Hawaiian Electric

Grid Needs Assessment & Solution Evaluation Methodology

March 2021 Update

Table of Contents

Table of Figures

1 Introduction

1.1 INTENT & PURPOSE

This document describes how Hawaiian Electric plans to use a combination of the RESOLVE & PLEXOS optimization models, among others, in the Integrated Grid Planning ("IGP") Process to:

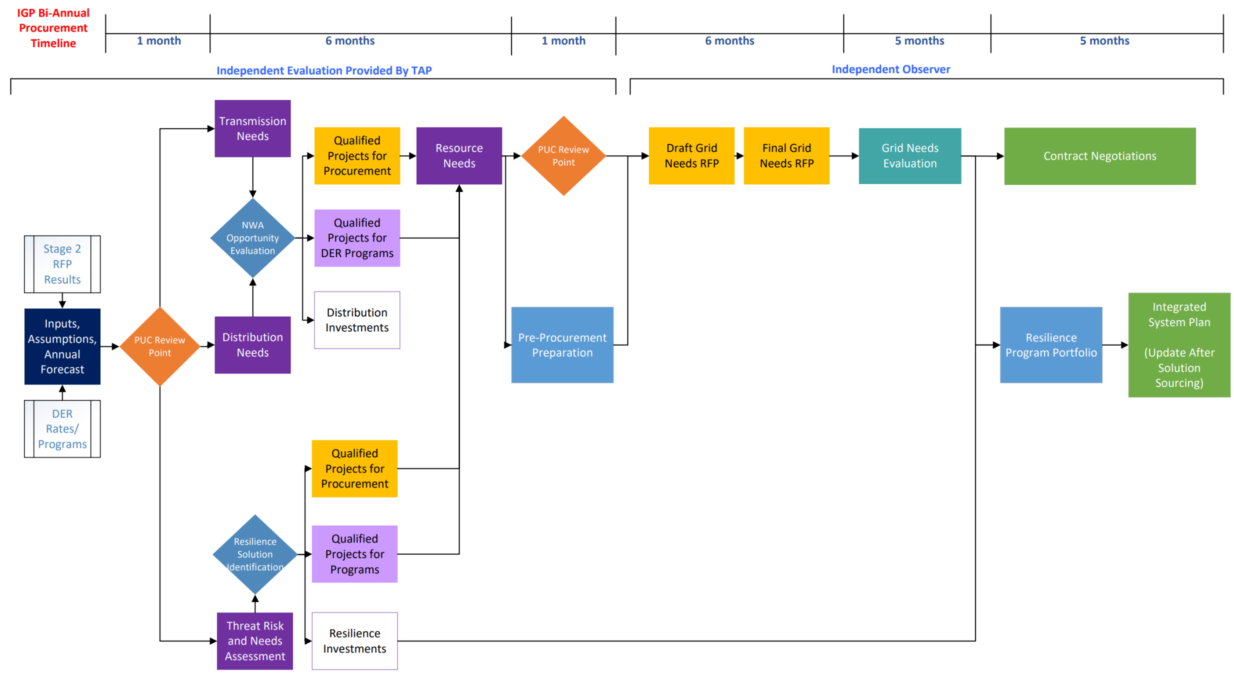
1. Identify the near-term quantity and timing of Grid Needs[1] that will drive future program development and procurement in each IGP cycle as part of the Grid Needs Assessment[2]; and
2. Develop resource plans to identify potential pathways to solve for near-term needs and long-term objectives such as achieving the 100 percent renewable energy goal in 2045.
3. Evaluate proposed solutions as part of an RFP to meet the Grid Needs defined in the Grid Needs Assessment

The main body of this document focuses on the overall process flow of and methodology behind the modeling and analysis, conducted in RESOLVE & PLEXOS, among other modeling tools, to derive the Grid Needs and select solutions to solve for them in an RFP. Hawaiian Electric worked extensively with the Solution Evaluation Optimization Working Group ("SEOWG"), the Technical Advisory Panel, and the Stakeholder Council throughout 2019 and 2020 to develop the methodologies.

[1] "Grid Needs" means the specific grid services (including but not limited to capacity, energy and ancillary services) identified in the Grid Needs Assessment, including transmission and distribution system needs that may be addressed through a Non-Wires Alternative.

[2] "Grid Needs Assessment" means the process step in the IGP where the technical analyses are conducted to determine the generation, transmission, and distribution grid service(s) needs to serve our customers while meeting state policy objectives, reliability standards, among other goals. The Grid Needs Assessment will be presented to the Commission for review and approval.

Figure 1 Updated IGP Solution Evaluation & Sourcing Process Diagram



The process flow in Figure 1 starts with the development of the inputs and assumptions used for the modeling analysis and includes the selected projects from the Stage 2 RFP and updates on any new rates and programs for DER resources. Together, these inputs and assumptions form the first review point to be reviewed by the Commission, Consumer Advocate, Technical Advisory Panel, and stakeholders. Details are available through several documents:

- IGP Inputs and Assumptions, March 2021[3]
- Model Inputs and Assumptions Workbooks[4]
- IGP Stakeholder Feedback Summary, March 2021[5]

Once the inputs and assumptions have been established, the planning work to identify the transmission, distribution, and resource grid needs on an integrated basis will commence. Collectively, the analyses for these three Grid Needs will form the Grid Needs Assessment. The NWA opportunity evaluation process[6] will be applied to the transmission and distribution

[3] Available at, https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/forecast-assumptions-documents.

[4] Inputs workbooks for Oʻahu, Hawaiʻi Island, Maui, Molokaʻi, and Lānaʻi, available under the September 25, 2020 materials at https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/forecast-assumptions-documents

[5] Available at, https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/dkt_2018_0165_20210304_HECO_reply_comments.pdf

[6] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/distribution_planning/20200602_dpwg_non_wires_opportunity_evaluation_methodology.pdf

needs to categorize their fit for a future procurement, program, or utility investment. Needs that could potentially be fulfilled in a procurement or program will be included as part of the resource portfolio that is developed in the resource needs process step. The NWA framework is further described in the *Non-Wires Opportunity Evaluation Methodology* report.[7]

In parallel with the transmission, distribution, and resource needs analyses, the resilience planning process step will begin, starting with the threat-risk and needs assessment. The threat-risk and needs assessment builds upon the work completed by the Resilience Working Group to identify and prioritize threats and locational analysis developed by Jupiter Intelligence to prioritize locations and assets most at risk from flooding and wind. Similar to the NWA process, resilience needs that can be addressed through a procurement or program will be included as part of the resource portfolio in the resource needs process step. The resilience framework is further described in Appendix C, Section 7, *Resilience Planning Framework*.

These analyses for the Grid Needs Assessment will form the second review point. While the analyses are under review, steps will be taken to begin preparation for the needs that can be addressed through a competitive procurement. The Grid Needs RFP will be drafted, finalized, and commenced. Projects that are proposed through the RFP process will be evaluated and contracts will be negotiated with final awardees. The process steps from the Draft Grid Needs RFP through the Contract Negotiations will be under the review of an Independent Observer for RFP within the IGP.

After determining the final awardees in the Grid Needs RFP, the portfolio of grid needs, including resilience, will be evaluated to assess what residual needs remain to be met, in priority order. The Companies' resource plans will also be updated with the known set of RFP projects or programs resulting from the Grid Needs solution sourcing efforts. If there are residual needs from the Grid Needs RFP, a follow-on residual needs solution sourcing may be conducted.

1.2 MODELING OBJECTIVES

Across all modeling described in this document, the Company aims to achieve three overarching objectives to deliver reliable, clean, and cost-effective service to customers.

- Renewable Portfolio Standards
- System Reliability
- Affordability

[7] Available at: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/distribution_planning/20200602_dpwg_non_wires_opportunity_evaluation_methodology.pdf

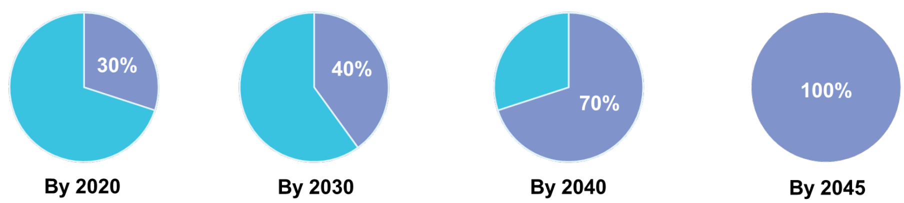
Consideration will also be given to the following factors in the Company's Grid Needs Assessment as part of the goals for the IGP process.

- Environmental Carbon Impact Reduction
- Grid Resilience
- Community Impacts and Land Use

1.2.1 Renewable Portfolio Standards (RPS)

The Grid Needs Assessment will seek to achieve and accelerate the State of Hawaiʻi's Renewable Portfolio Standards ("RPS")[8] mandate of achieving 100 percent of net electricity sales from renewable generation by year 2045, with breakout targets shown in Figure 2.

Figure 2 State of Hawaiʻi Renewable Portfolio Standard (RPS) Targets by Year



Under performance based regulation, the Company is incentivized to accelerate renewable energy achievement through annual targets and a renewable portfolio standard calculation that is based on total renewable energy generated, including customer-sited renewables, instead of the current RPS calculation based on sales. The Grid Needs Assessment will also seek a portfolio that recognizes the intent of the performance based regulation performance incentive for RPS.

1.2.2 System Reliability

The Grid Needs Assessment will account for multiple factors that assure system reliability; including the Grid Needs (*e.g.*, regulation, system security, etc.) as described herein. However, fundamentally, the Company is accountable for Adequacy of Supply[9], which is the ability of the electric system to supply the aggregate electrical demand and energy requirements of our customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

1.2.3 Affordability

The RESOLVE model will develop a resource portfolio to solve for the RPS and System Reliability objectives in a least-cost manner. The model will also consider the costs of installing

[8] *See* HRS §269-92 Renewable portfolio standards.

[9] *See* Adequacy of Supply filings, https://puc.hawaii.gov/reports/energy-reports/adequacy-of-supply/

new resources as well as the costs of operating existing resources in the development of the resource plans. The resource plan will provide insight into resource procurement and system investment decisions needed to achieve the 100 percent renewable energy goal and inform new programs and procurements over the short-term and long-term horizon (20-30 years).

1.2.4 Environmental Carbon Impact Reduction

With increasing renewable generation on the utility system and the retirement of fossil fuel generating units, the expectation is that greenhouse gas ("GHG") emissions will be significantly reduced. Long-term plans can be qualitatively assessed for GHG reduction. GHG reduction assessments of resource plans may also incorporate estimated reductions from an energy ecosystem perspective to include estimated reductions gained through electrification of other sections, including transportation, buildings, etc.

1.2.5 Grid Resilience

There are several ways of looking at grid resilience, the first being hardening of existing grid infrastructure (*e.g.*, upgrades to utility poles, transmission and distribution line monitoring, transformers, etc.) and the second being the ability of the system to return to service in a major outage event (*e.g.*, hurricane, tsunami, act-of-god, etc.). As outlined in the *Resilience Working Group Report for Integrated Grid Planning*,[10] comments from first responders, other infrastructure owners, and other RWG participants will be used to inform transmission and distribution planning needs, priorities for resilience improvement, and options to achieve those identified planning needs and priorities. Notably, this includes consideration of resilience enhancing microgrids to provide local, emergency power generation when parts of the system's transmission and/or distribution system are out of service due to emergency conditions.

Figure 1 illustrates how resilience is directly incorporated into the IGP process. Resilience needs will be assessed as part of the Grid Needs Assessment and then reconfirmed following the Grid Needs RFP. Further details of the resilience needs assessment are provided in Appendix C, Section 7.

1.2.6 Community Impacts and Land Use

The viability of a long-term plan will depend on an assessment of the community impacts and land use in Hawaii. It is imperative that any long-term plans balance multiple state policy objectives, such as energy and food sustainability. The IGP process will be responsive to the feedback received as part of the Company's broad public engagement.[11]

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[10] *See* https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/resilience-documents

[11] *See* https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/broad-public-engagement

Stakeholder Council feedback on community impacts and land use can help inform and modify certain planning inputs used in the modeling. As an example, one of the keys inputs into the modeling is the resource potential for onshore resources that define the maximum capacity of each resource that can be developed on each island. As part of the modeling input development, Hawaiian Electric engaged NREL to update the resource potential study they had conducted during the 2016 PSIP. Results of the updated analysis were shared with the IGP Stakeholder Council and posted to the Company website.[12]

[12] *See* https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/stakeholder-council

2 Industry Survey

The following discussion summarizes the combined learnings from leading states and experts, and feedback from stakeholder discussions in the several SEOWG meetings held in 2019 and 2020.

2.1 INDUSTRY SURVEY FINDINGS

Hawaiian Electric met with other utilities from the U.S. and Australia. At these meetings the other utilities discussed what did and did not work for them during their grid needs assessment and solution evaluation approaches. Based on their experience they have all generally said that they improved the outcome of their competitive solicitation process by providing more operational and technical detail about what specific need was being addressed in technology neutral terms. More specific and clear requirements presented in the Request for Proposal ("RFP") process tended to result in more thorough and consistent responses from bidders. Bidders appreciated the additional detail, because it allowed them to make better decisions about solicitations to pursue where they felt their proposal could be most competitive. They also instilled the importance of preparing structured bid response forms as well as including pro-forma contracts that allowed bidders to prepare accurate and complete proposals that in turn were more easily understood, resulting in a faster evaluation.

Some utilities are also utilizing the concept of Renewable Energy Zone ("REZ") to help foster the addition of more renewables on the system. This is detailed in the Transmission Needs in Section 3.3.

2.2 STAKEHOLDER FEEDBACK

The Company has held fourteen stakeholder working group meetings through the end of 2020 for the SEOWG that have discussed the timeline and methodology for (1) identifying the timing, quantity, and value of various Grid Needs, (2) evaluating potential solutions received in a competitive procurement or a utility program, and (3) presenting initial, preliminary results of the RESOLVE models using the assumptions that have been developed through the Forecast Assumptions Working Group.

During this process, stakeholders asked the Company to clarify and capture the suggestions and modifications to the initially proposed needs assessment and solution evaluation methodology and process in this methodology document. The following is a high level summary of changes and modifications adopted:

1. Inputs & methodology descriptions for the RESOLVE & PLEXOS models to help stakeholders understand the strengths and limitations of the modeling framework;

2. Coordination with the Forecast Assumptions Working Group ("FAWG") to share forecast assumption inputs earlier in the stakeholder engagement process to facilitate more robust discussion on sensitivity analysis;
3. Identify an Independent Evaluator for the Grid Needs Assessment phase and Independent Observer for the Solution Evaluation phase to provide oversight on the modeling and evaluation process;
4. Incorporation of utility programs and non-wires alternatives ("NWA") RFP within the IGP process to provide equal evaluation across resource types;
5. Clarification on the definitions and methodologies used to support identification of the Grid Needs;
6. Inclusion of mechanisms to gauge market interest in long-term projects within the IGP process with the possibility of including them into the IGP cycle;
7. Development of a diagram that depicts a high-level connection between one procurement cycle and the next to clarify the overarching process; and
8. Development of diagrams that show detail of the Transmission and Distribution Needs, and Grid Needs processes.

Further details of the stakeholder feedback that have been received and incorporated are described in *IGP Stakeholder Feedback Summary, March 2021*.

3 Grid Needs Assessment Methodology

3.1 OVERVIEW & PURPOSE

The intent of the modeling objectives and characteristics described herein is to provide a transparent and detailed view of the steps needed to identify the Grid Needs for the Integrated Grid Planning process, as well as the evaluation and optimization of solutions sourced through the Grid Needs procurement.

An overview of the process flow is shown in Figure 3. Forecast assumptions developed in the FAWG serve as the input assumptions into the Resource and Transmission and Distribution Needs assessment, which then inform the Resource Needs identification.

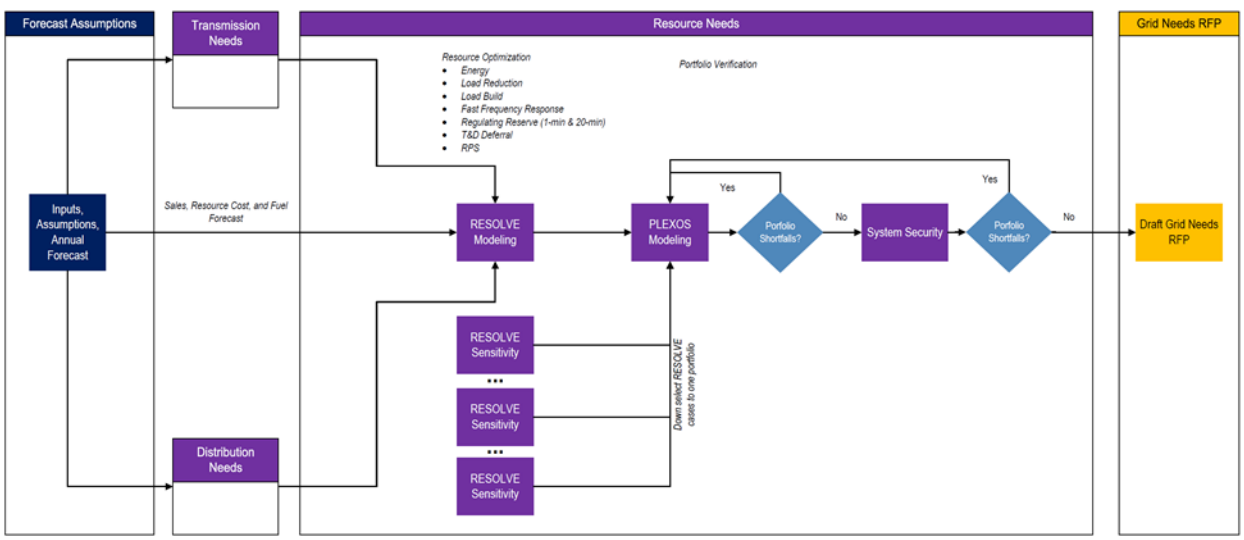


Figure 3 Grid Needs Assessment Modeling Process Flow Diagram

Two models used to identify and verify the grid needs are the RESOLVE model and the PLEXOS model. RESOLVE produces a proposed optimized resource plan of proxy resources that can fulfill the Grid Needs. The primary objective of this phase of the process is to identify Grid Needs using proxy resources; the actual resource plans will be determined subsequent to the solution sourcing step which would define the actual technology or resources that are able to meet the identified Grid Needs. In addition to the RESOLVE base case that is developed using a base set of planning assumptions, further sensitivities will be run in RESOLVE to stress test the key inputs and assumptions with the intent to better understand how certain assumptions influence outcomes and to the extent possible formulate an action plan with least regrets. Once the results of the RESOLVE sensitivities are incorporated into the base case, the resource plan is then evaluated in PLEXOS through an hourly production simulation to ensure that the Grid Needs continue to be met on an 8760 hourly basis and to more finely capture the

annual total system costs. The results of the production simulation in PLEXOS are then used as inputs into the System Security analyses. The System Security analysis will be completed in PSS/E, PSCAD, and/or ASPEN to evaluate needs for short circuit current, inertia, frequency response, voltage support, and assess inverter control interactions, weak grid/system strength issues. Although RESOLVE is solving for some of the requirements that are studied by Transmission Planning such as fast frequency response and inertia, these requirements are high-level estimates that will be validated, and if necessary, adjusted in the models used in the System Security analyses. If the System Security process step identifies any shortfalls in the Grid Needs, the resource plan will be iterated upon to meet those residual needs. To address shortfalls in the Grid Needs, the proxy resources identified in the resource plan may be increased or accelerated from future years.

Following the initial modeling to determine system needs is the Grid Needs RFP. The process iterates during this step, as the solutions bid into the RFP are evaluated through another round of RESOLVE and PLEXOS modeling to create the optimal portfolio of solutions that the utility should procure, while maintaining system reliability at a reasonable cost. In addition, the modeling considers other IGP objectives described in Section 1.2. The process used to evaluate solutions that are solicited in the Grid Needs RFP is further described in Section 4, Solution Evaluation Methodology.

3.2 INPUTS, ASSUMPTIONS & FORECASTS FOR GRID NEEDS IDENTIFICATION

The inputs and assumptions are briefly described in this section; however, a full description of the inputs and assumptions used for the Grid Needs Assessment can be found in the *Inputs and Assumptions*, *March 2021 Update* document.

3.2.1 Forecast Assumptions

The modeling process for the Grid Needs Assessment relies on a set of forecast assumptions to define what the future system could look like. Many of these assumptions will be developed by the FAWG.

3.2.1.1 Fuel Price Forecasts

Fuel price forecasts have been presented and discussed through the FAWG and SEOWG. These are based on a historical Brent correlation and Brent forecast provided by Facts Global Energy ("FGE"). FGE is an independent consultant that provides analysis on the oil & gas industry.

3.2.1.2 Retail Sales Forecasts

Retails sales forecasts have been presented and discussed through the FAWG. The FAWG will produce a deliverable that will have more details regarding the sales forecast.

3.2.1.3 DER Adoption Forecasts

As part of the reference sales forecast, the Company will use a market-based uptake of DER.

Based on stakeholder feedback, the Company clarified that incremental DER would be available as a resource option in the model to be economically selected. The Company proposed that the cost of DERs available for selection could be based on a combination of residential PV and residential battery energy storage to approximate the cost of a DER Aggregator.[13]

The SEOWG and FAWG worked to identify sensitivities for the forecast assumptions with further input from stakeholders. See Section 3.6 for discussion of sensitivities that have been proposed by stakeholders.

3.2.1.4 Resource Cost Forecasts

Resource cost assumptions are based on a combination of publicly available datasets as well as the Company's own assumptions, as shown in Table 1.

Table 1 Resource Cost Data Sources

US Department of Energy (DOE)	National Renewable Energy Laboratory (NREL)	US Energy Information Administration (EIA)	IHS Markit	Hawaiian Electric	General Electric	Siemens
• Distributed wind	• Geothermal • Biomass • Offshore wind	• Waste-to-energy	• Grid-scale PV • Distributed PV • Grid-scale wind • Grid-scale storage • Distributed storage	• Internal combustion engine (ICE) • Pumped storage hydro	• LM2500 and LM6000 Combustion Turbine and Combined Cycle Units	• Synchronous Condenser

Resource cost assumptions from public data sources will be adjusted based on:

1. Location-specific capital and O&M cost adjustments for Hawai'i;
2. Applicable federal & state tax incentives; and
3. Location-specific interconnection costs.

[13] A DER aggregator is a third party that consolidates the function and capability of multiple DER systems

3.2.2 Planned Resource Builds & Retirements

Hawaiian Electric will characterize the current and future planned fleet of resources on each island in the models. Future resources include the projects from the Stage 1 RFP that were filed and approved and the Stage 2 RFP final award group will be built into the modeling, as shown in Figure 1. Additionally, on April 9, 2020, the Commission issued Order No. 37070 in Docket No. 2015-0389, commencing Phase 2 of the CBRE Program, which set the program capacity at 235 MW across the Hawaiian Electric service territory.

Table 2 Near Term Additions to Resource Portfolio[14]

Project	Island	Technology	Size	GCOD[15]	Status
AES Kuihelani	Maui (Central Maui)	Solar + BESS	60 MW, 240 MWh (BESS)	Oct. 27, 2023	Approved by PUC
AES Waikoloa Solar, LLC	Hawai'i Island (Waikoloa)	Solar + BESS	30 MW, 120 MWh (BESS)	Nov. 3, 2022	Approved by PUC
AES West Oahu Solar, LLC	O'ahu (West O'ahu)	Solar + BESS	12.5 M, 50 MWh (BESS)	Sept. 7, 2022	Approved by PUC
Hale Kuawehi Solar LLC	Hawai'i Island (Waimea)	Solar + BESS	30 MW, 120 MWh (BESS)	Dec. 2, 2022	Approved by PUC
Ho'ohana Solar 1, LLC	O'ahu (Kunia)	Solar + BESS	52 MW, 208 MWh (BESS)	Aug. 31, 2023	Approved by PUC
Kupehau Solar	O'ahu (Kunia)	Solar + BESS	60 MW, 240 MWh (BESS)	May 31, 2022	Approved by PUC
Mahi Solar	O'ahu (Kunia)	Solar + BESS	120 MW, 480 MWh (BESS)	Dec. 31, 2023	Approved by PUC
Mililani I Solar, LLC	O'ahu (Mililani)	Solar + BESS	39 MW, 156 MWh (BESS)	Nov. 1, 2022	Approved by PUC
Paeahu Solar LLC	Maui (Wailea)	Solar + BESS	15 MW, 60 MWh (BESS)	Apr. 28, 2023	Approved by PUC
Waiawa Phase 2 Solar	O'ahu (Waiawa)	Solar + BESS	30 MW, 240 MWh (BESS)	Oct. 30, 2023	Approved by PUC
Waiawa Solar Power LLC	O'ahu (Waiawa)	Solar + BESS	36 MW, 144 MWh (BESS)	Dec. 1, 2022	Approved by PUC
Kapolei Energy Storage	O'ahu (Barbers Point Harbor)	BESS	185 MW, 565 MWh	June 1, 2022	Pending Approval
Keahole Battery Energy Storage	Hawai'i Island (Kailua-Kona)	BESS	12 MW, 12 MWh	Dec. 30, 2022	Pending Approval
Barbers Point Solar	O'ahu (Kapolei)	Solar + BESS	15 MW, 60 MWh (BESS)	Dec. 29, 2023	Pending Approval

[14] https://www.hawaiianelectric.com/clean-energy-hawaii/our-clean-energy-portfolio/renewable-project-status-board Retrieved on March 29, 2021

[15] Current status of project timelines for Stage 1 and Stage 2 RFP projects were provided in the Companies' Initial Status Update filed on March 5, 2021 in Docket No. 2021-0024.

Project	Island	Technology	Size	GCOD[15]	Status
Kahana Solar	Maui (Napili - Honokowai)	Solar + BESS	20 MW, 80 MWh (BESS)	Dec. 29, 2023	Pending Approval
Mountain View Solar	Oʻahu (Waiʻanae)	Solar + BESS	7 MW, 35 MWh (BESS)	May 17, 2023	Approved by PUC
Puako Solar PV + Battery Storage	Hawaiʻi Island (Puako, South Kohala)	Solar + BESS	60 MW, 240 MWh (BESS)	Sept. 30, 2023	Pending Approval
Pulehu Solar	Maui (Pulehu)	Solar + BESS	40 MW, 160 MWh (BESS)	Apr. 30, 2023	Pending Approval
Waena BESS	Maui - (Kahului)	BESS	40 MW, 160 MWh	Apr. 28, 2023	Pending Approval
Honua Ola (Hu Honua)	Hawaiʻi Island (Pepeʻekeo)	Biomass	21.5 MW	TBD[16]	Pending Approval
Puna Geothermal Venture	Hawaiʻi Island (Puna)	Geothermal	46 MW	2022	Pending Approval
Kamaole Solar	Maui (Kihei)	Solar + BESS	40 MW, 160 MWh (BESS)	Apr. 30, 2023	Pending Approval
CBRE Phase 2[17]	Oʻahu	Assumed Solar + BESS	170 MW	2025	Future RFP
CBRE phase 2	Hawaii	Assumed Solar + BESS	30 MW	2025	Future RFP
CBRE Phase 2	Maui	Assumed Solar + BESS	30.975 MW	2025	Future RFP
CBRE Phase 2	Molokaʻi	Assumed Solar + BESS	2.75	2025	Future RFP
CBRE Phase 2	Lānaʻi	Assumed Solar + BESS	3 MW	2025	Future RFP

The Company developed assumptions on planned generator retirements of the existing fleet of utility owned generation. These schedules represent initial assumptions made on the timing for the removal of utility-owned, thermal generating units, and can be found in Section 6 of *IGP Inputs and Assumptions, March 2021 Update*. For independent power producers, generally, contracted resources are assumed to expire upon the end of their contract term unless they have evergreen provisions which would allow the contract to continue. For customer sited resources that are participating in a DER program, their available capacity is assumed to continue through the duration of the planning period and no term is considered, although the production from these resources may degrade over time.

3.2.3 Resource Operating Characteristics

Hawaiian Electric characterizes the existing, planned (approved Stage 1 and 2 RFP projects) and new generating resources (capacity expansion candidates) to enable hourly operational

[16] On July 9, 2020, the Public Utilities Commission denied an application for a waiver from competitive bidding and an amended power purchase agreement, creating significant uncertainty about the project's future.

[17] All CBRE Phase 2 capacities will be updated with the RFP final award group projects when publicly available. For the purposes of modeling, we will assume Tranche 1 and Tranche 2 CBRE are put into service in 2025. LMI CBRE projects will be added as more information is available.

modeling for a representative subset of days in RESOLVE (which we will refer to as "day-weighted profiles") and a full 8760-hour simulation in PLEXOS, respectively. Characteristics include:

- Resource generation hourly profiles and day-weighted profiles;
- Operating characteristics (*e.g.*, minimum/maximum capacity, variable operations and maintenance (O&M) cost, fixed O&M cost, heat rate, ramp rate);
- Assumptions on ability to provide different services (duration);
- Location of resources (transmission/distribution constraints such as interconnection limits and additional transmission and distribution costs to interconnect resources);
- New resource potentials from National Renewable Energy Laboratory ("NREL") resource potential study. NREL will conduct a detailed assessment of grid-scale on-shore wind and PV deployment and assess rooftop potential for distributed PV generation. This analysis updates the previous study used as part of the December 2016 PSIP.[18]

3.2.3.1 NREL Resource Potential Study Update

NREL will use their Renewable Energy Potential Model (reV) to assess the potential for solar and wind energy deployment. The solar and wind resource data sets will be sourced from the National Solar Radiation Database and the Hawaii WIND toolkit. The NSRDB has a temporal interval of 30-minutes and nominal spatial resolution of 4 km. The WIND toolkit has an hourly temporal interval with a nominal spatial resolution of 2 km. The model will consider land exclusions such as slope, man-made structures, protected areas, and land cover. System configurations can also be considered in the model such as axis tracking, losses, tilt, panel type, inverter efficiency, and DC/AC ratio.

The NREL Resource Potential Study also includes PV rooftop potential analysis, which will rely upon Light Detection and Ranging (LiDAR) data. The model will consider LiDAR point clouds, buildings, solar resource from the NSRDB, parcels, and tree canopy. The system configurations can also be considered such as, fixed roof, losses, tilt, azimuth, panel type, module efficiency, inverter efficiency, and DC/AC ratio.

The NREL Resource Potential Study has been published on the Company's website.[19] Based on stakeholder feedback, an additional scenario for the grid-scale solar and wind will be modeled to create a "higher" potential case.[20]

[18] *See* December 2016 PSIP, Appendix F.

[19] Available at: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/stakeholder_council/20200818_sc_heco_tech_potential_final_report.pdf

[20] *See Integrated Grid Planning Stakeholder Feedback Summary, March 2021*, at 6.

3.3 TRANSMISSION NEEDS

Transmission Needs will be analyzed by the applicable system models. Identified needs, as described in this section, include the following transmission grid services:

- Inertia
- Short-circuit current
- Voltage support
- Fast frequency response (FFR)
- Primary frequency response (PFR)
- Transmission Capacity

As illustrated in Figure 3, the output of the transmission needs analysis will serve as inputs to the RESOLVE model.

Hawaiian Electric will characterize the transmission topology of each island to enable transmission constraints to be reflected in the RESOLVE and PLEXOS models. Similar to the Stage 1 and 2 Requests for Proposals for renewable dispatchable generation, developers are encouraged to utilize existing transmission infrastructure. However, the Stage 1 and Stage 2 market procurements demonstrated that transmission constraints reside in areas with high variable renewable development such as, South Maui, the Waikoloa area in West Hawai'i Island, and West O'ahu. To interconnect additional resources, transmission upgrades must be completed.

The Company will leverage the NREL resource potential study update described in Section 3.2.3.1, to identify major and minor transmission upgrades. Minor transmission upgrades, line reconductoring that can be completed within a two year timeframe, can be identified to maximize the utilization of existing infrastructure. The Company will also identify high potential renewable zones, that can be used to identify major transmission upgrades needed to harness renewable energy on each island.

The renewable energy zone concept[21] will require an extensive planning process centered around community and stakeholder engagement; however, the intent of the renewable energy zone concept in the first IGP cycle is to identify the cost of potential major & minor transmission upgrades that will allow RESOLVE to determine whether generation in various zones on each island and transmission buildout decisions are least-cost compared to non-wires alternatives or alternate sites and resources. If determined to be directionally cost-effective then developing renewable energy zones may be included in the resulting IGP action plan.

The RESOLVE model will incorporate a minimum inertia and frequency response requirement to assess high level system security. This is intended to reduce the iterations between the system security analysis and the resource planning grid needs development through RESOLVE

[21] *See* NREL's renewable energy zone guidebook, https://www.nrel.gov/docs/fy17osti/69043.pdf and the process undertaken at AEMO, https://aemo.com.au/-/media/files/major-publications/isp/2020/appendix--5.pdf?la=en

and PLEXOS. By recognizing inertia and FFR requirements, those services are presumably incorporated into the resource plan and likely meet most if not all of the need when evaluated in detail through the appropriate transmission planning software.

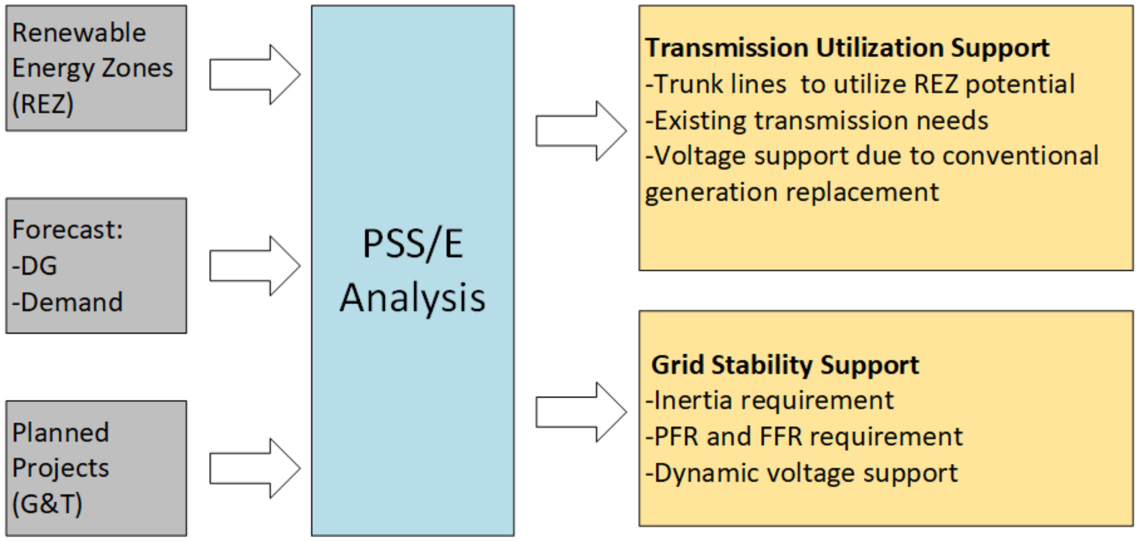


Figure 4 High level process for transmission needs analysis

Transmission needs analysis will be performed in accordance with the Hawaiian Electric transmission planning criteria included in Appendix C and common industry practices, as applicable. The analysis will include the following key components:

1) Develop a 2045 base case (end state) utilizing the forecasted demand, DER forecast and planned resources (e.g. stage 1 and 2 RFP projects). The NREL Resource Potential Update Study will provide renewable energy zone (REZ) maps for each island to inform the potential location of future renewable resources.
2) Identify the injection capacity available at each transmission substation to prioritize favorable locations for renewable energy injections into the system from a technical and engineering perspective. Land use and community engagement, and other issues, will be incorporated into the overall REZ process if first deemed viable from a technical and economic perspective.
3) Based on above insight and location of the potential REZ, identify if transmission trunk lines need to be built to transport renewable energy from the REZ locations to the favorable locations on the transmission grid.
4) Identify additional transmission capacity needs in 2045 based on the transmission planning criteria. This would include new transmission facilities as well as upgrades to the existing infrastructure.
5) Identify steady-state voltage support required, if any, due to taking conventional generation offline.
6) High-level evaluation of grid stability services. Further details are provided in Appendix C, Section 4 and 5.

a) Minimum inertia requirement for a 3Hz/s rate of change of frequency event to allow a minimum of 0.5 sec for fast frequency response to activate. Minimum inertia calculation takes into account largest generation trip contingency along with legacy DGPV that would trip based on under-frequency protection settings. The minimum inertia requirement is based on the acceptable load shedding criteria for each island.
b) Fast frequency response and primary frequency response requirements to survive largest generation loss contingency.

Short circuit current and voltage support will not be incorporated into RESOLVE, but rather assessed as part of the system security analyses described in Section 3.3.1, along with a validation of the inertial and frequency response requirements identified in the RESOLVE modeling.

After the Transmission Needs analysis is completed, the results will serve as inputs to the RESOLVE and PLEXOS modeling.

Table 3 Transmission Input Summary

Input	Units	Description	Data Source
Transmission limits between zones	MW	Depends on how topology is defined – RESOLVE is a zonal model	Transmission Need Analysis
Nomograms / Simultaneous imports/exports limits	MW	E.g. sum of imports from a zone can not exceed 5 GW. Results of the Transmission Need analysis would show if such a limit exists within each island system	Transmission Need Analysis
Losses	%	System losses for each year for the assumed transmission topology	PSS/E models
Transmission limits for renewable development	MW	If applicable, specify how much capacity can be integrated within current transmission infrastructure.	Transmission Need Analysis
Renewable transmission upgrade cost	$/kW-yr	If applicable, specify how much it would cost to upgrade transmission to deliver additional renewables beyond the transmission limit in the row above.	Company Unit Cost
Inertia requirement	MW-s	Minimum inertia requirement for a 3Hz/s rate of change of frequency event to allow a minimum of 0.5 sec for fast frequency response to activate	Transmission Need Analysis

Frequency response requirement	MW	Fast frequency response and primary frequency response requirements to survive largest generation loss contingency	Transmission Need Analysis

3.3.1 System Security Study

The preferred procurement scenario described in Section 3.7 will undergo a more extensive system security analysis in PSS/E, ASPEN, and / or PSCAD based on the outputs of hourly PLEXOS modeling, with the intent to validate the transmission grid needs identified through the RESOLVE model. The objective of the system security analysis is to understand the grid security and stability under a range of severe yet credible operating conditions of the preferred procurement scenario.

The system security analysis will analyze day minimum load, day peak load, night minimum load and evening peak load system conditions with appropriate generation dispatch for each condition as informed by the production cost simulation results. The dispatch for each case will honor the minimum inertia and minimum fault current requirements. The analysis will be performed in accordance with the Hawaiian Electric transmission planning criteria described in Appendix C, and common industry practices, as applicable.

