# Hawaiian Electric

# 2021 Integrated Grid Planning Inputs and Assumptions

**Revised August 2021 Update**

This Page Intentionally Left Blank

# Table of Contents

# List of Figures and Tables

# I Introduction

On January 19, 2021, the Company filed its first Review Point on the Inputs and Assumptions ("I&A") ("I&A Review Point"), for Hawaiian Electric's 2021 Integrated Grid Planning process which included stakeholder input incorporated over the previous two years of stakeholder engagement. In March 2021, Hawaiian Electric issued an updated Input and Assumptions document reflecting stakeholder feedback that was summarized in the *IGP Stakeholder Feedback Summary, March 2021*.

This August 2021 Update ("August I&A Update") provides an overview of how the inputs and assumptions are used by the RESOLVE and PLEXOS models to develop grid needs and reflects the most recent feedback received from stakeholders throughout the IGP process to date consistent with the Commission's Order No. 37730 described more fully below. In particular, the August I&A Update implements the directives of Order No. 37730 which includes: the Technical Advisory Panel ("TAP") "has thoroughly reviewed the revised Draft IGP Inputs and Assumptions, stakeholders have had ample opportunity to provide corrective feedback, and Hawaiian Electric has either incorporated that feedback, or clearly explains why it did not."[1]

The inputs and assumptions described herein include:

- Sales forecast by forecast layer for the underlying load, distributed energy resource, energy efficiency, and electrification of transportation layers
- Fuel price forecast
- Resource cost forecast
- Scenarios and sensitivities
- Additional assumptions used to characterize the existing and planned resource portfolio

Notably, certain key inputs and assumptions had broad agreement amongst stakeholders, including: general consensus on sales and peak forecasts, inclusion of warming trends based on Forecast Assumptions Working Group feedback, stakeholder comments acknowledging that the EV forecast and treatment of managed and unmanaged charging are reasonable, and modeling scenarios and sensitivities that were vetted through the Stakeholder Council and the TAP.

In addition, the TAP had previously reviewed the regulating reserve definitions, in which the Company incorporated additional analyses to examine different

[1][1] Order No. 37730 at 53-54.

time durations and confidence intervals. The TAP also indicated the prudency of the Company's proposal to transition to a reliability planning criteria that uses a new methodology that evaluates all hours of the year and chronological operations of the grid (Energy Reserve Margin).

On April 14, 2021, the Commission issued Order No. 37730 Directing Hawaiian Electric to File Revised Forecasts and Assumptions ("Review Point Guidance"), to address certain inputs and assumptions that warranted further discussion with stakeholders. Since April 2021, the Company has been engaged with stakeholders to address the remaining items highlighted in the Review Point Guidance. The 10 key areas include:[2]

(1) adjust resource/technology cost projections;
(2) adjust fuel price forecasts;
(3) adjust and better explain its DER and load forecasts;
(4) provide qualitative and quantitative summaries of LoadSEER findings and disaggregated location-specific load forecasts;
(5) provide the results of the probabilistic DER hosting capacity analysis from the Synergi circuit models;
(6) demonstrate how the probabilistic forecasts developed with LoadSEER will inform the different reference case load forecast scenarios to be established using the "bookends" approach;
(7) develop a retirement schedule for the baseline forecast;
(8) further develop and clearly explain its modeling sensitivities;
(9) better explain and analytically support its grid services and planning criteria; and
(10) work with AEG to develop modeling inputs for energy efficiency.

Section 2 of this document describes the approximately 17 stakeholder meetings held since the issuance of the Review Point Guidance, including a summary of areas of consensus reached to modify the I&A consistent with the Review Point Guidance, and areas where stakeholders may disagree with the Company's decision on certain inputs or assumptions. In total, the Company and stakeholders have logged over 34 hours of engagement since April 2021, with deep and detailed engagement from the Stakeholder Council, TAP, and STWG. In addition to the Commission Staff, other parties to this docket have significantly contributed, including, the Consumer Advocate, Ulupono, Life of the Land, Blue Planet Foundation ("Blue Planet"), DER Parties, and Progression Hawaii Offshore Wind. Along with the many formal meetings, subsequent follow up discussions have taken place, email correspondence to exchange data and information, which in sum, has shaped the revised I&A.

[2] Review Point Guidance at pages 51–52.

As noted in the Company's updated workplans filed on June 18, 2021, and July 28, 2021 in this docket, some items cannot be completed until certain inputs and assumptions are finalized or otherwise require more time to develop. Specifically, the summaries of LoadSEER findings and disaggregated location-specific load forecasts (item 4, above), demonstration of how the probabilistic forecasts developed with LoadSEER will inform the different reference case load forecast scenarios (item 5), analytical support for grid service and planning criteria (item 9), and development of energy efficiency supply curves with AEG (item 10). These remaining items are expected to be filed along with the Grid Needs Assessment deliverable Review Point by October 1, 2021.

Regarding LoadSEER location specific forecasts, in order to meet the October 1st deadline, the Company will use the current high and low bookend forecasts described in this document, which have been vetted through stakeholders, to develop the location specific forecasts. Modifications to any of the forecasts submitted as part of this August I&A Update may require more time to re-run LoadSEER models and subsequent analyses.

Regarding the planning criteria, the Company will continue to engage the TAP and seek their independent review on the reasonableness of the long-range planning criteria for IGP purposes. Long-range reliability planning criteria may be applied at a more coarse level than analyses used to evaluate short-term reliability needs. The Company has already started this process, with the filing of the TAP's independent review on June 1, 2021 of modeling methods, which included a review of the IGP modeling framework and tools, allowing RESOLVE to optimize energy storage paired with solar, the recommended approach to support the energy reserve margin planning criteria, and the provision of "virtual" inertia from inverter based resources. As discussed at the June 23, 2021 Stakeholder Council meeting and subsequent smaller group meetings, the Company is currently transitioning the TAP leadership to a new Chair and reviewing the core membership of the TAP in response to the Review Point Guidance to add a TAP member. Once a new TAP chair is selected, the TAP will resume its planned activities. The Company is actively working with stakeholders, including Commission Staff on modifications to the TAP.

As the Commission noted in its Review Point Guidance, "there is inherent uncertainty in predicting the future, so it is impossible to determine the accuracy of a forecast result a priori."[3] Accordingly, and consistent with Commission guidance, the Company has strived to employ best practices, focus on stakeholder engagement, develop appropriate scenarios and

[3] Order No. 37730 at 54–55.

sensitivities, and demonstrate forecasting rigor and reasonableness through transparent justification of their forecast to stakeholders and the Commission.[4]

The Company believes that the stakeholder engagement activities since April 2021 have substantially improved the IGP inputs and assumptions. As such, the IGP process is now well positioned to identify near-term and long-term grid needs portfolios that will provide a range of options to assist the Company, stakeholders, and Commission to make informed decisions on solution sourcing. The inputs and assumptions are designed to have the support of stakeholders that have been involved in the process as a substantial majority of the changes described herein are responsive to stakeholders and the Review Point Guidance. The Company looks forward to Commission acceptance of the forecasts, inputs and assumptions so that the modeling work to identify grid needs can start in earnest. Through Stakeholder Council and working group discussions, stakeholders are also eager to move forward with the next phases of the IGP process and start the process of modeling analysis.

[4] Id.

# 2 Stakeholder Engagement

The IGP stakeholder engagement plan has been a significant undertaking for the Company as well as stakeholders with a proactive engagement approach to attain:

- Constructive and long-term working relationships with stakeholders;
- Stronger communication and transparency between parties, regulators, and the utility;
- Building of common ground on key issues and common vocabulary;
- More efficient and streamlined regulatory proceedings related to grid planning;
- Stakeholder feedback to incorporate into the development of planning inputs, assumptions, methodologies, and processes; and
- Transparency, predictability, and buy-in from different interested parties.

As the Company's December 2018 IGP Workplan[5] described, seven working groups would be assembled in 2019 to address key areas of development that would shape the inputs, assumptions, and methods to integrate resource, transmission, distribution planning to produce a stakeholder driven long-term resource plan that meets the needs of customers and state policy objectives. The seven working groups each had a clear set of objectives and deliverables as outlined in the Workplan and working groups. Those objectives and deliverables were re-affirmed at the November 7, 2019 stakeholder council meeting[6] in response to the Commission's guidance provided on November 4, 2019 through Order No. 36725 in Docket No. 2018-0165. On November 5, 2020 the Commission issued Order No. 37419 in Docket No. 2018-0165, Providing Guidance, in it the Commission reiterated the importance of stakeholder input to the planning process, which included proactively seeking stakeholder feedback, and allowing stakeholders the time and resources to provide meaningful feedback, and incorporating feedback in the IGP deliverables.

Subsequently, on January 19, 2021, the Company filed its Inputs and Assumptions with the Commission, a culmination of nearly two years of working group, Stakeholder Council, and TAP meetings.

On March 4, 2021, the Company filed a Stakeholder Feedback Summary document summarizing the key themes from the various stakeholder groups,

---

[5] Integrated Grid Planning Workplan filed in Docket No. 2018-0165 on December 14, 2018 ("Workplan").

[6] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/stakeholder_council/20191107_sc_meeting_presentation_materials.pdf

including areas where the Company directly incorporated stakeholder feedback in the areas of transparency, resource costs and options, renewable resource potential, high and low bookend sensitivities, and generating unit retirements.

## 2.1 FORECAST ASSUMPTIONS WORKING GROUP

The Forecast Assumptions Working Group ("FAWG") was stood up in March 2019 with the primary role to provide strategic inputs and feedback on assumptions and methodologies used for load forecast development and results.

The FAWG supported development of forecast assumptions and sensitivities as part of the pre-IGP planning cycle activity and provides strategic inputs and feedback on assumptions and methodologies used for load forecast development and results. The FAWG structure and level of engagement was one of the most proactive in the industry to-date combining industry experts for best practice validation and resident Hawaii experts representing their respective contributions on economic outlook, energy efficiency potentials and program roadmaps, and transportation electrification. This was in addition to engaging a broad set of stakeholders in the FAWG and with the Stakeholder Council and TAP.

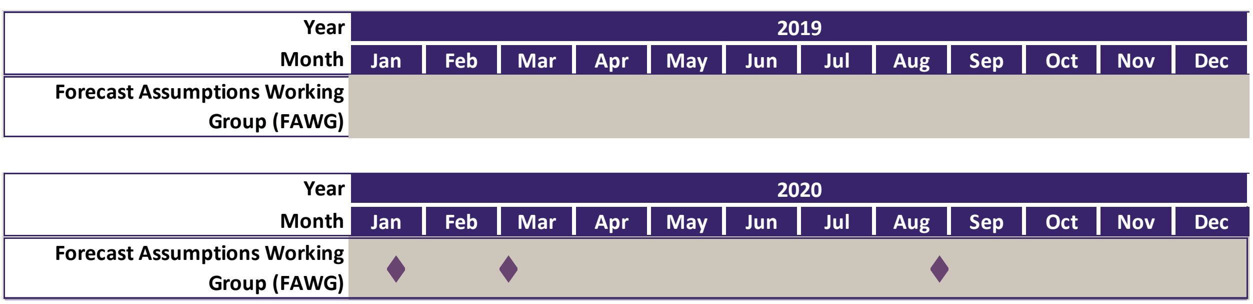



Figure 2-1: FAWG Meetings

The FAWG engaged 18 different organizations and 26 different individuals and various docket intervenors during the stakeholder engagement process. The FAWG met with stakeholders eight times (including a two-day meeting in May 2019) before finalizing the forecast. The forecast assumptions[7] informed by FAWG stakeholder input was presented to the FAWG on January 29, 2020 and

[7] FAWG draft IGP Inputs and Assumptions: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20200925_draft_IGP_inputs_and_assumptions.pdf

included the Applied Energy Group ("AEG") Energy Efficiency Potential Study,[8] Distributed Energy Resource forecasts,[9] Electrification of Transportation Forecast,[10] and a Behind the Meter (BTM) Solar Photovoltaic (PV) and Battery Energy Storage System (BESS) forecast.[11] The load forecast with these layers was presented to the FAWG on March 9, 2020.[12] Additionally, resource related inputs were shared with the FAWG including the Fuel Forecast[13] and Resource Cost forecast.[14] The FAWG reconvened on August 31, 2020 to review updates to the forecast based on near-term economic impacts forecasted by UHERO[15]

---

8 AEG Hawaii Statewide Market Potential Study (PDF): https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20200129_wg_fa_hawaii_market_potential_study_draft_results.pdf

9 IGP DER Forecast – Oahu (EXCEL) – https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/HE_DER_forecast_IGP.xlsx; IGP DER Forecast – Hawaii (EXCEL) – https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/HL_DER_forecast_IGP.xlsx; and IGP DER Forecast – Maui (EXCEL) – https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/ME_DER_forecast_IGP.xlsx

10 IGP EoT Forecast (EXCEL) – https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/EoT_forecast_IGP.xlsx

11 IGP BTM PV_BESS Cost Forecast (EXCEL) – https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/BTM_PV_and_paired_BESS_cost_forecast_IGP.xlsx

12 March 9, 2020 forecast presentation (https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20200309_wg_fa_meeting_presentation_materials.pdf) and Forecasts by layer: Hawaiʻi Island (EXCEL) – https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/hawaii_island_IGP_forecast_by_layer.xlsx; Maui, Molokaʻi, and Lanaʻi (EXCEL) – https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/MECO_IGP_forecast_by_layer.xlsx; and Oʻahu (EXCEL) – https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/oahu_IGP_forecast_by_layer.xlsx

13 IGP 2020 Fuels Forecast (EXCEL) https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/solution_evaluation_and_optimization/20200420_wg_seo_igp_2020_fuels_forecast.xlsx

14 Resource Cost Summary (Updated September 7, 2020) (EXCEL) https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/solution_evaluation_and_optimization/20200717_wg_seo_resource_cost_forecast.xlsx

15 UHERO Presentation (PDF) – https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20200831_wg_fa_meeting_presentation_materials_UHERO.pdf

as a result of the COVID-19 pandemic and effect on the forecasted sales and peak forecast.[16]

The Company summarized and submitted much of the forecast and planning input information to the Commission on July 2, 2020 in response to the Commission's June 8, 2020 information request.[17]

The TAP's independent review of the Company's I&A Review Point filed on January 19, 2021 indicated general agreement with the Company's forecast development and methodologies. However, the TAP recommended several improvements, which the Company has addressed as described in this document:

- Hawaiian Electric should consider testing the sensitivity of models and resulting portfolios by running bookend scenarios that utilize the cumulative potential high and low load forecasts for each layer.
- Hawaiian Electric should ensure that subsequent modeling tasks include sensitivities for time-of-use flexibility and/or random variation in the daily load profiles of DER and EV loads, rather than using a static load profile across modeling tasks.
- Hawaiian Electric should consider using a wider range of future energy efficiency and EV adoption rates due to the high uncertainty, especially beyond year 10. The TAP noted that proposed retirement of thermal units might be impacted by this uncertainty

[16] August 31, 2020 Forecast Assumptions Presentation: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20200831_wg_fa_meeting_presentation_materials_HECO.pdf; and notes including stakeholder feedback and questions: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20200831_wg_fa_meeting_summary_notes.pdf Hawai'i Sales and Peak Forecast (EXCEL) – https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/hawaii_sales_and_peak_FAWG.xlsx; O'ahu Sales and Peak Forecast (EXCEL) – https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/oahu_sales_and_peak_FAWG.xlsx; Maui, Moloka'i, Lana'i Sales and Peak Forecast (EXCEL) – https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/maui_sales_and_peak_FAWG.xlsx

[17] See Docket No. 2018-0165.

## 2.2 2021 STAKEHOLDER MEETINGS

The Company executed its stakeholder engagement plan[18] to meaningfully seek and incorporate stakeholder feedback through a number of different avenues. The Company appreciates the additional feedback and input from the Commission, TAP, and stakeholders subsequent to the Review Point Guidance. The Company held several meetings with stakeholders to listen and seek consensus on addressing the remaining items and provide clarity or further explanation on certain topics. The Stakeholder Working Group ("STWG") meeting materials and meeting notes referenced below are posted on the Company's website and may be accessed at: https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/stakeholder-technical. A summary of the Company's stakeholder engagement efforts included:

- On April 27, 2021, the Company convened a working group meeting to discuss the four modeling methods proposed by Ulupono Initiative ("Ulupono").[19] Through robust stakeholder discussion on the issues, including a presentation by Ulupono, the Company came to a consensus agreement with Ulupono and other stakeholders on recommendations to address the methods proposed by Ulupono.
- On May 25, 2021, the Company met with the TAP to discuss the recommendations resulting from the April 27, 2021 meeting. The TAP subsequently filed their independent review on June 1, 2021, which generally concurred with the modeling method recommendations.
- On May 20, 2021, the Company officially stood up the STWG to streamline and consolidate the previous working group structure.[20] The STWG will be called upon as the Company advances through the next couple of phases of the IGP process, including responding to the Review Point Guidance, input on the upcoming grid needs assessment step, and other work products for which the Company seeks stakeholder feedback.
    - Four working group agendas were sent out to working group members laying out objectives, key questions, topics to discuss,

[18] Hawaiian Electric Updated Timeline and Stakeholder Engagement Plan filed on June 18, 2021 in Docket No. 2018-0165.

[19] Review Point Guidance at pages 37-39.

[20] Combines the Forecast Assumptions, Competitive Procurement, Distribution Planning, Grid Services, and Solution Evaluation and Optimization Working Groups. The Standardized Contracts Working Group has completed its work for its specific task. The Resilience Working Group will continue as a separate working group.

and expected deliverables intended to address the Review Point Guidance. The Company also sought comments from stakeholders on agenda items and called on stakeholders to present on any topic of interest. No comments were received on the agenda and two stakeholders offered to present regarding DER forecasts and electric vehicles.

- On June 2, 2021 the Company convened the first STWG meeting to discuss the purpose and objective of each model being used in the grid needs assessment phase, RESOLVE day weight and day sample methodology, the TAP recommendations based on their review of the Ulupono modeling methods and planning criteria recommendations, DER forecasts, and bookend scenarios.
- On June 4, 2021 the Company participated in a PUC technical conference facilitated by Rocky Mountain Institute and discussed with stakeholders four key areas: energy efficiency, resource and fuel cost forecasts, DER and Load forecasts, and planning criteria. The technical conference led to foundational understanding of the Company's and different stakeholders' perspectives on certain topics, all of which would subsequently be discussed in more detail to reach consensus through the STWG meetings.
- On May 20, June 1, July 2, and July 16, 2021, the Company met with Applied Energy Group, 2050 Partners, and Hawai'i Energy to discuss the data needed to model energy efficiency on a comparable basis to other supply side options. The State of Hawai'i energy efficiency potential study would need to be updated to model energy efficiency on the supply side; however, the current study represents 85-90% of the work that would be needed to develop the supply curves.
    - Applied Energy Group, 2050 Partners, and Hawai'i Energy noted that this was not part of their current scope of work and funding would be needed to develop the specific modeling inputs.
    - The Company worked with AEG to refine the scope of work, schedule, and budget to develop energy efficiency supply curves. On July 28, 2021, the Company filed a letter in this docket updating the Commission on the status of this work, including the scope and schedule to develop energy efficiency supply curves.
- On May 27, 2021, the Company and Ulupono met to discuss the fuel price and resource cost forecasts.
    - For the fuel price forecasts, comparisons between the FGE and EIA forecasts were shared. In discussing the merits of both

forecasts, one suggested approach was to use the EIA reference as a high forecast and the FGE forecast as the low forecast if there was a wide enough spread between the two forecasts. There was general agreement that the EIA high forecast was not reasonable. However, based on additional analysis, Ulupono currently recommends using the Reference, High Oil Price and Low Oil Price forecasts from the EIA Annual Energy Outlook. Ulupono found that actual oil prices often reach the edges of EIA's range despite a significantly wide gap between the base and high forecast.

  - The Company provided the historical record of FGE forecasts and EIA forecasts to compare their long-term outlook performance against actuals.
  - For the resource cost forecasts, comparisons between the IHS based and NREL ATB based forecasts were shared. It was noted that the near term levelized costs for PV-storage was higher than recent procurements. The Company and Ulupono agreed to reconcile the forecasts by aligning the near-term forecast in real dollars to actual projects (i.e., Stage 1 and 2 solar paired with storage projects), then allow the forecast trend to determine the future costs according to the NREL ATB cost trends.
- On June 17, 2021, the Company convened the second meeting of the STWG to further explore issues raised in the Review Point Guidance in a collaborative fashion with stakeholders. More specifically, the STWG continued discussion regarding updated DER forecasts, including assumptions for best estimates of the tariff and program values for DER, EE and EoT. The STWG also conducted a deep dive into the LoadSEER and Synergi models including further disaggregation of forecasts by location and rate class and how LoadSEER is used to inform DER forecasts; discussion of EV managed and unmanaged charging assumptions, including a presentation by Blue Planet regarding legislative updates on EVs in Hawaii and how other jurisdictions account for EVs in their integrated grid planning; discussion of hourly charging profiles for managed charging and associated assumptions; and discussion of efforts to finalize the inputs and assumptions on bookend sensitivities.
- On June 18 and June 23, 2021, the Company met with the Stakeholder Council to review key inputs and assumptions, including the resource and fuel forecasts, planning assumptions surrounding generator deactivations, modeling scenarios and sensitivities, and updates to the

NREL solar and wind potential study. Ulupono also provided a presentation of their own modeling for plans on O'ahu that would minimize the use of agricultural land. The Stakeholder Council sought clarification on the inputs and assumptions discussed.

- There was robust discussion regarding the availability of Department of Defense/Federal lands for renewable generation development. Stakeholders noted that the availability of Federal lands are at the discretion of the Government and, if available, are provided on a highest and best use policy. The cost of the land is likely to be high.[21] Other stakeholders noted that the solar potential assumptions are overly optimistic based on experience working with land owners and communities.
- At the conclusion of the Stakeholder Council meetings regarding the inputs and assumptions, the Company committed to continuing to work closely with Ulupono, Blue Planet Foundation, DER Parties, among others that are members of the Stakeholder Council and actively engaged in the working group process to review the inputs and assumptions.

- On July 9, 2021, the Company met with a smaller group of stakeholders with a keen interest in the bookend assumptions. The Company updated stakeholders on preliminary updated forecast layers and development of high and low forecasts for EE, PV, and EV based on the feedback received at the June 17, 2021 STWG meeting.
- On July 14, 2021, the Company convened a third STWG meeting to review the updated DER layer forecasts, a review of the inputs for each scenario and sensitivity, a review of generating unit deactivation or retirement assumptions, and a review of the minimum inertia assumption in RESOLVE initially discussed at the April 27, 2021 working group meeting.
- On July 16, 2021, the Company convened a fourth STWG meeting to review the resource cost and fuel cost projections raised in the Review Point Guidance and at the June 4 technical conference, updated NREL Resource Potential scenarios consistent with the feedback provided by Ulupono, and a review of the transmission needs analysis methodology to determine the cost and upgrades needed to develop renewable energy zones.

---

[21] See June 23, 2021 Stakeholder Council Meeting notes at pages 4-5. (Available at, https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/stakeholder_council/20210623_sc_meeting_summary_notes.pdf)

- On July 27, 2021, the Company held follow up discussions with Blue Planet, among others, regarding the appropriate high EV forecast for low density vehicles to use. The details of those discussions are provided in the following section on areas of disagreement.
- On July 29, 2021, the Company continued discussions with interested stakeholders on the concept of import/export parity and how future fuel prices could be affected by the closure of the local refineries. An agreement was reached between the Company and stakeholders, which is more fully described in the following sections related to stakeholder areas of consensus and disagreement.

## 2.3 STAKEHOLDER AREAS OF CONSENSUS

The Company worked in a collaborative fashion with stakeholders to address the Review Point Guidance. Through the engagement process the Company sought areas of consensuses with stakeholders on the various issues. The following summarizes stakeholder feedback that was directly incorporated into the revised Inputs and Assumptions. Further details in each of these areas are described in specific sections throughout this document.

### *Resource and Technology Cost Projections*

- Calibrate resource and technology cost projects establishing near-term pricing on recent renewable projects using long-term trends based on NREL ATB.
    - Recent projects used in the calibration include, Stage 1 and 2 solar paired with BESS projects, West Loch Solar, Na Pua Makani Wind farm.
    - Resource cost projections do not include land and interconnection costs; however, pricing of recent projects used to calibrate the resource cost forecasts are assumed to contain land and interconnection costs as part of their PPA terms – the company does not have insight into what portion of the PPA price is attributed to interconnection or land costs. However, to help mitigate this issue, using the PPA pricing terms was applied consistently across all resource cost projections.
- Update cost projections with the recently released 2021 NREL ATB costs

- Add a pump storage hydro resource cost projection using the 2021 NREL ATB and studies cited therein

### *Fuel Price Forecasts*

- Switch from FGE Brent fuel forecast to a 2021 EIA reference fuel forecast as the base assumption
- Add a 2021 EIA low fuel price forecast; however, currently there are no sensitivities planned to use the low fuel price forecast
- Add a 2021 EIA high fuel price forecast, recognizing there is disagreement in the validity of EIA's high scenario. However, the Company and stakeholders do agree that the EIA high fuel price forecast should not be used as the base fuel assumption but that it is useful to evaluate a potential worst case fuel price and its impact on the resource plan

### *DER and Load Forecasts*

- Develop bookends (i.e., a high and low) for each technology layer (EE, EV, DER)
- The EE forecasts will utilize data from the State of Hawaii Market Potential Study[22]
    - Base: Business as usual plus codes and standards. This forecast will remain unchanged;
    - Low: Business as usual only;
    - High: Achievable high plus codes and standards forecast.
- The base electric vehicle forecast will remain unchanged. Blue Planet suggested using a 100% zero emission vehicle by 2045 forecast for the high EV forecast and to incorporate assumptions on the light duty vehicle forecast from the Transcending Oil Report and/or a Blue Planet generated forecast based on last 5 years registered vehicle counts. The Company will use the Transcending Oil Report's EV forecast for the high EV bookend. As explained below, Blue Planet expressed a preference for their forecast over the Transcending Oil report's forecast.
- The unmanaged EV Charging Profiles will be updated based on Hawaii specific data from the Company's DC fast charging network and a case study conducted through deployment of EnelX's Level 2 chargers in Hawaii.
- The EV managed charging system profiles have also been updated. Commission Staff raised during a STWG meeting that the managed profiles appeared fairly flat, expecting more load shifted to the daytime.

