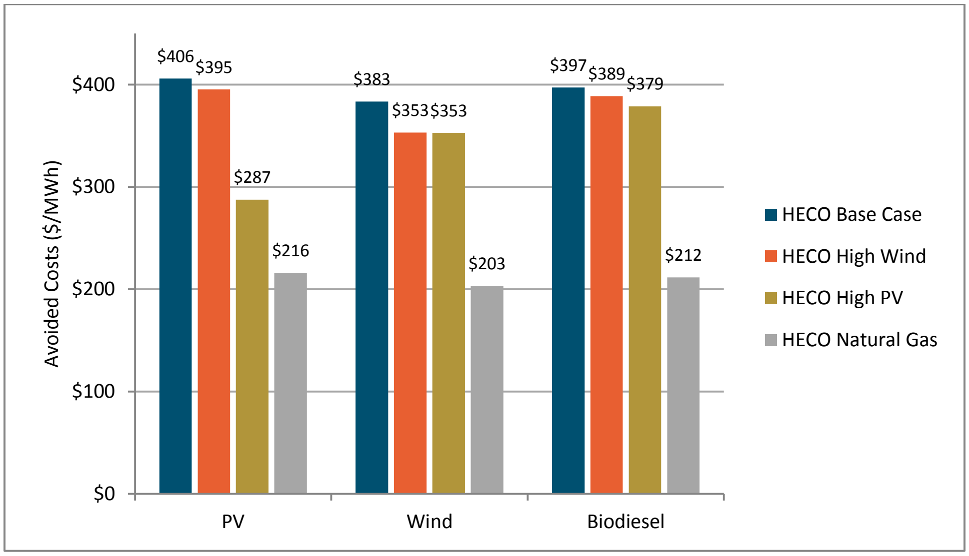
The graph below shows a 2020 snapshot of HECO's avoided costs. Each series represents one of the four HECO avoided cost scenarios: base case, high wind, high PV, and natural gas. On the x-axis, the value of three different renewable resource additions are compared across all scenarios. The avoided costs of each resource type represent the value of adding that type of renewable resource to the HECO system in 2020, given the renewable build-out in the selected scenario. Comparing avoided costs of a technology across scenarios illustrates the value of resource diversity on a system with high renewable penetration. For example, the avoided cost of incremental PV under the high wind scenario is \$304 per MWh, while the value of the same PV addition under the high PV scenario is \$297 per MWh. In the high PV scenario, existing PV generation causes lower cost conventional generators to operate on the margin in hours of high PV output, resulting in lower avoided costs for new PV additions. Also worth noting is that the 2020 snapshot generates identical avoided costs under the HECO base case and natural gas case, because the switch to natural gas occurs in 2022 in the stack model.

Figure 14 HECO Avoided Cost, 2020 Snapshot



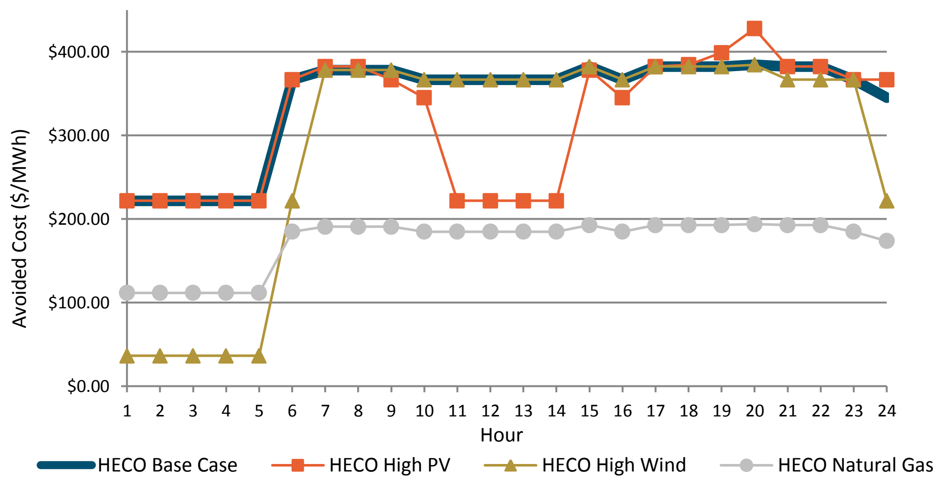
The 2030 snapshot of avoided costs in the figure below shows the impact of fuel cost increases and the significant difference between the base case and natural gas scenarios after the fuel switch takes place. In addition, you can see a dramatic difference in the PV avoided cost in the base case versus the high solar case as the marginal cost of energy drops in high solar production hours.

Figure 15 HECO Avoided Cost, 2030 Snapshot



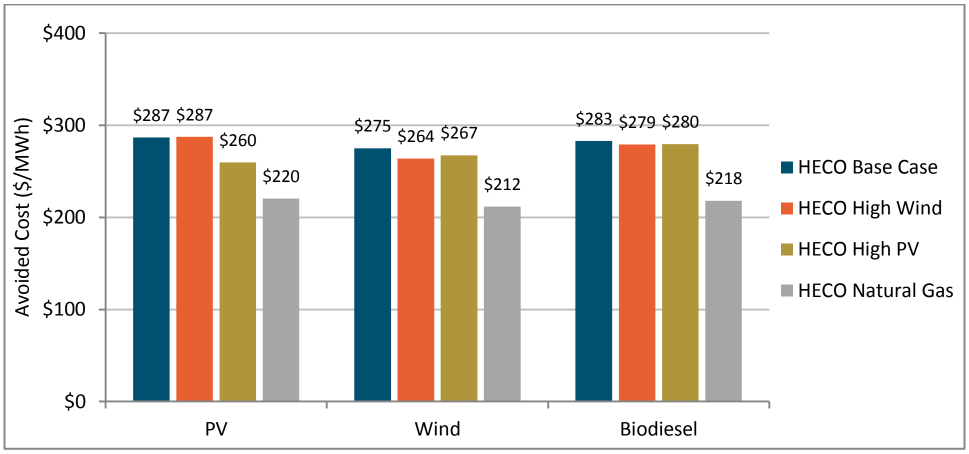
The chart below shows a single day in 2030 to illustrate how the avoided costs vary by scenario on an hourly basis. On this particular day, you can see how the additional solar pushes in the high PV case down the net load so that the system moves down the stack to more efficient conventional generators. You can also see the cost differential based on fuel price differences between the natural gas case and the base case that uses diesel. In the high wind scenario, wind generation drives down avoided costs in the late night and early morning.

Figure 16 HECO Avoided Cost on June 26, 2030



The 20-year levelized cost comparison provides the average cost over the expected life of the typical renewable project. Thus, the utility avoided cost benefits can be directly compared to the cost of the project.

Figure 17 HECO Avoided Cost, 20-year levelized

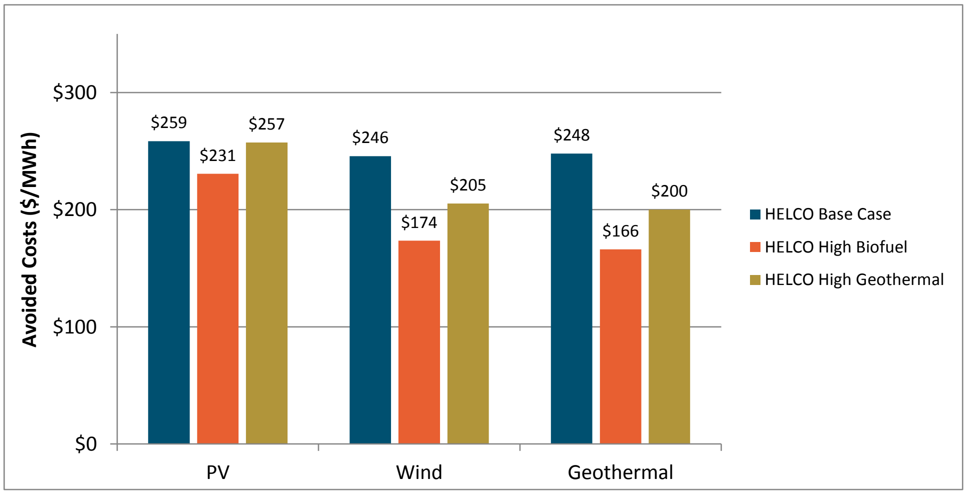


The 20-year levelized results are not as dramatic as the 2030 snapshot; however the same general trends remain. Under the high solar scenario, additional solar is valued less with lower avoided costs. Similarly under the high wind scenario, wind is valued less. However, it does not have quite as much of a drop as compared to solar. The avoided costs for renewable technologies under the LNG scenario are substantially lower by approximately $70/MWh.

