## Technical Advisory Panel (TAP) Meeting

**Thursday, December 17, 2020**
**8:00am – 11:00am**
**WebEx**

## Attendees

**WebEx**

Colton Ching, HE
Marc Asano, HE
Christopher Lau, HE
Earlynne Maile, HE
Ken Aramaki, HE
Paul De Martini, Newport Consulting
Andy Hoke, NREL
Kevin Schneider, PNNL
Robert Sheridan, National Grid
Jeffrey Burke, APS
Aidan Tuohy, EPRI
Richard Rocheleau, HNEI
Terry Surles, HNEI
Derek Stenclik, Telos Energy
Matthew Richwine, Telos Energy
Jeremy Laundergan, EnerNex
Robert Uyeunten, HE
Daniel Lum, HE
Dean Oshiro, HE
Isaac Lum, HE
Kenton Suzuki, HE

## Objective

- Review HECO's near-term plan to transition the current system to one where the majority of its generation comes from renewable solar and solar + storage resources.

## Agenda/ Discussion Topics

- Introduction – Why near-term matters
- Concise description of expected grid changes between now and 2025
- What are HECO's assumptions for utilization of solar + storage assets?
- Detailed review of tools and methodologies used to evaluate near-term changes.
- How should an aging generation fleet be addressed with consideration for impacts of weather and climate?

## Discussion

I. **Grid Service Capability by Technology Table (Slide 7)**

a. Stakeholder: The short circuit current (SCC) coded in yellow seems appropriate. Generally, I agree with the information in the chart. SCC could be provided by a grid-following inverter but may not respond as quickly.
   i. Stakeholder: Grid-forming versus grid-following is the larger question at hand. The issue is not necessarily PV or wind technology specific.

b. HECO: Not all the inverters respond in the same way in the PSCAD model. We test for voltage capability but need to supplement the plant design.
   i. Stakeholder: Software-limited models may not show the full capability of inverters.
   ii. Stakeholder: Consider a reactive capability curve versus a square one.
   iii. Stakeholder: The modeling should consider a replacement reserve/ non-spinning reserve. This would be a slower response than frequency response or regulating reserve. The state of charge for BESS resources would need to be managed.
      1. HECO: We will soon have many BESS resources to manage, but it will be difficult to value a replacement reserve.

c. Stakeholder: In a future meeting, it would be helpful to spend some time to talk through how the Stage 1 and 2 projects will be operated. There may be a surplus of services after those projects are in service, potentially leading to a lower value for some services.

d. Stakeholder: The yellow coding for distributed resources seems reasonable as they may not be able to run on AGC (automatic generation control) or require curtailment.

e. Stakeholder: The grid services by technology table seems more comprehensive than what we've previously looked at.

f. Stakeholder: For standalone PV, wind, and storage resources, I'm unsure if those should be marked as green for transmission and distribution capacity. These would be capable of providing a portion of the deferral (yellow coding) and could fully defer the need if they were paired resources (green coding).
   i. HECO: We could add additional columns to the grid services by technology table to distinguish paired systems from standalone resources.
   ii. Stakeholder: It could be informative to sort the chart by speed of response. This may illustrate a gap in the breadth of services where only partially capable resources can contribute.

g. Stakeholder: Should a new service called, Grid Forming, be considered? It would be especially relevant on Maui or Hawaii Island at or near 100% IBR (inverter-based resource). There is emerging consensus in the industry that you need something to provide very short-term voltage stability (i.e., form the voltage waveform). Conventional thermal, pumped storage hydro, synchronous condensers, and grid-forming IBRs would be coded green. All others would be coded red.

## II. Load Build and Load Reduce Grid Services

a. Stakeholder: How do you think about load build and load reduce versus a permanent change in load?
    i. HECO: In the market, we've seen more PV+BESS type projects providing the load build and load reduce services. Are you thinking more of a traditional energy efficiency approach as a permanent reduction?
        1. Stakeholder: In Arizona, an example would be pool pumps.
    ii. HECO: Our first approach would be through time-varying rates. This could also include EV charging loads.
b. Stakeholder: How would load build / load reduce be modeled?
    i. HECO: It could be modeled as a subset of energy, looking at the 8760 hourly results from PLEXOS for arbitrage opportunities.
c. HECO: Any thoughts on the limited dispatch of load build / load reduce?
    i. Stakeholder: Price can be used as a signal. However, in Hawaii, I don't know what supplants that. What would these reserves respond to?
    ii. Stakeholder: The number of times the resource is called could be adjusted over time.
    iii. HECO: Load build / load reduce could respond through widespread TOU rates. We don't want to pay for free riders.