The system security analysis will be an expansion of the transmission need analysis and will include a more detailed evaluation of varying system conditions and credible contingencies including loss of the largest generation event. The analysis will produce the following key deliverables:

- Strategies and mitigations required for safe and reliable operation of the grid with 100% renewables
- Typical dispatch and operational requirements for grid operation with 100% renewables
- Frequency stability, voltage stability and rotor angle stability (if applicable) performance of the future grid
- Impacts of transmission events on the distribution system and vice versa
- Evaluation of the need for grid forming technology and demonstration of system performance with this technology when and if needed for the future grid
- Evaluation of weak grid issues and development of a “weak grid” definition for each of the island grids, which includes investments or mitigation strategies to operate a gird with little to no synchronous generation. Weak grid conditions could include low short circuit current availability, low inertia, and limited reactive power support.
- Identification of additional transmission grid services needed over the near-term 5-year planning horizon

- Road map of transmission needs and strategies required to achieve 100 percent renewable energy goals by 2045

It is important to note that currently there is no universally accepted definition of grid forming technology. Grid forming inverters are capable of operating in grid forming mode supporting system operation under normal and emergency conditions without relying on the characteristics of synchronous machines. This includes operation as a current independent AC voltage source during normal and transient conditions (as long as no limits are reached within the inverter), and the ability to synchronize to other voltage sources or operate autonomously if a grid reference is unavailable. These capabilities will vary from manufacturer to manufacturer. However, it is expected that the grid forming inverters will enable safe and reliable grid operation when less synchronous generation is present on the grid. The grid forming inverters will also help with integrating more grid following inverters. While there are some uncertainties related to the impacts of grid forming technology, as the industry evolves and the technology matures, grid forming inverters will play a key role in achieving the 100 percent RPS goal.

If system security deficiencies exist on the selected PLEXOS long term resource portfolio, then there may need to be an additional iteration between the system security and RESOLVE and PLEXOS modeling. However, it is expected that the identification of transmission grid services in the transmission needs step will substantially cover the needed transmission grid services.

3.4 DISTRIBUTION NEEDS

Distribution needs will be analyzed using LoadSEER and Synergi distribution planning models. Identified needs include:

- Distribution capacity
- Distribution reliability (back-tie)

Refer to the DPWG deliverables, *NWA Opportunity Evaluation* and *Distribution Planning Methodology* for further discussion.[22]

3.5 GRID NEEDS

Inclusive of the inputs and analyses described above, the following Grid Services have been identified as defining the Grid Needs. The definitions provided in Table 4 describe which models will either partially or fully evaluate the specific service. Generally, RESOLVE and PLEXOS will evaluate services as part of the resource needs step whereas PSSE, PSCAD, and

[22] https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/distribution-planning-and-grid-services-documents

ASPEN will evaluate services as part of either the transmission or distribution needs steps. The types of properties needed to characterize each service are shown in Table 5, Table 6, and Table 7.

Table 4 Grid Service Definitions

Grid Service	Definition	Represented in RESOLVE & PLEXOS	Represented in PSSE/PSCAD/ASPEN
Energy	A continuous, controllable, and predictable supply of megawatt-hours to serve system load needs in response to Company Dispatch[23]	✓	Not Represented
Energy Reserve Margin	A guideline to minimize risk of insufficient generation capability from a diverse mix of generating resources available to the system in long-range generation expansion studies	✓	Not Represented
Load Reduce	Capacity that can be provided by a generator, storage or controlled load to reduce system load in the required timeframes and durations in response to a remote dispatch signal.	✓	Not Represented
Load Build	Capacity that can be provided by storage or controlled load to increase system load in the required timeframes and durations in response to a remote dispatch signal.	✓	Not Represented
Regulating Reserves	A reserve capacity provided by generating and load resources to allow continuous energy balance over the next 1 minute and 20 to 30 minute time interval due to the variability in renewable resources and load that can be called upon in response to Company Dispatch. The quantitative analysis for Regulating Reserves is described in **Appendix C.**	✓	Not Represented

[23] "Company Dispatch" as defined in the PPA and SFC means Company's right, through supervisory equipment or otherwise, to direct or control both the capacity and the energy output of the Facility from its minimum output rating to its maximum output rating consistent with this Agreement (including, without limitation, Good Engineering and Operating Practices and the requirements set forth in Section 3 (Performance Standards) of Attachment B (Facility Owned by Subscriber Organization to this Agreement), which dispatch shall include real power, reactive power, voltage, frequency, the determination to cycle a unit off-line or to restart a unit, the droop control setting, the ramp rate setting, and other characteristics of such electric energy output whose parameters are normally controlled or accounted for in a utility dispatching system.

Grid Service	Definition	Represented in RESOLVE & PLEXOS	Represented in PSSE/PSCAD/ASPEN
Inertia	Contribution to the capability of the power system to resist changes in frequency by means of an inertial response from a generating unit, network element or other equipment that is electromagnetically coupled with the power system and synchronized to the frequency of the power system.	✓	✓
Primary Frequency Response (PFR)	Automatic and autonomous response to frequency variations through a generator's droop parameter and governor response.	◑	✓
Fast Frequency Response (FFR1)	An autonomous and predictable capacity to limit the frequency drop resulting from a frequency disturbance.	✓	✓
Voltage Support	Ability of generators or other equipment to produce or absorb reactive power to maintain the system voltages within specified limits.	Not Represented	✓
Short-Circuit Current	Available current under fault conditions at a given location. A minimum value is required for proper coordination of protective devices and a safe and reliable operation of protection system.	Not Represented	✓
RPS	% of annual retail sales forecast	✓	Not Represented
Transmission Capacity	A supply and/or a load modifying service that DERs and grid-scale resources provide as required via the dispatch of power output for generators and electric storage, and/or reduction in load that is capable of reliably and consistently reducing net loading on desired transmission infrastructure in response to Company Dispatch.	◑	✓
Distribution Capacity	A supply and/or a load modifying service that DERs provide as required via the dispatch of power output for generators and electric storage, and/or reduction in load that is capable of reliably and consistently reducing net loading on desired distribution infrastructure in response to Company Dispatch.	◑	Represented in Synergi/LoadSEER

Grid Service	Definition	Represented in RESOLVE & PLEXOS	Represented in PSSE/PSCAD/ASPEN
Distribution Reliability	A load modifying or supply service capable of improving local distribution reliability under abnormal conditions (i.e., substation N-1) in response to Company Dispatch.	◑	Represented in Synergi/LoadSEER

Table 5 Grid Service Properties for Modeling (1 of 3)

Property	Energy Service	Energy Reserve Margin Service	Load Reduce Service	Load Build Service	Regulating Reserve Service
Resource Type	Firm Generator Variable Generators Storage	Firm Generator Variable Generators Storage	Firm Generator Variable Generator Storage Load Under Control	Storage Load Under Control	Firm Generator Variable Generator Storage Load Under Control
Availability	Months	Months	Months	Months	Need by Hour
Size	MW	MW	MW	MW	MW
Duration	Hours	Hours	Hours	Hours	
Delivery Timeframe	Hours	Hours	Hours	Hours	
Probability of Exceedance	%	%			
Number of Service Calls			As specified	As specified	
Regulating Reserve Type					1 – minute or 20-30 minute
Ramping Capability					MW/ minute
Service Source	Market Service	Market Service	Market Service	Market Service	Market Service

Table 6 Grid Service Properties for Modeling (2 of 3)

Property	**Fast Frequency Response (FFR-1) Service**	**Primary Frequency Response (PFR)**	**Short Circuit Current**	**Inertia**	**Voltage Support**
Resource Type	Variable Generator Storage Load Under Control	Firm Generator Variable Generator Storage Load Under Control?	Synchronous generators Synchronous Condensers	Synchronous generators Synchronous Condensers	Firm/Variable Generator Storage Synchronous Condenser Reactive Devices (SVC, Statcom, Capacitors, etc.)
Availability	12 cycles or less	Seconds	Cycles	Instantaneous	Cycles
Size	MW	MW	Amperes	Joules	MVAR
Duration	Minutes	Seconds	Cycles		
Number of Service Calls	As specified				
Reaction Time	As specified	As specified	Instantaneous	Instantaneous	As Specified
Rise Time	Milliseconds	Milliseconds			
Setting Time	Milliseconds	Milliseconds			
Overshoot	%	%			
Setting Band	%	%			
Service Source	Market Service	Mandatory Requirement in 14H and PPAs	Non-Market Service	Non-Market Service	Non-Market Service

Table 7 Grid Service Properties for Modeling (3 of 3)

Property	**Distribution Capacity Service**	**Distribution Reliability (Back-Tie) Service**
Resource Type	Firm Generator Variable Generator Storage Load Under Control	Firm Generator Variable Generator Storage Load Under Control
Availability	Seconds	Seconds
Size	MW	MW
Duration	Hours	Hours

Number of Service Calls	Delivery Months, Delivery Hours, and Max Days per year	Delivery Months, Delivery Hours, and Max Days per year
Service Source	Market Service	Market Service

In addition to the tables above, the Grid Needs can be shown graphically to illustrate the seasonal and time of day need for certain services. As an illustrative example, Grid Needs for the load reduce service are shown below.

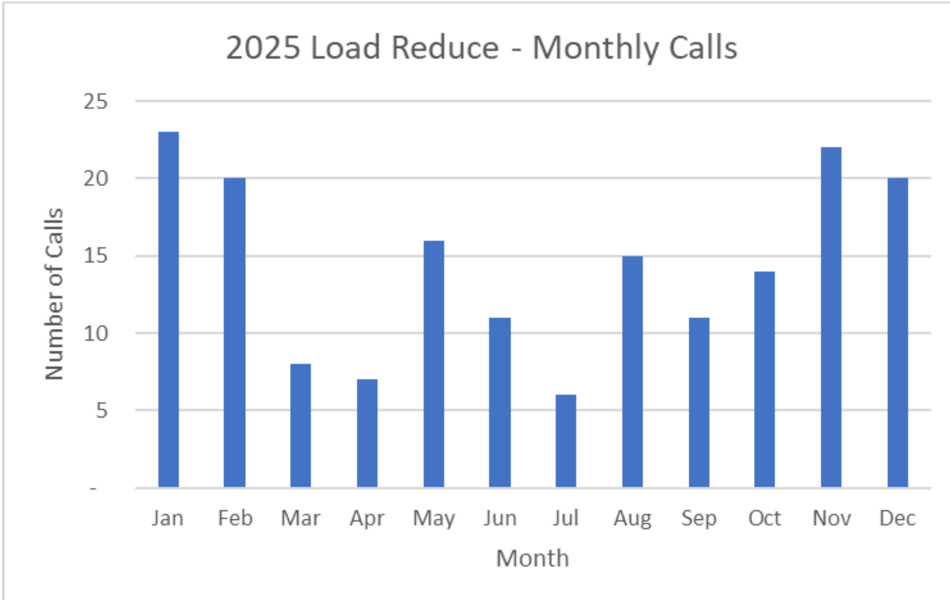


Figure 5 Example of Monthly Calls for Load Reduce in Year 2025

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2025	23	20	8	7	16	11	6	15	11	14	22	20
2030	26	22	14	9	15	15	5	23	12	15	21	22
2040	22	22	11	6	12	14	5	18	9	15	22	22
2045	18	20	7	4	8	9	1	12	11	17	19	16
2050	3	4	-	-	-	-	2	4	2	3	2	1

Figure 6 Example of Monthly Calls for Load Reduce Across the Planning Horizon

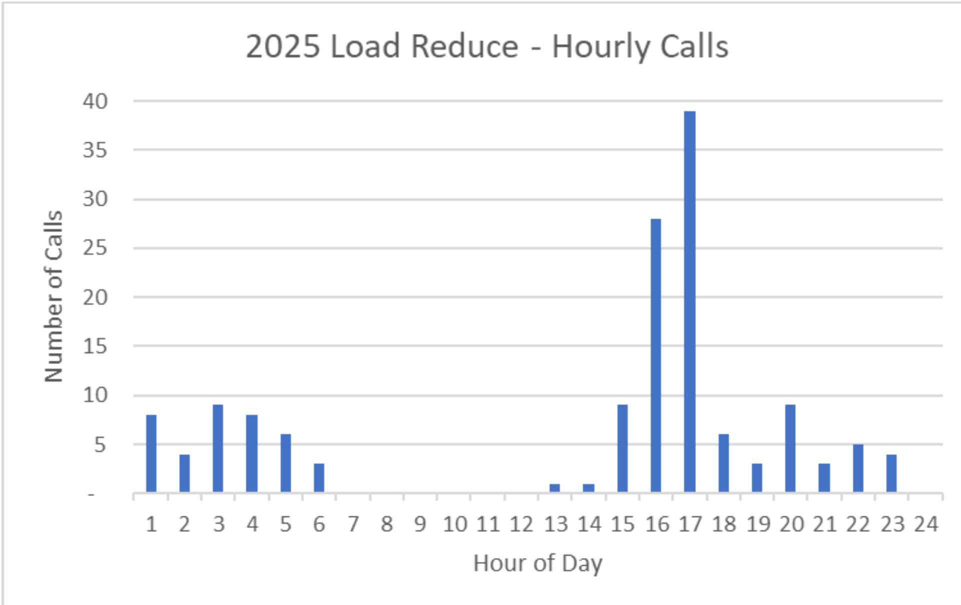


Figure 7 Example of Hourly Calls for Load Reduce in 2025

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
2025	8	4	9	8	6	3	-	-	-	-	-	-	1	1	9	28	39	6	3	9	3	5	4	-
2030	5	2	9	13	7	3	1	-	-	-	-	-	-	-	15	30	32	15	10	6	4	6	3	-
2040	6	8	3	9	8	1	-	-	-	-	-	-	-	-	3	26	35	13	3	6	7	8	5	-
2045	7	5	5	4	10	2	1	-	-	-	-	-	-	-	3	8	19	8	6	9	4	7	2	-
2050	-	3	3	-	3	2	-	-	-	-	-	-	-	-	-	-	3	1	-	1	2	-	-	-

Figure 8 Example of Hourly Calls for Load Reduce Across the Planning Horizon

3.5.1 Grid Service Capability by Technology

Based on feedback from both the TAP and stakeholders, Table 8 provides technologies that are available today and can provide the various grid services. However, solution sourcing is intended to be technology-neutral; therefore, Table 8 is not meant to constrain potential solution proposals. Further, not all candidate resources may be modeled as an option for selection in RESOLVE. The least-cost representative technology from each of these resource categories will be input into RESOLVE to allow the portfolio selection to solve in a timely manner. For example, a conventional thermal resource could be represented by a biofuel capable combined cycle and not require modeling of all conventional thermal resources as resource options. The representative technology is only meant to serve as a proxy for a resource capable of providing the suite of grid services in Table 8 and does not assume any requirements for a particular resource in the RFPs that are evaluated in the solution evaluation phase of the IGP process.

Table 8 Grid Service Capability by Technology

Service by Resource	Inertia	Fast freq. response	Primary freq. response	Reg Reserve	Energy Reserve Margin	Tx Capacity	Dist Capacity	Energy	Load Reduce	Load Build	Short-circuit current	Volt. Support	RPS	Grid Forming[5]
Conventional Thermal														
PSH					3									
GS BESS					3						1			
Paired Wind					2						1			
Paired GS PV					2						1			
Standalone Wind					2	*	*				1			
Standalone GS PV					2	*	*				1			
Dist. BESS				4	3						1			
Dist. PV				4	2	*	*			*	1			
Load Control				4										
Energy Efficiency														
Sync. Cond.														

1. Requires grid forming inverter capability; 3-5+ years away (Technology in transition)
2. Contribution to ERM limited by hourly dependable capacity
3. Contribution to ERM subject to change as resource portfolio changes
4. Requires controllability/communications for frequent dispatch signals (i.e., AGC)
5. Area of research; however in general there's an emerging consensus that a resource is needed to provide very short-term voltage stability (i.e., form the voltage waveform) in high inverter-based systems.

* Partially capable following stakeholder feedback

3.6 SCENARIO DESIGN FOR GRID SERVICE NEEDS IDENTIFICATION

Hawaiian Electric proposes using scenario analysis as the principal framework for identifying Grid Needs for each island's grid. The inputs and grid service definitions described below will be used to develop scenarios and sensitivities to capture a reasonable range of potential outcomes relevant for the Company's planning.

Hawaiian Electric and stakeholders have developed a core set of planning scenarios that represent the most plausible combination of input assumptions. The Company has also solicited feedback from stakeholders to identify additional sensitivities (similar to the work

done in the December 2016 Power Supply Improvement Plan update) to understand the effects of certain assumption changes.

To date, stakeholders have proposed numerous sensitivities on topics such as:

- Bookends of the load forecast
- DER uptake up to and exceeding the market forecast
- Higher levels of energy efficiency
- Removal of the State ITC for PV
- Limiting onshore grid-scale resource development
- Extended periods of low renewable generation
- Electric vehicle charging behaviors

Hawaiian Electric has further described the sensitivities and their inputs in Appendix E.

3.7 GRID NEEDS ASSESSMENT MODELING PROCESS

Hawaiian Electric proposes that the overall IGP process will run on a two-year cycle as shown in Figure 1. Within this process, the Company expects large resource and grid service procurements to occur once per cycle, while utility programs and Transmission and Distribution ("T&D") NWAs will be evaluated on an annual basis to address rapidly evolving local needs.

Based on guidance provided by the Commission, Hawaiian Electric will expand the role of the TAP to provide independent evaluation of the Grid Service Needs Identification. In this phase of the IGP process, the TAP may independently model and verify the methodology and results developed by the Company.

The resource portfolio selected at the end of each IGP cycle will form the basis for the assumptions in the next cycle. At the start of each cycle, as shown in Figure 1, existing resource plans and input assumptions will be re-evaluated and refreshed based on the best-available information on each island. Additionally, the Company will solicit stakeholder, Commission, and Consumer Advocate ("CA") review on these input assumptions.

3.7.1 Initial Scenario Analysis

In the first phase of Grid Needs Assessment, Hawaiian Electric will run RESOLVE in increments through the modeling horizon (2025-2034, 2040, 2045, 2050) to develop long-term resource portfolio plans ("reference portfolios") based on a base set of assumptions as well as the scenarios and sensitivities described in Appendix E. Running RESOLVE in increments in the initial phase allows more scenarios and sensitivities to be run in order to inform and develop robust reference portfolios. Based on stakeholder feedback, having additional contextual information on various assumptions will be useful for guiding discussion on both short- and

long-term needs. As an example, the Commission recently issued Order No. 37070 in Docket No. 2015-0389 that commenced Phase 2 of the Community-Based Renewable Energy ("CBRE") Program. The RFPs in this CBRE order provide an opportunity to apply the grid needs assessment and solution evaluation methodologies described herein as well as additional contextual information on the Company's long-term needs.

3.7.2 Preferred Procurement Scenario

As shown in the Figure 3 , after developing various scenarios and sensitivities, Hawaiian Electric will reconcile the multiple potential portfolio options, since each sensitivity could potentially produce different least-cost resource portfolios. The sensitivities in Appendix E will be used to test assumptions made in the reference portfolio as well as test the reference portfolio. Sensitivity analyses will also be used to address the TAP's feedback on creating high and low bookends around the market forecast by adjusting the levels of DER and energy efficiency, among other forecast layers. The results of the sensitivities may be incorporated into the reference portfolio by modifying the resource plan. Hawaiian Electric will then rank the potential portfolios based on the Modeling Objectives described in Section 1.2**.**

The sensitivity and feasibility analysis may be used to capture non-cost considerations, such as community impacts and its effect on developable resource potentials for various resources. This may be achieved by changing resource or system assumptions to reflect different factors based on stakeholder feedback.

Proposed Methodology:

1. Rerun RESOLVE to develop a grid service needs forecast for the same planning horizon (2025-2034, 2040, 2045, 2050), focusing only on the updated reference portfolio and core scenarios.
2. Since RESOLVE uses representative sampled days in its resource selection, the reference portfolio will be transferred into PLEXOS for a detailed 8760-hour, annual feasibility check.
3. Conduct a system security assessment using power systems tools (like PSS/E or other) to identify grid service needs like inertia, voltage support, grid strength for each scenario/sensitivity. Additional investments or constraints required as a result of this assessment will then inform RESOLVE/PLEXOS models and inputs.
4. Should there be any shortfalls in any of the grid services on an hourly basis that were not met by RESOLVE's reference portfolio, Hawaiian Electric may determine that adjustments need to be made to the RESOLVE constraints and rerun or that adjustments can be made manually to the reference portfolio without requiring additional modeling. Manual adjustments may include expanding selected resources in the same year as the shortfall or accelerating resources from later years into the year with the shortfall.
5. Qualitatively assess the resources selected in RESOLVE that have been mapped from the NREL Resource Potential Study described in **Section 3.2.3.1**. In developing a

resource portfolio, if RESOLVE chooses to develop certain areas of each island (by selecting additional grid-scale PV or on-shore wind), a qualitative assessment can be performed to characterize the location of the resource and any additional transmission infrastructure that would be required to interconnect to determine potential community impacts and resilience benefits.

Through this sensitivity and feasibility analysis process (described above), the Company will identify a Preferred Procurement Scenario to potentially use in defining the Grid Needs and NWA RFPs, subject to Commission review.

The comparison of the various resource portfolios and the determination of Hawaiian Electric's Preferred Procurement Scenario will be shared with stakeholders at the second PUC Review Point shown on Figure 1. During this review point, the TAP and the Commission may ask Hawaiian Electric to perform feasibility checks on additional scenarios if the additional analysis is deemed prudent to make a final determination during Commission review.

3.7.3 Final Procurement Scenario

Based on stakeholder and Commission feedback during the second Review Point, a Final Procurement Scenario will be established for use in defining the Grid Needs and NWA RFPs. The Commission may ask Hawaiian Electric to perform additional feasibility and reliability checks to aid in the determination of the Final Procurement Scenario. If different than the Preferred Procurement Scenario, the Company will complete any additional feasibility or reliability checks not already completed for the scenario before proceeding.

The Final Procurement Scenario will determine a final reference portfolio of resources that meets the identified Grid Needs.

3.8 ADDITIONAL OUTPUTS FROM GRID SERVICE NEEDS IDENTIFICATION MODELING

3.8.1 Avoided Cost of Service

As described in Section 3.5, Grid Services are defined in RESOLVE and PLEXOS as mathematical constraints.[24] Given that the Final Procurement Portfolio represents Hawaiian Electric's best estimate at a least cost portfolio that meets all these Grid Services, this portfolio will set a baseline for the expected quantity, timing, and marginal avoided cost for each of the Grid Services. See Table 9 for more details.

Table 9 Quantity Units, Time Granularity, and Avoided Cost Units for Grid Services

Grid Service	Quantity Units	Time Granularity	Avoided Cost Units

[24] Transmission deferral, distribution capacity, and distribution reliability will be modeled externally.

Energy	MWh	Hourly	$/MWh
Energy Reserve Margin (ERM)	MW-hour	Hourly	$/MW-year
Load Reduce	MW-hour	Hourly	$/MW-hour
Load Build	MW-hour	Hourly	$/MW-hour
Fast Frequency Response (FFR1)	MW-hour	Hourly	$/MW-hour
Regulating Reserves	MW-hour	Hourly	$/MW-hour
RPS	MWh	Annual	$/MWh
Transmission Deferral	MW-year	Annual	$/MW-year
Distribution Capacity	MW-year	Annual	$/MW-year
Distribution Reliability	MW-year	Annual	$/MW-year

These Grid Needs Assessment modeling outputs will define the procurement targets that Hawaiian Electric will use when developing the RFPs and programs. Due to the interdependent and dynamic nature of many of the Grid Service definitions (as described below), the exact quantity procured at the end of the Solution Evaluation process may differ from those initially set out in the procurement targets; however, Hawaiian Electric will provide stakeholders with a clear understanding of the formulas used to determine the Grid Needs.

Subsequent subsections describe how the quantity, timing, and avoided cost of services are derived from the modeling outputs.

3.8.1.1 Quantity and Timing

The input parameters to these modeling constraints will determine the quantity of each Grid Need to support the grid. Forecasted load and load shape determines the amount of capacity and energy that needs to be generated on an hourly basis to meet that load. For some Grid Services, such as Regulating Reserve, the requirement will be modeled on an hourly basis and is dependent on the installed capacity of variable energy resources. RESOLVE takes these interdependent requirements into consideration when calculating the least-cost resource portfolio.

The timing of Grid Needs is captured in RESOLVE and PLEXOS through these modeling constraints. As existing resources that provide certain services retire or as the requirement varies due to changing system and portfolio conditions, new resources will be selected to meet each of the modeled Grid Need requirements, indicating the year and time of year that new resources are needed to provide the service.

Resources selected by RESOLVE provide proxies for the amount of grid services that are required in a specific year, month, day and hour. These can be summarized in tabular form and graphically. Examples are provided in Section 3.5.

3.8.1.2 Avoided Cost

Hawaiian Electric proposes to use the marginal cost of each Grid Service as the avoided cost of each Grid Service. These marginal costs are derived from the shadow price on the relevant constraints in the RESOLVE and PLEXOS models. Shadow prices are a fundamental output of constrained optimization problems like those used in RESOLVE and PLEXOS and represent the marginal cost to the overall system of procuring and dispatching resources to provide the next incremental unit of the service. Shadow prices are useful to define prices for hard to value services where a market based price does not exist.

This marginal cost approach is analogous to a market clearing price for procuring an equivalent service in a market context.

The EIA Handbook of Energy Modeling Methods includes an introduction to optimization modeling in Appendix B6 on Mathematical Programming[25]. As explained in the handbook,

> An optimization model seeks to optimize (minimize or maximize) an *objective function* subject to *constraints*.

The EIA handbook goes on to explain that several different outputs are intrinsic to the optimal solution:

> An optimal solution is characterized by:
> - Objective function value
> - Decision variable values
> - Shadow prices (for constraints)
> - Slacks (for constraints)
> - Reduced costs (for decision variables)

The EIA handbook defines the shadow price as follows:

> The *shadow price*, or dual price, of a constraint is the partial derivative of the objective function with respect to the right-hand side of the constraint, evaluated at the point specified by the optimal solution. In other words, a constraint's shadow price tells how much the value of the objective function would change if the scalar portion of the constraint were changed by a small amount.

[25] Energy Information Administration, "Handbook of Energy Modeling Methods. Appendix B6: Mathematical Programming" (2020). https://www.eia.gov/analysis/handbook/ (accessed March 26, 2021).

> For some carefully constructed [optimization problems], the shadow price can be interpreted as the price of a resource or product.

As noted in the textbook "Applied Mathematical Programming,"[26]

> The shadow price associated with a given constraint corresponds to the change in the objective function when [the constraint] is increased by one unit. Shadow prices usually can be interpreted as marginal costs (if we are minimizing) or marginal profits (if we are maximizing).

To summarize: the solution to an optimization problem includes the marginal costs (*i.e. shadow prices*) of every constraint as an intrinsic part of the solution.

In the RESOLVE model, the *objective function* is the net present value (NPV) of the total resource cost. There are numerous constraints in the model including the service requirements for Grid Needs, RPS, resource potential, etc. In the optimal solution, every constraint will have an associated *shadow price*.

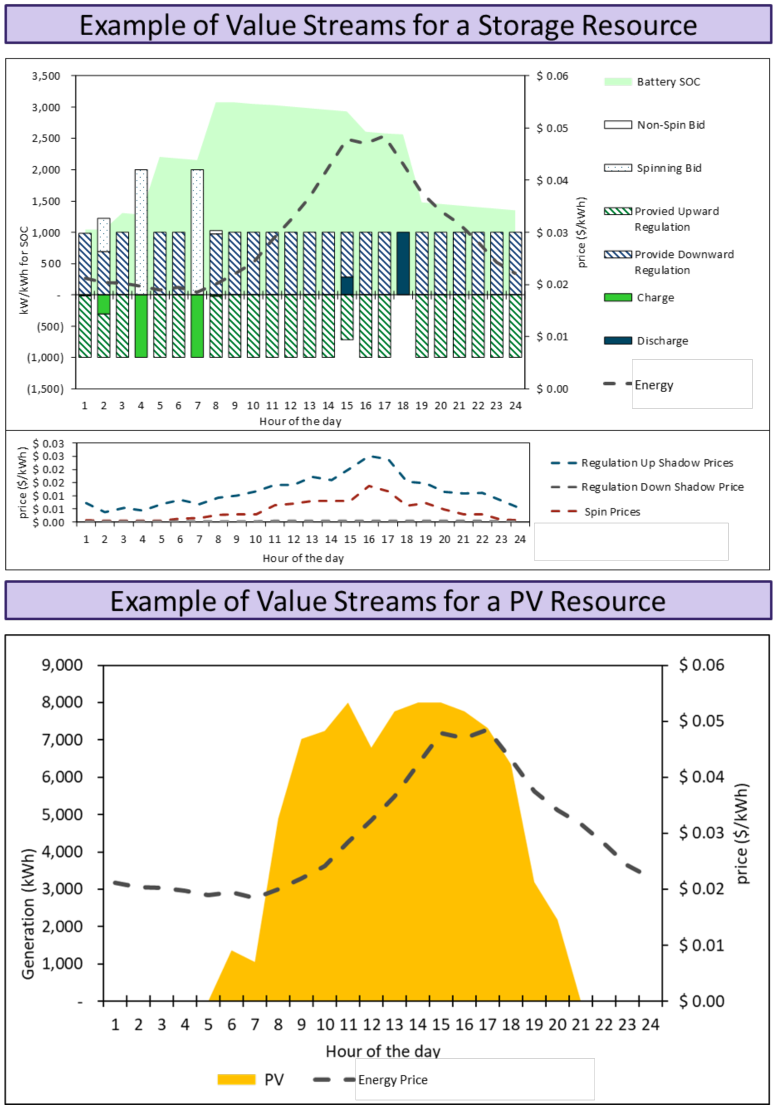
In fact, each Grid Need at every timepoint reflects an individual constraint. For example, a single constraint in the Oahu model is that hour 1 on day 1 in year 2025 must have 75 MW of Downward Regulating Reserves. The *shadow price* on this constraint reflects the change in total system cost that would occur from increasing the reserve need incrementally in that hour. In other words, the *shadow price* on this constraint reflects the marginal cost of Downward Regulating Reserve in that hour.

These marginal costs (*i.e. shadow prices)* are an intrinsic part of the optimal solution alongside the *objective function value* (NPV total system cost) and the *decision variable values* (resource build in each year and operations in each hour).

Figure 9 shows how the avoided cost of energy (dashed grey line) can be matched against expected resource production profiles (in this case, storage on the left and solar on the right) to estimate the incremental value of various resource options.

[26] Bradley, Hax, and Magnanti, "Applied Mathematical Programming" (1977). Addison-Wesley. Available at http://web.mit.edu/15.053/www/AMP.htm.

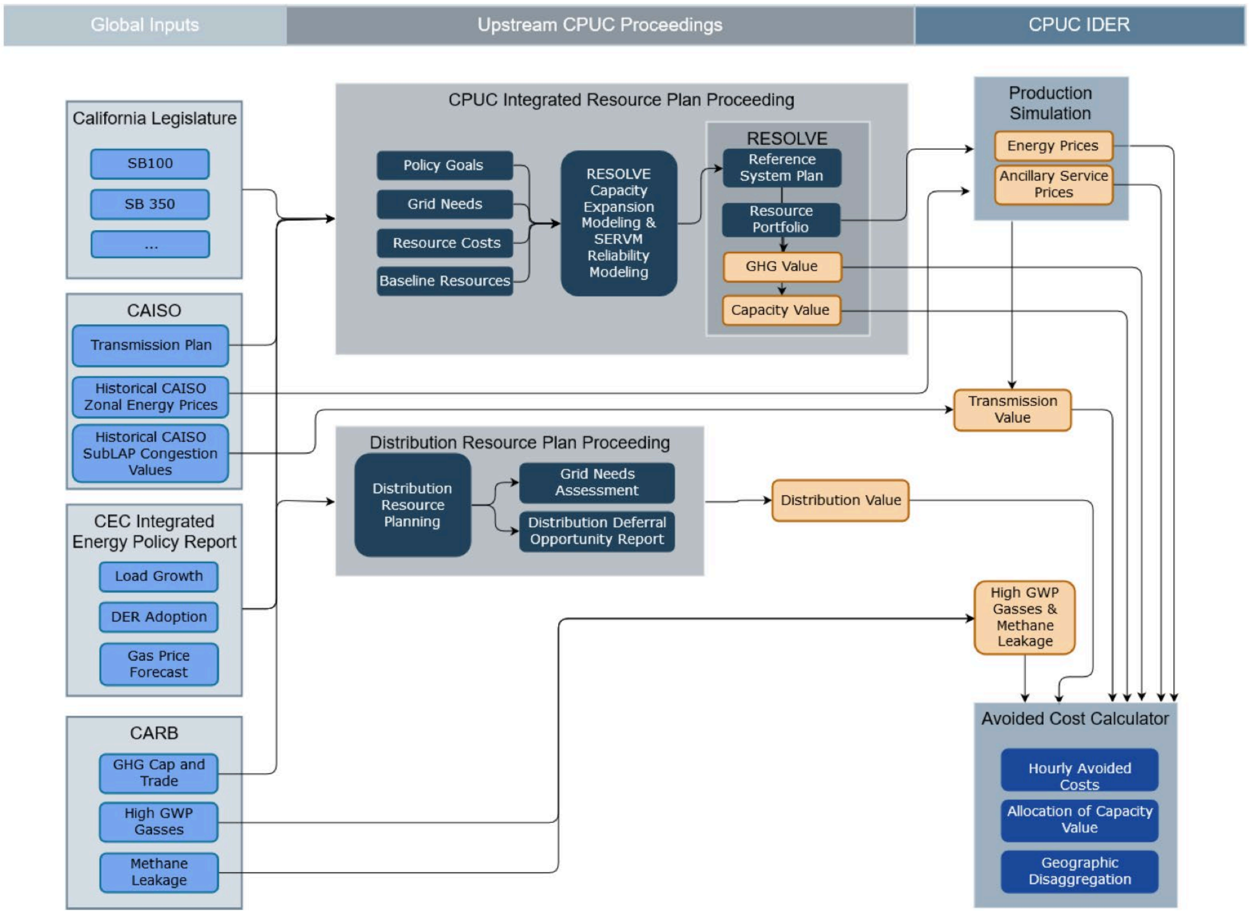
Figure 9 Example of Shadow Prices Reflecting the Value & Least-Cost Provision of Various Grid Services



This approach to calculating and using avoided costs is similar to the one proposed by the California Public Utilities Commission (CPUC) Integrated Distributed Energy Resources (IDER) proceeding, as shown in Figure 10. In California, the Integrated Resource Planning (IRP) process produces a Reference System Portfolio, which in combination with production simulation modeling, produces avoided cost streams used to evaluate DER resources in the IDER proceeding.[27]

[27] *See* Hawaiian Electric's Response to June 25, 2020 Commission Questions and June 15, 2020 Letter from DER Parties filed on July 2, 2020 in Docket No. 2019-0323.

Figure 10 Linkage between avoided costs and capacity expansion and production simulation modeling



3.8.2 Other Modeling Outputs

In addition to the Grid Services identified above, the modeling can provide additional information:

1. Longer term forecast outputs could be used to inform interested parties of future needs and allow developers to indicate interest in projects that have a lead time beyond the first 5 years as part of a Long-Term RFP.
    a. The Grid Needs Assessment may also identify the need to begin developing transmission capacity on the islands. As discussed in Section 3.3, Hawaiian Electric may use IGP results to begin the transmission planning process to develop Renewable Energy Zones.
2. Least-cost dispatch for each resource modeled (*i.e.*, how much of each service is provided by resource type in each operating hour).
3. Other output metrics can be reported or derived from these outputs, such as annual emissions, contributions to RPS and other non-price metrics.

4 Solution Evaluation Methodology

4.1 OVERVIEW & PURPOSE

The Solution Evaluation phase comes after the Grid Needs Identification phase and after resource options have been returned via the Grid Needs RFP, NWA RFPs, and development of utility programs. Here, "resource options" refer to the full range of grid-scale development, utility programs, and other DERs.

4.2 SOLUTION EVALUATION MODELING PROCESS

As with the Grid Needs Assessment phase, Hawaiian Electric acknowledges stakeholder feedback to have independent oversight of the IGP process and will engage an Independent Observer to oversee the Grid Needs RFP process similar to how the TAP provides oversight of the Grid Needs Assessment process.

We will mainly use results from the Grid Needs Assessment phase and RESOLVE to compare the various resource options received via the Grid Needs RFP, NWA RFPs, or utility programs. These resource options will replace the generic resource options inputted during the Grid Needs Assessment phase of the modeling.

As in the Grid Needs Assessment phase described above, the Company will then rank the potential resource portfolios based on the Modeling Objectives described in Section 1.2. The goal of this ranking and selection process is to select least-regrets options for the final portfolio, which will be called the *Action Plan*.

The Company will use a two step Solution Evaluation process to identify the *Action Plan*:

1. The first step will evaluate proposals using an avoided cost-based screening process to develop a ranking of projects to be examined more closely. This step has the advantage of being less time consuming than extensive modeling analysis and will allow for a quick screening of large number of projects.
2. The second step uses the RESOLVE and PLEXOS models already developed in the Grid Needs Assessment process to evaluate a portfolio of projects to study the interactive operational effects of a least-cost portfolio.

Once applications for resources from the *Action Plan* have been submitted for approval, they will become input assumptions into the next IGP cycle.

4.2.1 Avoided Cost Screening Approach

First, Hawaiian Electric will use an avoided cost screening approach (*i.e.*, initial evaluation) to enable efficient screening evaluation of the costs and benefits of an individual resource without time-consuming process of rerunning multiple models. A similar screening approach was used in the Stage 1 and Stage 2 RFP evaluation process; however, that process did not consider other value streams a proposal could provide to the system. As explained below this process would recognize a project's ability to provide multiple services.

This benefit/cost analysis would be done using an avoided cost methodology based on the avoided costs derived from the Grid Needs Assessment process (as described in Section 3.8.1). For each Grid Need, the expected ability of the resource to provide that service (Grid Need) would be multiplied by the avoided cost of the service. Resources may be able to provide multiple services, and such capabilities should be reflected in the bid or program design; however, in the case where services are exclusive, the benefit would be calculated based on the higher value service.

The annual sum of benefits across the services will be reduced by the annual cost of the resource. Taking the net present value of this net benefit and dividing by the net present value of the available energy that can be produced by the resource results in the levelized benefit that will be used for the avoided cost screening. The levelized benefit ("LB") is summarized in the formulas below.

$$Levelized\ Benefit = \frac{\$}{MWh}$$

$$Levelized\ Benefit = \frac{NPV\ of\ (Benefit - Cost))}{NPV\ of\ Available\ Energy}$$

$$Levelized\ Benefit = \frac{NPV\ of\ (\sum(Avoided\ Cost\ x\ Provision) - (Lump\ Sum\ Payment + Energy\ Price\ x\ NEP)}{NPV\ of\ NEP}$$

Figure 11 Formula for Calculating Levelized Benefit

Avoided Cost in the LB formula are the marginal avoided costs output for each modeled service from RESOLVE.

Provision in the LB formula are the modeled dispatch of small, representative proxy resources (<0.1 MW) that are added to the RESOLVE resource plan to represent potential proposals. These proxy resources allow RESOLVE to determine an indicative dispatch for specific technologies that can then be scaled to the proposal's capacity provided in the developer's bid.

Lump Sum Payment, *Energy Price*, and *Net Energy Potential* will be provided by the developer's bid.

The levelized benefit will account for the potential benefits of a resource as well as its costs, and unitize the net benefit by the available energy that can be produced. This allows larger and

smaller resources to be evaluated on similar basis, provided they can supply similar services. Resources will be sorted from highest to lowest levelized benefit.