3.3 HELCO Avoided Cost Results

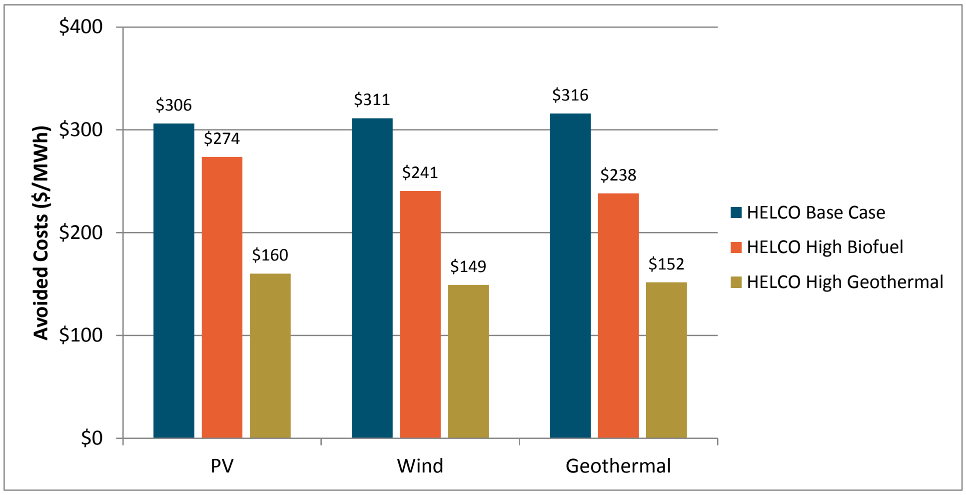
The avoided costs by renewable technology type on the Big Island are shown in the figures below. The charts compare the avoided cost for PV, biofuels, and geothermal under different RPS scenarios. The biofuel and geothermal shapes are modeled as flat baseload shapes. The high biofuel scenario envisions switching the existing Keahole units to biofuel, which entails removing Keahole from the island's generation stack and adding 40 MW of baseload biodiesel to HELCO's renewable portfolio.

Figure 18 HELCO Avoided Cost, 2020 Snapshot



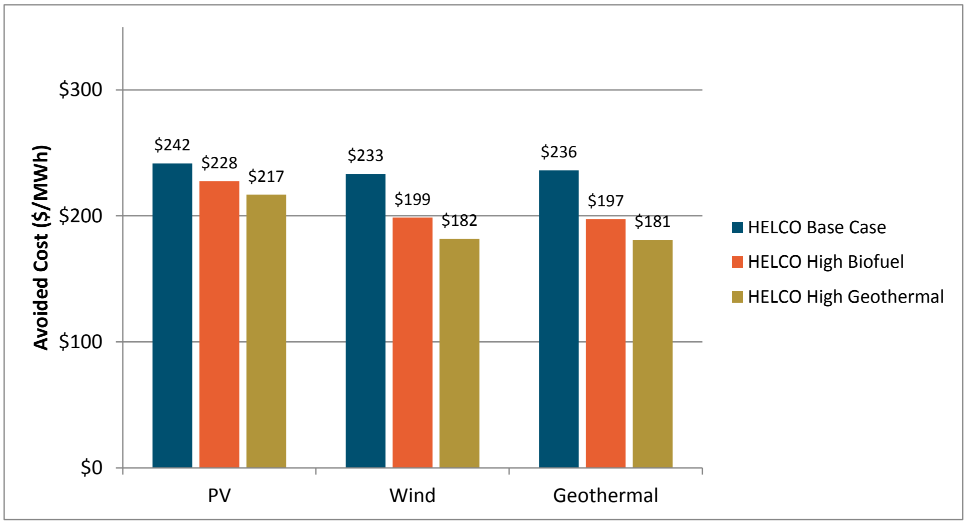
The 2020 snapshot shows lower avoided costs for PV, wind, and geothermal under the high biofuel scenario. This is due to the fact that the switch of Keahole is modeled in 2020, causing the island to jump from approximately 40% renewable penetration to 63% renewable penetration in one year. The very high penetration of renewables in 2020 and beyond results in low avoided costs for additional renewable resources. In contrast, the base case and high geothermal cases add resources more gradually: the base case has a renewable penetration of 41% in 2020, and the geothermal case has a penetration of 55%.

Figure 19 HELCO Avoided Cost, 2030 Snapshot



In the 2030 snapshot, incremental renewables now have less value in the high geothermal case. This is because the geothermal case gradually adds 50 MW of new geothermal resources through 2030, resulting in a higher total renewable penetration in 2030 than seen in the high biofuel case. With so many renewables on the system, curtailment increases, and the total avoided cost of the resource drops below the marginal cost of any conventional resource in the stack.

Figure 20 HELCO Avoided Cost, 20-year levelized

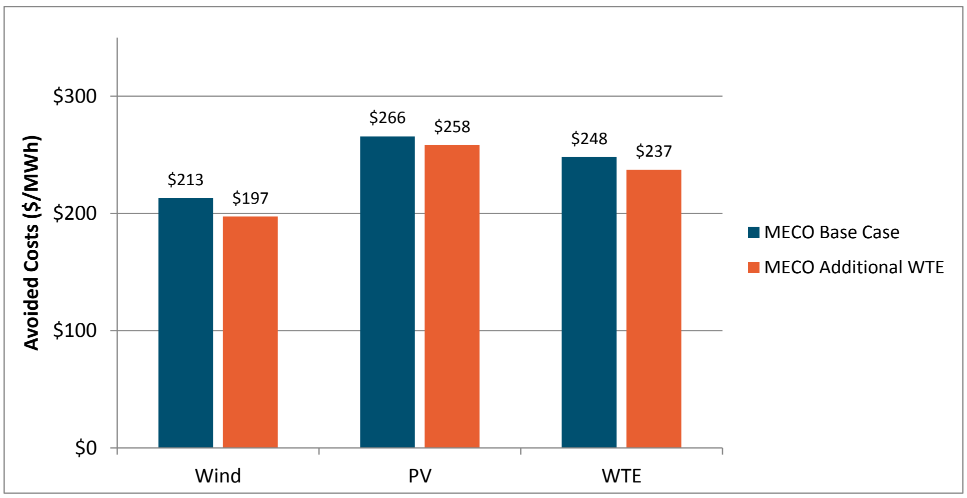


The 20-year levelized avoided costs of incremental renewables on the HELCO system show less variation across scenarios. In comparison to the HECO avoided costs, the HELCO avoided costs are lower partly due to higher levels of renewable generation. The HELCO avoided costs shown are the benefit provided by incremental renewable generation under the different scenarios. This is compared to the cost of renewables under different procurement mechanisms to determine the net value. A lower avoided cost means that renewable generation with similar cost are less valuable on a net value basis since they provide less benefits.

3.4 MECO Avoided Cost Results

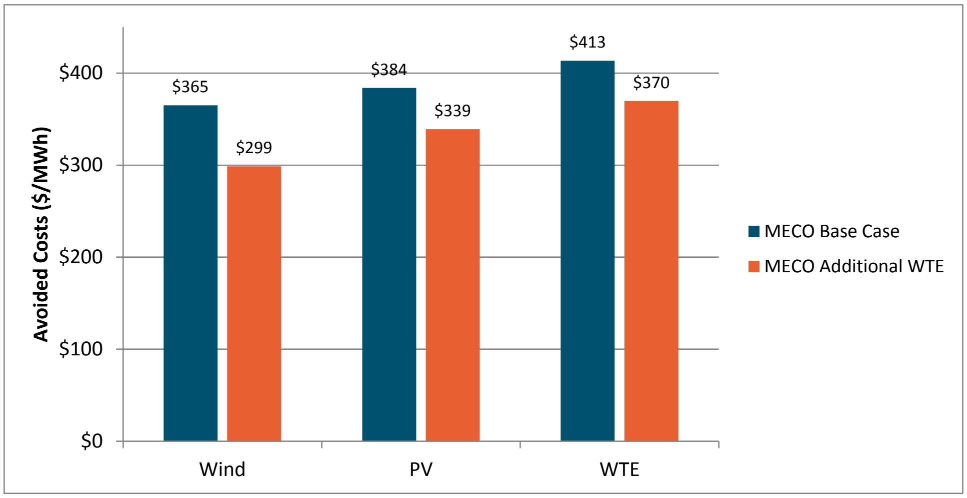
This section will show the base case scenario and waste-to-energy scenario for the island of Maui. The second scenario only adds 10 MW of new renewable generation so the differences between cases are not as dramatic.