[22] Available at, https://puc.hawaii.gov/wp-content/uploads/2021/02/Hawaii-2020-Market-Potential-Study-Final-Report.pdf

Upon further review, the Company's consultant found that their model should have shifted more load to the daytime. The models were re-run and resulted in new managed EV charging shapes with more load shifted to the daytime.

- The Company modified the base customer solar and battery storage forecast to include updated system cost projections, tax credit assumptions and future DER program export rates based on the DER docket proceeding. In the case of O'ahu and Maui, additional changes included increasing the addressable market by including NEM customers for a limited time window, including Emergency Demand Response Program ("EDRP") and long-term upfront incentives for grid services program participation.
- The Company developed a high customer solar and battery energy storage forecast by adjusting the following adoption drivers: adding a long-term upfront incentive based on the DER docket proceeding, adding NEM customers back to the addressable market pool, extending federal tax credits, increasing addressable market (i.e., from 2-4 multi-unit dwellings to 2-49 multi-unit dwellings, commercial expansion of Rate Schedule P customers to 100% of customers), and assuming lower DER system costs.
- Re-purposed the previous base or market forecast based on self-consumption with updated system cost and tax credit assumptions to be the part of the low DER forecast.
- Addition of a time-of-use ("TOU") layer that represents non-DER and EV customer participation

### *LoadSEER Findings and Forecasts for Bookends*

- LoadSEER used to develop circuit-level forecasts consisting of new loads/demand and DER.
- LoadSEER is currently used on O'ahu to inform the Hosting Capacity Analysis.
- Company confirmed bookend Corporate forecasts will be used to develop location-based forecasts at the circuit level, and analyzed to determine how the High-DER and Low-DER forecasts impact grid needs.

### *Hosting Capacity Analysis*

- Company currently undergoing Hosting Capacity Analysis with results included in this report.
- Analysis is done to determine if distribution circuits are able to accommodate the 5-year forecasted DER (based on Corporate forecast).

### *Retirement Schedules*

- Proposed starting point planning assumptions for when units would no longer be dispatched (or deactivated or retired).
- High fuel sensitivity will be run, and allow RESOLVE to make economic-driven retirement decisions
- Addition of updated capital and operations and maintenance costs to upkeep O‘ahu generating units for the foreseeable future.

### *Modeling Sensitivities*

- Clarified modeling scenarios and sensitivities and associated inputs
- Added a high fuel sensitivity
- Stakeholders suggested that the bookend scenarios should be based on the lowest and highest possible demand. The resulting resource portfolios would inform, for example, whether the resource mix changes dramatically between bookends. If the same types of resources are selected, then perhaps we do not need to focus so much time on individual layers, e.g., increased EV uptake.
- Added similar DER Freeze cases for the other customer forecast layers to be used to approximate valuation of programs. These sensitivities can be conducted as part of the solution sourcing process to design programs.

### *Energy Efficiency*

- Incorporate energy efficiency as a supply-side resource. The Company will work with AEG to develop the appropriate supply curves, leveraging the State of Hawaii Market Potential Study.

### *NREL Resource Potential and Renewable Energy Zone*

- Use the updated solar and wind potential based on input from Ulupono. This includes allowing solar development on up to 30% sloped land and exclusion of Federal Department of Defense land based on stakeholder discussions.
- Additional sensitivity using a lower solar potential based on limited land availability
- Consider transmission needs to interconnect offshore wind locations based on the NREL offshore wind report
- Community engagement is needed early in the process to communicate additional transmission needs

### *Inertia Requirement*

- Despite the negligible cost difference[23] in resulting plans with and without the minimum inertia requirement modeled in RESOLVE, the Company will remove the minimum inertia requirement from the RESOLVE optimization as to not limit or bias resources that can be selected to fulfill various grid services.
- Inertia needs will be verified in the system security step of the process. This may increase the modeling iterations that are needed to ensure grid needs are adequately met.

## 2.4 STAKEHOLDER AREAS OF DISAGREEMENT

### *High EV Forecast*

Following the June 17, 2021 STWG meeting, Blue Planet provided two additional sources of information on June 29, 2021, to inform their suggested sensitivity representing a policy of 100% zero emissions vehicles by 2045 in the high customer technology adoption bookend. The first was the Transcending Oil Report prepared by the Rhodium Group in 2018.[24] The second was Blue Planet's self-developed estimate using the State Energy Office's Monthly Energy Trends data and a regression for the past 5 years on electric vehicle registrations. Saturation curves were developed using the data provided by the Transcending Oil Report and Blue Planet's estimate.

At a July 9, 2021 meeting with a smaller group of stakeholders, the Company commented that the data provided in the Transcending Oil Report provided a fuller set of assumptions to develop a forecast while Blue Planet's estimate could be further supplemented with data on scrappage rates or number of years that drivers retain their vehicles and the total vehicle count assumed to develop proper saturation curves. In reviewing the preliminary saturation curves, the Company noted that the Transcending Oil curve was a better candidate for the high bookend because it tracked above the base forecast. The Blue Planet curve overlapped with base forecast through the first 10 years and would not be as informative as a bookend and the Company inquired if curves could be provided for each island.

---

[23] *See* July 14, 2021 STWG Meeting Presentation at pages 26-28, available at: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/igp_meetings/20210714_presentation_slides_igp.pdf

[24] *See* Transcending Oil Report by Rhodium Group available at: https://rhg.com/wp-content/uploads/2018/04/rhodium_transcendingoil_final_report_4-18-2018-final.pdf

On July 27, 2021, the Company and Blue Planet met to further discuss Blue Planet's 100% ZEV forecast. Given the original forecast provided by Blue Planet was at the State-level, the Company requested if individual island saturation curves could be provided. On July 29, 2021, Blue Planet provided updated electric vehicle saturation forecasts for O'ahu, Maui, and Hawai'i Island. Blue Planet explained that data was not provided for Moloka'i and Lāna'i because the State Energy Office's Monthly Energy Trends data does not include registered electric vehicle counts for Moloka'i and Lāna'i. Data would also need to be provided for Moloka'i and Lāna'i to develop a high bookend for those islands. Because the additional data was received from Blue Planet late in the process, the Company was not able to both develop forecasts using the data and vet the resulting forecasts with the broader stakeholder groups. However, as shown in Figure 2-2 through Figure 2-4, the Transcending Oil Report's saturation curve captures the feedback provided by Blue Planet within its bounds and was adopted for the high EV bookend.

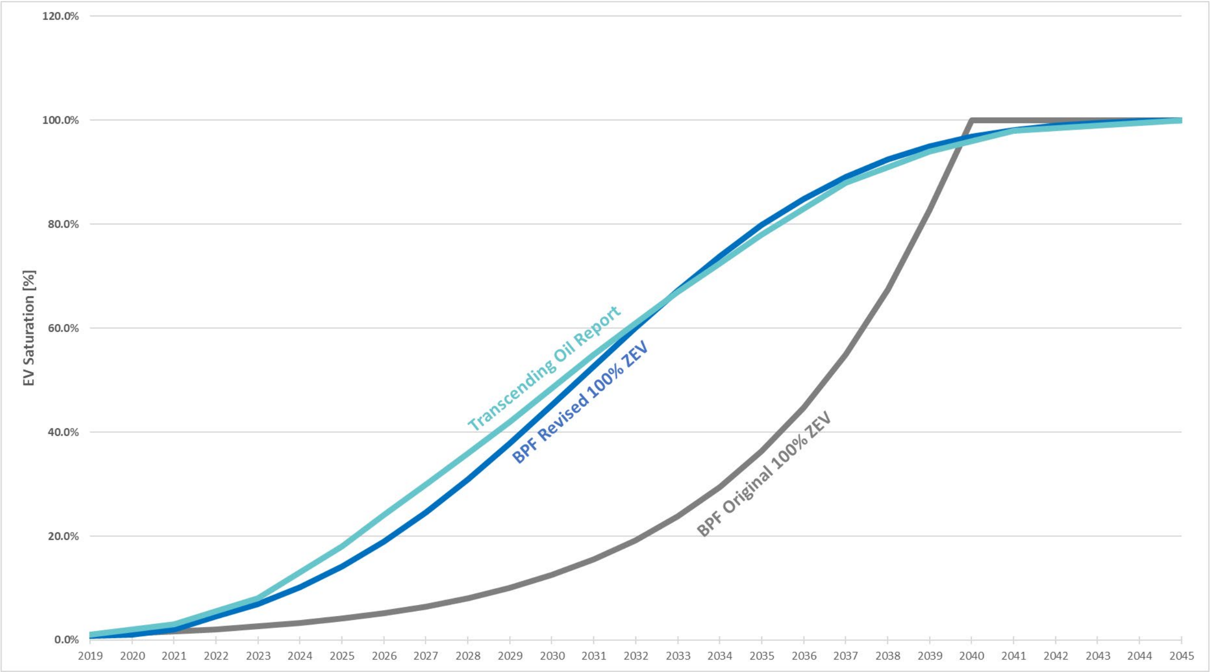



Figure 2-2: O‘ahu High EV Bookend Sensitivity Comparison

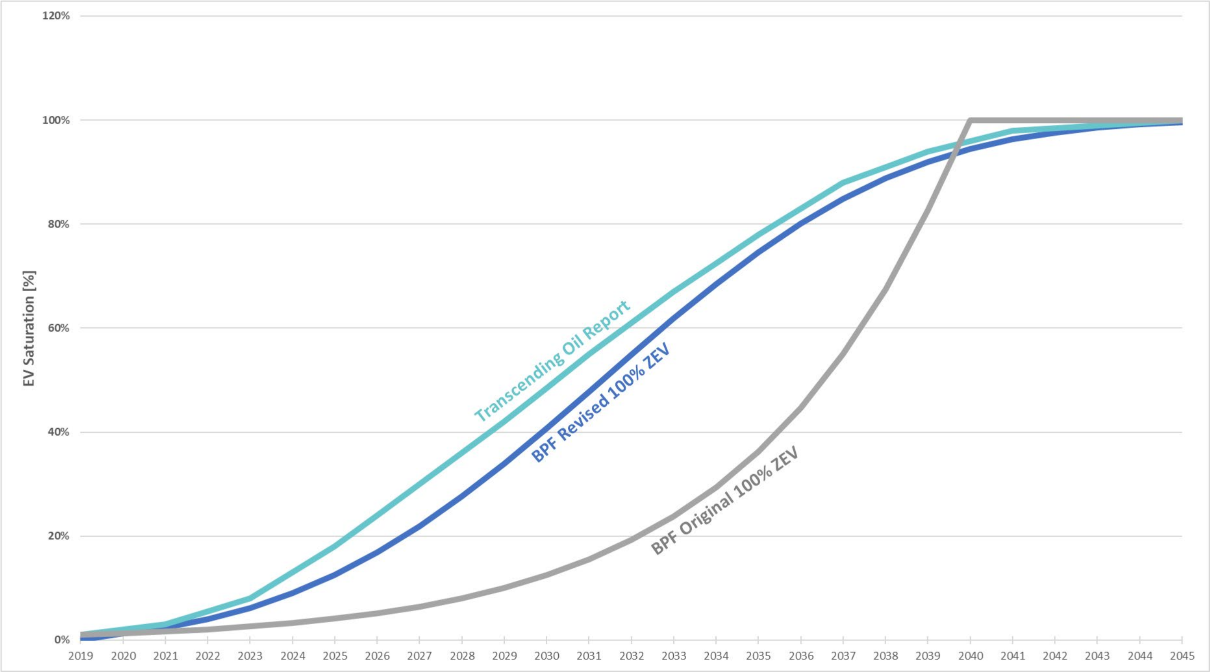



Figure 2-3: Maui High EV Bookend Sensitivity Comparison

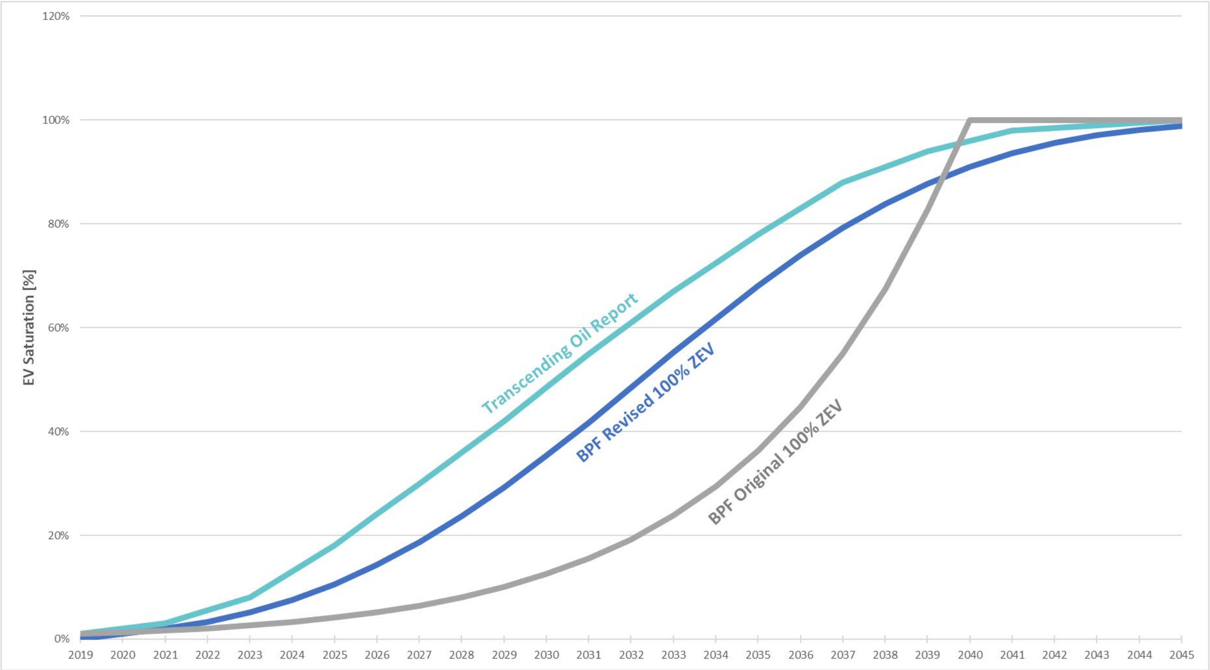



Figure 2-4: Hawai'i Island High EV Bookend Sensitivity Comparison

## *Grid-scale Solar and Wind Potential*

On the developable resource potential for onshore grid-scale PV and wind, the Company received stakeholder feedback that Federal contracting rules would require that the Department of Defense ("DoD") seek the highest and best use for properties under their control, in addition to deciding whether that land would be made available for renewable energy development. Because of this circumstance, it would be difficult to make a blanket assumption that all DoD lands are available to develop. Further, stakeholders raised concerns on the ease of developing projects at slopes higher than 10% due to the additional work and cost involved. However, other stakeholders felt that higher slopes could be developed, up to 30%, with some additional cost adder. Because some projects have already been developed on steeper slopes, the Company is moving forward with excluding DoD lands but including slopes up to 30%. In addition to this base assumption, a Land Constrained scenario will be developed to test the possibility of future limited land availability for solar, wind, and biomass development and provide a meaningful bookend of analysis that incorporates stakeholder feedback to assume a lower amount of land is available for project development.

## *Fuel Forecasts*

On the fuel price forecasts, the Company views the high fuel price forecast using the EIA AEO high scenario as unrealistic because fundamentally, it assumes that high oil prices are sustained across the entire planning horizon. Historically, actual Brent prices have breached the EIA high fuel price forecast at points in time but not in every year. The FGE fuel price forecast is a more accurate forecast of future fuel prices because it accounts for the tendency for the fuel prices to regress to the mean and for political drivers that can affect fuel prices.

The Company continued discussions with interested stakeholders on the concept of import/export parity and how it could affect the fuel price forecasts. Import parity is the price that a purchaser can expect to pay for an imported product (cost at market + freight + handling fees). Similarly, export parity is the price that a producer can expect to receive if its product were exported (cost at market – freight – handling fees). Import and export parity prices can be used to define a range of expected prices for a locally produced good. If there are multiple producers in the local market then the pricing is likely going to be closer to the export parity since neither producer will want to pay the cost of exporting their product. Similarly, if there is only one producer in the local market then the pricing is likely going to closer to import parity since the purchaser wouldn't want to pay the cost of importing the product on their own.

As shown in Figure 2-5 below, in recent history, the estimated cost impacts if fuels were to be imported (higher dashed line) or exported (lower dashed line) represents the range of prices that constrain future fuel contract pricing. The higher dashed line represents the threshold price above which the Company is better off importing fuels instead of buying from Par (import parity) and the lower dashed line represents the threshold price below which Par is better off exporting their fuels instead of selling to the Company (export parity). The import / export adder varies due to the cost of freight and recent Interation Maratime Organization ("IMO") regulations but generally is within the range of $4 - $6 per barrel. Par would want to sell to the Company at a cost based on the index plus an adder for freight and other considerations that remains just below the higher dashed line for import parity.

Under the latest amendment, the import cost could be as low as $2 - $3 per barrel if the Company were to decide to import. When there was more competition for the previous agreement, the pricing was as high as $10 - $12 per barrel below import parity. The Company was already paying close to import parity prior to 2015 and those data points are included in the regression that was performed to develop the fuel price forecasts.

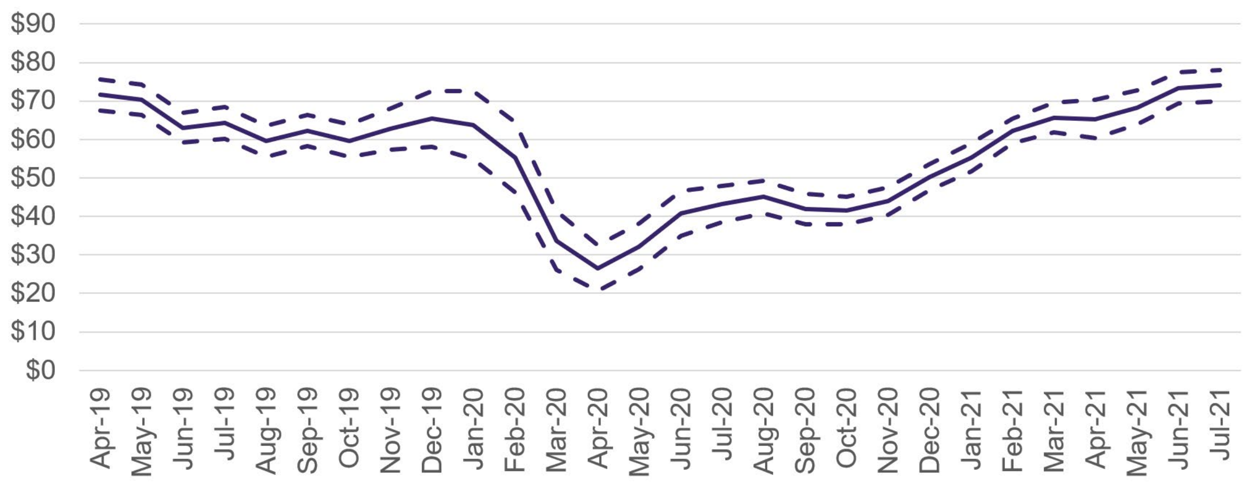



Figure 2-5: Fuel prices with estimated import / export adder

The historical purchase volume for LSFO is shown below in Figure 2-6. Prior to 2015, the Company was buying from both refineries, Chevron and Tesoro. After 2015, the Company was able to negotiate a lower cost contract because the two refineries had to compete for the Company's demand for LSFO. However, now only one refinery remains. Refining margins decreased everywhere due to COVID-19 and are not expected to vary regionally between Hawaii and the mainland since fuel can be transported. However, the Par refinery on the west coast does have access to lower cost crude which may affect margins compared to other parts within its business.

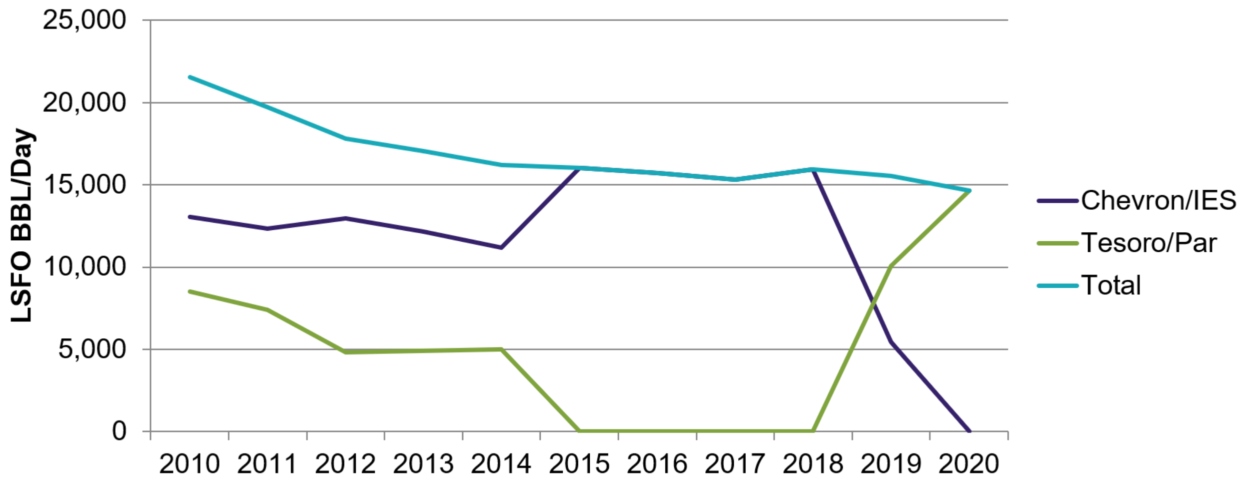



Figure 2-6: Historic LSFO Purchase Volume

In response to the Commission's Review Point Guidance, and Ulupono's position, the Company will adopt the EIA AEO reference, low and high forecasts. The intent is to examine worst case and best case scenarios and not weight resource plans that were developed using the EIA high and low fuel price forecasts because of concerns raised that the EIA high forecast is assumed to be a high fuel price that is sustained through the planning period and is much higher than historical actuals for Brent on the order of a 100% increase. With the large range between the EIA low and EIA high forecast, any scenario for a refinery shutdown and import option is covered by that spread.

## 2.5 PARKING LOT FOR ISSUES TO BE RESOLVED IN FUTURE PLANNING CYCLES

Through its latest round of stakeholder engagement, the Company established a parking lot list of items that were raised during stakeholder discussions that are worthy of consideration in future IGP cycles. The Company will continue to explore these areas with stakeholders; however, resolving these issues prior to starting the Grid Needs Assessment in this first IGP cycle, and therefore delaying the finalization of the inputs and assumptions does not outweigh its benefits. In some cases, the state of technology or modeling tools are areas that are still in development within the industry which also inhibits the ability to define modeling inputs to properly characterize the technology. It can be expected that more clarity in the future will allow for better incorporation into the IGP process. Additionally, data required to address some of parking lot items may not currently exist and require further evaluation on the viability and methodology of implementation in future IGP cycles. For example, the Company would need to better understand from stakeholders the intent, objective, and value of separating DER Schedule-R forecast with the current limited data availability. Included below is a list of "parking lot" items thus far. The Company will continue to maintain this list as it progresses through the rest of the steps in the IGP process.

- Separating DER Schedule-R forecast into individual customer types:
    - Single Family Residences
    - Multi-Family Residences
    - Rentals
- Incorporating LoadSEER needs directly into RESOLVE
- Modeling EVs as a selectable resource in RESOLVE
- Defining the services EVs can provide.
- Modeling EV as a selectable resource and V2G
- Medium and heavy duty electric vehicle forecast

# 3 Overview of the RESOLVE and PLEXOS Models

Hawaiian Electric will use the RESOLVE model to produce a reference optimized resource plan that is then verified in PLEXOS through an hourly production simulation to capture total system costs as part of the Grid Needs Assessment.

## 3.1 RESOLVE CAPACITY EXPANSION MODEL

RESOLVE is a mixed-integer linear optimization model that is explicitly tailored to the study of electricity systems with high renewable and clean energy policy goals. The optimization performed in RESOLVE balances the fixed costs of new investments with variable costs of system operations, identifying a least-cost portfolio of resources to meet planning needs across a long-term horizon.

RESOLVE can solve for:

- Optimal investments in renewable resources, energy storage, thermal generating units as well as retention of existing thermal resources.

Subject to the following constraints:

- An annual renewable energy constraint that reflects the State of Hawai'i's Renewable Portfolio Standards policy;
- An Energy Reserve Margin constraint to maintain adequacy of supply for reliability;
- Operational reserves for regulating reserve, and other flexibility services;
- Operational restrictions and performance characteristics for generators and resources;
- Hourly load requirements; and
- Constraints on the ability to develop specific new resources (timing and amount).

RESOLVE uses statistical sampling to downscale annual data to 30 representative days per year. These representative days are weighted based on historical data to capture operational costs under most conditions. In addition to the day sampling, resources with similar operating characteristics are aggregated to facilitate efficient solving for the optimized portfolio.

The day sampling algorithm is based on a mixed-integer linear program that allows selection of a sampled number of days using historical or synthetic timeseries data to find a subset of days that are representative of the long-run distributions for system load, wind, solar, and hydro conditions. The optimization model minimizes the absolute error between the overall distribution of data and the sampled distribution for the selected days.

For example, a common implementation of the day sampling algorithm is to have 30 sampled days and select one representative day for summer peak, winter peak, and each month-weekday/weekend combination. This results in 26 represented day types that will be included in the final sample. Once the day sampling processing has selected an initial set of 26 day types, the overall sampling algorithm is rerun to find an additional 4 days to reduce the overall absolute error and calculate weights for each of the selected days.

Historical data to be used for sampling includes:

- Gross Load
- Aggregate Solar
- Aggregate Wind
- Net Load

The representative days developed for the RESOLVE modeling, including their day weights and distributions, are provided below. For each island, comparisons of the representative days to the historical distribution are provided for net load below. Consistent overlap of the net load duration curves and bins within the histograms indicate that the days selected for the RESOLVE modeling are representative of the expectations for the year.