Through this process, Hawaiian Electric can screen out resource options and develop a ranked list of resource options to help guide additional modeling in the Solution Evaluation process. Resources that have a higher levelized benefit provide more potential benefits per megawatt-hour of energy produced than lower levelized benefit resources and therefore, will rank higher. Should the Company be unable to contract resource options that were initially ranked highly, the ranking also serves as a shortlist for which resource options to next bring into the portfolio.

4.2.2 Optimal Portfolio Approach

Second, in this step (*i.e.*, detailed evaluation), a combination of the RESOLVE and PLEXOS models will be used. The proposals from the priority list developed during the avoided cost screening step will be available for the RESOLVE model to select as candidate resources. Hawaiian Electric will rerun RESOLVE using the same Modeling Objectives described earlier in this document (primarily least-cost) and evaluate the portfolio in PLEXOS, as was done in the Grid Needs Assessment process. This approach will use the models and inputs already set up in the Grid Needs Assessment process but will replace the generic modeled resources with specific resource cost and performance characteristics provided by the developers in their bids.

This approach provides additional information beyond ranking individual resources by demonstrating how different resource portfolios could operate together on an hourly basis and identifying feasible combinations of resources.

Due to computational limitations, it may not be feasible to include all the resource options received in the solicitation process to be evaluated together in RESOLVE and PLEXOS. In this situation, we would use the screening analysis described in Section 4.2.1 to help reduce the number of resource options being analyzed simultaneously, prioritizing the resource options that the screening analysis determined to provide the highest benefit/cost to the system.

The resource plan developed by RESOLVE will then be modeled in PLEXOS to evaluate the operational aspects and grid services provided by the proposals received. As in the Grid Needs Assessment phase, Hawaiian Electric will use PLEXOS to provide an additional feasibility check on the final resource portfolios. If deemed necessary by Hawaiian Electric staff or the Independent Observer, the Company may run additional resource portfolios in PLEXOS to provide additional information in the decision-making process. The Company intends to select projects that meet the targeted grid needs and provide customer benefits.

Appendix A. RESOLVE & PLEXOS Modeling Description

1. INTRODUCTION TO RESOLVE & PLEXOS

As discussed above, the Company proposes to use the RESOLVE model, a capacity expansion model, to create resource plans for the Grid Needs Assessment phase. These resource plans would be verified in PLEXOS, which is an hourly production simulation model.

1.1. Creating the Resource Plan in RESOLVE Model

RESOLVE is a capacity expansion model used to determine an optimal resource plan to meet the 100% renewable energy goal in 2045 and identify the required grid services needed to support the renewable resource portfolio. The model creates a least-cost portfolio, including timing and quantity of resources, to serve the system needs by island over a select set of representative days and a multi-year horizon. RESOLVE also takes into consideration other modeling objectives such as the renewable portfolio standard (RPS) as well as operational requirements, such as energy reserve margin (ERM).

1.2. Verifying results using PLEXOS

PLEXOS is the production simulation model used by Hawaiian Electric to analyze the least cost dispatch of resources on the electric system and co-optimize resources for the provision of energy and ancillary services.

1.3. Modeling Inputs

RESOLVE & PLEXOS models use similar data inputs to characterize resources on the system, as summarized in the table below:

Table 10 RESOLVE and PLEXOS Inputs

Resource Category	RESOLVE Inputs	PLEXOS Inputs
Thermal/Firm	• **Fuel Inputs** ○ Fuel type/name	• **Fuel Inputs** ○ Fuel type/name

Resource Category	RESOLVE Inputs	PLEXOS Inputs
	○ Fuel cost ($/MMBtu) ○ Fuel GHG content (tCO_2/MMBtu) ○ Fuel burn slope (MMBtu/MW-hr) ○ Fuel burn intercept (MMBtu/hr) ○ Can blend with biofuel (w/ associated cost adder) (T/F) • **Operating Inputs** ○ Nameplate capacity (MW) ○ Unit Pmax rating (MW) ○ Unit Pmin rating (% of Pmax) ○ Minimum up/down time (hr) ○ Startup/shutdown costs ($/MW) ○ Start fuel (MMBtu/start) ○ Max ramp up/down (MW/hr) ○ Fixed O&M cost ($/kW-year) ○ Variable O&M cost ($/MWh) • **Ancillary Service Capability** ○ Regulating reserve ○ Frequency response ○ Inertia • **Capacity Expansion Inputs** ○ Levelized capital cost ($/kW-year) ○ New capacity limit (MW) • **Miscellaneous Inputs** ○ Must-Run (base-loaded) (T/F) ○ Must-Commit (T/F) ○ Eligible for economic retirement (T/F)	○ Fuel cost ($/MMBtu) ○ Fuel GHG content (tCO_2e/MMBtu) ○ Heat rate (using quadratic $a + bx + cx^2$ where a, b, and c inputs) ○ Can blend with biofuel (w/ associated cost adder) (T/F) • **Operating Inputs** ○ Nameplate capacity (MW) ○ Unit Pmax rating (MW) ○ Unit Pmin rating (MW) ○ Minimum up/down time (hr) ○ Startup/shutdown costs ($/MW) ○ Start fuel (MMBtu/start) ○ Max ramp up/down (MW/hr) ○ Fixed O&M cost ($/kW-year) ○ Variable O&M cost ($/MWh) • **Ancillary Service Capability** ○ Regulating reserve (20-30 minute, 1-minute) ○ Frequency response ○ Inertia • **Maintenance** ○ Maintenance outage rate (%) ○ Repair time (hr) ○ Forced outage rate (%) • **Miscellaneous Inputs** ○ Must-Run (base-loaded) (T/F)
Variable (including DGPV)	• **Operating Inputs** ○ Unitized profile ○ Variable O&M cost ($/MWh) ○ Is Curtailable (T/F) ○ Is RPS Eligible (T/F) • **Capacity Expansion Inputs** ○ Levelized capital costs ($/kW-year) ○ New capacity limit (MW)	• **Operating Inputs** ○ Unitized profile ○ Mark-Up ($/MWh) ○ Is Curtailable (T/F)
Standalone Storage	• **Operating Inputs** ○ Charge/discharge efficiency (%) ○ Power rating (MW) ○ Energy Capacity (MWh)	• **Operating Inputs** ○ Charge/discharge efficiency (%) ○ Power rating (MW) ○ Energy Capacity (MWh)

Resource Category	RESOLVE Inputs	PLEXOS Inputs
	• **Capacity Expansion Inputs** ○ Levelized capital costs ($/kW-year & $/kWh-year) ○ New capacity limit (MW) ○ Storage duration constraint (minimum or fixed duration for new-built capacity)	○ Cycles (#/year)
Paired Variable + Storage	• **Operating Inputs** ○ Unitized profile ○ Charge/discharge efficiency (%) ○ Power rating (MW) ○ Energy Capacity (MWh) • **Capacity Expansion Inputs** ○ Levelized capital costs ($/kW-year & $/kWh-year) ○ New capacity limit (MW) ○ Storage duration constraint (minimum or fixed duration for new-built capacity) ○ Pairing Ratio (MW of paired supply resource / MW of paired storage resource)	• **Operating Inputs** ○ Unitized profile ○ Charge/discharge efficiency (%) ○ Power rating (MW) ○ Energy Capacity (MWh) ○ Cycles (#/year) ○ Custom constraints (create a custom constraint/rule in PLEXOS stating that battery must only charge from paired generator)
DERs	• Optional DERs ○ Flexible loads ○ Managed EV charging ○ Energy efficiency ○ Demand response ○ Hydrogen electrolysis	• Optional DERs ○ Flexible loads ○ Demand response

1.4. Loads & Hourly Profiles

While PLEXOS is a detailed production simulation that models every hour in a year, RESOLVE samples 8760-hour profiles to a representative set of 30-40 days to reduce computation time. These days are weighted and selected based on multiple criteria—most commonly the long-run distribution of gross load, wind, solar, net load, net load ramp, and day type—to estimate the annual operating costs of the system. This sampling process is shown graphically in Figure 12 below:

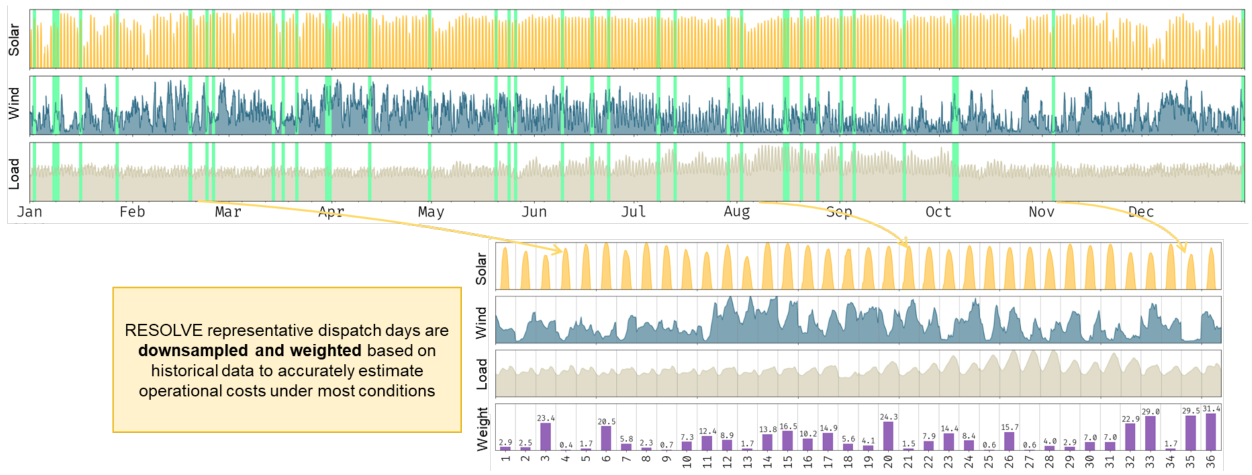


Figure 12 RESOLVE Sampling Process

Once the days have been selected and weighted, all hourly profiles are sampled to the representative days—load profiles (both baseline load shapes and load modifiers), EV, DGPV, grid-scale wind, and grid-scale solar resource profiles.

1.5. RESOLVE Outputs

RESOLVE uses a spreadsheet called the Results Tool to extract the modeling results for review and analysis. The Results Tool packages the optimized resource plan in a stacked-bar chart form, with specific MW quantities of resources in additional tables.

Various costs are also produced, including the present value ($MM) and annual ($MM/year) incremental fixed costs, total operating costs, total RESOLVE costs, respectively. Total RESOLVE cost represents the total cost of the resource plan. The costs are used as a representative check to compare different scenarios and portfolios that are produced by RESOLVE. The actual hourly total system costs are determined after running the resource plan produced by RESOLVE in the PLEXOS model, which is an hourly production simulation model. RESOLVE's resource plan is performed in increments of about 5 years for an entire 20-30 year planning horizon, using typical day-weights (not all days of the year are modeled). PLEXOS fills in the details of the proposed resource plan and includes finer tuning of the operational and system constraints.

The model also produces annual effective RPS (%/year), greenhouse gas emissions (MMtCO_2/year), renewable curtailment (GWh/year), unserved energy (GWh/year), and overgeneration (GWh/year).

1.6. PLEXOS Outputs

PLEXOS generates a solution file that contains many output properties that can be examined. Each property can be examined on the interval level, usually hourly, up to a year. Some of the outputs that are used to characterize a resource plan are generation, fuel costs, unserved energy and reserve shortage.

The solution file contains the hourly energy generation (MWh) for all generators modeled on the system. The yearly energy generation of each system is used to determine system costs.

Fuel costs of the system are based on the fuel offtake of the generator multiplied by the price of that fuel. Costs for startup fuels are also included in the model but are separated to allow the use of a different start up fuel.

Unserved energy (MWh) and Shortage (MW) are important outputs that measure whether an adequate amount of grid services were made available in the model. Unserved energy is the amount of load that was not able to be served due to a lack of available resources. Shortage is the amount of reserve that was require but not by available resources.

Appendix B. Model Input Definitions

1. DEFINITIONS FOR VARIOUS MODEL INPUTS

The table below describes the various inputs that can be captured in the RESOLVE and PLEXOS models. Detailed workbooks of assumptions currently assumed in the modeling for O'ahu, Hawai'i Island, Maui, Moloka'i, and Lāna'i, are available under the September 25, 2020 materials at https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/forecast-assumptions-documents.

Table 11 Model Input Definitions

INPUT			
Property Name	**Description**	**Unit**	**Category**
Generator Inputs			
Bid-Cost Mark-up	A modifier to offer price to influence the order units are dispatched. NOTE: Offer price is not actually used when calculating costs of the system.	%	Generator
Mark-up	A modifier to offer price to influence the order units are dispatched. NOTE: Offer price is not actually used when calculating costs of the system.	$/MWh	Generator
Commit	Number of units on a generator that must be used when it is available. NOTE: This is a fixed commitment and not minimum		Generator
Forced Outage Rate	Annual expected levels of unplanned outages	%	Generator
Maintenance Rate	Annual expected levels of planned outages	%	Generator
Heat Rate Base	Heat rate is defined by $\boldsymbol{a} + bx + cx^2$ This is a '**a**' term of the equation	-	Generator
Heat Rate Incr	Heat rate is defined by $a + \boldsymbol{b}x + cx^2$ This is a '**b**' term of the equation	-	Generator
Heat Rate Incr2	Heat rate is defined by $a + bx + \boldsymbol{c}x^2$	-	Generator

	This is a '**c**' term of the equation		
Max Capacity	Max power of each unit on a generator	MW	Generator
Max Ramp Down	Limit on the amount that generation can decrease	MW/min	Generator
Max Ramp Up	Limit on the amount that generation can increase	MW/min	Generator
Mean Time to Repair	How long outages will take	hrs	Generator
Repair Time Distribution	Distribution used to generate repair times	-	Generator
Min Up Time	Minimum number of hours the unit must be run after being started	hrs	Generator
Min Stable Level	Unit minimum power, not including ramp-up and ramp-down	MW	Generator
Random Number Seed	Random number seed assigned to the generator for the generation of outages	-	Generator
Rating Factor	Maximum dispatchable capacity of each unit expressed as a percentage of Max Capacity	%	Generator
Start Cost Time	Incremental cooling time over which the corresponding Start Cost applies	hrs	Generator
Units	Number of installed units	-	Generator
Units Out	Number of units out of service		Generator
Fuel Inputs			
Price	Fuel price	$/MMBTU	Fuel
Is Available	Flag if fuel exists	0 or 1	Fuel
Is Enabled	Flag if the reserve is enabled	0 or 1	Reserves
Min Provision	Minimum required reserve	MW	Reserves
Timeframe	Timeframe in which the reserve is required	Seconds	Reserves
Type	Type of reserve, i.e. Raise, Reg, Replacement		Reserves
VoRS	Value of reserve shortage		Reserves

Battery Inputs			
Capacity	Energy the battery can store	MWh	Batteries
Charge Efficiency	Efficiency of charging the battery	%	Batteries
Discharge Efficiency	Efficiency of discharging the battery	%	Batteries
Initial SoC	Initial state of charge of the battery at the start of the run	%	Batteries
Maintenance Rate	Expected levels of unplanned outages	%	Batteries
Max Cycles Year	Max cycles the battery is allowed to use in a year	Cycles	Batteries
Max Power	Max power the battery can generate excluding inverter losses i.e. If Max power is 100MW with 99% discharge efficiency, total effective power is 99MW	MW	Batteries
Max SoC	Maximum state of charge	%	Batteries
Min SoC	Minimum state of charge	%	Batteries
Mean Time to Repair	How long the outages will take	%	Batteries
Random Number Seed	Random number seed assigned to the generator for the generation of outages	-	Batteries
Units	Number of BESS units installed		Batteries
VO&M Charge	Variable operation and maintenance charge	$/MWh	Batteries
Region Input			
Load	System Load	MW	Region
Fixed Load	Additional load added to Load Used for different layers	MW	Region
Price of Dump Energy	Price of energy in excess of total load	$/MWh	Region
VoLL	Value of unserved load Usually quite high so that to deter model from having unserved energy.	$/MWh	Region

Load Participation Factor	Proportion of region load that occurs at this node	Between -1 and 1	Nodes
Penalty Price	Price for violating the constraint	$	Constraints
RHS	Right hand side of inequality equation		Constraints
LHS	Left hand side of inequality equation		Constraints
Sense	Type of inequality for constraint	≤,≥,=	Constraints

Appendix C. Grid Service Definitions Methodology

1. UPDATES TO CAPACITY PLANNING CRITERIA

The function of a planning criteria is to establish guidelines to minimize the risk of insufficient generation capability from a diverse mix of generating resources available to the system in long-range generation expansion studies. Resource plan development is evaluated based on a consistent guideline or criteria to provide adequate generation to meet customer demand, with reasonable reserves to account for routine maintenance or overhauls of units, unexpected outages of generating units, growth in customer demand over time, and possibilities of higher than forecasted instantaneous peak demand. Because each island has an isolated electrical system, and is not interconnected to other utilities, it has been necessary to consider different planning criteria than mainland utilities.

1.1. Current Planning Criteria

Hawaiian Electric's capacity planning criteria for the island of O'ahu consists of one rule and one reliability guideline. Capacity planning criteria for the islands of Maui and Hawai'i Island consist of one rule, with consideration given to maintaining a reserve margin of approximately 20 percent. The islands of Lāna'i and Moloka'i generally follow the planning criteria rule consistent with O'ahu, Maui and Hawai'i Islands.

The current capacity planning rule states:

The total capability of the system must at all times be equal to or greater than the summation of the following:

a. The capacity needed to serve the estimated system peak load, less the amount of interruptible loads;
b. The capacity of the unit scheduled for maintenance; and
c. The capacity that would be lost by the forced outage of the largest unit in service.

However, with the increasing quantities of variable renewable wind and solar resources, and future energy storage additions to the system, Hawaiian Electric's current planning rule and guidelines do not account for the dynamic nature of variable resources and limited duration storage.

1.2. Energy Reserve Margin

Reliability planning criteria for utilities long-range generation expansion planning varies among different jurisdictions, and includes criteria such as, but not limited to, loss of largest unit, loss of load expectation, expected unserved energy, loss of load probability, and reserve margin percentages. An energy reserve margin, similar to a capacity reserve margin, was selected as a means to establish guidelines to minimize the risk of insufficient generation capability from a diverse mix of generating resources available to the system in Hawaiian Electric's long-range generation expansion studies. Using an energy reserve margin planning criteria is intended to provide enough energy resources for safe and reliable service to customers and to serve future system needs.

In concept, if future resource portfolios consist of enough load shifting storage to shift all excess variable renewable generation to the hours of the day when energy is needed, then the resource portfolio need only to generate a total energy amount equal to the day's energy usage plus storage losses. However, to plan for adequate generating capability and to provide for reasonable emergencies, the loss of the resource that can generate the most energy in a day needs to be planned for with the energy reserve margin.

1.3. Definitions

Available Unit

Unit which is capable of providing service, whether or not it is actually in service, regardless of the capacity level that can be provided.

Normal Net Capability Rating: (N1, N2, N3... NN)

a. For applicable firm capacity units such as steam units, combustion turbines, and internal combustion engines, this is the maximum net load the units are capable of carrying continuously on a day-to-day basis. This is the maximum net load to which the unit is normally dispatched.

b. Firm capacity provided by other suppliers is represented as generating units with normal net capability ratings, consistent with the intent of these definitions and applicable power purchase agreements.

Hourly Dependable Capacity

The Hourly Dependable Capacity ("HDC") is the minimum expected capacity from variable generation resources based on empirical data. The HDC (MW) is calculated for each hour as follows:

$HDC_{hr} = \chi - N * \sigma$, where χ = the mean,

σ = a standard deviation,

N = the number of standard deviations

Shifted Load

The energy charged and discharged by energy storage systems in each hour. Energy storage systems that shifts load include but are not limited to utility scale batteries and batteries paired with renewable resources. Shifted load may include customer owned energy storage systems that could shift load per the terms of their particular tariff or distributed energy program.

Interruptible Load

The reduction of customer loads to support system capacity needs, for example, demand response programs that can reduce system load when needed, or tariffs that allow changes in load.

Energy Reserve Margin

The Energy Reserve Margin is the percentage of system load in which the system capacity must exceed the system load in each hour. The energy reserve margin for each island is listed in the table below.

Table 12: Energy Reserve Margin Percentages by Island

Island	Energy Reserve Margin
O'ahu	30%
Hawai'i	30%
Maui	30%
Moloka'i	60%
Lāna'i	60%

Energy reserve margins are derived from an assessment of historical data. Identified at risk hours were evaluated to determine minimum energy reserve targets for planning purposes. The loss of largest unit, multiple forced outages, and unplanned maintenance were some of the largest contributing factors for hours considered to be at-risk. Energy reserve margin targets plan for the loss of largest unit and an additional hourly reserve for emergencies.

The size of generating units on each island are contributing factors to energy reserve margin targets. For instance, on Moloka'i and Lāna'i, the largest generating units on the island have the capability to produce roughly 60% of each island's average daily energy usage. For

comparison to the current planning criteria described above, which is to meet the peak load with the loss of the largest available unit, the 60% energy reserve margin target for Moloka'i and Lāna'i is to plan for resources that can generate enough energy throughout the day to meet the island's energy load without the largest available unit.

1.4. Generation Addition Rule

New generation will be added to prevent the violation of the rule listed below. Available units include available Hawaiian Electric and independent power producer units and facilities.

> The sum of the amount net capability ratings of all available units minus planned maintenance, plus Hourly Dependable Capacity, plus shifted load by energy storage, plus interruptible loads must be equal to or greater than the system hourly load multiplied by the quantity of one plus the Energy Reserve Margin.

$$\sum N_i - \text{Maintenance} + \text{Hourly Dependable Capacity} + \text{Shifted Load} + \text{Interruptible Load} \geq \text{System Hourly Load} * (1 + \text{Energy Reserve Margin})$$

The rule above, applies to resource planning in long-range generation expansion studies. The timing of generating resource additions should be examined using these rules as guides, with due consideration given to short-term operating conditions, equipment procurement, construction, financial and regulatory constraints.

1.5. Planning Considerations for an Energy Reserve Margin

Hawaiian Electric decided to use an energy reserve margin for IGP as a means of incorporating a robust capacity planning criteria in its long term planning processes. Although several utilities use a loss of load expectation ("LOLE") criteria for capacity planning, the probabilistic analyses to support a robust LOLE calculation with very high quantities of variable generation and energy storage resources would be difficult to integrate into a capacity expansion model.

When considering the contributions of variable renewables toward the ERM criteria, the HDC framework was preferred over other approaches like Effective Load-Carrying Capability (ELCC). HDC does not depend on assumed load profiles, maintenance schedules, and resource mix of the system and can be calculated independent of the other generators in the portfolio. The intent of HDC is to plan for a different variable resource capability in every hour and could be described as an hourly ELCC. Its derivation allows for a granular analysis of weather variability and reliability of generation from variable renewable resources in each hour. As recorded variable renewable data changes, new data can be easily incorporated to update the HDC values and would not require a system level analysis like the ELCC.

2. REGULATING RESERVE

The purpose of the regulation criteria is to establish guidelines to minimize the risk of supply and demand imbalances by ensuring sufficient regulating reserves are available to the system in long-range planning studies. This criterion applies to standalone distributed energy resources ("DER"), standalone grid-scale solar resources, standalone grid-scale wind resources, and gross system load.

2.1. Background

The methodology being presented here is similar to the methodology used at ERCOT. To calculate their reserve requirement, they start by gathering historical 5-minute average load data, wind production data, and solar production data. They use that information to calculate the net load. Subsequently, they calculate the difference in net load between the previous 5 minutes and the next five minutes. They group these differences by hour and then further group them into negative differences for Regulation Down calculations and positive differences for Regulation Up calculations. For each group, the 95th percentile is calculated.

ERCOT then pulls the historical average 5-minute Regulation Up and Regulation Down deployments, groups these by hour, and also calculates the 95th percentile for each group. ERCOT takes the larger of the regulation calculated based on the net load change and the actual regulation deployment. This is the regulation that would be required based on the current operating system.

2.2. Methodology

Similar to ERCOT, for O'ahu, Maui, and Hawai'i Island, we obtained minutely data for 2017 and 2018 for installed grid-scale solar projects, aggregated by island. The same was done for installed grid-scale wind projects. Minutely data for 2017 and 2018 was also obtained for gross load as well as estimated DER output. Aggregated grid-scale solar projects, aggregated grid-scale wind projects, aggregated DER, and gross load comprise the four categories used in this study. Shown below in Figure 13 is a sample day of the minutely data gathered for each of the categories.

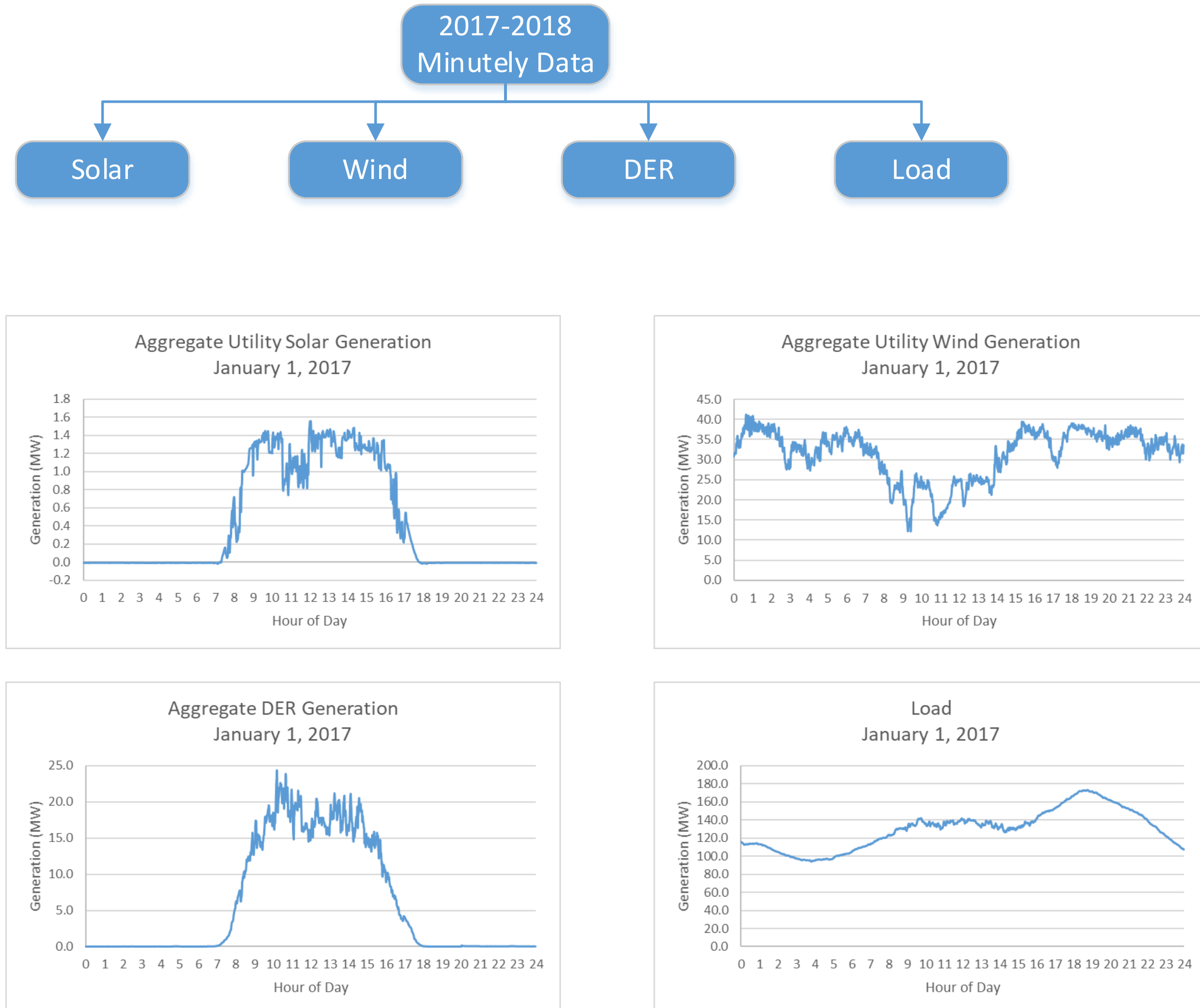


Figure 13 Sample minutely data of aggregated grid-scale solar generation, aggregated grid-scale wind generation, aggregated grid-scale DER generation, and gross load for January 1, 2017

Due to the lack of data on Lāna‘i and Moloka‘i, Maui data for grid-scale solar projects and grid-scale wind projects was used. Lāna‘i and Moloka‘i also lacked minutely estimated DER generation, so net load was used in place of DER generation and gross load.

For O‘ahu and Maui, for each category, the change over a 30-minute time-interval was calculated. For Hawai‘i Island, Moloka‘i, and Lāna‘i, the change was calculated over a 20-minute time-interval. These time-intervals were provided by our system operators and were based on the time they required to bring additional units online, if needed. Hawai‘i Island, Moloka‘i, and Lāna‘i have a shorter time-interval because they have generators that can start faster than the generators on O‘ahu and Maui.

The change in renewable energy was then divided by the aggregated installed capacity to normalize it. In the case of load, the change was divided by the peak load. Figure 14, shown below, provides an example of the calculation done.

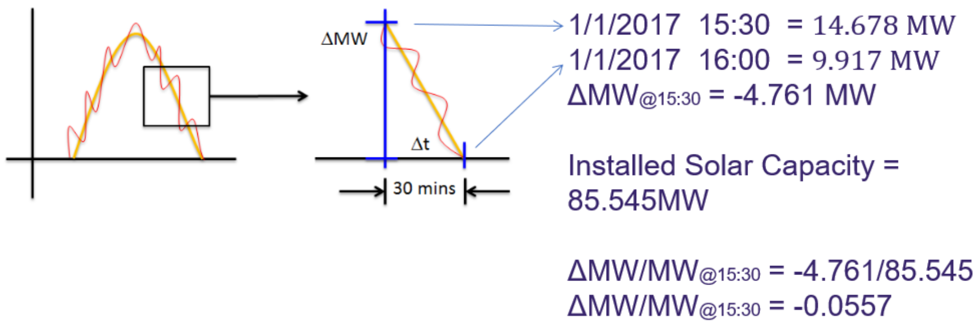


Figure 14 Sample calculation used to convert the minutely data into a unitized rate of change

As shown below in Figure 15, for each category, all the positive changes were grouped together, and all the negative changes were grouped together. The reason for this is because the direction of change dictates whether upward regulation or downward regulation is required. For the renewable categories, positive changes represented an increase in renewable generation, and consequently, the need for downward regulation. Conversely, negative changes represented a decrease in renewable generation, and consequently, the need for upward regulation. For changes in load, the opposite occurs. Positive changes in load represented a need for upward regulation and negative changes in load represented a need for downward regulation.

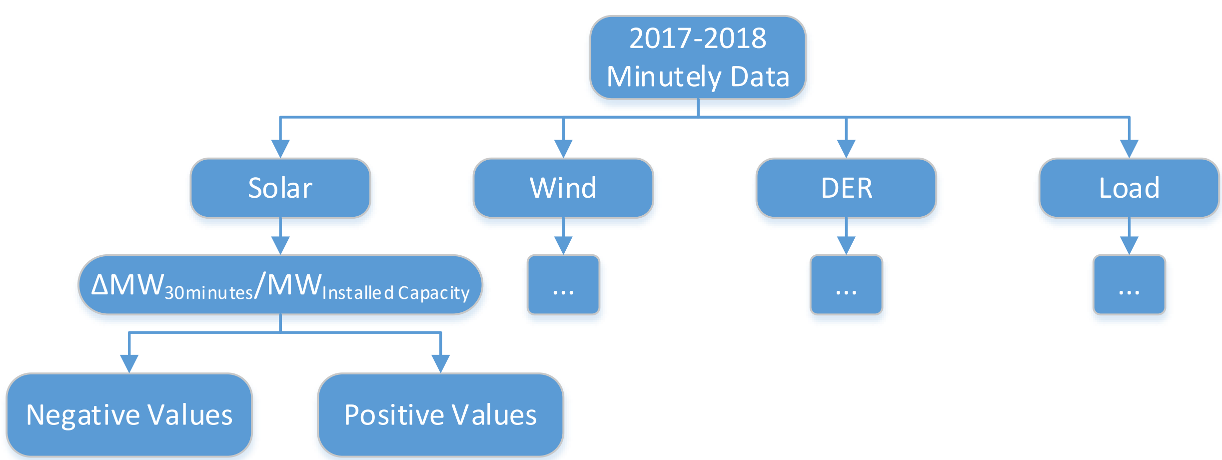
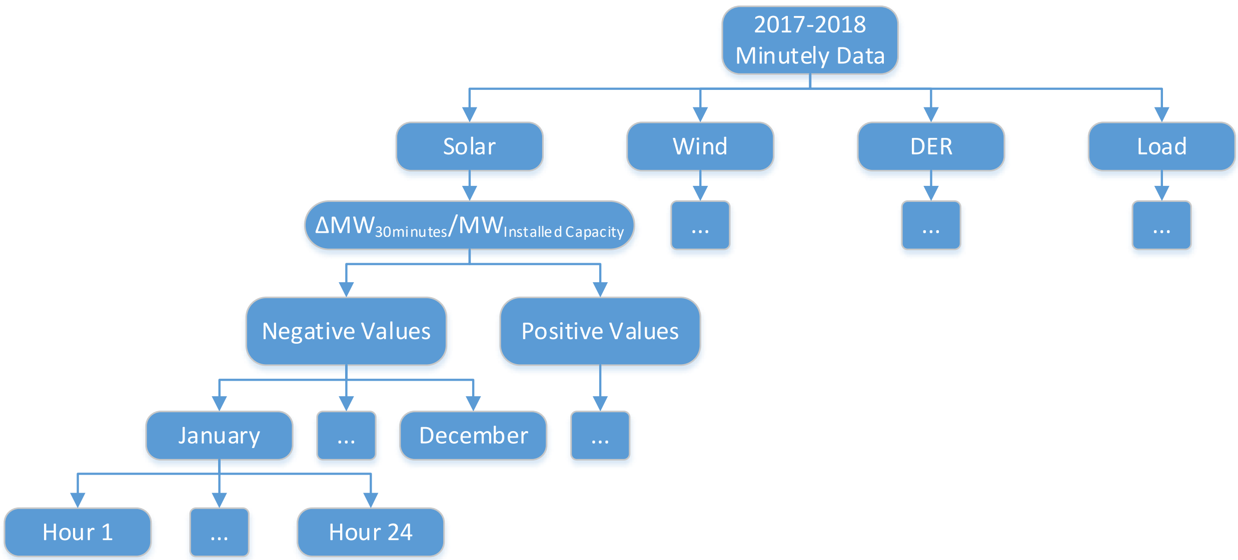
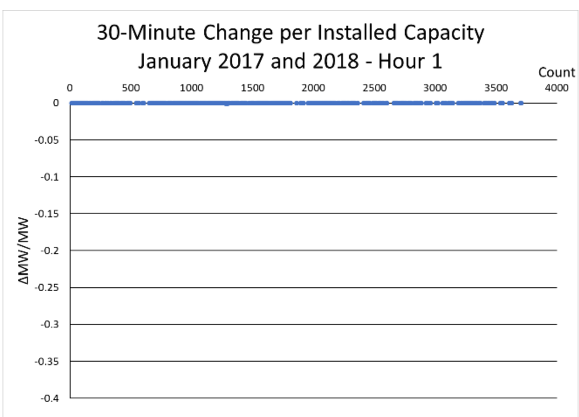
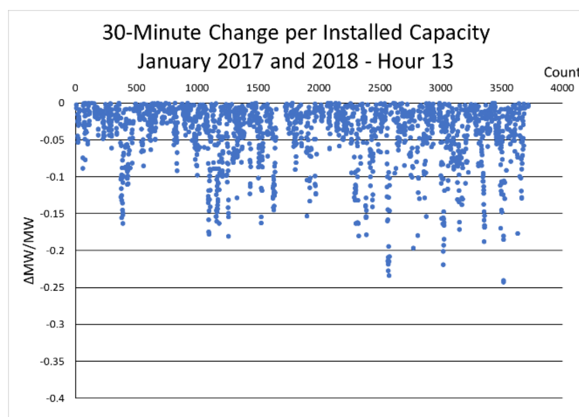


Figure 15 Grouping of the minutely data into positive and negative values[28]

As shown below in Figure 16, the data was further segregated based on month of the year and hour of the day. This was done to ensure that any seasonal or hourly impact on renewable generation or load would be considered. For example, solar output is significantly different between January and July, and between midnight and noon, as shown in Figure 16.







[28] Positive changes in generation (negative changes in load) represent a need for downward regulation. Negative changes in generation (positive changes in load) represent a need for upward regulation.

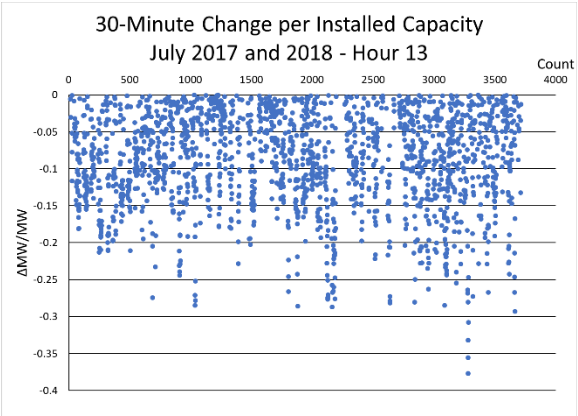


Figure 16 Segregation of data based on the month of the year and time of the day. This was done to take into consideration any influence that these parameters have on renewable generation and load

For each category, positive/negative change, and month and hour, the average and standard deviation was determined. For positive changes, the average plus three standard deviation was calculated, and for negative changes, the average minus three standard deviation was calculated. While ERCOT uses the 95th percentile when calculating their reserve requirement, given our islanded system and high renewable penetration, a more stringent requirement was used. These values were then multiplied by the installed capacity or peak load to determine the requirement needed for that category, month, and hour, as shown in Figure 17.

