



June 1, 2021

The Honorable Chair and Members
of the Hawai'i Public Utilities Commission
Kekuanao'a Building, First Floor
465 South King Street
Honolulu, Hawai'i 96813

Dear Commissioners:

Subject: Docket No. 2018-0165 – Integrated Grid Planning
Instituting a Proceeding to Investigate Integrated Grid Planning
Grid Services and Planning Criteria Feedback

In accordance with Ordering Paragraph No. 2.B of Order No. 37730,¹ issued April 14, 2021 in the subject proceeding, Hawaiian Electric² respectfully submits written feedback received from the Technical Advisory Panel (“TAP”) regarding the TAP’s review of certain modeling methods proposed for IGP.³

Sincerely,

/s/ Marc Asano

Marc Asano
Director, Integrated Grid Planning

Enclosure

c: Service List

¹ Ordering Paragraph No. 2.B of Order No. 37730 provided: “[R]egarding Grid Services and Planning Criteria, Hawaiian Electric shall seek feedback from the TAP, in writing, and file it with the Commission no later than May 21, 2021.” Subsequently, on May 17, 2021, Hawaiian Electric and the TAP, jointly informed the Commission that the subject deliverable was expected to be filed no later than June 1, 2021.

² Hawaiian Electric Company, Inc., Maui Electric Company, Limited, and Hawai'i Electric Light Company, Inc. are each doing business as “Hawaiian Electric” and have jointly registered “Hawaiian Electric” as a trade name with the State of Hawai'i Department of Commerce and Consumer Affairs, as evidenced by Certificate of Registration No. 4235929, dated December 20, 2019.

³ Order No. 37043 *Setting Forth Public Utilities Commission Emergency Filing and Service Procedures related to COVID-19* (non-docketed), issued on March 13, 2020, the Company is serving this filing to the Parties on the Service List via email.

Subject: Docket No. 2018-0165

Instituting a Proceeding to Investigate Integrated Grid Planning (“IGP”)
Hawaiian Electric Stakeholder Meeting to Address Order No. 37730 and
Ulupono’s Comments on Modeling Approaches

1. Background/Timeline

On May 21, 2021 in preparation for the May 25 meeting of the Technical Advisory Panel (TAP) and Hawaiian Electric Company (HECO, Company) staff, read ahead materials were distributed to TAP members for review. These materials including a Power Point presentation(v2) and a memo to HNEI (v2) and are included here as Appendix 1 and Appendix 2. This memo has been developed utilizing (and where appropriate duplicating) the materials provided in the memo to HNEI with additional comments from TAP reflecting input solicited during a May 25, 2021 meeting between TAP and the Company. The approximate timeline for development of this response is as follows:

- April 14, 2021 – Release of Order No. 37730 *Directing Hawaiian Electric to File Revised Forecasts and Assumptions.*
- April 27, 2021 - The Company met with the Parties and Stakeholder Council, with some members of the TAP in attendance to discuss its current modeling approaches and how it differs from Ulupono’s, the tradeoffs between approaches, and which is preferred by the Parties, TAP, and stakeholders. Members of the HNEI team were in attendance. Concluding this meeting, the HNEI team, in support of TAP, asked HECO for additional clarification on the MODELS and Process flow
- May 7, 2021 – HNEI received slide deck from HECO with initial process flow showing iteration of the models.
- May 18, 2021 – HNEI, as a result of concerns the process flow provided by the Company on May 7, believed that the information provided was not sufficiently explicit to support the TAP review; HNEI, in support of TAP, submitted an alternative grid-analysis model flow chart and supporting detail to the Company.
- May 19, 2021 – The Company provided a modified Power Point to HNEI that, with minor modifications, adopted the suggested process flow; and including additional slides intended to facilitate that questions being directed to TAP. HNEI returned the May 19 slide deck to HECO with very minor suggestions to the process flow/model charts and suggestions for clarification of the questions to be posed to TAP.
- May 21, 2021 – The HNEI suggestions were adopted and the final slide deck and “memo to HNEI (v2)” were distributed to the TAP members ahead of the planned May 25, 2021 meeting.

2. May 25, 2021 TAP meeting: Overview

As stated above, the material included in Appendices 1 and 2 were distributed to TAP members ahead of the May 25th meeting. The meeting was held on-line between 10AM and 1PM HST. Including the Chair, five TAP members joined the meeting although some had to leave the meeting intermittently due to other commitments.

TAP participants included:

- Rick Rocheleau
- Andy Hoke, NREL
- Kevin Schneider, PNNL
- Jeff Burke, APS
- Aidan Tuohy, EPRI

Others in attendance:

- HNEI Support: Terry Surles, Matt Richwine
- HECO: Marc Asano, Chris Lau, Colton Ching, Earlynne Maile, Kenton Suzuki, Dean Oshiro, Robert Uyeunten, Therese Klaty, Dan Lum, Anne Fuller, Ken Aramaki, Li Yu
- HECO Support: Paul DeMartini, Sean Morash, Jeremy Laundergan

A substantial amount of time was allocated to discussion of the process flow/modeling tools for IGP analysis (Slides 3-9, Appendix 1). This was followed by discussion of a number of general modeling questions (Slide 12 and 13, Appendix 1). The meeting concluded with additional discussion of the merits and drawbacks of Ulupono's suggested approaches and HECO's response to these suggested modeling tactics (Slides 15-18, Appendix 1). Specifically, the TAP responded to the first three of the following Ulupono suggestions:

- Allow RESOLVE to optimize the amount of storage needed for both standalone and paired with solar PV sites, rather than require exactly four hours of storage with utility scale solar,
- Use alternatives to the proposed Energy Reserve Margin ("ERM") calculation or adopt a reserve margin in later years that is tied to a reliability analysis,
- Assume batteries and curtailed renewables will be able to provide virtual inertia when needed,
- Assume 30-year contracts as the life of the Solar PV system or assume 20-25 with 5-10 year extensions at lower costs.

The discussion of the TAP response is covered in Sections 3 through 7 below. Section 3 summarizes the TAP discussion on the suggested model process flow, including summarizes of TAP discussions of the general questions posed in Slides 12 and 13 in Appendix 1.

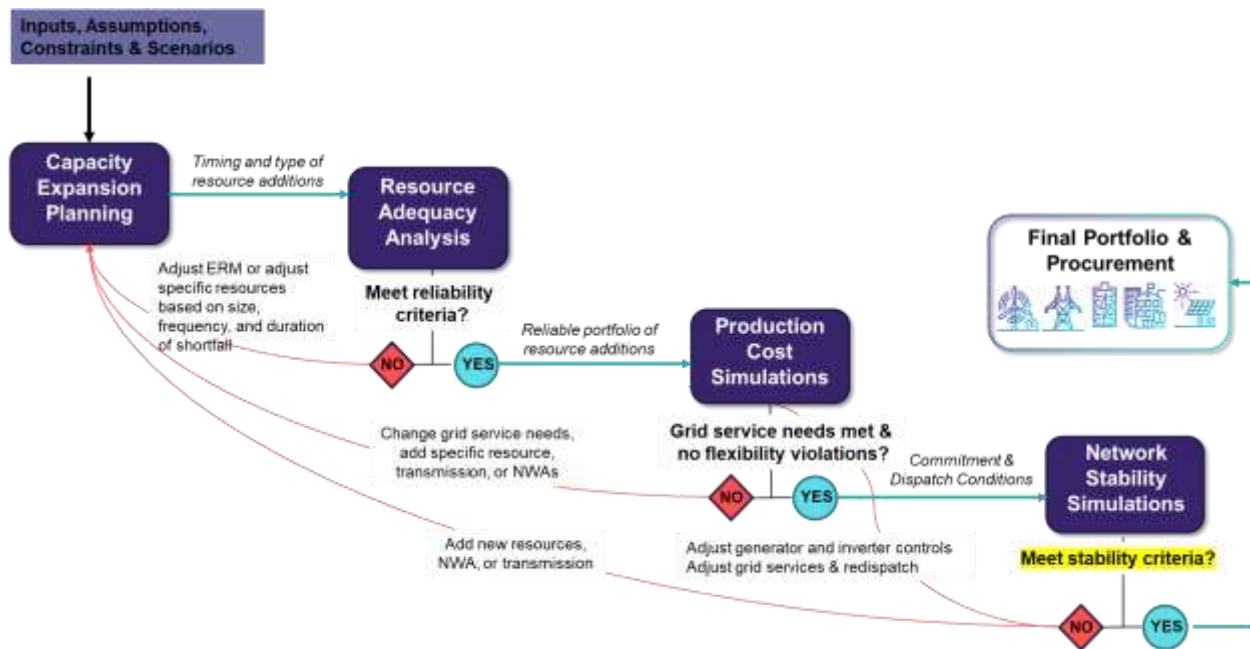
Sections 4 through 6 summarize TAP review of the specific issues raised by Ulupono. Each of these Sections include a short summary of the Ulupono suggestions followed by:

- a. a summary of the proposed Hawaiian Electric approach (as provided in the Memo to HNEI, (v2), provided to the TAP);
- b. additional stakeholder comments and tradeoffs (Company summary of stakeholder comments provided in the Memo to HNEI, (v2), provided to the TAP);
- c. a short statement of areas of agreement and recommendations (as provided in the Memo to HNEI, v2, provided to the TAP); and ,
- d. a summary of the TAP review of the above materials presented during the May 25, 2021 meeting. Sections a, b, and c of Sections 4 – 6 are taken verbatim from the HECO memo to HNEI, (v2), Appendix 2.

3. Model Selection and Process Flow Chart

At various time during the IGP process, the Technical Advisory Panel and separately, the HNEI team, have raised concerns regarding the lack of fidelity in HECO's description of the selection of models for analysis and a perceived overreliance on RESOLVE for portfolio planning. While Company presentations did show an iterative process between RESOLVE and PLEXOS, the details of the use of these tools and the use of other modeling tools for issues such as resource adequacy was unclear. HECO's materials did not explicitly state the objective for the use of each model including; (a) a description of the key inputs and outputs used for each model, (b) how information was passed between the models, or (c) how feedback loops would be triggered and evaluated. The lack of a clearly defined modeling process and flow - recognizing the interdependencies of each modeling task - raised the concern that the IGP portfolios could result in unreliable or overly conservative portfolio plans. It should be noted that this was a significant issue with the prior PSIP effort, which required a manual adjustment to include combined cycle generators for reliability *after* the model optimizations were complete.

The HNEI team, upon reviewing the Ulupono suggestions for modeling, became concerned that lack of common understanding of the input assumptions and outputs of the various modeling efforts was adding confusion to the efforts to reach common ground. The HNEI team reviewed the models and model flow submitted by the Company on May 7th and deemed it insufficient to facilitate review of the process by the TAP. Subsequently, HNEI developed a new model flow chart and then collaborated with HECO to clarify the use of the various models and developed a revised Process Flow. The new Process Flow identifies the objective of each tool, the interdependencies between tools, and the specific steps addressed in feedback loops between models. The top-level process flow slide is shown below. Additional detail for each model was developed and included in the presentation to the TAP on May 25, 2021 (Appendix 1).



The TAP agreed with the process flow summarized in the above figure. TAP also provided some additional detail in response to HECO questions and/or TAP commentary. These are summarized in the following bullets:

- The TAP initiated a discussion on the use of RESOLVE vs PLEXOS as the screening tool. All parties agreed that both PLEXOS and RESOLVE can be used for capacity expansion, but HECO stated that the ability for RESOLVE to run faster than PLEXOS is a significant advantage given the number of runs that are likely to be required. There was no objection to this position by the Company. However, consistent with the diagram above, it was again noted that RESOLVE provides limited fidelity and should be used only as a technology screening tool. Subsequent determination of reliability, analysis of multi-year weather data, retirements, and avoided costs, etc. requires the use of other modeling tools. It was emphasized more than once that the other models should be an integral part of the overall process, NOT just a check on the output from RESOLVE.
- During the May 25 meeting, HECO sought TAP guidance from TAP that essentially asked “What is the tolerance used to know when to go back and iterate” and “Is it necessary to always rerun the full process or can estimations serve. TAP did not provide a hard and fast answer to these questions, noting the need for ‘engineering judgement’ and ‘experience’ to determine what needs to be done. While TAP recognizes that engineering judgement can reduce the requirement for the full process to be used for all iterations, TAP recommends that solutions be vetted by the full process before proceeding to the procurement phase.