### *O'ahu*

Table 3-1: O'ahu Day Weights

| Model Day | Weight | Historical Day |
|---|---|---|
| 1 | 26.327 | 11/16/2016 |
| 2 | 20.132 | 8/8/2016 |
| 3 | 19.134 | 6/12/2016 |
| 4 | 18.757 | 5/30/2015 |
| 5 | 18.040 | 2/25/2016 |
| 6 | 17.242 | 3/4/2017 |
| 7 | 16.360 | 9/7/2015 |
| 8 | 16.312 | 1/31/2016 |

| Model Day | Weight | Historical Day |
|---|---|---|
| 9 | 15.927 | 12/1/2016 |
| 10 | | |
| 11 | 15.737 | 7/6/2017 |
| 12 | | |
| 13 | 14.913 | 12/3/2018 |
| 14 | | |
| 15 | 13.738 | 3/28/2016 |
| 16 | | |
| 17 | 12.282 | 10/26/2018 |
| 18 | | |
| 19 | 10.192 | 2/25/2018 |
| 20 | | |
| 21 | 9.394 | 8/17/2017 |
| 22 | | |
| 23 | 7.679 | 9/4/2016 |
| 24 | | |
| 25 | 5.941 | 9/10/2018 |
| 26 | | |
| 27 | 2.654 | 11/23/2018 |
| 28 | | |
| 29 | 1.175 | 12/10/2017 |
| 30 | | |

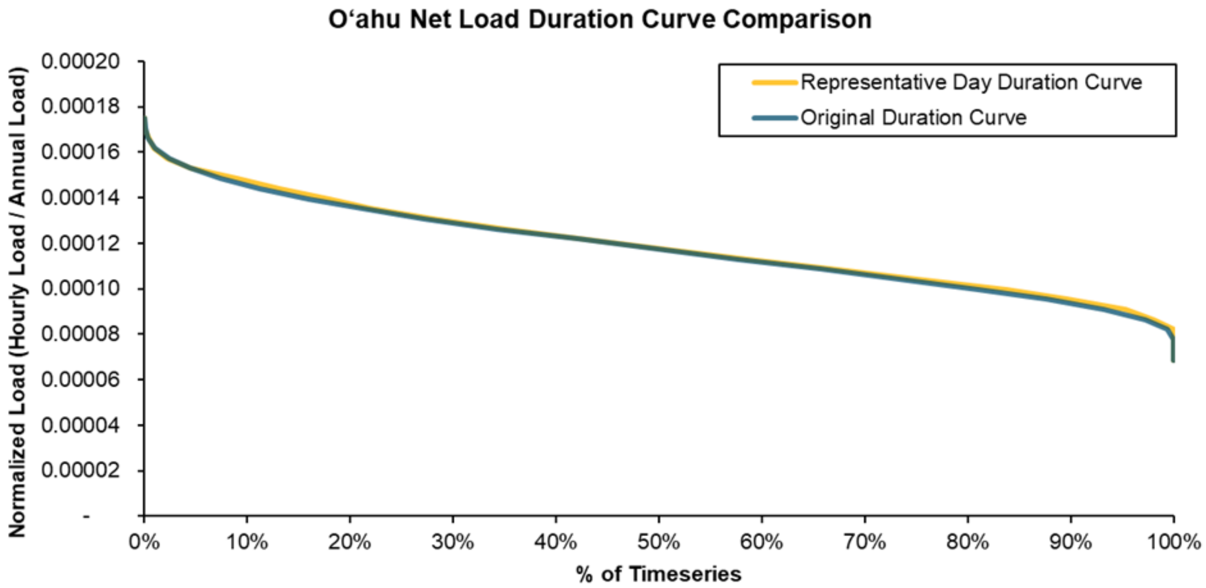



Figure 3-1: O'ahu Net Load Duration Curve Comparison

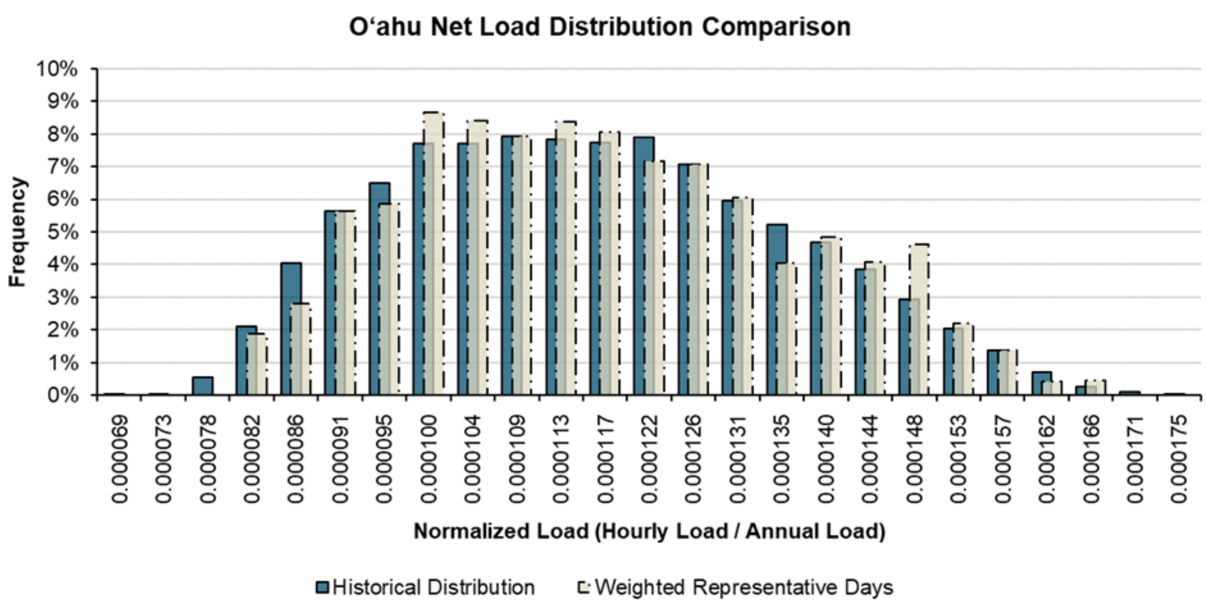



Figure 3-2: O'ahu Net Load Distribution Comparison

## *Hawai'i Island*

Table 3-2: Hawai'i Island Day Weights

| Model Day | Weight | Historical Day |
|---|---|---|
| 1 | 29.984 | 8/3/2017 |
| 2 | 26.625 | 4/5/2016 |
| 3 | 26.040 | 2/3/2017 |
| 4 | 25.358 | 6/9/2016 |
| 5 | 21.690 | 1/24/2017 |
| 6 | 21.568 | 5/8/2015 |
| 7 | 19.093 | 10/10/2016 |
| 8 | 18.935 | 3/11/2015 |
| 9 | 16.383 | 11/26/2015 |
| 10 | 16.315 | 12/5/2017 |
| 11 | 15.444 | 7/8/2017 |
| 12 | 15.337 | 9/10/2017 |
| 13 | 14.647 | 9/3/2018 |
| 14 | 13.647 | 7/6/2017 |
| 15 | 11.958 | 12/17/2016 |
| 16 | 11.891 | 10/22/2017 |
| 17 | 11.049 | 3/3/2018 |
| 18 | 9.294 | 1/3/2016 |
| 19 | 8.416 | 5/7/2017 |
| 20 | 8.101 | 11/3/2016 |
| 21 | 5.500 | 11/11/2017 |
| 22 | 4.626 | 6/25/2017 |
| 23 | 3.359 | 4/21/2018 |
| 24 | 2.703 | 12/21/2018 |
| 25 | 1.893 | 7/20/2016 |
| 26 | 1.144 | 2/14/2016 |
| 27 | 1.001 | 2/16/2017 |
| 28 | 1.000 | 3/19/2015 |

| Model Day | Weight | Historical Day |
|---|---|---|
| 29 | 1.000 | 8/20/2017 |
| 30 | 1.000 | 5/11/2018 |

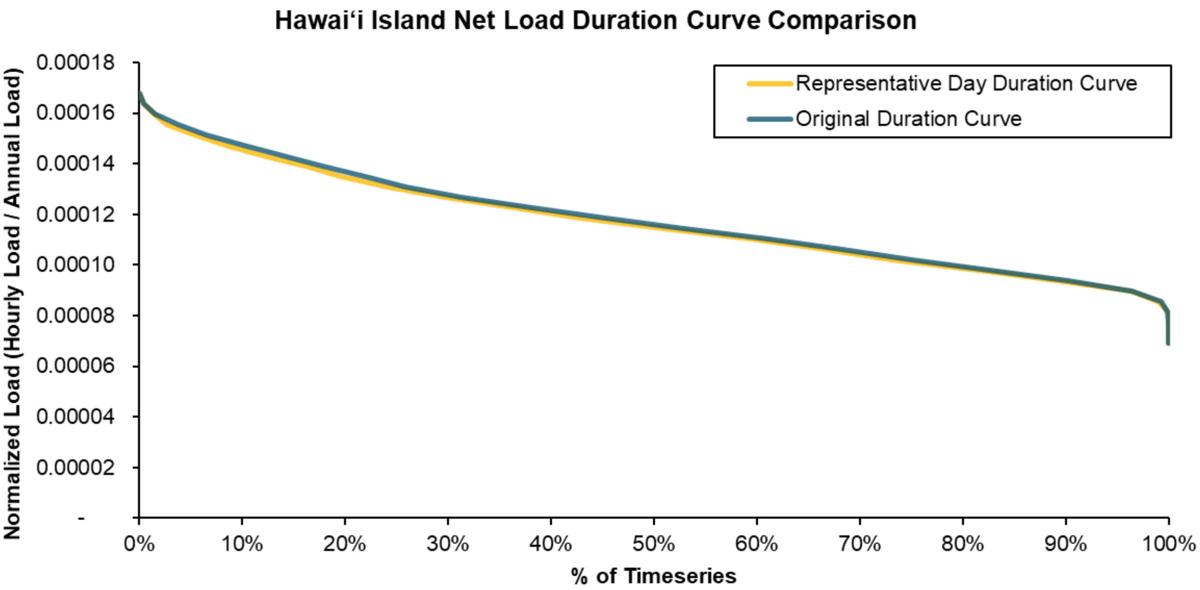



Figure 3-3: Hawai‘i Island Net Load Duration Curve Comparison

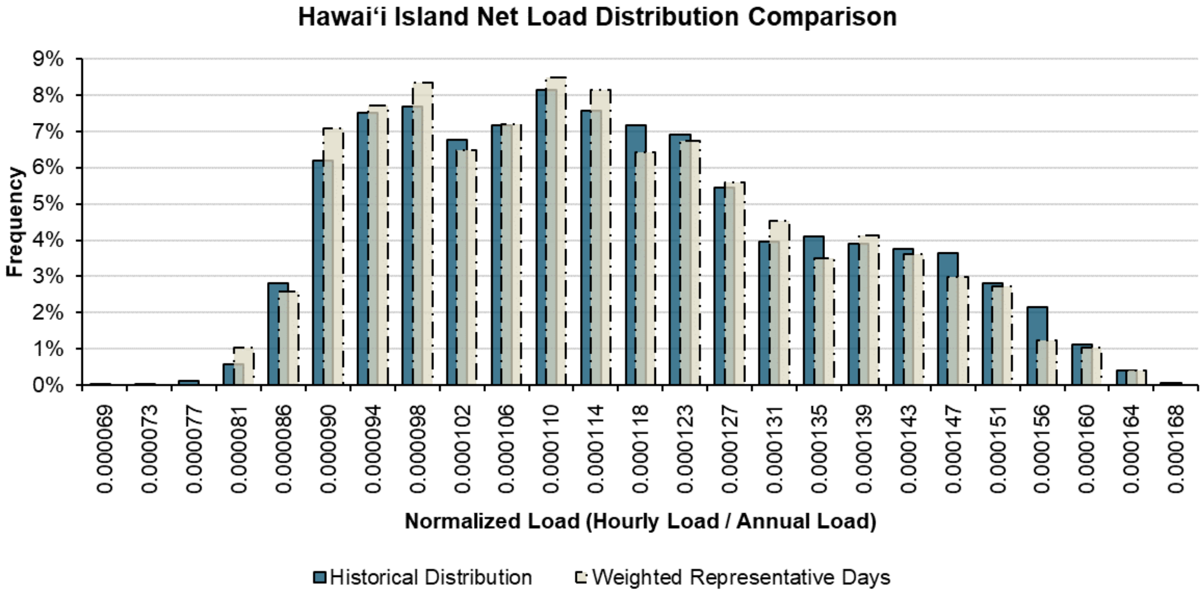



Figure 3-4: Hawai'i Island Net Load Distribution Comparison

## *Maui*

Table 3-3: Maui Day Weights

| Model Day | Weight | Historical Day |
|---|---|---|
| 1 | 20.599 | 2/6/2018 |
| 2 | 20.506 | 5/16/2016 |
| 3 | 18.987 | 8/18/2018 |
| 4 | 18.818 | 4/18/2017 |
| 5 | 18.208 | 1/31/2016 |
| 6 | 18.081 | 6/15/2017 |
| 7 | 17.924 | 7/22/2016 |
| 8 | 17.295 | 9/11/2016 |
| 9 | 16.926 | 11/24/2017 |
| 10 | 16.855 | 3/25/2015 |
| 11 | 14.129 | 3/29/2015 |
| 12 | 14.038 | 10/20/2016 |
| 13 | 12.776 | 1/17/2017 |
| 14 | 12.689 | 9/28/2018 |

| Model Day | Weight | Historical Day |
|---|---|---|
| 15 | 12.282 | 12/26/2016 |
| 16 | 12.214 | 12/22/2018 |
| 17 | 11.996 | 8/6/2015 |
| 18 | 11.903 | 6/12/2016 |
| 19 | 11.167 | 4/10/2016 |
| 20 | 11.166 | 10/17/2015 |
| 21 | 10.124 | 11/8/2016 |
| 22 | 8.674 | 7/26/2018 |
| 23 | 6.810 | 5/31/2015 |
| 24 | 6.586 | 2/14/2016 |
| 25 | 6.479 | 12/23/2015 |
| 26 | 5.780 | 10/3/2016 |
| 27 | 4.386 | 7/8/2017 |
| 28 | 3.667 | 5/4/2018 |
| 29 | 2.934 | 11/21/2015 |
| 30 | 1.000 | 2/19/2016 |

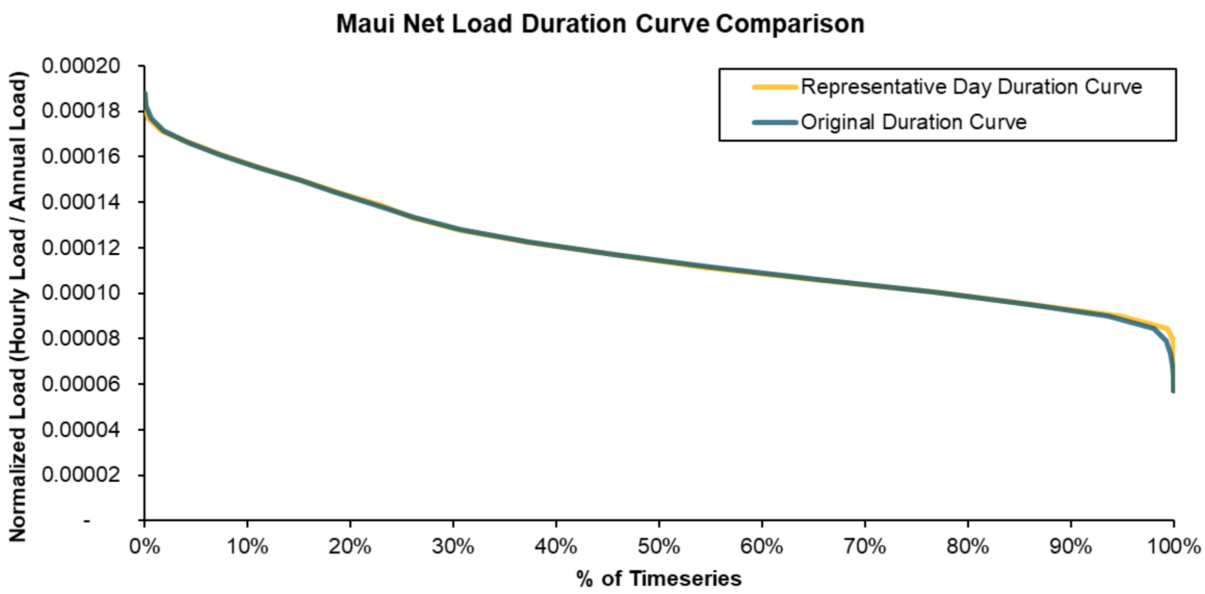



Figure 3-5: Maui Net Load Duration Curve Comparison

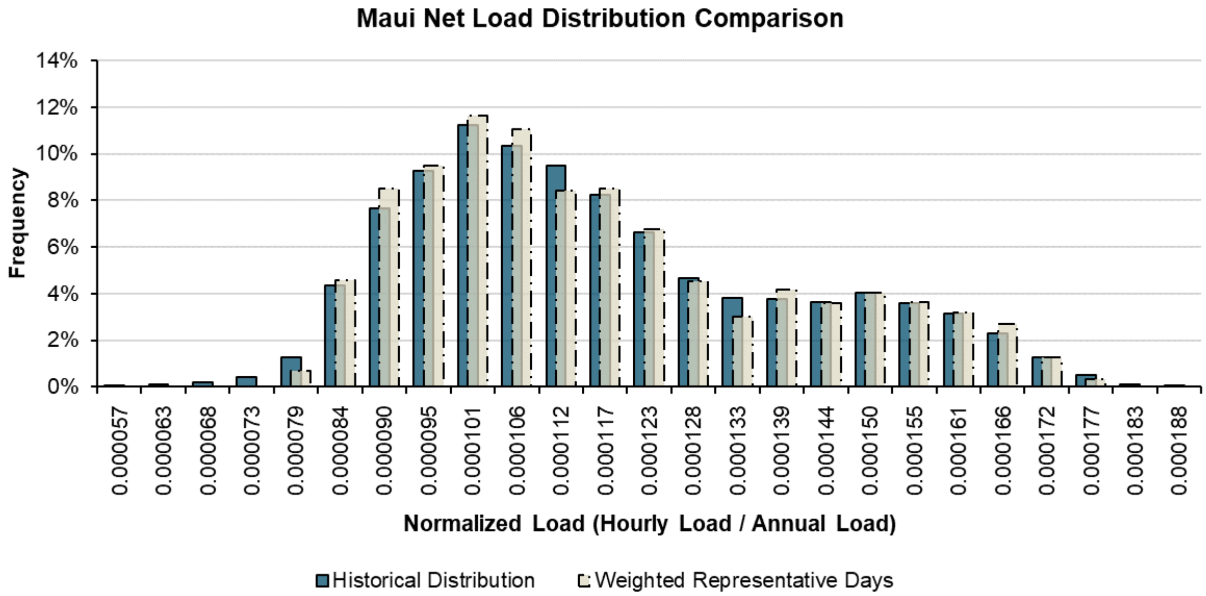



Figure 3-6: Maui Net Load Distribution Comparison

### *Moloka‘i*

Table 3-4: Moloka‘i Day Weights

| Model Day | Weight | Historical Day |
|---|---|---|
| 1 | 26.64 | 7/23/2017 |
| 2 | 23.83 | 8/23/2017 |
| 3 | 21.21 | 9/1/2018 |
| 4 | 19.75 | 1/21/2017 |
| 5 | 16.96 | 3/22/2017 |
| 6 | 16.42 | 2/27/2017 |
| 7 | 15.78 | 11/2/2018 |
| 8 | 15.74 | 5/4/2018 |
| 9 | 15.63 | 6/9/2018 |
| 10 | 15.53 | 12/25/2017 |
| 11 | 15.45 | 12/22/2018 |
| 12 | 15.43 | 10/31/2018 |

| Model Day | Weight | Historical Day |
|---|---|---|
| 13 | 15.24 | 5/20/2017 |
| 14 | | |
| 15 | 14.03 | 3/25/2017 |
| 16 | | |
| 17 | 13.20 | 11/22/2017 |
| 18 | | |
| 19 | 11.80 | 4/7/2017 |
| 20 | | |
| 21 | 11.23 | 1/17/2017 |
| 22 | | |
| 23 | 6.16 | 8/18/2018 |
| 24 | | |
| 25 | 3.35 | 7/14/2018 |
| 26 | | |
| 27 | 1.00 | 6/15/2017 |
| 28 | | |
| 29 | 1.00 | 8/2/2017 |
| 30 | | |

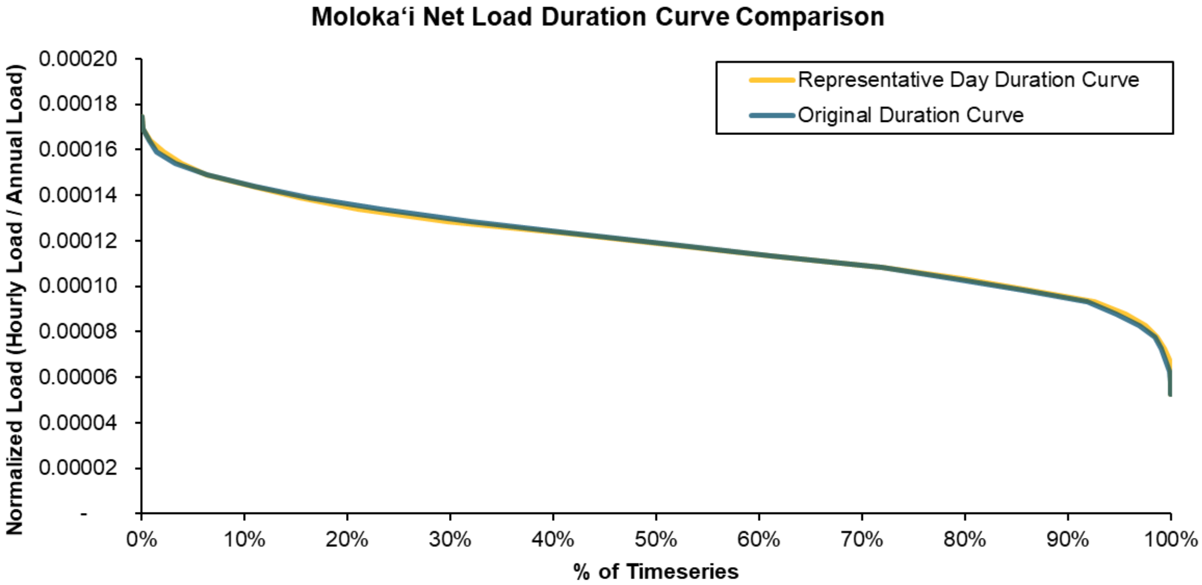



Figure 3-7: Moloka'i Net Load Duration Curve Comparison

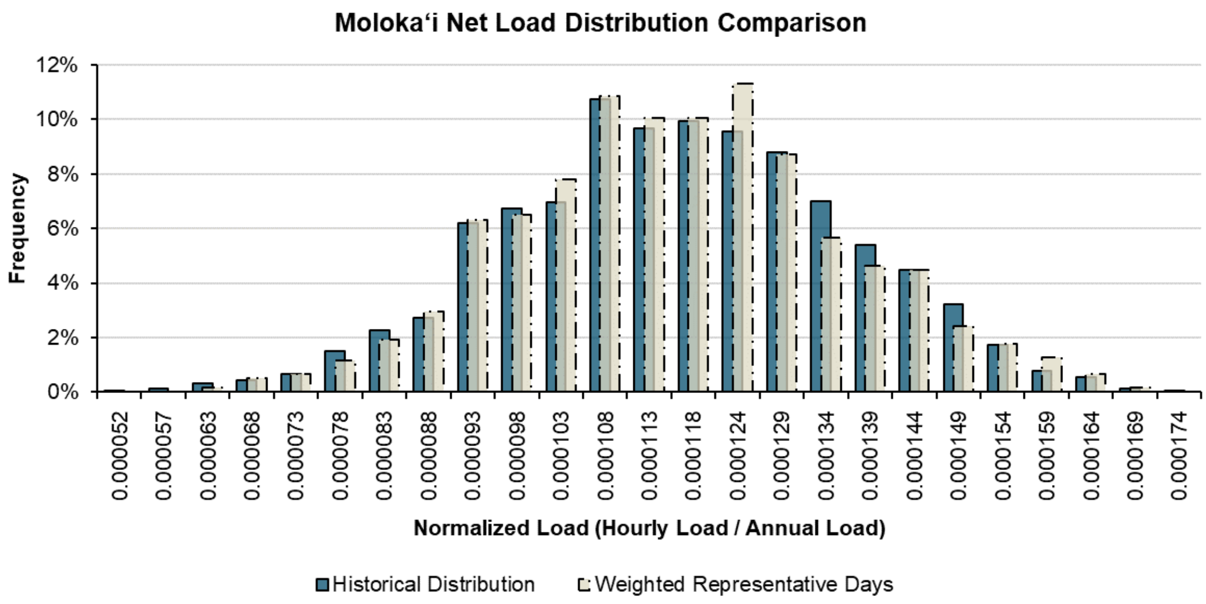



Figure 3-8: Moloka'i Net Load Distribution Comparison

## *Lānaʻi*

Table 3-5: Lāna'i Day Weights

| Model Day | Weight | Historical Day |
|---|---|---|
| 1 | 26.803 | 1/17/2017 |
| 2 | 26.214 | 7/18/2017 |
| 3 | 23.755 | 10/13/2017 |
| 4 | 19.847 | 8/11/2017 |
| 5 | 19.206 | 9/3/2018 |
| 6 | 18.965 | 6/15/2017 |
| 7 | 18.125 | 5/11/2017 |
| 8 | 17.128 | 2/18/2018 |
| 9 | 16.906 | 3/9/2018 |
| 10 | 16.280 | 12/22/2018 |
| 11 | 15.442 | 4/15/2018 |
| 12 | 14.708 | 12/6/2017 |
| 13 | 14.559 | 4/18/2018 |
| 14 | 14.104 | 11/12/2018 |
| 15 | 13.095 | 3/3/2018 |
| 16 | 11.876 | 5/10/2018 |
| 17 | 11.036 | 6/24/2017 |
| 18 | 10.873 | 2/14/2018 |
| 19 | 10.795 | 9/22/2018 |
| 20 | 10.155 | 8/30/2017 |
| 21 | 8.079 | 11/15/2018 |
| 22 | 7.818 | 11/11/2017 |
| 23 | 6.247 | 10/8/2018 |
| 24 | 4.198 | 1/20/2018 |
| 25 | 3.787 | 7/14/2018 |
| 26 | 1.000 | 5/6/2017 |
| 27 | 1.000 | 7/13/2017 |
| 28 | 1.000 | 3/21/2018 |

| Model Day | Weight | Historical Day |
|---|---|---|
| 29 | 1.000 | 8/18/2018 |
| 30 | 1.000 | 10/6/2018 |