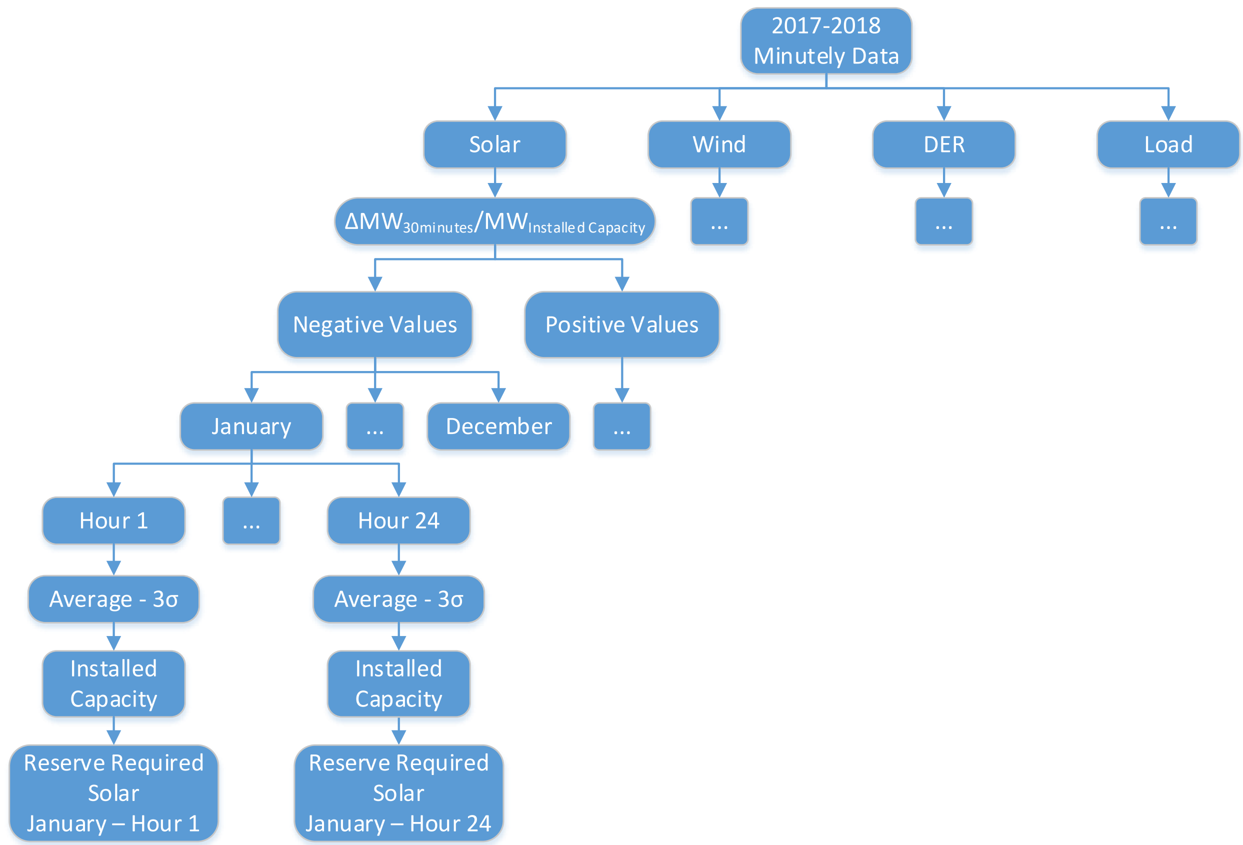


Figure 17 Data flow from minutely data to reserve requirement for each category/month/hour

The total reserve required for a given month and hour was calculated by summing the requirement in each of the four categories: Aggregated Grid-Scale Solar, Aggregated Grid-Scale Wind, Aggregated DER, and Gross Load.

2.3. Assumptions

As shown below in Table 13, the installed capacity used to calculate the reserve requirement depends on whether the resource is controllable and whether the resource is paired.

Table 13 Resources included and excluded from the calculation of Regulation Up and Regulation Down

	Regulation Calculation		Regulation Provision	
	Included in Regulation Up	Included in Regulation Down	Provides Regulation Up	Provides Regulation Down
Uncontrollable Customer Resources	Yes	Yes	No	No
Controllable Customer Resources	Yes	No	Yes	Yes

Uncontrollable Grid-Scale Resources	Yes	Yes	No	No
Controllable Grid-Scale Resources (Unpaired)	Yes	No	Yes	Yes
Controllable Grid-Scale Resources (Paired)	No	No	Yes	Yes

All controllable resources were not included in the calculation of Down Regulation because it is assumed that our operators would be able to control these resources if an emergency arises. By not including controllable resources in calculating the Down Regulation, this prevents the need to turn on generators solely to provide Down Regulation for these controllable resources. Paired resources were also not included in the calculation of both Up and Down Regulation because it is assumed that the paired energy storage system would be able to provide any regulation needed by the paired resource. All other resources were included in the calculation of Up and Down Regulation.

2.4. O'ahu Results

Shown below in Table 14 and Table 15 is a comparison of the Maximum, Average, and Minimum regulation requirement for O'ahu based on the current methodology used in the PSIP and the methodology being proposed. The current methodology used in the PSIP was the GE method.

Table 14 Maximum, Average, and Minimum Regulation Up requirement based on the current methodology used in the PSIP and the proposed methodology for the island of O'ahu

	Regulation Up (MW)					
	Minimum		Average		Maximum	
Year	Current Rule	Proposed Rule	Current Rule	Proposed Rule	Current Rule	Proposed Rule
2020	180.00	180.00	263.78	220.80	349.95	362.95
2025	146.00	140.00	310.17	280.41	436.64	612.93
2030	146.22	140.00	333.72	304.76	492.29	683.40
2035	140.00	140.00	357.06	331.67	548.00	758.81
2040	146.38	140.00	402.11	407.81	654.13	988.61
2045	145.61	140.00	516.70	645.77	922.29	1721.38

Table 15 Maximum, Average, and Minimum Regulation Down requirement based on the current methodology used in the PSIP and the proposed methodology for the island of O'ahu

	Regulation Down (MW)					
	Minimum		Average		Maximum	
Year	Current Rule	Proposed Rule	Current Rule	Proposed Rule	Current Rule	Proposed Rule
2020	60.00	60.00	60.00	115.87	60.00	236.00
2025	60.00	60.00	60.00	129.75	60.00	277.96
2030	60.00	60.00	60.00	145.65	60.00	326.46
2035	60.00	60.00	60.00	149.33	60.00	357.47
2040	60.00	60.00	60.00	164.33	60.00	408.29
2045	60.00	60.00	60.00	182.76	60.00	465.52

Shown below in Figure 18 through Figure 21 is a comparison of the regulation requirement between the current method and proposed method for the day, in 2020 and 2025, with the highest average regulation based on the current method.

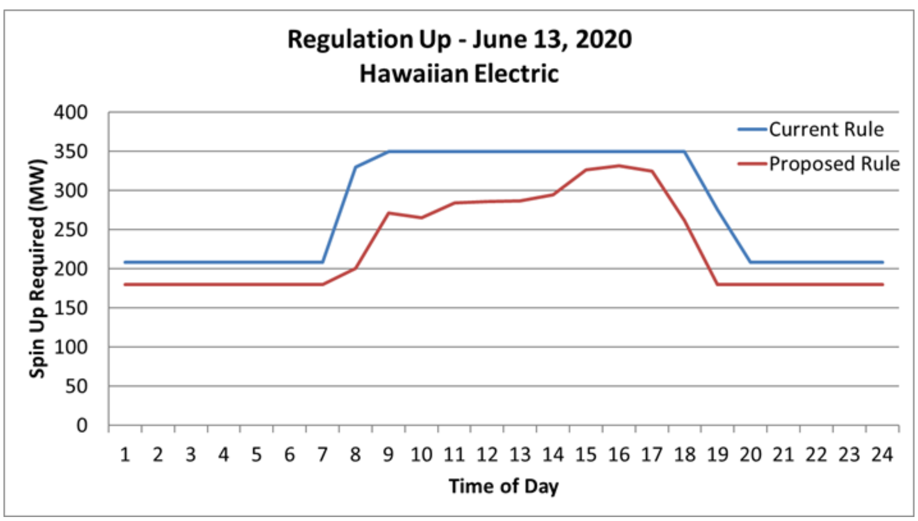


Figure 18 Comparison of Regulation Up requirement between the current methodology and the proposed methodology for June 13, 2020 for the island of O'ahu

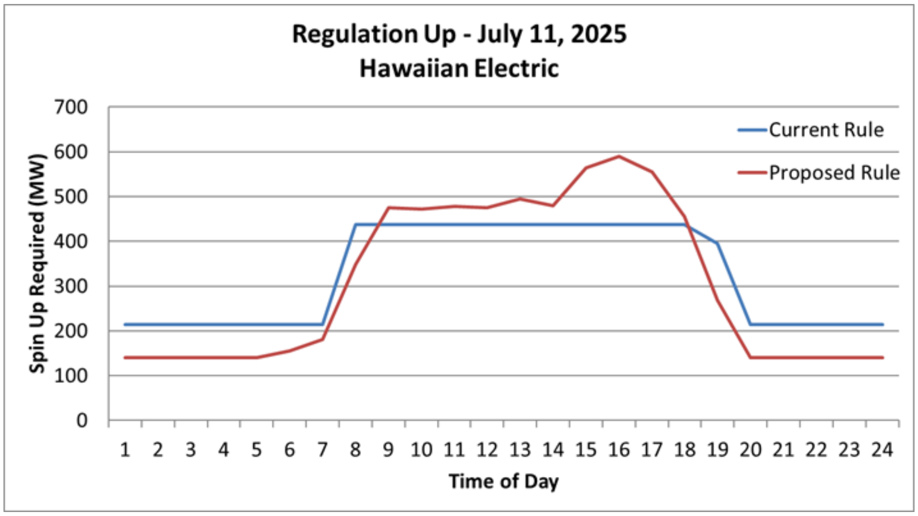


Figure 19 Comparison of Regulation Up requirement between the current methodology and the proposed methodology for July 11, 2025 for the island of O‘ahu

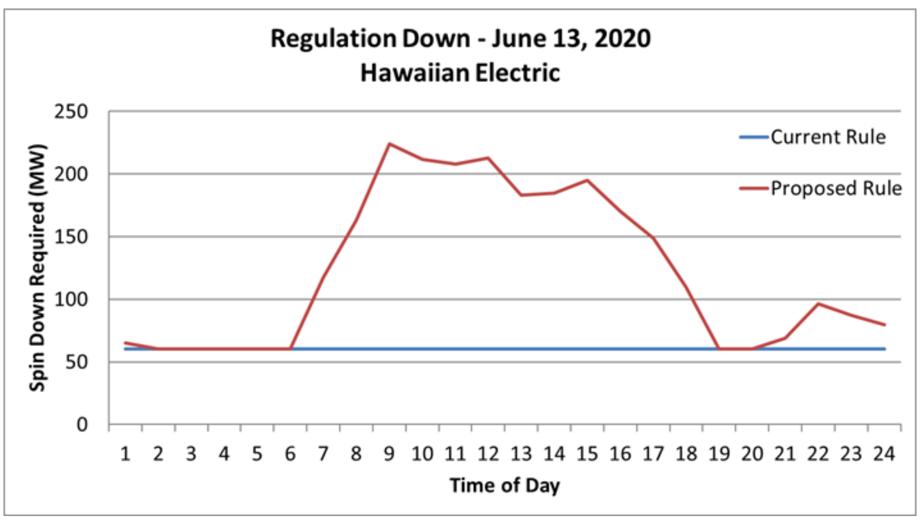


Figure 20 Comparison of Regulation Down requirement between the current methodology and the proposed methodology for June 13, 2020 for the island of O‘ahu

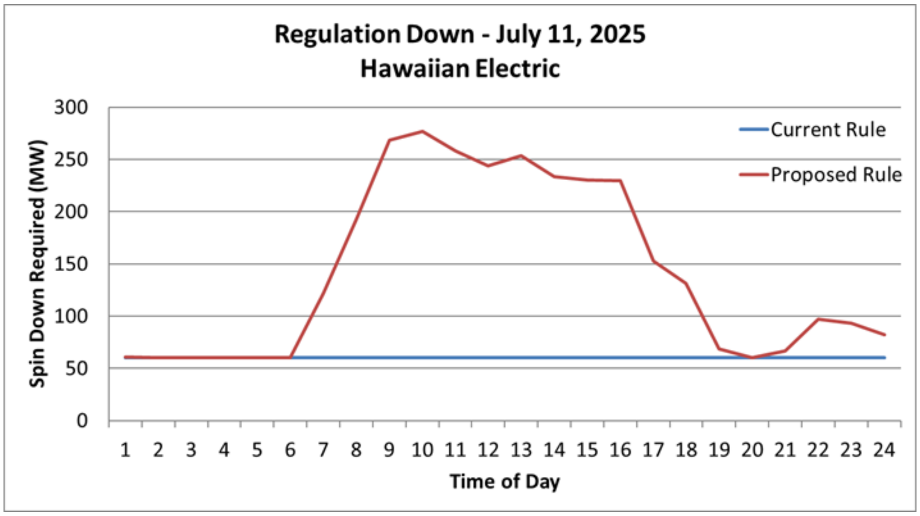


Figure 21 Comparison of Regulation Down requirement between the current methodology and the proposed methodology for July 11, 2025 for the island of Oʻahu

2.5. Maui Results

Shown below in Table 16 and Table 17 is a comparison of the Maximum, Average, and Minimum regulation requirement for Maui based on the current methodology used in the PSIP and the methodology being proposed. The current methodology used in the PSIP was the EPS method.

Table 16 Maximum, Average, and Minimum Regulation Up requirement based on the current methodology used in the PSIP and the proposed methodology for the island of Maui

	Regulation Up (MW)					
	Minimum		Average		Maximum	
Year	Current Rule	Proposed Rule	Current Rule	Proposed Rule	Current Rule	Proposed Rule
2020	6.00	6.00	28.50	28.31	57.95	70.71
2025	0.00	6.00	31.65	34.29	69.30	88.61
2030	0.00	6.00	36.84	39.88	82.12	107.08
2035	0.00	6.00	42.00	46.21	94.96	128.26
2040	0.00	6.00	47.21	52.75	107.76	149.80
2045	0.00	6.00	68.70	70.72	166.09	203.14

Table 17 Maximum, Average, and Minimum Regulation Down requirement based on the current methodology used in the PSIP and the proposed methodology for the island of Maui

	Regulation Down (MW)					
	Minimum		Average		Maximum	
Year	Current Rule	Proposed Rule	Current Rule	Proposed Rule	Current Rule	Proposed Rule
2020	3.00	3.10	3.00	27.90	3.00	64.79
2025	3.00	6.18	3.00	32.84	3.00	74.36
2030	3.00	3.24	3.00	29.51	3.00	79.03
2035	3.00	3.00	3.00	25.44	3.00	84.13
2040	3.00	3.00	3.00	29.20	3.00	96.95
2045	3.00	3.00	3.00	33.21	3.00	110.54

Shown below in Figure 22 through Figure 25 is a comparison of the regulation requirement between the current method and proposed method for the day, in 2020 and 2025, with the highest average regulation based on the current method.

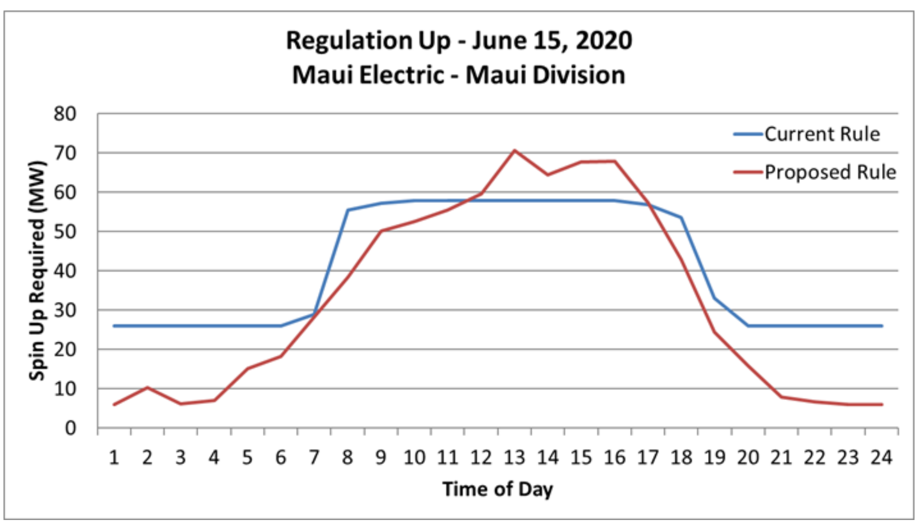


Figure 22 Comparison of Regulation Up requirement between the current methodology and the proposed methodology for June 15, 2020 for the island of Maui

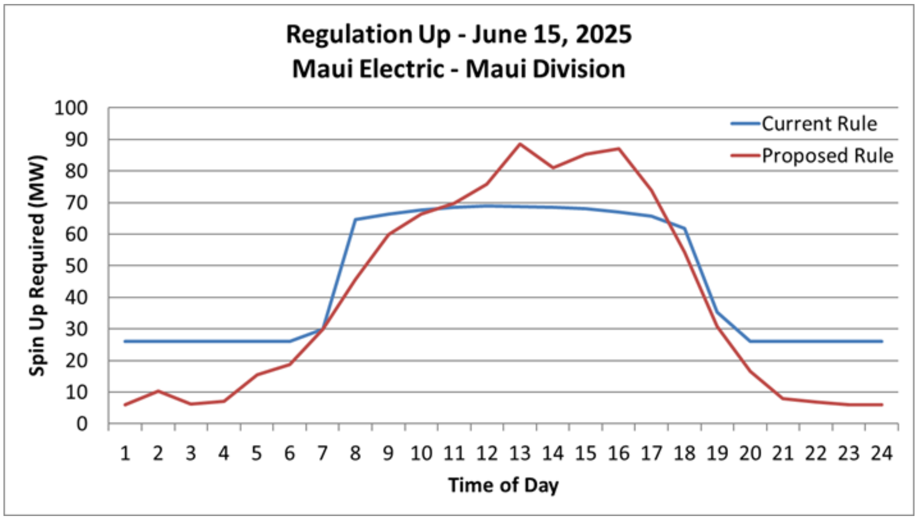


Figure 23 Comparison of Regulation Up requirement between the current methodology and the proposed methodology for June 15, 2025 for the island of Maui

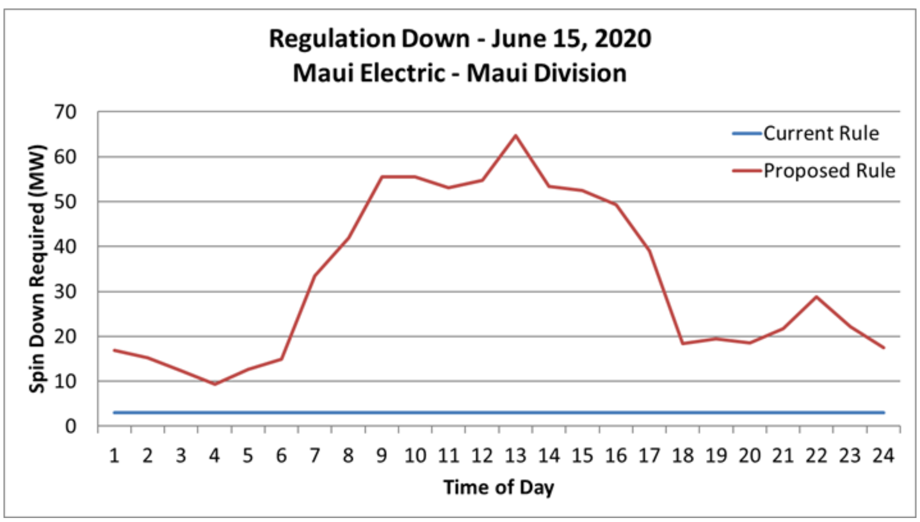


Figure 24 Comparison of Regulation Down requirement between the current methodology and the proposed methodology for June 15, 2020 for the island of Maui

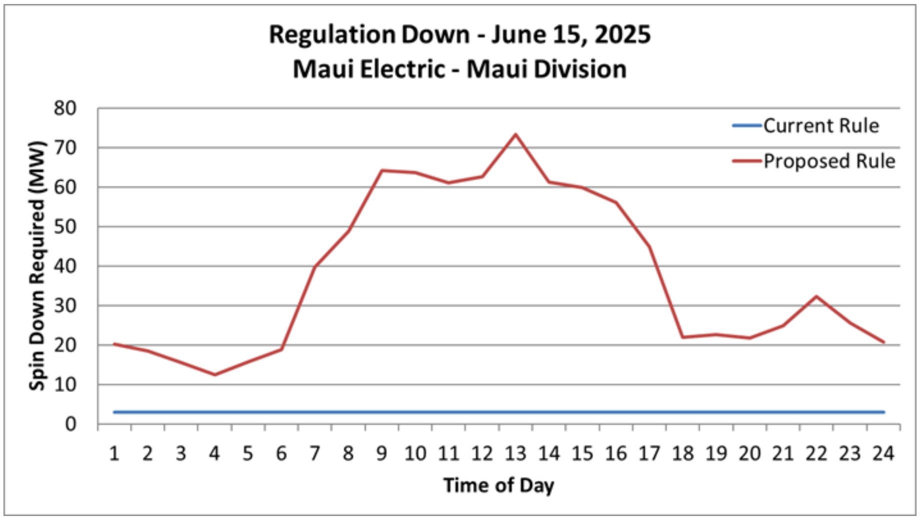


Figure 25 Comparison of Regulation Down requirement between the current methodology and the proposed methodology for June 15, 2025 for the island of Maui

2.6. Molokaʻi Results

Shown below in Table 18 and Table 19 is a comparison of the Maximum, Average, and Minimum regulation requirement for Molokaʻi based on the current methodology used in the PSIP and the methodology being proposed. The current methodology used in the PSIP was developed by Ascend Analytics.

Table 18 Maximum, Average, and Minimum Regulation Up requirement based on the current methodology used in the PSIP and the proposed methodology for the island of Molokaʻi

	Regulation Up (MW)					
	Minimum		Average		Maximum	
Year	Current Rule	Proposed Rule	Current Rule	Proposed Rule	Current Rule	Proposed Rule
2020	0.06	0.19	0.40	0.48	0.74	0.89
2025	0.06	0.18	0.48	0.51	0.89	0.86
2030	0.06	0.18	0.47	0.50	0.89	0.84
2035	0.06	0.18	0.48	0.51	0.89	0.86
2040	0.14	0.18	0.52	0.51	0.90	0.87
2045	0.15	0.19	0.53	0.53	0.90	0.90

Table 19 Maximum, Average, and Minimum Regulation Down requirement based on the current methodology used in the PSIP and the proposed methodology for the island of Molokaʻi

	Regulation Down (MW)					
	Minimum		Average		Maximum	
Year	Current Rule	Proposed Rule	Current Rule	Proposed Rule	Current Rule	Proposed Rule
2020	0.70	0.70	0.70	0.70	0.70	0.91
2025	0.70	0.70	0.70	0.70	0.70	0.88
2030	0.70	0.70	0.70	0.70	0.70	0.86
2035	0.70	0.70	0.70	0.70	0.70	0.88
2040	0.70	0.70	0.70	0.70	0.70	0.89
2045	0.70	0.70	0.70	0.70	0.70	0.92

Shown below in Figure 26 through Figure 29 is a comparison of the regulation requirement between the current method and proposed method for the day, in 2020 and 2025, with the highest average regulation based on the proposed method. The current rule developed by Ascend Analytics is the same for each day of the year.

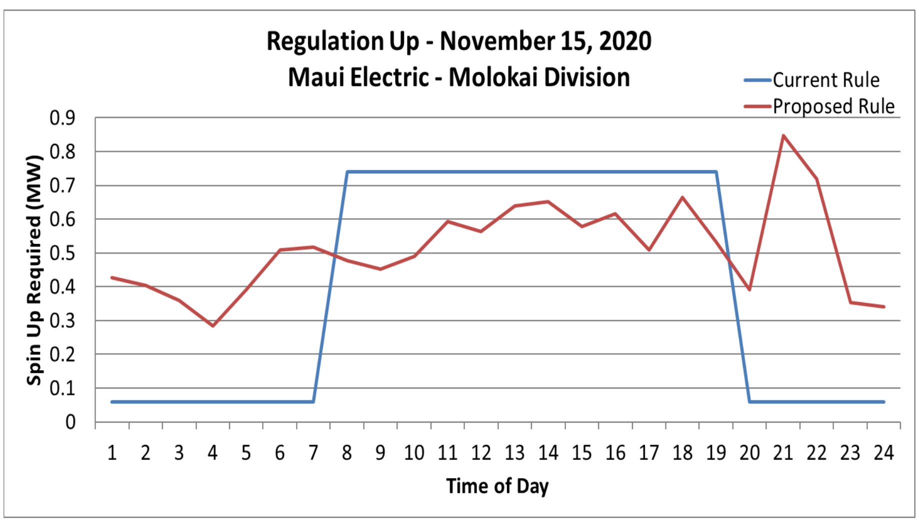


Figure 26 Comparison of Regulation Up requirement between the current methodology and the proposed methodology for November 15, 2020 for the island of Molokaʻi

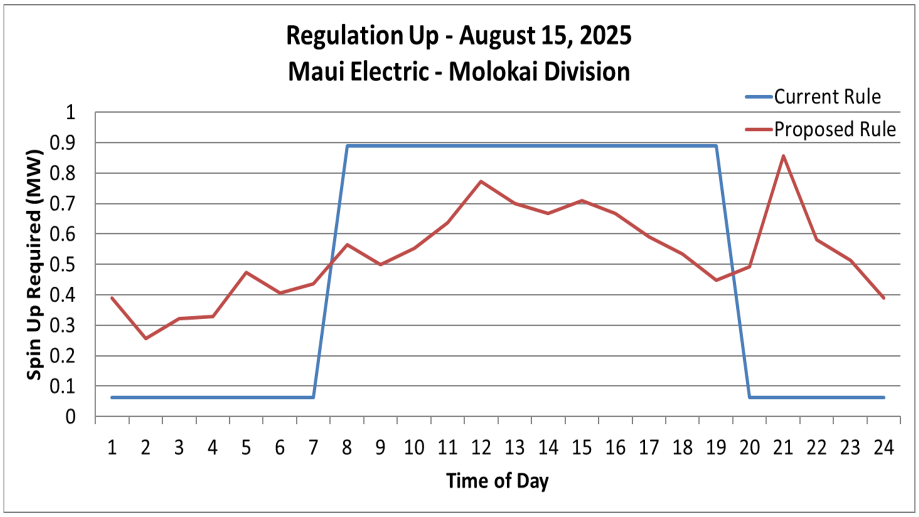


Figure 27 Comparison of Regulation Up requirement between the current methodology and the proposed methodology for August 15, 2025 for the island of Moloka'i

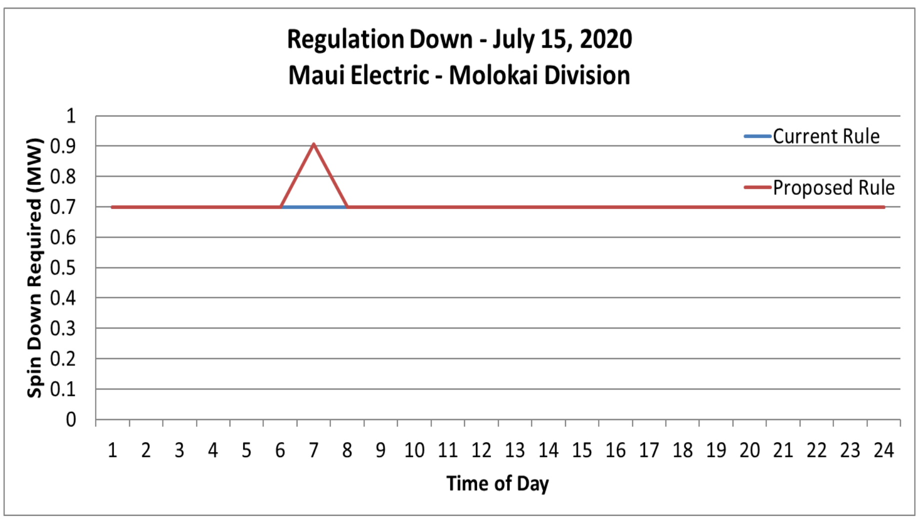


Figure 28 Comparison of Regulation Down requirement between the current methodology and the proposed methodology for July 15, 2020 for the island of Moloka'i

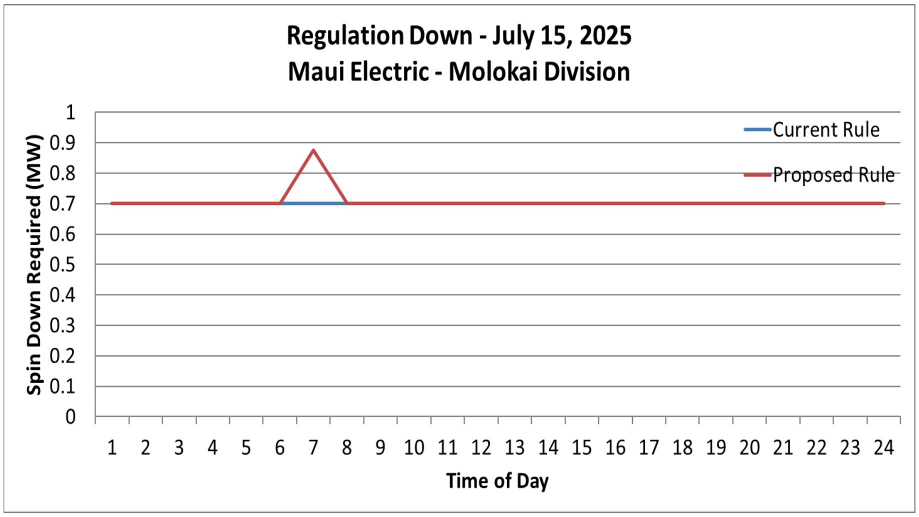


Figure 29 Comparison of Regulation Down requirement between the current methodology and the proposed methodology for July 15, 2025 for the island of Molokaʻi

2.7. Lānaʻi Results

Shown below in Table 20 and Table 21 is a comparison of the Maximum, Average, and Minimum regulation requirement for Lānaʻi based on the current methodology used in the PSIP and the methodology being proposed. The current methodology used in the PSIP was developed by Ascend Analytics.

Table 20 Maximum, Average, and Minimum Regulation Up requirement based on the current methodology used in the PSIP and the proposed methodology for the island of Lānaʻi

	Regulation Up (MW)					
	Minimum		Average		Maximum	
Year	Current Rule	Proposed Rule	Current Rule	Proposed Rule	Current Rule	Proposed Rule
2020	0.06	0.14	0.18	0.39	0.30	0.76
2025	0.06	0.15	0.18	0.40	0.30	0.78
2030	0.06	0.15	0.18	0.41	0.30	0.80
2035	0.06	0.15	0.18	0.43	0.30	0.83
2040	0.14	0.16	0.23	0.44	0.33	0.85
2045	0.15	0.16	0.24	0.45	0.34	0.87

Table 21 Maximum, Average, and Minimum Regulation Down requirement based on the current methodology used in the PSIP and the proposed methodology for the island of Lānaʻi

	Regulation Down (MW)					
	Minimum		Average		Maximum	
Year	Current Rule	Proposed Rule	Current Rule	Proposed Rule	Current Rule	Proposed Rule
2020	0.50	0.50	0.50	0.51	0.50	0.72
2025	0.50	0.50	0.50	0.51	0.50	0.74
2030	0.50	0.50	0.50	0.51	0.50	0.76
2035	0.50	0.50	0.50	0.51	0.50	0.78
2040	0.50	0.50	0.50	0.52	0.50	0.80
2045	0.50	0.50	0.50	0.52	0.50	0.83

Shown below in Figure 30 through Figure 33 is a comparison of the regulation requirement between the current method and proposed method for the day, in 2020 and 2025, with the highest average regulation based on the proposed method. The current rule developed by Ascend Analytics is the same for each day of the year.

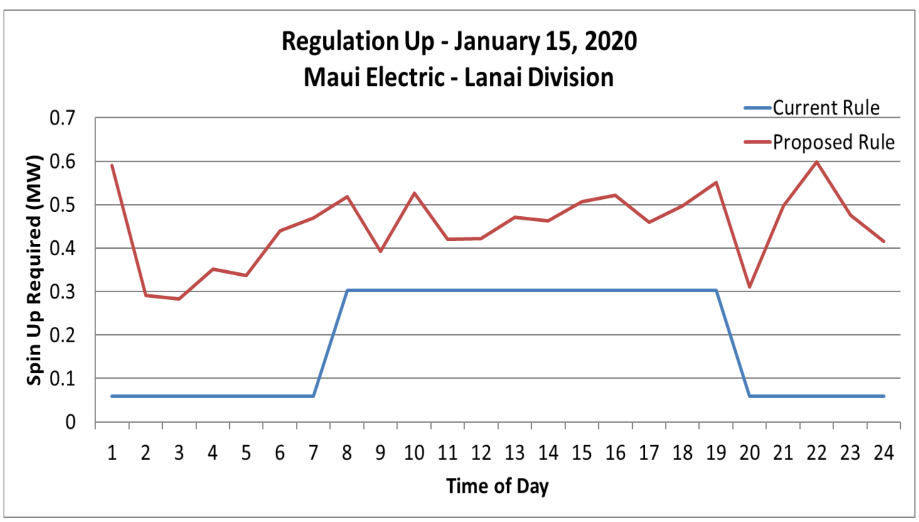


Figure 30 Comparison of Regulation Up requirement between the current methodology and the proposed methodology for January 15, 2020 for the island of Lānaʻi

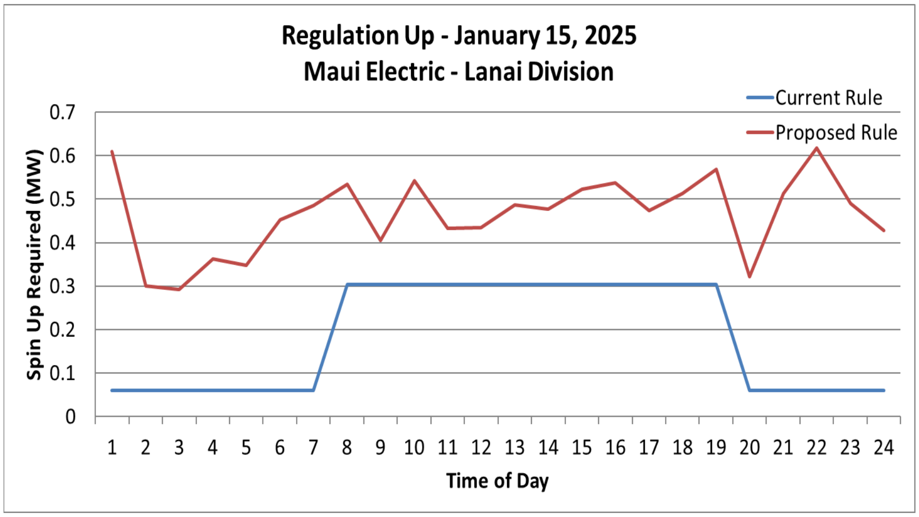


Figure 31 Comparison of Regulation Up requirement between the current methodology and the proposed methodology for January 15, 2025 for the island of Lāna‘i

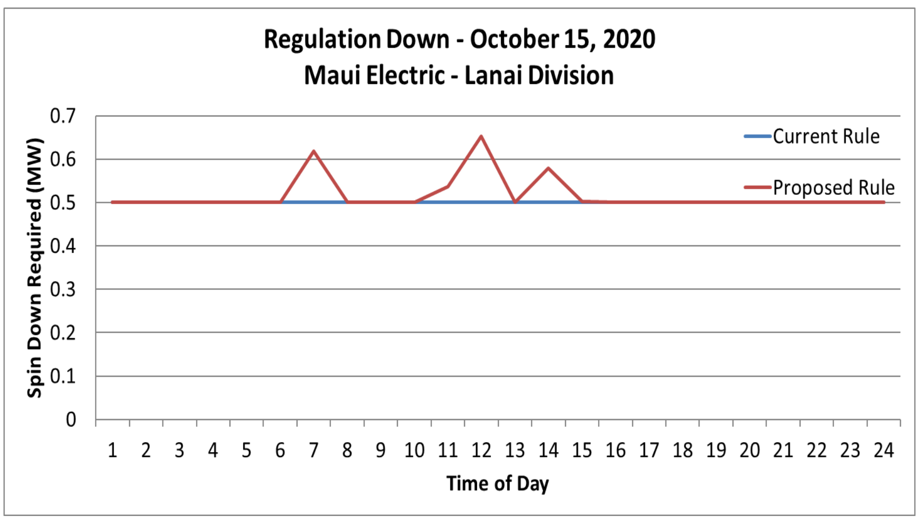


Figure 32 Comparison of Regulation Down requirement between the current methodology and the proposed methodology for October 15, 2020 for the island of Lāna‘i

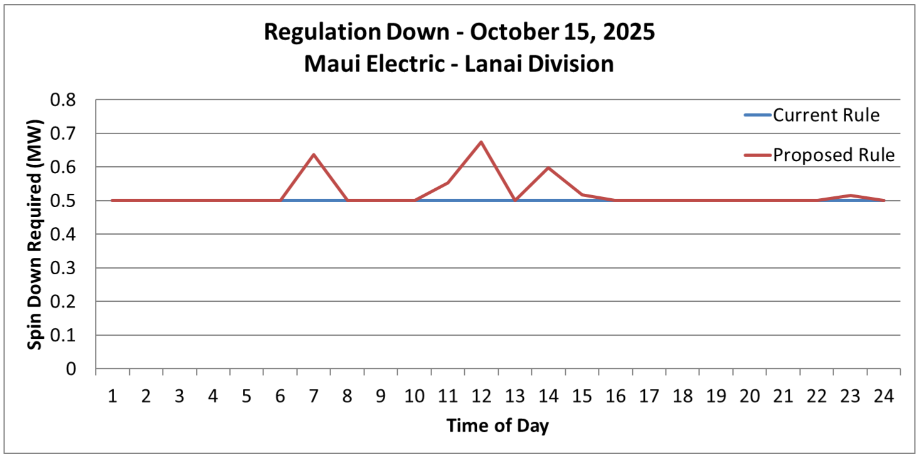


Figure 33 Comparison of Regulation Down requirement between the current methodology and the proposed methodology for October 15, 2025 for the island of Lānaʻi

2.8. Hawaiʻi Island Results

Shown below in Table 22 and Table 23 is a comparison of the Maximum, Average, and Minimum regulation requirement for Hawaiʻi Island based on the current methodology used in the PSIP and the methodology being proposed. The current methodology used in the PSIP was the EPS method.

Table 22 Maximum, Average, and Minimum Regulation Up requirement based on the current methodology used in the PSIP and the proposed methodology for Hawaiʻi Island

	Regulation Up (MW)					
	Min		Average		Max	
Year	Current Rule	Proposed Rule	Current Rule	Proposed Rule	Current Rule	Proposed Rule
2020	6.00	6.00	29.66	20.17	46.83	42.52
2025	6.00	6.00	31.72	25.22	50.79	59.32
2030	6.00	6.00	33.11	29.35	53.14	72.88
2035	6.00	6.00	34.32	33.82	55.23	86.96
2040	6.00	6.00	34.74	38.52	55.76	101.42
2045	6.00	6.00	35.09	43.29	56.08	115.95

Table 23 Maximum, Average, and Minimum Regulation Down requirement based on the current methodology used in the PSIP and the proposed methodology for Hawai'i Island

	Regulation Down (MW)					
	Min		Average		Max	
Year	Current Rule	Proposed Rule	Current Rule	Proposed Rule	Current Rule	Proposed Rule
2020	9.00	9.00	9.00	17.80	9.00	35.84
2025	9.00	9.00	9.00	17.99	9.00	39.43
2030	9.00	9.00	9.00	17.38	9.00	42.22
2035	9.00	9.00	9.00	19.56	9.00	49.96
2040	9.00	9.00	9.00	22.07	9.00	58.48
2045	9.00	9.00	9.00	24.83	9.00	67.54

Shown below in Figure 34 through Figure 37 is a comparison of the regulation requirement between the current method and proposed method for the day in 2020 and 2025 with the highest average regulation based on the current method.