Figure 21 MECO Avoided Cost, 2020 Snapshot



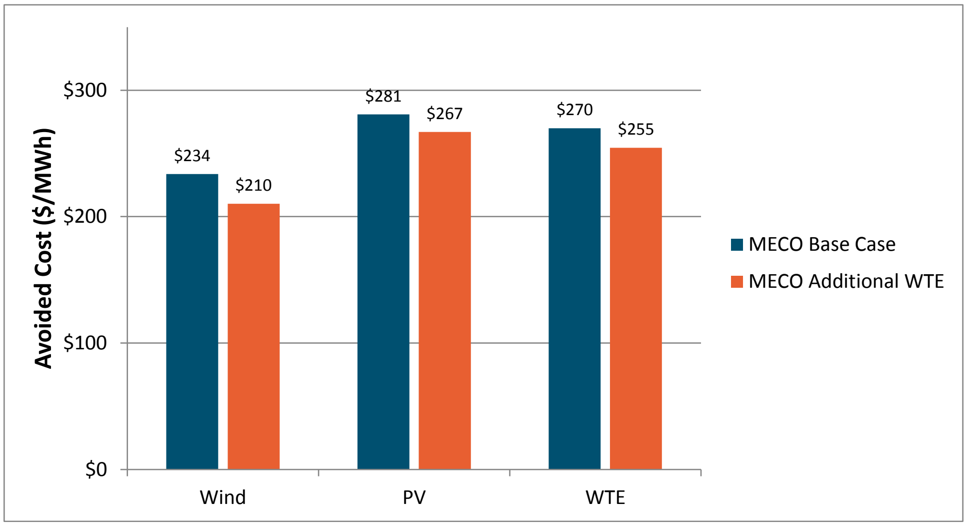
In the 2020 snapshot, we see a slightly lower price avoided cost for all added renewable technologies under the additional waste-to-energy avoided cost scenario, which has a higher renewable penetration than the base case. Furthermore, additional solar has substantially higher avoided costs under both scenarios when compared to incremental wind or waste-to-energy resources, due to solar's daytime-peaking output shape. This is due to a combination of higher load during the day and the marginal generation costs of the specific units which must come online to serve that load. The avoided cost for wind is fairly low on the MECO system under both avoided cost scenarios due the early build out and saturation of that wind resources on Maui.

Figure 22 MECO Avoided Cost, 2030 Snapshot



In 2030, the avoided costs increase substantially due to increasing fuel costs. The difference between the base case and additional WTE case also grows larger, as the renewable penetration under the additional WTE scenario continues to increase relative to the base case.

Figure 23 MECO Avoided Cost, 20-year levelized

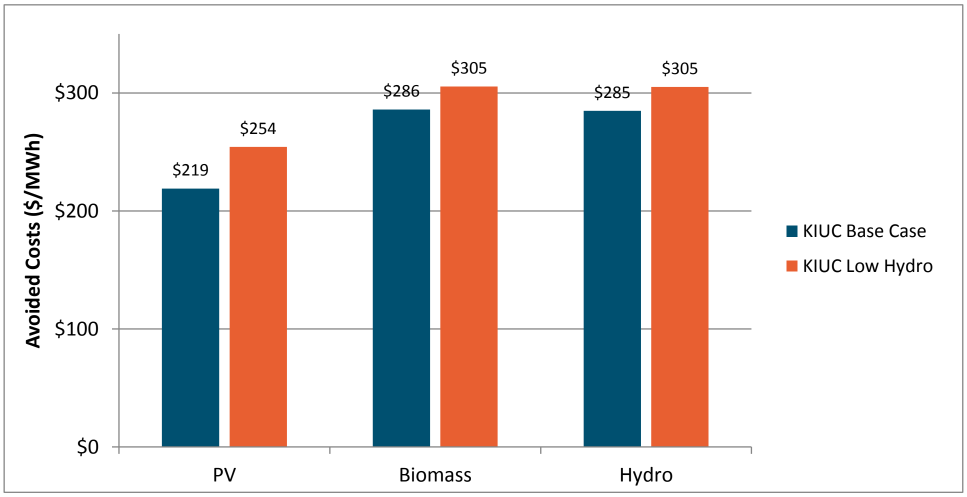


MECO has lower 20-year levelized avoided costs compared to HECO. This is partly due to higher penetration levels of existing wind, which already causes curtailment conditions on the MECO system. MECO also does not need new capacity until 2035, which reduces the capacity component of avoided cost.

3.5 KIUC Avoided Cost Results

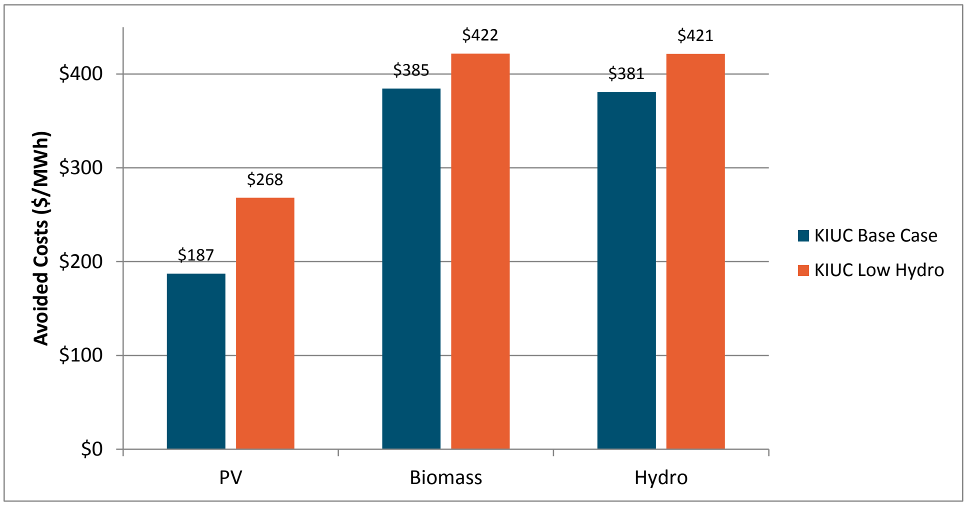
E3 modeled a base case that included the expansion of hydroelectric and then an additional scenario where the hydroelectric resource was not built out. The first graph below shows the 2020 snapshot of the avoided costs on Kauai.

Figure 24 KIUC Avoided Cost, 2020 Snapshot



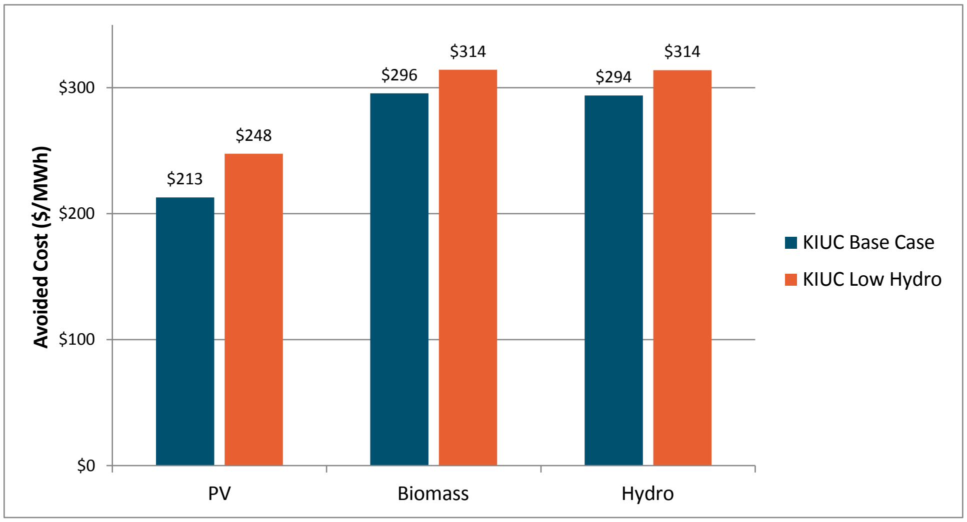
The 2020 snapshot of KIUC's avoided costs shows higher avoided costs for all additional renewable types under the low hydro case, due to a lower overall penetration of renewables in the low hydro scenario. Furthermore, the value of additional PV on KIUC's system is lower than the value of additional biomass and hydro resources under both scenarios. This is because the PV penetration on Kauai is already relatively high, especially when considering the 24 MW of new PV included in both avoided cost scenarios. The large amount of PV generation results in low marginal avoided costs and some curtailment during hours of high PV generation, limiting the value of adding more PV to KIUC's system.

Figure 25 KIUC Avoided Cost, 2030 Snapshot



By 2030, the lower avoided cost value of PV is even more dramatic. This is partly due to curtailment conditions. In 2030, almost all the curtailment that is seen is between the hours of 10:00am and 2:00pm.

Figure 26 KIUC Avoided Cost, 20-year levelized



KIUC's avoided costs are similar to HECO's with the exception of the low avoided costs associated with PV. This is due to higher levels of penetration of solar resources on Kauai. The base case with the additional hydroelectric reduces avoided costs by about the same amount over each of the cases.

3.6 Avoided Cost Conclusions

The avoided costs vary substantially by island and scenario. However, across all islands the average avoided cost remains relatively high over a 20-year levelized period. The 20-year levelized cost ranges from $181/MWh in the high geothermal case on HELCO to $314/MWh for the low hydroelectric case on KIUC. The level of renewables, the efficiency of the existing conventional fleet, the type of renewable generation, and whether the island needs new capacity resources are the major drivers of avoided costs and are the cause for the differences between island systems. It is also clear from the analysis that with high levels of penetration of a specific type of resource, the system becomes saturated and incremental additions of that same resource type earn lower avoided costs, becoming less valuable. The drop in value becomes especially pronounced when a new resource results in additional curtailment, since curtailed renewable generation is not assigned any avoided cost value. This is seen on the KIUC system with PV and on the MECO system with wind.