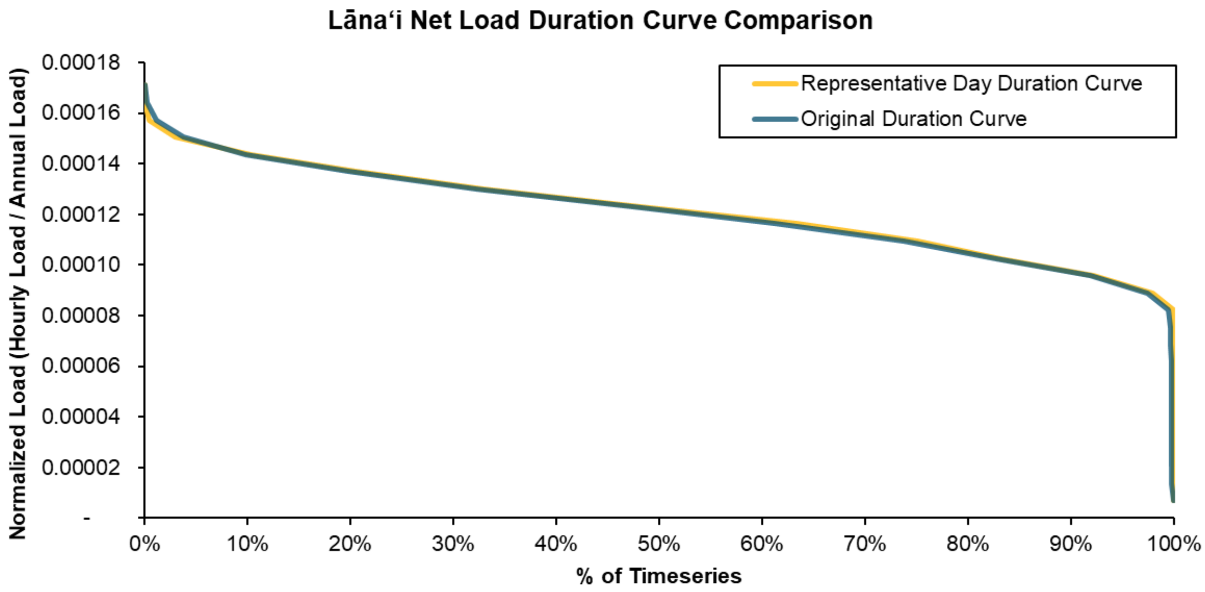



Figure 3-9: Lānaʻi Net Load Duration Curve Comparison

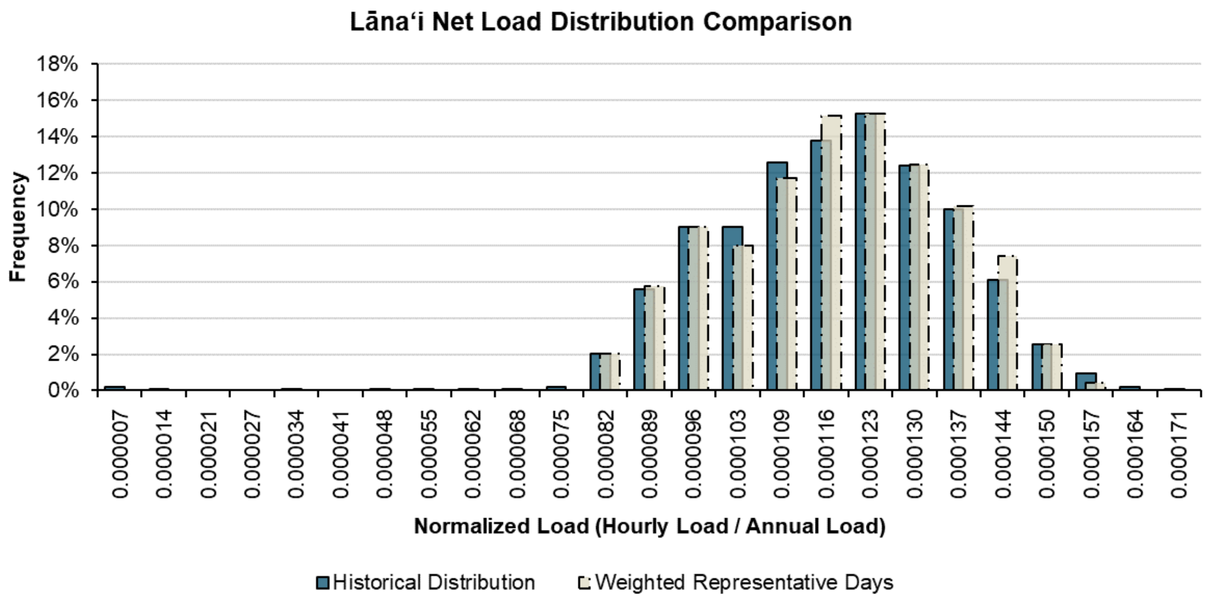



Figure 3-10: Lāna'i Net Load Distribution Comparison

## 3.2 PLEXOS PRODUCTION SIMULATION MODEL

PLEXOS is a production simulation model that analyzes the chronological, hour-by-hour operation of a utility's generation system. PLEXOS dispatches (mathematically allocates) the forecasted hourly net megawatt (MW) load among the dispatchable generating units in operation. Unit commitment (starting and stopping of units) and dispatch levels of generation are generally based on fuel cost and unit efficiency.

The net load – that is, the load remaining after partly being served by non-dispatchable energy – is allocated to the dispatchable resources such that overall fuel expense of the system is minimized (*i.e.*, economically dispatched) within the constraints of the system. The model calculates the fuel consumed using the generating unit dispatch described above. The total fuel consumed is the summation of hourly fuel consumption from all the generating units.

The PLEXOS modeling software provides the flexibility to model a wide range of current and future technologies, such as energy storage, demand response, variable generation renewable resources, firm renewable resources and fast starting resources.

The key inputs to the PLEXOS production simulation model, as applied to the Hawaiian Electric system, are as follows:

- Hourly load to be served by all units (dispatchable and non-dispatchable);
- Operating characteristics of each Hawaiian Electric and IPP generating unit;
- Operating constraints such as system inertia, fast frequency response, and regulating reserve requirements;
- Contractual terms for IPP generating units;
- Planned maintenance schedules for the generating units;
- Estimated forced outage rates for Hawaiian Electric and thermal IPP generating units;
- Prices for fuels used by the dispatchable generating units; and
- Hourly MW profiles for non-dispatchable, variable renewable generation sources.

Inputs workbooks for O'ahu, Hawai'i Island, Maui, Moloka'i, and Lāna'i will be made available on the Company's IGP website and provide additional information on the modeling inputs used by the RESOLVE and PLEXOS models.

# 4 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 have been developed by the Forecast Assumptions Working Group (FAWG), the Solution Evaluation & Optimization Working Group (SEOWG), and the STWG.

## 4.1 LOAD FORECAST

The load forecast is a key assumption for the planning models that provides the energy requirements and peak demands that must be served by Hawaiian Electric through the planning horizon. The forecasts will be used to start the planning process along with sensitivities discussed with the TAP, FAWG, SEOWG, and STWG. Because of the importance of the load forecast and peak demand in resource modeling, the TAP recommended the use of high and low bookends to test how the cost and portfolio of resources would change for a range of peak demand and load profiles. The load forecast is just one of the many assumptions that the resource planners use in their models to stress test the various plans under varying conditions. Scenario and sensitivities as described in Section 6 were developed to help address uncertainty in providing a range of forecasts to plan around given the uncertainties surrounding adoption of behind the meter technologies, which ultimately drive the load forecast and peak demand. Additional sensitivities may also be identified in the resource planning stage.

The forecasts were developed for each of the five islands and began with the development of the energy forecast (i.e., sales forecast) by rate class (residential, small, medium and large commercial and street lighting) and by layer (underlying load forecast and adjusting layers – energy efficiency, distributed energy resources, and electrification of transportation).

The underlying load forecast is driven primarily by the economy, weather, electricity price, and known adjustments to large customer loads and is informed by historical data, structural changes[25], and historical and future disruptions. The impacts of energy efficiency (EE), distributed energy resources (DER), primarily photovoltaic systems with and without storage (*i.e.*, batteries), and electrification of transportation (light duty electric vehicles (EV) and

[25] Structural changes include the addition of new resort loads or new air conditioning loads that have a persistent impact on the forecast.

electric buses (eBus), collectively "EoT") were layered onto the underlying sales outlook to develop the sales forecast at the customer level.

Multiple methods and models were analyzed to develop the underlying forecast as presented in the July 17, 2019 FAWG meeting.[26] The forecasts and assumptions presented in the FAWG meetings held from March 2019 through March 2020 and described in the response to PUC-HECO-IR-1[27] were developed prior to the unprecedented global and local events of the COVID-19 pandemic and therefore do not include impacts of the virus on the forecasts. The Company updated its forecasts to account for the impacts of COVID-19 as presented in the August 31, 2020 FAWG meeting and described further in Appendix C: Forecast Methodologies.[28] Feedback from stakeholders on the assumptions used to develop the forecasts and the resulting forecast were an important part of the process and are summarized in *IGP Stakeholder Feedback Summary, March 2021*. Additional updates made based on recent stakeholder engagement in response to the Review Point Guidance are described throughout this document.

The residential and commercial sectors are forecasted separately as each sector's electricity usage has been found to be related to a different set of drivers as described in Appendix C: Forecast Methodologies. Historical recorded sales used in econometric models are adjusted to remove sales impact of DER, EE and EoT, which are treated as separate layers. Input data sources for developing the underlying sales forecast include economic drivers, weather variables, electricity price and historical data from the Company's own assumptions, as shown in the table below.

---

[26] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20190717_wg_fa_meeting_presentation_materials.pdf, slides 10-12.

[27] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/dkt_20180165_20200702_HECO_response_to_PUC_IRs_1-2.pdf

[28] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20200831_wg_fa_meeting_presentation_materials_HECO.pdf, slides 6, 9, 11, 13 and 16 for O'ahu, Maui, Moloka'i, Lāna'i and Hawai'i islands respectively.

Table 4-1: Input Data Sources for Underlying Forecast

| | |
|---|---|
| **University of Hawaii Economic Research Organization** | Real personal income<br>Resident population<br>Non-farm jobs<br>Visitor arrivals |
| **NOAA - Honolulu, Kahului, Hilo and Kona Airports** | Cooling degree days<br>Dewpoint Temperature<br>Rainfall |
| **Itron, Inc.** | Commercial energy intensity trend for Pacific Region for non-heating/cooling end uses. |
| **Hawaiian Electric** | Recorded kWh sales<br>Recorded customer counts<br>Large load adjustments<br>Real electricity price |

### 4.1.1 Distributed Energy Resource Forecasts

Through the STWG, the DER Docket proceeding, and other meetings, the DER forecasts have been updated, including the development of a high and low forecast for the bookend sensitivities. Several stakeholder suggestions were made at the June 17, 2021 STWG meeting[29] to develop bookend DER forecasts and revisions to the base scenario. Stakeholder comments included:

- There are pockets of schedule-R (multi-family residences) that are not currently reachable in the DER market, and this has more to do with a lack of available programs for these customers. It's more of a policy issue than a DER supply issue. Specifically, there are AOAOs that are not currently reachable.
- For the bookend, one way is to remove the addressable market constraints.
- Are we looking at bookends from the perspective of capturing untouched markets, such as rental properties? How much DER should be included in load versus how much is export?
- It seems to make sense as a realistic possibility [to extend tax credits].
- In the longer term, it is reasonable to consider an export program extension in the base case as well as in the high bookend scenario.

[29] Available at, https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/igp_meetings/20210617_stwg_meeting_notes.pdf

As a direct result of this feedback, Table 4-2, below summarizes the changes and assumptions the Company made in the development of the updated DER forecasts.

Table 4-2. Summary of assumptions used to develop DER forecast sensitivities

| Input | No State ITC | Low | Base | High |
|---|---|---|---|---|
| Synopsis | Revised lower DER uptake below market forecast | Market Forecast based on self-consumption | Revised uptake based on DER docket proposals (The Company), include EDRP (Oahu, Maui), expanded addressable market | Revised uptake based on DER docket proposals (DER Parties), include EDRP, updated resource costs, expanded addressable market |
| Cost Projections | NREL ATB - Moderate | NREL ATB - Moderate | NREL ATB - Moderate | NREL ATB Advanced |
| Federal Tax Credits | Dec 2020 COVID-19 Relief | Dec 2020 COVID-19 Relief | Dec 2020 COVID-19 Relief | 10-year extension |
| State Tax Credits | 0% | Increased 2021 to 35% | Increased 2021 to 35% | Increased 2021 to 35% |
| Includes EDR Program | No | No | Yes (Oahu, Maui) | Yes |
| Long Term Upfront Incentives | None | None | $250/kW (Oahu, Maui) | $500/kW |
| Long Term Export Program | NA | NA | Standard DER Tariff (All Islands) with Scheduled Dispatch (Oahu, Maui) | Smart Export+ with Scheduled Dispatch |
| Addressable Residential Market | Single Family/2-4 Unit Multi- Family/Owner Occupied/Consumption Threshold | Single Family/2-4 Unit Multi- Family/Owner Occupied/Consumption Threshold | Single Family/2-4 Unit Multi- Family/Owner Occupied/Consumption Threshold | Single Family/2-49 Unit Multi-Family/Consumption Threshold |
| Addressable Commercial Market | Public or Private Owned/<6 stories/Consumption Thresholds | Public or Private Owned/<6 stories/Consumption Thresholds | Public or Private Owned/<6 stories/Consumption Thresholds | Public or Private Owned/<6 stories/Consumption Thresholds/Expand Sch-P Customer Pool to 100% |

| Input | No State ITC | Low | Base | High |
|---|---|---|---|---|
| Add-Ons | NEM+ | NEM+ | Sch-R NEM above minimum bill customers from 2021-2023 (Oahu, Maui), NEM+[30] | Sch-R NEM customers from 2021-forward |

The DER layer includes impacts of behind the meter PV and battery energy storage systems as well as known projects for other technologies (*e.g.*, wind). This forecast adjustment estimated new additions of DER capacity in each month by island, rate class and program, and projected the resulting monthly sales impact from these additions. Future DER capacity modeling considered two-time horizons:

- Near term (next one to three years) reflects the current pace of incoming applications and executed agreements, existing program (NEM, NEM+, SIA, CGS, GSP, CSS and ISE)[31] subscription level and caps, feedback from the Companies' program administrators and installers, customer input and any studies or upgrades being done to address short-term hurdles (e.g. circuit study, equipment upgrades) that affect the installation pace; and

- Longer term forecast is model-based as the detailed application information is not available.

To extend the DER forecast from the short-term through the full planning period an economic choice model using simple payback considers a set of assumptions such as the installed cost of PV and battery, installation incentives, electricity price, program structure that affect the economic benefit to the customer which is the primary driver of their decision to adopt the system. The addressable market, or the number of utility customers that have the potential to install a DER behind the meter is also considered.

Another important assumption to consider was the structure of programs. There is an array of program choices today, some of which are subject to capacity caps. Assumptions were made as to the structure of future programs for the long term after obtaining input and perspectives from program

[30] Customers participating in NEM+ is included in the Base case scenario for all islands, but only from 2024-forward for Oahu and Maui because Schedule-R NEM customers were re-introduced in the customer pool for 2021-2023.

[31] Existing programs include Net Energy Metering, Net Energy Metering Plus, Standard Interconnection Agreement, Customer Grid Supply, Customer Grid Supply Plus, Customer Self Supply, and Interim Smart Export.

administrators/designers, industry, and policy/consultancies. The future new tariff is assumed to have compensation for export[32] that is aligned with system needs and allows for controllability during system emergencies. The export compensation and tariff structure was based on the Standard DER Tariff for all islands proposed by the Company in the DER docket[33]. Insight from the DER panel members on the Panel of Experts meeting held on March 22, 2019 as well as already interconnected systems, applications and permit data show that customers are choosing to use battery storage to shift their generation to offset their own load rather than exporting to the grid during the daytime. In addition, for O'ahu and Maui, the DER forecast also incorporated the Emergency Demand Response Program (EDRP), Scheduled Dispatch program[34], and assumed that an upfront incentive of $250/kW would continue to be available beyond EDRP for new DER customers in exchange for provision of grid services (i.e., bring your own device programs) as part of a long-term DER program. Consistent with the EDRP, incentives would be paid based on performance and commitment of the customer resource.

Under the EDRP assumption, DER customers are modeled to export at the battery system's rated capacity [kW] (if energy is available) for a two-hour duration during the evening peak window, 5 PM to 9 PM, each day.

NREL 2021 Annual Technology Baseline (ATB) forecasts storage continues to decline in cost and it seems likely that compensation for daytime export will continue to be relatively low compared to retail rates, therefore the assumption was made that most future systems under the future tariff will be paired with storage. Furthermore, the rollout of a broad opt-out time-of-use (TOU) rate would increase the incentive to pair future systems with storage, adding additional credence to this assumption. Hawaiian Electric is including high and low scenarios, to test different rates of technology adoption by customers. Since advanced rate designs and long-term distributed energy resource programs are in the process of being finalized and implemented, the Companies will take a "best guess" approach to assume high and low levels of TOU adoption within the high and low scenarios.

These assumptions based on stakeholder feedback and information from the DER Docket proceeding, represent the collective best guess from all

[32] *See* Order No. 37066 issued on April 9, 2020 in Docket No. 2019-0323, Instituting a Proceeding to Investigate Distributed Energy Resource Policies pertaining to the Hawaiian Electric Companies.

[33] *See* Hawaiian Electric's DER Program Track Final Proposal filed on May 3, 2021 in Docket No. 2019-0323, Instituting a Proceeding to Investigate Distributed Energy Resource Policies pertaining to the Hawaiian Electric Companies.

[34] *See* Order No. 37816 issued on June 8, 2020 in Docket No. 2019-0323, Instituting a Proceeding to Investigate Distributed Energy Resource Policies pertaining to the Hawaiian Electric Companies.

stakeholders. Though, potential impacts from adjustments made to these assumptions may not necessarily require restating the forecast since the "spread" between the low, base, and high forecast should sufficiently capture any impacts within the bounds of the forecasted sensitivities.

The current rate of DER applications and remaining capacities to reach set caps of interim programs, coupled with recent system configuration trends in DER applications were used to set the pace, capacities and amount of PV systems paired storage in the near term. The increasing trends in PV systems paired with batteries was observed among recent DER applications. The forecasted ramping up of paired storage systems was also supported from feedback received during the Panel of Experts meeting held on March 22, 2019 from industry leaders.[35] For residential systems in the near-term, the number of systems paired with storage increased from roughly 60% to as high as 95% for some islands in 2022. Similarly, the small and medium commercial classes had a ramping up of paired storage systems through the course of the near term to meet with the assumptions of the model that picks up after the near-term.

The model assumptions were that all small and medium commercial and all residential systems will be paired with storage after the near-term forecast. Storage size assumptions for each island and rate class were optimized based on return on investment for an average customer. By modeling average customer's optimal pairing size, the amount of forecasted storage was appropriately captured for the overall rate class as customers with larger storage requirements offset those with smaller or no storage requirements. PV installs for large commercial customers were modeled without battery storage.

Monthly DER capacity factors for each island were used to convert installed capacity to customer energy reductions. The monthly capacity factors recognize the variations in solar irradiance throughout the year rather than using a single average annual capacity factor to more accurately reflect monthly variations in the energy production of DER systems. A degradation factor of 0.5% a year[36] was applied to the sales impacts to recognize that the DER system's performance degrades over time.

For incentives, the following was assumed for Federal and State investment tax credits.

- Cap on residential PV-only systems: $5,000 in all years

[35] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20190522_wg_fa_meeting_presentation_materials.pdf

[36] Median degradation rate from NREL "Photovoltaic Degradation Rates – An Analytical Review", D.C. Jordan and S.R. Kurz, 2012, http://www.nrel.gov/docs/fy12osti/51664.pdf

- Cap on residential PV+storage systems: $5,000 in 2019-2021, $10,000 in 2022-forward

Table 4-3: Federal Tax Incentive Rate Schedule

| Class | 2019 | 2020 | 2021 | 2022 | 2023 | 2024+ |
|---|---|---|---|---|---|---|
| **Residential** | 30% | 26% | 26% | 26% | 22% | 0% |
| **Commercial** | 30% | 26% | 26% | 26% | 22% | 10% |

Table 4-4: State Tax Incentive Rate Schedule

| 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027+ |
|---|---|---|---|---|---|---|---|---|
| 35% | 35% | 35% | 25% | 25% | 20% | 20% | 20% | 15% |

One of the key drivers in the long-term DER forecast is the addressable market, including customers that can add-on to existing systems. Expanding the addressable market compared to the original IGP market forecast assumption was a common theme from stakeholders. The addressable market for residential customers included single family and multi-family homes with a maximum of four units that were owner occupied and with a high enough energy consumption to utilize at least a 3 kW PV system, as shown in Table 4-5. Historically, only 15-20% of residential PV installations have been below 3 kW. From a practical perspective, customers with low consumption are less likely to make an investment in rooftop PV. Smaller systems are also less cost-effective due to fixed portions of the installation and material costs being spread out over smaller total capacity and savings potential.

Stakeholders commented on the addressable market for DER customers at the June 17th, 2021 Stakeholder Technical Working Group meeting and June 28th, 2021 DER Docket Status Conference. For example, at the DER Docket Status Conference, stakeholders commented retrofitting existing DER customers with added PV capacity and battery systems would likely be the most attractive option to meet the EDRP's 50 MW target. On June 8th, 2020, the Commission issued Order No. 37816 in Docket No. 2019-0323 approving the EDR Program and Scheduled Dispatch rider for new and existing DER customers.[37] Considering the comments and feedback provided by stakeholders and Order No. 37816, existing NEM customers who were not reaching a minimum bill were added to the addressable market from 2021 through 2023 for O'ahu and

[37] *See* Order No. 37816 issued on June 8, 2020 in Docket No. 2019-0323, Instituting a Proceeding to Investigate Distributed Energy Resource Policies pertaining to the Hawaiian Electric Companies.

Maui, Table 4-6. In addition, comments from stakeholders indicated that there might be DER customers who only install on a battery. However, others may increase their PV capacity to capture the total value of tax credits. Considering these comments, future retrofits for NEM customers assumed both an addition of a battery system, 5 kW/13.5 kWh, and an increase in PV capacity, 5kW[38].

| Island | Percent of Schedule R Customers | Average PV System Size (KW) | Average Storage Size (KWH) |
|---|---|---|---|
| O'ahu | 37% | 7.0 | 15.5 |
| Hawai'i Island | 41% | 6.0 | 11.0 |
| Maui | 43% | 7.0 | 15.0 |
| Lāna'i | 24% | 4.0 | 9.0 |
| Moloka'i | 30% | 4.0 | 12.0 |

Table 4-6: NEM Customers Added to Residential Addressable Market

| Island | Percent of Schedule R NEM Customers | Average PV System Size (KW) | Average Storage Size (KWH) |
|---|---|---|---|
| O'ahu | 85% | 5 | 13.5 |
| Maui | 71% | 5 | 13.5 |

For commercial customers, public and private building ownership was considered. Structures greater than six stories were excluded. Similar to residential customers, small and medium commercial consumption needed to be above a set threshold. Commercial thresholds were established using rate class customers' previous 12-months usage, historical PV installation data, and business types. PV and non-PV customers were segmented by business type and distributions for total usage[39] were created for PV customers. Usage at the lower 1/8th quantile was used as the threshold for business types that had five or more customers who already installed PV. The default thresholds of 500kWh for Schedule G and 5,000 kWh for Schedule J are used for business types with less than five existing customers

[38] Order No. 37816 permits existing PV customers to add up to 5 kW of additional PV generation capacity.

[39] Total usage is the sum of the previous 12-months sales plus the sum of the previous 12-months estimated PV generation.

with PV already installed. The resulting addressable market for the commercial sector can be seen in Table 4-7 through Table 4-10.

| Island | Percent of Schedule G Customers | Percent of Schedule J Customers | Percent of Schedule P Customers |
|---|---|---|---|
| O‘ahu | 37% | 53% | 78% |
| | | | |
| Maui | 41% | 63% | 68% |

Table 4-8: Addressable Market, Average PV System Size, and Average Storage Size for

| Island | Percent of Schedule G Customers | Average PV System Size (KW) | Average Storage Size (KWH) |
|---|---|---|---|
| O‘ahu | 37% | 7.0 | 12.5 |
| | | | |
| Maui | 41% | 7.0 | 14.5 |

Table 4-9: Addressable Market, Average PV System Size, and Average Storage Size for

| Island | Percent of Schedule J Customers | Average PV System Size (KW) | Average Storage Size (KWH) |
|---|---|---|---|
| O‘ahu | 53% | 76.0 | 40.0 |
| | | | |
| Maui | 63% | 59.0 | 45.0 |

Table 4-10: Addressable Market, Average PV System Size, and Average Storage Size for Schedule P Customers

| Island | Percent of Schedule P Customers | Average PV System Size (KW) | Average Storage Size (KWH) |
|---|---|---|---|
| O‘ahu | 78% | 330.0 | 0.0 |
| Hawai‘i | 44% | 64.0 | 0.0 |
| Maui | 68% | 330.0 | 0.0 |

Table 4-11: Cumulative Distributed PV Capacity (kW)

| Year | O‘ahu | Hawai i Island | Maui | Moloka‘i | Lāna‘i | Consolidated |
|---|---|---|---|---|---|---|
| kW | A | B | C | D | E | F =A + B + C + D +E |
| | | | | | | |
| 2030 | 830,974 | 164,392 | 185,501 | 3,696 | 1,356 | 1,185,919 |
| | | | | | | |
| 2045 | 1,053,934 | 227,449 | 242,917 | 4,768 | 2,085 | 1,531,153 |
| | | | | | | |

| Year | O‘ahu | Hawai i Island | Maui | Moloka‘i | Lāna‘i | Consolidated |
|---|---|---|---|---|---|---|
| kWh | A | B | C | D | E | F =A + B + C + D +E |
| 2025 | 317,754 | 84,230 | 128,263 | 1,348 | 515 | 532,110 |
| 2030 | 493,412 | 126,316 | 179,030 | 2,308 | 875 | 801,941 |
| 2040 | 756,521 | 196,611 | 254,943 | 3,976 | 1,550 | 1,213,601 |
| 2045 | 848,456 | 224,301 | 282,258 | 4,588 | 1,829 | 1,361,432 |
| 2050 | 923,096 | 247,272 | 303,603 | 5,068 | 2,072 | 1,481,111 |

### *Advanced Rate Design Impacts*

One of the key components of the Advanced Rate Design ("ARD") discussed in the DER docket includes the implementation of TOU rates, including mandatory TOU for DER customers. Consistent with ARD discussions, each customer that adopts DER (solar paired with storage) and/or electric vehicles under managed charging scenarios is effectively shaping their consumption to operate consistent with a TOU rate. For example, DER customers would charge their energy storage system with rooftop solar during the day and discharging the system in the evening, and in managed charging cases, customers charging electric vehicles during the day.

