Hawaiʻi Natural Energy Institute Research Highlights

Energy Policy & Analysis

DER Aggregation and Control with High Penetration Solar + Storage

OBJECTIVE AND SIGNIFICANCE: Over the past decade, the Oʻahu power grid has integrated substantial amounts of solar PV. With over 550 MW of uncontrollable and unobservable distributed PV, and 190 MW of utility-scale PV installed, there was limited available room on the grid for further solar deployment without energy storage. However, recent developments, including the planned retirement of the AES coal plant, the expected addition of large amounts of battery storage, and new options for grid flexibility, have created new opportunities to integrate distributed rooftop PV. The objective of this study was to quantify how much room may be available on the grid (referred to as system hosting capacity) for additional DER resources. A second objective of this analysis was to provide understanding how much aggregation and direct control is necessary in a high solar grid.

KEY RESULTS: Results of this analysis indicate that the Oʻahu grid can host roughly 600 GWh of additional distributed solar resources without energy storage before curtailment becomes appreciable. On a capacity basis, this represents approximately 400 MWac of distributed PV. Deployment of distributed PV beyond this amount could lead to significant curtailment of utility-scale resources, potentially impacting the viability of existing and future utility scale projects, and increased costs to ratepayers without rooftop PV.

Distributed PV offers a solar pathway that can defer transmission upgrades due to its proximity to load and reduce land use. The pairing of storage with distributed PV would allow for higher amounts to be accommodated. While shifting solar energy out of the middle of the day is necessary, results indicate that direct aggregation and control of distributed resources does not provide significant value to the system. Specifically, more passive and autonomous controls at the customer level provides substantial grid support without the need for costly communications, control systems, and payments for DER grid services.

BACKGROUND: Over the past 10 years, the Oʻahu power grid has experienced rapid growth of renewables. Following modest utility scale wind development, this growth has been mostly in solar PV additions. The first several years, driven by high utility costs, net metering and large state tax credits; were predominately distributed rooftop PV (DPV) systems, resulting in approximately 550 MW of DPV on a 1000 MW mid-day load system. This growth made the Hawaiʻi grids one of the highest distributed solar markets in the world as a percentage of total load. However, in recent years, this growth has slowed considerably due to changes in the rate structure and due to integration challenges at both the system and circuit-levels.

As the growth of DPV was slowing, a limited amount of utility scale PV, without storage, was deployed. At the conclusion of these Waiver PV projects, the Oʻahu grid was largely limited in the amount of additional PV that could be integrated effectively without storage.

To overcome the curtailment and saturation concerns, the Hawaiʻi Public Utilities Commission (PUC) approved, in 2018, fifteen utility-scale hybrid solar and storage (solar + storage) projects. These projects, often referred to as Stage 1 and Stage 2 resources, total approximately 670 MW solar and 3,538 MWh of storage statewide that includes up to 415 MWac solar and 1,781 MWh of hybrid storage on Oʻahu as well as what will become one of the largest standalone battery storage systems anywhere in the world: the 185 MWac and 565 MWh storage system to be located in Kapolei. The projected renewable energy use on Oʻahu, based on the RPS definition, through the Stage 2 projects, is shown in Figure 1.

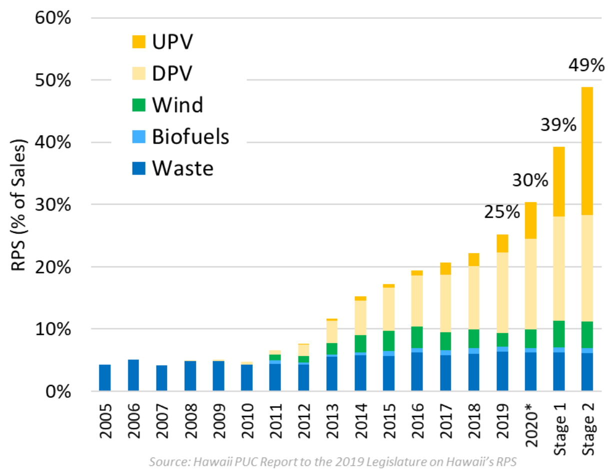

Figure 1. Oʻahu RPS Growth 2005-2020, and Stage 1+2.