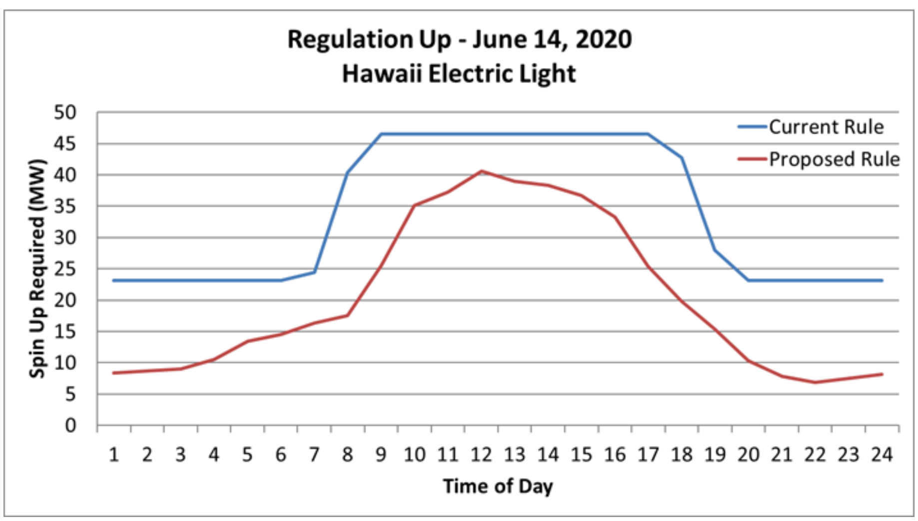


Figure 34 Comparison of Regulation Up requirement between the current methodology and the proposed methodology for June 14, 2020 for Hawai'i Island

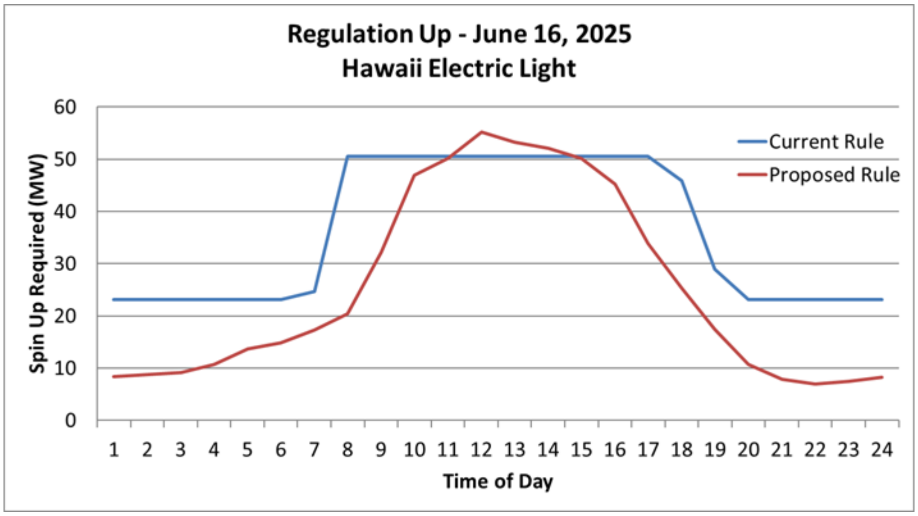


Figure 35 Comparison of Regulation Up requirement between the current methodology and the proposed methodology for June 16, 2025 for Hawai'i Island

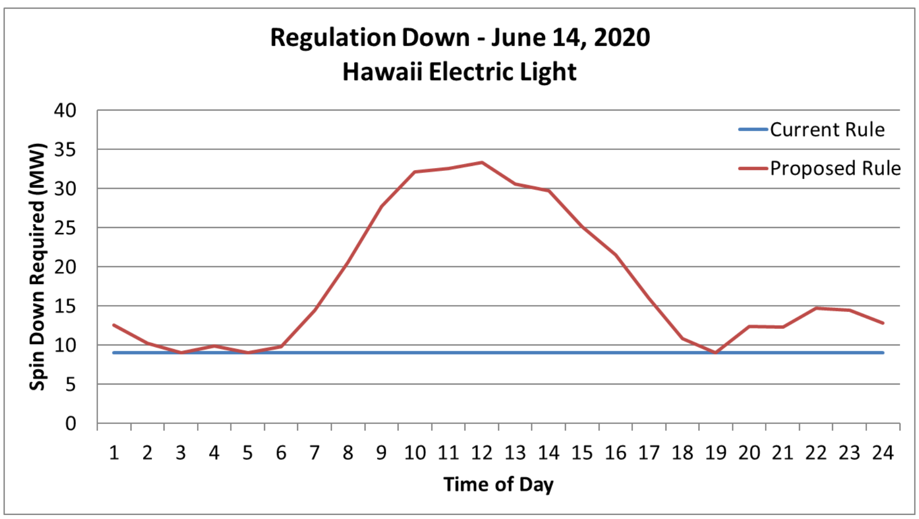


Figure 36 Comparison of Regulation Down requirement between the current methodology and the proposed methodology for June 14, 2020 for Hawai'i Island

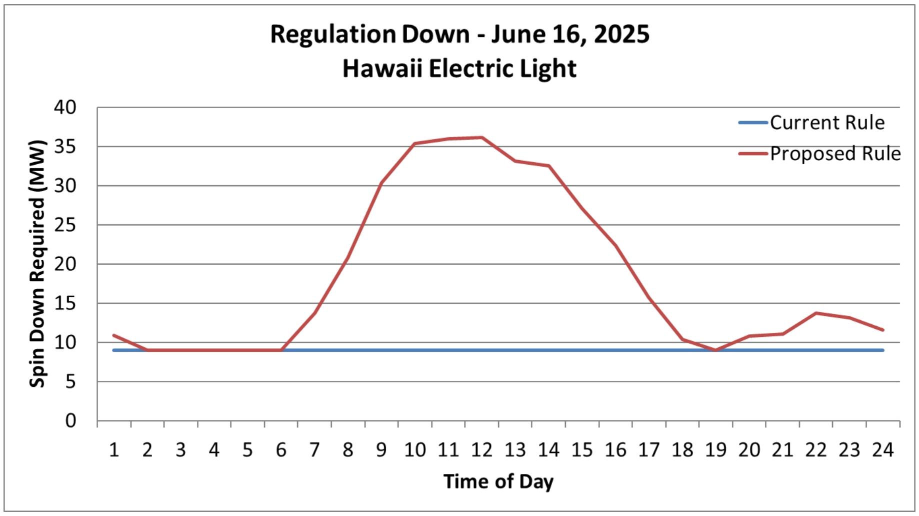


Figure 37 Comparison of Regulation Down requirement between the current methodology and the proposed methodology for June 16, 2025 for Hawai'i Island

2.9. Discussion

2.9.1. Resource Diversification

There was an inquiry from the Technical Advisory Panel ("TAP") members regarding why the requirement was calculated for each resource separately and then aggregated at the end of the calculation versus aggregating all categories at the beginning of the calculation. The TAP members felt that by aggregating all the resources at the start, any changes in wind and solar may offset each other and result in a lower requirement.

The reason why we chose to calculate the requirement for each resource separately was because if, in the future, an island becomes predominantly reliant on one type of resource over another, we want to be able to accurately reflect that in the reserve requirement. Without calculating the requirement for each resource separately, some of the volatility in one resource may be reduced, or amplified, by the volatility in other resources. For example, if an island becomes more heavily weighted towards Grid-Scale Solar than Grid-Scale Wind, we want to be sure that we can accurately capture the unique reserve requirements associated with Grid-Scale Solar versus Grid-Scale Wind.

2.9.2. Standard Deviation

One question raised by the TAP members was why we chose to use three standard deviations when calculating the reserve requirement. To address this question, the requirement for one

and two standard deviations was also calculated. A comparison of the Maximum, Average, and Minimum regulation requirement for the different standard deviations are shown below in Table 24 and Table 25 for Oʻahu, Table 26 and Table 27 for Maui, Table 28 and Table 29 for Molokaʻi, Table 30 and Table 31 for Lānaʻi, and Table 32 and Table 33 for Hawaiʻi Island. As expected, the requirement increases as the standard deviation increases.

Table 24 Impact of Standard Deviation on the Maximum, Average, and Minimum Regulation Up requirement for the island of Oʻahu

		Oʻahu – Regulation Up (MW)		
		Minimum	Average	Maximum
2020	1 Standard Deviation	180.00	180.07	190.94
	2 Standard Deviation	180.00	194.72	276.95
	3 Standard Deviation	180.00	220.80	362.95
2025	1 Standard Deviation	140.00	181.13	319.12
	2 Standard Deviation	140.00	229.51	466.02
	3 Standard Deviation	140.00	280.41	612.93

Table 25 Impact of Standard Deviation on the Maximum, Average, and Minimum Regulation Down requirement for the island of Oʻahu

		Oʻahu – Regulation Down (MW)		
		Minimum	Average	Maximum
2020	1 Standard Deviation	60.00	74.59	124.15
	2 Standard Deviation	60.00	94.43	178.53
	3 Standard Deviation	60.00	115.87	236.00
2025	1 Standard Deviation	60.00	81.42	149.65
	2 Standard Deviation	60.00	104.87	212.51
	3 Standard Deviation	60.00	129.75	277.96

Table 26 Impact of Standard Deviation on the Maximum, Average, and Minimum Regulation Up requirement for the island of Maui

		Maui – Regulation Up (MW)		
		Minimum	Average	Maximum

2020	1 Standard Deviation	6.00	12.82	33.02
	2 Standard Deviation	6.00	20.19	51.87
	3 Standard Deviation	6.00	28.31	70.71
2025	1 Standard Deviation	6.00	15.91	42.62
	2 Standard Deviation	6.00	24.74	65.60
	3 Standard Deviation	6.00	34.29	88.61

Table 27 Impact of Standard Deviation on the Maximum, Average, and Minimum Regulation Down requirement for the island of Maui

		Maui – Regulation Down (MW)		
		Minimum	Average	Maximum
2020	1 Standard Deviation	0.00	11.95	31.96
	2 Standard Deviation	0.80	19.92	48.21
	3 Standard Deviation	3.10	27.90	64.79
2025	1 Standard Deviation	3.00	16.01	38.07
	2 Standard Deviation	3.86	24.42	55.92
	3 Standard Deviation	6.18	32.84	74.36

Table 28 Impact of Standard Deviation on the Maximum, Average, and Minimum Regulation Up requirement for the island of Molokaʻi

		Molokaʻi – Regulation Up (MW)		
		Minimum	Average	Maximum
2020	1 Standard Deviation	0.09	0.25	0.45
	2 Standard Deviation	0.14	0.37	0.67
	3 Standard Deviation	0.19	0.48	0.89
2025	1 Standard Deviation	0.09	0.26	0.44
	2 Standard Deviation	0.14	0.38	0.65
	3 Standard Deviation	0.18	0.51	0.86

Table 29 Impact of Standard Deviation on the Maximum, Average, and Minimum Regulation Down requirement for the island of Molokaʻi

		Molokaʻi – Regulation Down (MW)		
		Minimum	Average	Maximum
2020	1 Standard Deviation	0.70	0.70	0.70
	2 Standard Deviation	0.70	0.70	0.70
	3 Standard Deviation	0.70	0.70	0.91
2025	1 Standard Deviation	0.70	0.70	0.70
	2 Standard Deviation	0.70	0.70	0.70
	3 Standard Deviation	0.70	0.70	0.88

Table 30 Impact of Standard Deviation on the Maximum, Average, and Minimum Regulation Up requirement for the island of Lānaʻi

		Lānaʻi – Regulation Up (MW)		
		Minimum	Average	Maximum
2020	1 Standard Deviation	0.07	0.20	0.36
	2 Standard Deviation	0.11	0.30	0.56
	3 Standard Deviation	0.14	0.39	0.76
2025	1 Standard Deviation	0.07	0.21	0.37
	2 Standard Deviation	0.11	0.31	0.57
	3 Standard Deviation	0.15	0.40	0.78

Table 31 Impact of Standard Deviation on the Maximum, Average, and Minimum Regulation Down requirement for the island of Lānaʻi

		Lānaʻi – Regulation Down (MW)		
		Minimum	Average	Maximum
2020	1 Standard Deviation	0.50	0.50	0.50
	2 Standard Deviation	0.50	0.50	0.53
	3 Standard Deviation	0.50	0.51	0.72
2025	1 Standard Deviation	0.50	0.50	0.50
	2 Standard Deviation	0.50	0.50	0.55

	3 Standard Deviation	0.50	0.51	0.74

Table 32 Impact of Standard Deviation on the Maximum, Average, and Minimum Regulation Up requirement for Hawaiʻi Island

		Hawaiʻi Island – Regulation Up (MW)		
		Minimum	Average	Maximum
2020	1 Standard Deviation	6.00	11.25	22.21
	2 Standard Deviation	6.00	15.52	32.36
	3 Standard Deviation	6.00	20.17	42.52
2025	1 Standard Deviation	6.00	13.89	31.03
	2 Standard Deviation	6.00	19.36	45.17
	3 Standard Deviation	6.00	25.22	59.32

Table 33 Impact of Standard Deviation on the Maximum, Average, and Minimum Regulation Down requirement for Hawaiʻi Island

		Hawaiʻi Island – Regulation Down (MW)		
		Minimum	Average	Maximum
2020	1 Standard Deviation	9.00	11.09	18.91
	2 Standard Deviation	9.00	14.18	27.37
	3 Standard Deviation	9.00	17.80	35.84
2025	1 Standard Deviation	9.00	11.49	20.98
	2 Standard Deviation	9.00	14.52	30.20
	3 Standard Deviation	9.00	17.99	39.43

Given the small island systems with high levels of renewable penetration, we decided to use three standard deviations to calculate our reserve requirement.

2.9.3. Time Interval

TAP members also questioned the time interval used when calculating the change in renewable generation and load. The time interval was based on feedback from system operators to account for the time it would take to decide to start a unit plus the time needed,

after the decision is made, to bring the unit online. Therefore, the time interval used was partially driven by the unique generator characteristics on each island.

Nevertheless, we still examined how the requirement would change when using time intervals of 1-, 10-, 20-, and 30-minutes. A comparison of the Maximum, Average, and Minimum for the different time intervals are shown below in Table 35 and Table 36 for O'ahu, Table 37 and Table 38 for Maui, Table 39 and Table 40 for Moloka'i, Table 41 and Table 42 for Lāna'i, and Table 43 and Table 44 for Hawai'i Island. It is important to note that for the 1-minute time interval, it was assumed that the operator would not be able to react fast enough to control these resources in an emergency. As a result, unlike for the longer duration time-intervals, for the 1-minute time-interval, controllable resources were included in the Down Regulation calculation. An update to Table 13 for the 1-minute regulation calculation is shown in Table 34 below.

Table 34 Resources included and excluded from the calculation of Regulation Up and Regulation Down for 1-minute intervals

	Regulation Calculation 1-minute Interval		Regulation Provision 1-minute Interval	
	Included in Regulation Up	Included in Regulation Down	Provides Regulation Up	Provides Regulation Down
Uncontrollable Customer Resources	Yes	Yes	No	No
Controllable Customer Resources	Yes	Yes	Yes	Yes
Uncontrollable Grid-Scale Resources	Yes	Yes	No	No
Controllable Grid-Scale Resources (Unpaired)	Yes	Yes	Yes	Yes
Controllable Grid-Scale Resources (Paired)	No	No	Yes	Yes

Table 35 Impact of time interval on the Maximum, Average, and Minimum Regulation Up requirement for the island of O'ahu

		O'ahu - Regulation Up (MW)		
		Minimum	Average	Maximum
2020	1 Minute	6.62	51.63	154.26
	10 Minute	180.00	194.76	266.76
	20 Minute	180.00	208.30	320.29
	30 Minute	180.00	220.80	362.95
2025	1 Minute	13.11	82.49	229.06

	10 Minute	140.00	223.54	431.50
	20 Minute	140.00	254.49	523.23
	30 Minute	140.00	280.41	612.93

Table 36 Impact of time interval on the Maximum, Average, and Minimum Regulation Down requirement for the island of O'ahu

		O'ahu – Regulation Down (MW)		
		Minimum	Average	Maximum
2020	1 Minute	6.56	49.37	146.41
	10 Minute	60.00	93.69	189.52
	20 Minute	60.00	104.41	219.65
	30 Minute	60.00	115.87	236.00
2025	1 Minute	13.71	77.31	212.39
	10 Minute	60.00	103.46	222.19
	20 Minute	60.00	116.40	257.97
	30 Minute	60.00	129.75	277.96

Table 37 Impact of time interval on the Maximum, Average, and Minimum Regulation Up requirement for the island of Maui

		Maui – Regulation Up (MW)		
		Minimum	Average	Maximum
2020	1 Minute	1.91	10.30	30.16
	10 Minute	6.00	18.51	55.41
	20 Minute	6.00	23.78	65.02
	30 Minute	6.00	28.31	70.71
2025	1 Minute	1.94	12.39	37.23
	10 Minute	6.00	22.99	70.37
	20 Minute	6.00	29.12	82.26
	30 Minute	6.00	34.29	88.61

Table 38 Impact of time interval on the Maximum, Average, and Minimum Regulation Down requirement for the island of Maui

		Maui – Regulation Down (MW)		
		Minimum	Average	Maximum
2020	1 Minute	1.89	10.15	30.58
	10 Minute	0.71	17.10	52.52
	20 Minute	2.10	23.30	63.64
	30 Minute	3.10	27.90	64.79
2025	1 Minute	1.92	12.20	37.83
	10 Minute	3.76	21.57	60.92
	20 Minute	5.17	28.04	73.09
	30 Minute	6.18	32.84	74.36

Table 39 Impact of time interval on the Maximum, Average, and Minimum Regulation Up requirement for the island of Molokaʻi

		Molokaʻi – Regulation Up (MW)		
		Minimum	Average	Maximum
2020	1 Minute	0.07	0.14	0.26
	10 Minute	0.14	0.37	0.69
	20 Minute	0.19	0.48	0.89
	30 Minute	0.21	0.56	0.98
2025	1 Minute	0.06	0.15	0.25
	10 Minute	0.14	0.39	0.67
	20 Minute	0.18	0.51	0.86
	30 Minute	0.21	0.58	0.95

Table 40 Impact of time interval on the Maximum, Average, and Minimum Regulation Down requirement for the island of Molokaʻi

		Molokaʻi – Regulation Down (MW)		
		Minimum	Average	Maximum
2020	1 Minute	0.08	0.13	0.23

	10 Minute	0.70	0.70	0.73
	20 Minute	0.70	0.70	0.91
	30 Minute	0.70	0.71	0.92
2025	1 Minute	0.08	0.14	0.23
	10 Minute	0.70	0.70	0.71
	20 Minute	0.70	0.70	0.88
	30 Minute	0.70	0.70	0.89

Table 41 Impact of time interval on the Maximum, Average, and Minimum Regulation Up requirement for the island of Lānaʻi

		Lānaʻi – Regulation Up (MW)		
		Minimum	Average	Maximum
2020	1 Minute	0.07	0.15	0.22
	10 Minute	0.14	0.32	0.56
	20 Minute	0.14	0.39	0.76
	30 Minute	0.11	0.44	0.90
2025	1 Minute	0.08	0.16	0.23
	10 Minute	0.15	0.33	0.58
	20 Minute	0.15	0.40	0.78
	30 Minute	0.11	0.46	0.93

Table 42 Impact of time interval on the Maximum, Average, and Minimum Regulation Down requirement for the island of Lānaʻi

		Lānaʻi – Regulation Down (MW)		
		Minimum	Average	Maximum
2020	1 Minute	0.07	0.15	0.23
	10 Minute	0.50	0.50	0.54
	20 Minute	0.50	0.51	0.72
	30 Minute	0.50	0.53	0.92
2025	1 Minute	0.07	0.15	0.23
	10 Minute	0.50	0.50	0.56

	20 Minute	0.50	0.51	0.74
	30 Minute	0.50	0.53	0.95

Table 43 Impact of time interval on the Maximum, Average, and Minimum Regulation Up requirement for Hawai‘i Island

		Hawai‘i Island – Regulation Up (MW)		
		Minimum	Average	Maximum
2020	1 Minute	1.58	7.21	21.32
	10 Minute	6.00	15.66	35.11
	20 Minute	6.00	20.17	42.52
	30 Minute	6.00	23.68	48.36
2025	1 Minute	1.61	9.35	29.83
	10 Minute	6.00	19.77	49.35
	20 Minute	6.00	25.22	59.32
	30 Minute	6.00	29.46	67.64

Table 44 Impact of time interval on the Maximum, Average, and Minimum Regulation Down requirement for Hawai‘i Island

		Hawai‘i Island – Regulation Down (MW)		
		Minimum	Average	Maximum
2020	1 Minute	1.65	6.94	20.34
	10 Minute	9.00	14.38	29.19
	20 Minute	9.00	17.80	35.84
	30 Minute	9.00	20.89	41.08
2025	1 Minute	1.68	9.01	28.22
	10 Minute	9.00	14.92	32.01
	20 Minute	9.00	17.99	39.43
	30 Minute	9.00	20.91	45.37

To capture both the regulation needed by our operators to bring units online, as well as, the regulation needed to manage short-term fluctuations associated with variable renewable

generation, it was decided that for O'ahu and Maui, requirements based on both the 1-minute and 30-minute interval would be used. For Hawai'i Island, requirements based on both the 1-minute and 20-minute interval would be used. The 1-minute requirement would ensure that there is enough generation on the system to meet any short-term fluctuations in variable energy, while the 20 to 30-minute requirement would ensure that there is enough reserve for our operators to bring units online if needed.

3. LOAD BUILD AND LOAD REDUCE

Load reduce is capacity that can be provided by a generator, storage or controlled load to reduce system load in the required timeframes and durations in response to a remote dispatch signal. Similarly, load build is capacity that can be provided by storage or controlled load to increase system load in the required timeframes and durations in response to a remote dispatch signal. The intent of these two services is to encourage more load resources to participate economically in the provision of grid services.

In tandem, load build and load reduce grid needs would identify a potential for energy arbitrage although the capacity for and timing of these needs may not be identical.

Load Reduce

- Aligned with high marginal cost hours
- Subset of the energy service for resources that can't participate in the regular provision of energy or are constrained on the number of calls for service

Load Build

- Aligned with high variable renewable generation hours
- Identified by the charging of a standalone storage resource selected by RESOLVE
- Reduce hours of overgeneration or to serve unmet downward regulating reserves

3.1. Methodology

A service requirement will not be input into the RESOLVE model for this service. Rather, a subset of hours (and their marginal avoided costs) for the energy service will be used to identify the need for load build and load reduce.

A production simulation will be utilized to evaluate changes in marginal energy cost across all hours. The results of the production simulation will be analyzed to identify the amount and timing of the need for the load reduce services by binning high marginal cost hours.

The same production simulation can be used to bin the hours where there is a high availability of variable renewable generation on the system. The need for load build services can be identified where these high available energy hours overlap with the charging of a standalone storage resource selected by RESOLVE. If RESOLVE did not select a standalone storage resource to shift load, then the model decided that the level of curtailment on the system was a lower cost option than installing the storage resource to enable the load build service.

The avoided cost for each grid service will be calculated for 2025-20234, 2040, 2045, and 2050, consistent with the planning horizon used in RESOLVE.

4. FAST FREQUENCY RESPONSE

Fast frequency response (FFR) is an autonomous and predictable capacity to limit the frequency drop resulting from a frequency disturbance. The minimum FFR requirements were based on several factors:

1. Largest generation loss contingency
2. Legacy DGPV capacity for Hawai'i Island and Maui County
3. 15% of load shed for Hawai'i Island and Maui County, no load shed for Oahu
4. Stage 1 RFP project primary frequency response (PFR) contributions

Preliminary analysis was performed to assess the contributions of the Stage 1 RFP projects ability to contribute primary frequency response. Their contributions were accounted for directly in the development of the grid service requirement. This service requirement is input into the RESOLVE and PLEXOS models and must be met in all hours. Future projects such as the Stage 2 RFP projects and future, candidate resources selected in RESOLVE can provide PFR depending on state of charge and their available headroom (rated MW output less pre-disturbance MW output).

The FFR requirements vary by island due to differences in droop and under-frequency load shed schemes (UFLS).

Common terms used in the definition of the FFR requirement include:

- **GTRIP** – Largest single unit contingency, typically the largest thermal unit still available on the system (MW)
- **DGPV** – Hourly output of the aggregated DER (MW)
- **DGPV_CAP** – Total installed DER capacity (MW)
- **NTLOAD** – Gross load less the DGPV output (MW)
- **PFR** – Combined contribution of the available Stage 1 RFP projects

- **LEGPV** – Legacy DER capacity on Hawaiʻi Island and Maui (MW)
- **UFLS** – 15% of NTLOAD (MW)

O'ahu

The FFR requirement for O'ahu is defined as:

FFR = Max (**GTRIP** – 26.7 – **PFR**)

Where **PFR** is the minimum of 24 MW and the available headroom on the Stage 1 RFP projects during day or the minimum of 39 MW and the available headroom on the Stage 1 RFP projects during the night.

26.7 MW of FFR2 is assumed to be available at all times.

Hawaiʻi Island

The FFR requirement for Hawaiʻi Island is defined as:

FFR = Max (**GTRIP** + [**LEGPV** * (**DGPV** / **DGPV_CAP**)] – **UFLS** – **PFR**)

Where [**LEGPV** * (**DGPV** / **DGPV_CAP**)] is the portion of DER generation attributable to legacy PV only and **PFR** is the minimum of 31 MW and the available headroom on the Stage 1 RFP projects.

Maui

The FFR requirement for Maui is defined as:

FFR = Max (**GTRIP** + [**LEGPV** * (**DGPV** / **DGPV_CAP**)] – **UFLS** – **PFR**)

Where [**LEGPV** * (**DGPV** / **DGPV_CAP**)] is the portion of DER generation attributable to legacy PV only and **PFR** is the minimum of 30 MW and the available headroom on the Stage 1 RFP projects.

5. INERTIA

In an under-frequency event, inertia provides the initial response, buying time for FFR to activate. Minimum inertia requirements were based on two constraints:

1. Limit the max rate of change of frequency to 3 Hz/second
2. Allow FFR to respond in 0.5 seconds before unacceptable load shedding occurs

The inertia grid service requirement is input into the RESOLVE and PLEXOS models and must be met in all hours. Inertia contributions for each resource, in terms of kinetic energy (MJ), were assumed for each qualifying resource.

Further definition of the minimum inertia requirements are provided below.

$$\Delta f_{Hz} = 60 \times \frac{\Delta P_{MW}}{D_{pct} P_{load}} \left(1 - e^{-\frac{D_{pct} P_{load}}{2KE_{MJ}} t}\right)$$

$$ROCOF = \frac{df_{Hz}}{dt} = 60 \times \frac{\Delta P_{MW}}{2KE_{MJ}} e^{-\frac{D_{pct} P_{load}}{2KE_{MJ}} t}$$

If load damping constant D is zero, then

ROCOF = 30 * ΔP / KE

KE = 30 * ΔP / ROCOF

ΔP = KE * ROCOF / 30

Given			Calculate	
ROCOF	KE	ΔP		
	170	8	**1.41176**	ROCOF
2		190.125	**2851.88**	KE
1.5	170		8.5	ΔP

Item Description	Hawaii	Maui	Oahu	Units
Generation Contingency	30	30	135	MW
Legacy DGPV Capacity	5.2	7.2	73.5	MW
%75 of DGPV Capacity	3.9	5.4	55.125	MW
Total Loss of Generation	33.9	35.4	190.125	MW
Block 1	59.1	59	58.9	Hz
Block 2	58.8	58.7	58.7	Hz
Block 3	58.5	58.4	58.4	Hz
Assuming PV trips instantaneously at 59.3 Hz				
Target ROCOF	3	3	3	Hz/s
Required KE to meet ROCOF constraint	339	354	1901.25	MW-s
Gen Trip ROCOF	2.654867	2.542373	2.130178	Hz/s
Time to reach PV freq trip setting	0.263667	0.275333	0.328611	sec
PV trip time delay	0	0	0	cycles
Time of PV tripping	0.263667	0.275333	0.328611	sec
Freq at PV trip	59.3	59.3	59.3	Hz
Time to unacceptable load shed+0.1Hz	0.497	0.542	0.428611	sec

Frequency Target (Block + 0.1 Hz)	58.6	58.5	59	Hz
Required Time to Freq. Target	0.5	0.5	0.5	sec
Required KE to meet time constraint	341.0463	326.5683	2217.92	MW-s
max ROCOF	2.982	3.252	2.571667	Hz/s
Minimum Inertia	341.0463	354	2217.92	MW-s
Minimum Inertia (round up)	**350**	**360**	**2220**	**MW-s**
Minimum Inertia satisfies two constraints:				
1) ROCOF <= 3 Hz/sec	2.905714	2.95	2.569257	Hz/s
2) Time to Load Shed <= 0.5 sec	0.513127	0.551186	0.500469	sec

6. TRANSMISSION PLANNING CRITERIA

The transmission planning criteria for O'ahu, Hawai'i Island, and Maui will be used in the identification of transmission needs, including system security.

6.1. O'ahu Transmission Criteria

6.1.1. Purpose

The purpose of these criteria is to establish guidelines for planning the Hawaiian Electric O'ahu Transmission System to ensure safe and reliable service to its customers to serve current and future system needs. These criteria also apply to facilities that interconnect to the O'ahu Transmission System. The primary objectives of these criteria are to maintain reliable Transmission System operation (i.e., continuity of service) include the following:

- Ensure public safety.
- Maintain system stability under a wide range of operating conditions identified in Section 6.1.9.
- Maintain equipment operating limits under a wide range of operating conditions identified in Section 6.1.9.
- Minimize losses where cost effective.
- Preserve the reliability of the existing transmission infrastructure.
- Maintain an acceptable level of impact to customers for contingencies and events as defined within this planning criteria.
- Prevent cascading outages or system failure following credible contingencies and events.

The criteria outlined below are intended to be used as a general guide in planning the O'ahu Transmission System, for which transmission needs for reinforcement, enhancements, and mitigations will be determined.

6.1.2. Definitions

Acceptable Damping: A continuous attenuation of oscillations required to achieve equilibrium over a four-cycle period.

Cascading: The uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies. (Source: Glossary of Terms Used in NERC Reliability Standards; Effective Date July 1, 2016)

Consequential Load Loss: All load that is no longer served by the Transmission System as a result of Transmission System Facilities being removed from service by a Protection System operation designed to isolate the fault. (Source: Glossary of Terms Used in NERC Reliability Standards; Effective Date January, 1 2015)

Contingency: The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element. (Source: Glossary of Terms Used in NERC Reliability Standards; February 8, 2005)

Contingency Reserve: The provision of capacity deployed by system operator to meet reliability requirements in Section 6.1.9.

Corrective Action Plan: A list of actions and an associated timetable for implementation to remedy a specific problem. (Source: Glossary of Terms Used in NERC Reliability Standards; February 7, 2006)

Distributed Energy Resources or DER: Resources interconnected to the distribution system that produce electricity.

Droop Response or Primary Frequency Response: Open-loop proportional control defined as a percentage of turbine speed or system frequency divided by its rated capacity (i.e., turbine or IBR rating). For a 5% droop response, a unit operating at full speed no load or zero output will instantaneously, without any intentional time delays, issue a control signal to export 100% rated capacity for a 5% decrease in turbine speed or system frequency.

Element or Elements: Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components. (Source: Glossary of Terms Used in NERC Reliability Standards; Effective Date July 1, 2016)

Equipment Rating: The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved. (Source: Glossary of Terms Used in NERC Reliability Standards; February 8, 2005)

Extreme Events: Less frequent but more severe Contingencies that could result in a cascading effect.

Facility or Facilities: A set of electrical equipment that operates as a single bulk electric system Element (for example, a line, a generator, a shunt compensator, transformer, etc.). (Source: Glossary of Terms Used in NERC Reliability Standards; February 7, 2006)

Inverter-Based Resource or IBR: A resource that is asynchronously connected to the sub-transmission or Transmission System through power electronics.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete. (Source: Glossary of Terms Used in NERC Reliability Standards; Effective Date January 1, 2015)

Near-Term Transmission Planning Horizon: The transmission planning period that covers year one through five. (Source: Glossary of Terms Used in NERC Reliability Standards; January 24, 2011)

Non-Consequential Load Loss: Load that is disconnected from the system by the utility to stabilize system frequency or voltage. Non-Consequential Load loss does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive load, or (3) load that is disconnected from the system by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. (Source: Glossary of Terms Used in NERC Reliability Standards; Effective Date January 1, 2015)

Protection System: Includes, Protective relays which respond to electrical quantities; Communications systems necessary for correct operation of protective functions; Voltage and current sensing devices providing inputs to protective relays; Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply); and Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices. (Source: Glossary of Terms Used in NERC Reliability Standards; Effective Date April 1, 2013)

Short Circuit Ratio or SCR[29]: Short circuit ratio is defined as the ratio between short circuit apparent power (SCMVA) from a 3LG fault at a given location in the power system to the rating of the Inverter-Based Resource connected to that location. Since the numerator of the SCR metric is dependent on the specific measurement location, this location is usually stated along with the SCR number.

$$SCR_{POI} = \frac{SCMVA_{POI}}{MW_{IBR}}$$

Where SCMVA is the short circuit MVA level at the POI without the current contribution of the Inverter-Based Resource, and MW IBR is the nominal power rating of the Inverter-Based Resource being connected at the POI.

Stability: The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances. (Source: Glossary of Terms Used in NERC Reliability Standards; February 8, 2005)

System: A combination of generation, transmission, and distribution components. (Source: Glossary of Terms Used in NERC Reliability Standards; February 8, 2005)

Transmission System: A network of circuits that operate at a nominal voltage of 138 kV. The Transmission System can also include sections of the 46 kV sub-transmission system as defined by these criteria.

Weak Grid: A transmission system that has at least one transmission node with a calculated short circuit ratio of less than 3 (i.e., SCR < 3).

6.1.3. Transmission System Defined

For the purpose of these criteria, the Transmission System is defined as all transmission lines, substation equipment, structures, and land utilized for transporting power at 138 kV and above. In addition, the following 138-46 kV transformers, 46 kV buses, and 46 kV circuits are part of the transmission system.

- Honolulu-School No. 1 and No. 2, 46 kV circuits.
- Honolulu-Iwilei No. 1 and No. 2, 46 kV circuits.
- Iwilei-School 46 kV circuit.
- School Street 48/80 MVA, 138-46 kV Transformers A and B.
- Iwilei 48/80 MVA, 138-46 kV Transformers A and B.
- Waiau 48/80 MVA, 138-46 kV Transformers A and B.

[29] NERC Reliability Guidelines, December 2017 – Integrating Inverter Based Resources into Low Short Circuit Ratio Systems

- Honolulu 46 kV Buses A and B.
- Waiau 46 kV Buses A and B.
- School 46 kV Buses A and B.
- Iwilei 46 kV Buses A and B.

Crossing Points

All transmission line crossing points are to be considered while planning the Transmission System. Following is a list of known crossing points.

1) Halawa-Makalapa and Waiau-Koolau 1 & 2 (just outside of Halawa Sub)
2) Kahe-Halawa No. 1 and Waiau-Wahiawa (between Structures 21 and 22)
3) Kahe-Halawa No. 2 (Structure 85) and Waiau-Wahiawa (Structure 26)
4) Waiau-Koolau 2 and Waiau-Wahiawa (between Structures 18 and 19)
5) Waiau-Koolau 1 & 2 and Halawa-Iwilei (just outside of Halawa Sub)
6) Waiau-Koolau 1 & 2 and Halawa-School (just outside of Halawa Sub)

6.1.4. Transmission Planning Criteria – Thermal Limits

At a minimum, the Oʻahu system shall meet the performance requirements specified by Planning Events P0 through P4 in Section 6.1.9. In addition, the Oʻahu Transmission System shall meet the following steady-state performance requirements:

With any generating unit offline for maintenance, all Transmission System Elements will operate within their NORMAL ratings while maintaining voltage levels within their upper or lower limits for any of the following outages:

- Any other generating unit or IBR that is deemed as a single Contingency equivalent
- Any synchronous condenser or IBR equivalent
- Any transmission circuit
- Any transmission transformer
- Any transmission bus

With any generating unit offline for maintenance, all Transmission System Elements will operate within their EMERGENCY ratings while maintaining voltage levels within their upper or lower limits for any multiple transmission circuit outages caused by a line down at a crossing point.

With any generating unit offline for maintenance, and any transmission line out of service for maintenance, all Transmission System Elements will operate within their EMERGENCY ratings while maintaining voltage levels within their upper or lower limits for any of the following outages:

- Any other generating unit or IBR equivalent
- Any synchronous condenser or IBR equivalent
- Any other transmission circuit
- Any multiple transmission circuit outage caused by a line down at a crossing point
- Any transmission transformer
- Any transmission bus

The purpose of this criterion is to ensure the system will remain stable but all loads may not continue to be served. These conditions must be met without operator intervention.

Any generating station must be able to export real and reactive power equal to the sum of the individual generating unit's NORMAL capability ratings in MW at 100 percent of rated generator field current /power factor with no Transmission System Element loading exceeding its EMERGENCY rating while maintaining voltage levels within their upper or lower limits for any of the following outages:

- Any transmission circuit
- Any multiple transmission circuit outage caused by a line down at a crossing point
- Any transmission transformer
- Any transmission bus

Additionally, for any transmission Element outage, the aggregate generating capacity on any remaining radial transmission circuit will not exceed the maximum single-point failure for the system.

With the Transmission System intact, the failure of any single transmission Element, coupled with a 138 kV breaker failure while attempting to clear the initial failure, will not result in the loss of:

- More than one generator or IBR
- More than one sub-transmission transformer
- More than one "source" circuit to a transmission station

With two 138 kV transmission circuits on common steel poles taken out of service at the same time for maintenance, all Transmission System Elements will operate within their NORMAL ratings while maintaining voltage levels within their upper or lower limits. This is a maintenance requirement based on present maintenance practices.

The 138 kV system is the backbone of the Oʻahu electrical system. Excessive segmentation of a 138 kV transmission line can result in increasingly complex protection coordination schemes, greater susceptibility to mis-operation of relays, maintenance and operational issues, and excessive curtailment of resources for certain transmission line contingencies. The total generation on any transmission line must be limited to the single-point failure capacity of the system. Generating Facilities should interconnect to an existing substation if practical or interconnect to multiple transmission lines through a new standard transmission substation.

6.1.5. Loading Limits

Conductor loading limits are based on the Engineering Standards Practice Manual (ESPM) that are to be updated periodically as appropriate. Operational planning mitigations that utilize operator interventions within the duration of allowed Equipment Ratings are not governed by this transmission planning criteria.

Power Transformer Loading Limits

Loading limits of transmission power transformers shall be as follows:

1) The normal loading limit of a transmission power transformer shall be its zero percent loss-of-life kVA capability.
2) The emergency loading limit of a transmission power transformer shall be its one percent loss-of-life kVA capability.
3) The extreme emergency loading limit of a transmission power transformer shall be 200 percent of its maximum nameplate rating.

Loading limits shall be determined in accordance with the latest edition of C-57.92, ANSI Guide for Loading Mineral - Oil - Immersed Power Transformers Up to and Including 100 MVA with 55°C or 65°C Winding Rise.

6.1.6. Current Carrying Capacity

Overhead

Conductors for overhead transmission lines shall be considered to have current carrying capacity in accordance with Engineering Standard 1-2038, "Current Carrying Capacity Outdoor Bare Conductor." A conductor bundle with identical conductors shall have the rating of a single conductor multiplied by the number of conductors per phase in the bundle.