At the June 17, 2021 STWG, stakeholders asserted that the additional demand charge under the Company's ARD proposal would affect the forecasted DER uptake. Under the current ARD proposal, new DER customers would be defaulted into a Three-Part TOU rate that includes a $3/kW monthly demand charge. Referencing the Company's Bill Comparison of 2017 TY and Proposed Three-Part TOU Rates under the ARD Track Initial Proposal[40], a 300 kWh monthly usage and 3.336 kW peak residential customer's monthly bill, including the demand charge, would be an estimated $5.86 higher under the proposed TOU rate compared to the 2017 TY rates. For a 600 kWh monthly usage and 3.336 kW peak residential customer, their estimated monthly bill would be $3.69 lower under the ARD rates compared to 2017 TY rates. This small difference would not affect the economic choice model DER uptake forecast in either direction for the average customer with the assumed average PV and battery system size. Stakeholders also commented that prospective DER customers looking toward purchasing a future EV may be dissuaded from adopting DER because of the potential impact of a large demand charge from vehicle charging. While a demand increase would lead to a higher demand charge under the Company's proposed ARD rates, DER uptake would not necessarily be decreased under this scenario. The DER uptake model assumes a system size for PV and storage based on average customer usage. Introduction of an EV load would require adjusting the assumed PV and storage system size to account for the planned load increase, which ultimately adjusts the payback period.

As discussed in its Workplan update letter to the Commission filed on July 28, 2021, the Company is further evaluating TOU for non-DER and non-EV customers. The Company will provide an update on this issue no later than the October 1, 2021 Review Point filing.

However, the Company believes that the high and low bookend scenario already provides significant load shaping; for example, see Figure 4-5. Any impacts of increased demand charges or behavioral changes for customers without EV or DER will be captured within the bookends. The uncertainty of these and other future changes in customer trends are precisely what the bookends are intended to capture such that any changes that may occur, that impact the net demand, would fall within the bookends.

### *High and Low Bookend Sensitivities*

To support the bookend scenarios, the Company sought additional feedback to derive assumptions for the DER sensitivities. At the June 17, 2020 STWG meeting, stakeholders provided comments on removing the addressable market constraints to account for the possibility for faster customer adoption and support the High DER sensitivity. As a result, the addressable market was expanded beyond to the Base case to include all existing NEM customers from

[40] *See* Hawaiian Electric's Advanced Rate Design Initial Proposal filed on December 17, 2020 in Docket No. 2019-0323, Instituting a Proceeding to Investigate Distributed Energy Resource Policies pertaining to the Hawaiian Electric Companies.

2021 through 2050. Additionally, the High DER sensitivity further extended the addressable market by removing the owner-occupied requirement, increasing the multi-family unit size threshold from 4 to 49 units, and included 100% of Schedule-P customers.

The Company also sought stakeholder feedback regarding future incentive structures. At the June 17, 2021 STWG meeting, the Company requested input on the possibility of extended tax credits and a longer-term export program. Stakeholders responded that both seem to be realistic possibilities. Although an extension of the Federal investment tax credit is still unknown with the current information available on the bipartisan infrastructure plan, the Company extended the Federal investment tax credit through 2032, with residential investment tax credits ending and commercial investment tax credits settling at 10% in 2033. The long-term upfront incentives for future grid services program on all islands were also increased to $500/kW for the high DER forecast.

At the June 2, 2021 STWG meetings, stakeholders commented on the advancement of technology and supply chains that may drive down the costs of DER systems. In response, the Company used NREL 2021 ATB – Advanced Scenario cost curves for residential and commercial PV and battery systems for the High DER sensitivity forecast. The ATB – Advanced Scenario assumes a rapid advancement in technology innovation and manufacturing at levels above and beyond the current market. Resulting from the ATB – Advanced Scenario are more aggressive PV and battery system costs curves compared to the ATB – Moderate Scenario.

The Company re-purposed the previous July 2020 IGP base/market DER forecast as the Low DER sensitivity and as the basis for the No State ITC sensitivity. The No State ITC sensitivity was modeled assuming a 0% State ITC starting in 2022, resulting in lower DER uptake compared to the market forecast. In both sensitivities, DER system costs and tax credit assumptions were updated similarly to the current Base case, as shown in Table 4-2.

As a direct result of stakeholder input, Figure 4-1, below illustrates the revised DER forecasts.

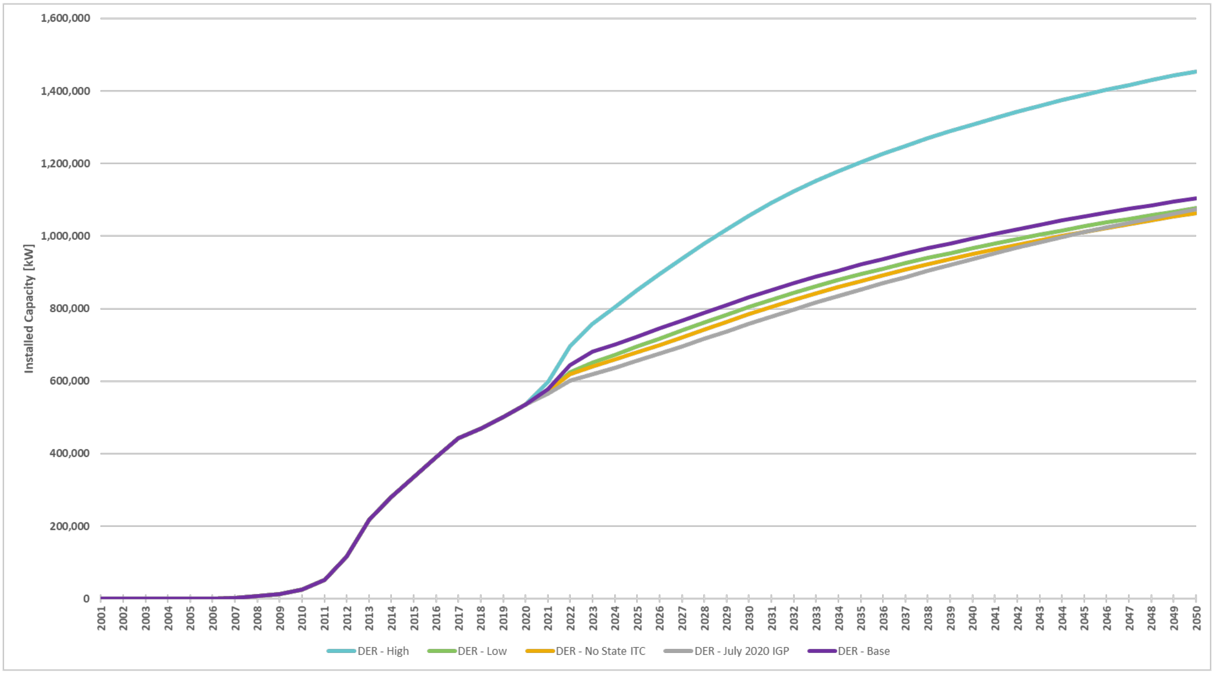



Figure 4-1: O'ahu DER Bookend Sensitivities

### 4.1.2 Energy Efficiency

The energy efficiency layer is based on projections from the July 2020 State of Hawaii Market Potential Study prepared by Applied Energy Group (AEG) and sponsored by the Hawai'i Public Utilities Commission.[41] The preliminary results from the study were presented to the FAWG on January 29, 2020.[42] The market potential study considered customer segmentation, technologies and measures, building codes and appliance standards as well as the progress towards achieving the Energy Efficiency Portfolio Standards. The study included technical, economic, and achievable energy efficiency potentials.

An achievable Business As Usual (BAU) energy efficiency potential forecast by island and sector covering the years 2020 through 2045 was provided to the Company in February 2020 to use for the Company's forecasts. The BAU potential forecast represented savings from realistic customer adoption of energy efficiency measures through future interventions that were similar in

[41] *See* https://puc.hawaii.gov/wp-content/uploads/2021/02/Hawaii-2020-Market-Potential-Study-Final-Report.pdf

[42] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20200129_wg_fa_hawaii_market_potential_study_draft_results.pdf

nature to existing interventions. In addition to the BAU forecast, AEG provided a codes and standards (C&S) forecast and an Achievable – High forecast. The Achievable - High potential forecast assumed higher levels of savings and participation through expanded programs, new codes and standards, and market transformation.

The forecasts provided to the Company reclassified certain market segments to different customer classes to align with how the Company forecasts sales. Since a thirty-year forecast was needed, the Company extended the forecast out to 2050 using trends in AEG's forecast. AEG's forecast for Lānaʻi and Molokaʻi was adjusted to be consistent with Hawaii Energy's historical island allocation. A five year average net-to-gross ratio from Hawaii Energy's program years 2014 through 2018 for each island was applied to the forecasts in order to exclude free riders[43] from the energy savings estimates as impacts from free riders were assumed to be embedded in the underlying forecasts described above. The impacts from AEG were derived at an annualized level and included free riders which reflected savings for all measures as if they were all installed in January and provided savings for the whole year. The annualized impacts were ramped throughout the year to arrive at energy efficiency impacts by month for each forecasted year. For simplicity, the installations were assumed to be evenly distributed throughout the year.

### *High and Low Bookend Sensitivities*

The additional energy efficiency potentials provided by AEG allowed for the creation of various forecast sensitivities. As a result, the Company developed three different sensitivities, Low, High, and Freeze. These sensitivities were presented on July 9, 2021 with a smaller group of stakeholders and at the July 14, 2021 STWG meeting. The following Table 4-13 and Figure 4-2 summarize the energy efficiency sensitivities and their forecasted annual sales [GWh].

Table 4-13: Energy Efficiency Bookend Sensitivities

| Low | Base | High | Freeze |
|---|---|---|---|
| BAU only | BAU + C&S | Achievable High + C&S | Forecasted capacity fixed at 2021 Base forecast |

[43] A free rider is someone who would install an energy efficient measure without program incentives.

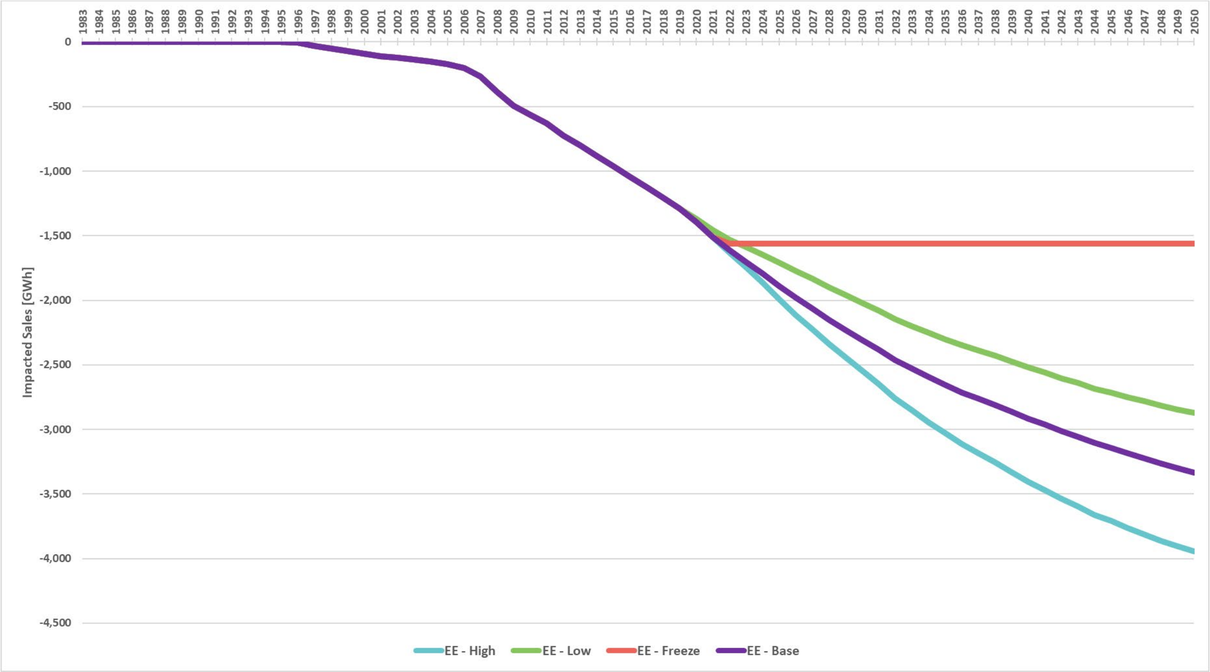



Figure 4-2: O'ahu Energy Efficiency Annual Sales Forecast Impact Sensitivities

As summarized in Section 2.2, the Company has already met with AEG to discuss the scope of work to bundle energy efficiency measures into resource options for selection by RESOLVE, in addition to and separate from the minimum uptake of energy efficiency that is assumed through the forecast layers. Draft supply curves for the energy efficiency resources will be shared with stakeholders once developed.

### 4.1.3 Electrification of Transportation

The electrification of transportation layer consists of impacts from the charging of light duty electric vehicles and electric buses.

#### *Light Duty Electric Vehicles*

The light duty electric vehicle forecast was based on an adoption model developed by Integral Analytics, Inc. as described in Appendix E of the EoT Roadmap[44] to arrive at EV saturations of total light duty vehicles (LDV) by year for each island. Historical data for LDV registrations were provided by the Department of Business, Economic Development, and Tourism (DBEDT) and reported at the county level. In order to get to the island level for Maui County,

[44] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/electrification_of_transportation/201803_eot_roadmap.pdf

an allocation factor supplied by DBEDT and based on vehicle registration for the three islands was used. The total LDV forecast for each county was estimated using a regression model driven by population and jobs based on UHERO's October 2019 economic forecast. The development of the EV forecast utilized the EV saturation by island as shown on tab "EV Saturation" in Attachment 8 of PUC-HECO-IR-1 and applied the saturation to the LDV forecast for each island to arrive at the number of light duty EVs.[45] Although EV saturations were not specifically consistent with carbon neutrality in Hawaii by 2045, they are consistent with County goals for 2035.

To estimate the sales impact from EV charging for each island, the annual kWh used per vehicle was calculated based on the following equation:

$$Annual\ kWh\ per\ vehicle\ = \frac{\left(Annual\ VMT * (kWh\ per\ mile)\right) * 10^6}{Total\ LDV\ Forecast}$$

where

- *Annual VMT* is the annual vehicle miles travelled
- *kWh per mile* is a weighted average of fuel economies of electric vehicles registered

*Annual VMT* is forecasted by applying the baseline economic growth rate developed by the Federal Highway Administration for light duty vehicles to DBEDT's reported vehicle miles travelled for each county.[46] For Lānaʻi and Molokaʻi, vehicle miles travelled were developed based on information from DBEDT and on-island sources.

Historical *kWh per mile* was obtained using the weighted average fuel economy of registered electric vehicles by island. For Lānaʻi and Molokaʻi, the fuel economy from the Nissan Leaf represented each island's average. Fuel economy and vehicle registration by type data were obtained from the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy and Electric Power Research Institute (EPRI), respectively[47]. *Annual kWh per vehicle* was forecasted by applying a reference growth rate developed using the U.S.

---

[45] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/PUC-HECO-IR-1_att_8_electric_vehicles.xlsx

[46] *See* https://www.fhwa.dot.gov/policyinformation/tables/vmt/vmt_forecast_sum.pdf

[47] *See* http://www.fueleconomy.gov

Energy Information Administration's (EIA) Annual Energy Outlook to the historical weighted average fuel economies.[48] The reference fuel economy growth rate was developed based on the expectation that battery technology will improve and larger vehicles will be produced.

Car registration data at the ownership level was not available to determine whether a car was a personally or commercially owned vehicle. Therefore, the Company used a ratio between residential and commercial PV installations in historical years to allocate the number of EVs between residential and commercial customers for each island. EVs were a relatively new technology and the number of PV installations were found to be correlated to EV adoption. Within the commercial EVs, a percentage based on PV capacity installed by commercial rate Schedules G, J, and P was applied to the total commercial EV count to arrive at the number of EVs at the commercial rate schedule level. The sales impact by rate schedule was calculated by multiplying the number of EVs by sales impact per vehicle for each island.

### *Light Duty Electric Vehicles Charging Profiles*

Previous unmanaged charging profiles were developed using third party and public charging station telemetry, load research conducted by several utilities in California, as well as Hawaiian Electric specific advanced metering infrastructure (AMI) data. The unmanaged residential and commercial light duty electric vehicle charging profiles were updated by leveraging data from the Company's DC fast charging network and a case study[49] conducted through the deployment of EnelX's Level 2 chargers in Hawai'i. Figure 4-3 below highlights the revised residential and commercial charging profiles compared to the previous IGP profiles, including a demand reduction during the evening peak hours in the residential charging profile. The revised charging profiles were presented on July 9, 2021 with a smaller group of stakeholders and again at the July 14, 2021 STWG meeting.

---

[48] *See* https://www.eia.gov/outlooks/aeo/data/browser/#/?id=113-AEO2019&cases=ref2019&sourcekey=0

[49] *See* Smart Charge Hawai'i Case Study, In partnership with Hawaiian Electric & Elemental Excelerator, EnelX

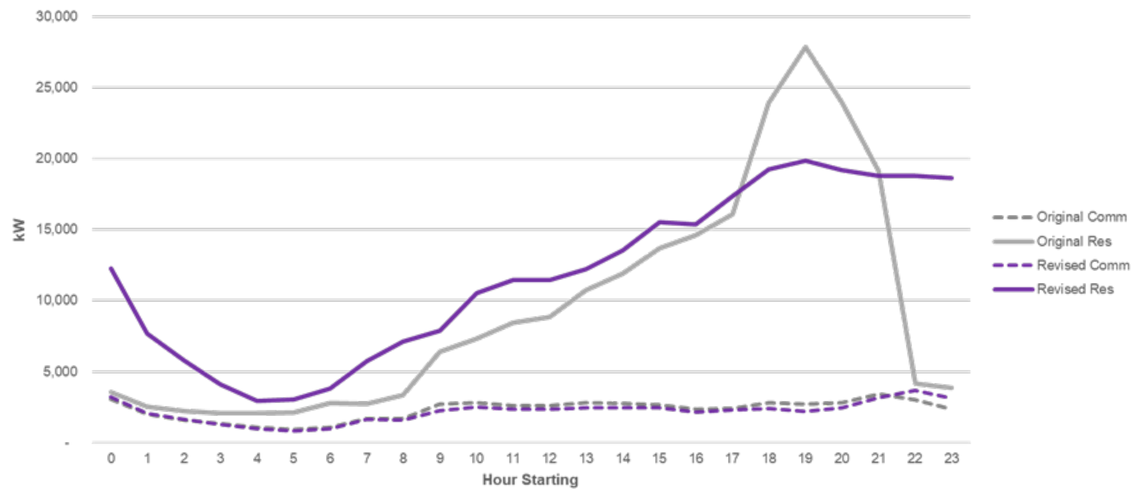



Figure 4-3: Revised Light Duty Electric Vehicle Charging Profiles

## *Electric Buses*

The electric bus forecast was based on information provided by the Company's Electrification of Transportation team following discussions with several bus operators throughout Honolulu, Hawai'i and Maui counties. Route information and schedules for weekdays, weekends and holidays were used to estimate the miles traveled for each bus operator. Since specific information on the buses were not available for most operators, the Company used the average bus efficiency (kWh per mile) for two different Proterra models. For each island, the total sales impact for each bus operator was applied to the rate schedule on which each bus operator was serviced.

## *High and Low Bookend Sensitivities*

Three additional light duty electric vehicle forecast sensitivities (Low, High, and Freeze) were developed using varying adoption saturation curves. Low and high saturation curves were presented at the August 27, 2019 and January 20, 2020 FAWG meetings, with the low saturation curve implemented for the Low EV sensitivity. At the June 17, 2021 STWG meeting, Blue Planet presented their suggested sensitivity representing a policy of 100% zero emissions vehicles by 2045 in the high customer technology adoption bookend, a change from the previously presented high saturation curve. Following that meeting, Blue Planet provided two forecast scenarios as suggestive references for a 100% ZEV on the road scenario. The first was the Transcending Oil Report prepared by the Rhodium Group in 2018. The Transcending Oil Report study considered vehicle scrappage rates and the transition rate of vehicle sales to fully electric. The study estimated all vehicle sales by 2030 would need to be electric to reach

100% electric vehicle stock by 2045.[50] The second was Blue Planet's self-developed estimate using the State Energy Office's Monthly Energy Trends data and a regression for the past 5 years on electric vehicle registrations. As discussed in Section 2.4 regarding areas of disagreement, Blue Planet most recently provided a revised high forecast that tracks closely with the Transcending Oil Report EV forecast. Ultimately, the High sensitivity used the 100% ZEV saturation scenario provided in the Transcending Oil Report. A freeze sensitivity was also developed, assuming no new additional electric vehicles above the Base forecast after 2021. These sensitivities were presented on July 9, 2021 with a smaller group of stakeholders and at the July 14, 2021 STWG meeting. The following Table 4-14 and Figure 4-4 summarize the light duty electric vehicle sensitivities and their forecasted annual sales [GWh].

Table 4-14: Electric Vehicle Forecast Sensitivities

| Low | Base | High | Freeze |
|---|---|---|---|
| Low Adoption Saturation | Market Forecast | 100% of ZEV by 2045 | Forecasted EV counts fixed at 2021 Base forecast |

[50] See Transcending Oil Report by Rhodium Group available at: https://rhg.com/wp-content/uploads/2018/04/rhodium_transcendingoil_final_report_4-18-2018-final.pdf

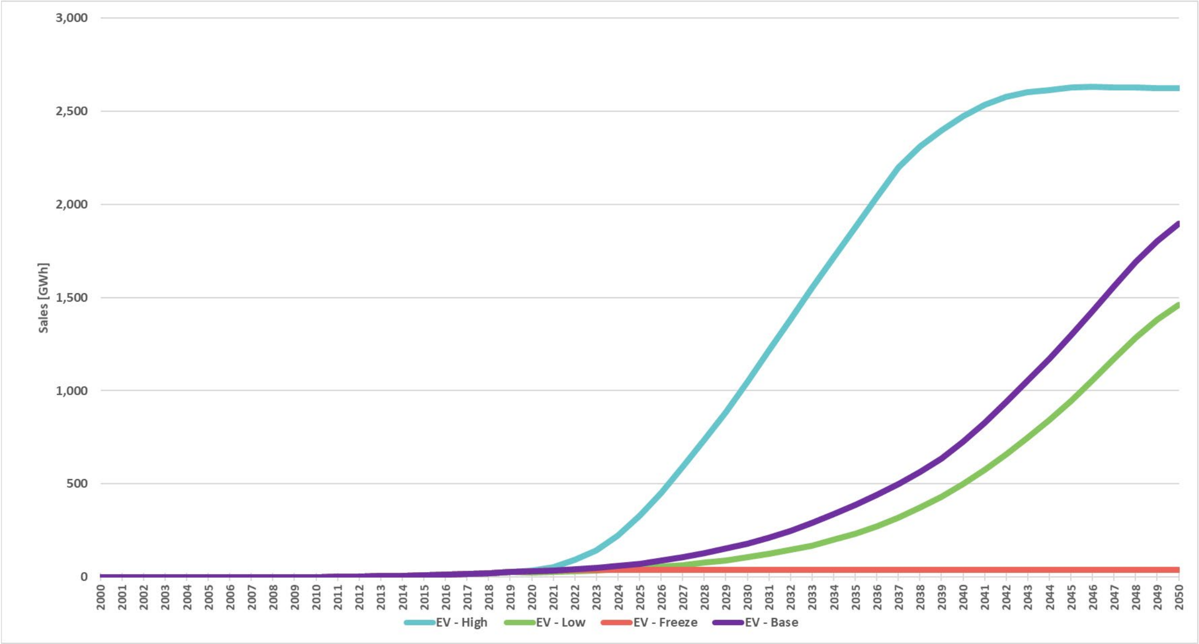



Figure 4-4: O‘ahu Electric Vehicle Annual Sales Forecast Sensitivities

### 4.1.4 Managed Electric Vehicle Charging

The managed electric vehicle charging profile considers EV driver response to time of use rates that were proposed for each island in the EV pilot programs in Docket No. 2020-0152. E3's linear optimization was used to model drivers who shift their usage in order to reduce their electricity bill as much as possible, while still retaining enough state of charge to meet their underlying driving profiles. The underlying trip data is the same so the managed and unmanaged charging have the same annual loads. The managed charging profiles from the I&A Review Point showed a flatter profile. E3 has since provided updated managed charging profiles based on their model, which shifts for of the charging load during the daytime. The updated average managed EV charging profile for select years is provided for O‘ahu in Figure 4-5 below.

