Hawaiʻi Natural Energy Institute Research Highlights

Energy Policy & Analysis

Oʻahu Grid Stability with High Solar + Storage Integration

OBJECTIVE AND SIGNIFICANCE: The objective of this activity was to evaluate the dynamic stability of the Oʻahu grid after a sudden loss of the largest generating unit. Specifically, the analysis was intended to identify any potential concerns regarding stability of the Oʻahu grid following the upcoming retirement of the AES coal plant and addition of the Stage 1 solar + storage projects.

As the Hawaiʻi grids are transformed to include large amounts of solar and solar + storage, it is important to understand the dynamic behavior of these systems. An unstable response of the grid to such an event could result in significant levels of load-shedding with interruption of electric service to customers and even a potential black-out of the entire Oʻahu grid.

KEY RESULTS: The new screening tool, described in the "**Integrated Stability and Cost Production Analysis**" project summary, developed for the purpose of assessing dynamic grid stability for each hour of an entire year (8,760 hours) of grid operations was used to perform a stability screening analysis for two scenarios; one with AES retired and a second for the retirement of AES with the addition of the Stage 1 solar + storage projects. The results show that dynamic frequency stability of the grid is improved with retirement of AES. While the addition of the Stage 1 projects slightly degrades the response relative to AES without the addition of the Stage 1 projects, the response to the largest contingency event further improves if the solar + storage Stage 1 projects are configured to provide fast frequency response (FFR). These results are discussed in more detail below.

BACKGROUND: Events like a sudden loss of a power plant challenge the stability of the grid because the unexpected loss of generation throws the grid "off-balance." This is because generation and load must always be balanced on any electric grid. When a power plant suddenly goes offline, for instance, due to a weather event or equipment failure, the result is a generation deficit as the total load does not change immediately after the event. The generation deficit must be corrected in a matter of seconds in order to avoid a blackout of the entire grid. This means that resources on the grid must recognize the generation deficit and begin responding in fractions of a second. The two means of correcting the imbalance are increasing power generation from other sources and/or reducing load by disconnecting customers.

Another related grid event is a sudden loss-of-load, where there is suddenly an excess of generation on the grid that causes an imbalance that must quickly be corrected to keep the grid stable and operating. In the loss-of-load event, generation must be quickly reduced to match load. Because it is generally easier for grid resources to quickly reduce generation than to increase generation, this analysis did not consider loss-of-load events, but focused on the more challenging loss-of-generation events.

Historically, the inertia from the generators in conventional power plants provide an inherently stabilizing dynamic response to such grid events by immediately increasing power generation, while the ability of inverter-based resources to provide a stabilizing increase in power generation, depends on the inverter's controls. FFR is one example of a type of inverter control function that supports the dynamic response of the grid by quickly injecting or absorbing additional power in response to changes in grid frequency in order to quickly restore balance to the grid. Furthermore, FFR does not require any external communication (like a command from the grid operator) to work. This means that grid resources, both utility-scale and distributed, can have the autonomy to respond quickly to emergency events to keep the grid operating.

PROJECT STATUS/RESULTS: To determine the impact of the changing generation fleet on grid reliability (stability), the response of the grid to a challenging, yet credible, grid event is studied. This begins with the 8,760 dataset output from a production cost simulation that contains the details of grid operations (total load, generator dispatch, and production of wind, solar, storage) for each hour of a year for a given scenario analyzed. For each hour of the dataset, a dynamic simulation is performed for the loss of the single largest (highest-dispatched) generator on the Oʻahu grid during that hour, using the new screening tool. The loss of the single highest-dispatched generator is selected because it is the worst-case generation contingency considered in transmission planning studies.

The output from each dynamic simulation is a measure of grid stress and customer impact resulting from the loss of generation event. The "stress on the grid" is quantified by the grid frequency nadir (excursion from the nominal 60Hz), where lower frequency nadirs (greater excursions) are indicative of higher levels of grid stress, where the grid is closer to a system-wide blackout. The customer impact is quantified by the amount of load shedding due to the under-frequency load-shedding scheme that was triggered by the event. More grid stress (lower frequency nadirs) result in greater customer impact (more load shedding).

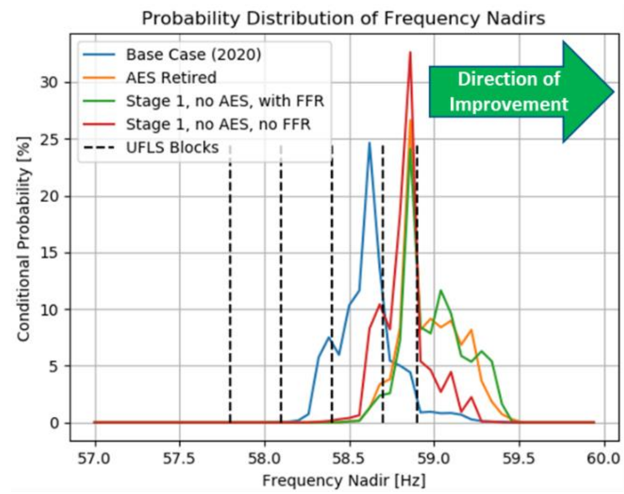
This analysis was performed for the following scenarios:

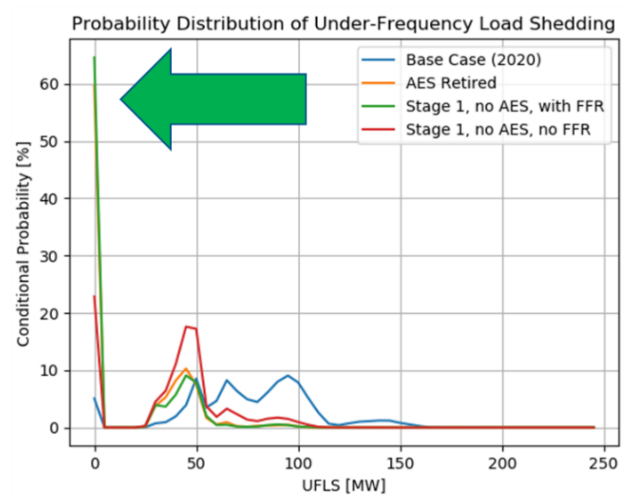
- Today's (2020) Oʻahu grid;
- The retirement of AES (2022);
- The retirement of AES with the addition of Stage 1 solar + storage projects (without FFR); and
- The retirement of AES with the addition of Stage 1 solar + storage projects (with FFR).

The scenarios with the Stage 1 solar + storage projects were configured in two ways. The first assumed that the plant's inverters could not provide FFR by rapidly injecting power to the grid after a contingency event. The second assumed the plants could provide FFR and help restore frequency by injecting power rapidly (milliseconds) after an event. It should be noted that the technology is capable of providing this response, but the actual reserve provision is dependent on contractual terms and inverter control settings.

Because the analytical tools simulate a potential contingency event across every hour of the year, it generates significant data – with over 70,000 values across 4 scenarios – results are summarized as probability distributions. Each curve shows the likelihood of reaching a certain level of stress on the grid or load shedding level, given a trip of the largest generating unit at the time.

As shown in the next figure (top), the retirement of AES and the addition of Stage 1 projects moves the probability distribution to the right – an indicator of improvement, since the greatest excursions move closer to the nominal 60Hz value that utilities always try to maintain and farther away from 57.0Hz where the grid would black out. The companion figure on the bottom shows that the amount of customer disconnection (UFLS) moves to the left – closer to zero, where no customers would be impacted by a worst-case loss-of-generation event.





In comparing the blue and orange traces of the plots, this analysis shows a significant improvement in the dynamic stability of the Oʻahu grid for loss-of-generation events with the retirement of AES. This result is counter-intuitive because it is showing better grid stability for a shift away from conventional resources, which we know have a stabilizing impact on the grid because of their inertia contributions. Because AES is the largest single generator on Oʻahu – with a potential loss of 200 MW of net load – it is often the single largest contingency. Therefore, by retiring AES, the largest generation contingency is dramatically reduced, resulting in a more stable grid.

When AES retires, the largest contingency is reduced to 140 MW loss of Kahe 5 or Kahe 6. This change will help improve dynamic stability because the emergency events will no longer be as severe, regardless of any other potential benefits from the Stage 1 solar + storage projects.

The addition of Stage 1 projects without FFR following the retirement of AES shows a slightly negative impact on the dynamic stability of the grid for loss-of-generation events (when compared against the case without the AES retirement and no Stage 1 projects), as shown by a comparison of the orange and red curves in the plots. While this scenario is still much better than the Base Case, it is slightly worse than the AES retired case because the additional Stage 1 renewables is displacing other conventional resources and not reducing the size of the worst-case contingency.

However, the addition of Stage 1 projects with FFR shows an improvement in grid stability over the scenario with Stage 1 projects without FFR, as shown by comparing the red and green traces of the plots. In this case, the provision of FFR from Stage 1 projects improves the dynamic stability of the grid such that there is no negative impact to stability resulting from the Stage 1 projects, as shown by the similarity of the orange and green curves of the plots.

The shift away from conventional technologies and towards inverter technology (solar + storage plants) constitutes a major change in the way the electric power grid responds to challenging grid events like the sudden loss of a power plant on the grid. As the system continues to evolve towards increasing percentages of inverter-based technologies (solar, storage, wind), the behavior (software-defined controls) of the inverters will become increasingly important to the dynamic stability of the grid. This goes beyond simply enabling useful features like FFR, but also ensuring correct tuning of those features.

This new analysis tool will be applied to look at more future scenarios that consider the addition of more solar + storage (Stage 2) projects as well as the retirement of additional conventional power plants like Waiau 3 and 4 to inform stakeholders of risk to grid stability and assess the benefits of grid-services like FFR. In addition, a closer examination of the inverter behavior is warranted to determine an appropriate balance fast-response and stable response, which is an inherent trade-off in inverter controls.

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

Contact: Richard Rocheleau, rochelea@hawaii.edu

Last Updated: November 2020