3.7 Net Cost Comparison

In this section, E3 compares the cost of the FIT, the NEM policy, and direct utility procurement using the avoided cost benchmarks results to calculate net costs or net value.

3.7.1 UTILITY PROCUREMENT

To evaluate the net value of utility-scale procurement, E3 used pricing information from HECO's recent invitation for low-cost renewable energy projects.

Under this process, the maximum bid for renewable projects was set at \$170/MWh. Several wind and solar bids came in under this price point. According to HECO, there was a natural cluster of renewable energy bids around \$162.5/MWh. Thus, until further data on recent pricing is publicly available, E3 uses this proxy cost for both wind and solar in our example below. For biofuel switching, E3 uses the average heat rate and variable O&M costs of all the Kahe units (1-6) and the 20-year levelized cost with biodiesel used as fuel. The 20-

year levelized cost of using biodiesel in the Kahe units was calculated at $500/MWh.

In addition to the cost of the PPA or the expected cost of fuel switching, the PUC and the utilities need to consider any additional system costs including additional transmission and distribution needs that are not paid for by the developer and any cost of integration (e.g., increasing the operating reserves or ramping requirements of the system to maintain reliability when the renewable resource is in operation). E3 did not investigate the typical additional cost of transmission or integration in this report as it is a complex topic which requires system specific modeling and research. We include proxy values below to show the relative difference between renewable resources. Both wind and solar are given additional T&D and integration costs due to the need to build out the system, while biofuels use the existing infrastructure and do not have these additional costs. The proxy value for integration for wind and solar is from a Western Electricity Coordinating Council (WECC) meta-analysis of cost of integration studies which was performed for the WECC for their 2010 cost update.[6] Many jurisdictions have continued to refine this analysis and the specific integration costs for each Hawaiian system would necessarily be different from the WECC market systems which are larger and interconnected. The proxy cost for transmission is set at $10/MWh based on the range of assumed transmission costs presented in E3's RPS calculator which reviews current and potential future renewable projects which could serve California

[6] Capital Cost Recommendations for 2009 TEPPC Study. E3 Presentation, January 6, 2010. http://www.wecc.biz/committees/BOD/TEPPC/TAS/SWG/Lists/Calendar/Attachments/27/E3_CapitalCosts_TEPPC_2010-01-06.pdf

markets.[7] The example shows net costs or net value results for HECO. The net cost/net value analysis shows that both wind and solar represent a substantial net value to the system. However, biofuel switching results in a net cost.

Table 6 Sample Utility Procurement Net Cost Calculation

Technology Resource Type	PPA Cost or Fuel Switching Cost (A)	T&D Cost (B)	Integration (C)	Avoided Cost (D)	Net Cost (Value) A+B+C-D
	Per Unit Cost ($/MWh)				
Wind	$162	$10	$6	$287	($109)
Solar PV	$162	$10	$6	$275	($97)
Biodiesel	$500	$0	$0	$283	$217

3.7.2 FEED-IN TARIFF

The FIT rates for Tiers 1 and 2 were approved by the PUC in 2010, and the Tier 3 rates were approved in 2011. The FIT was developed on a cost basis for each technology type and size. The FIT rates are shown in the table below and have not changed since they were approved by the PUC. However, the PUC recently opened a proceeding to re-evaluate the FIT program (Docket No. 2013-0194).

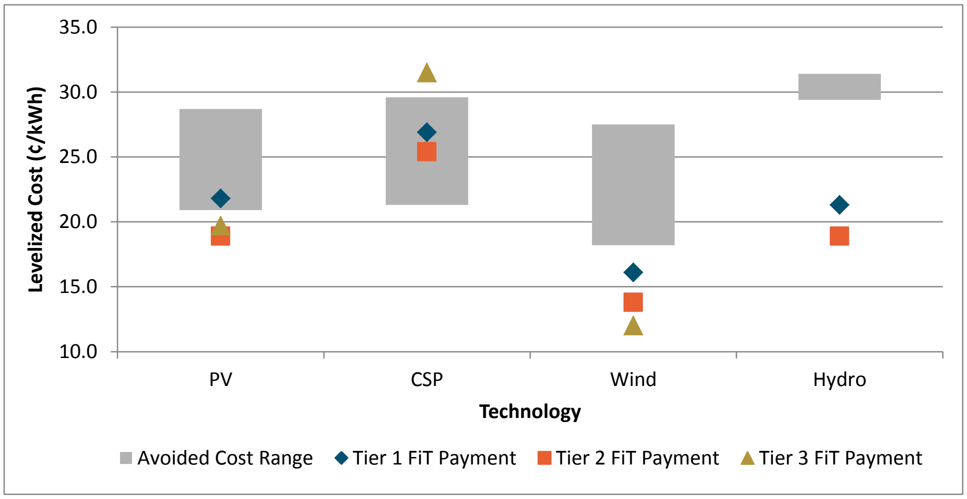
[7] The latest RPS calculator can be found at the following link. http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/2012+LTPP+Tools+and+Spreadsheets.htm

Table 7 Hawaii Feed-in Tariff Rates, cents/kWh

Tier	PV	CSP	Wind	Hydroelectric
1	21.8	26.9	16.1	21.3
2	18.9	25.4	13.8	18.9
3	19.7	31.5	12.0	N/A

The net cost or net value of these FIT rates depends on the island system where the project gets developed. E3 provides the 20-year avoided cost levelized cost range of values from the base case scenarios on HECO, HELCO, MECO, and KIUC to compare at a high level to the various FIT rates by technology in the chart below.

Figure 27 Avoided Cost Range and Feed-in Tariff Rates



The FIT policy was based on the cost of the technology and did not consider the value to the system. Therefore there are large ranges in the net value to the system. The table below shows the net cost/value for the HECO system. All the

FIT rates represent a net value to the system with the exception of the Tier 3 CSP rate. Note, that E3 did not have differentiated generation shapes based on technology size. Therefore the avoided costs do not vary by tier. If we had accurate shapes by technology and size there would be some variation between tiers but the differences between a small scale PV shape and a larger size PV generation shape would not substantially change the results. There is much more variation between wind and solar than different size solar shapes and the avoided cost difference between wind and solar is only about $10/MWh.

Table 8 HECO Net Cost (Value) of Feed-in Tariff Rates ($/MWh)

	FiT Rate	Avoided Cost	Net Cost or (Value)
Tier 1 PV	$218	$287	($69)
Tier 1 CSP	$269	$296	($27)
Tier 1 On-Shore Wind	$161	$275	($114)
Tier 1 In-Line Hydropower	$213	$283	($70)
Tier 2 PV	$189	$287	($98)
Tier 2 CSP	$254	$296	($42)
Tier 2 On-Shore Wind	$138	$275	($137)
Tier 2 In-Line Hydropower	$189	$283	($94)
Tier 3 PV	$197	$287	($90)
Tier 3 CSP	$315	$296	$19
Tier 3 On-Shore Wind	$120	$275	($155)

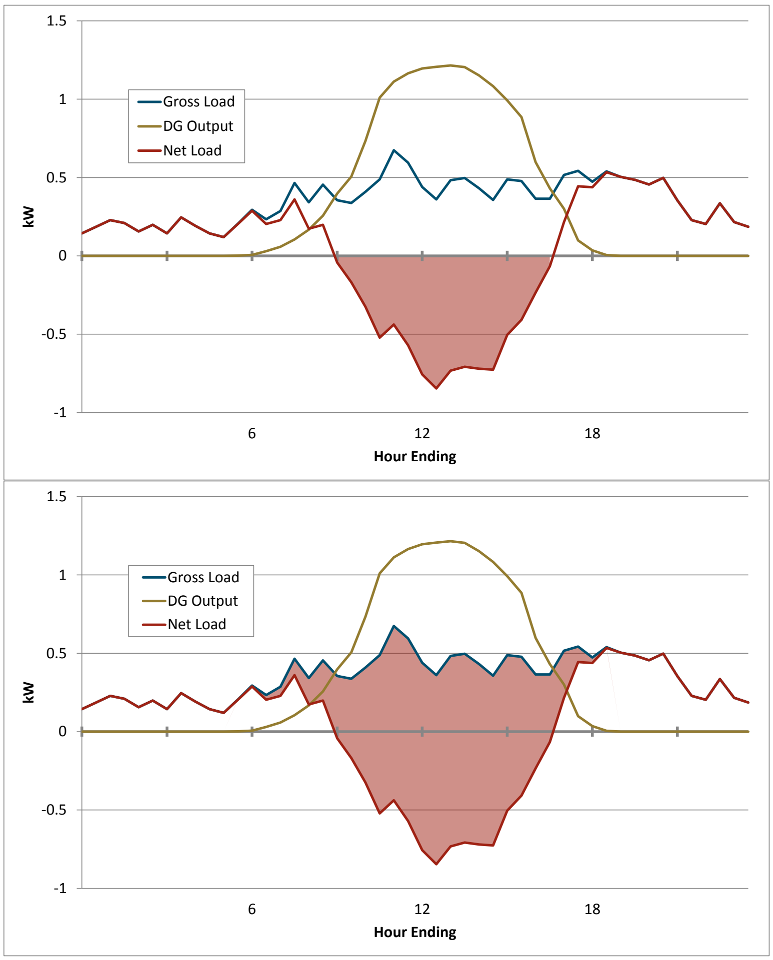
Comparing the net costs, it is clear that some of the resource types provide greater benefits. This is due to the design of the FIT solely on a cost basis without considering the value to the Hawaii grid systems. Furthermore, these cost-based prices do not automatically change as the cost of the technology changes over time. For example, PV has seen substantial price decreases over the last three years, and, thus, the FIT rates today may be higher than what would currently be calculated on a cost basis for these systems.