- The TAP also initiated a discussion that suggested the possibility of putting LOLP in as a hard constraint during the capacity expansion modeling effort. It was noted that some utilities define their resource adequacy needs first, using clearly specified LOLP metrics for every day of the year to develop a reserve margin. Hawaiian Electric uses a 1 day in 4.5 year LOLP planning metric for Oahu. This reserve margin then goes to the capacity expansion model, which solves to meet the required reserve margin. After some discussion, it was generally agreed that this approach may be more appropriate for systems that are less distributed, and less reliant on renewables with short-term battery energy storage than the Hawaii systems, and which experience relatively minor year to year changes because of different resources or outages showing up on different resources in different years. There is additional discussion of the use of ERM with RESOLVE in Section 6, below.
- The question was raised as to whether the proposed Process Flow was adequately accounting for the growth and value of DER. DER growth is not an explicit output of any of the models. TAP conveyed that while not an output, carefully selected scenarios, such as different assumptions about DER, would allow evaluation of the cost/benefit of these technologies. It was again noted that to properly assess and incorporate DER would require use of the Process Flow, not just RESOLVE to ensure that viable, reliable scenarios were being compared. This discussion was broadened some with TAP recommending that before running different scenarios, HECO clearly define the objective of those comparative scenarios before running the models and fully define the process to be used for those comparisons.
- The question was raised in regard to “What cases would be evaluated in network stability? Is it day min/max and evening min/max or others?” The related question was that if inertia and FFR are modeled in both RESOLVE/PLEXOS and a stability tool such as PSSE/PSCAD, which would take priority? HECO stated that they would give priority to PSSE/PSCAD, but if they found the RESOLVE/PLEXOS is adequate, then there may be no changes. The determination of what cases would be evaluated for network stability was less clear. TAP stated that it was important to put cases in context such as with duration curves and believes this question requires more effort.
- Several times was emphasized by TAP that reliability is critical and “when we think about reliability, we do not want to be short.” This may require prioritizing the near-term over the long-term - because in the near-term we’re not able to change things as much. There is a need to think about this issue as “minimums,” that are required and then looking at the costs of the alternatives for meeting the minimums. Utilities don’t want to get caught short on reliability. While the TAP agreed that there can be advantages to going long and growing into it, it was also pointed out that the time-

frame for utilization of these resources must be carefully considered. This is another area, requiring ‘engineering judgement’, not just models.

- There was some discussion of the ability of RESOLVE to handle things like negative pricing. HECO stated that RESOLVE uses “shadow” prices that have a floor at zero. It was acknowledged that negative prices, might result from an oversupply due to things that can’t be controlled. It was noted by one member of TAP that this might obscure an important incentive. The question was left open without clear guidance from TAP.

4. Ulupono #1: Allow RESOLVE to Optimize Paired with Solar Resources

“For energy, Ulupono says that RESOLVE should be allowed to optimize the amount of storage needed for both stand-alone and paired with Solar PV sites. Allowing RESOLVE to “optimize the amount of storage needed for both stand-alone and paired with Solar PV sites, rather than requiring exactly four hours of storage with utility-scale solar”

a. Hawaiian Electric’s Approach

In the Company’s model, RESOLVE is allowed to build paired PV and battery systems that are either 4-hour or 6-hour duration as well as standalone storage. Standalone storage is allowed to be optimized for both the capacity (megawatt) and energy (megawatt-hour). Specific durations for paired PV and battery systems are assumed to capture the State Investment Tax Credit (“ITC”) rules more precisely. To capture the impact of the Federal and State ITC on paired PV and battery systems, the ITCs are assumed to directly reduce the dollar per kW capital costs input into RESOLVE. For a paired PV and battery system, a fixed duration for storage is assumed to capture the cap on the State ITC on a per system basis. One system is defined as 1,000 kW. The ITC is first applied to the PV and any residual tax credit under the cap is then applied to the battery.

b. Stakeholder Comments and Tradeoffs

In Ulupono’s approach, without bounding the storage duration for a paired PV and battery system and allowing it to freely optimize, the State ITC may be overstated in the resource’s cost. In Hawaiian Electric’s approach, considering only 4-hour and 6-hour durations may be too rigid and may cause a small amount of excess battery investment. Other stakeholders recognized that the RESOLVE modeling efforts are intended to identify the grid needs on a technology-neutral basis. The selected resources in RESOLVE serve as a proxy for those needs. Therefore, the current treatment of the State ITC is reasonable. If the ITC is overstated, that might suggest there are more cost-effective resources. Ultimately the RFP and the market will verify the numbers (i.e., price and appropriate duration of storage).

c. Areas of Agreement and Recommendations

Hawaiian Electric and Ulupono agree that allowing additional paired PV and battery system options in RESOLVE is reasonable. The recommendation is to include paired PV with 2-hour, 4-hour, 6-hour, and 8-hour battery systems.

d. TAP Comments

At the beginning of the discussion, HECO stated that for standalone storage, RESOLVE can optimize capacity and energy separately. For paired PV+BESS projects, to allow different hours of storage (2,4,6,8) in RESOLVE.

TAP agreed that additional analysis in RESOLVE to estimate optimal battery sizes should be conducted but identified some issues to be considered. The TAP stated that the estimation of alternative storage sizing using RESOLVE should be considered an “estimation,” recognizing that more detailed reliability, cost and stability analysis should be conducted to guide decision making. TAP also noted that it was important to consider what time frame was being solved for, with consideration of the nearer term being more important. TAP noted that being “long” - meaning that HECO has overbuilt – might make sense for a limited duration (a year or two) to ensure reliability but might not be appropriate if the intent is to solve a 2040 problem with today’s storage. Again, there needs to be engineering and operational judgment looking at all aspects of the problem.

Some members of TAP were confused by the stakeholder comment “If the ITC is overstated, that might suggest there are more cost-effective resources. Ultimately the RFP and the market will verify the numbers (i.e., price and appropriate duration of storage)”. TAP does agree that it is important to evaluate a variety of options and that the RFP will determine the final price. However, the “appropriate duration of storage” needs to be specified based on the grid needs, both energy and services.

TAP members responded that while it is okay to start with RESOLVE, any conclusions from this model need to be evaluated. Fundamentally, RESOLVE is being expected to do analyses for which it is not designed to do. Explicitly, RESOLVE is not designed for modeling resource adequacy needs or integration of inverter-based resources which is necessary for storage systems.

5. Ulupono #2: Use Alternatives to ERM or Adopt a Reserve Margin that is Tied to a Reliability Analysis

“While Ulupono looks to Hawaiian Electric for more detailed responses to our initial questions in Exhibit I\ Ulupono recommends that Hawaiian Electric adopt a reserve margin in later years that is tied to a reliability analysis. Ulupono does not believe it is appropriate to assume that a 30% reserve margin will be needed for the system’s load based on the assumption of “poor

weather days for renewables.” Dr. Fripp notes that poor weather days are already addressed by the requirement that RESOLVE and PLEXOS select resources to keep the power system consistently balanced, including a regulating reserve margin.

Including the worst-weather day in the RESOLVE optimization will ensure that the system has a least-cost design that provides enough power at all times. Consequently, it is not appropriate to apply an ERM as an additional, arbitrary mechanism to achieve generation adequacy. We recommend that Hawaiian Electric eliminate the ERM calculation and margin. Alternatively, if there are reliability factors that are not addressed adequately by the hourly energy and reserve balancing in RESOLVE and PLEXOS, Hawaiian Electric should demonstrate that using analysis and data, and should use a more targeted calculation to achieve reliability.”

a. Hawaiian Electric’s Approach

In the IGP process, the Company introduced a new planning criterion called Energy Reserve Margin (“ERM”) to satisfy load and plan for a reasonable reserve that can be called upon in emergencies. The ERM planning criterion considers the total firm system capability that is reduced by planned maintenance and outages and increased by hourly dependable capacity (“HDC”) of variable renewable resources, shifted load from energy storage resources, and interruptible load, the sum of which must be greater than the load that is increased by the ERM percentage on an hourly basis. The margin provided by ERM is intended to provide reserves to mitigate:

- Loss of largest unit
- Multiple forced outages
- Unplanned maintenance
- Fluctuations in generation from variable resources
- Prolonged poor weather patterns or atypical weather
- Battery failures
- Forecast error

ERM targets are 30% for O’ahu, Hawai’i Island, and Maui and 60% for Moloka’i and Lāna’i. The targets were selected by analyzing historical data. High risk incidents were studied to examine reserves, unit availability, loads, loss of load hours, and frequency of at-risk conditions.

b. Stakeholder Comments and Tradeoffs

In Ulupono’s approach, planning only to include the worst weather day will assume that the worst weather day occurs every year that is simulated and assumes that the worst weather day will also account for unexpected, forced outages or forecast error where load is unexpectedly higher. Ulupono recommends a 7-step process to assess the “optimal” ERM for the system that starts at 0% ERM and increases the ERM percentage until the desired reliability level is reached.

1. Include worst days in time sampling in RESOLVE

2. Count renewables at their full hourly availability in RESOLVE
3. Set initial ERM to 0%
4. Run RESOLVE with current ERM
5. Test the resulting plan with many years of data (e.g., in PLEXOS) – include all possible weather, realistic forecast errors for load and renewables, forced outages for thermal plants and batteries, etc.
6. If shortfalls are found: increase ERM by a few percent and return to step 4
7. Repeat until shortfalls are resolved

Stakeholders felt that in Hawaiian Electric’s approach, ERM may be too conservative and lead to an overbuild of capacity. ERM may also favor thermal units in its derivation because loss of largest unit, multiple forced outages, and unplanned maintenance are implicit thermal unit considerations. Uluono noted that the HDC used to calculate the variable renewable contributions excessively discounts the generation provided by these resources and is not necessary.

At this particular meeting, a TAP member was present and commented that they support transition away from a planning reserve looking at peak to one that assesses hourly load. For reference, Southern California Edison and Community Choice Aggregators have proposed a similar planning criteria to energy reserve margin that examines all hours. Planning reserve margins focused on system peak was based on resource adequacy and loss of load. To meet the reliability criteria, the system needed X% of margin. It would be interesting to link and correlate traditional metrics such as loss of load expectation (“LOLE”) with ERM. A large driver of 30% was driven by multiple unit outages. When considering retirement of fossil units, the risk of concurrent outages diminishes. Another stakeholder liked the idea of linking ERM to LOLE.

c. Areas of Agreement and Recommendations

Hawaiian Electric and Uluono agree that further study of the ERM criteria is warranted to determine the appropriate level of reliability that should be solved for in the optimization models. Hawaiian Electric proposes to test lower percentages (0%, 10%, 20%) for the ERM target in RESOLVE and evaluate the reliability impact on the resulting resource plans in PLEXOS. A sensitivity analysis will also be performed to remove the HDCs and instead consider the full production profiles. The Company is also open to having HNEI test the reliability of the various resource plans generated from RESOLVE at different ERM levels using their stochastic resource adequacy methodology.

d. TAP Comments

TAP agrees that HECO is correct to identify a need to change the conventional planning reserve margin used in previous planning efforts with a new methodology that evaluates all hours of the year and chronological operations of the grid. A reliability criterion that only evaluates peak

load is inadequate for a system with high percentage penetrations of variable renewables and energy limited resources (storage and load flexibility). ERM is a step in the right direction. If developed and implemented correctly, it may help reduce or eliminate reliability shortfalls that were present in past portfolios without grid modifications.

The TAP also recognizes that capacity planning models requires some ‘relatively simple’ methodologies to address the many issues impacting reliability including the various reserve margins, renewable variability, and unit outages in order to efficiently analyze the many options available for capacity expansion. TAP agrees that ERM is a reasonable approach to take. However, there should be clarity on how values are reached and how different grid resources are considered in analyses.

That said, caution should be applied to using only RESOLVE to arrive at answers. However accurately the ERM or other methodology selected is, RESOLVE alone does not provide the fidelity needed to determine and validate a cost effective, reliable expansion plan. A number of comments/suggestions in regard to the use of ERM in RESOLVE to determine reliable least cost design are summarized below.