Underground

The 46 kV underground circuit ampacities are:

Table 45: 46 kV Underground Ampacities

	NORMAL	EMERGENCY "A"	EMERGENCY "B"
Honolulu-Iwilei #1 & #2	315 Amps	400 Amps	375 Amps
Honolulu-School #1 & #2	315 Amps	375 Amps	400 Amps
Iwilei-School	292 Amps	375 Amps	349 Amps

The Emergency "A" rating is based on one Honolulu-Iwilei circuit out of service. Emergency "B" rating is based on one Honolulu-School circuit out of service.

Open Bus

Open buses shall be considered to have current carrying capacity in accordance with Engineering Standard, 1-2039, "Current Carrying Capacity- Outdoor Open Bus."

Power Transformer Equipment

Transmission power transformer connections, switches, protective relays, and current transformers shall be designed to allow the power transformer to carry 200 percent of maximum nameplate rating under extreme emergency conditions in accordance with the latest edition of C-57.92, ANSI Guide for Loading Mineral - Oil - Immersed Power Transformers Up to and Including 100 MVA with 55°C or 65°C Winding Rise. (The relay settings associated with this type of transformer shall allow the transformer to carry 200 percent of maximum nameplate rating.)

Substation Equipment

Switches, disconnects, circuit breakers, and associated equipment shall be considered to have a current carrying capacity equivalent to their respective nameplate current rating.

Generator MVAR Loading Limits

For planning purposes, the reactive capability of a given machine will be determined using the manufacturer's machine capability curve and normal MW at rated power factor for generating units. At no time will the system be planned with any generator or IBR exceeding its rating as determined by its capability curve corresponding to the appropriate ambient temperature suitable for the O‘ahu system.

6.1.7. Voltage Levels

Transmission voltage levels shall be kept within the prescribed limits for any condition for which the Transmission System is planned. These limits apply after automatic corrective action has been taken by LTC and/or switched capacitors.

The maximum voltage limits are based on *Standards for Electric Utility Service in the State of Hawaii* (General Order No.7).

1) 138 kV System. For any system operating condition, the voltage at any 138 kV bus shall not exceed 145 kV.

2) 46 kV System. For any system operating condition, the voltage on the 46 kV system shall not exceed 48 kV.

The minimum voltage limits are based upon maintaining customer voltages in accordance with *Standards for Electric Utility Service in the State of Hawaii* (General Order No.7). To accomplish this, the 46 kV bus voltages at the transmission and sub-transmission substations must be maintained within the limits that are used to plan the distribution system.

1) 138 kV System. The minimum allowable voltage on any 138 kV bus is 126.5 kV for any operating condition for which the transmission system is planned.
2) 46 kV System. The minimum allowable voltage on any 46 kV bus is 45 kV for any operating condition for which the system is planned.

The system's short-circuit current requirements and resources should be considered when evaluating near-term voltage and MVAR mitigation alternatives.

6.1.8. System Stability

The system shall maintain operating equilibrium with acceptable damping ratio of 3% for all reasonable combinations of planned outages and system contingencies defined in Section 6.1.9. Power oscillations exhibit an acceptable damping ratio of 3% when the oscillation magnitude decreases by 17% over the first period of oscillation, or by 53% over four periods of oscillations. Displacement of synchronous generation has a direct impact on dynamic and transient stability. In addition to traditional analyses, new planning metrics and analysis are required to maintain Stability under plausible operating conditions. If the conditions for Weak Grid are met, further analysis may be required in appropriate software modeling platform to fully investigate any Stability concerns.

Steady State Voltage

The power-voltage (PV) and reactive power-voltage (QV) analysis shall be performed to determine the steady-state voltage stability of critical load buses.

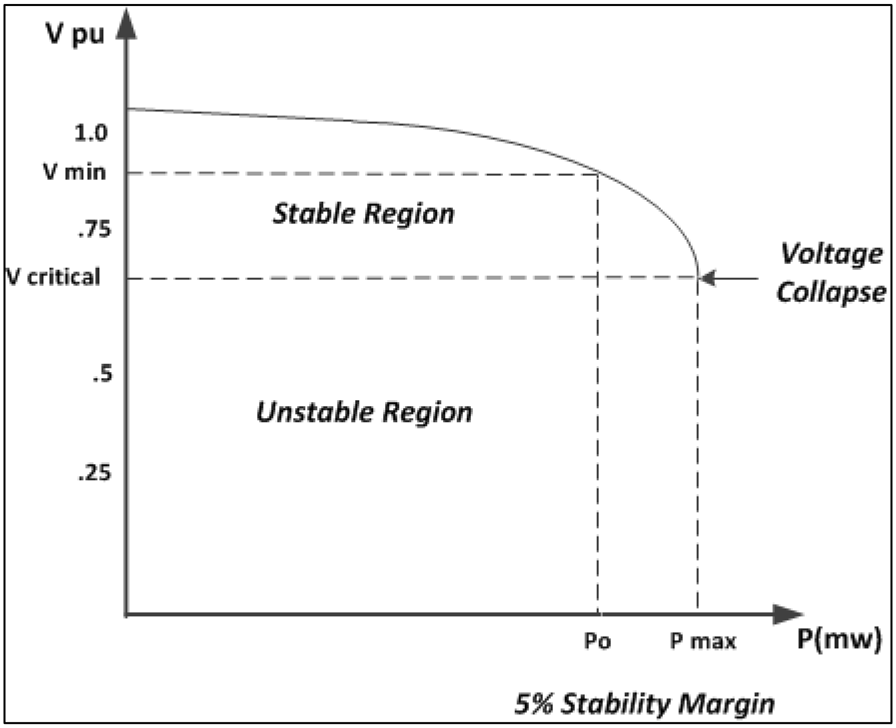


Figure 38 Typical PV Curve

Figure 38 shows a typical PV curve that depicts the thermal limit of the transmission system. To ensure voltage stability, a 5% margin from P_0 to Pmax, identified as P_0, shall be maintained under planning events described in Section 6.1.9. In addition, the intersection of the QV curve with the x-axis shall occur above the minimum allowable voltage level, and the reactive power margin, represented by the value at the minimum point of the QV curve, shall be greater than the size of a nearby capacitor bank or reactive power device.

Weak Grid Assessment

Weak power systems are more susceptible to voltage transients and can be exacerbated by control instabilities. Short circuit ratio (SCR) is the most basic metric to assess the relative strength of an electrical system for a specific area when evaluating performance of a specific IBR[30]. For system planning purposes, a more appropriate quantity is the weighted short circuit ratio (WSCR)[31], defined by:

$$WSCR = \frac{\sum_i^N SCMVA_i * P_{RMW_i}}{\left(\sum_i^N P_{RMW_i}\right)^2}$$

30 NERC Reliability Guideline – Integrating Variable Energy Resources into Weak Power Systems

31 Electranix, System Strength Assessment of the Panhandle System, Electric Reliability Council of Texas, 2016

Where $\boldsymbol{SCMVA_i}$ is the short circuit capacity at bus $\boldsymbol{i}$ and $\boldsymbol{P_{RMWi}}$ is the MW rating of the IBR; $\boldsymbol{N}$ is the number of total IBR fully interacting with each other and $\boldsymbol{i}$ is the IBR index. The WSCR takes into account the aggregate IBR of the system to ensure the system has sufficient short circuit current for transient voltage stability. There is currently no industry standard for WSCR of a transmission system.

Control Stability

Control stability refers to the behavior of grid-connected IBR like wind and solar PV plants to operate in a stable manner for both small disturbances and large disturbances on the grid over a wide range of operating conditions and disturbances. Unstable behavior can result in oscillatory behavior, extreme overshoots in voltage or current, and/or a failure to ride-through a disturbance. The stability of equipment controls is impacted by many factors, including equipment tuning, operating conditions, grid strength, disturbance types, and the electrical proximity to other IBR or synchronous machines on the grid, among others.

As more IBR with complex control system connect to the system, it is important to assess the control stability of these resources to assess the robustness of controls to the range of expected operating conditions over the planning horizon. This will be done through a combination of screening, scenario modeling, and testing/demonstration of performance. As such, supplying accurate and sufficiently detailed models of equipment and functional descriptions of equipment control and protection schemes is necessary well in advance of interconnection. Equipment performance will be evaluated for combinations of:

- Full and partial power operating conditions, high and low voltages (within continuous limits)
- Symmetric and asymmetric fault disturbances (with reclosing), line switching disturbances, loss of generation and load disturbances
- Low grid strength conditions

Rotor Angle Stability Criteria

Rotor angle stability simulations involve the evaluation of critical clearing times ("CCT") for close-in faults to generating stations, generating units, and transmission lines. Generator rotor angle deviation with respect to a "distant" generator shall be less than 180 degrees to prevent generator pole-slipping and in addition to avoiding loss of synchronism. Dynamic performance shall exhibit acceptable damping to ensure rotor angle stability. Pole-slipping could impose mechanical stresses on the generator shaft and could result in catastrophic failure of the unit.

Critical Clearing Times

The Transmission Planning Department performs Stability simulations using the standard fault clearing times for breakers provided by the System Protection Department. If a fault event

results in a planning criteria violation, the Transmission Planning Department shall determine the CCT for that event and will provide it to the System Protection Department for its review and feedback. If the CCT cannot be achieved by the existing protective devices, Transmission Planning Department will work with System Protection Department to develop appropriate mitigation measures. Such mitigation measures may include but not limited to the system protection upgrade, generator size or power export reduction, application of synchronous condenser or adjustments to resource commitment as applicable.

Frequency Stability

Frequency stability is determined by 1) the amount of inertia on the system; 2) the amount and response characteristics of fast-frequency and primary frequency response reserves on the system; and 3) the magnitude of the generation Contingency. The system shall carry sufficient inertia and frequency response reserves to mitigate the loss of the largest generating unit, including any aggregate loss of distributed energy resources in response to the Contingency events, with appropriate Non-Consequential Load Loss criteria defined in Section 6.1.9. In order to meet these criteria, mitigation measures may require establishing minimum inertia requirement for a generation loss event.

Planning Criteria for Stability

Stability of an electric power system is the attribute of the system to regain a state of operating equilibrium after being subjected to disrupting forces (Contingency events), such that the majority of the system remains intact. Generating units and transmission Elements must remain online and in synchronism with the system to prevent an island-wide blackout. Therefore, the Transmission System shall be tested by simulating frequent Contingency events and reasonable cascading Contingency events that may occur on the system to ensure operating equilibrium is restored.

1) For the more frequent types of contingencies listed below, not more than one generating unit can disconnect from the system, all generating units must remain connected and synchronized to the system, all generating units must participate towards beneficial system response, no circuits should trip on stability swings, transient voltage stability must be maintained, and no Non-Consequential Load Loss or Consequential Load Loss should take place.
    - Normally cleared, three-phase faults on transmission lines with automatic reclosing as applicable to the circuit being analyzed.
    - Delayed clearing of three-phase faults due to failure of the pilot relay on circuits that have one pilot scheme, and one step-distance scheme for backup to the pilot scheme. Dual-pilot relay schemes require independent communication technologies (e.g. both microwave and fiber-optic cable) to mitigate failure of single-pilot relay schemes. Analysis shall be performed for the simulation of the longest delayed clearing time scenario.

- Delayed clearing of single line-to-ground faults due to failure of a circuit breaker to open.
- Normally cleared simultaneous single line-to-ground faults on both circuits that share a common tower (on different phase of each circuit).
- Exceptions include small units (e.g. internal combustion engines) that share a common generator step-up transformer and combined-cycle units. Other exceptions will be considered on a case-by-case basis.

2) For the less frequent contingencies listed below, Non-Consequential Load Loss or generator tripping may be required to prevent equipment damage and maintain Stability.
   - Sudden loss of all transmission lines emanating from a power plant switching station.
   - Sudden loss of all transmission lines in a common right-of-way.
   - Sudden loss of any combined cycle units or any two synchronous generating units (synchronous, asynchronous, or both), including any aggregate loss of DER.
   - Sudden loss of any combination of two transmission Elements.
   - Cascading loss of generation
3) Extreme Events—For Extreme Events system preservation shall be tested. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. If any Extreme Events result in an island-wide blackout, mitigation measures shall be formulated and analyzed to see if a reasonable solution can be implemented. Examples of Extreme Events include but not limited to:
   - A three-phase fault on generator, transmission circuit, transformer or bus section with stuck breaker resulting in delayed fault clearing
   - A three phase fault on generator, transmission circuit, transformer or bus section with failure of a non-redundant component of a Protection System resulting in delayed fault clearing
   - Three phase internal breaker fault
   - Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances.

6.1.9. Transmission Planning Assessment

A Planning Assessment of the Transmission System must be performed on an annual basis to ensure compliance with these criteria for the Near-Term Planning Horizon and Long-Term Planning Horizons. This Planning Assessment must use current models to analyze steady-state, dynamic, and transient system stability to ensure compliance with these criteria. Updated assumptions, forecasts, and study results shall be summarized and documented in a report.

Near-Term Transmission Planning Horizon

The Near-Term Transmission Planning Horizon should assess a five-year period and evaluate year one, year five, and any other year in between that has a significant system change, e.g., the planned addition or deactivation of a generating unit, the addition of a transmission line, etc. As a minimum, the study shall assess system performance for the following operating periods and conditions:

- Day minimum load (high DER, low gross load)
- Day peak load (low DER, high gross load)
- Evening peak load
- Night minimum load

Base cases may include consideration of each major unit outage period.

For each of these periods, only the applicable Stability analysis and system events shall be performed. Additional sensitivity cases and/or analyses should be performed on an as-needed basis to ensure system performance meets the Stability criteria specified in Section 6.1.8, and may be informed by identified operational constraints.

The Planning Assessment should periodically analyze cascading Contingency events to ensure preservation of the system for plausible planning events. As a minimum, the system shall meet performance requirements of Planning Events P5 through P7 from Table 47.

Long-Term Transmission Planning Horizon

The Long-Term Transmission Planning Horizon should be performed in conjunction with the Integrated Grid Planning process. Evaluation years will be dictated by the proposed resource plans. As a minimum, the study shall assess system performance for the following operating periods and conditions:

- Day minimum load (high DER, low gross load)
- Day peak load (low DER, high gross load)
- Evening peak load
- Night minimum load

For each of these periods, only the applicable Stability analysis and system events shall be performed. Models of future generating units will not be readily available; therefore, discretion should be used in: 1) developing the scope of work and sensitivity cases for this Planning Assessment, and 2) interpreting results of these analyses.

Past Studies

Past studies may be used to support the Planning Assessment if they meet the following requirements:

For steady state, short circuit, or Stability analysis:

- The study must contain a technical rationale that can be provided to demonstrate that the results of an older study are still valid, or
- No material changes have occurred to the system represented in the study. Documentation to support the technical rationale for determining material changes must be included.

Planning Events

As a minimum, the stability criteria in Section 6.1.8 ensures that the transmission system meets or exceeds the performance requirements of Planning Events P1 through P4 in Table 47. A periodic assessment of the under- frequency load shed scheme should be performed to ensure that the system meets the minimum requirements of Planning Events P5 through P7 in Table 47.

Table 46 Steady State and Stability Performance Planning Events

Steady State & Stability:

1. The system must remain stable. Cascading and uncontrolled islanding shall not occur.
2. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
3. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
4. Simulate normal clearing unless otherwise specified.
5. Planned system adjustments such as transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Equipment Rating.
6. Phase angle separation for line Contingency shall not preclude automatic reclosing unless system adjustments can be performed within fifteen minutes.

Steady State Only:

7. Applicable Equipment Rating must not be exceeded.
8. System steady state voltages and post-Contingency voltage deviations must be within acceptable limits as established by this Planning Criteria.
9. Planning event P0 is applicable to steady state only.

Table 47 Categories of Contingency Events

Category	Initial Condition	Event	Fault(s) Type	Non- Consequential Load Loss Allowed
P0 No Contingency	Normal system	None	N/A	None
P1 Single Contingency	Normal system	Loss of one of the following: 1. Generator 2. Transmission Circuits 3. Transformer 4. Shunt Device-Ancillary Service Device	3Ø	None
		5. Generator – no fault	N/A	
P2 Single Contingency	Normal system	1. Bus Section fault 2. Internal Breaker Fault (Transmission line breaker)	3Ø	None
P3 Single Contingency	Loss of generator unit followed by system adjustments (e.g., corrective action and re-dispatch)	Loss of one of the following: 1. Generator 2. Transmission Circuits 3. Transformer	3Ø	None

		4. Shunt Device/ Ancillary Service Device		
P4 Multiple Contingency (Fault plus stuck breaker)	Normal system	Loss of multiple elements caused by a stuck breaker (non-Bus-tie Breaker) attempting to clear a fault on one of the following: 1. Generator 2. Transmission Circuits 3. Transformer 4. Shunt Device 5. Bus Section	SLG	None
		6. Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a fault on the associated bus	SLG	None
P5 Multiple Contingency (Fault plus non-redundant component of a Protection System failure to operate)	Normal system	Delayed fault clearing due to the failure of a non-redundant component of a Protection System protecting the faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuits 3. Transformer 4. Shunt Device 5. Bus Section	3Ø	None
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the followed by system adjustments: 1. Transmission Circuits 2. Transformer 3. Shunt Device	Loss of one of the following: 1. Transmission Circuits 2. Transformer 3. Shunt Device	3Ø	None
P7 Multiple Contingency	Normal system	Loss of one of the following: 1. Cascading Generators 2. Transmission Corridor 3. Any two adjacent circuits on common structure	SLG	None

Table 48 Steady State & Stability Performance Extreme Events

Steady State & Stability For all extreme events evaluated: 1. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

<table>
<tr><td colspan="2">2. Simulate normal clearing unless otherwise specified.</td></tr>
<tr><td>Steady State
1. Loss of a single generator, transmission circuit, shunt device, or transformer force out of service followed by another single generator, transmission circuit, shunt device, or transformer forced out of service prior to system adjustments.
2. Local area events affecting the Transmission System such as:
a. Loss of a tower line with three or more circuits.
b. Loss of all transmission lines on a common Right-of-Way
c. Loss of a switching station or substation (loss of one voltage level plus transformers).
d. Loss of all generating units at a generating station.
e. Loss of a large load or major load center.
3. Wide area events affecting the Transmission System based on system topology such as:
a. Loss of two generating stations resulting from conditions such as:
i. Loss of a large fuel line into an area.
ii. Loss of the use of a large body of water as the cooling source for generation.
iii. Wildfires
iv. Severe weather, for example, hurricanes
v. A successful cyber attack
vi. Large earthquake, tsunami or volcanic eruption
b. Other events based upon operating experience that may result in wide area disturbances.</td><td>Stability
1. Loss of a single generator, transmission circuit, shunt device, or transformer force out of service apply a 3Ø fault on another single generator, transmission circuit, shunt device, or transformer prior to system adjustments.
2. Local area events affecting the Transmission System such as:
a. 3Ø fault on generator with stuck breaker or a relay failure resulting in delayed fault clearing.
b. 3Ø fault on transmission circuit with stuck breaker or a relay failure resulting in delayed fault clearing.
c. 3Ø fault on transformer with stuck breaker or a relay failure resulting in delayed fault clearing.
d. 3Ø fault on bus section with stuck breaker or a relay failure resulting in delayed fault clearing.
e. 3Ø internal breaker fault.
f. Other events based upon operating experience, such as consideration of initiating events that experience, such as consideration of initiating events that experience suggests may result in wide area disturbances.</td></tr>
</table>

Table 49 Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)

Planning Events and Extreme Events
1. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a

double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.

2. For non-generator step up transformer outage events, the reference voltage, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
3. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
4. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
5. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole
   operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
6. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.

For purposes of this standard, non-redundant components of a Protection System to consider are as follows:

a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;
b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center);
c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit);
d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

6.2. Hawai‘i Island Transmission Criteria

6.2.1. Purpose

The purpose of these criteria is to establish guidelines for planning the Hawaiian Electric Hawai‘i Island Transmission System to ensure safe and reliable service to its customers to serve current and future system needs. These criteria also apply to facilities that interconnect to the Hawai‘i Island Transmission System. The primary objectives of these criteria to maintain reliable Transmission System operation (i.e., continuity of service) include the following:

- Ensure public safety.
- Maintain system stability under a wide range of operating conditions identified in Section 6.2.9.
- Maintain equipment operating limits under a wide range of operating conditions identified in Section 6.2.9.
- Minimize losses where cost effective.
- Preserve the reliability of the existing transmission infrastructure.
- Maintain an acceptable level of impact to customers for contingencies and events as defined within this planning criteria.
- Prevent cascading outages or system failure following credible contingencies and events.

The criteria outlined below are intended to be used as a general guide in planning the Hawai‘i Island Transmission System, for which transmission needs for reinforcement, enhancements, and mitigations will be determined.

6.2.2. Definitions

Acceptable Damping: A continuous attenuation of oscillations required to achieve equilibrium over a four-cycle period.

Cascading: The uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies. (Source: Glossary of Terms Used in NERC Reliability Standards; Effective Date July 1, 2016)

Consequential Load Loss: All load that is no longer served by the Transmission System as a result of Transmission System Facilities being removed from service by a Protection System operation designed to isolate a fault. (Source: Glossary of Terms Used in NERC Reliability Standards; Effective Date January, 1 2015)

Contingency: The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element. (Source: Glossary of Terms Used in NERC Reliability Standards; February 8, 2005)

Contingency Reserve: The provision of capacity deployed by the Balancing Authority to meet reliability requirements in Section 6.2.9.

Corrective Action Plan: A list of actions and an associated timetable for implementation to remedy a specific problem. (Source: Glossary of Terms Used in NERC Reliability Standards; February 7, 2006)

Distributed Energy Resources or DER: Resources interconnected to the distribution system that produce electricity.

Droop Response or Primary Frequency Response: Open-loop proportional control defined as a percentage of turbine speed or system frequency divided by its rated capacity (i.e., turbine or IBR rating). For a 5% droop response, a unit operating at full speed no load or zero output will instantaneously, without any intentional time delays, issue a control signal to export 100% rated capacity for a 5% decrease in turbine speed or system frequency.

Element or Elements: Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components. (Source: Glossary of Terms Used in NERC Reliability Standards; Effective Date July 1, 2016)

Equipment Rating: The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner. (Source: Glossary of Terms Used in NERC Reliability Standards; February 8, 2005)

Extreme Events: Less frequent but more severe Contingencies that could result in a cascading effect.

Facility or Facilities: A set of electrical equipment that operates as a single bulk electric system Element (for example, a line, a generator, a shunt compensator, transformer, etc.). (Source: Glossary of Terms Used in NERC Reliability Standards; February 7, 2006)

Inverter-Based Resource: A resource that is asynchronously connected to the sub-transmission or Transmission System through power electronics.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete. (Source: Glossary of Terms Used in NERC Reliability Standards; Effective Date January 1, 2015)

Near-Term Transmission Planning Horizon: The transmission planning period that covers year one through five. (Source: Glossary of Terms Used in NERC Reliability Standards; January 24, 2011)

Non-Consequential Load Loss: Load that is disconnected from the system by the utility to stabilize system frequency or voltage. Non-Consequential Load loss does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive load, or (3) load that is disconnected from the system by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. (Source: Glossary of Terms Used in NERC Reliability Standards; Effective Date January 1, 2015)

Protection System: Includes, Protective relays which respond to electrical quantities; Communications systems necessary for correct operation of protective functions; Voltage and current sensing devices providing inputs to protective relays; Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply); and Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices. (Source: Glossary of Terms Used in NERC Reliability Standards; Effective Date April 1, 2013)

Short Circuit Ratio or SCR[32]: Short circuit ratio is defined as the ratio between short circuit apparent power (SCMVA) from a 3LG fault at a given location in the power system to the rating of the Inverter-Based Resource connected to that location. Since the numerator of the SCR metric is dependent on the specific measurement location, this location is usually stated along with the SCR number.

$$SCR_{POI} = \frac{SCMVA_{POI}}{MW_{IBR}}$$

Where SCMVA is the short circuit MVA level at the POI without the current contribution of the Inverter-Based Resource, and MW IBR is the nominal power rating of the Inverter-Based Resource being connected at the POI.

Stability: The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances. (Source: Glossary of Terms Used in NERC Reliability Standards; February 8, 2005)

System: A combination of generation, transmission, and distribution components. (Source: Glossary of Terms Used in NERC Reliability Standards; February 8, 2005)

Transmission System: A network of circuits that operate at a nominal voltage of 69 kV. The Transmission System can also include sections of the 34.5 kV sub-transmission system as defined by these criteria.

Weak Grid: A transmission system that has at least one transmission node with a calculated short circuit ratio of less than 3 (i.e., SCR < 3).

32 NERC Reliability Guidelines, December 2017 – Integrating Inverter Based Resources into Low Short Circuit Ratio Systems

6.2.3. Transmission System Defined

For the purpose of these criteria, the Transmission System is defined as all transmission lines, substation equipment, structures, and land utilized for transporting power at 69 kV & 34.5 kV. In addition, the 69-34.5 kV, 69-13.8 kV, and 34.5-13.8 kV tie transformers are part of the Transmission System.

6.2.4. Transmission Planning Criteria – Thermal Limits

At a minimum, the Hawai'i Island system shall meet the performance requirements specified by Planning Events P0 through P4 in Section 6.2.9. In addition, the Hawai'i Island Transmission System shall meet the following steady-state performance requirements:

With any generating unit offline for maintenance, all Transmission System Elements will operate within their EMERGENCY ratings while maintaining voltage levels within their upper or lower limits for any of the following outages:

- Any other generating unit or IBR that is deemed as a single Contingency equivalent
- Any synchronous condenser or IBR equivalent
- Any transmission circuit
- Any transmission transformer
- Any transmission bus
- Any wood transmission structure

Any generating station must be able to export real and reactive power equal to the sum of the individual generating unit's NORMAL capability ratings in MW at 100 percent of rated generator field current/power factor with no Transmission System Element loading exceeding its EMERGENCY ratings while maintaining voltage levels within their upper or lower limits for any of the following outages:

- Any transmission circuit
- Any wood transmission structure
- Any transmission transformer
- Any transmission bus

Additionally, for any transmission Element outage, the aggregate generating capacity on any remaining radial transmission circuit will not exceed the maximum single-point failure for the system. The outage of not more than one generating unit caused by the failure of a transmission circuit breaker to operate during fault conditions.

With two 69 kV transmission circuits on common steel poles taken out of service at the same time for maintenance, all Transmission System Elements will operate within their NORMAL ratings while maintaining voltage levels within their upper or lower limits. This is a maintenance requirement based on present maintenance practices.

The 69 kV system is the backbone of the Hawai'i Island electrical system. Excessive segmentation of a 69 kV transmission line can result in increasingly complex protection coordination schemes, greater susceptibility to mis-operation of relays, maintenance and operational issues, and excessive curtailment of resources for certain transmission line contingencies. The total generation on any transmission line must be limited to the single-point failure capacity of the system. Generating Facilities should interconnect to an existing substation if practical or interconnect to multiple transmission lines through a new standard configured transmission substation.

6.2.5. Loading Limits

Conductor loading limits are based on the Engineering Standards Practice Manual (ESPM) that are to be updated periodically as appropriate. Operational planning mitigations that utilize operator interventions within the duration of allowed Equipment Ratings are not governed by this transmission planning criteria.

Power Transformer Loading Limits

Loading limits of transmission power transformers shall be as follows:

1) The normal loading limit of a transmission power transformer shall be its zero percent loss-of-life kVA capability.
2) The emergency loading limit of a transmission power transformer shall be its one percent loss-of-life kVA capability.
3) The extreme emergency loading limit of a transmission power transformer shall be 200 percent of its maximum nameplate rating.

Loading limits shall be determined in accordance with the latest edition of C-57.92, ANSI Guide for Loading Mineral - Oil - Immersed Power Transformers Up to and Including 100 MVA with 55°C or 65°C Winding Rise.

6.2.6. Current Carrying Capacity

Overhead

Conductors for overhead transmission lines shall be considered to have current carrying capacity in accordance with Engineering Standard 1-2038, "Current Carrying Capacity Outdoor Bare Conductor." A conductor bundle with identical conductors shall have the rating of a single conductor multiplied by the number of conductors per phase in the bundle.

Underground

Cable for underground transmission circuits shall be considered to have current carrying capacity in accordance with HECO Engineering Standard 21-1021, “Cable Ampacity Tables – Underground Data.”

Open Bus

Open buses shall be considered to have current carrying capacity in accordance with Engineering Standard, 1-2039, "Current Carrying Capacity- Outdoor Open Bus."

Power Transformer Equipment

Transmission power transformer connections, switches, protective relays, and current transformers shall be designed to allow the power transformer to carry 200 percent of maximum nameplate rating under extreme emergency conditions in accordance with the latest edition of C-57.92, ANSI Guide for Loading Mineral - Oil - Immersed Power Transformers Up to and Including 100 MVA with 55°C or 65°C Winding Rise. (The relay settings associated with this type of transformer shall allow the transformer to carry 200 percent of maximum nameplate rating.)

Substation Equipment

Switches, disconnects, circuit breakers, and associated equipment shall be considered to have a current carrying capacity equivalent to their respective nameplate current rating.

Generator MVAR Loading Limits

For planning purposes, the reactive capability of a given machine will be determined using the manufacturer's machine capability curve and normal MW at rated power factor for generating units. At no time will the system be planned with any generator or IBR exceeding its rating as determined by its capability curve corresponding to the appropriate ambient temperature suitable for the Hawaiʻi Island system.

6.2.7. Voltage Levels

Transmission voltage levels shall be kept within the prescribed limits for any condition for which the Transmission System is planned. These limits apply after automatic corrective action has been taken by LTC and/or switched capacitors.

The maximum voltage limits are based on *Utility Service in the State of Hawaii* (General Order No.7).

1) 69 kV System. For any system operating condition, the voltage at any 69 kV bus shall not exceed 72.5 kV.

2) 34.5 kV System. For any system operating condition, the voltage on the 34.5 kV system shall not exceed 36.2 kV.

The minimum voltage limits are based upon maintaining customer voltages in accordance with *Standards for Electric Utility Service in the State of Hawaii* (General Order No.7). To accomplish this, bus voltages at the transmission and sub-transmission substations must be maintained within the limits that are used to plan the distribution system.

1) 69 kV System. The minimum allowable voltage on any 69 kV bus is 63.5 kV for any emergency condition for which the transmission system is planned.
2) 34.5 kV System. The minimum allowable voltage on any 34.5 kV bus is 32.8 kV for any emergency condition for which the system is planned.

The system's short-circuit current requirements and resources should be considered when evaluating near-term voltage and MVAR mitigation alternatives.

6.2.8. System Stability

The system shall maintain operating equilibrium with acceptable damping ratio of 3% for all reasonable combinations of planned outages and system contingencies defined in Section 6.2.9. Power oscillations exhibit an acceptable damping ratio of 3% when the oscillation magnitude decreases by 17% over the first period of oscillation, or by 53% over four periods of oscillations. Displacement of synchronous generation has a direct impact on dynamic and transient stability. In addition to traditional analyses, new planning metrics and analysis are required to maintain Stability under plausible operating conditions. If the conditions for Weak Grid are met, further analysis may be required in appropriate software modeling platform to fully investigate any Stability concerns.

Steady State Voltage

The power-voltage (PV) and reactive power-voltage (QV) analysis shall be performed to determine the steady-state voltage stability of critical load buses.

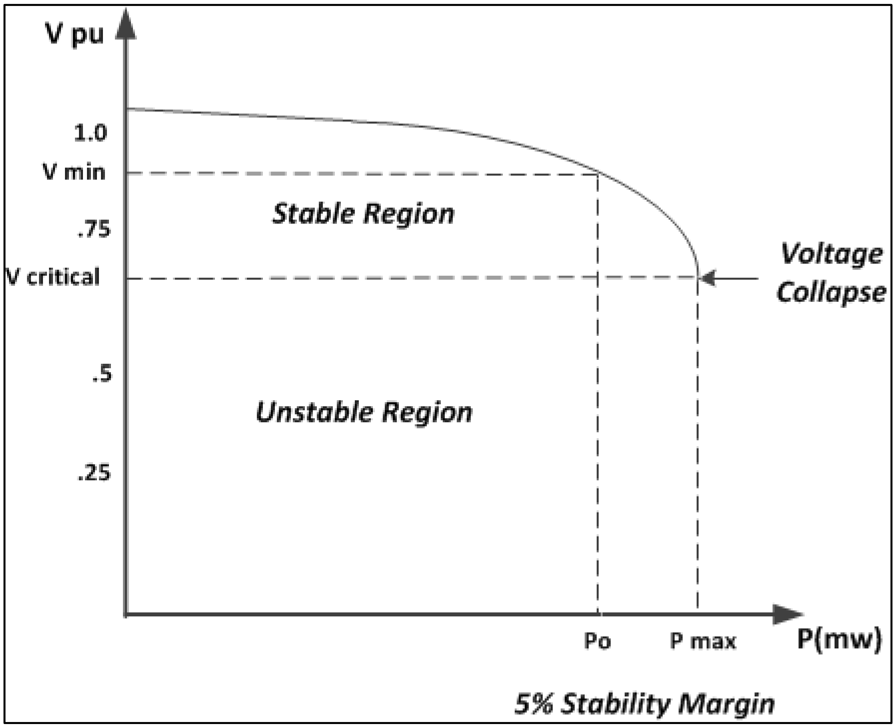


Figure 39 Typical PV Curve

Figure 39 Typical PV Curve shows a typical PV curve that depicts the thermal limit of the transmission system. To ensure voltage stability, a 5% margin from P_O to Pmax, identified as P_o, shall be maintained under planning events described in Section 6.2.9. In addition, the intersection of the QV curve with the x-axis shall occur above the minimum allowable voltage level, and the reactive power margin, represented by the value at the minimum point of the QV curve, shall be greater than the size of a nearby capacitor bank or reactive power device.

Weak Grid Assessment

Weak power systems are more susceptible to voltage transients and can be exacerbated by control instabilities. Short circuit ratio (SCR) is the most basic metric to assess the relative strength of an electrical system for a specific area when evaluating performance of a specific IBR[33]. For system planning purposes, a more appropriate quantity is the weighted short circuit ratio (WSCR)[34], defined by:

$$WSCR = \frac{\sum_i^N SCMVA_i * P_{RMW_i}}{\left(\sum_i^N P_{RMW_i}\right)^2}$$

Where ***$SCMVA_i$*** is the short circuit capacity at bus ***i*** and ***P_{RMWi}*** is the MW rating of the IBR; ***N*** is the number of total IBR fully interacting with each other and ***i*** is the IBR index. The WSCR takes into account the aggregate IBR of the system to ensure the system has sufficient short circuit current for

[33] NERC Reliability Guideline – Integrating Variable Energy Resources into Weak Power Systems

[34] Electranix, System Strength Assessment of the Panhandle System, Electric Reliability Council of Texas, 2016

transient voltage stability. There is currently no industry standard for WSCR of a transmission system.

Control Stability

Control stability refers to the behavior of grid-connected IBR like wind and solar PV plants to operate in a stable manner for both small disturbances and large disturbances on the grid over a wide range of operating conditions and disturbances. Unstable behavior can result in oscillatory behavior, extreme overshoots in voltage or current, and/or a failure to ride-through a disturbance. The stability of equipment controls is impacted by many factors, including equipment tuning, operating conditions, grid strength, disturbance types, and the electrical proximity to other IBR or synchronous machines on the grid, among others.

As more IBR with complex control system connect to the system, it is important to assess the control stability of these resources to assess the robustness of controls to the range of expected operating conditions over the planning horizon. This will be done through a combination of screening, scenario modeling, and testing/demonstration of performance. As such, supplying accurate and sufficiently detailed models of equipment and functional descriptions of equipment control and protection schemes is necessary well in advance of interconnection. Equipment performance will be evaluated for combinations of:

- Full and partial power operating conditions, high and low voltages (within continuous limits)
- Symmetric and asymmetric fault disturbances (with reclosing), line switching disturbances, loss of generation and load disturbances
- Low grid strength conditions

Rotor Angle Stability Criteria

Rotor angle stability simulations involve the evaluation of critical clearing times (“CCT”) for close-in faults to generating stations, generating units, and transmission lines. Generator rotor angle deviation with respect to a “distant” generator shall be less than 180 degrees to prevent generator pole-slipping and in addition to avoiding loss of synchronism. Dynamic performance shall exhibit acceptable damping to ensure rotor angle stability. Pole-slipping could impose mechanical stresses on the generator shaft and could result in catastrophic failure of the unit.

Critical Clearing Times

The Transmission Planning Department performs Stability simulations using the standard fault clearing times for breakers provided by the System Protection Department. If a fault event results in a planning criteria violation, the Transmission Planning Department shall determine the CCT for that event and will provide it to the System Protection Department for its review and feedback. If the CCT cannot be achieved by the existing protective devices, Transmission Planning Department will work with System Protection Department to develop appropriate mitigation measures. Such mitigation measures may include but not limited to the system protection upgrade, generator size or power

export reduction, application of synchronous condenser or adjustments to resource commitment as applicable.

Frequency Stability

Frequency stability is determined by 1) the amount of inertia on the system; 2) the amount and response characteristics of fast-frequency and primary frequency response reserves on the system; and 3) the magnitude of the generation Contingency. The system shall carry sufficient inertia and frequency response reserves to mitigate the loss of the largest generating unit, including any aggregate loss of distributed energy resources in response to the Contingency events, with appropriate Non-Consequential Load Loss criteria defined in Section 6.2.9. In order to meet these criteria, mitigation measures may require establishing minimum inertia requirement for a generation loss event.

Planning Criteria for Stability

Stability of an electric power system is the attribute of the system to regain a state of operating equilibrium after being subjected to disrupting forces (Contingency events), such that the majority of the system remains intact. Generating units and transmission Elements must remain online and in synchronism with the system to prevent an island-wide blackout. Therefore, the Transmission System shall be tested by simulating frequent Contingency events and reasonable cascading contingency events that may occur on the system to ensure operating equilibrium is restored.

1) For the more frequent types of contingencies listed below, not more than one generating unit can disconnect from the system, all generating units must remain connected and synchronized to the system, all generating units must participate towards beneficial system response, no circuits should trip on stability swings, transient voltage stability must be maintained, and no Non-Consequential Load Loss or Consequential Load Loss should take place.
    - Normally cleared, three-phase faults on transmission lines with automatic reclosing as applicable to the circuit being analyzed.
    - Delayed clearing of three-phase faults due to failure of the pilot relay on circuits that have one pilot scheme, and one step-distance scheme for backup to the pilot scheme. Dual-pilot relay schemes require independent communication technologies (e.g. both microwave and fiber-optic cable) to mitigate failure of single-pilot relay schemes. Analysis shall be performed for the simulation of the longest delayed clearing time scenario.
    - Delayed clearing of single line-to-ground faults due to failure of a circuit breaker to open.
2) Exceptions include small units (e.g. internal combustion engines) that share a common generator step-up transformer and combined-cycle units. Other exceptions will be considered on a case-by-case basis.
    - For the less frequent contingencies listed below, Non-Consequential Load Loss or generator tripping may be required to prevent equipment damage and maintain Stability.