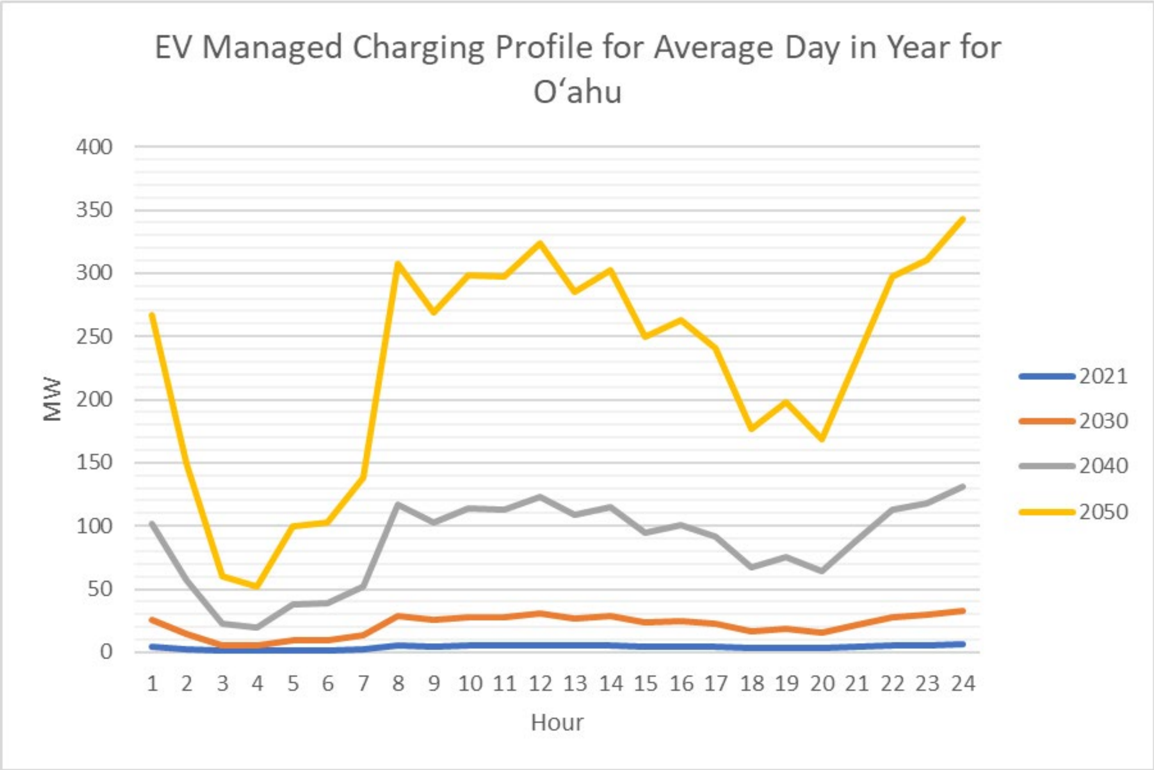



Figure 4-5: Average Managed EV Charging Profile for O'ahu

## 4.2 SALES FORECASTS

Once all the layers are developed for each island, they are added together to arrive at the sales forecast at the customer level by island as shown in the following tables.

Table 4-15: O'ahu Sales Forecast

| Year | Underlying | Distributed Energy Resources (PV and BESS) | Energy Efficiency | Electric Vehicles | Customer Level Sales Forecast |
|---|---|---|---|---|---|
| GWH | A | B | C | D | E =A + B + C + D |
| 2025 | 9,456 | (1,255) | (1,887) | 92 | 6,407 |
| 2030 | 10,133 | (1,415) | (2,307) | 221 | 6,632 |
| 2040 | 11,110 | (1,642) | (2,917) | 789 | 7,341 |

| | | | | | |
|---|---|---|---|---|---|
| 2045 | 11,499 | (1,707) | (3,142) | 1,366 | 8,016 |
| | | | | | |

| Year | Underlying | Distributed Energy Resources (PV and BESS) | Energy Efficiency | Electric Vehicles | Customer Level |
|---|---|---|---|---|---|
| GWH | A | B | C | D | E =A + B + C + D |
| | | | | | |
| 2030 | 1,535 | (263) | (345) | 39 | 967 |
| | | | | | |
| 2045 | 1,670 | (346) | (501) | 288 | 1,110 |
| | | | | | |

| Year | Underlying | Distributed Energy Resources (PV and BESS) | Energy Efficiency | Electric Vehicles | Customer Level Sales Forecast |
|---|---|---|---|---|---|
| GWH | A | B | C | D | E =A + B + C + D |
| 2025 | 1,474 | (271) | (300) | 14 | 917 |
| 2030 | 1,572 | (312) | (371) | 56 | 945 |
| 2040 | 1,726 | (374) | (473) | 255 | 1,134 |
| 2045 | 1,787 | (390) | (505) | 357 | 1,248 |
| 2050 | 1,852 | (403) | (529) | 443 | 1,363 |

| Year | Underlying | Distributed Energy Resources (PV and BESS) | Energy Efficiency | Electric Vehicles | Customer Level |
|---|---|---|---|---|---|
| GWH | A | B | C | D | E =A + B + C + D |
| | | | | | |
| 2030 | 36.4 | (6.5) | (3.6) | 0.3 | 26.6 |
| | | | | | |
| 2045 | 38.3 | (8.0) | (4.5) | 2.1 | 27.9 |
| | | | | | |

| Year | Underlying | Distributed Energy Resources (PV and BESS) | Energy Efficiency | Electric Vehicles | Customer Level Sales Forecast |
|---|---|---|---|---|---|
| GWH | A | B | C | D | E =A + B + C + D |
| 2025 | 40.8 | (1.7) | (1.6) | 0.1 | 37.6 |
| 2030 | 42.2 | (2.1) | (2.0) | 0.2 | 38.2 |
| 2040 | 44.1 | (2.9) | (2.8) | 0.7 | 39.1 |
| 2045 | 44.7 | (3.2) | (3.0) | 1.3 | 39.8 |
| 2050 | 45.6 | (3.4) | (3.3) | 1.9 | 40.8 |

The customer level sales forecasts were compiled by incorporating the separate layers for the underlying, distributed energy resources, energy efficiency, and electric vehicles sales. The Base forecast would incorporate the base forecast for each of the layers. In the Company's proposal for Customer Technology Adoption bookends, the high layers would be added together to create a high bookend. Similarly, the low layers would be added together to create a low bookend. This process would incorporate layers that have offsetting effects on sales i.e. high DER and EE layers would reduce sales and offset the increased sales of the high EV layer. When compiling the sales layers, separate sales forecasts were also developed to incorporate a combination of layers that purposefully lead to high and low sales. In the charts below, Figure 4-6 through Figure 4-10, the High and Low Customer Technology Adoption sales forecasts are shown in teal and green, labeled as High Adoption and Low Adoption, respectively. Separately, the high and low load sales forecasts are shown in shades of orange, labeled as High Load and Low Load, respectively.

Upon review of these sales forecasts, the Low Customer Technology Adoption bookend was observed to track the Base forecast and was not significantly different to serve as a bookend. Similarly, the High Customer Technology Adoption bookend was observed to cross over the Low Customer Technology Adoption bookend and Base forecasts and would not serve as an appropriate bookend. However, the High Load and Low Load forecasts were significantly different from the Base forecasts, did not cross over other forecasts, and captured the High and Low Customer Technology Adoption forecasts within its bounds, making them a better candidate to serve as bookends. The selection of the High Load and Low Load scenarios is consistent with the TAP's recommendation to test the sensitivity of models and resulting portfolios by running bookend scenarios that utilize the cumulative potential high and low load forecasts for each layer. Section 6 further describes the adjustments made to the high and low bookends.

### *High and Low Bookend Scenarios*

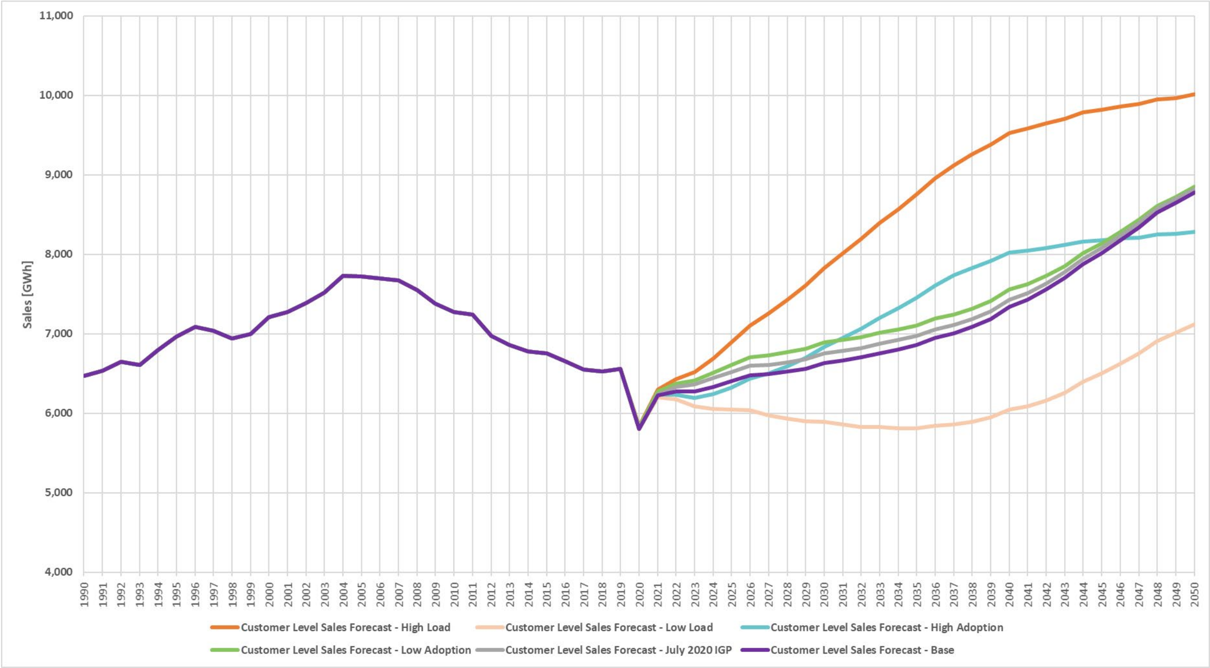



Figure 4-6: O'ahu Sales Forecast Bookend Sensitivities

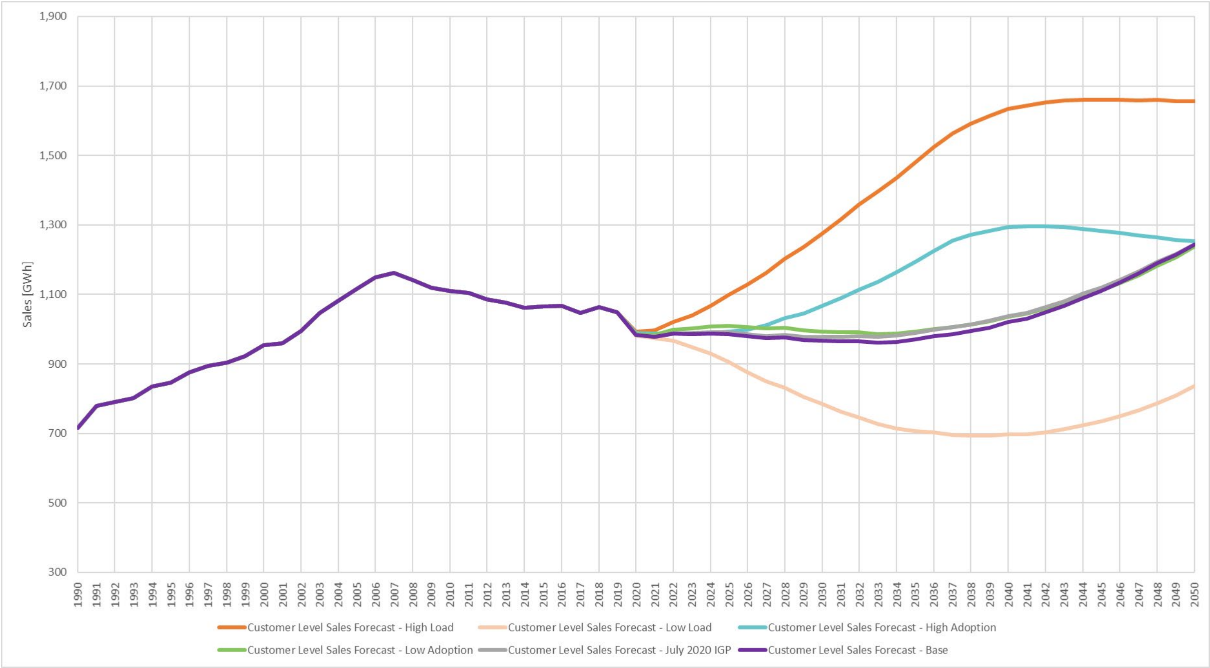



Figure 4-7: Hawai'i Sales Forecast Bookend Sensitivities

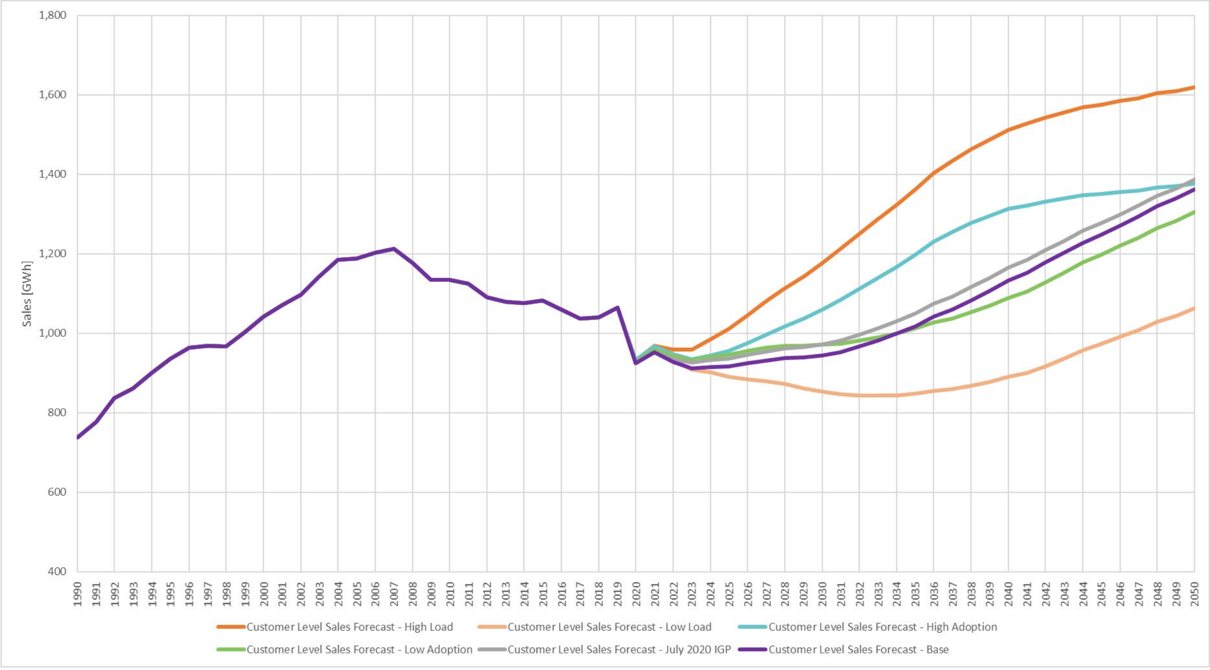



Figure 4-8: Maui Sales Forecast Bookend Sensitivities

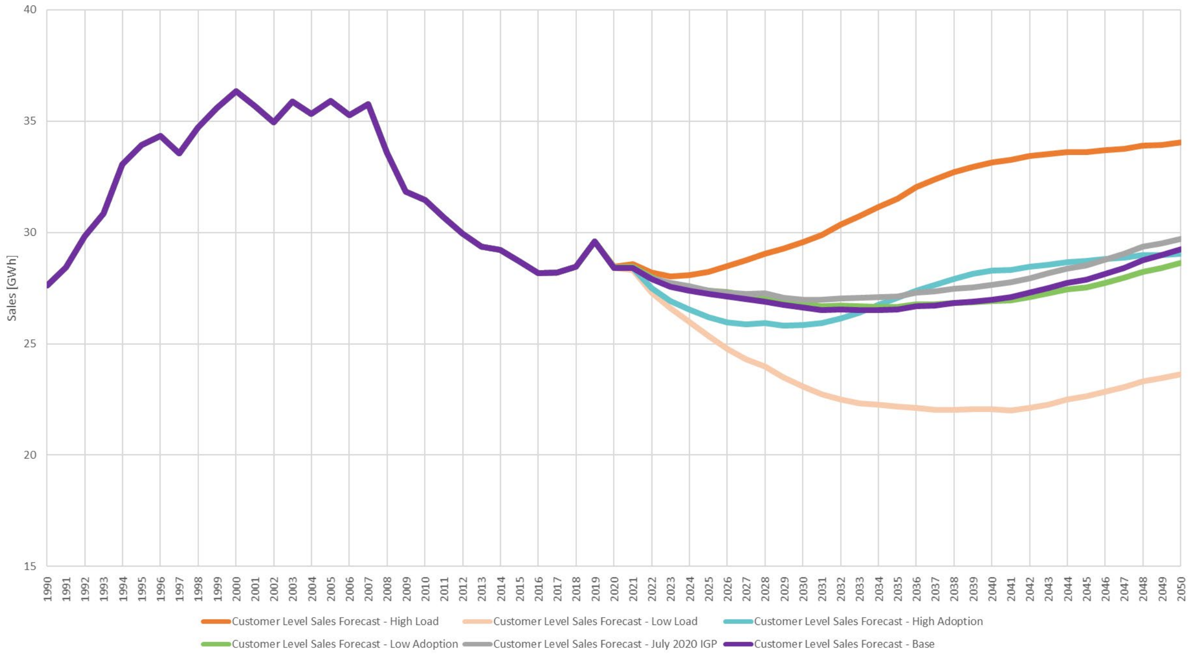



Figure 4-9: Molokaʻi Sales Forecast Bookend Sensitivities

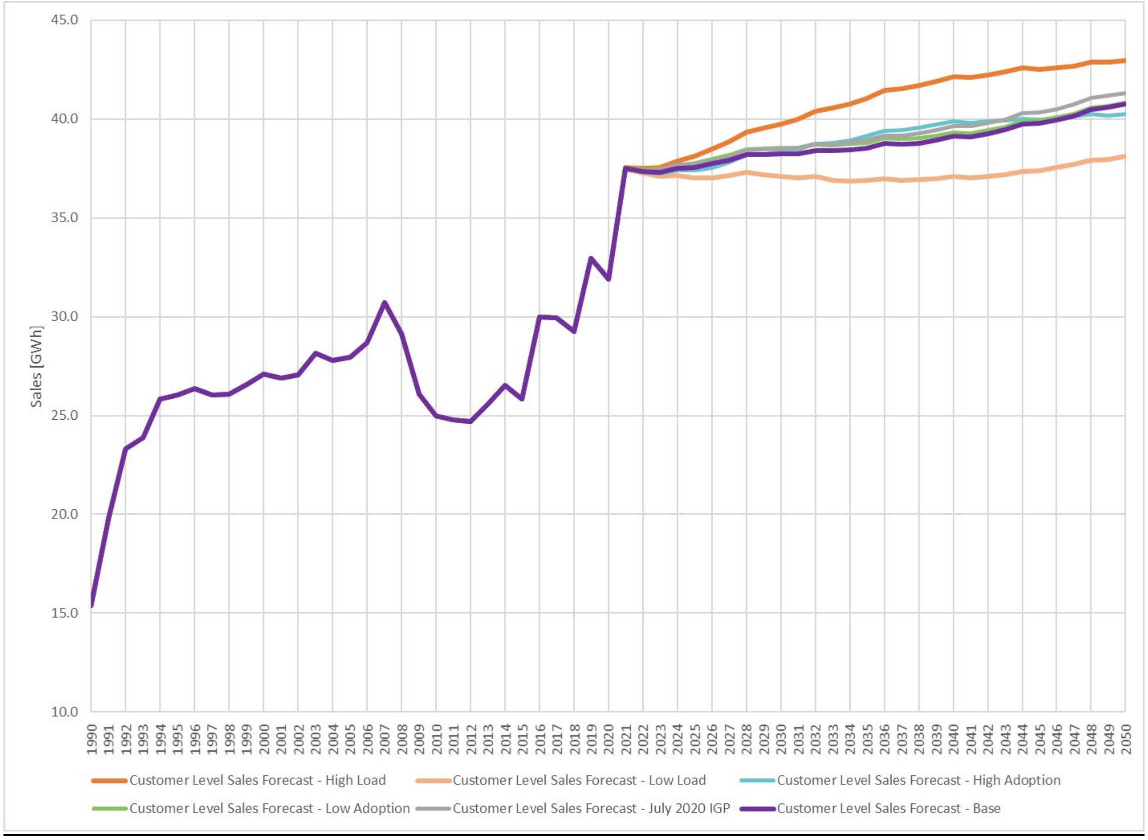
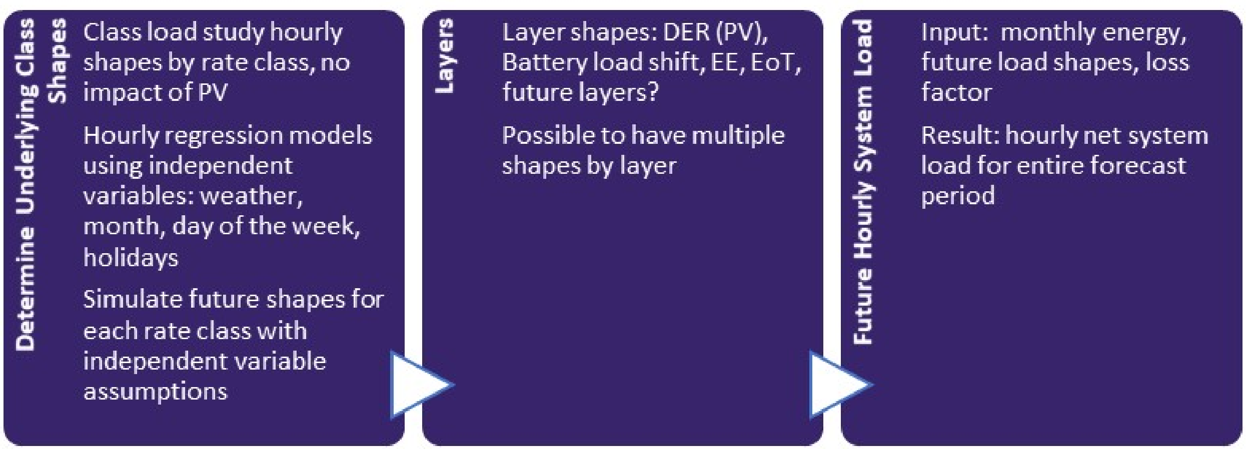



Figure 4-10: Lānaʻi Sales Forecast Bookend Sensitivities

## 4.3 PEAK FORECASTS

Once the sales forecast is developed by layer (underlying, DER, EE and EoT) for each island, it is converted from a monthly sales forecast into a load forecast at the system level for each hour over the entire forecast horizon. The method to do the conversion from sales to an hourly load forecast is shown in the figure below. Hourly shapes from class load studies ("CLS") for each rate class or the total system load excluding the impact from PV are used to derive the underlying system load forecast shape. Hourly regression models are evaluated to look for relationships with explanatory variables (weather, month, day of the week, holidays) in order to accommodate change in the underlying shapes over time for each rate class or total system load. The hourly regression models are used to simulate shapes for the underlying forecast based on the forecast assumptions over the entire horizon. The forecasted energy for the underlying and each adjusting layer (DER PV, battery load shift, energy efficiency and EoT) is placed under its respective future load shape then converted from the customer level to system level using a loss factor[51] as presented in the July 17, 2019[52] and March 9, 2020[53] FAWG meetings.




The result is an hourly net system load for the entire forecast period.

[51] The net-to-system factor used to convert customer sales to system level load is calculated as equal to 1/(1-loss factor) and include company use. The loss factors are included below: - Oahu: 4.43% - Hawaii: 6.76% - Maui: 5.17% - Lanai: 4.39% - Molokai: 9.07%

[52] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20190717_wg_fa_meeting_presentation_materials.pdf

[53] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20200309_wg_fa_meeting_presentation_materials.pdf

Once all the forecasted layers are developed by hour for each island, they are combined to arrive at an aggregated hourly load forecast. The annual peak forecast is the highest value in each year. The peaks presented in the August 31, 2020 FAWG meeting include the impacts of COVID-19.[54] This forecast assumes EVs will be charged at each owner's convenience which may occur during the daytime on-peak period. This initial forecast will inform downstream processes in the development of programs and incentives related to shifting EV charging to off-peak periods. These programs and incentives will then be integrated into the forecast through an iterative process in the Grid Needs Assessment. As a result of this initial forecast which utilizes "unmanaged" charging, the peak contribution from EVs increases over time as EVs become more widely owned.

| Year | Underlying | Distributed (PV and BESS) | Energy Efficiency | Electric Vehicles | Peak Forecast |
|---|---|---|---|---|---|
| MW | A | B | C | D | E =A + B + C + D |
| | | | | | |
| 2030 | 1,642 | (95) | (402) | 39 | 1,184 |
| | | | | | |
| 2045 | 1,702 | (43) | (452) | 286 | 1,493 |
| | | | | | |

| Year | Underlying | Distributed Energy Resources (PV and BESS) | Energy Efficiency | Electric Vehicles | Peak Forecast |
|---|---|---|---|---|---|
| MW | A | B | C | D | E =A + B + C + D |
| 2025 | 229.5 | (10.0) | (42.6) | 2.1 | 178.9 |
| 2030 | 236.8 | (12.5) | (55.5) | 8.7 | 177.5 |

54 *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20200831_wg_fa_meeting_presentation_materials_HECO.pdf See slides 7, 10, 12, 14 and 17 for O'ahu, Maui, Moloka'i, Lāna'i and Hawai'i islands respectively.

| | | | | | |
|---|---|---|---|---|---|
| | | | | | |
| **2045** | 247.2 | (3.4) | (85.3) | 64.5 | 223.1 |
| | | | | | |

| Year | Underlying | Distributed Energy Resources (PV and BESS) | Energy Efficiency | Electric Vehicles | Peak Forecast |
|---|---|---|---|---|---|
| **MW** | A | B | C | D | E =A + B + C + D |
| | | | | | |
| **2030** | 261.1 | (29.2) | (58.1) | 11.4 | 185.2 |
| | | | | | |
| **2045** | 255.4 | (4.1) | (67.7) | 77.8 | 261.4 |
| | | | | | |

| Year | Underlying | Distributed | Energy Efficiency | Electric Vehicles | Peak Forecast |
|---|---|---|---|---|---|
| **MW** | A | B | C | D | E =A + B + C + D |
| | | | | | |
| **2030** | 5.8 | (0.1) | (0.2) | 0.0 | 5.6 |
| | | | | | |
| **2045** | 6.3 | (0.3) | (0.2) | 0.5 | 6.3 |
| | | | | | |

| Year | Underlying | Distributed Energy Resources (PV and BESS) | Energy Efficiency | Electric Vehicles | Peak Forecast |
|---|---|---|---|---|---|
| **MW** | A | B | C | D | E =A + B + C + D |

| | | | | | |
|---|---|---|---|---|---|
| 2025 | 6.5 | – | (0.1) | – | 6.4 |
| 2030 | 6.8 | (0.1) | (0.2) | – | 6.6 |
| 2040 | 7.2 | (0.1) | (0.3) | 0.1 | 6.9 |
| 2045 | 7.3 | (0.2) | (0.4) | 0.3 | 7.0 |
| 2050 | 7.5 | (0.2) | (0.4) | 0.4 | 7.3 |

Similar to the customer level sales forecast, the peak forecast sensitivities were compiled by incorporating varying combinations of the underlying, distributed energy resources, energy efficiency, and electric vehicles hourly forecasts. The following chart includes the O'ahu peak forecast sensitivities that correspond to the customer sales level forecast sensitivities.