- ERM is a novel approach that does not have precedence in Hawaii or other jurisdictions. As a result, additional information, analysis, and testing is required to ensure that ERM is used effectively in the HECO planning process. In regard to this, HECO has not, to date, provided sufficient information on the ERM to assess the ERM values currently proposed (30% ERM target on Oahu, Maui, and Hawaii or the 60% targets on Molokai and Lanai). In particular, TAP has requested additional information on the calculation of hourly dependable capacity. Recognizing the value of a metric like ERM for use in capacity expansion models and the need to continue progressing down the IGP pathway, the TAP recommends that a) a more complete description of the determination of the current ERM values be developed and made available for review as soon as possible and b) analysis be conducted to determine the relationship between ERM and detailed resource adequacy analysis. The latter is discussed in more detail below. The TAP agrees that engineering judgment is important when going from reliability planning concepts and models to operational reliability.
- Ulupono states *“Including the worst-weather day in the RESOLVE optimization will ensure that the system has a least-cost design that provides enough power at all times. Consequently, it is not appropriate to apply an ERM as an additional, arbitrary mechanism to achieve generation adequacy”*. The TAP does not agree with this statement. While selection of a broad range of daily operations and best estimates of reserves might provide a closer estimate for capacity growth, final determination of the cost-effective, reliable path forward requires use of all the tools identified as was discussed in detail in Section 3.

- One member of TAP noted that the current ERM equation is flawed because it does not explicitly address unplanned outage rates of fossil generation. The model incorporates uncertainty for maintenance (planned outages) and variability of the renewable resources, but treats fossil generation as “firm capability.” The 30% ERM is then meant to cover unexpected outages of the fossil fleet and load uncertainty. This method is biased in that it assigns reliability risk to variable renewables, but does not discount fossil generation which is treated as perfect capacity.
- As stated above, there is agreement that a metric for RESOLVE is needed, but it should be allowed to evolve and change as new information and subsequent process steps are run. TAP recommends that a plan be developed to conduct the analysis to determine the relationship between ERM and detailed resource adequacy analysis as discussed below. This may yield a better value for ERM or a process for ERM determination. At a minimum, RESOLVE should be run with various values of ERM and outputs assessed using detailed reliability tools.

Uluono has suggested a seven-step plan for assessment of the ERM. The TAP is concerned that this plan is wholly focused on RESOLVE for the determination of the final plan. Weaknesses in this methodology have already been discussed.

In response to the Uluono recommendation, the Company has suggested a portfolio that meets ERM requirements of 10%, 20% and 30% could be evaluated for a single year and compared to a detailed probabilistic resource adequacy assessment across many weather years and generator outage draws. The results of the different ERM portfolios could be quantified with resource adequacy metrics like LOLE, LOLP, LOLH, and EUE to validate various ERM levels to common RA metrics. The TAP generally agrees with this approach with the recommendation that all parties be involved in the design of the scenarios to be used for this analysis.

- As discussed in Section 3, it was noted that at least some mainland utilities utilize LOLP as a hard constraint (i.e., 1 day in 10 years), utilizing daily outage profiles to develop a reserve margin. Hawaiian Electric previously used a 1 day in 4.5 year LOLP metric for Oahu. While TAP thought there may be limitations to this process for more distributed systems such as those in Hawaii, a more thorough assessment of this process could be included as part of the evaluation of ERM and reliability.

6. Uluono #3: Assume batteries and curtailed renewables will be able to provide virtual inertia

“Ulupono recommends that Hawaiian Electric modify their current assumptions for inertia, and assume that batteries and curtailed renewables will be able to provide virtual inertia when needed.”^ Under Hawaiian Electric’s current assumptions, it is likely that RESOLVE will be biased and strongly favor large synchronous condensers and thermal generators.”

a. Hawaiian Electric’s Approach

In the IGP process, the Company proposed minimum inertia and fast frequency response (“FFR”) requirements that are complementary and work together to support system frequency in an under-frequency event. The minimum inertia plans for a 3 Hz per second change of frequency event and to allow 0.5 seconds for FFR to activate. The requirement also considers the loss of the largest generator and the impact of legacy distributed PV trip settings. Inertia requirements based on maintaining 3 Hz per second is a progressive metric as mainland systems will rarely see such fast rates of change of frequency. Historically in Hawai’i, the rate of change of frequency has been lower/slower than 3 Hz per second. Therefore, the minimum inertia requirements have already been minimized to the extent possible.

b. Stakeholder Comments and Tradeoffs

Ulupono recommends the following:

- Make reasonable assumptions for when inertial response will be available from inverters
 - May be available soon based on literature review and recent commercial experience
 - Possibly earlier for grid-scale facilities than DER
- Calculate inertial requirements based on stability studies of power systems with very fast frequency response and virtual inertia from inverters
- Identify near-term, low-cost sources of inertia that can be used until inverter-based inertia is widely available
- Include those assumptions in the RESOLVE modeling
 - The current treatment is arbitrary and likely to result in stranded/unnecessary assets

In Ulupono’s approach, virtual inertia, or specifically, grid forming inverters are promising. However, requirements for grid forming inverters are still being studied. Many questions remain concerning the use of grid forming inverters and are current areas of research. Ulupono states that the Company should assume there will be progress within the planning horizon of IGP and that inertia and frequency response should be provided by a reasonable source, which will likely be inverters in long term plans. Ulupono does not object to the use of synchronous condensers for other critical services such as system protection and fault current, only to omitting inverter response which may reduce the needs for synchronous condensers.

A stakeholder for a large customer mentioned that they have concerns regarding protection. The amount of inverter-based short circuit current may cause significant cost and possible

reduced reliability. Other customers with large campuses or facilities would need to adapt their protection.

c. Areas of Agreement and Recommendations

Hawaiian Electric and Ulupono agree that further study of the provision of virtual inertia is warranted. The inertia assumption in RESOLVE is directional only. Detailed requirements will be determined through stability studies using other software tools such as PSS/E and PSCAD.

Hawaiian Electric proposes that sensitivity analysis be performed in RESOLVE to assess the cost and impact on the resource plan where batteries and curtailed renewables can provide inertia in the model. To mitigate near-term stability issues, where inverter-based resources are expected to make up 95-100% of the dispatched resources for certain hours of the year in 2023-2025, the Company will minimize synchronous condenser investments to the extent possible based on stability studies in PSS/E and PSCAD and repurposing of generation assets to synchronous condensers to minimize costs.

d. TAP Comments

Procuring inertia (which is different from FFR) from inverters utilizes nascent “grid-forming” controls technology, where there are many open questions for implementation at scale.

TAP agrees that, in the relatively near future, more inverters providing services such as inertia and/or FFR will become available. A major question remains as to how this will be implemented. Specifically, TAP members raised the issue of, “how will a system operator coordinate FFR from many (perhaps thousands) units?” Multiple members of the TAP noted that just because inverters can provide this service, doesn’t mean that a system operator can implement this in a controllable manner. At this point in time, TAP sees high risk in relying exclusively on inverters (i.e. with no synchronous machines) for inertia required by the Hawaiian grids. However, the TAP did state that with the recent advances, particularly with utility scale inverters, providing services like inertia from inverters can and should coexist with synchronous machine-based technology. This would allow HECO to gain experience in getting the needed services from multiple types of resources. Synchronous condenser conversions are a reasonable and realistic short-term bridge as the inverter technology matures. However, as noted below, the Company should invest in condenser technology only as needed to meet grid requirements and include inverters in their analysis to provide on-going cost comparison.

Ulupono is concerned about how to plan today versus what may be available 5 or 10 years in the future. TAP members agree that there is considerable potential in the technology, and while it has been applied to smaller microgrids or single inverter systems, it remains unproven for complex systems like those operated by the Company. This issue again prompted TAP comment that “reliability is paramount”. From a system perspective, an operator must ensure

the proper management and operation of a new technology to ensure meeting grid service needs. TAP members recognize that this technology is developing quickly and should be constantly reevaluated for use.

TAP noted that Ulupono's comments seemed concerned that inverter technology was being categorically excluded from providing services like inertia. On synchronous condensers, which have been discussed as the primary mitigation, HECO should be clear as to whether these are considered conversions or new units. There's a big cost difference. New units cost far more and have a 40 years life, which may not be appropriate if they plan to bridge a temporary gap in technology maturity. HECO's response in the meeting was that they are considering conversions first where possible and are currently performing PSCAD studies of the system that are looking at the grid-forming services from Stage 2 projects.

TAP members acknowledged that Ulupono was not clear whether it's FFR or inertia. TAP members added that the language and definitions are not clear or uniform across the industry. However, TAP members also acknowledged that Ulupono's concern may be that a forthcoming solution will be pre-empted by these investments. Thus, some sensitivity on inverters providing these services is appropriate.

The TAP also acknowledges that there can be a distinction between relying on grid forming inverter capability for long-term planning versus short-term procurement. For a planning analysis conducted decades in the future, the assumption of grid forming inverter capability is likely sufficient. However, near term procurement should be more conservative and ensure reliability can be effectively maintained with new technology.

7. Assume 30 year contracts as the life of the Solar PV system

"The current contract term Hawaiian Electric assumes for renewable and storage technologies is 20 years. Noting that recent Power Purchase Agreements ("PPAs") are most often approved for 20-to-25-year terms, Ulupono recommends that Hawaiian Electric assume a 30 year PPA term or consider a lower cost replacement resource to be available at the end of the 20 year contract for an additional five to ten years. This is an important issue as assuming 20-year contracts with full cost replacement needed after 20 years would effectively overstate the cost of solar."

a. Hawaiian Electric's Approach

In the IGP process, the power purchase agreements ("PPAs") signed with independent power producers ("IPPs") were assumed to terminate at the end of the contract term to allow the RESOLVE model to re-optimize grid needs when contracts end. New PV and wind resources were assumed to have 20 year term lengths, consistent with the recent Stage 1 and 2 RFP projects.

b. Stakeholder Comments and Tradeoffs

Assuming Ulupono's preference for 30-year contracts, extending existing IPPs may not allow the RESOLVE model to re-optimize in the future when grid needs have changed. Assuming Hawaiian Electric's approach to end PPAs at the end of their term, there could be missed opportunities from extensions of existing IPPs that could be lower cost than requiring a new resource to be built. For new resources, longer contract terms, from 20 years to 30 years, would allow for a lower contract cost and to better match the contract term to the expected service life of the resource. Ulupono asserted that when an existing IPP reaches the end of its 20-year contract, the Company may not receive significantly lower pricing if the contract were renegotiated for another 10 years.

A stakeholder commented that the market provides financing for solar and storage projects over 35 to 40-year terms. Also, assuming battery warranties were 15 years, within a 20-year contract, the batteries would be replaced in year 15 and still have 10 years of life remaining when the 20-year contract ends.

Another stakeholder did not favor long-term contracts because it may prevent customers from realizing the benefits of declining technology costs. A stakeholder commented that asking communities to host longer term projects at 40 year terms may potentially span 3 generations.

c. Areas of Agreement and Recommendations

For long-term planning purposes, Hawaiian Electric and Ulupono agree that new PV and wind resources can assume a 30-year term. Stage 1 and 2 RFP projects will also be extended at 50% of their current lump sum costs for a total term of 30 years. Existing PV and wind resources will continue to be removed from service at the end of the contract term.