## III. Primary Frequency Response (PFR), Fast Frequency Response (FFR) and Inertia

a. HECO: PFR is already required contractually.
b. Stakeholder: We can share notes on this. We've developed a means of modeling the tradeoff between inertia, PFR, and FFR in PLEXOS.
c. Stakeholder: A quicker droop response seems preferable, so good that's being considered, but this will blur the line with PFR. Essentially, it will be a fast PFR.
d. HECO: It will come down to how we manage the state of charge on the batteries.
e. Stakeholder: Near-term transition will be important. I'm not seeing how this process here will help to identify near term challenges with Stage 1 and 2 projects.
    i. HECO: Stage 1 and 2 RFP portfolio studies will identify resources needed to maintain system security. System impact studies will identify additional requirements for those facilities and needs on the grid side. These will be inputs into the RESOLVE and PLEXOS modeling.
    ii. HECO: Subject to check, we can share this material with the TAP.
f. HECO: We can socialize the studies referenced on slide 13 with the TAP, including the results of the island wide PSCAD models for Stage 2 RFP resources.
    i. Stakeholder: NREL MIDAS study is a PSCAD simulation of the near future scenario on Maui. It is also a tool to integrate scheduling and dynamics. Generic models are used that have been modified to mimic the black box developer models.
    ii. Stakeholder: A follow on project to MIDAS called SAPPHIRE will also look at FFR and inertia to incorporate into the dispatch tool.

g. Stakeholder: Is the TAP only going to be looking at the outputs of these studies, or will the TAP be able to provide feedback on the inputs and whether the tools are appropriate?
    i. HECO: The TAP can address whether we are on the right track and whether these studies are appropriate for input into IGP.
    ii. Stakeholder: I encourage earlier engagement of the TAP to avoid needing to circle back to revise.
h. HECO: We can share the scope of the studies and preliminary results at our next TAP meeting in Q1. We will ask the study consultant to put together materials about the system impact studies to share, and to provide the spreadsheet for the minimum inertia requirements calculation.
i. HECO: Has the TAP looked at the minimum inertia requirements for over- and under-frequency events, especially where over-frequency events lead to under-frequency events?
    i. Stakeholder: The loss of load tripping DGPV systems was studied on Oahu. I think a minimum inertia requirement seems reasonable in the near term, but the question may be asked whether the requirement will continue further out.
j. HECO: How much can grid-forming inverters help to reduce or minimize the need for synchronous condensers?

## IV. <u>Energy Reserve Margin (ERM) and Hourly Dependable Capacity (HDC)</u>

a. Stakeholder: How were the ERM target percentages set? What is accounted for in the percentage? It seems like there may be some double counting there. How is the future maintenance and forced outages captured?
    i. HECO: The targets are based on testing that was done to ensure the percentage could account for certain emergency conditions. Forced outages are accounted for under the right-hand side of the equation under the ERM percentage.
b. Stakeholder: Traditional reserve margin accounts for generator outages, weather, and load uncertainty. I like that the ERM accounts for an hourly requirement. Would it be possible to move all of the uncertainty to the left-hand side of the equation, resulting in a lower ERM target percentage?
c. Stakeholder: Were generator outages associated with transmission outages considered? How is transmission maintenance accounted for?
    i. HECO: We have generation today on the sub-transmission and distribution. We don’t have the same redundancy as if it were on the transmission network.
d. Stakeholder: Is the standard deviation the same across the year?
    i. HECO: The standard deviation varies by hour.
e. Stakeholder: Does this consider multiple years of data?
    i. HECO: Yes.
f. Stakeholder: Is the data based on recorded plant data or simulated?

g. HECO: Are there ideas on how to incorporate additional data to better inform the HDC statistics?
    i. Stakeholder: How is the PV minimum HDC 0%? The solar HDC percentage will be important.
    ii. Stakeholder: On a cloudy day, you might still get around 10% from solar.
    iii. Stakeholder: It will be important to account for BESS SOC (battery state of charge) in ERM. There may be a saturation risk and unintended ERM shortfalls.

h. Stakeholder: It's surprising that there is a high ERM in 2022, even though AES is gone, and this is before the Stage 2 RFP projects are in service. In 2024-2025, the ERM is lower with Stage 2 RFP projects in service. Does the PV HDC consider generation in the shoulders? It seems conservative during the day.

i. HECO: It might be helpful to share the ERM monthly to show when violations occur in the year.

j. Stakeholder: Does the HDC change monthly, seasonally? How are the HDCs influencing ERM in 2023 and 2024 when Stage 1 and 2 RFP projects are in service?

## Next Steps

- Revise Grid Services by Technology Table to separate paired resources from standalone.
- Prepare materials from high IBR penetration studies to share with the TAP.
- Next meeting – TBD, 2021
    - Feedback and questions may be sent to Chris Lau at igp@hawaiianelectric.com.