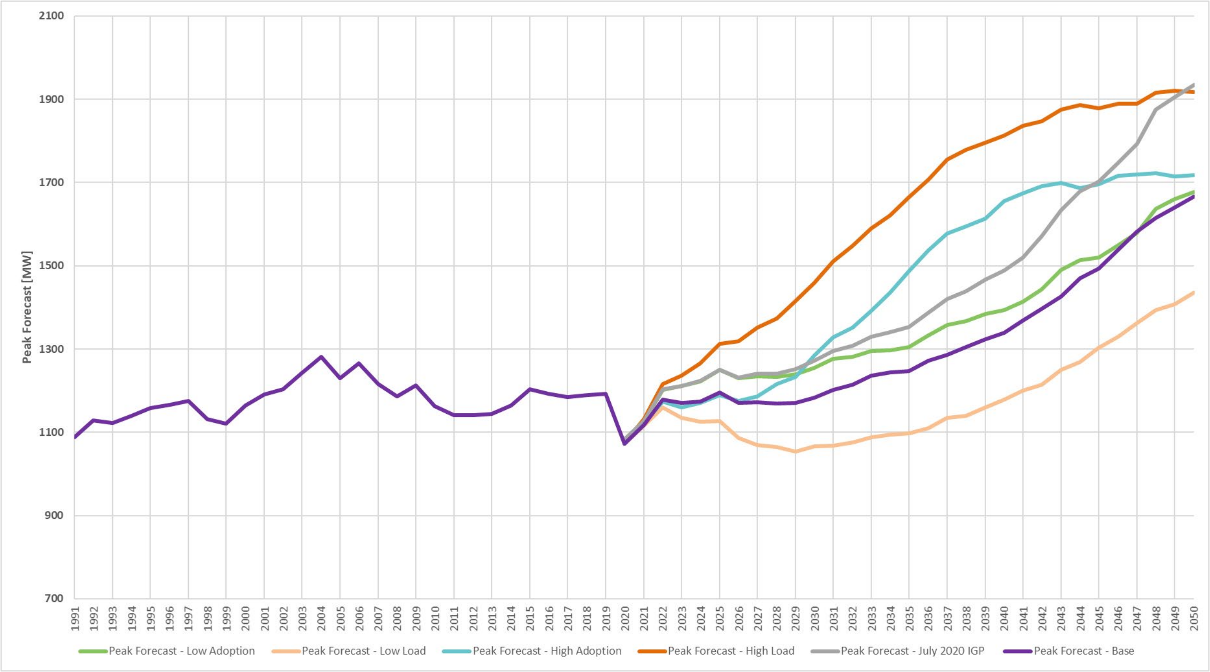



Figure 4-11: O'ahu Peak Forecast Bookend Sensitivities

## 4.4 FUEL PRICE FORECASTS

The cost of producing electricity is dependent upon, in part, the cost of fuels utilized to generate power. Hawaiian Electric uses the following fuel types:

- Low Sulfur Fuel Oil (LSFO): A residual fuel oil similar to No. 6 fuel oil that contains less than 5,000 parts per million of sulfur; about 0.5% sulfur content

- No. 2 Diesel Oil
- Ultra-Low Sulfur Diesel (ULSD)
- Naphtha
- High Sulfur Fuel Oil (HSFO): Also called Industrial Fuel Oil (IFO), HSFO contains less than 2% sulfur

The fuel price forecast was developed using a correlation between historical, actual fuel prices and the Brent North Sea Crude Oil Benchmark (Brent) from 1983-2019.[55] The $R^2$ value for petroleum fuels was greater than 0.93. Hawaiian Electric's 2021 forecast was based on the Brent forecast provided by the Energy Information Administration ("EIA") Annual Energy Outlook ("AEO").

Table 4-25: O'ahu Fuel Price Forecast

| Year $/MMBTU | LSFO | Diesel | ULSD CIP | ULSD SGS | Biodiesel |
|---|---|---|---|---|---|
| 2021 | 8.73 | 11.49 | 11.93 | 12.72 | 28.55 |
| 2022 | 9.43 | 12.24 | 12.71 | 13.51 | 29.32 |
| 2023 | 10.51 | 13.38 | 13.87 | 14.68 | 30.39 |
| 2024 | 11.36 | 14.28 | 14.80 | 15.62 | 31.37 |
| 2025 | 12.14 | 15.14 | 15.68 | 16.52 | 32.41 |
| 2026 | 13.03 | 16.11 | 16.68 | 17.54 | 33.60 |
| 2027 | 13.82 | 16.99 | 17.58 | 18.46 | 34.78 |
| 2028 | 14.67 | 17.94 | 18.56 | 19.46 | 36.04 |
| 2029 | 15.49 | 18.85 | 19.50 | 20.42 | 37.30 |
| 2030 | 16.36 | 19.82 | 20.49 | 21.45 | 38.60 |
| 2031 | 17.14 | 20.69 | 21.38 | 22.36 | 39.82 |
| 2032 | 18.03 | 21.67 | 22.40 | 23.40 | 41.12 |
| 2033 | 18.74 | 22.47 | 23.22 | 24.25 | 42.29 |
| 2034 | 19.47 | 23.29 | 24.07 | 25.11 | 43.45 |
| 2035 | 20.10 | 24.02 | 24.81 | 25.88 | 44.56 |
| 2036 | 20.90 | 24.90 | 25.72 | 26.82 | 45.77 |
| 2037 | 21.76 | 25.86 | 26.70 | 27.82 | 47.03 |

[55] Hawaiian Electric updated its assumptions to use the fuel price forecast provided by the EIA AEO instead of FGE in response to stakeholder feedback to use publicly available, non-proprietary sources.

| | | | | | |
|---|---|---|---|---|---|
| **2038** | 22.63 | 26.82 | 27.69 | 28.83 | 48.31 |
| | | | | | |
| **2040** | 24.37 | 28.76 | 29.69 | 30.88 | 50.91 |
| | | | | | |
| **2042** | 26.15 | 30.75 | 31.74 | 32.98 | 53.65 |
| | | | | | |
| **2044** | 28.16 | 32.99 | 34.04 | 35.34 | 56.73 |
| | | | | | |
| **2046** | 29.99 | 35.08 | 36.19 | 37.56 | 59.92 |
| | | | | | |
| **2048** | 32.03 | 37.40 | 38.59 | 40.03 | 63.49 |
| | | | | | |
| **2050** | 34.10 | 39.79 | 41.05 | 42.57 | 67.35 |

Table 4-26: Hawai‘i Island Fuel Price Forecast

| Year $/MMBTU | IFO | Diesel | ULSD | Naphtha | Biodiesel |
|---|---|---|---|---|---|
| **2021** | 7.45 | 12.16 | 12.68 | 13.71 | 28.55 |
| **2022** | 8.06 | 12.98 | 13.52 | 14.50 | 29.32 |
| **2023** | 8.99 | 14.21 | 14.78 | 15.69 | 30.39 |
| **2024** | 9.72 | 15.18 | 15.78 | 16.65 | 31.37 |
| **2025** | 10.40 | 16.10 | 16.73 | 17.56 | 32.41 |
| **2026** | 11.17 | 17.15 | 17.81 | 18.61 | 33.60 |
| **2027** | 11.85 | 18.09 | 18.77 | 19.56 | 34.78 |
| **2028** | 12.59 | 19.11 | 19.82 | 20.58 | 36.04 |
| **2029** | 13.29 | 20.09 | 20.83 | 21.58 | 37.30 |
| **2030** | 14.05 | 21.13 | 21.91 | 22.63 | 38.60 |
| **2031** | 14.71 | 22.06 | 22.87 | 23.57 | 39.82 |
| **2032** | 15.48 | 23.13 | 23.96 | 24.64 | 41.12 |
| **2033** | 16.10 | 23.99 | 24.85 | 25.52 | 42.29 |

| | | | | | |
|---|---|---|---|---|---|
| 2034 | 16.72 | 24.86 | 25.75 | 26.41 | 43.45 |
| | | | | | |
| 2036 | 17.96 | 26.59 | 27.53 | 28.17 | 45.77 |
| | | | | | |
| 2038 | 19.45 | 28.65 | 29.65 | 30.24 | 48.31 |
| | | | | | |
| 2040 | 20.96 | 30.74 | 31.80 | 32.35 | 50.91 |
| | | | | | |
| 2042 | 22.50 | 32.87 | 34.00 | 34.51 | 53.65 |
| | | | | | |
| 2044 | 24.23 | 35.28 | 36.48 | 36.94 | 56.73 |
| | | | | | |
| 2046 | 25.81 | 37.52 | 38.79 | 39.24 | 59.92 |
| | | | | | |
| 2048 | 27.57 | 40.01 | 41.37 | 41.81 | 63.49 |
| | | | | | |
| 2050 | 29.35 | 42.57 | 44.01 | 44.46 | 67.35 |

| Year | Maui | | | | Moloka‘i | Lāna‘i |
|---|---|---|---|---|---|---|
| $/MMBTU | IFO | Diesel | ULSD | Biodiesel | ULSD | ULSD |
| 2021 | 7.09 | 11.75 | 12.09 | 28.55 | 12.91 | 16.08 |
| 2022 | 7.69 | 12.58 | 12.94 | 29.32 | 13.76 | 16.95 |
| 2023 | 8.62 | 13.85 | 14.23 | 30.39 | 15.04 | 18.26 |
| 2024 | 9.33 | 14.85 | 15.26 | 31.37 | 16.07 | 19.33 |
| 2025 | 10.00 | 15.78 | 16.22 | 32.41 | 17.03 | 20.35 |
| 2026 | 10.75 | 16.85 | 17.31 | 33.60 | 18.13 | 21.51 |
| 2027 | 11.42 | 17.80 | 18.28 | 34.78 | 19.12 | 22.58 |
| 2028 | 12.14 | 18.83 | 19.34 | 36.04 | 20.19 | 23.73 |
| 2029 | 12.83 | 19.82 | 20.36 | 37.30 | 21.22 | 24.84 |
| 2030 | 13.57 | 20.88 | 21.44 | 38.60 | 22.31 | 26.02 |

| | | | | | | |
|---|---|---|---|---|---|---|
| **2031** | 14.22 | 21.82 | 22.40 | 39.82 | 23.29 | 27.08 |
| **2032** | 14.97 | 22.89 | 23.50 | 41.12 | 24.40 | 28.28 |
| **2033** | 15.57 | 23.76 | 24.39 | 42.29 | 25.31 | 29.27 |
| **2034** | 16.19 | 24.65 | 25.30 | 43.45 | 26.23 | 30.27 |
| **2035** | 16.72 | 25.43 | 26.10 | 44.56 | 27.05 | 31.17 |
| **2036** | 17.39 | 26.39 | 27.09 | 45.77 | 28.05 | 32.26 |
| **2037** | 18.12 | 27.43 | 28.15 | 47.03 | 29.12 | 33.41 |
| **2038** | 18.85 | 28.48 | 29.22 | 48.31 | 30.21 | 34.58 |
| **2039** | 19.31 | 29.16 | 29.93 | 49.37 | 30.93 | 35.39 |
| **2040** | 20.33 | 30.59 | 31.39 | 50.91 | 32.40 | 36.94 |
| **2041** | 21.14 | 31.75 | 32.58 | 52.32 | 33.60 | 38.23 |
| **2042** | 21.83 | 32.75 | 33.60 | 53.65 | 34.64 | 39.36 |
| **2043** | 22.73 | 34.03 | 34.92 | 55.21 | 35.97 | 40.79 |
| **2044** | 23.52 | 35.18 | 36.09 | 56.73 | 37.16 | 42.09 |
| **2045** | 23.93 | 35.81 | 36.74 | 57.99 | 37.84 | 42.90 |
| **2046** | 25.07 | 37.43 | 38.40 | 59.92 | 39.52 | 44.70 |
| **2047** | 25.98 | 38.76 | 39.76 | 61.72 | 40.90 | 46.22 |
| **2048** | 26.78 | 39.93 | 40.97 | 63.49 | 42.14 | 47.60 |
| **2049** | 27.63 | 41.19 | 42.26 | 65.38 | 43.46 | 49.07 |
| **2050** | 28.51 | 42.49 | 43.60 | 67.35 | 44.83 | 50.60 |

## 4.5 RESOURCE COST FORECASTS

Resource cost assumptions were based on publicly available datasets, as shown in Table 4-28.

Table 4-28: Resource Cost Data Sources

| | |
|---|---|
| **U.S. Department of Energy (DOE)** | • Distributed wind[56],[57]<br>• Pumped Storage Hydro[58] |
| **National Renewable Energy Laboratory (NREL)** [59] | • Grid-Scale PV<br>• Distributed PV<br>• Onshore Wind<br>• Geothermal<br>• Biomass<br>• Grid-Scale Storage<br>• Distributed Storage<br>• Combustion Turbine<br>• Combined Cycle<br>• Synchronous Condenser<br>• Offshore wind[60] |
| **US Energy Information Administration (EIA)** [61] | • Waste-to-energy |
| **Hawaiian Electric**[62] | • ICE |

[56] U.S. Department of Energy, 2017 Distributed Wind Market Report, https://www.energy.gov/eere/wind/downloads/2017-distributed-wind-market-report

[57] U.S. Department of Energy, 2018 Distributed Wind Market Report, https://www.energy.gov/eere/wind/downloads/2018-distributed-wind-market-report

[58] U.S. Department of Energy, 2020 Grid Energy Storage Technologies Cost and Performance Assessment, https://www.energy.gov/energy-storage-grand-challenge/downloads/2020-grid-energy-storage-technology-cost-and-performance#:~:text=Pacific%20Northwest%20National%20Laboratory%E2%80%99s%202020%20Grid%20Energy%20Storage,down%20different%20cost%20categories%20of%20energy%20storage%20systems.

[59] National Renewable Energy Laboratory 2021 Annual Technology Baseline, 2021 ATB Data, https://atb.nrel.gov/electricity/2021/data

[60] National Renewable Energy Laboratory Bureau of Ocean Energy Management, Cost Modeling for Floating Wind Energy Technology Offshore Oahu, Hawaii, https://www.boem.gov/sites/default/files/documents/regions/pacific-ocs-region/environmental-analysis/HI%20Cost%20Study%20Fact%20Sheet.pdf

[61] U.S. Energy Information Administration, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2019

[62] ICE costs are based on the Schofield Generating Station provided in Docket No. 2017-0213, in response to the Consumer Advocate’s information request number 19.

Resource cost assumptions began with a base technology capital cost that was adjusted for:

1. Future technology trends through the planning period;
2. Location-specific capital and O&M cost adjustments for Hawai'i; and
3. Applicable Federal & State tax incentives;
4. Price parity to recent renewable projects.

Figure 4-12 is a summary of the resource forecasts in nominal dollars. The resource cost forecasts from 2020-2050 can be found in Appendix A: Nominal Resource Cost Forecasts (2020 – 2050). In the near-term, there are price declines after accounting for the investment tax credit schedules for the Federal and State investment tax credits. Over the longer term, after the tax credit schedules ramp down and are held constant, the resources costs generally increase over time. As noted in the NREL ATB, all technologies include electrical infrastructure and interconnection costs for internal and control connections, onsite electrical equipment e.g. switchyard, power electronics and transmission substation upgrades. [63] Similarly, all technologies also include site costs for access roads, buildings for operation and maintenance, fencing, land acquisition, and site preparation in the capital expenditures as well as land lease payments in the fixed costs for O&M.[64] Although the ATB does not discretely break out the percentage of the capital costs or O&M costs associated with either of these items, their inclusion is consistent with the adjustment made for recent PV, wind, geothermal, and PV+BESS projects as actual project pricing would have accounted for interconnection and land costs.

[63] See https://atb.nrel.gov/electricity/2021/definitions#capitalexpenditures

[64] Ibid.

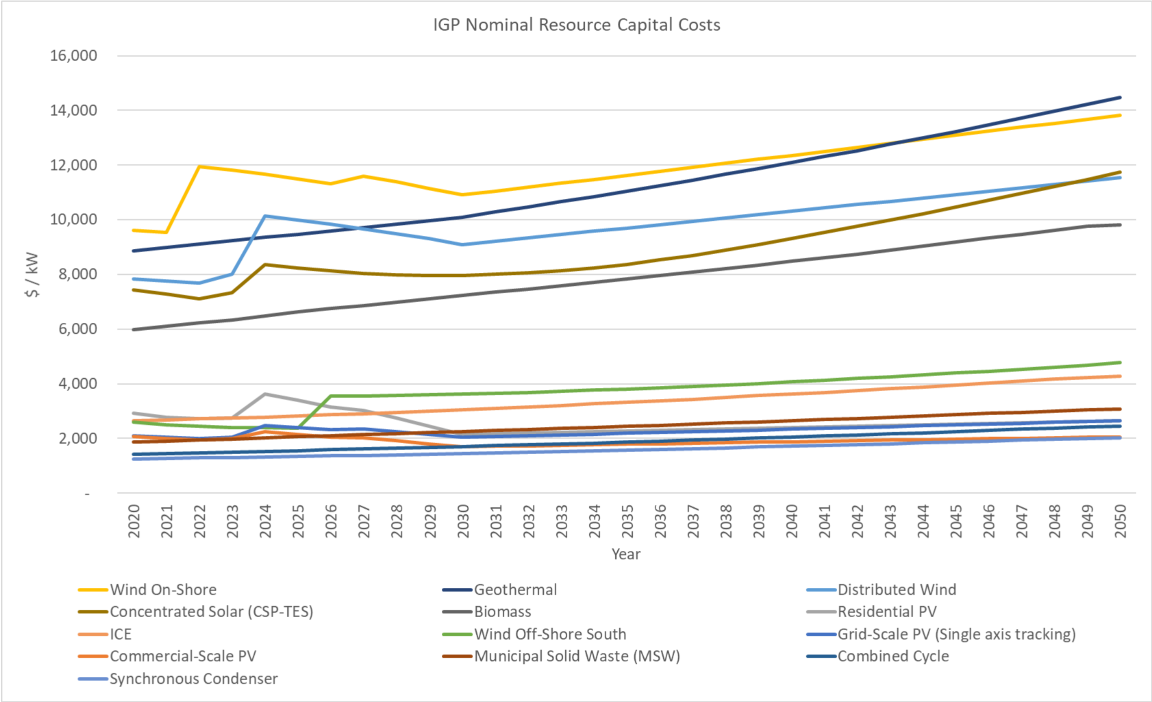



Figure 4-12: Capital Costs for IGP Candidate Resources

A comparison of the levelized cost of energy for select resources to the recently procured solar paired with storage PPAs[65] is shown below in Figure 4-13.

[65] *See* https://www.hawaiianelectric.com/new-renewable-projects-submitted-to-regulators-will-produce-lower-cost-electricity-advance-clean-energy

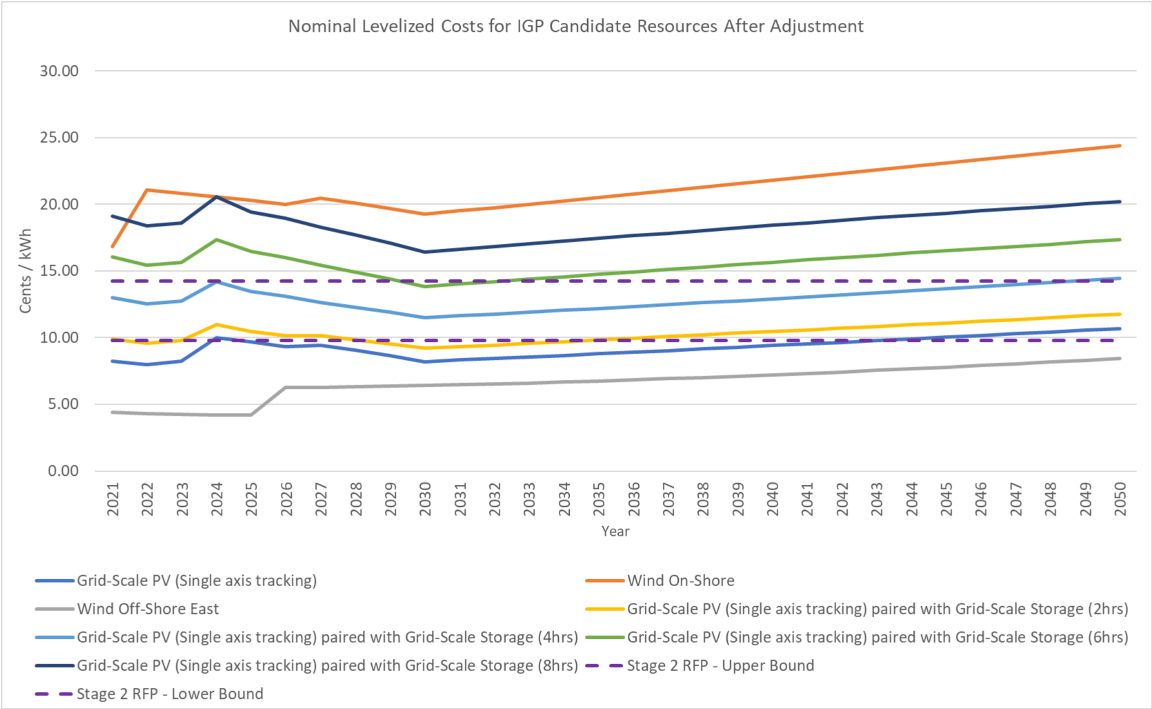



Figure 4-13: Levelized Cost of Energy for Select IGP Candidate Resources

## *Photovoltaics (PV)*

For Photovoltaics (PV), three different classes were forecasted: Grid-Scale PV, Commercial PV, and Residential PV. Each class used a similar process to develop the cost forecast.

**Data Source**

The source data for capital and fixed operations and maintenance (O&M) costs was provided by the 2021 NREL ATB. For Grid-Scale PV, the capital costs provided were in Real 2019 dollars $/kW$_{ac}$ and the O&M costs provided were in Real 2019 dollars $/kW$_{ac}$-year. For Commercial and Residential PV, the capital costs provided were in Real 2019 dollars $/kW$_{dc}$ and the O&M costs provided were in Real 2019 dollars $/kW$_{dc}$-year. The future trend for the capital and fixed O&M cost was derived from the 2021 NREL ATB projections. The Real 2019 dollars were converted to nominal dollars by applying an escalation factor of 2.3%.

**Location Adjustment**

A location adjustment factor was applied to convert both capital costs ($/kW) and O&M costs ($/kW-year) to Hawaiʻi costs. A 63% location adjustment factor for capital[66] was provided by the U.S. Energy Information Administration (EIA)[67] for Grid-Scale PV and a 62% location adjustment factor for Commercial and Residential PV. An 18.5% location adjustment factor for fixed O&M costs was provided by the RSMeans City Cost Index.[68]

### DC to AC Conversion

Capital costs for Commercial and Residential PV were converted from $/kW$_{dc}$ to $/kW$_{ac}$. For Commercial and Residential PV, a DC to AC conversion factor of 1.15 was used. These conversion factors were based on assumptions provided by NREL.

### Investment Tax Credit Adjustment

The Federal[69] and State ITC[70] schedules assumed for PV are summarized in Table 4-29 below. In December 2020, the Federal ITC for PV was given a two-year extension.[71] As a result, the capital cost for Grid-Scale PV, Commercial PV, and Residential PV were adjusted accordingly.

Table 4-29: Federal and State ITC Schedule for PV

| Year | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | Future |
|---|---|---|---|---|---|---|---|---|---|
| Federal ITC for Grid-Scale and Commercial-Scale PV | 26% | 26% | 26% | 22% | 10% | 10% | 10% | 10% | 10% |
| Federal ITC for Residential PV | 26% | 26% | 26% | 22% | 0% | 0% | 0% | 0% | 0% |
| State ITC for Grid-Scale, Commercial and Residential PV | 35% | 35% | 25% | 25% | 20% | 20% | 20% | 15% | 15% |

### Recent Project Adjustment

Final capital costs were adjusted based on actual costs from recent projects. For standalone PV, the cost was adjusted by approximately 162% so that the LCOE was similar to West Loch PV (7.5 cents/kWh). For paired PV, the costs

66 A location cost variation percentage from the EIA Capital Cost Estimates for Utility Scale Electricity Generating Plants.

67 *See* https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf

68 RSMeans Building Construction Cost Data (BCCD) is a reference book for estimating construction costs in the U.S. and Canada.

69 *See* https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

70 See https://tax.hawaii.gov/geninfo/renewable

71 *See* https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

were adjusted by approximately 106% so that the annual payment of the paired system would be similar to the lump sum payments of the Stage 2 projects that had a term of 25 years and a 4-hour Battery.

### *Onshore Wind*

**Data Source**

The source data for capital and fixed O&M costs for Onshore Wind was provided by the 2021 NREL ATB. The capital costs were in Real 2019 dollars $/kW. The fixed O&M costs were in Real 2019 $/kW-year. The future trend for the capital and O&M costs was derived from the 2021 NREL ATB projections. The Real 2019 dollars were converted to nominal dollars by applying an escalation factor of 2.3%.

**Location Adjustment**

The capital costs were converted to Hawai'i costs using a 35% factor from EIA for wind technology. The O&M costs were converted to Hawai'i costs using an 18.5% RSMeans factor. Location-specific interconnection costs were not included in the estimate.

**Investment Tax Credit Adjustment**

The Federal[72,73] and State ITC[74] schedules assumed for Onshore Wind are summarized in Table 4-30 below. Initially, the Federal ITC for Onshore Wind was to expire at the end of 2020.[75] In December 2020, however, the expiration date was extended a year.[76] As a result, the capital cost was for Onshore Wind was adjusted accordingly.

Table 4-30: Federal and State ITC Schedule for Onshore Wind

| Year | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | Future |
|---|---|---|---|---|---|---|---|---|---|
| Federal ITC | 18% | 18% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| State ITC | 20% | 20% | 20% | 20% | 20% | 20% | 20% | 15% | 15% |

72 https://www.energy.gov/sites/prod/files/2020/02/f71/weto-funding-factsheet-2020.pdf and https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

73 https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

74 https://tax.hawaii.gov/geninfo/renewable

75 https://www.energy.gov/sites/prod/files/2020/02/f71/weto-funding-factsheet-2020.pdf and https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

76 https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

**Recent Project Adjustment**
Final capital costs were adjusted based on actual costs from recent projects. For Onshore Wind, the costs were adjusted by approximately 772% so that the LCOE was similar to Na Pua Makani (15.3 cents/kWh).