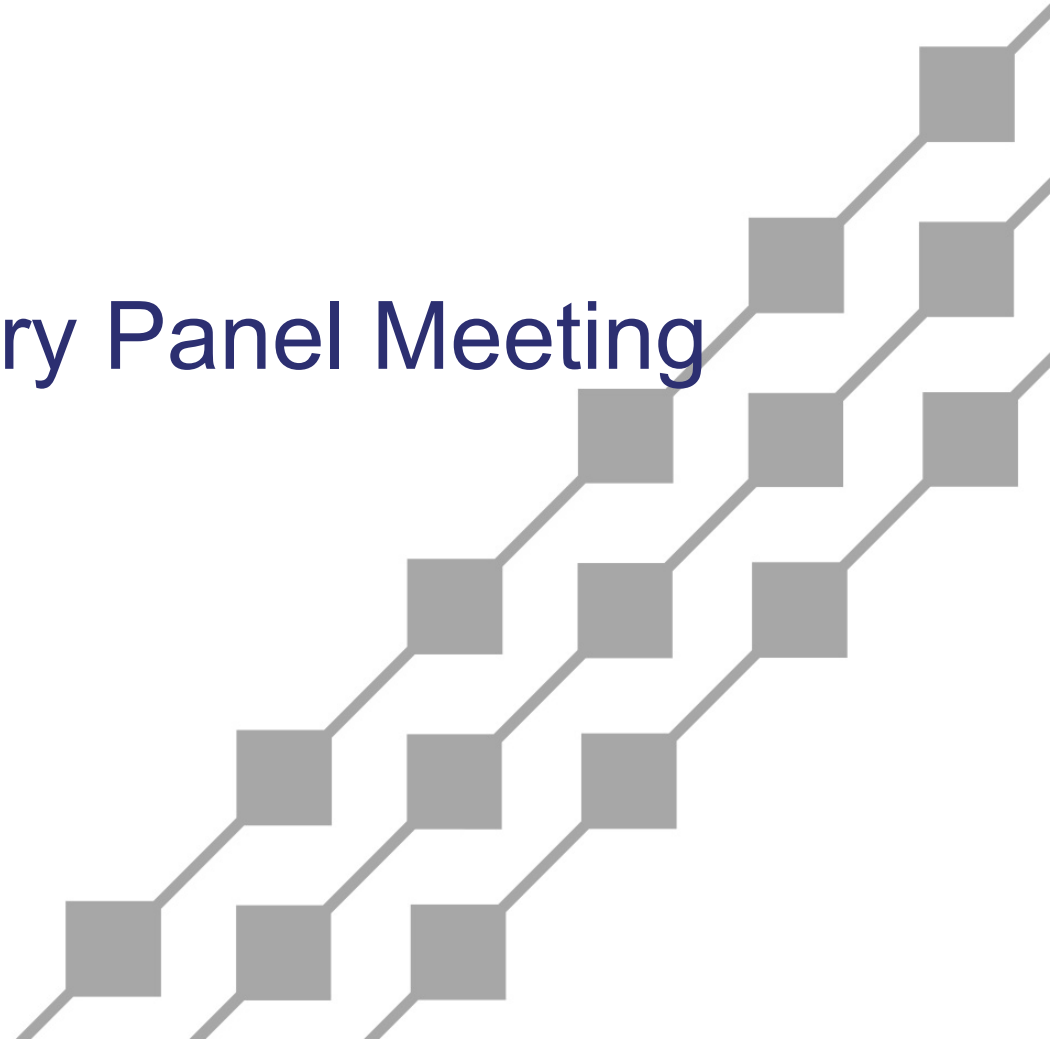
d. TAP Review – TAP did not review these recommendations due to time constraints.



**Hawaiian
Electric**

IGP Technical Advisory Panel Meeting

May 25, 2021



Agenda

- ◆ Solicit TAP feedback on:
 - IGP resource planning analyses and modeling tools
 - Ulupono's four modeling suggestions and recommendations discussed on 4/27/21 for filing no later than June 1

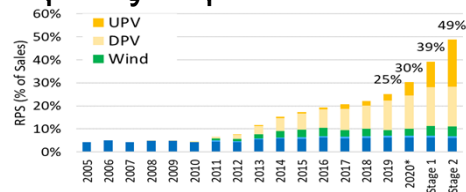


Suite of Modeling Tools

- ◆ Interaction between RESOLVE and PLEXOS models
- ◆ Additional models to identify grid services
- ◆ Modeling questions for TAP



Capacity Expansion



Objective:

Screening analysis to determine type, quantity, and timing of utility-scale resource additions across a range of constraints

Tool(s): RESOLVE

Key Inputs:

- Cumulative daily load and load shape, including DR, DER, EE, EVs
- Fuel price forecasts
- Candidate technology costs
- Proposed retirement schedules
- Reliability requirement (PRM, ERM)
- Grid service requirements

Key Outputs:

- Timing, type, quantity of utility-scale resource additions, including BESS
- Economic retirements
- Estimated capital and production costs
- Hourly marginal cost for services

Resource Adequacy



Objective:

Validate resource adequacy of portfolios in selected years to quantify system risk of proposed capacity expansion including timing of retirements

Tool(s): PLEXOS

Key Inputs:

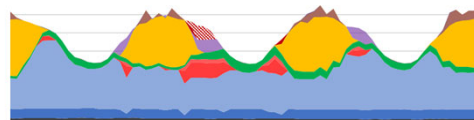
 (additional to previous)

- Resource portfolio, including BESS, DR and DER
- Multiple years of wind, solar, and net load profiles
- Detailed generator outage data

Key Outputs:

- Reliability metrics (LOLE, EUE, etc.)
- Size, frequency and duration of capacity shortfalls

Production Cost



Objective:

Confirm operability of portfolios: reserves, ramp rates, unit commitment, storage schedules.
Quantify production costs and avoided costs
Assess transmission needs

Tool(s): PLEXOS

Key Inputs:

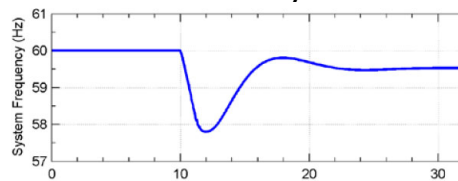
 (additional to previous)

- Detailed grid service requirements & capabilities
- Sub-hourly resource profiles
- Detailed unit operating constraints (ramp rates, heat rate curves)
- Transmission line parameters

Key Outputs:

- Production Cost (Fuel, O&M)
- Hourly marginal cost \$/MWh
- Curtailment, emissions, storage utilization
- Transmission congestion
- Size, frequency, duration of non-capacity shortfalls

Network Stability Screening



Objective:

Validate grid stability, including frequency resp., voltage regulation, and short-circuit strength to determine if transmission upgrades are required.

Tool(s): PSS/E and PSCAD

Key Inputs:

 (additional to previous)

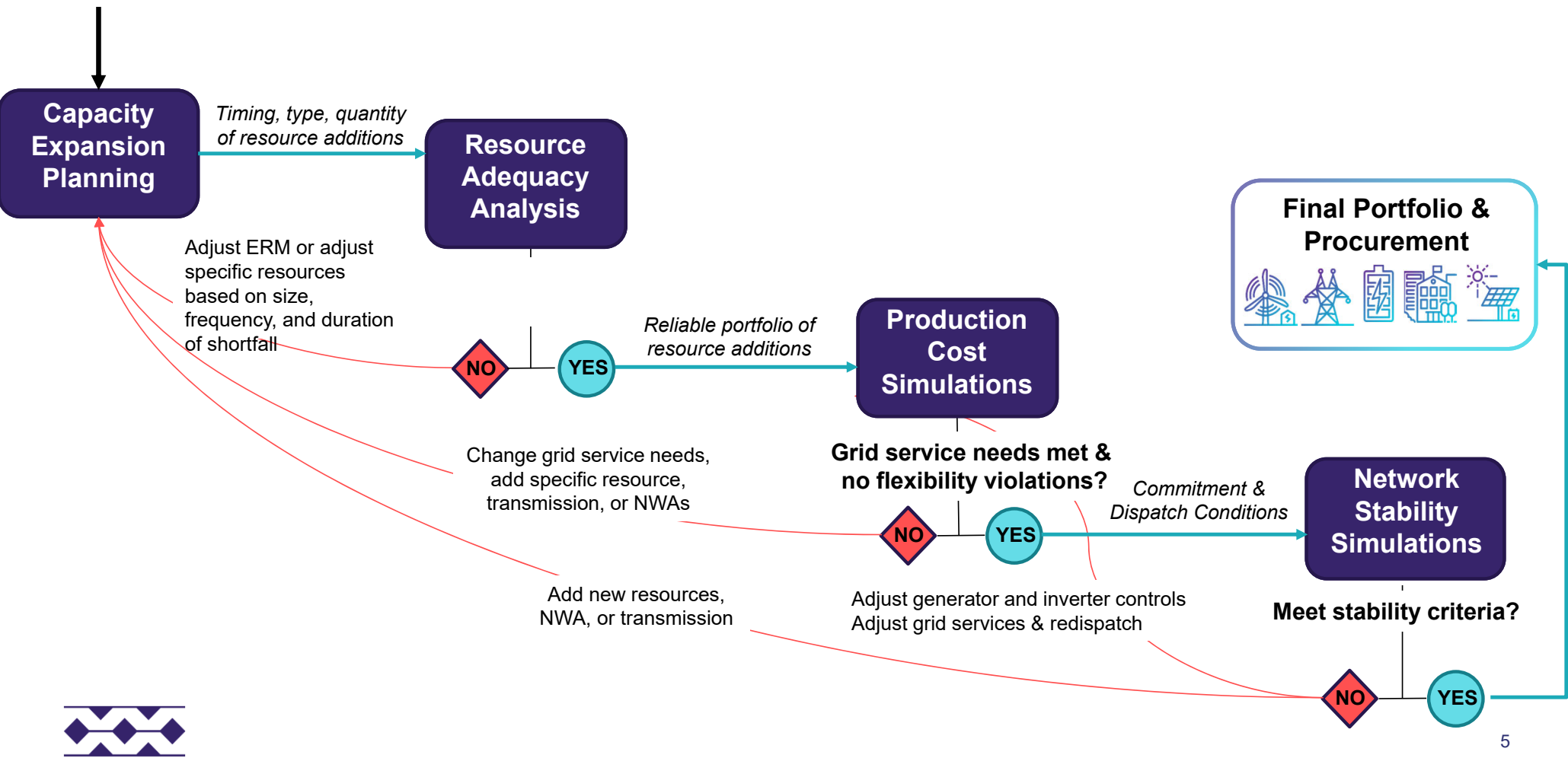
- Transmission topology
- Selected unit commitment & dispatch
- Thermal unit performance: governor response
- Inverter settings & performance

Key Outputs:

- Transmission overloads
- Frequency and voltage violations
- System dynamic performance after a disturbance
- Enabling technologies or inverter control changes to mitigate stability concerns



Inputs, Assumptions,
Constraints & Scenarios



Capacity Expansion Planning

Objective:

Screening analysis to determine type, quantity, and timing of utility-scale resource additions across a *range of constraints*

Tool(s): RESOLVE

Key Inputs:

- Cumulative daily load and load shape, including DR, DER, EE, EVs
- Fuel price forecasts
- Candidate technology costs
- Proposed retirement schedules
- Reliability requirement (PRM, ERM)
- Grid service requirements

Key Outputs:

- Timing, type, quantity of utility-scale resource additions, including BESS
- Economic retirements
- Estimated capital and production costs
- Hourly marginal cost of services

Capacity
Expansion
Planning

Timing, type, quantity
of resource additions

- RESOLVE identifies potential least cost portfolios that meet RPS requirements based on a user defined reliability requirement such as Energy Reserve Margin and grid service requirements for inertia, fast frequency response, and regulating reserve
- RESOLVE only evaluates 30 representative days, single weather year
- Each day evaluated in isolation (no multi-day analysis)
- With limited capability to determine if a portfolio is operable or reliable. Additional analysis is needed in subsequent tools

Inputs: Range of load and load shapes, not individual layers, is most important;
Relative technology costs more important than absolute value
When used to meet RPS requirements, fuel costs are less important

Outputs from RESOLVE, including timing, type, and quantity of resource additions to enable retirements, require additional analysis to ensure reliability, operability and stability metrics are met



Resource Adequacy Analysis

Objective:

Validate resource adequacy of portfolios in selected years to quantify system risk of proposed capacity expansion including timing of unit *retirements*

Key Inputs: (additional to previous)

- Resource portfolio, including BESS, DR and DER
- Multiple years of wind, solar, and net load profiles
- Detailed generator outage data

Key Outputs:

- Reliability metrics (LOLE, EUE, etc.)
- Size, frequency and duration of capacity shortfalls

Tool(s): PLEXOS (or other probabilistic RA tools)

Inputs, Assumptions, Constraints & Scenarios

Capacity Expansion Planning

Resource Adequacy Analysis

Meet reliability criteria?

NO

YES

Reliable portfolio of resource additions

Adjust ERM or adjust specific resources based on size, frequency, and duration of shortfall

- Stochastic analysis to quantify if a portfolio meets a reliability criterion across every hour of the year
 - Loss of load expectation (LOLE)
 - Loss of Load Hours (LOLH)
 - Expected Unserved Energy (EUE)
- Must incorporate wind, solar, and net load variability; and random generator outages to determine probability of unserved load
- Often assumes simplifications on grid operations and unit properties, so detailed production cost simulations will be needed

Outputs from RA, including size, frequency, and duration of capacity shortfall can be used to adjust the reliability requirement or adjust resource mix derived from the capacity expansion plan



Production Cost Simulations (PCS)

Objective:

Confirm operability of portfolios: reserves, ramp rates, unit commitment, storage schedules.