These changes are taking place against the backdrop of other significant change to the grid that could enable further solar deployment. Most notably are the retirement of the AES coal plant, the largest fossil fuel-based generator on the Oʻahu grid and the addition of the standalone Kapolei battery that can charge during the day using surplus solar resources. These storage systems, both the PV connected and the stand-alone Kapolei BESS, can also provide grid services that were traditionally provided by the steam oil fleet. As a result, the grid will soon be significantly more flexible than a traditional system.

<u>PROJECT STATUS/RESULTS</u>: In this work, analysis was conducted to evaluate the need and value of aggregation and control for additional distributed solar + storage (DER) deployments. In order to quantify this value, a series of production cost grid simulations were conducted at increasing solar penetrations, with increasing 100 MWac blocks of installed distributed solar capacity. Each PV block was added with two different storage capacity configurations shown in the table below. These configurations are based on HECO's IGP forecast for DER solar + storage resources (#1) and a review of commonly configured behind the meter residential PV and storage systems used in Hawaiʻi (#2).

	PV Capacity (MW)	BESS Capacity (MW)	BESS Energy (MWh)	BESS Duration (hrs.)
#1	100	30	96	3.2
#2	100	77	154	2.0

The simulations were conducted assuming the completion of Stage 1 and 2 projects, the retirement of AES coal plant, and the retirement of HECO's Waiau 3 and 4 generators. The net impact of these resource changes would increase the system hosting capacity.

The production cost models simulate grid operations across all 8,760 hours per year, and incorporate fluctuating loads, solar, and wind resources. The remaining grid resources, including thermal generation and battery energy storage, are economically scheduled to serve load in a least-cost manner subject to utility defined operational limitations and transmission constraints. If the underlying generation mix does not have ample flexibility (either storage to charge using surplus solar or ability of thermal generators to cycle offline) solar may be curtailed and unused.

The benefits of DER aggregation and control were evaluated by simulating two bookend scenarios, illustrated in Figure 2. In actual practice, DER aggregation and control would likely fall somewhere between these two bookend points, but the analysis was conducted using assumptions on either end of the DER control spectrum to amplify potential differences between the two approaches.

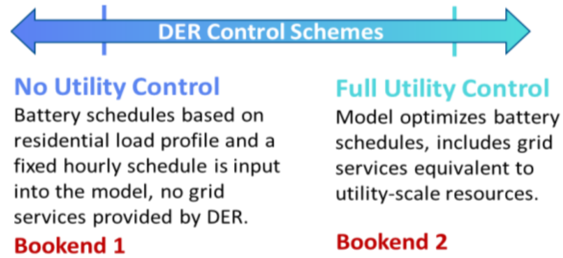

Figure 2. Overview of DER Control Schemes.

The simulations first assumed that DER resources were fully controllable and dispatchable by the system operator. Following that, cases were reevaluated assuming the DER followed a fixed schedule and could not deviate based on system conditions.

The resulting incremental solar curtailment, assuming full control, with increasing solar deployment is provided in Figure 3. Results are shown assuming no storage and for the two storage configurations described above. Incremental curtailment is the increase in curtailment relative to the amount of available PV energy resulting from the last block of additional capacity. As additional PV is added to the grid, not all of it can be accepted, even when combined with the storage configurations that were evaluated.

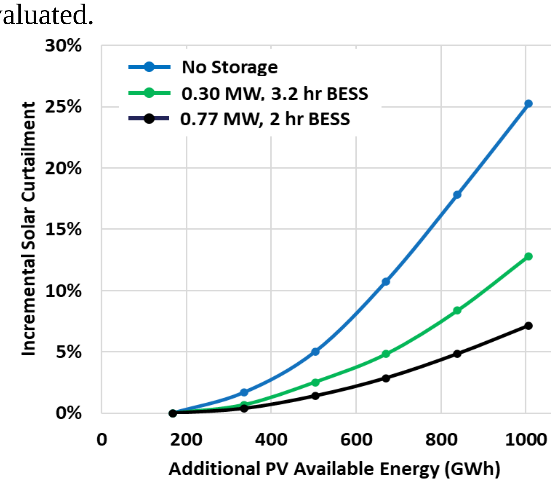

Figure 3. Solar Curtailment at Increase Deployment.

It should be noted that with 4-hour storage with a 1:1 battery to solar configuration, all curtailment is eliminated. In practice, although this study assumes the addition of DER, curtailment would likely be applied to the available utility-scale projects, not the new distributed systems.