3.7.3 NET ENERGY METERING

To calculate the costs of the NEM policy, E3 simulated the bills for different types of customers with and without the NEM PV systems. As discussed in the methodology section, there are two ways to consider the impact of a NEM policy. In one case, you only count the energy that is exported or sold to the system and consider the other energy produced which offsets customer load as energy efficiency. Alternatively, you can calculate the costs of all the generation that is associated with the NEM system. The graphic below shows the difference between the export only versus the all generation calculation.

Figure 28 Load and DG generation example for residential customer

Export Only (top chart) All Generation (bottom chart)



E3 presents the net cost results for the NEM policy by rate class, by island and location and by calculation method in the tables below.

Table 9 HECO Net Costs for All Generation

Scenario Inputs				20 Year Levelized Costs		
Utility	Schedule	Location	Avoided Cost Scenario	Bill Savings (A)	Avoided Costs (B)	Net Costs (A-B)
HECO	G	Honolulu	HECO Base Case	$0.37	$0.29	$0.08
HECO	G	Kailua	HECO Base Case	$0.37	$0.28	$0.09
HECO	R	Honolulu	HECO Base Case	$0.39	$0.29	$0.10
HECO	R	Kailua	HECO Base Case	$0.39	$0.28	$0.11
HECO	P	Honolulu	HECO Base Case	$0.35	$0.29	$0.06
HECO	P	Kailua	HECO Base Case	$0.33	$0.28	$0.05
HECO	J	Honolulu	HECO Base Case	$0.32	$0.29	$0.03
HECO	J	Kailua	HECO Base Case	$0.32	$0.28	$0.04

Table 10 HECO Net Costs for Export Only

Scenario Inputs				20 Year Levelized Costs		
Utility	Schedule	Location	Avoided Cost Scenario	Bill Savings (A)	Avoided Costs (B)	Net Costs (A-B)
HECO	G	Honolulu	HECO Base Case	$0.37	$0.25	$0.12
HECO	G	Kailua	HECO Base Case	$0.37	$0.26	$0.11
HECO	R	Honolulu	HECO Base Case	$0.39	$0.28	$0.11
HECO	R	Kailua	HECO Base Case	$0.39	$0.27	$0.12
HECO	P	Honolulu	HECO Base Case	$0.00	$0.00	$0.00
HECO	P	Kailua	HECO Base Case	$0.00	$0.00	$0.00
HECO	J	Honolulu	HECO Base Case	$0.31	$0.26	$0.05
HECO	J	Kailua	HECO Base Case	$0.31	$0.26	$0.05

The net costs vary based on rate class but are relatively low on the HECO system due to relatively high avoided costs. Note that under the industrial rate, HECO schedule P, the system caps for NEM and the load shape for the industrial facilities result in no modeled exports. Therefore, the avoided cost, bill savings and net costs are all $0/kWh.

The results above are only shown for the base case. When you compare the results of the base case to the high solar case you can see the increase in the net costs of the NEM policy as the value of PV declines due to high penetrations and increased curtailment. The comparison of the base case to the high solar case for HECO is shown below for the all generation case.

Table 11 HECO Net Costs Comparison All Generation Base Case vs High Solar

Scenario Inputs				20 Year Levelized Costs		
Utility	Schedule	Location	Avoided Cost Scenario	Bill Savings (A)	Avoided Costs (B)	Net Costs (A-B)
HECO	G	Honolulu	HECO Base Case	$0.37	$0.29	$0.08
HECO	G	Honolulu	HECO High PV	$0.37	$0.26	$0.11
HECO	R	Honolulu	HECO Base Case	$0.39	$0.29	$0.10
HECO	R	Honolulu	HECO High PV	$0.39	$0.26	$0.13
HECO	P	Honolulu	HECO Base Case	$0.35	$0.29	$0.06
HECO	P	Honolulu	HECO High PV	$0.35	$0.26	$0.09
HECO	J	Honolulu	HECO Base Case	$0.32	$0.29	$0.03
HECO	J	Honolulu	HECO High PV	$0.32	$0.26	$0.06

Understanding the increased cost of NEM under different long-term portfolios will help the PUC and other stakeholders understand tradeoffs between procurement decisions. The net costs of the NEM policy are much higher on the other island systems as shown in the tables below.

Table 12 HELCO Net Costs All Generation

Scenario Inputs				20 Year Levelized Costs		
Utility	Schedule	Location	Avoided Cost Scenario	Bill Savings (A)	Avoided Costs (B)	Net Costs (A-B)
HELCO	G	Kona	HELCO Base Case	$0.49	$0.24	$0.25
HELCO	G	Hilo	HELCO Base Case	$0.49	$0.24	$0.25
HELCO	J	Kona	HELCO Base Case	$0.41	$0.24	$0.17
HELCO	J	Hilo	HELCO Base Case	$0.41	$0.24	$0.17
HELCO	P	Kona	HELCO Base Case	$0.38	$0.24	$0.14
HELCO	P	Hilo	HELCO Base Case	$0.38	$0.24	$0.14
HELCO	R	Kona	HELCO Base Case	$0.48	$0.24	$0.24
HELCO	R	Hilo	HELCO Base Case	$0.48	$0.24	$0.24

Table 13 HELCO Net Costs Export Only

Scenario Inputs				20 Year Levelized Costs		
Utility	Schedule	Location	Avoided Cost Scenario	Bill Savings (A)	Avoided Costs (B)	Net Costs (A-B)
HELCO	G	Kona	HELCO Base Case	$0.49	$0.24	$0.25
HELCO	G	Hilo	HELCO Base Case	$0.49	$0.24	$0.25
HELCO	J	Kona	HELCO Base Case	$0.40	$0.24	$0.16
HELCO	J	Hilo	HELCO Base Case	$0.40	$0.24	$0.16
HELCO	P	Kona	HELCO Base Case	$0.00	$0.00	$0.00
HELCO	P	Hilo	HELCO Base Case	$0.00	$0.00	$0.00
HELCO	R	Kona	HELCO Base Case	$0.47	$0.24	$0.23
HELCO	R	Hilo	HELCO Base Case	$0.47	$0.24	$0.23

HELCO’s net costs associated with the NEM policy are substantially higher than HECO’s due to higher projected rates and lower avoided costs.

Table 14 MECO Net Costs All Generation

Scenario Inputs				20 Year Levelized Costs		
Utility	Schedule	Location	Avoided Cost Scenario	Bill Savings (A)	Avoided Costs (B)	Net Costs (A-B)
MECO	G	Hana	MECO Base Case	$0.53	$0.28	$0.25
MECO	G	Kahului	MECO Base Case	$0.53	$0.28	$0.25
MECO	J	Hana	MECO Base Case	$0.48	$0.28	$0.20
MECO	J	Kahului	MECO Base Case	$0.48	$0.28	$0.20
MECO	P	Hana	MECO Base Case	$0.45	$0.28	$0.17
MECO	P	Kahului	MECO Base Case	$0.45	$0.28	$0.17
MECO	R	Hana	MECO Base Case	$0.53	$0.28	$0.25
MECO	R	Kahului	MECO Base Case	$0.53	$0.28	$0.25

Table 15 MECO Net Costs Export Only

Scenario Inputs				20 Year Levelized Costs		
Utility	Schedule	Location	Avoided Cost Scenario	Bill Savings (A)	Avoided Costs (B)	Net Costs (A-B)
MECO	G	Hana	MECO Base Case	$0.53	$0.27	$0.26
MECO	G	Kahului	MECO Base Case	$0.53	$0.26	$0.27
MECO	J	Hana	MECO Base Case	$0.48	$0.27	$0.21
MECO	J	Kahului	MECO Base Case	$0.48	$0.27	$0.21
MECO	P	Hana	MECO Base Case	$0.00	$0.00	$0.00
MECO	P	Kahului	MECO Base Case	$0.00	$0.00	$0.00
MECO	R	Hana	MECO Base Case	$0.52	$0.28	$0.24
MECO	R	Kahului	MECO Base Case	$0.52	$0.28	$0.24

MECO's net costs are higher than HECO's largely due to much higher rates. The 20-year rate forecast for the MECO system escalates at a higher rate compared to the other systems due to the heavy reliance on diesel fuel, while avoided costs for PV are similar on the MECO and HECO systems.