Quantify production costs and avoided costs
Assess transmission needs

Tool(s): PLEXOS

Key Inputs: (additional to previous)

- Detailed grid service requirements & capabilities
- Sub-hourly resource profiles
- Detailed unit operating constraints (ramp rates, heat rate curves)
- Transmission line parameters

Key Outputs:

- Production Cost (Fuel, O&M)
- Hourly marginal cost \$/MWh
- Curtailment, emissions, storage utilization
- Transmission congestion
- Size, frequency, duration of non-capacity shortfalls

- PCS determines if a portfolio is operable on an hourly, or sub-hourly basis for every day of the year
- PCS yields high-fidelity representation of unit characteristics, grid services, system constraints, and transmission topology, and more granular costs
- Operating violations can be used to adjust reliability requirement and grid service needs for RESOLVE or specific resource changes

Inputs, Assumptions, Constraints & Scenarios

Capacity Expansion Planning

Resource Adequacy Analysis

Meet reliability criteria?

NO

YES

Production Cost Simulations

Grid service needs met & no flexibility violations?

NO

YES

Commitment & Dispatch Conditions

Change grid service needs, add specific resource, transmission, or NWAs

Periods of potential stability challenges are passed through for more detailed grid stability simulations.



Inputs, Assumptions,
Constraints & Scenarios

Network Stability Screening

Objective:

Validate *grid stability*, including frequency resp., voltage regulation, short-circuit strength, and system protection to determine if transmission upgrades are required.

Tool(s): PSS/E and PSCAD

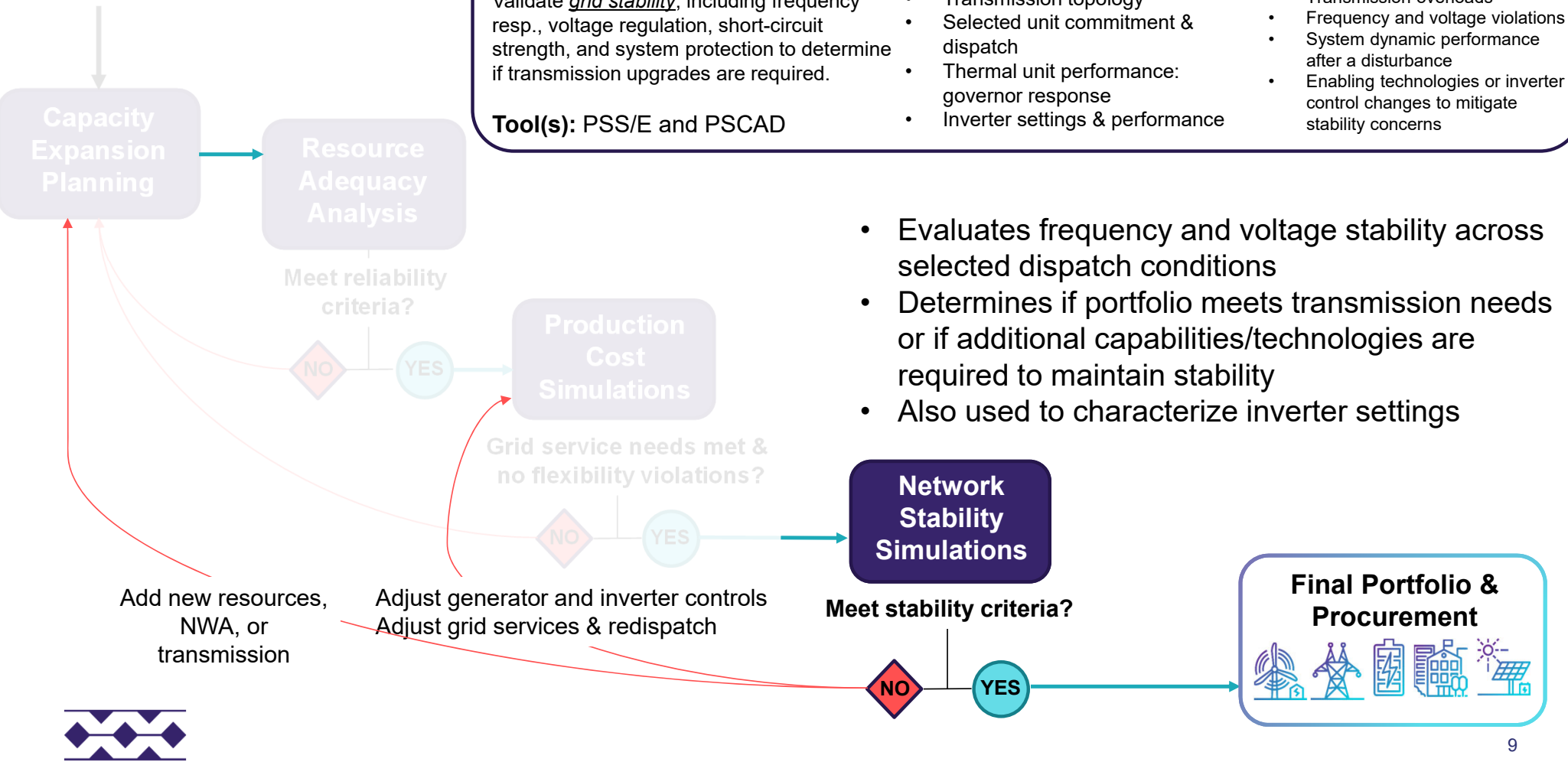
Key Inputs: (additional to previous)

- Transmission topology
- Selected unit commitment & dispatch
- Thermal unit performance: governor response
- Inverter settings & performance

Key Outputs:

- Transmission overloads
- Frequency and voltage violations
- System dynamic performance after a disturbance
- Enabling technologies or inverter control changes to mitigate stability concerns

- Evaluates frequency and voltage stability across selected dispatch conditions
- Determines if portfolio meets transmission needs or if additional capabilities/technologies are required to maintain stability
- Also used to characterize inverter settings



Grid Service Modeling

Grid Service	RESOLVE PLEXOS	PSSE/PSCAD ASPEN	Synergi LoadSEER
Energy	✓	Not represented	Not represented
Energy Reserve Margin	✓	Not represented	Not represented
Load Reduce	✓	Not represented	Not represented
Load Build	✓	Not represented	Not represented
Regulating Reserve	✓	Not represented	Not represented
Inertia	✓	✓	Not represented
FFR	✓	✓	Not represented



Grid Service Modeling

Grid Service	RESOLVE PLEXOS	PSSE/PSCAD ASPEN	Synergi LoadSEER
PFR	<u>Partially represented</u>	✓	Not represented
Voltage Support	Not represented	✓	Not represented
Short-Circuit Current	Not represented	✓	Not represented
RPS	✓	Not represented	Not represented
Transmission Capacity	<u>Partially represented</u>	✓	Not represented
Distribution Capacity	<u>Partially represented</u>	Not represented	✓
Distribution Reliability	<u>Partially represented</u>	Not represented	✓



Questions for TAP

- ◆ Are the suite of modeling tools aligned with best practices to identify cost effective and reliable pathways to 100% renewable energy?
 - Is the assessment of each grid service (process step and modeling tool) clearly defined?
 - Are the handoffs between the models in the process well understood?
 - Are the limitations and intended use case for each model clearly defined?
- ◆ Are any adjustments to the IGP modeling framework or grid service modeling needed?
 - Do all grid service shortfalls require a complete process iteration? Can shortfalls be summarized as part of the procurement target and not require model re-run if they are not significant?
 - What is the threshold for a large shortfall that requires a process iteration?
- ◆ The marginal avoided costs reported from RESOLVE are intended to be used as part of an initial screening analyses in the RFP evaluation.
 - Is this a reasonable approach if the process flow is successfully completed with no large shortfalls?
 - Given that RESOLVE and PLEXOS are different models but using largely the same assumptions, is there a means to validate the marginal avoided costs produced?

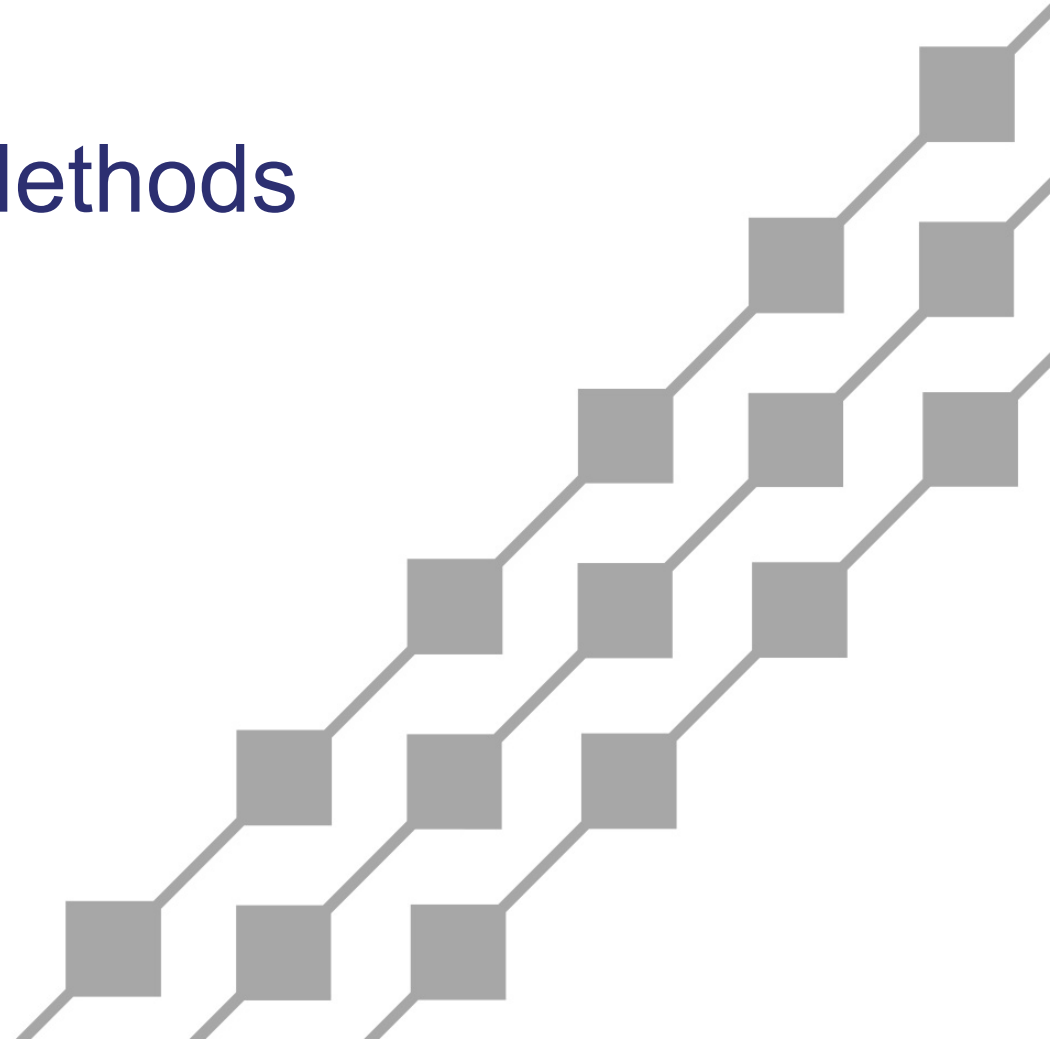


Questions for TAP

- ◆ Subhourly variability is being addressed through regulating reserve requirements that have been defined using minutely load and generation data and modeled in RESOLVE and PLEXOS.
 - Is the treatment of subhourly variability through the regulating reserve requirement appropriate?
 - Are further subhourly analyses needed? What type of additional subhourly analyses would be needed and what is the intended use case?
- ◆ Transmission constraints are captured in the interconnection limits modeled on projects and have been proposed as part of the renewable energy zones i.e. new resource options that reflect the resource potential in certain areas across the island and the associated cost of new transmission to interconnect. After the network stability simulation is completed, the production cost simulation may also be iterated to incorporate adjusted generator controls or revised grid service requirements.
 - Is the current treatment of transmission constraints reasonable?
 - Are there additional considerations to capture transmission constraints in the production cost modeling?