At the other end of the spectrum (bookend 2), cases were reevaluated assuming the DER followed a fixed schedule and could not deviate based on system conditions. This schedule was based on a simple heuristic that combined existing utility time of use rates, discharging rules associated with the utility's Smart Export Program, and the average system net load curve. This schedule assumed the following constraints and is illustrated in Figure 4:

- Battery charging occurs between 9 AM and 5 PM, and most charging occurs during the lowest net load hours (during mid-day solar availability);
- Battery charging is limited to the associated rooftop PV production;
- Battery discharging occurs between 5 PM and 10 PM, and is highest during the peak net load hours; and
- Total battery utilization is limited to one cycle per day.

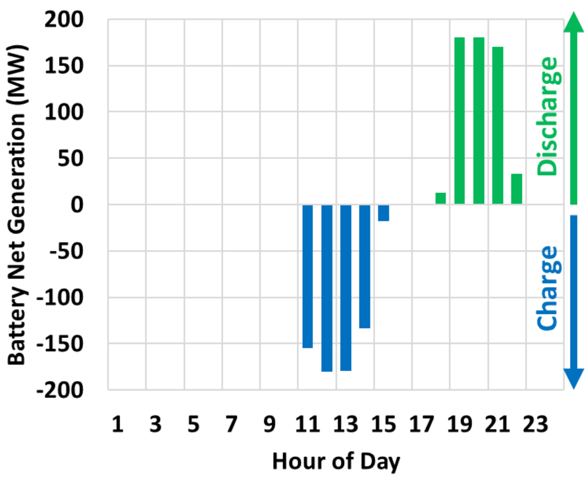

Figure 4. Average daily battery schedule for DERs.

The results, provided in Figure 5, indicate that there are no differences in curtailment between cases with full utility control and when systems follow a fixed profile. This is because there is ample flexibility on the remaining utility-scale hybrid solar + storage resources to adjust to the static DER profile.

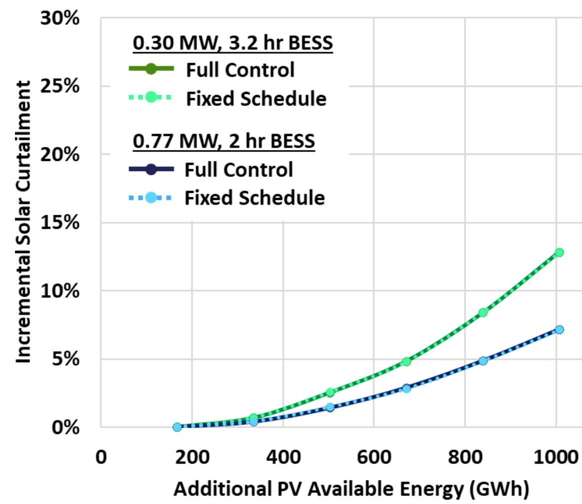

Figure 5: Curtailment of solar resources with and without utility control.

In addition, the results showed no appreciable difference in total system generation cost (less than 0.1%) because there was no change in oil-fired generation and grid services were already saturated by the utility-scale storage systems.

These results support two key conclusions. First, there is limited need for direct communication and control of DER resources to avoid system curtailment of utility-scale solar resources. As long as behind the meter storage shifts energy out of the middle of the day via a simple rules-based approach (i.e. the utility's Smart Export program), curtailment can be effectively mitigated. Second, there is no economic benefit of DER control and coordination once there is sufficient utility-scale storage resources available on the system. The flexibility and grid service benefits saturate once a certain amount of battery storage is installed on the system.

From a policy and regulatory perspective, this indicates that programs to require or compensate DER resources for coordination and control may not be necessary or warranted once sufficient grid scale storage is available to the system operator and that well designed tariffs and autonomous response of DER to grid conditions (i.e. frequency or voltage response) are sufficient for further DER integration.

It should be noted that these findings are specific to the O‘ahu power system and are largely dependent on the amount of utility-scale storage systems present.

By the end of 2023, Oʻahu is expected to have 600 MW (2,400 MWh) of utility-scale storage installed with direct utility control capability. This is relative to a ~1200 MW peak load system. Thus, incremental value for additional flexibility and grid services is limited.

It should also be noted that this analysis did not evaluate benefits of DER coordination and control that might be important for circuit-level hosting capacity constraints, which may be a limiting factor for future DER installations at specific locations. Future work is planned to address this.

Funding Source: Office of Naval Research; Energy Systems Development Special Fund

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Last Updated: November 2021