Table 16 KIUC Net Costs All Generation

Scenario Inputs				20 Year Levelized Costs		
Utility	Schedule	Location	Avoided Cost Scenario	Bill Savings (A)	Avoided Costs (B)	Net Costs (A-B)
KIUC	D	Kapaa	KIUC Base Case	$0.46	$0.22	$0.24
KIUC	D	Lihue	KIUC Base Case	$0.46	$0.22	$0.24
KIUC	G	Kapaa	KIUC Base Case	$0.48	$0.22	$0.26
KIUC	G	Lihue	KIUC Base Case	$0.48	$0.22	$0.26
KIUC	J	Kapaa	KIUC Base Case	$0.45	$0.22	$0.23
KIUC	J	Lihue	KIUC Base Case	$0.45	$0.22	$0.23
KIUC	L	Kapaa	KIUC Base Case	$0.42	$0.22	$0.20
KIUC	L	Lihue	KIUC Base Case	$0.42	$0.22	$0.20

Table 17 KIUC Net Costs Export Only

Scenario Inputs				20 Year Levelized Costs		
Utility	Schedule	Location	Avoided Cost Scenario	Bill Savings (A)	Avoided Costs (B)	Net Costs (A-B)
KIUC	D	Kapaa	KIUC Base Case	$0.46	$0.19	$0.27
KIUC	D	Lihue	KIUC Base Case	$0.46	$0.19	$0.27
KIUC	G	Kapaa	KIUC Base Case	$0.48	$0.17	$0.31
KIUC	G	Lihue	KIUC Base Case	$0.48	$0.17	$0.31
KIUC	J	Kapaa	KIUC Base Case	$0.44	$0.16	$0.28
KIUC	J	Lihue	KIUC Base Case	$0.44	$0.16	$0.28
KIUC	L	Kapaa	KIUC Base Case	$0.00	$0.00	$0.00
KIUC	L	Lihue	KIUC Base Case	$0.00	$0.00	$0.00

KIUC has the highest net costs associated with the NEM policy. This is due to a combination of high rates and low avoided cost values for PV with the large amount of PV that is already installed on the KIUC system and with most curtailment occurring between 10:00am and 2:00pm. It should be noted that KIUC offers different customer-sited renewable energy acquisition options for “behind-the-meter” renewable energy systems, including KIUC’s NEM Pilot Program and KIUC’s Schedule Q offering (Schedule Q). The results shown above are based on E3’s analysis of figures associated with KIUC’s NEM Pilot Program, and not KIUC’s Schedule Q. As KIUC’s Schedule Q offering is based on a calculation of KIUC’s avoided cost of generation rather than retail rates, an analysis of the effects of KIUC’s NEM Pilot Program is considered to be more meaningful for the purposes of this study and report.

3.8 Net Cost Policy Comparison Conclusions

Most of the RPS procurement which is being implemented or considered by the Hawaiian utilities and the PUC represents a net benefit to ratepayers. The high cost of petroleum-derived fuels and the expected increase in those costs over time leads to a strongly favorable environment for renewable investment.

However, when comparing the relative value of NEM, FIT, and utility-scale procurement mechanisms, the utility-scale and FIT mechanisms provide the greatest value, while the NEM policy represents higher renewable procurement costs due to the use of retail rates. Retail rates are significantly higher than either FIT payment rates or recently proposed payment rates for utility-scale renewable generation, indicating procurement through the FIT program or through utility-scale solicitations may provide greater value to ratepayers than procurement through the NEM policy. In addition, retail rates include costs for other non-energy components, including grid services, which provide value and are utilized by NEM customers. Furthermore, these non-energy costs may be shifted to non-participants in the NEM program if they are not fully recovered through NEM customer rates.

In contrast to the NEM program, most FIT payment rates represent a substantial net value to ratepayers, with the exception of certain concentrating solar power and small PV systems on some islands. Finally, biofuel switching in comparison with other options represents a net cost to the system. However, the long-term potential for increases in transmission and integration charges and the possible saturation of wind and/or solar on the system, may cause biofuels to become more competitive.

4 Comparison to Alternate Policy Design

In this section, E3 compares the structure and implementation of Hawaii's programs to programs in other states with similarly aggressive renewable goals, including California, Colorado, and New York.

4.1 Traditional Net Energy Metering Policy

NEM allows utility customers to install on-site renewable generation to offset their electricity consumption. NEM programs are available in 43 US states, with variations in subscription limitations, system size requirements, and policies for utility purchase of any generation that is not consumed on site and is exported to the grid.

4.1.1 NET ENERGY METERING IN HAWAII

NEM has existed in Hawaii since 2001, and has been modified and expanded multiple times since its inception by the state legislature and the PUC. Residential and small commercial customers can participate in NEM, and third party-owned systems are eligible. The on-site generation installed can be solar, wind, biomass, or hydroelectric. At the end of every month, any generation that exceeds the customer's consumption earns a bill credit using the customer's retail rate. Bill credits can be rolled forward to future months to offset any bill charges the customer incurs. However, bill credits can only be rolled forward for twelve months; at the end of the year, the customer surrenders any remaining credits or net generation to the utility.

NEM is available to customers of HECO, HELCO, MECO, and KIUC, while the programs differ slightly by island. In the HECO, HELCO, and MECO service territories, the maximum system size is 100 kW and as the program has grown rapidly in recent years aggregate system caps were replaced by a screening process at the distribution circuit level. Under recently announced policy changes in September 2013, HECO may require additional studies and circuit upgrades to interconnect NEM customers when the total capacity of PV installed on the circuit exceeds 100% of the circuit's daytime minimum load. In January 2014, HECO announced that customers with PV inverters that meet new technical standards for voltage trip settings may be allowed to interconnect on high saturation circuits. The utility is currently in the process of providing further guidance on the details of this policy change. In the KIUC service territory, the NEM Pilot Program has set the maximum system size at 50 kW, and the aggregate capacity is capped at 1% of Kauai's system peak demand.

4.1.2 CALIFORNIA NET ENERGY METERING

California's NEM policy originally took effect in 1996 and has since been significantly revised. Under current NEM policy, residential and non-residential utility customers can install on-site renewable generation to offset their utility bills and earn utility credits for excess generation. In 2011, California State Bill

489 extended NEM eligibility to all technologies that qualify towards California's RPS. The maximum system size for participation is 1 MW.

Under California's NEM tariffs, customers receive a bill credit for energy generated in excess of electric load that is exported to the grid. Surplus generation is credited on a monthly basis at retail rates, and any excess bill credits can be applied to future utility bills over a one year period. If a customer generator produces a net surplus of electricity over the course of a year that net export is compensated at the Net Surplus Compensation rate, which is representative of the utility's avoided cost of generation.

Currently over 120,000 residential and non-residential accounts are enrolled in the program. E3 performed a cost effectiveness evaluation of the NEM program released in 2010 which found that 99% of NEM customers in 2008 had installed solar PV, as opposed to other eligible technologies.[8] NEM participation is capped at 5% of the state's aggregate peak customer demand, which the CPUC defined in 2012 to mean the sum of non-coincident peak demand of all customers. California's NEM program will be suspended at the end of 2014 (regardless of the subscription level), while the CPUC and state legislature determine the policy's future.

[8] The CPUC 2010 NEM cost effectiveness report including E3's analysis can be found at http://www.cpuc.ca.gov/NR/rdonlyres/0F42385A-FDBE-4B76-9AB3-E6AD522DB862/0/nem_combined.pdf

4.2 Virtual Net Metering and Community Energy

Traditional NEM is only available to utility customers who own rooftop space; participation is further limited because the rooftop must be suitable for PV in terms of shading conditions and building construction. Virtual Net Metering programs and Community Energy programs have been established by various US utilities to broaden the availability of NEM participation, especially for customers who are renters, live in multifamily dwellings, or do not have access to suitable rooftop space for any other reason. These programs allow utility customers who want to consume electricity from renewable sources to purchase or lease part of a renewable project, which can be located at a different site from their utility service.

4.2.1 COMMUNITY SOLAR IN HAWAII

In January 2013, the Hawaii legislature introduced Senate Bill 1330 and accompanying House Bill 1363, which would establish a community-based energy program.[9] The bill's stated goal is to increase accessibility to renewable energy generation to groups who are not able to participate in Hawaii's existing NEM program, including renters and owners of properties with shaded or otherwise unsuitable roofs. The proposed program would be a 50 MW pilot, with a 1 MW system size limit. Renewable generation would be credited at retail rates as it is under Hawaii's existing NEM policy. Both bills were deferred in the initial committee hearing.