Ulupono Modeling Methods Recommendations



Commission Directives

- ◆ The Commission would like to better understand the merits and drawbacks of Ulupono's suggested approaches, and whether other stakeholders are aligned on desired modeling tactics.
- ◆ Hawaiian Electric shall offer these preliminary findings to the TAP for independent analysis and specific recommendations to adopt (either in full or modified) or reject each of the above alternatives. Hawaiian Electric shall seek this feedback from the TAP, in writing, and file it with the Commission no later than May 21, 2021.



Ulupono's Approach to Modeling and Recommendations Discussed on 4/27/21

1. Allow RESOLVE to optimize the amount of storage needed for both standalone and paired with solar PV sites, rather than requiring exactly four hours of storage with utility scale solar

Recommendation #1

Paired PV with 2, 4, 6, and 8 hour duration battery systems will be available in RESOLVE as candidate options.

2. Use alternatives to the proposed Energy Reserve Margin calculation or adopt a reserve margin in later years that is tied to a reliability analysis

Recommendation #2

Further study is warranted. The Company will test lower Energy Reserve Margin target percentages in RESOLVE and evaluate the impact on the resulting resource plans in PLEXOS. A sensitivity will also be performed to remove the Hourly Dependable Capacity assumption for variable renewables and instead consider the full production profiles. The Company is also open to having HNEI test the reliability of the various resource plans generated from RESOLVE at different ERM levels using their stochastic resource adequacy methodology.



Ulupono's Approach to Modeling and Recommendations Discussed on 4/27/21

3. Assume batteries and curtailed renewables will be able to provide virtual inertia when needed

Recommendation #3

Further study is warranted. The Company will test the provision of inertia from batteries and curtailed renewables in RESOLVE to assess the cost and impact on the resource plan.

To mitigate near-term stability issues in 2023-2025, where inverter-based resources are expected to make up 95-100% of the dispatched resources for certain hours of the year, the Company will minimize synchronous condenser investments based on stability studies in PSS/E and PSCAD and repurpose generation assets to synchronous condensers to minimize costs and risk of stranded assets due to future technological advancements.

4. Assume 30-year contracts as the life of the Solar PV system or assume 20-25 with 5-10 year extensions at lower costs

Recommendation #4

New PV and wind resources will assume a 30-year term. Stage 1 and 2 RFP projects will be extended at their current lump sum costs for a total term of 30 years. Existing PV and wind resources will continue to be removed from service at the end of their contract term.

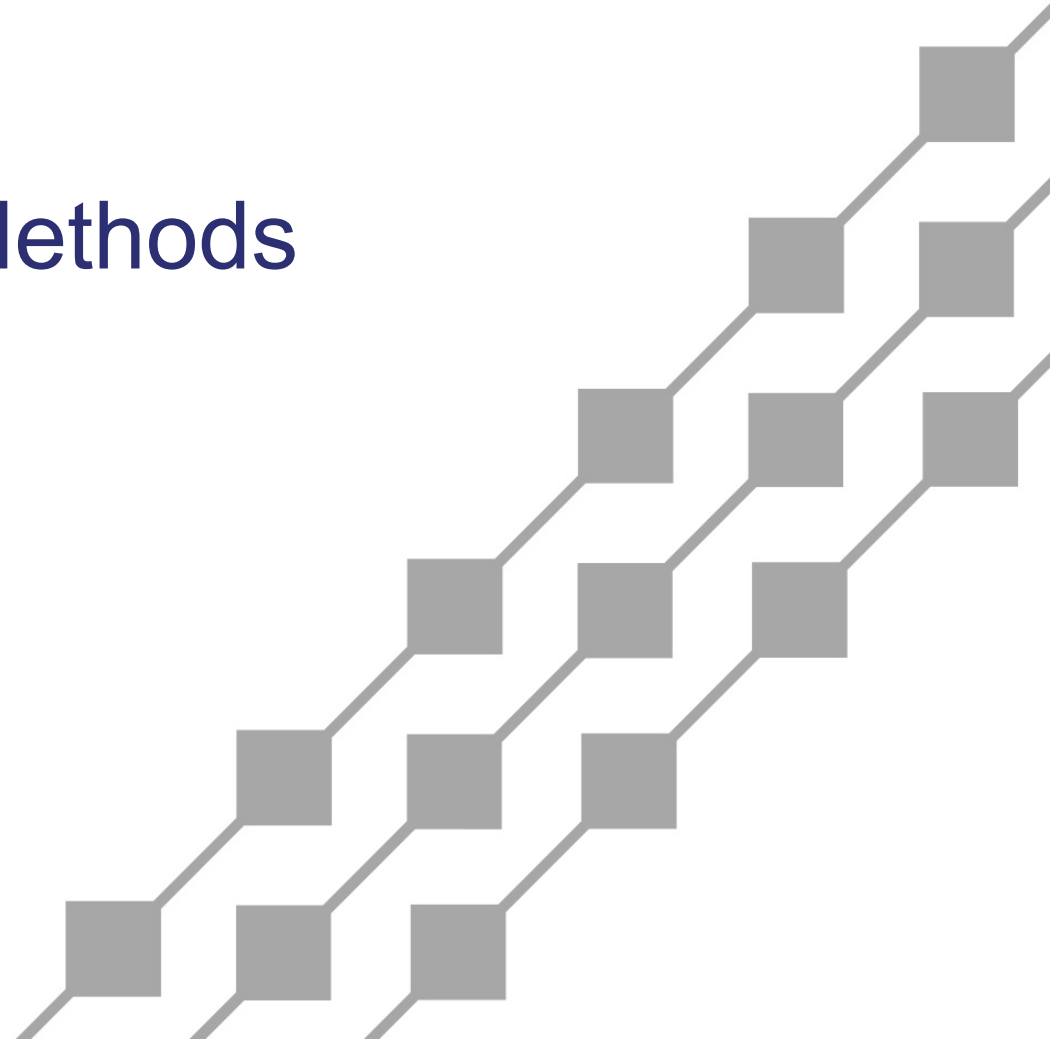


Questions for TAP

- ◆ Are the recommendations provided in response to Ulupono's suggestions reasonable?
- ◆ Are there alternatives to consider in assessing resource adequacy of various resource plans?
- ◆ Is the minimum inertia requirement reasonable?
 - Are near-term synchronous condenser investments to satisfy system stability in the near-term with higher dependency on inverters for stability in the long-term appropriate?
- ◆ Is the scope of follow up analyses reasonable for recommendations that require further study?



Ulupono Modeling Methods Recommendations



Comments on Hawaiian Electric Proposals Addressing Order No. 37730

April 27, 2021

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(affiliations listed for identification only; views are my own)



Storage Sizing

- The proposed approach is to fix the size of storage paired with PV at 4 or 6 hours (maybe also 2 and 8 hr), but allow free sizing of standalone storage
- There is a risk that considering only 4 and 6 hours will cause a small amount of excess inverter investment (the system can build extra storage depth in standalone storage, but may need to add extra inverter capacity to bring it to market)
- This risk is smaller when including 2 and 8 hr options
- **Either proposed solution is acceptable**

Energy Reserve Margin

- Is intended to cover many factors that will decrease as renewables increase and/or should be modeled as fixed size problems, not percent of load
 - loss of largest unit (implicitly thermal)
 - multiple forced outages (implicitly thermal)
 - unplanned maintenance (implicitly thermal)

Energy Reserve Margin

- Renewable resources are treated prejudicially
 - discounted excessively, then required to have a 30% ERM on top
 - intended to cover variability, unusually poor weather and forecast error
 - variability is already handled by the time sampling, doesn't need ERM on top of that
 - out-of-range weather should be handled by including most difficult days in time sampling, doesn't need ERM on top of that
 - battery failures: how often, what size?
- HDC calculation is unsound
 - doesn't account for non-normality of data
 - doesn't include forecast errors
 - doesn't account for independence of different types of uncertainty
 - should not be used to handle variability (covered by time sampling)
- **There is no analysis to justify the 30% blanket ERM in future power systems or the treatment of renewables in this calculation**

Energy Reserve Margin, Recommended Approach

1. Include worst days in time sampling in RESOLVE
2. Count renewables at their full hourly availability in RESOLVE
3. Set initial ERM to 0%
4. Run RESOLVE with current ERM
5. Test the resulting plan with many years of data (e.g., in PLEXOS)
 - include all possible weather, realistic forecast errors for load and renewables, forced outages for thermal plants and batteries, etc.
6. If shortfalls are found: increase ERM by a few percent and return to step 4
7. Repeat until shortfalls are cleared

Inertia

- Hawaiian Electric's model of system response is roughly right, with some caveats
 - inertia-type response can come from inverters (by various names)
 - backed by curtailed renewables or batteries:
 - grid forming
 - virtual synchronous generator
 - response to rate of change of frequency
 - wind farms (curtailed or not):
 - convert real inertia from wind turbines to inertial response on the grid
 - FFR can be faster with inverters
 - may be able to get by with less inertia-type response if FFR can kick in faster
 - FFR and PFR are the same thing, just split on arbitrary time scales
 - secondary frequency control is typically on same time scale as PFR
 - (not important in this discussion)

Shortcomings in Treatment of Inertia

- Yes, the system still needs to survive largest contingency, but...
 - Largest contingency may get smaller
 - Future grids will be dominated by inverters, not spinning machines
 - Inverters can provide inertia-type response
 - Grid may need less inertia with nearly instantaneous FFR from inverters
 - Omitting inverter inertial response will prejudice the results toward spinning machines, overlooking nearly free inverter-based solutions

Recommended Treatment of Inertia

- Make reasonable assumptions about when inertial response will be available from inverters
 - based on literature review and recent commercial experience
 - possibly earlier for grid-scale facilities than DER
- Calculate inertial requirements based on stability studies of power systems with very fast frequency response and virtual inertia from inverters
- Identify near-term, low-cost sources of inertia that can be used until inverter-based inertia is widely available
- Include those assumptions in the RESOLVE modeling
 - current treatment is arbitrary and likely to result in stranded/unnecessary assets

Response to Hawaiian Electric Questions

- “What is the basis for objecting to the use of synchronous condensers for inertia, fault current, voltage support, as has been applied in other jurisdictions (Kauai, AEMO, ERCOT, etc.)?”
 - we don’t object to using synchronous condensers, only to omitting inverter response which may make them unnecessary
- “Maintaining grid frequency in a low inertia system is an ongoing area of research”
 - Yes. That means you should assume there will be progress and that we can get inertia and frequency response from the most reasonable source, which will likely be inverters
- “Before a large power system can fully rely on fast power injection from IBRs for stability, we need to gradually gain confidence through field operations, detailed modeling, and other means that IBRs can indeed reliably provide this in practice.”
 - yes, so let’s do it
 - looking longer-term (as IGP does), we know this will be possible, so long-term plans should expect to use these new capabilities, rather than locking in potentially stranded investments in spinning machines

Response to Hawaiian Electric Questions

- “In addition, for IBRs to fully replace synchronous condensers, the transmission protection system would need to be re-designed in an unprecedented way, or IBRs would need to be built with significant temporary overload capacity and advanced controls, which most don’t have today.”
 - This appears to be about short-circuit current, not inertia; if you are concerned about short-circuit current, you should address that directly
- “It appears likely that in the near term, when Hawaii is expected to have significant hours of 100% renewable generation, synchronous condensers will continue to be the most economical solution to achieving 100% renewable energy, including conversion of existing generators.”
 - How soon do you expect these situations to occur? Are there low-cost solutions that can be used near-term while standards are set for virtual inertia from inverters?

Response to Hawaiian Electric Questions

- “Longer term, that may change – it is very difficult for any software including RESOLVE to capture future technological developments.”
 - This is one of the main purposes of RESOLVE: make a plan now in light of reasonably expected future technological developments
- “Condensers appear to be the quickest route to operating with 100% PV, wind, and battery energy while meeting system stability and protection needs. That may change 5-10 years in the future as inverter and protection technology develops, or it may not.”
 - Again, how soon do you expect these conditions to occur? Inverters with these capabilities are already in early commercial stage. Why does Hawaiian Electric think it’s more reasonable to assume they will not come to market rather than assuming they will? Consider the progress with other inverter standards in the last five years (volt-var, volt-watt, frequency-watt, fast voltage trip, etc.)