- Sudden loss of all transmission lines emanating from a power plant switching station.
- Sudden loss of all transmission lines in a common right-of-way.
- Sudden loss of any combined cycle units or any two synchronous generating units (synchronous, asynchronous, or both), including any aggregate loss of DER.
- Sudden loss of any combination of two transmission Elements.
- Cascading loss of generation

3) Extreme Events – For Extreme Events system preservation shall be tested. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. If any Extreme Events result in an island-wide blackout, mitigation measures shall be formulated and analyzed to see if a reasonable solution can be implemented. Examples of Extreme Events include but not limited to:
   - A three phase fault on generator, transmission circuit, transformer or bus section with stuck breaker resulting in delayed fault clearing
   - A three phase fault on generator, transmission circuit, transformer or bus section with failure of a non-redundant component of a Protection System resulting in delayed fault clearing
   - Three phase internal breaker fault
   - Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

6.2.9. Transmission Planning Assessment

A Planning Assessment of the Transmission System must be performed on an annual basis to ensure compliance with these criteria for the Near-Term Planning Horizon and Long-Term Planning Horizons. This Planning Assessment must use current models to analyze steady-state, dynamic, and transient system stability to ensure compliance with these criteria. Updated assumptions, forecasts, and study results shall be summarized and documented in a report.

Near-Term Transmission Planning Horizon

The Near-Term Transmission Planning Horizon should assess a five year period and evaluate year one, year five, and any other year in between that has a significant system change, e.g., the planned addition or deactivation of a generating unit, the addition of a transmission line, etc. As a minimum, the study shall assess system performance for the following operating periods and conditions:

- Day minimum load (high DER, low gross load)
- Day peak load (low DER, high gross load)
- Evening peak load
- Night minimum load

Base cases may include consideration of each major unit outage period.

For each of these periods, only the applicable Stability analysis and system events shall be performed. Additional sensitivity cases and/or analyses should be performed on an as-needed basis to ensure system performance meets the stability criteria specified in Section 6.2.8, and may be informed by identified operational constraints.

The Planning Assessment should periodically analyze cascading Contingency events to ensure preservation of the system for plausible planning events. As a minimum, the system shall meet performance requirements of Planning Events P5 through P7 from Table 51.

Long-Term Transmission Planning Horizon

The Long-Term Transmission Planning Horizon should be performed in conjunction with the Integrated Grid Planning process. Evaluation years will be dictated by the proposed resource plans. As a minimum, the study shall assess system performance for the following operating periods and conditions:

- Day minimum load (high DER, low gross load)
- Day peak load (low DER, high gross load)
- Evening peak load
- Night minimum load

For each of these periods, only the applicable Stability analysis and system events shall be performed. Models of future generating units will not be readily available; therefore discretion should be used in: 1) developing the scope of work and sensitivity cases for this Planning Assessment and 2) interpreting results of these analyses.

Past Studies

Past studies may be used to support the Planning Assessment if they meet the following requirements:

- For steady state, short circuit, or Stability analysis:
  - The study must contain a technical rationale that can be provided to demonstrate that the results of an older study are still valid, or
  - No material changes have occurred to the system represented in the study. Documentation to support the technical rationale for determining material changes must be included.

Planning Events

As a minimum, the Stability criteria in Section 6.2.8 ensures that the transmission system meets or exceeds the performance requirements of Planning Events P1 through P4 in Table 51. A periodic assessment of the under-frequency load shed scheme should be performed to ensure that the system meets the minimum requirements of Planning Events P5 through P7 in Table 51.

Table 50 Steady State and Stability Performance Planning Events

Steady State & Stability: 1. The system must remain stable. Cascading and uncontrolled islanding shall not occur. 2. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0. 3. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. 4. Simulate normal clearing unless otherwise specified. 5. Planned system adjustments such as transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Equipment Rating. 6. Phase angle separation for line Contingency shall not preclude automatic reclosing unless system adjustments can be performed within fifteen minutes. Steady State Only: 7. Applicable Equipment Rating must not be exceeded. 8. System steady state voltages and post-Contingency voltage deviations must be within acceptable limits as established by this Planning Criteria. 9. Planning event P0 is applicable to steady state only.

Table 51 Categories of Contingency Events

Category	Initial Condition	Event	Fault(s) Type	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal system	None	N/A	None
P1 Single Contingency	Normal system	Loss of one of the following: 1. Generator 2. Transmission Circuits 3. Transformer 4. Shunt Device-Ancillary Service Device	3Ø	Up to 15% for Generator Trip Only
		5. Generator – no fault	N/A	
P2 Single Contingency	Normal system	1. Bus Section fault 2. Internal Breaker Fault (Transmission line breaker)	3Ø	Up to 15%
P3 Single Contingency	Loss of generator unit followed by system adjustments (e.g., corrective action and re-dispatch)	Loss of one of the following: 1. Generator 2. Transmission Circuits 3. Transformer 4. Shunt Device/ Ancillary Service Device	3Ø	Up to 20%
P4 Multiple Contingency	Normal system	Loss of multiple elements caused by a stuck breaker (non-Bus-tie Breaker) attempting to clear a fault on one of the following:	SLG	Up to 40%

(Fault plus stuck breaker)		1. Generator 2. Transmission Circuits 3. Transformer 4. Shunt Device 5. Bus Section		
		6. Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a fault on the associated bus	SLG	Up to 40%
P5 Multiple Contingency (Fault plus non-redundant component of a Protection System failure to operate)	Normal system	Delayed fault clearing due to the failure of a non-redundant component of a Protection System protecting the faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuits 3. Transformer 4. Shunt Device 5. Bus Section	3Ø	Up to 15%
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the followed by system adjustments: 1. Transmission Circuits 2. Transformer 3. Shunt Device	Loss of one of the following: 1. Transmission Circuits 2. Transformer 3. Shunt Device	3Ø	Up to 65%
P7 Multiple Contingency	Normal system	Loss of one of the following: 1. Cascading Generators 2. Transmission Corridor 3. Any two adjacent circuits on common structure	SLG	Up to 65%

Table 52 Steady State & Stability Performance Extreme Events

Steady State & Stability For all extreme events evaluated: 1. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency. 2. Simulate normal clearing unless otherwise specified.	
Steady State 1. Loss of a single generator, transmission circuit, shunt device, or transformer force out of service followed by another single generator, transmission circuit, shunt device, or transformer forced out of service prior to system adjustments. 2. Local area events affecting the Transmission System such as: a. Loss of a tower line with three or more circuits. b. Loss of all transmission lines on a common Right-of-Way	Stability 1. Loss of a single generator, transmission circuit, shunt device, or transformer force out of service apply a 3Ø fault on another single generator, transmission circuit, shunt device, or transformer prior to system adjustments. 2. Local area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker or a relay failure resulting in delayed fault clearing. b. 3Ø fault on transmission circuit with stuck breaker or a relay failure resulting in delayed fault clearing.

c. Loss of a switching station or substation (loss of one voltage level plus transformers). d. Loss of all generating units at a generating station. e. Loss of a large load or major load center. 3. Wide area events affecting the Transmission System based on system topology such as: a. Loss of two generating stations resulting from conditions such as: i. Loss of a large fuel line into an area. ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires iv. Severe weather, for example, hurricanes v. A successful cyber attack vi. Large earthquake, tsunami or volcanic eruption b. Other events based upon operating experience that may result in wide area disturbances.	c. 3Ø fault on transformer with stuck breaker or a relay failure resulting in delayed fault clearing. d. 3Ø fault on bus section with stuck breaker or a relay failure resulting in delayed fault clearing. e. 3Ø internal breaker fault. f. Other events based upon operating experience, such as consideration of initiating events that experience, such as consideration of initiating events that experience suggests may result in wide area disturbances.

Table 53 Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)

Planning Events and Extreme Events
1. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria 2. For non-generator step up transformer outage events, the reference voltage, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. 3. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.

4. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
5. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
6. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.

For purposes of this standard, non-redundant components of a Protection System to consider are as follows:

a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;
b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center);
c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit);
d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

6.3. Maui Transmission Criteria

6.3.1. Purpose

The purpose of these criteria is to establish guidelines for planning the Hawaiian Electric Maui Island Transmission System to ensure safe and reliable service to its customers to serve current and future system needs. These criteria also apply to facilities that interconnect to the Maui Island Transmission System. The primary objectives of these criteria to maintain reliable Transmission System operation (i.e., continuity of service) include the following:

- Ensure public safety.
- Maintain system stability under a wide range of operating conditions identified in Section 6.3.9.
- Maintain equipment operating limits under a wide range of operating conditions identified in Section 6.3.9.
- Minimize losses where cost effective.
- Preserve the reliability of the existing transmission infrastructure.

- Maintain an acceptable level of impact to customers for contingencies and events as defined within this planning criteria.
- Prevent cascading outages or system failure following credible contingencies and events.

The criteria outlined below are intended to be used as a general guide in planning the Maui Island Transmission System, for which transmission needs for reinforcement, enhancements, and mitigations will be determined.

6.3.2. Definitions

Acceptable Damping: A continuous attenuation of oscillations required to achieve equilibrium over a four-cycle period.

Cascading: The uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies. (Source: Glossary of Terms Used in NERC Reliability Standards; Effective Date July 1, 2016)

Consequential Load Loss: All load that is no longer served by the Transmission System as a result of Transmission System Facilities being removed from service by a Protection System operation designed to isolate a fault. (Source: Glossary of Terms Used in NERC Reliability Standards; Effective Date January, 1 2015)

Contingency: The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element. (Source: Glossary of Terms Used in NERC Reliability Standards; February 8, 2005)

Contingency Reserve: The provision of capacity deployed by the Balancing Authority to meet reliability requirements in Section 6.3.9.

Corrective Action Plan: A list of actions and an associated timetable for implementation to remedy a specific problem. (Source: Glossary of Terms Used in NERC Reliability Standards; February 7, 2006)

Distributed Energy Resources or DER: Resources interconnected to the distribution system that produce electricity.

Droop Response or Primary Frequency Response: Open-loop proportional control defined as a percentage of turbine speed or system frequency divided by its rated capacity (i.e., turbine or IBR rating). For a 5% droop response, a unit operating at full speed no load or zero output will instantaneously, without any intentional time delays, issue a control signal to export 100% rated capacity for a 5% decrease in turbine speed or system frequency.

Element or Elements: Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An

Element may be comprised of one or more components. (Source: Glossary of Terms Used in NERC Reliability Standards; Effective Date July 1, 2016)

Equipment Rating: The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner. (Source: Glossary of Terms Used in NERC Reliability Standards; February 8, 2005)

Extreme Events: Less frequent but more severe Contingencies that could result in a cascading effect.

Facility or Facilities: A set of electrical equipment that operates as a single bulk electric system Element (for example, a line, a generator, a shunt compensator, transformer, etc.). (Source: Glossary of Terms Used in NERC Reliability Standards; February 7, 2006)

Inverter-Based Resource: A resource that is asynchronously connected to the sub-transmission or Transmission System through power electronics.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete. (Source: Glossary of Terms Used in NERC Reliability Standards; Effective Date January 1, 2015)

Near-Term Transmission Planning Horizon: The transmission planning period that covers year one through five. (Source: Glossary of Terms Used in NERC Reliability Standards; January 24, 2011)

Non-Consequential Load Loss: Load that is disconnected from the system by the utility to stabilize system frequency or voltage. Non-Consequential Load loss does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive load, or (3) load that is disconnected from the system by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. (Source: Glossary of Terms Used in NERC Reliability Standards; Effective Date January 1, 2015)

Protection System: Includes, Protective relays which respond to electrical quantities; Communications systems necessary for correct operation of protective functions; Voltage and current sensing devices providing inputs to protective relays; Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply); and Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices. (Source: Glossary of Terms Used in NERC Reliability Standards; Effective Date April 1, 2013)

Short Circuit Ratio or SCR[35]: Short circuit ratio is defined as the ratio between short circuit apparent

[35] NERC Reliability Guidelines, December 2017 - Integrating Inverter Based Resources into Low Short Circuit Ratio Systems

power (SCMVA) from a 3LG fault at a given location in the power system to the rating of the Inverter-Based Resource connected to that location. Since the numerator of the SCR metric is dependent on the specific measurement location, this location is usually stated along with the SCR number.

$$SCR_{POI} = \frac{SCMVA_{POI}}{MW_{IBR}}$$

Where SCMVA is the short circuit MVA level at the POI without the current contribution of the Inverter-Based Resource, and MW IBR is the nominal power rating of the Inverter-Based Resource being connected at the POI.

Stability: The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances. (Source: Glossary of Terms Used in NERC Reliability Standards; February 8, 2005)

System: A combination of generation, transmission, and distribution components. (Source: Glossary of Terms Used in NERC Reliability Standards; February 8, 2005)

Transmission System: A network of circuits that operate at a nominal voltage of 69 kV and 23 kV.

Weak Grid: A transmission system that has at least one transmission node with a calculated short circuit ratio of less than 3 (i.e., SCR < 3).

6.3.3. Transmission System Defined

For the purpose of these criteria, the Transmission System is defined as all transmission lines, substation equipment, structures, and land utilized for transporting power at 69 kV and 23 kV. In addition, the 69-23 kV tie transformers are part of the Transmission System.

6.3.4. Transmission Planning Criteria – Thermal Limits

At a minimum, the Maui Island system shall meet the performance requirements specified by Planning Events P0 through P4 in Section 6.3.9. In addition, the Maui Island Transmission System shall meet the following steady-state performance requirements:

With any generating unit offline for maintenance, all Transmission System Elements will operate within their EMERGENCY ratings while maintaining voltage levels within their upper or lower limits for any of the following outages:

- Any other generating unit or IBR that is deemed as a single Contingency equivalent
- Any synchronous condenser or IBR equivalent
- Any transmission circuit
- Any transmission transformer

- Any transmission bus
- Any wood transmission structure

Any generating station must be able to export real and reactive power equal to the sum of the individual generating unit's NORMAL capability ratings in MW at 100 percent of rated generator field current/power factor with no Transmission System Element loading exceeding its EMERGENCY ratings while maintaining voltage levels within their upper or lower limits for any of the following outages:

- Any transmission circuit
- Any wood transmission structure
- Any transmission transformer
- Any transmission bus

Additionally, for any transmission Element outage, the aggregate generating capacity on any remaining radial transmission circuit will not exceed the maximum single-point failure for the system.

The outage of not more than one generating unit caused by the failure of a transmission circuit breaker to operate during fault conditions.

With two 69 kV transmission circuits on common steel poles taken out of service at the same time for maintenance, all Transmission System Elements will operate within their EMERGENCY ratings while maintaining voltage levels within their upper or lower limits. This is a maintenance requirement based on present maintenance practices.

The 69 kV system is the backbone of the Maui Island electrical system. Excessive segmentation of a 69 kV transmission line can result in increasingly complex protection coordination schemes, greater susceptibility to mis-operation of relays, maintenance and operational issues, and excessive curtailment of resources for certain transmission line contingencies. The total generation on any transmission line must be limited to the single-point failure capacity of the system. Generating Facilities should interconnect to an existing substation if practical or interconnect to multiple transmission lines through a new standard configured transmission substation.

6.3.5. Loading Limits

Conductor loading limits are based on the Engineering Standards Practice Manual (ESPM) that are to be updated periodically as appropriate. Operational planning mitigations that utilize operator interventions within the duration of allowed Equipment Ratings are not governed by this transmission planning criteria.

Power Transformer Loading Limits

Loading limits of transmission power transformers shall be as follows:

1) The normal loading limit of a transmission power transformer shall be its zero percent loss-of-life kVA capability.
2) The emergency loading limit of a transmission power transformer shall be its one percent loss-of-life kVA capability.
3) The extreme emergency loading limit of a transmission power transformer shall be 200 percent of its maximum nameplate rating.

Loading limits shall be determined in accordance with the latest edition of C-57.92, ANSI Guide for Loading Mineral - Oil - Immersed Power Transformers Up to and Including 100 MVA with 55°C or 65°C Winding Rise.

6.3.6. Current Carrying Capacity

Overhead

Conductors for overhead transmission lines shall be considered to have current carrying capacity in accordance with Engineering Standard 1-2038, "Current Carrying Capacity Outdoor Bare Conductor" or other applicable standard. A conductor bundle with identical conductors shall have the rating of a single conductor multiplied by the number of conductors per phase in the bundle.

Underground

Cable for underground transmission circuits shall be considered to have current carrying capacity in accordance with HECO Engineering Standard 21-1021, “Cable Ampacity Tables – Underground Data” or other applicable standard.

Open Bus

Open buses shall be considered to have current carrying capacity in accordance with Engineering Standard, 1-2039, "Current Carrying Capacity- Outdoor Open Bus."

Power Transformer Equipment

Transmission power transformer connections, switches, protective relays, and current transformers shall be designed to allow the power transformer to carry 200 percent of maximum nameplate rating under extreme emergency conditions in accordance with the latest edition of C-57.92, ANSI Guide for Loading Mineral - Oil - Immersed Power Transformers Up to and Including 100 MVA with 55°C or 65°C Winding Rise. (The relay settings associated with this type of transformer shall allow the transformer to carry 200 percent of maximum nameplate rating.)

Substation Equipment

Switches, disconnects, circuit breakers, and associated equipment shall be considered to have a current carrying capacity equivalent to their respective nameplate current rating.

Generator MVAR Loading Limits

For planning purposes, the reactive capability of a given machine will be determined using the manufacturer's machine capability curve and normal MW at rated power factor for generating units. At no time will the system be planned with any generator or IBR exceeding its rating as determined by its capability curve corresponding to the appropriate ambient temperature suitable for the Maui Island system.

6.3.7. Voltage Levels

Transmission voltage levels shall be kept within the prescribed limits for any condition for which the Transmission System is planned. These limits apply after automatic corrective action has been taken by LTC and/or switched capacitors.

The maximum voltage limits are based on *Utility Service in the State of Hawaii* (General Order No.7).

1) 69 kV System. For any system operating condition, the voltage at any 69 kV bus shall not exceed 72.5 kV.
2) 23 kV System. For any system operating condition, the voltage on the 23 kV system shall not exceed 24.15 kV.

The minimum voltage limits are based upon maintaining customer voltages in accordance with *Standards for Electric Utility Service in the State of Hawaii* (General Order No.7). To accomplish this, bus voltages at the transmission substations must be maintained within the limits that are used to plan the distribution system.

1) 69 kV System. The minimum allowable voltage on any 69 kV bus is 62.1 kV for any emergency condition for which the transmission system is planned.
2) 23 kV System. The minimum allowable voltage on any 23 kV bus is 20.7 kV for any emergency condition for which the system is planned.

The system's short-circuit current requirements and resources should be considered when evaluating near-term voltage and MVAR mitigation alternatives.

6.3.8. System Stability

The system shall maintain operating equilibrium with acceptable damping ratio of 3% for all reasonable combinations of planned outages and system contingencies defined in Section 6.3.9. Power oscillations exhibit an acceptable damping ratio of 3% when the oscillation magnitude decreases by 17% over the first period of oscillation, or by 53% over four periods of oscillations. Displacement of synchronous generation has a direct impact on dynamic and transient stability. In addition to traditional analyses, new planning metrics and analysis are required to maintain Stability

under plausible operating conditions. If the conditions for Weak Grid are met, further analysis may be required in appropriate software modeling platform to fully investigate any Stability concerns.

Steady State Voltage

The power-voltage (PV) and reactive power-voltage (QV) analysis shall be performed to determine the steady-state voltage stability of critical load buses.

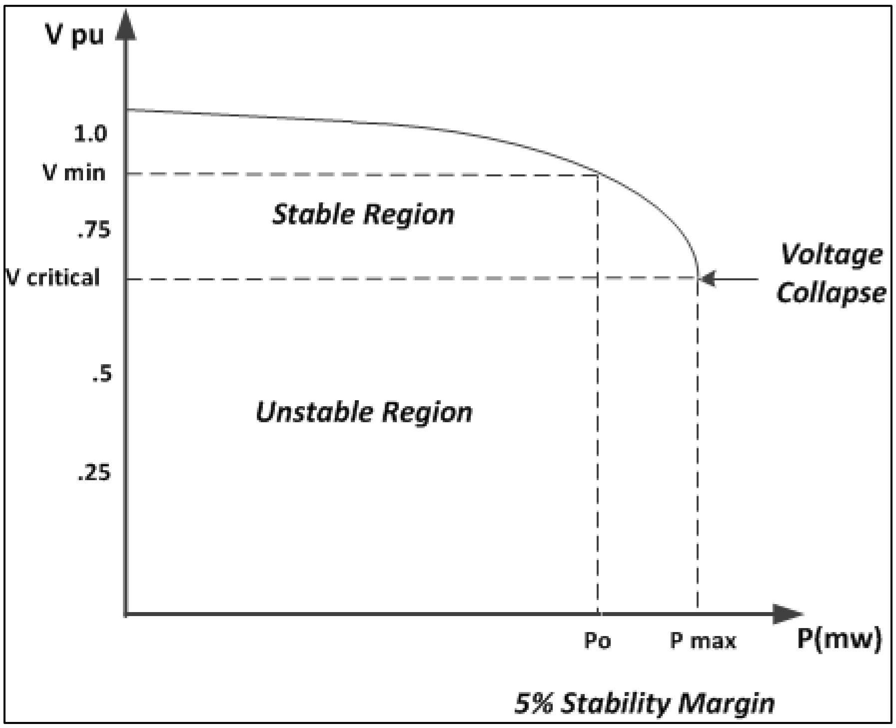


Figure 40 Typical PV Curve

Figure 40 shows a typical PV curve that depicts the thermal limit of the transmission system. To ensure voltage stability, a 5% margin from P_O to Pmax, identified as P_o, shall be maintained under planning events described in Section 6.3.9. In addition, the intersection of the QV curve with the x-axis shall occur above the minimum allowable voltage level, and the reactive power margin, represented by the value at the minimum point of the QV curve, shall be greater than the size of a nearby capacitor bank or reactive power device.

Weak Grid Assessment

Weak power systems are more susceptible to voltage transients and can be exacerbated by control instabilities. Short circuit ratio (SCR) is the most basic metric to assess the relative strength of an electrical system for a specific area when evaluating performance of a specific IBR[36]. For system

[36] NERC Reliability Guideline – Integrating Variable Energy Resources into Weak Power Systems

planning purposes, a more appropriate quantity is the weighted short circuit ratio (WSCR)[37], defined by:

$$WSCR = \frac{\sum_i^N SCMVA_i * P_{RMW_i}}{\left(\sum_i^N P_{RMW_i}\right)^2}$$

Where $\boldsymbol{SCMVA_i}$ is the short circuit capacity at bus $\boldsymbol{i}$ and $\boldsymbol{P_{RMWi}}$ is the MW rating of the IBR; $\boldsymbol{N}$ is the number of total IBR fully interacting with each other and $\boldsymbol{i}$ is the IBR index. The WSCR takes into account the aggregate IBR of the system to ensure the system has sufficient short circuit current for transient voltage stability. There is currently no industry standard for WSCR of a transmission system.

Control Stability

Control stability refers to the behavior of grid-connected IBR like wind and solar PV plants to operate in a stable manner for both small disturbances and large disturbances on the grid over a wide range of operating conditions and disturbances. Unstable behavior can result in oscillatory behavior, extreme overshoots in voltage or current, and/or a failure to ride-through a disturbance. The stability of equipment controls is impacted by many factors, including equipment tuning, operating conditions, grid strength, disturbance types, and the electrical proximity to other IBR or synchronous machines on the grid, among others.

As more IBR with complex control system connect to the system, it is important to assess the control stability of these resources to assess the robustness of controls to the range of expected operating conditions over the planning horizon. This will be done through a combination of screening, scenario modeling, and testing/demonstration of performance. As such, supplying accurate and sufficiently detailed models of equipment and functional descriptions of equipment control and protection schemes is necessary well in advance of interconnection. Equipment performance will be evaluated for combinations of:

- Full and partial power operating conditions, high and low voltages (within continuous limits)
- Symmetric and asymmetric fault disturbances (with reclosing), line switching disturbances, loss of generation and load disturbances
- Low grid strength conditions

Rotor Angle Stability Criteria

Rotor angle stability simulations involve the evaluation of critical clearing times ("CCT") for close-in faults to generating stations, generating units, and transmission lines. Generator rotor angle deviation with respect to a "distant" generator shall be less than 180 degrees to prevent generator pole-slipping and in addition to avoiding loss of synchronism. Dynamic performance shall exhibit acceptable damping to ensure rotor angle stability. Pole-slipping could impose mechanical stresses on the generator shaft and could result in catastrophic failure of the unit.

[37] Electranix, System Strength Assessment of the Panhandle System, Electric Reliability Council of Texas, 2016

Critical Clearing Times

The Transmission Planning Department performs Stability simulations using the standard fault clearing times for breakers provided by the System Protection Department. If a fault event results in a planning criteria violation, the Transmission Planning Department shall determine the CCT for that event and will provide it to the System Protection Department for its review and feedback. If the CCT cannot be achieved by the existing protective devices, Transmission Planning Department will work with System Protection Department to develop appropriate mitigation measures. Such mitigation measures may include but not limited to the system protection upgrade, generator size or power export reduction, application of synchronous condenser or adjustments to resource commitment as applicable.

Frequency Stability

Frequency stability is determined by 1) the amount of inertia on the system; 2) the amount and response characteristics of fast-frequency and primary frequency response reserves on the system; and 3) the magnitude of the generation Contingency. The system shall carry sufficient inertia and frequency response reserves to mitigate the loss of the largest generating unit, including any aggregate loss of distributed energy resources in response to the Contingency events, with appropriate Non-Consequential Load Loss criteria defined in Section 6.3.9. In order to meet these criteria, mitigation measures may require establishing minimum inertia requirement for a generation loss event.

Planning Criteria for Stability

Stability of an electric power system is the attribute of the system to regain a state of operating equilibrium after being subjected to disrupting forces (Contingency events), such that the majority of the system remains intact. Generating units and transmission Elements must remain online and in synchronism with the system to prevent an island-wide blackout. Therefore, the Transmission System shall be tested by simulating frequent Contingency events and reasonable cascading contingency events that may occur on the system to ensure operating equilibrium is restored.

1) For the more frequent types of contingencies listed below, not more than one generating unit can disconnect from the system, all generating units must remain connected and synchronized to the system, all generating units must participate towards beneficial system response, no circuits should trip on stability swings, transient voltage stability must be maintained, and Non-Consequential Load Loss defined in Section 6.3.9 is allowable.
    - Normally cleared, three-phase faults on transmission lines with automatic reclosing as applicable to the circuit being analyzed.
    - Delayed clearing of three-phase faults due to failure of the pilot relay on circuits that have one pilot scheme, and one step-distance scheme for backup to the pilot scheme. Dual-pilot relay schemes require independent communication technologies (e.g. both microwave and fiber-optic cable) to mitigate failure of single-pilot relay schemes. Analysis shall be performed for the simulation of the longest delayed clearing time scenario.
    - Delayed clearing of single line-to-ground faults due to failure of a circuit breaker to open.

Exceptions include small units (e.g. internal combustion engines) that share a common generator step-up transformer and combined-cycle units. Other exceptions will be considered on a case-by-case basis.

2) For the less frequent contingencies listed below, increased amounts of Non-Consequential Load Loss or generator tripping may be required to prevent equipment damage and maintain Stability.
   - Sudden loss of all transmission lines emanating from a power plant switching station.
   - Sudden loss of all transmission lines in a common right-of-way.
   - Sudden loss of any combined cycle units or any two synchronous generating units (synchronous, asynchronous, or both), including any aggregate loss of DER.
   - Sudden loss of any combination of two transmission Elements.
   - Cascading loss of generation
3) Extreme Events – For Extreme Events system preservation shall be tested. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. If any Extreme Events result in an island-wide blackout, mitigation measures shall be formulated and analyzed to see if a reasonable solution can be implemented. Examples of Extreme Events include but not limited to:
   - A three phase fault on generator, transmission circuit, transformer or bus section with stuck breaker resulting in delayed fault clearing
   - A three phase fault on generator, transmission circuit, transformer or bus section with failure of a non-redundant component of a Protection System resulting in delayed fault clearing
   - Three phase internal breaker fault
   - Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

6.3.9. Transmission Planning Assessment

A Planning Assessment of the Transmission System must be performed on an annual basis to ensure compliance with these criteria for the Near-Term Planning Horizon and Long-Term Planning Horizons. This Planning Assessment must use current models to analyze steady-state, dynamic, and transient system stability to ensure compliance with these criteria. Updated assumptions, forecasts, and study results shall be summarized and documented in a report.

Near-Term Transmission Planning Horizon

The Near-Term Transmission Planning Horizon should assess a five-year period and evaluate year one, year five, and any other year in between that has a significant system change, e.g., the planned addition or deactivation of a generating unit, the addition of a transmission line, etc. As a minimum, the study shall assess system performance for the following operating periods and conditions:

- Day minimum load (high DER, low gross load)
- Day peak load (low DER, high gross load)

- Evening peak load
- Night minimum load

Base cases may include consideration of each major unit outage period.

For each of these periods, only the applicable Stability analysis and system events shall be performed. Additional sensitivity cases and/or analyses should be performed on an as-needed basis to ensure system performance meets the stability criteria specified in Section 6.3.8, and may be informed by identified operational constraints.

The Planning Assessment should periodically analyze cascading Contingency events to ensure preservation of the system for plausible planning events. As a minimum, the system shall meet performance requirements of Planning Events P5 through P7 from Table 55.

Long-Term Transmission Planning Horizon

The Long-Term Transmission Planning Horizon should be performed in conjunction with the Integrated Grid Planning process. Evaluation years will be dictated by the proposed resource plans. As a minimum, the study shall assess system performance for the following operating periods and conditions:

- Day minimum load (high DER, low gross load)
- Day peak load (low DER, high gross load)
- Evening peak load
- Night minimum load

For each of these periods, only the applicable Stability analysis and system events shall be performed. Models of future generating units will not be readily available; therefore discretion should be used in: 1) developing the scope of work and sensitivity cases for this Planning Assessment and 2) interpreting results of these analyses.

Past Studies

Past studies may be used to support the Planning Assessment if they meet the following requirements:

- For steady state, short circuit, or Stability analysis:
  - The study must contain a technical rationale that can be provided to demonstrate that the results of an older study are still valid, or
  - No material changes have occurred to the system represented in the study. Documentation to support the technical rationale for determining material changes must be included.

Planning Events

As a minimum, the Stability criteria in 6.3.8 ensures that the transmission system meets or exceeds the performance requirements of Planning Events P1 through P4 in Table 55. A periodic assessment of the under-frequency load shed scheme should be performed to ensure that the system meets the minimum requirements of Planning Events P5 through P7 in Table 55.

Table 54 Steady State and Stability Performance Planning Events

Steady State & Stability:

1. The system must remain stable. Cascading and uncontrolled islanding shall not occur.
2. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
3. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
4. Simulate normal clearing unless otherwise specified.
5. Planned system adjustments such as transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Equipment Rating.
6. Phase angle separation for line Contingency shall not preclude automatic reclosing unless system adjustments can be performed within fifteen minutes.

Steady State Only:

7. Applicable Equipment Rating must not be exceeded.
8. System steady state voltages and post-Contingency voltage deviations must be within acceptable limits as established by this Planning Criteria.
9. Planning event P0 is applicable to steady state only.

Table 55 Categories of Contingency Events

Category	Initial Condition	Event	Fault(s) Type	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal system	None	N/A	None
P1 Single Contingency	Normal system	Loss of one of the following: 1. Generator 2. Transmission Circuits 3. Transformer 4. Shunt Device-Ancillary Service Device	3Ø	Up to 15% for Generator Trip Only
		5. Generator - no fault	N/A	
P2 Single Contingency	Normal system	1. Bus Section fault 2. Internal Breaker Fault (Transmission line breaker)	3Ø	Up to 15%
P3 Single Contingency	Loss of generator unit followed by system adjustments (e.g.,	Loss of one of the following: 1. Generator 2. Transmission Circuits	3Ø	Up to 20%

	corrective action and re-dispatch)	3. Transformer 4. Shunt Device/ Ancillary Service Device		
P4 Multiple Contingency (Fault plus stuck breaker)	Normal system	Loss of multiple elements caused by a stuck breaker (non-Bus-tie Breaker) attempting to clear a fault on one of the following: 1. Generator 2. Transmission Circuits 3. Transformer 4. Shunt Device 5. Bus Section	SLG	Up to 40%
		6. Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a fault on the associated bus	SLG	Up to 40%
P5 Multiple Contingency (Fault plus non-redundant component of a Protection System failure to operate)	Normal system	Delayed fault clearing due to the failure of a non-redundant component of a Protection System protecting the faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuits 3. Transformer 4. Shunt Device 5. Bus Section	3Ø	Up to 15%
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the followed by system adjustments: 1. Transmission Circuits 2. Transformer 3. Shunt Device	Loss of one of the following: 1. Transmission Circuits 2. Transformer 3. Shunt Device	3Ø	Up to 65%
P7 Multiple Contingency	Normal system	Loss of one of the following: 1. Cascading Generators 2. Transmission Corridor 3. Any two adjacent circuits on common structure	SLG	Up to 65%

Table 56 Steady State & Stability Performance Extreme Events

Steady State & Stability For all extreme events evaluated: 1. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency. 2. Simulate normal clearing unless otherwise specified.

Steady State	Stability

1. Loss of a single generator, transmission circuit, shunt device, or transformer force out of service followed by another single generator, transmission circuit, shunt device, or transformer forced out of service prior to system adjustments.
2. Local area events affecting the Transmission System such as:
  a. Loss of a tower line with three or more circuits.
  b. Loss of all transmission lines on a common Right-of-Way
  c. Loss of a switching station or substation (loss of one voltage level plus transformers).
  d. Loss of all generating units at a generating station.
  e. Loss of a large load or major load center.
3. Wide area events affecting the Transmission System based on system topology such as:
  a. Loss of two generating stations resulting from conditions such as:
    i. Loss of a large fuel line into an area.
    ii. Loss of the use of a large body of water as the cooling source for generation.
    iii. Wildfires
    iv. Severe weather, for example, hurricanes
    v. A successful cyber attack
    vi. Large earthquake, tsunami or volcanic eruption
4. Other events based upon operating experience that may result in wide area disturbances.
	1. Loss of a single generator, transmission circuit, shunt device, or transformer force out of service apply a 3Ø fault on another single generator, transmission circuit, shunt device, or transformer prior to system adjustments.
	2. Local area events affecting the Transmission System such as:
	  a. 3Ø fault on generator with stuck breaker or a relay failure resulting in delayed fault clearing.
	  b. 3Ø fault on transmission circuit with stuck breaker or a relay failure resulting in delayed fault clearing.
	  c. 3Ø fault on transformer with stuck breaker or a relay failure resulting in delayed fault clearing.
	  d. 3Ø fault on bus section with stuck breaker or a relay failure resulting in delayed fault clearing.
	  e. 3Ø internal breaker fault.
	  f. Other events based upon operating experience, such as consideration of initiating events that experience, such as consideration of initiating events that experience suggests may result in wide area disturbances.

Table 57 Steady State & Stability Performance Footnotes

Planning Events and Extreme Events

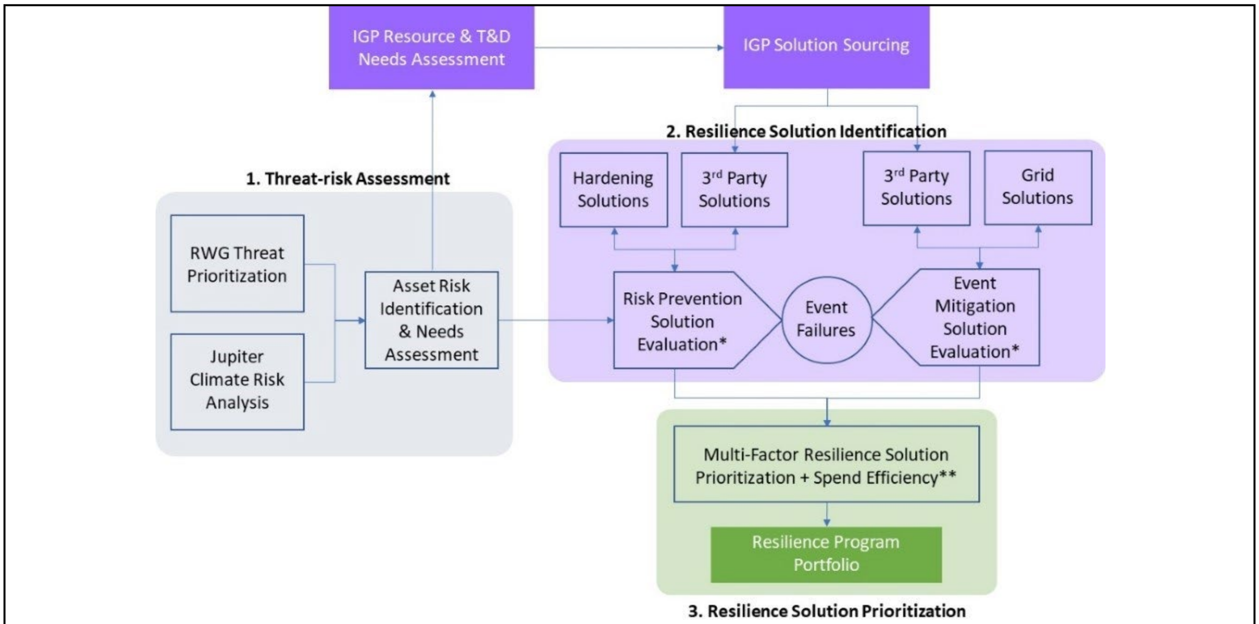
1. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria
2. For non-generator step up transformer outage events, the reference voltage, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
3. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
4. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
5. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
6. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.

For purposes of this standard, non-redundant components of a Protection System to consider are as follows:

a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;
b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center);
c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit);
d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

7. RESILIENCE PLANNING FRAMEWORK

The Companies have been focused on power system resilience in response to the increasing threats from climate change. Resilience planning is about mitigating risks, including outages and public safety. A specific resilience planning process, based on industry best practices, is under development to integrate with IGP. This process has three distinct steps, 1) threat-risk assessment, 2) resilience solution identification, and 3) resilience solution prioritization. This resilience planning approach and linkage with IGP is illustrated Figure 41 below.



* Resilience solution evaluation includes technical resilience performance assessment & secondarily other beneficial factors

** This customer & community-centric prioritization & cost effectiveness method can be applied to all T&D capital expenditures

Figure 41 Resilience Planning Approach

The Resilience Working Group (RWG) reached a general agreement that all relevant costs need to be captured, which includes the costs that utilities might incur to mitigate severe outages, as well as the cost of the outage to customers and stakeholders.[38] This process attempts to address this objective in the context of a multi-factor evaluation that leads to a risk-spend efficiency prioritization adapting leading resilience planning practices in the industry.

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[38] *See* RWG Report at 57. https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/resilience/20200429_rwg_report.pdf

7.1. Threat-Risk Assessment

The Companies' prior efforts with the Department of Defense and critical facilities in our communities has expanded through the work with the RWG. The stakeholder driven threat identification and prioritization combined with customer segmentation and prioritization provide a key input into the resilience planning process. The RWG final report is publicly available.[39]

Jupiter Intelligence's high-resolution climate analytics provide asset-level resolution for short and long-term flooding and wind risk to assess physical risks over a 30-year time horizon to help the Companies address the resiliency of its generation, transmission, and distribution infrastructure. In its first phase, the Jupiter climate risk data will help the Companies prioritize geographic locations and assets that are most at risk. Subsequently, it will provide detailed area analyses of all assets.[40]

The Jupiter locational analysis combined with the RWG prioritization provides the basis for a detailed customer and community-based threat-risk assessment of the Companies' assets. This informs the need, location, and timing of investment to cost effectively provide the level of electric system resilience our customers expect. The result is a set of resilience needs in the form of specific performance requirements to prevent and mitigate event-based risks.