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[9] Text of SB1330 (2013) is located at http://www.capitol.hawaii.gov/session2013/Bills/SB1330_.HTM

4.2.2 CALIFORNIA VIRTUAL NET METERING

California's Virtual Net Metering program (VNM) was originally instated by the CPUC in 2009 as a pilot program targeting low income housing. The program allowed owners of low income multi-tenant housing developments to install rooftop PV systems and then allocate the resulting bill savings to multiple tenants. In 2011 the program was expanded to include all multi-tenant properties, both low income and market rate. Each of the three California investor-owned utilities[10] (IOU) participates in the VNM program.[11]

Compensation to VNM participants is similar to compensation under California's traditional NEM program. Generation allocated to each tenant is credited by the utility at the customer's retail rate; the total credit appears on the customer's utility bill and can carry over to future months. The maximum system size is 1 MW, which is the maximum for the traditional NEM program. Tenants who receive VNEM credits must opt in to participate. The system owner, presumably the building owner or landlord, determines how the system generation is allocated to different tenants. Generation must be allocated to at least two different parties.

PV systems under VNM are metered completely independently of tenant loads. Each system is installed with its own meter, which tracks the system's output. For market rate properties, an individual system can serve only those accounts which

[10] California's three IOUs are Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric.

[11] The program was created via CPUC decisions 11-07-031 and 08-10-036.

connect to the utility distribution system at the same point (called a service delivery point). Low income developments often have multiple buildings which are connected at different service delivery points, so they are not subject to the same requirement — a single system's generation can be allocated to tenants anywhere within the housing property.

A report issued by SF Environment highlighted several issues with VNM adoption in San Francisco, a community with a very high percentage of renters and multi-tenant housing.[12] The report identifies a lack of awareness of the program among multi-tenant property owners and a lack of familiarity with the program's requirements among solar installers as key issues. SF Environment also points out that standard methods of cost recovery have not yet been established. The property owners purchase and own the system, but the bill savings go to tenants. Property owners can recover their investment either by charging tenant participants a fee for participation, or by embedding the cost of participation in rents. VNM is a new program in California and it is not yet apparent what cost recovery method is most feasible or what impact the program will have.

4.2.3 COLORADO COMMUNITY SOLAR GARDENS

The Colorado Public Utilities Commission adopted a decision in 2010 creating a virtual NEM called Community Solar Gardens (CSG). CSG is an example of a community solar policy with very flexible rules. The program allows a for-profit or

[12] Full report available at http://www.sfenvironment.org/sites/default/files/fliers/files/virtual_net_energy_metering_at_multitenant_buildings_0.pdf

nonprofit entity to own a solar generation facility and to sell the energy produced to voluntary subscribers. The subscribers must be customers of the two impacted Colorado utilities, Xcel Energy and Black Hills Energy, and there are some requirements detailing the required proximity between the PV system and the location of the customer's utility account. The rates at which subscribers purchase or lease portions of the community solar installations from the system owners are not regulated by the Colorado Public Utilities Commission.

In order for a PV system to qualify for CSG, it must have a capacity smaller than 2 MW, and it must have at least 10 different subscribers. No individual subscriber can own or lease a share larger than 40% of the total system size. The minimum subscription size is 1 kW (with an exception for participants designated as low income), and a participant's maximum subscription size is equal to 120% of their total annual electricity usage. A subscriber's CSG purchases earn credits on their utility bill, paid as a value per kWh of generation. The credit value is set based on the customer's total aggregate retail rate, less Colorado PUC approved utility charge for delivery, integration, and administration costs associated with the CSG program.

Under CSG requirements, Xcel Energy has created their Solar*Rewards program. CSG system owners can apply to participate in Solar*Rewards in order to receive subsidies from the utility, in the form of REC purchases. Projects are categorized as small, medium, or large installations. Small and medium installations, defined as smaller than 10 kW and between 10kW and 500 kW respectively, are accepted into CSG via a Standard Offer program. System owners are paid a flat $/kWh performance-based incentive, which declines as program subscription increases; the incentive is larger for customer owners than third-party owners and larger for small systems than medium systems. At current subscription levels, the incentive ranges from 7 to 13 cents/kWh generated. Large systems, 500 kW to 2 MW, apply for participation in CSG via a request for proposals (RFP) process. In 2012 and 2013, the first years of the Solar*Rewards program, Xcel energy accepted 4.5 MW of small and medium projects in each year. A number of large projects totaling 4.5 MW in capacity were accepted through the RFP process in 2012; the RFP application process has not yet concluded for 2013. Colorado's CSG program is relatively new and its full impact is still uncertain, but its high subscription rates have led the program to be held up as a successful community solar program example.

4.2.4 SACRAMENTO MUNICIPAL UTILITY DISTRICT SOLAR SHARES PROGRAM

Sacramento Municipal Utility District (SMUD) is a small municipal utility located in Northern California. Through its Solar Shares program, SMUD purchases electricity from third-party owned PV systems and sells it to the utility's customers. Thus far, the program consists of a 1 MW PV installation. SMUD has signed a twenty-year PPA with the system's owner, and sells the electricity to program participants at rates lower than the PPA cost. The utility is able to reduce the charge to customers due to subsidies from the California Solar Initiative program, a PV incentive program in California. SMUD retains the renewable energy credits (REC) from the project.

SMUD customers voluntarily elect to participate in the Solar Shares program. A customer's subscription size can range from 0.5 kW to 4 kW. The subscription size and cost are both influenced by the customer's total usage in the previous year, which prevents system oversizing and encourages equitable pricing. SMUD's residential rates are tiered, meaning that larger users stand to save more for their participation in Solar Shares; they pay a higher participation fee as a result. Participation fees are fixed monthly amounts, and participants earn bill credits for their share following the same credit model as traditional NEM: each kWh of generation is credited at the customer's retail rate. Current participation fees are set to slightly exceed the existing average grid energy price, escalated at three percent per year. SMUD has described plans to build a second 1 MW system, and anticipates that the decrease in PV costs over time will result in a lower PPA price than for the first project; the utility intends to adjust the participation cost of existing customers to reflect the lower average cost to the utility when multiple projects are online.

4.3 Feed-In Tariff Policy

FIT programs are designed to encourage utilities to offer long-term contracts to renewable energy producers. The contract price is typically designed to reflect the cost of the generation. Various different programs exist in the US, and represent a wide range of different structures. The energy purchase price can be a fixed, flat value for any participating generators, or the price can vary by technology type. Some FIT programs have contract prices that change over time to adapt to changes in renewable generation costs. Hawaii, California, and the

Long Island Power Authority each have a FIT program, and the three different structures provide a sense of the wide variety of possible program designs.

4.3.1 HAWAII FEED-IN TARIFF

The Hawaii PUC established the state's FIT program in 2009. Hawaii's FIT program is open to PV, concentrated solar power (CSP), on-shore wind, and hydroelectric generation. The program is offered by the State's three investor-owned utilities: HECO, MECO, and HELCO. Interested renewable projects apply directly to a participating utility, where they are placed in the FIT queue. The capacity of the queue differs by island: Oahu's queue capacity is 60 MW, while Hawaii and Maui's queues are 10 MW each, with the Maui queue including any projects on Lanai and Molokai as well.

Projects in the FIT queue which meet all program requirements have the option of signing a PPA with the utility. The PPA rate is a fixed, flat value per kWh of energy produced; the value differs by project size and technology. The FIT values were designed to reflect the cost of each renewable technology at different installation sizes. Hawaii's FIT program creates three size ranges for each technology, referred to as Tiers 1, 2, and 3. The FIT rates for Tiers 1 and 2 were approved by the PUC in 2010, and the Tier 3 rates were approved in 2011. Currently, only Tiers 1 and 2 are available for hydroelectric resources. Table 18 shows the Tier definitions for each island and each technology type.

Table 18 FIT Tier Definitions by Technology and Island

Tier	Technology	Oahu	Hawaii	Maui
Tier 1	All	0-20 kW	0-20 kW	0-20 kW
Tier 2	PV	20-500 kW	20-250 kW	20-250 kW
	CSP	20-500 kW	20-500 kW	20-500 kW
	Wind, Hydro	20-100 kW	20-100 kW	20-100 kW
Tier 3	PV, CSP	Tier 2 maximum to 5 MW, capped at 1% of previous year's system peak load	Tier 2 maximum to 2.72 MW, capped at 1% of previous year's system peak load	Tier 2 maximum to 2.72 MW, capped at 1% of previous year's system peak load
	Wind	Tier 2 maximum to 5 MW, capped at 1% of previous year's system peak load	None	None
	Hydro	None	None	None

Table 19 below shows the FIT payment value for each technology and tier. The different rates reflect the range in cost of different eligible renewable technologies in Hawaii, as well as the overall trend of decreasing costs as project size increases. FIT rates can be modified by the PUC, but once a project is accepted and executes a contract, the rate for that development is fixed.