Another Untapped Resource

- Allow customers to buy and sell power at real-time avoided cost
 - makes it reasonable to require DER to provide grid services (**virtual inertia, FFR**, congestion management) as part of the package
 - makes curtailed customer-sited renewables **available for system balancing**
 - makes customer-sited batteries **available for system balancing**
 - eliminates conflict about curtailing DER during times of excess production (avoided customer revenue becomes \$0)
 - makes it more likely customers will use PV-only systems and **let HECO procure/manage large batteries** (which can readily provide inertia and FFR)
 - makes better use of scarce roof area
 - reduces curtailment of renewables, makes better use of batteries, lowers overall costs of the transition

Contract Term Length

- IPP must sign a PPA that covers the full capital cost of projects, whether it is written for 20 or 30 years
- If the contract is written shorter, it will have roughly the same total costs, and just leave the later life of the project untapped (or pay again to get it)
- Getting extra flexibility from the IPP is a mirage if there is no flexibility to give (is there?)
- Concerns about the proposal (pay additional 50% of lump sum costs to get 5-10 years more life)
 - How could HECO get IPP's to agree to these prices when they know they are competing with new assets?

Contract Term Length

- Recommended approach:
 - Assume PPAs will be written for the full life of assets and cover the full capital cost of the assets
 - 25-30 years for wind/solar
 - 15 years for batteries? (could be two rounds for batteries paired with PV)

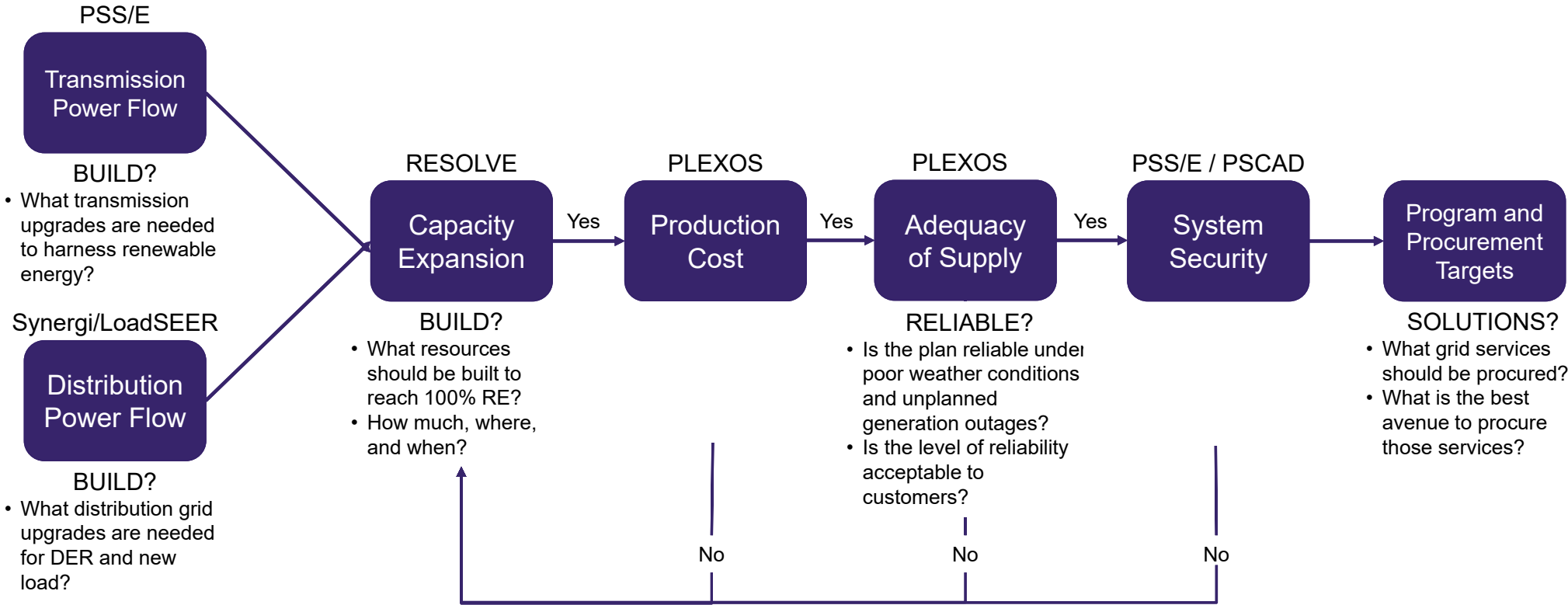
Pre-read Materials

Slides 15-36

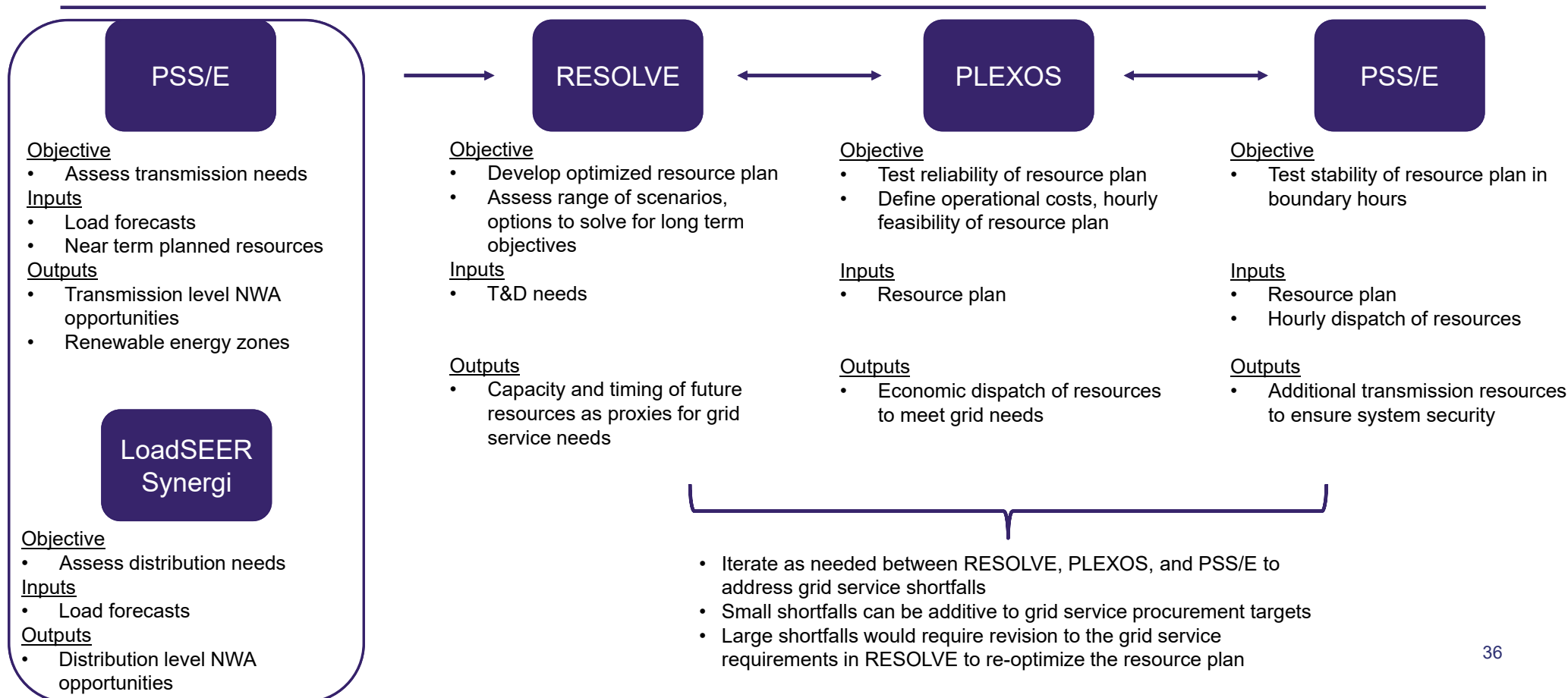
- Additional Description of Resource Planning Methods and Tools
- Ulupono Modeling Methods



IGP Modeling Framework



IGP Resource Planning Analyses



IGP Suite of Modeling Tools Modeling Framework



IGP Resource Planning Analyses

1. A capacity expansion model (RESOLVE) is run to identify the least-cost timing and amount of investments in new transmission and generation resources to achieve the 100% RE by 2045 and other planning objectives.
2. The capacity expansion model is able to account for many different constraints and factors that drive long term investment decisions.
 - Resource and fuel costs, including policy changes that may affect those costs
 - Resource operating characteristics
 - Total demand for electricity, including changes in the load shape due to customer adoption of various technologies
3. Due to the complex problem that the capacity expansion model solves for (new investment decisions and operations of those investments along with the broader electric system), simplified parameters for operations and grid requirements are used to allow the model to solve in a reasonable timeframe. RESOLVE uses 30 sample days per year.
4. Because of this tradeoff, detailed analyses for economic operations and reliability of the future electric system are evaluated in subsequent modeling steps.



IGP Resource Planning Analyses

5. A production cost model (PLEXOS) uses the resource plan developed by RESOLVE to then model the hourly operations of the future system for the full 30 years of the planning horizon.
6. The results of this modeling will allow us to assess whether the load can be served and operational reserves can be maintained in a wider range of system conditions. The reliability of the resource plan will also be tested to ensure that sufficient margins can be held in each hour to minimize the risk of insufficient generation.
7. The outputs of the PLEXOS model will be used to inform the set of unit dispatches in the system security analyses. The dispatches will be screened to determine representative cases for normal operations and boundary hours to be more closely examined in the power flow model (PSS/E).
8. Depending upon the results of the system security analyses, the capacity expansion modeling may need to be iterated upon to refine the resource plan for the high level inertia and fast frequency response requirements that were initially modeled or if other system constraints/resources need to be considered in the resource plan.



RESOLVE Model Summary

Objective

- ◆ Capacity expansion model
- ◆ 30 representative days for modified horizon (2025-2034, 2040, 2045, 2050)
- ◆ Models requirements for the following services:
 - Energy
 - Energy Reserve Margin
 - Regulating Reserves
 - Inertia
 - Fast Frequency Response
 - RPS
- ◆ Can solve for portfolios across multiple grid service requirements and for resources that provide a diverse range of grid services
- ◆ Can calculate marginal avoided costs for each grid service
- ◆ Used extensively in California IRP process, Pacific Northwest and many other jurisdictions

Limitations

- ◆ Does not capture granular needs on hourly basis for all years in planning horizon
- ◆ 30 representative days may not capture total range of grid needs and costs, especially in more stressful conditions
- ◆ Does not directly account for maintenance or forced outages

Input Interdependencies

- ◆ PSSE to RESOLVE – Transmission upgrades for renewable energy zones, opportunities for transmission level non-wires alternatives
- ◆ Synergi to RESOLVE – Opportunities for distribution level non-wires alternatives, distribution upgrades for increased DER adoption

Output Interdependencies

- ◆ RESOLVE to PLEXOS – Resource plans through planning horizon (capacity and timing of future resources)



PLEXOS Model Summary

Objective

- ◆ Production simulation model
- ◆ 8760 hours for 30 years of planning horizon
- ◆ Models grid constraints and resource operating characteristics in finer detail
- ◆ Can consider diverse profiles to stress test variable renewable production (i.e., poor weather)
- ◆ Can consider impact of forced and maintenance outages on system reliability

Limitations

- ◆ Capable of resource optimization but requires significant model simplifications to run timely

Input Interdependencies

- ◆ RESOLVE to PLEXOS – Resource plans through planning horizon (capacity and timing of future resources)

Output Interdependencies

- ◆ PLEXOS to PSSE – Hourly dispatch of generating units for system security studies



PSS/E, PSCAD Model Summary

Objective

- ◆ Understand grid security and stability under a range of severe yet credible operation conditions of a resource plan
- ◆ Assess frequency stability, voltage stability, and rotor angle stability of the future grid
- ◆ Evaluate grid forming inverter needs and weak grid issues
- ◆ Understand control interactions between power electronics of inverters and conventional synchronous machines

Limitations

- ◆ Requires a set of unit dispatches to evaluate cases, does not determine economic dispatch independently

Input Interdependencies

- ◆ IGP forecasts and planned resources
- ◆ PLEXOS to PSS/E – Hourly dispatch of generating units for system security studies to create typical and boundary study cases

Output Interdependencies

- ◆ PSS/E to PLEXOS – Transmission-related resources or constraints to address transmission criteria violations



LoadSEER/Synergi Model Summary

Objective

- ◆ Develop locational (circuit level) load and DER forecasts
- ◆ Assess DER hosting capacity
- ◆ Conduct contingency analyses for N-1 scenarios
- ◆ Determine grid upgrades for load growth and DER integration

Limitations

- ◆ Grid upgrades will be highly dependent on location of future resources. LoadSEER will evaluate where future resources will be adopted

Input Interdependencies

- ◆ System level load forecasts for IGP for geospatial allocation

Output Interdependencies

- ◆ LoadSEER to Synergi to model probabilistic hosting capacity
- ◆ Synergi to RESOLVE – Opportunities for distribution level non-wires alternatives and distribution upgrade costs



Subject: Docket No. 2018-0165
Instituting a Proceeding to Investigate Integrated Grid Planning (“IGP”)
Hawaiian Electric Stakeholder Meeting to Address Order No. 37730 and
Ulupono’s Comments on Modeling Approaches

1. Overview

In response to Order No. 37730 *Directing Hawaiian Electric to File Revised Forecasts and Assumptions* issued in the subject proceeding on April 14, 2021, the Company met with the Parties, Stakeholder Council, and members of the TAP on April 27, 2021 to discuss its current modeling approaches and how it differs from Ulupono’s, the tradeoffs between approaches, and which is preferred by the Parties, TAP, and stakeholders.