7.2. Resilience Solution Identification

The Companies are applying the "bowtie method" (Figure 42) as increasingly used in the industry to leverage risk-threat assessments as described above into a structured solution identification process involving two aspects, event risk prevention and event consequence mitigation. This method, employed in California's wildfire mitigation planning, translates the threat-risk assessment and asset vulnerabilities in Step 1 into specific event risk prevention and mitigation analysis and solution identification. A bow-tie approach helps identify where and how solutions would have the greatest impact for customers and communities.

[39] Resilience Working Group Report (PDF): https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/resilience/20200429_rwg_report.pdf

[40] *See* https://view.hawaiianelectric.com/jupiter-intelligence-special-report/page/1

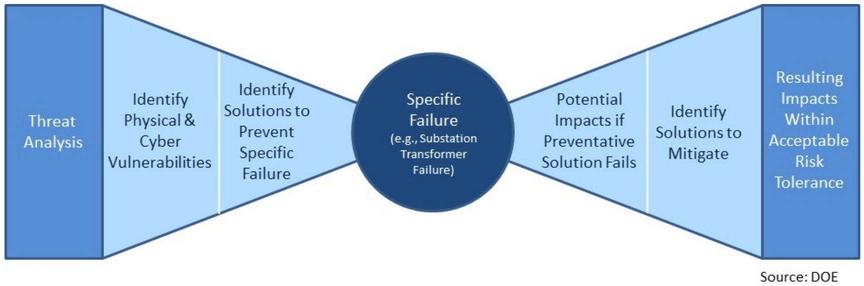

Figure 42 "Bowtie Method" Risk-Threat Assessment

This is done by implementing solutions to prevent certain events from causing system failures. Preventive solutions are shown on the left side of the bowtie. Mitigation solutions can either reduce the impact of a failure event or facilitate recovery of the failure to reduce the consequences of an event. Mitigation solutions are shown on the right side of the bowtie. Challenges involve identifying the additional risk exposure from a range of threats and the system impacts given the increasing complexity of a more distributed power system along with the potential overlapping set of grid needs identified in the IGP analyses. The Companies recognize the need to start more simply and evolve sophistication over time as with climate analysis.

The specific prevention and mitigation solutions will be identified through both utility asset options and potential third-party and customer solutions. The utility asset options involve vegetation management, hardening, undergrounding, and increasing switching flexibility, for example. Third-party solutions may involve microgrids, local energy producing resources, and load management. Customer options include back-up generation, storage, and microgrids. The third-party solution opportunities will be incorporated into the IGP sourcing process to streamline and hopefully identify solutions that achieve multiple objectives. The result is a portfolio of solutions to address the various and unique resilience needs of the power system, communities, and individual critical facilities and customers as illustrated in Figure 43 below.

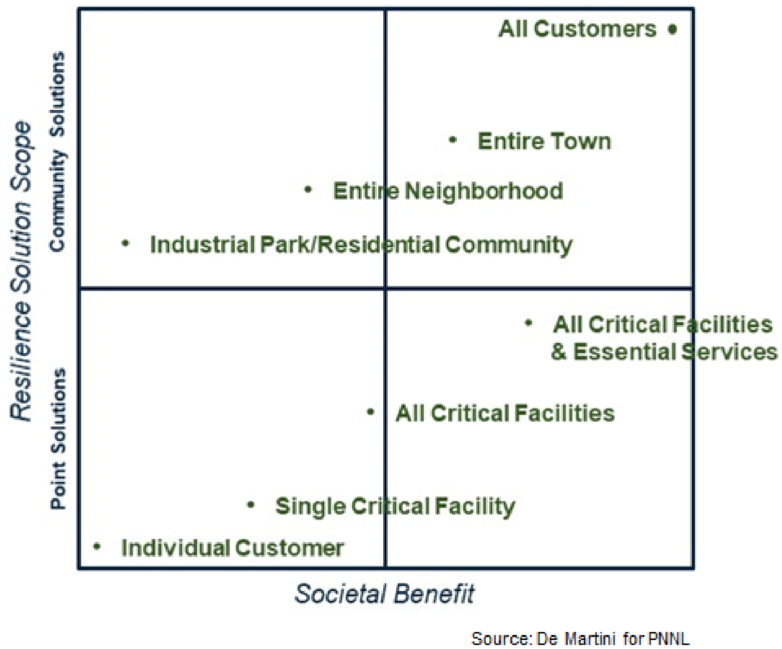

Figure 43 Resilience Solution Portfolio

This portfolio is developed by assessing the utility, third-party, and customer solutions against the respective prevention and mitigation performance requirements identified in Step 1. The resulting solution set will then be prioritized in Step 3.

7.3. Resilience Solution Prioritization

Resilience solution prioritization involves assessing the comparative customer and community risk reduction value of the solutions related to associated generation, transmission, substation, and distribution infrastructure. The Companies intend to use a risk-spend efficiency (RSE) metric to ascertain the benefit to cost ratio of resilience risk reduction solutions. The benefit is expressed in terms of the magnitude of risk reduction while the costs include solution expenditure. This process begins with assessing solution value in terms of community and customer resilience risk reduction in terms of estimated customer minutes of interruption (CMI) avoided over the planning horizon.

7.3.1. Locational Propensity Factor

The Locational Propensity Factor estimates the potential event risk reduction and the propensity of the event to occur during the planning horizon. Each island and area on each island have different relative levels of exposure to major climate event risk. The Companies' assets have been assessed for the propensity to experience major climate events based on the Jupiter analysis performed in Step 1. While not a predictor of future events, it is nonetheless a

useful factor for prioritizing where to focus on certain efforts. The number of events is multiplied by the estimated outage risk reduction per event provided by a solution. The aggregate avoided CMI value is then considered in relation to community impact.

7.3.2. Community & Customer Impact Factor

Resilience events involve long outage durations which can have much larger impacts on Hawaii's national security facilities and communities than short duration outages. As such, assessing the impact on communities involves consideration of national security and community impacts to defense facilities, critical facilities, vulnerable population, and other priorities identified by the RWG stakeholders in Step 1. The RWG identified these priorities in their report and can be applied to assess aggregate community impacts. For example, identifying the defense facilities, critical facilities and number of vulnerable people and assigning weights to reflect the priority of providing electricity to these people and facilities. This would more fully assess the national security, community impacts, and individual population risk reduction from major events.

The resulting weighted community impact number is multiplied by the aggregate CMI value to create a resilience value denoted in avoided CMI.

7.3.3. Other Resilience Values

As in California, the monetary impact of avoided safety-related incidents (e.g., wildfire risk mitigation, wires/poles down) can be incorporated. Likewise, damage reduction solutions can also be incorporated (e.g., targeted hardening of poles/structures that would be expensive/difficult to replace after an event due to their location, equipment on pole/structure, etc.)

7.3.4. Non-Resilience Values

Additionally, other desirable values provided by a solution will be considered. For example, if a resilience solution also improved the normal, blue-sky capability to integrate DER or enable electrification these values could be assessed within the IGP framework. The California Public Utility Commission provided direction to identify these types of associated benefits when evaluating resilience solutions. This may involve incorporating a second weighting based on the aggregate value from other factors to apply to the resilience value (CMI). This type of multi-factor weighted value analysis is used in several states, including Michigan. The weighted solution values identified are averaged and used to multiply the CMI value to yield a composite value number.

7.4. Risk-Spend Efficiency (RSE) Prioritization

The last step is to divide the risk reduction value by the cost of the solution (utility or third-party) to determine the risk-spend efficiency of the solution. This approach is an adaptation of the RSE used more narrowly in California for wildfire mitigation planning. This approach aligns with the RWG's recognition that all relevant impacts need to be captured, which includes the impact of a long duration outage to customers and communities as well as the cost that utilities might incur to mitigate severe outages.

The resulting RSE score is used to rank the solutions with the highest ranked solutions prioritized within budget and other financial considerations. This overall framework prioritizes/ranks solutions in respect to specific needs and within an overall portfolio that also accounts for customer-based solutions. As such, this enables the Companies to determine how many solutions of various types are needed in order achieve resilience goals or objectives as a matter of policy (e.g., total length of outage by critical facility/customer tiers).[41]

[41] *See* RWG Report at 59-60.

Appendix D. Solution Sourcing Diagram Evolution

1. IGP PROCESS FOR IDENTIFYING AND SOURCING SOLUTIONS TO MEET GRID NEEDS

The Company's proposed process for solution sourcing has evolved over the course of several stakeholder meetings in response to developments in the working groups and stakeholder discussion.

In the first meeting of the Solution Evaluation & Optimization Working Group, a proposed process was introduced to procure capacity, energy, ancillary services and non-wires alternatives through separate RFPs.

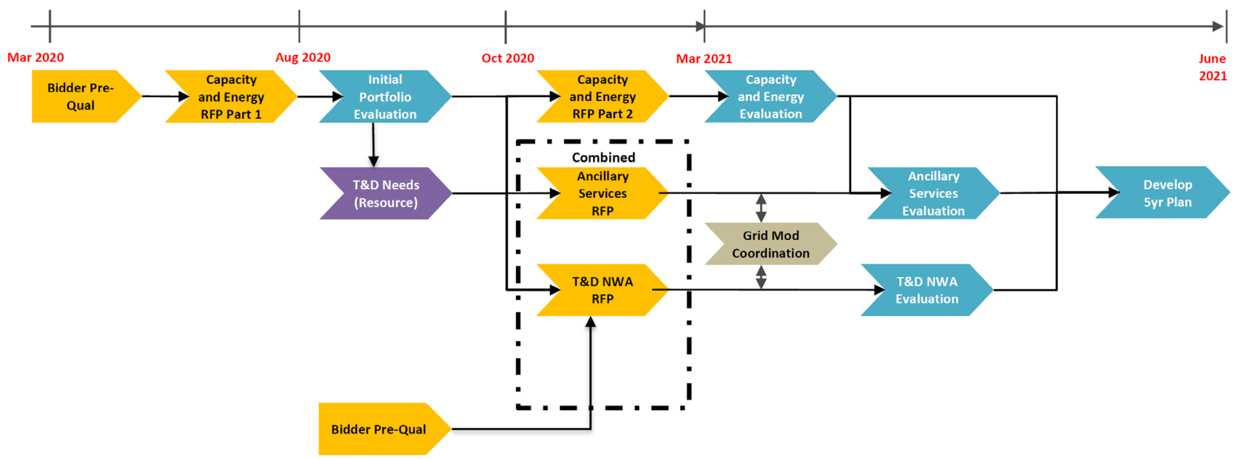

Figure 44 Initial Solution Sourcing Proposal Introduced on May 9, 2019

The sourcing diagram was significantly expanded on August 1, 2019 to show the three separate needs assessments conducted for resource and ancillary services, transmission, and distribution. The NWA opportunity evaluation proposed in the Distribution Planning Working Group was incorporated into the process, leading to a T&D NWA RFP for qualified projects[42].

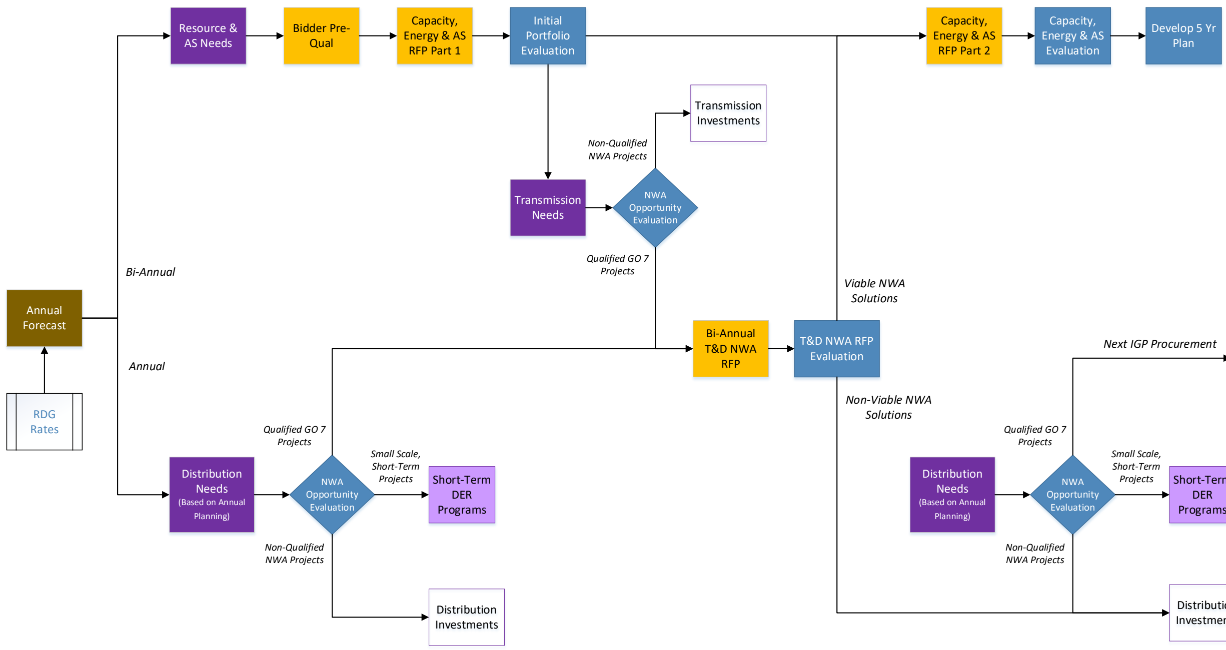

Figure 45 Expanded Sourcing Diagram Introduced on August 1, 2019

[42] *See* Non-Wires Opportunity Evaluation Methodology, April 2020.

On November 13, 2019, the review points were added to the sourcing diagram. The capacity, energy & ancillary services needs, transmission needs, and distribution needs process steps were reorganized to better show their interdependency and a long term RFI step was introduced based on stakeholder feedback. For all process steps shown, estimated durations were provided in the monthly timeline.

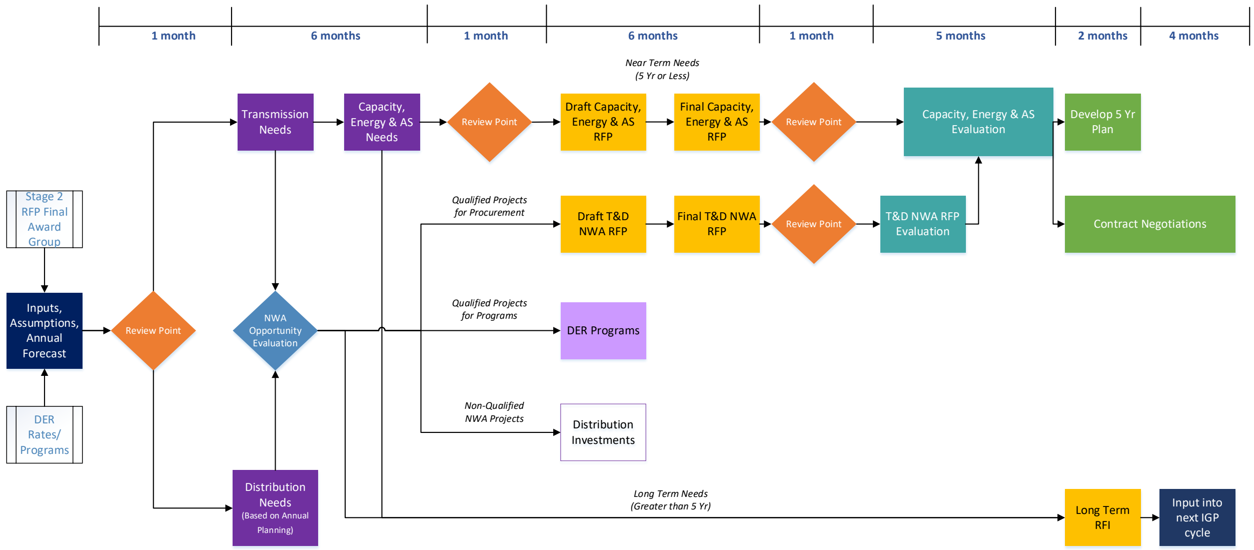

Figure 46 Sourcing Diagram Presented on November 13, 2019

On December 9, 2019, the sourcing diagram was clarified to show both the transmission needs and distribution needs were inputs into the capacity, energy & ancillary services needs with a single review point for the set of needs assessments. Following feedback from stakeholders, the Long Term RFI step was replaced with the Long Term RFP. Brackets were also placed over parts of the process that would be reviewed by the TAP and the Independent Observer.

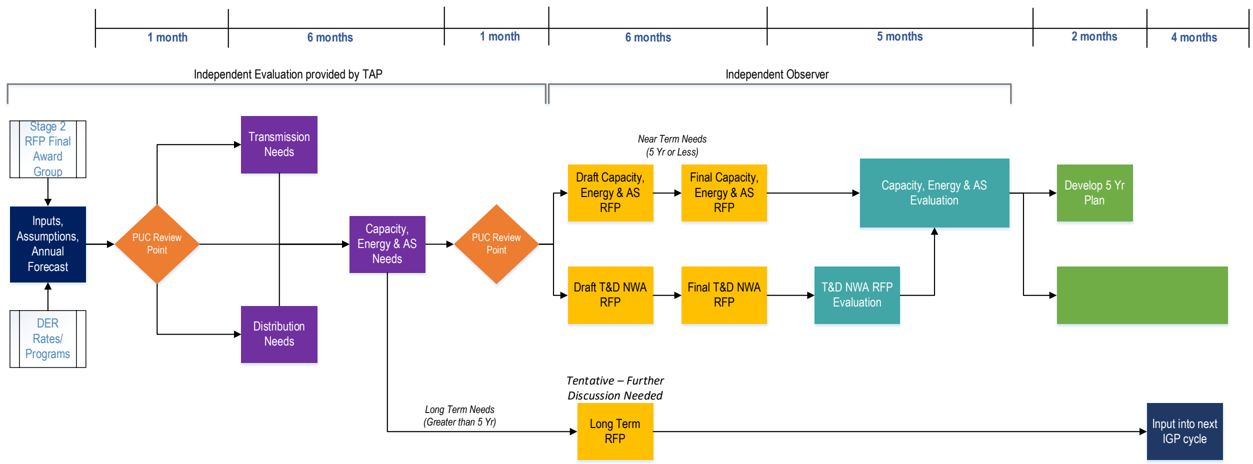

Figure 47 Sourcing Diagram Presented on December 9, 2019

On January 23, 2020, a one-time iteration of the sales forecast was added into the process based on stakeholder feedback to provide one round of iteration of the assumptions. The sourcing diagram was also revised to show the distribution needs assessment occurring on an annual basis.

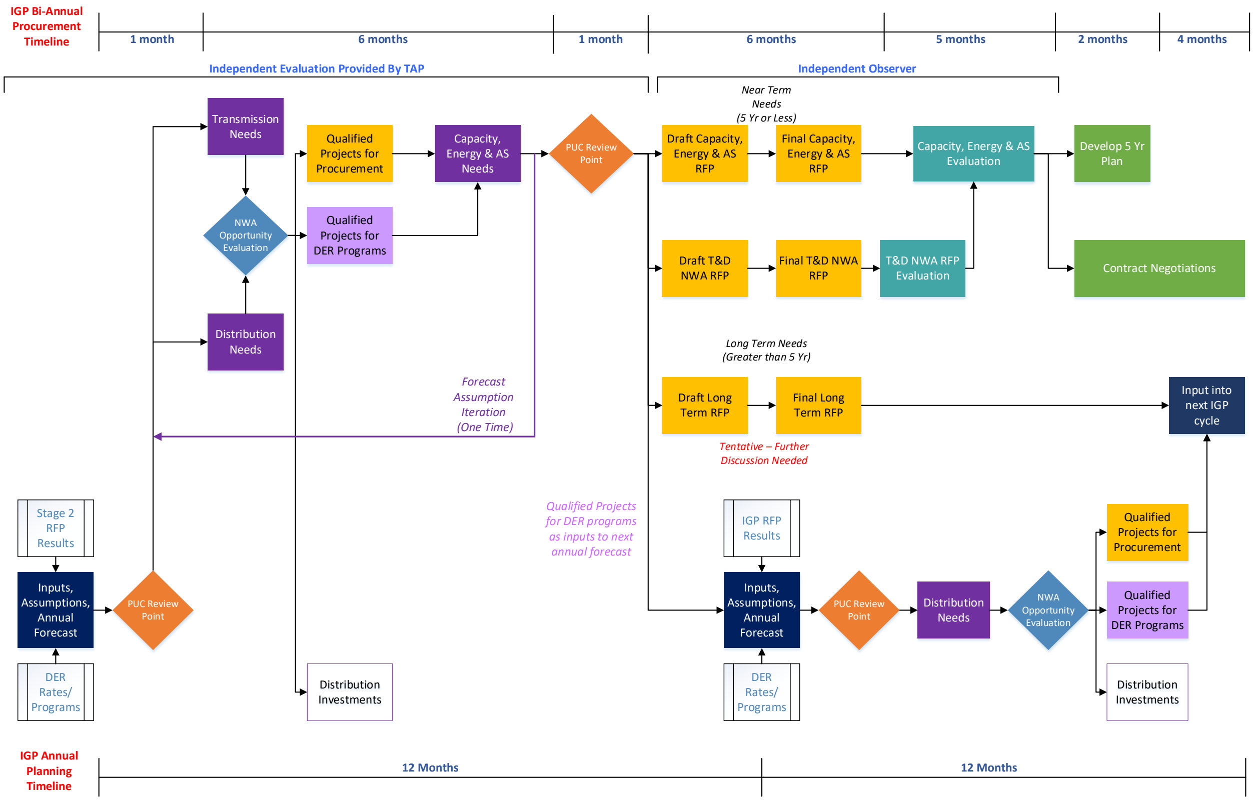

Figure 48 Sourcing Diagram Presented on January 23, 2020

On February 12, 2020, the process step to "Develop 5-year Plan" was removed to emphasize that the needs assessment will provide transmission needs, distribution needs, and capacity, energy and ancillary service needs over the entire planning horizon and not just the next five years.

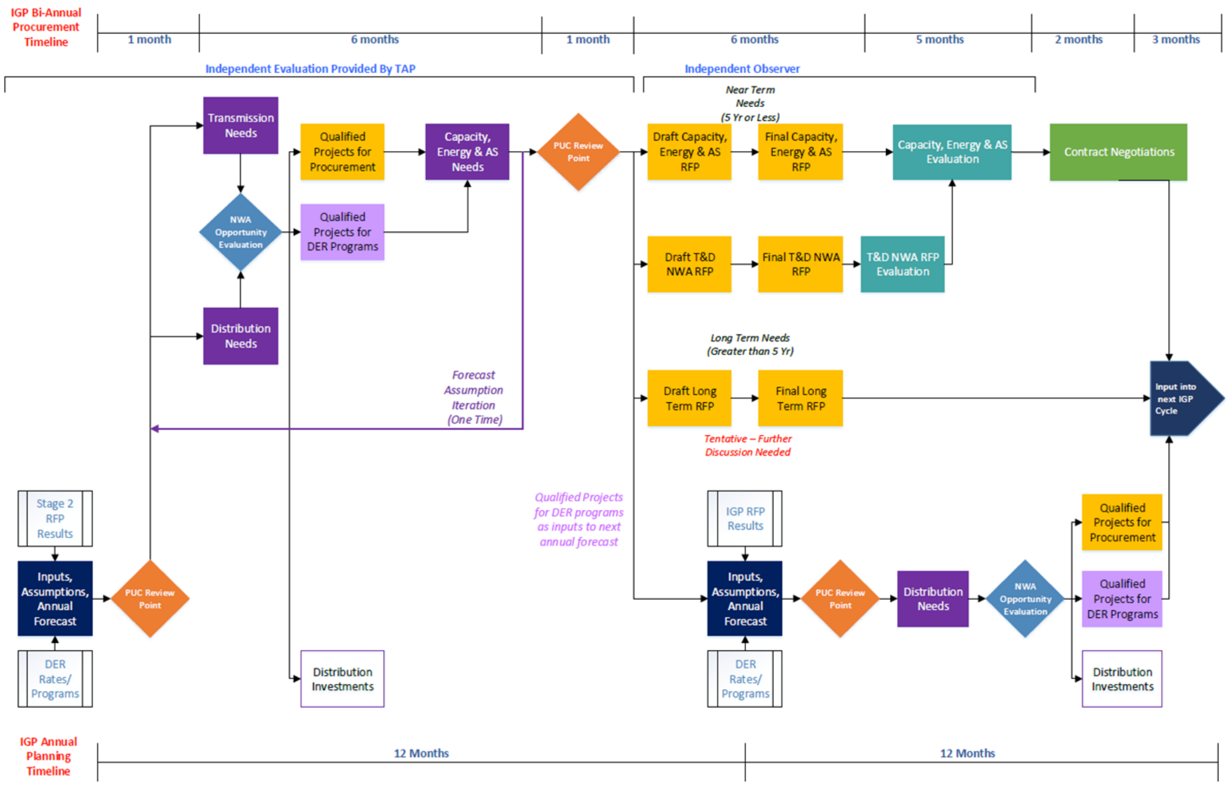

Figure 49 Sourcing Diagram Presented on February 12, 2020

On March 16, 2020, the independent evaluation by the TAP was clarified to also include the distribution needs and NWA opportunity evaluation that occurs in the second year of the IGP cycle. Following several working group meeting discussions in the SEOWG and FAWG, the forecast iteration was removed as the forecasts and other assumptions would be stress tested through sensitivity analyses proposed by stakeholders using RESOLVE as described in Appendix E.

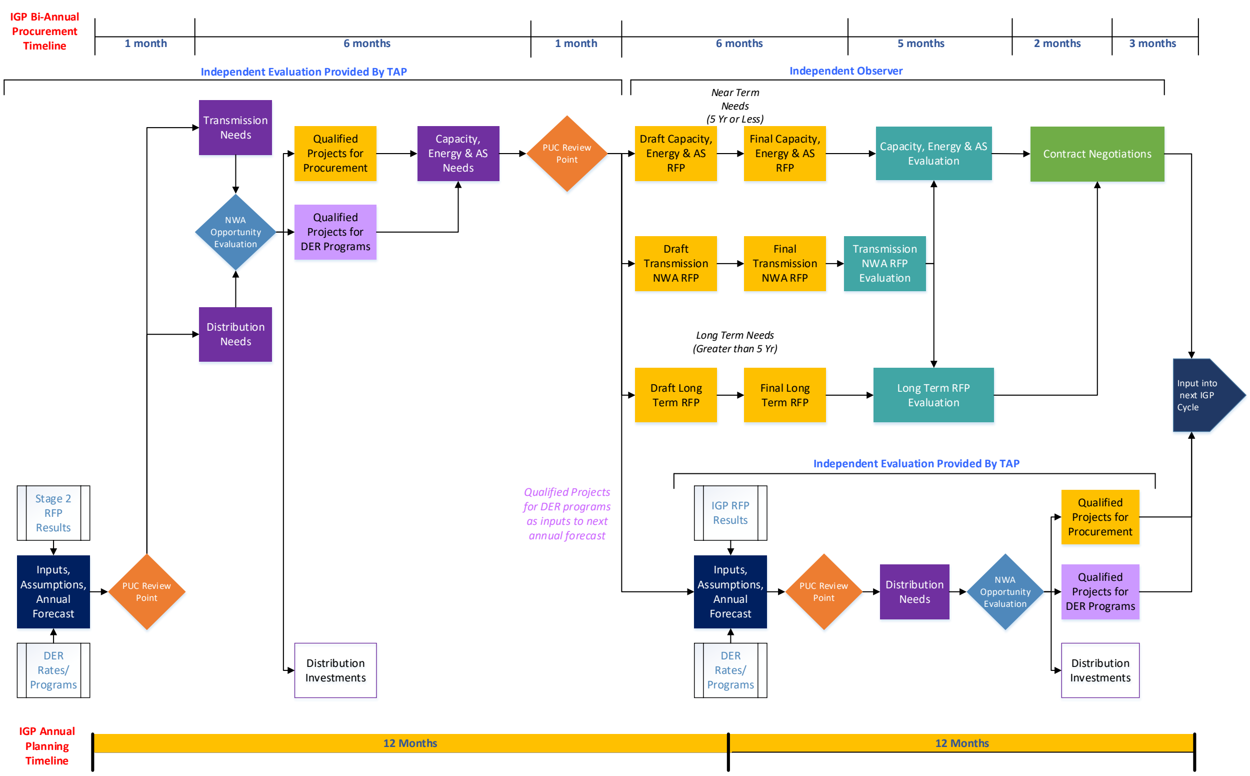

Figure 50 Sourcing Diagram Presented on March 16, 2020

Appendix E. Modeling Sensitivity Analyses

1. RESOLVE MODELING SENSITIVITIES

This appendix describes the process for developing sensitivity analyses in the Grid Needs Assessment. Sensitivity analyses can help inform and stress test the RESOLVE reference case to develop a more robust portfolio. Hawaiian Electric, in collaboration with stakeholders in the Solution Evaluation and Optimization Working Group (SEOWG), Stakeholder Council, and Technical Advisory Panel propose the following set of sensitivities.

These sensitivities prioritize cases that are meaningfully different than the reference portfolio. They are intended to test different customer behaviors and changes in policy, rather than specific programs or technologies. Although certain technologies will be selected in the reference portfolio in the Grid Needs Assessment, ultimately, the solution evaluation process will determine the specific resources that become part of the Hawaiian Electric's portfolio.

Sensitivity Development Process

The process for developing sensitivities and incorporating their results into the reference case is described below.

Step 1: Hawaiian Electric proposes sensitivities to inform the Grid Needs.

Step 2: Stakeholders in the SEOWG provide feedback and suggestions for each sensitivity. The SEOWG has been serving as the venue to solicit feedback and clarify the details for each of the sensitivities.

Step 3: Hawaiian Electric incorporates feedback to refine each sensitivity. As part of this step, Hawaiian Electric will formulate meaningful scenarios for each of the sensitivities and develop them into modeling cases that can be analyzed in RESOLVE.

Step 4: The Technical Advisory Panel (TAP) provides independent review of the grid service needs assessment and sensitivities as the independent evaluator for the IGP process. Over the course its review, the TAP can recommend additional sensitivity analyses or feasibility checks as deemed prudent to facilitate its review.

Step 5: The Stakeholder Council reviews the grid service needs assessment and sensitivities. The Stakeholder Council members will have an advance opportunity to review and comment on the Grid Needs Assessment and sensitivity analyses prior to the review point filing.

Sensitivity Categories

The sensitivities are organized into the following categories:

Table 58 Table of Proposed Sensitivities

Sensitivity Name	Purpose
Bookend Sensitivity	Understand the impact of slower and faster customer adoption of technologies for DER, electric vehicles, energy efficiency, and time-of-use rates
Market DER Sensitivities	Understand the value of DER, up to and exceeding the market uptake forecast
High Energy Efficiency Sensitivity	Understand the value of additional energy efficiency above the reference forecast
State ITC Sensitivity	Understand the impact of removing the state ITC for PV
No Onshore Development Sensitivity	Understand the value of an offshore wind generation portfolio
Low Renewable Sensitivities	Understand the value of storage and thermal generation during periods of low renewable production
Customer Load Shift Sensitivities	Understand the value of distributed storage
EV Sensitivities	Understand the value of customers charging their electric vehicles

Sensitivity #1: Bookends for Customer Technology Adoption

Bookends will be evaluated as a sensitivity around the reference forecast, to establish a plausible set of assumptions for each of the layers within the load forecast to define a cumulative high forecast and cumulative low forecast. These high and low bookends include the evaluation of higher and lower adoption of distributed energy resources, electric vehicles, energy efficiency, and time-of-use ("TOU") rates adoption. While the market forecast provided in the inputs workbooks represent the best estimate of those assumptions, the results of the bookends will be useful to directionally inform how the resource plan and system costs will change as load increases or decreases.

- For electric vehicles, a factor can be applied to the unmanaged charging to account different levels of adoption.
- A wider range of energy efficiency measures will be incorporated; however, modeling more detailed energy efficiency sensitivities will require additional guidance and information to do so.
- For time-of-use rates, initial "best guess" assumptions for TOU adoption and load shapes will be developed as a placeholder until proposals can be finalized in the ARDS track of the DER docket.

In sum, the low and high bookends, labeled as Slower Customer Technology Adoption and Faster Customer Technology Adoption respectively, represent a deceleration and acceleration of customer adoption of distributed energy resources, electric vehicles, energy efficiency, and time-of-use rates which are all key drivers of the load forecast.

Table 59 Bookend Sensitivity

Assumption	Slower Customer Technology Adoption	Base	Faster Customer Technology Adoption
DER	Market Forecast DER aggregator as a resource option	Market Forecast DER aggregator as a resource option	Increase DER layer in market forecast by 30%, capped at the technical potential established by NREL DER aggregator as a resource option
Electric Vehicles	Reduce electric vehicle layer in market forecast by 30%	Market Forecast	Increase electric vehicle layer in the market forecast by 30%, capped at the same market saturation levels in the Market Forecast
Energy Efficiency	Reduce energy efficiency layer in market forecast by 30%	Market Forecast	Increase energy efficiency layer in market forecast by 30%
TOU	Market Forecast (no assumed TOU)	Managed EV TOU Managed DER TOU	Higher Managed EV TOU adoption Higher Managed DER TOU adoption

Sensitivity #2: Market DER

The purpose of this sensitivity is to determine the value of the forecasted market DER uptake that is already assumed in the reference portfolio by evaluating a case where no incremental DER is added beyond 2020 levels. RESOLVE will be allowed to build grid-scale resources to

meet future RPS and grid needs. Compared to the reference case, this will provide the value of the market DER forecast and a lower bound on the value of DER in the portfolio.

Sensitivity applies to:	Existing DER capacity
Sensitivity duration:	2021 - 2050
Changes to the model:	Fix DER capacity to 2020 levels in RESOLVE

Sensitivity #3: No Future Transmission Infrastructure

The purpose of this sensitivity is to understand value of additional DER, above the forecasted market DER uptake by limiting the expansion of transmission infrastructure. RESOLVE will be allowed to build future grid-scale generation options up to the available transmission capacity as well as DER resources to meet RPS and grid needs. Compared to the reference case, this will provide the value of additional DER above the market forecast and an upper bound on the value of DER in the portfolio.

A DER aggregator resource option will be available to be selected by the RESOLVE model. The DER aggregator will be costed as 20 MW of residential PV paired with 20 MW of residential storage with a 10% adder for customer acquisition costs.

Sensitivity applies to:	Forecasted DER and future DER aggregation
Sensitivity duration:	2021 - 2050
Changes to the model:	Allow future grid-scale capacity up to the available transmission capacity

Sensitivity #4: High Energy Efficiency

The purpose of this sensitivity is to understand the value of increased energy efficiency. A higher uptake of energy efficiency, above the Business as Usual assumed in the reference case, will be incorporated into RESOLVE to determine the impact on the resulting resource portfolio.

Sensitivity applies to:	Forecasted energy efficiency
Sensitivity duration:	2021 - 2050
Changes to the model:	Increase assumed energy efficiency forecasted embedded in sales

Higher (as well as lower) levels of energy efficiency are being considered as part of the slower and faster customer technology adoption scenarios in the proposed bookend sensitivity so this standalone sensitivity will not be carried forward.

Sensitivity #5: No State ITC Sensitivity for PV

The purpose of this sensitivity is to understand the impact of not having the State investment tax credit as part of the resource cost assumption for PV. This sensitivity will compare the resulting resource plan without state tax credits against the reference case.

Sensitivity applies to:	Resource cost assumption for PV
Sensitivity duration:	2021 - 2050
Changes to the model:	Update the assumed resource cost for PV to remove the State ITC

Sensitivity #6: No Onshore Development

The purpose of this sensitivity is to understand the value of offshore resources, specifically for O'ahu, if future onshore, grid-scale options are limited. DER uptake will continue as forecasted, however, only offshore wind will be available in RESOLVE as a grid-scale resource option. This sensitivity will compare the resulting offshore wind portfolio against the reference case.

Sensitivity applies to:	Resource option for offshore wind
Sensitivity duration:	2021 – 2050
Changes to the model:	Allow offshore wind as the only resource option for capacity expansion

Sensitivity #7 : Low Renewable Generation

The purpose of this sensitivity is to understand how periods of low energy production from wind and PV resources impact the resilience and reliability of the resource portfolio. Modeling cases will consider low PV generation and low wind generation separately as well as the combined effects of low generation from both resource types based on historical data. Low renewable production will be examined over a week and an extended period of several weeks.

Sensitivity applies to:	PV, wind, storage, and thermal resources
Sensitivity duration:	Select weeks over the planning horizon
Changes to the model:	Derate the profiles for PV and wind resources Include forecasted forced outage rates and costs to maintain thermal fleet

Sensitivity #8: Non Grid-Participating Customer Storage

The purpose of this sensitivity is to understand the value of existing net energy metering customers adopting storage and operating as non-export customer load shift resources. In the March 12 Stakeholder Council meeting, the council members discussed the merits of this sensitivity and decided that detailed analyses like this sensitivity were better suited for the DER docket.

Sensitivity applies to:	Existing net energy metering capacity
Sensitivity duration:	2021 – 2050
Changes to the model:	Pair existing NEM capacity with no cost 4-hour storage that is not allowed to charge from nor export to the grid

Sensitivity #9: Grid-Participating Customer Storage

The purpose of this sensitivity is to understand the value of additional distributed storage that is able to charge from and export to the grid when added to existing and future DER resources. In the March 12 Stakeholder Council meeting, the council members discussed the merits of this sensitivity and decided that detailed analyses like this sensitivity were better suited for the DER docket.

Sensitivity applies to:	Existing and future DER
Sensitivity duration:	2021 – 2050
Changes to the model:	Pair existing DER programs with storage Consider paired PV-storage for future DER uptake Allow DER to participate in grid services

Recognizing further feedback from stakeholders, this sensitivity will be carried forward with modifications. The forecasted DER will be modeled as a resource instead of a load modifier. For the purposes of this sensitivity, the forecasted distributed BESS energy will be converted to capacity assuming a 5 kW, 13.5 kWh BESS as the typical paired BESS. Both the paired and unpaired DER systems that are controllable will be able to participate in grid services, as defined in Section 3 Grid Service Capability by Technology.

Sensitivity #10: Unmanaged Electric Vehicle Charging

The purpose of this sensitivity is to understand the value of customers managing their electric vehicle charging through their own means. Generally, this behavior will already be captured in the reference case as part of the electric vehicle layer of the sales forecast. Additional unmanaged and managed charging scenarios will be developed as part of the EoT docket using the same RESOLVE model and data inputs as IGP to then inform rate design discussions.

Unmanaged electric vehicle charging will be considered as part of the slower customer technology adoption scenario in the bookend sensitivity so this standalone sensitivity will not be carried forward.

Sensitivity #11: Managed Electric Vehicle Charging

The purpose of this sensitivity is to understand the value of electric vehicle charging that is managed by the utility. Unmanaged and managed charging scenarios will be developed as part

of the EoT docket using the same RESOLVE model and data inputs as IGP to then inform rate design discussions.

A base adoption of managed electric vehicle charging under a time-of-use rate will be considered in the base scenario of the bookend sensitivity and a higher level of electric vehicle time-of-use adoption will be considered in the faster customer technology adoption scenario so this standalone sensitivity will not be carried forward.