Table 19 FIT Energy Payment Rates, ¢/kWh

Tier	PV	CSP	Wind	Hydro
1	21.8	26.9	16.1	21.3
2	18.9	25.4	13.8	18.9
3	19.7	31.5	12.0	N/A

Owners of PV and CPS generation in Hawaii are eligible for either a 35% or 24.5% state investment tax credit (ITC). If the project owner elects the lower ITC value, higher FIT energy payment rates are available. The tradeoff represents a choice between an upfront incentive (ITC) and a performance-based incentive (FIT); the relative value of each depends on both the generator's upfront cost and the expected electricity output.

4.3.2 CALIFORNIA FEED-IN TARIFF

California's current FIT program was created in 2012, via heavy revision of the pre-existing program that had been in place since 2008. In the program's current form, California utilities – both IOUs and publicly owned utilities (POU) – are required to sign contracts for 750 MW of renewable generation through the program. The capacity requirement is divided among the utilities based on their load share. The CPUC-designed program outlined below applies only to the IOUs; the POUs are required to create their own program design in order to procure the requisite capacity.

To qualify for the FIT program, renewable developments must be 3 MW or smaller. The CPUC has defined three different product categories: baseload energy (bioenergy and geothermal), peaking as-available (solar), and non-peaking as-available (wind and hydroelectric). Interested generators submit participation requests to a utility, and the utility establishes a project queue for each product category.

In the project bidding process, each utility offers 10 MW of project contracts in each product category. The PPA price in each period is determined by the Renewable Market Adjusting Tariff (ReMAT). The ReMAT starting price is based on the results of a different California renewable generator procurement program, called the Renewable Auction Mechanism, which relies on an auction to ensure competitive PPA prices. The starting value is approximately $90/MWh.[13]

In the first bidding process, projects in the queue have the option of accepting contracts at the starting ReMAT value. If the total capacity of projects that express willingness to accept that PPA price is greater than the 10 MW on offer, a price decrease adjustment is triggered. The process is repeated, with the price dropped $4/MWh until fewer than 10 MW of capacity remains interested. Alternately, if the total capacity of projects that accept the initial price is smaller than 5 MW, a price increase adjustment is triggered. The price adjustment process takes place at two-month intervals. When the set price results in between 5 MW and 10 MW of contracts being accepted, those contracts are issued and the utility offers an additional 10 MW of capacity at the next interval.

Each utility must continue to offer contracts in 10 MW tranches until its capacity requirements are satisfied. This means that the duration of the FIT program is not fixed; the contracting process will close when all utilities have fulfilled their requirements. Since the CPUC began revising the program in 2012, the IOUs have worked with the CPUC to create proposed tariffs for participation in the FIT program. The utilities are expected to open the new tariffs to applicants in October of 2013.

[13] PG&E's draft ReMAT tariff is available at **https://www.pge.com/regulation/RenewablePortfolioStdsOIR-IV/Pleadings/PGE/2013/RenewablePortfolioStdsOIR-IV_Plea_PGE_20130118_260182.pdf**

4.3.3 LONG ISLAND POWER AUTHORITY FEED-IN TARIFF

The Long Island Power Authority (LIPA) in New York offers a FIT for PV systems, instated in 2012. The program offers PV generators a 20-year PPA. In contrast to the programs in Hawaii and California, LIPA pays generators a fixed, flat rate of $0.22/kWh; the rate is subject to adjustment as the program matures, but all contracts will be granted at a fixed, flat rate for the program's duration. The utility purchases all of the participating generators' output — no generation is used to offset onsite consumption.

The FIT program cap is currently set at 50 MW of solar capacity. 5 MW is reserved for systems sized from 50 kW to 150 kW, and 10 MW is reserved for systems between 150 kW to 500 kW. The maximum system size is 20 MW. LIPA is enrolling PV systems on a rolling basis through the program's close in 2014.

4.4 Alternate Policy Design Summary

There is a wide variety of policy design elements for NEM, FIT and direct utility renewable procurement. Some of these policy elements could be evaluated in the Hawaii context using the avoided cost model to understand their relative impact. Policy changes proposed or considered in the future could therefore be compared against a common cost benchmark in addition to their non-quantifiable benefits and costs.

5 Summary and Conclusions

E3 has developed a tool which allows the Hawaii PUC to directly compare the costs and benefits of renewable energy in Hawaii under different procurement mechanisms by comparing each project or portfolio's impact on the existing conventional generation system. The methodology and tools created can compare a broad range of renewable procurement and policies across technology types and sizes within the service territories of HECO, HELCO, MECO, and KIUC.

The first step in this process was to develop a transparent methodology and approach that is then used in step two to evaluate net cost in a consistent manner. In step one, we developed an analysis tool to calculate avoided costs that can be made publicly available and that can serve as a foundation for future analyses and can be adjusted through revised assumptions. E3 identifies those areas where improvements can be made and the inherent limitations in the modeling approach. In step two, E3 calculates the net value across renewable technology types and sizes.

Finally, E3 reviews alternative renewable procurement approaches from other jurisdictions, and use that to inform some concepts to reduce costs of renewable procurement and / or increase their value in a future study. We recognize that any adjustments to the current renewable process would have to be completed in stakeholder consultation and consider a broader view of renewable energy than net cost and value.

Methodology and Approach

In the first step of this project E3 developed a transparent, repeatable, and easily understood methodology to value the output of renewable generation as a displacement of conventional generation. The modeling approach is typically called a 'stacking model' in which generators are ranked by their variable operating cost and assumed to operate in economic order. A few adjustments are made for generators that must operate for reliability or contractual reasons. The strength of a stacking model is in its simplicity, and for systems whose costs are predominantly driven by fuel consumption E3 believes it is a reasonable approximation to the underlying avoided costs. The analysis tool is designed to be publicly available, is in a spreadsheet, and can be used to see all underlying input assumptions and methodology. We believe that this public stakeholder approach can facilitate broader understanding of the key drivers of avoided cost. The other benefit of using a stack model is that it can be easily used to compare a variety of future scenarios with different renewable generation build outs.

The HECO utilities use a different approach and use a production simulation model to estimate marginal costs of their respective systems and report avoided cost to the PUC. Production simulation allows the utilities to more accurately capture startup and shutdown costs as the system load fluctuates and to account for transmission or distribution constraints. This type of model can also account for part load performance of generators when operating below their most efficient output level. Therefore, E3 would expect some differences in the results of our stacking model and the utility avoided cost estimates based on production simulation.

Indeed, benchmarking the results of the public avoided cost tool to the avoided cost assumptions developed by each utility in their respective IRP process highlights some differences. Some of these can be explained by differences in approach and input assumptions. However, some of the differences are larger than we would expect from differences in methodology and input assumptions alone. Additional investigation with the utilities could be undertaken in a future study to reconcile all of the differences. However, given the proprietary nature of the utility tools and lack of access to the assumptions, a full investigation was not possible in this study.

<u>Findings</u>

Given the existing renewable costs compared to the existing conventional power system, there are many opportunities for renewable energy to provide net value to Hawaii. These are primarily driven by the high cost of petroleum fuels used in electric generation. In a future liquefied natural gas (LNG) scenario, renewables still appear to be a lower cost option in many cases. The analysis also shows that biofuel approaches are higher cost than wind, solar, and hydroelectric, and that biofuels are more costly than conventional power generation. The analysis demonstrates that the current NEM policy, which provides a full retail rate credit, results in a higher cost renewable option than FIT or utility-scale procurement mechanisms. The NEM program may ultimately shift costs to other non-participating customers, to the extent that NEM program costs exceed the value provided to the system. There are still reasons to promote customer-sited behind the meter systems and some of these qualitative policy elements may partially provide a counterweight to the higher costs of the policy.

In our framework, we calculate the net value of NEM on the same basis as procurement of other renewable generation types. NEM is a mechanism in Hawaii to enable customer-owned renewable generation. As customer-owned generators they serve primarily the host customer, with compensation for exports. The cost of those exports attributable to the NEM policy that effectively purchases excess generation at retail rates is a small share of the overall costs. Clearly, there are additional considerations for customer-owned renewable generation than net cost, such as freedom of customer choice. In future work, we could consider alternative mechanisms to encourage customer-owned generation at lower cost to other customers.

Future Work

There are two main areas of future work. The first is to refine the value assessment of renewables based on the avoided cost tool developed for this project. Improvements to the methodology could be adopted in Phase 2 with better load data, additional locational-specific RPS generation profiles, additional review of transmission and distribution costs, and better modeling of operations, which could include a stochastic approach to unit dispatch and understanding curtailment and integration risks. The second major area of future work is to consider the implications of this analysis for current and future proposed modifications to renewable procurement. The tools and any improvements made to them subsequently will help the PUC design renewable policy to decrease costs and increase the value of renewables and provide greater ratepayer benefits of renewables to Hawaii. It is expected that the cost analysis will only be one component of procurement and policy design. Reliability, environmental impacts, market transformation, and issues of equity can be of equal or greater importance depending upon the situation. However, a net cost or net value framework is one step towards understanding the renewable options and their impact and we believe the tool created for this analysis will support the PUC's decision making and provide additional transparency for all stakeholders.