2. Ulupono’s Approach to Modeling

Ulupono’s approach to modeling focuses on four specific issues.

- Allow RESOLVE to optimize the amount of storage needed for both standalone and paired with solar PV sites, rather than require exactly four hours of storage with utility scale solar
- Use alternatives to the proposed Energy Reserve Margin (“ERM”) calculation or adopt a reserve margin in later years that is tied to a reliability analysis
- Assume batteries and curtailed renewables will be able to provide virtual inertia when needed
- Assume 30 year contracts as the life of the Solar PV system or assume 20-25 with 5-10 year extensions at lower costs

A summary of Hawaiian Electric’s approach, tradeoffs between Ulupono’s and Hawaiian Electric’s approaches, areas of agreement and recommendations are provided below for each of the four issues.

3. Allow RESOLVE to Optimize Paired with Solar Resources

a. Hawaiian Electric’s Approach

In the Company’s model, RESOLVE is allowed to build paired PV and battery systems that are either 4 hour or 6 hour duration as well as standalone storage. Standalone storage is allowed to be optimized for both the capacity (megawatt) and energy (megawatt-hour). Specific durations for paired PV and battery systems are assumed to capture the State Investment Tax Credit (“ITC”) rules more precisely. To capture the impact of the Federal and State ITC on paired PV and battery systems, the ITCs are assumed to directly reduce the dollar per kW capital costs input into RESOLVE. For a paired PV and battery system, a fixed duration for storage is assumed to capture the cap on the State ITC on a per system basis. One system is defined as 1,000 kW. The ITC is first applied to the PV and any residual tax credit under the cap is then applied to the battery.¹

¹ Per HRS §235-12.5, the cap amount shall be \$500,000 per system for commercial property. See https://www.capitol.hawaii.gov/hrscurrent/Vol04_Ch0201-0257/HRS0235/HRS_0235-0012_0005.htm

b. Stakeholder Comments and Tradeoffs

In Ulupono's approach, without bounding the storage duration for a paired PV and battery system and allowing it to freely optimize, the State ITC may be overstated in the resource's cost. In Hawaiian Electric's approach, considering only 4 hour and 6 hour durations may be too rigid and may cause a small amount of excess battery investment.

Other stakeholders recognized that the RESOLVE modeling efforts are intended to identify the grid needs on a technology-neutral basis. The selected resources in RESOLVE serve as a proxy for those needs. Therefore, the current treatment of the State ITC is reasonable. If the ITC is overstated, that might suggest there are more cost-effective resources. Ultimately the RFP and the market will verify the numbers (i.e., price and appropriate duration of storage).

c. Areas of Agreement and Recommendations

Hawaiian Electric and Ulupono both agree that allowing additional paired PV and battery system options in RESOLVE is reasonable.

The recommendation is to include paired PV with 2 hour, 4 hour, 6 hour, and 8 hour battery systems.

4. Use Alternatives to ERM or Adopt a Reserve Margin that is Tied to a Reliability Analysis

a. Hawaiian Electric's Approach

In the IGP process, the Company introduced a new planning criteria called Energy Reserve Margin ("ERM") to satisfy load and plan for a reasonable reserve that can be called upon in emergencies. The ERM planning criteria considers the total firm system capability that is reduced by planned maintenance and outages and increased by hourly dependable capacity ("HDC") of variable renewable resources, shifted load from energy storage resources, and interruptible load, the sum of which must be greater than the load that is increased by the ERM percentage on an hourly basis. The margin provided by ERM is intended to provide reserves to mitigate:

- Loss of largest unit
- Multiple forced outages
- Unplanned maintenance
- Fluctuations in generation from variable resources
- Prolonged poor weather patterns or atypical weather
- Battery failures
- Forecast error

The ERM targets are 30% for O'ahu, Hawai'i Island, and Maui and 60% for Moloka'i and Lāna'i. The targets were selected by analyzing historical data. High risk incidents were studied to examine reserves, unit availability, loads, loss of load hours, and frequency of at-risk conditions.

b. Stakeholder Comments and Tradeoffs

In Ulupono's approach, planning only to include the worst weather day will assume that the worst weather day occurs every year that is simulated and assumes that the worst weather day will also

account for unexpected, forced outages or forecast error where load is unexpectedly higher. Ulupono recommends a 7-step process to assess the “optimal” ERM for the system that starts at 0% ERM and increases the ERM percentage until the desired reliability level is reached.

1. Include worst days in time sampling in RESOLVE
2. Count renewables at their full hourly availability in RESOLVE
3. Set initial ERM to 0%
4. Run RESOLVE with current ERM
5. Test the resulting plan with many years of data (e.g., in PLEXOS) – include all possible weather, realistic forecast errors for load and renewables, forced outages for thermal plants and batteries, etc.
6. If shortfalls are found: increase ERM by a few percent and return to step 4
7. Repeat until shortfalls are cleared

Stakeholders felt that in Hawaiian Electric’s approach, the ERM may be too conservative and overbuild capacity. The ERM may also favor thermal units in its derivation because loss of largest unit, multiple forced outages, and unplanned maintenance are implicit thermal unit considerations. Ulupono noted that the HDC used to calculate the variable renewable contributions excessively discounts the generation provided by these resources and is not necessary

A TAP member commented that they support transition away from a planning reserve looking at peak to one that assesses hourly load. For reference, Southern California Edison and Community Choice Aggregators have proposed a similar planning criteria to energy reserve margin that examines all hours. Planning reserve margin focused on system peak was based on resource adequacy and loss of load. To meet the reliability criteria, the system needed X% of margin. It could be interesting to link and correlate traditional metrics such as loss of load expectation (“LOLE”) with ERM. A large driver of the 30% was driven by multiple unit outages. When considering retirement of fossil units, the risk of concurrent outages diminishes.

Another stakeholder liked the idea of linking ERM to LOLE.

c. Areas of Agreement and Recommendations

Hawaiian Electric and Ulupono agree that further study of the ERM criteria is warranted to determine the appropriate level of reliability that should be solved for in the optimization models.

Hawaiian Electric proposes to test lower percentages (0%, 10%, 20%, 30%) for the ERM target in RESOLVE and evaluate the reliability impact on the resulting resource plans in PLEXOS. A sensitivity will also be performed to remove the HDCs and instead consider the full production profiles. The Company is also open to having HNEI test the reliability of the various resource plans generated from RESOLVE at different ERM levels using their stochastic resource adequacy methodology.

5. Assume batteries and curtailed renewables will be able to provide virtual inertia
 - a. Hawaiian Electric’s Approach

In the IGP process, the Company proposed minimum inertia and fast frequency response (“FFR”) requirements that are complementary and work together to support system frequency in an under-frequency event. The minimum inertia plans for a 3 Hz per second change of frequency event and to allow 0.5 seconds for FFR to activate. The requirement also considers the loss of the largest generator and the impact of legacy distributed PV trip settings. Inertia requirements based on maintaining 3 Hz per second is a progressive metric as mainland systems will rarely see such fast rate of change of frequency, and historically in Hawai‘i, the rate of change of frequency has been lower/slower than 3 Hz per second. Therefore, the minimum inertia requirements have already been minimized to the extent possible.

b. Stakeholder Comments and Tradeoffs

Ulupono recommends the following:

- Make reasonable assumptions for when inertial response will be available from inverters
 - May be available soon based on literature review and recent commercial experience
 - Possibly earlier for grid-scale facilities than DER
- Calculate inertial requirements based on stability studies of power systems with very fast frequency response and virtual inertia from inverters
- Identify near-term, low-cost sources of inertia that can be used until inverter-based inertia is widely available
- Include those assumptions in the RESOLVE modeling
 - The current treatment is arbitrary and likely to result in stranded/unnecessary assets

In Ulupono’s approach, virtual inertia, or specifically, grid forming inverters are promising; however, requirements for grid forming inverters are still being studied. Many questions remain concerning the use of grid forming inverters and are current areas of research. However, Ulupono states that the Company should assume there will be progress within the planning horizon of IGP and that inertia and frequency response should be provided by a reasonable source, which will likely be inverters in the long term plans. Ulupono does not object to the use of synchronous condensers for other critical services such as system protection and fault current, only to omitting inverter response which may reduce the needs for synchronous condensers.

A stakeholder for a large customer mentioned that they have concerns regarding protection. The amount of inverter based short circuit current may cause significant cost and possible reduced reliability. Other customers with large campuses or facilities would need to adapt their protection.

c. Areas of Agreement and Recommendations

Hawaiian Electric and Ulupono agree that further study of the provision of virtual inertia is warranted, that the inertia assumption in RESOLVE is directional only, and that the detailed requirements will be determined through stability studies using other software tools such as PSS/E and PSCAD.

Hawaiian Electric proposes that sensitivity analysis be performed in RESOLVE to assess the cost and impact on the resource plan where batteries and curtailed renewables can provide inertia in the model. To mitigate near-term stability issues, where inverter-based resources are expected to make up 95-100% of the dispatched resources for certain hours of the year in 2023-2025, the Company will minimize

synchronous condenser investments to the extent possible based on stability studies in PSS/E and PSCAD and repurposing of generation assets to synchronous condensers to minimize costs.

6. Assume 30 year contracts as the life of the Solar PV system

a. Hawaiian Electric's Approach

In the IGP process, the power purchase agreements ("PPAs") signed with independent power producers ("IPPs") were assumed to terminate at the end of the contract term to allow the RESOLVE model to re-optimize grid needs when contracts end. New PV and wind resources were assumed to have 20 year term lengths, consistent with the recent Stage 1 and 2 RFP projects.

b. Stakeholder Comments and Tradeoffs

Assuming Ulupono's preference for 30-year contracts, extending existing IPPs may not allow the RESOLVE model to re-optimize in the future when grid needs have changed. Assuming Hawaiian Electric's approach to end PPAs at the end of their term, there could be missed opportunities from extensions of existing IPPs that could be lower cost than requiring a new resource to be built. For new resources, longer contract terms, from 20 years to 30 years, would allow for a lower contract cost and to better match the contract term to the expected service life of the resource. Ulupono asserted that when an existing IPP reaches the end of its 20-year contract, the Company may not receive significantly lower pricing if the contract were renegotiated for another 10 years.

A stakeholder commented that the market provides financing for solar and storage projects over 35-40 year terms. Also, assuming battery warranties were 15 years, within a 20-year contract, the batteries would be replaced in year 15 and still have 10 years of life remaining when the 20-year contract ends.

Another stakeholder did not favor long-term contracts because it may prevent customers from realizing the benefits of declining technology costs.

A stakeholder commented that asking communities to host longer term projects at 40 year terms may potentially span 3 generations.

c. Areas of Agreement and Recommendations

For long-term planning purposes, Hawaiian Electric and Ulupono agree that new PV and wind resources can assume a 30 year term. Stage 1 and 2 RFP projects will also be extended at 50% of their current lump sum costs for a total term of 30 years. Existing PV and wind resources will continue to be removed from service at the end of the contract term.

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