### *Offshore Wind*

**Data Source**
The source data for the Offshore wind estimate was developed specially for Hawaii by NREL. The NREL study was used to determine the underlying costs for both capital and O&M.

**Location Adjustment**
The capital costs and O&M cost provided by NREL were specifically tailored for Hawaii. Therefore, no location adjustment was needed. The location-specific onshore interconnection costs were not included in the estimate.

**Investment Tax Credit Adjustment**
The Federal[77] and State ITC[78] schedules assumed for Offshore Wind are summarized in Table 4-31 below. Initially, Offshore Wind followed the same schedule as Onshore Wind. In December 2020, the Federal ITC for Offshore Wind was developed.[79] As a result, the capital cost for Offshore Wind was adjusted accordingly.

Table 4-31: Federal and State ITC Schedule for Offshore Wind

| Year | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | Future |
|---|---|---|---|---|---|---|---|---|---|
| Federal ITC | 30% | 30% | 30% | 30% | 30% | 30% | 0% | 0% | 0% |
| State ITC | 20% | 20% | 20% | 20% | 20% | 20% | 20% | 15% | 15% |

### *Distributed Wind*

**Data Source**

[77] https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

[78] https://tax.hawaii.gov/geninfo/renewable

[79] https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

The capital and fixed O&M source data for distributed wind was provided by the Department of Energy's Distributed Wind Market Reports. The capital cost was provided in the Department of Energy's 2017 Distributed Wind Market Report.[80] Initially, capital costs in the report were interpreted to be in 2017 dollars. Upon further review, the costs provided in the report were stated in 2016 dollars. Resource costs for distributed wind stated in this document were then adjusted accordingly. The O&M cost were provided in the Department of Energy's 2018 Distributed Wind Market Report. Initially, O&M cost in the report were from the Department of Energy's 2017 Wind Technologies Market Report, but were updated based on the 2018 Distributed Wind Market Report. The average installed small wind costs were used from these reports. These costs were converted to 2019 dollars using a fixed escalation rate of 2.3%. The future cost trend was estimated using the future cost projections from the 2021 NREL ATB for land-based wind.

**Location Adjustment**

The U.S. benchmark cost was converted to Hawai'i costs for capital and O&M cost estimates. A 35% EIA factor for wind technology was applied for the capital cost conversion to Hawai'i. An 18.5% RSMeans factor was used to convert fixed O&M costs to Hawai'i costs. Location-specific interconnection costs were not included in the estimate.

**Investment Tax Credit Adjustment**

The Federal[81,82] and State ITC[83] schedules assumed for Distributed Wind are summarized in Table 4-32 below. In December 2020, the Federal ITC was given a two-year extension.[84]

Table 4-32: Federal and State ITC for Distributed Wind

| Year | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | Future |
|---|---|---|---|---|---|---|---|---|---|
| Federal ITC | 26% | 26% | 26% | 22% | 0% | 0% | 0% | 0% | 0% |
| State ITC | 20% | 20% | 20% | 20% | 20% | 20% | 20% | 15% | 15% |

80 As stated in the 2018 report, because of the extremely low number of small wind project records with installed cost data, a 2018 average cost analysis was not presented in the 2018 report.

81 https://www.law.cornell.edu/uscode/text/26/48

82 https://rules.house.gov/sites/democrats.rules.house.gov/files/BILLS-116HR133SA-RCP-116-68.pdf

83 https://tax.hawaii.gov/geninfo/renewable

84 See https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

## *Biomass*

**Data Source**
The source data for Biomass capital, fixed O&M, and variable O&M costs as well as Biomass fuel sources were provided by the 2021 NREL ATB for dedicated biomass technology. The capital costs, O&M costs, and fuel costs were given in Real 2019 dollars. The Real 2019 costs were converted to nominal dollars by applying an escalation factor of 2.3%.

**Location Adjustment**
Nominal capital, O&M and fuel costs for Biomass were converted to Hawai'i costs. The capital costs were converted using a 46% EIA factor. The O&M and fuel costs were converted to Hawaii using an 18.5% RSMeans factor. Location-specific interconnection costs were not included in the estimate.

## *Pumped Storage Hydro*

**Data Source**
The source data for Pumped Storage Hydro capital, fixed O&M, and variable O&M costs were provided by the Department of Energy and the Pacific Northwest National Laboratory for a 100 MW, 10 hour duration resource. Capital costs and O&M costs were given in 2020 dollars. Future costs were assumed to increase at an escalation rate of 2.3%.

**Location Adjustment**
A 45% EIA factor for CT technology was used to convert the capital costs to Hawai'i costs and an 18.5% RSMeans factor was used to convert the fixed O&M and variable O&M costs to Hawai'i costs. Location-specific interconnection costs were not included in the estimate.

## *Combustion Turbine and Combined Cycle with Synchronous Condenser Function*

**Data Source**
The source data for Combustion Turbine (CT) and Combined Cycle (CC) capital, fixed O&M, and variable O&M costs as well as fuel sources were provided by the 2021 NREL ATB forecast. The capital costs, O&M costs, and fuel costs were given in Real 2019 dollars. The Real 2019 costs were converted to nominal dollars by applying an escalation factor of 2.3%.

**Location Adjustment**

A 45% EIA factor for CT and CC technology was used to convert the capital costs to Hawai'i costs and an 18.5% RSMeans factor was used to convert the fixed O&M and variable O&M costs to Hawai'i costs. Location-specific interconnection costs were not included in the estimate.

### *Concentrated Solar Power (CSP)*

**Data Source**

The source data for Concentrated Solar Power (CSP) capital, fixed O&M, and variable O&M costs was provided by the 2021 NREL ATB. Capital costs and O&M costs were given in Real 2019 dollars. The Real 2019 costs were converted to nominal dollars by applying an escalation factor of 2.3%.

**Location Adjustment**

A 62% EIA factor for PV was used as an approximation to convert capital costs to Hawai'i costs. The federal and state investment tax credit schedule was assumed to be the same as grid scale PV. Fixed and variable O&M costs were converted to Hawai'i costs using an 18.5% RSMeans factor. Location-specific interconnection costs were not included in the estimate.

**Investment Tax Credit Adjustment**

The Federal[85] and State ITC[86] schedules assumed for CSP are summarized in Table , below. Initially, there were no Federal or State ITC assumed for CSP. After additional consideration, it was determined that a CSP system should be considered as a system that uses solar energy to generate electricity. As a result, CSP should receive the Federal and State ITC. The latest Federal and State ITC were applied, and the capital cost was adjusted.

Table 4-33: Federal and State ITC Schedule for CSP

| Year | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | Future |
|---|---|---|---|---|---|---|---|---|---|
| Federal ITC | 26% | 26% | 26% | 22% | 10% | 10% | 10% | 10% | 10% |
| State ITC | 35% | 35% | 25% | 25% | 20% | 20% | 20% | 15% | 15% |

[85] https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

[86] https://tax.hawaii.gov/geninfo/renewable

### *Geothermal*

**Data Source**

The source data for the Geothermal capital, fixed and variable O&M were provided by the 2021 NREL ATB for Geothermal geo-hydro binary technology. The capital costs, O&M costs and fuel costs in ATB were given in Real 2019 dollars and converted to nominal dollars by applying an escalation factor of 2.3%.

**Location Adjustment**

A 20% EIA factor for Geothermal technology was used to convert capital costs to Hawai‘i costs. Fixed O&M and variable O&M costs used an 18.5% RSMeans factor. Location-specific interconnection costs were not included in the estimate.

**Investment Tax Credit Adjustment**

The following federal tax credit schedule[87] was assumed for Geothermal technology.

Table 4-34: Federal and State ITC for Geothermal

| Year | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | Future |
|---|---|---|---|---|---|---|---|---|---|
| Federal ITC | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% |
| State ITC | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |

**Recent Project Adjustment**

Final capital costs were adjusted based on actual costs from the current PGV contract and amended contract application provided in Docket No. 2019-0333. For Geothermal, the costs were adjusted by approximately 141% based on an average LCOE of the current (16.4 cents/kWh) and amended contract (11.4 cents/kWh), calculated using the minimum purchase requirement from the amended contract and historical annual payments made to PGV under the current contract.

### *Internal Combustion Engine (ICE)*

**Data Source**

The source data to estimate Internal Combustion Engine (ICE) technology was informed by actual costs for the Schofield Generating Station project

[87] https://programs.dsireusa.org/system/program/detail/658

constructed on O'ahu. The cost estimates were escalated from 2017 dollars by applying an escalation factor of 2.3%. The future cost trend was estimated using the cost trend for gas CT technology discussed above due to limited information on a future ICE capital cost trend.

### *Municipal Solid Waste (MSW)*

**Data Source**
The Municipal Solid Waste (MSW) source data was based on the U.S. Energy Information Administration Cost and Performance Characteristics of New Generating Technologies Annual Energy Outlook for 2019. The costs were adjusted from 2018 dollars to 2019 dollars by applying an escalation factor of 2.3%. The future cost projections were estimated using future cost trend from Biomass technology discussed above due to limited information on future MSW capital cost trend.

**Location Adjustment**
A 20% EIA factor for Biomass technology was used as an approximation to convert capital costs. Fixed O&M and variable O&M costs were converted to Hawai'i costs using an 18.5% RSMeans factor.

### *Battery Energy Storage*

**Data Source**
The source data for Grid-Scale and Residential Battery Energy Storage Systems (BESS) was provided in the 2021 NREL ATB. Both the Balance of System cost, provided in $/kW, and the Module costs, provided in $/kWh, were in provided in Real 2019 dollars. Embedded interconnection cost was removed from the estimate. The Real 2019 costs were converted to nominal dollars by applying an escalation factor of 2.3%.

**Location Adjustment**
The capital costs for Balance of System and Modules were converted to Hawai'i costs using a 32% EIA factor. Fixed O&M and variable O&M costs were converted to Hawai'i costs using an 18.5% RSMeans factor.

**Pairing Adjustment**
Paired storage capital costs were adjusted based on the PV tax credit schedule. Because the State tax credit has a dollar cap, the State tax credit applied to paired storage is the difference between the cap and the amount already applied to the PV system.

**Recent Project Adjustment**

Final capital costs were adjusted based on actual costs from recent projects. For standalone BESS, the costs were adjusted by approximately 105% so the annual payment would be similar to the lump sum payments for the Kapolei Energy Storage System. For paired BESS, the costs were given the same adjustment as the paired PV, as described earlier.

### *Synchronous Condenser*

**Data Source**

The cost projections were estimated using Combustion Turbine technology discussed above due to limited information on Synchronous Condenser capital cost in the 2021 NREL ATB. Cost for conversion of existing generators to synchronous condensers will be considered on a case-by-case basis.

# 5 Resource Potential and Renewable Energy Zones

The first year available for each of the candidate resources that can be selected in RESOLVE reflects typical development timelines to bring the resource online. The first year available varies by resource and is summarized in Table 5-1, below. Planned resources will be built according to their commercial operations date before 2025.

Table 5-1: First Year Available for Candidate Resources

| Resource Type | First Year Available |
|---|---|
| Grid-Scale PV | 2025 |
| Onshore Wind | 2025 |
| Battery Energy Storage | 2025 |
| Synchronous Condenser | 2025 |
| Offshore Wind | 2028-2030 |
| ICE | 2028-2030 |
| Combustion Turbine | 2028-2030 |
| Combined Cycle | 2028-2030 |
| Biomass | 2028-2030 |
| Geothermal | 2028-2030 |

## 5.1 NREL SOLAR AND WIND RESOURCE POTENTIAL STUDY UPDATE

NREL utilized 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 will also include 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 October 2020 NREL Resource Potential Study can be found online[88] as part of the August 18, 2020 Stakeholder Council meeting materials. Table 5-2 below summarizes the original scenarios modeled in the NREL Resource Potential Study.

Table 5-2 Summarized installable capacity in MW for grid-scale 1-axis tracking PV systems all scenarios; Lands with capacity factors >= 0.10

| Island | PV 1 3 | PV 1 5 | PV 1 HS | PV 2 3 | PV 2 5 | PV 2 HS | PV 3 3 | PV 3 5 |
|---|---|---|---|---|---|---|---|---|
| **O‘ahu** | 907 | 1,954 | 9,634 | 1,412 | 2,794 | 13,965 | 561 | 1,008 |
| **Moloka‘i** | 1,225 | 3,016 | 13,387 | 1,225 | 3,016 | 13,387 | 1,177 | 2,918 |
| **Maui** | 1,038 | 2,669 | 26,728 | 1,038 | 2,669 | 26,728 | 508 | 1,411 |
| **Lāna‘i** | 697 | 1,478 | 9,599 | 697 | 1,478 | 9,599 | 557 | 1,199 |
| **Hawai‘i** | 12,417 | 29,384 | 117,231 | 15,083 | 35,319 | 129,977 | 13,621 | 31,841 |

Based on feedback from Ulupono, the Company requested NREL to include updated scenarios for 15% and 30% slope development, among other changes to inputs. Table 5-3, below, shows the revised potentials based on Ulupono's input. PV-Alt-2 and PV-Alt-4, include Department of Defense lands. PV-Alt 1 and PV-Alt-2 use a threshold of 30% slope land and PV-Alt-3 and PV-Alt-4 use a threshold of up to 15%. The updated NREL Resource Potential Study (*Assessment of Wind and Photovoltaic Technical Potential for the Hawaiian Electric Company, Updated July 30, 2021*) is available at https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/stakeholder_council/20210730_sc_heco_tech_potential_final_report.pdf.

[88] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/stakeholder_council/20200818_sc_heco_tech_potential_final_report.pdf

Table 5-3 Summarized installable capacity in MW for grid-scale 1-axis tracking PV systems up to 15% and 30% slope land; Input assumptions based on Ulupono input

| Island | PV Alt 1 | PV Alt 2 | PV Alt 3 | PV Alt 4 |
|---|---|---|---|---|
| **O'ahu** | 3,810 | 7,026 | 1,405 | 2,932 |
| **Moloka'i** | 10,411 | 10,411 | 7,107 | 7,107 |
| **Maui** | 13,687 | 13,687 | 6,613 | 6,613 |
| **Lāna'i** | 9,691 | 9,691 | 6,330 | 6,330 |
| **Hawai'i** | 76,179 | 89,470 | 62,198 | 74,751 |

Table 5-4 details the land exclusions assumptions used to determine the MW PV potentials, above.

Table 5-4 Land exclusion assumptions for PV potential scenarios

| | | PV | | | | | | | | | PV | PV | PV | PV |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | PV-1-3 | PV-1-5 | PV-1-HS | PV-2-3 | PV-2-5 | PV-2-HS | PV-3-3 | PV-3-5 | | PV-Alt-1 | PV-Alt-2 | PV-Alt-3 | PV-Alt-4 |
| Exclusion Category | Land Category | | | | | | | | | | | | | |
| Federal Lands | National Guard | Include | Include | Include | Include | Include | Include | Include | Include | | exclude | exclude | exclude | exclude |
| | National Park Service | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | | exclude | exclude | exclude | exclude |
| | Other Federal Lands | Include | Include | Include | Include | Include | Include | Include | Include | | exclude | exclude | exclude | exclude |
| | U.S. Department of Defense Lands | Exclude | Exclude | Exclude | | | | | | | exclude | include | exclude | include |
| | U.S Fish & Wildlife Service | | | | | | | | | | | | | |
| State Parks | State Park | | | | | | | | | | | | | |
| | State Bird Sanctuary | | | | | | | | | | | | | |
| | State Cultural/Historic Area | | | | | | | | | | | | | |
| | State Ecological Reserve | | | | | | | | | | | | | |
| | State Estuary Reserve | | | | | | | | | | | | | |
| | State Game Land | | | | | | | | | | | | | |
| | State Game or Wildlife Sanctuary | | | | | | | | | | | | | |
| | State Monument | | | | | | | | | | | | | |
| | State Nature Preserve/Reserve | | | | | | | | | | | | | |
| | State Wildlife Mgmt. Area | | | | | | | | | | | | | |
| | Other State Lands | | | | | | | | | | | | | |
| Dept. of Defense | Dept. of Defense Lands | Exclude | Exclude | Exclude | | | | | | | exclude | include | exclude | include |
| Wetlands | Estuarine and Marine Deepwater | | | | | | | | | | | | | |
| | Estuarine and Marine Wetland | | | | | | | | | | | | | |
| | Fresh. Emergent Wetland | | | | | | | | | | | | | |
| | Fresh. Forested/Shrub Wetland | | | | | | | | | | | | | |
| | Fresh. Pond | | | | | | | | | | | | | |
| | Lake | | | | | | | | | | | | | |
| | Riverine | | | | | | | | | | | | | |
| Lava flow | Highest | | | | | | | | | | | | | |
| | Second Highest | | | | | | | | | | | | | |
| | Kilauea Lava Flow (2018) | | | | | | | | | | | | | |
| Flood Zones | "A" | | | | | | | | | | | | | |
| Ag Areas | Important Agricultural Lands (IAG) | | | | | | | | | | | | | |
| Urban Zones | Urban Areas | | | | | | | | | | | | | |
| | HCDA Oahu Affordable Housing Prj | | | | | | | | | | | | | |
| Slope | Slope percent > 3% | Exclude | Include | Include | Exclude | Include | Include | Exclude | Include | | include | include | include | include |
| | Slope percent > 5% | Exclude | Exclude | Include | Exclude | Exclude | Include | Exclude | Exclude | | include | include | include | include |
| | Slope percent > 10% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | | include | include | include | include |
| | Slope percent > 15% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | | cost addr | cost addr | exclude | exclude |
| | Slope percent > 20% | Exclude | Exclude | Include | Exclude | Exclude | Include | Exclude | Exclude | | cost addr | cost addr | exclude | exclude |
| | Slope percent > 30% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | | exclude | exclude | exclude | exclude |
| | Slope percent > 40% | | | | | | | | | | exclude | exclude | exclude | exclude |
| Setbacks | Road Setback (173m) | | | | | | | | | | include | include | include | include |
| | Building Setback (173m) | | | | | | | | | | include | include | include | include |
| | Transmission ROW Setback (173m) | | | | | | | | | | include | include | include | include |
| Land Study Bureau Agricultural Lands | Class A Land | Include | Include | Include | Include | Include | Include | 90% Exc. | 90% Exc. | | exclude | exclude | exclude | exclude |
| | Class B Land | | | | | | | 90% Exc. | 90% Exc. | | 10% Inc | 10% Inc | 10% Inc | 10% Inc |
| | Class C Land | | | | | | | 90% Exc. | 90% Exc. | | 10% Inc | 10% Inc | 10% Inc | 10% Inc |
| Sea Level Rise | SLR 1ft - 50yr | | | | | | | | | | n/a | n/a | n/a | n/a |
| | SLR 1ft - 100yr | | | | | | | | | | n/a | n/a | n/a | n/a |
| | SLR 1ft - 500yr | | | | | | | | | | n/a | n/a | n/a | n/a |
| | SLR 3.2 ft at 1 ft flood height - 100yr (majority pixels) | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | exclude | exclude | exclude | exclude |
| Tsunami Evacuations Zones | Tsunami Evacuation Zones | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | | exclude | exclude | exclude | exclude |
| | Extreme Tsunami Evacuation Zones | Include | Include | Include | Include | Include | Include | Include | Include | | include | include | include | include |
| RE Development Zones | Oahu, Molokai, Hawaii (x2) | Include | Include | Include | Include | Include | Include | Include | Include | | include | include | include | include |
| Oahu Land Use Ordinance - Urban Zones | A-1, A-2, A-3, Aloha, AMX-1, AMX-2, AMX-3, Apart, ApartMix, B-1, B-2, BMX-3, BMX-4, I-1, I-2, I-3, IMX-1, Kak, MU, PU, Pub, R-10, R-20, R-3.5, R-5, R-7.5, ResMix, Resort, WI | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | | exclude | exclude | exclude | exclude |
| Private Land Use | Golf Courses | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | exclude | exclude | exclude | exclude |

Table 5-5, below, shows the original wind potential scenarios modeled.

Table 5-5 Summarized installable capacity in MW for gird-scale wind systems all scenarios; Lands with Wind speeds >= 6.5 m/s

| Island | Wind 1 20 | Wind 1 HS | Wind 2 20 | Wind 2 HS | Wind 3 20 | Wind 3 HS | Wind 4 20 | Wind 4 HS |
|---|---|---|---|---|---|---|---|---|
| O'ahu | 436 | 761 | 640 | 1,147 | 230 | 465 | 333 | 728 |
| Moloka'i | 951 | 1,249 | 951 | 1,249 | 688 | 958 | 688 | 958 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Maui** | 634 | 940 | 634 | 940 | 421 | 659 | 421 | 659 |
| | | | | | | | | |
| **Hawaiʻi** | 1,189 | 1,254 | 1,189 | 1,254 | 982 | 1,039 | 982 | 1,039 |

Table 5-6, below, shows the updated wind scenarios based on Ulupono's input. Wind-Alt-2 includes Department of Defense land. Both Wind-Alt-1 and Wind-Alt-2 cut off wind speeds as 6.5 m/s as in the original wind scenarios, above. NREL also summarized the wind scenarios assuming no wind speed threshold.

Table 5-6 Summarized installable capacity in MW for grid-scale wind systems up to 15% slope land; Input assumptions based on Ulupono input

| Island | Wind Alt 1 | Wind Alt 2 | Wind Alt 1 (No Wind Speed Threshold) | Wind Alt 2 (No Wind Speed Threshold) |
|---|---|---|---|---|
| **Oʻahu** | 186 | 284 | 256 | 365 |
| **Molokaʻi** | 515 | 515 | 515 | 515 |
| **Maui** | 278 | 278 | 767 | 767 |
| **Lānaʻi** | 305 | 305 | 509 | 509 |
| **Hawaiʻi** | 670 | 670 | 5,037 | 5,974 |

Table 5-7 details the land exclusions assumptions used to determine the wind potentials, above.

Table 5-7 Land exclusion assumptions for wind potential scenarios

| | | Wind | | | | | | | | Wind | Wind |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | WIND-1-20 | WIND-1-40 | WIND-2-20 | WIND-2-40 | WIND-3-20 | WIND-3-40 | WIND-4-20 | WIND-4-40 | Wind-Alt-1 | Wind-Alt-2 |
| Exclusion Category | Land Category | | | | | | | | | | |
| Federal Lands | National Guard | Include | Include | Include | Include | Include | Include | Include | Include | exclude | exclude |
| | National Park Service | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | exclude | exclude |
| | Other Federal Lands | Include | Include | Include | Include | Include | Include | Include | Include | exclude | exclude |
| | U.S. Department of Defense Lands | Exclude | Exclude | | | Exclude | Exclude | | | exclude | include |
| | U.S Fish & Wildlife Service | | | | | | | | | | |
| State Parks | State Park | | | | | | | | | | |
| | State Bird Sanctuary | | | | | | | | | | |
| | State Cultural/Historic Area | | | | | | | | | | |
| | State Ecological Reserve | | | | | | | | | | |
| | State Estuary Reserve | | | | | | | | | | |
| | State Game Land | | | | | | | | | | |
| | State Game or Wildlife Sanctuary | | | | | | | | | | |
| | State Monument | | | | | | | | | | |
| | State Nature Preserve/Reserve | | | | | | | | | | |
| | State Wildlife Mgmt. Area | | | | | | | | | | |
| | Other State Lands | | | | | | | | | | |
| Dept. of Defense | Dept. of Defense Lands | Exclude | Exclude | | | Exclude | Exclude | | | exclude | include |
| Wetlands | Estuarine and Marine Deepwater | | | | | | | | | | |
| | Estuarine and Marine Wetland | | | | | | | | | | |
| | Fresh. Emergent Wetland | | | | | | | | | | |
| | Fresh. Forested/Shrub Wetland | | | | | | | | | | |
| | Fresh. Pond | | | | | | | | | | |
| | Lake | | | | | | | | | | |
| | Riverine | | | | | | | | | | |
| Lava flow | Highest | | | | | | | | | | |
| | Second Highest | | | | | | | | | | |
| | Kilauea Lava Flow (2018) | | | | | | | | | | |
| Flood Zones | "A" | | | | | | | | | | |
| Ag Areas | Important Agricultural Lands (IAG) | | | | | | | | | | |
| Urban Zones | Urban Areas | | | | | | | | | | |
| | HCDA Oahu Affordable Housing Prj | | | | | | | | | | |
| Slope | Slope percent > 3% | Include | Include | Include | Include | Include | Include | Include | Include | include | include |
| | Slope percent > 5% | Include | Include | Include | Include | Include | Include | Include | Include | include | include |
| | Slope percent > 10% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | include | include |
| | Slope percent > 15% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | include | include |
| | Slope percent > 20% | Exclude | Include | Exclude | Include | Exclude | Include | Exclude | Include | exclude | exclude |
| | Slope percent > 30% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | exclude | exclude |
| | Slope percent > 40% | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | exclude | exclude |
| Setbacks | Road Setback (173m) | Include | Include | Include | Include | | | | | exclude | exclude |
| | Building Setback (173m) | Include | Include | Include | Include | | | | | exclude | exclude |
| | Transmission ROW Setback (173m) | Include | Include | Include | Include | | | | | exclude | exclude |
| Land Study Bureau Agricultural Lands | Class A Land | | | | | | | | | include | include |
| | Class B Land | | | | | | | | | include | include |
| | Class C Land | | | | | | | | | include | include |
| Sea Level Rise | SLR 1ft - 50yr | | | | | | | | | n/a | n/a |
| | SLR 1ft - 100yr | | | | | | | | | n/a | n/a |
| | SLR 1ft - 500yr | | | | | | | | | n/a | n/a |
| | SLR 3.2 ft at 1 ft flood height - 100yr (majority pixels) | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | exclude | exclude |
| Tsunami Evacuations Zones | Tsunami Evacuation Zones | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | exclude | exclude |
| | Extreme Tsunami Evacuation Zones | Include | Include | Include | Include | Include | Include | Include | Include | include | include |
| RE Development Zones | Oahu, Molokai, Hawaii (x2) | Include | Include | Include | Include | Include | Include | Include | Include | include | include |
| Oahu Land Use Ordinance - Urban Zones | A-1, A-2, A-3, Aloha, AMX-1, AMX-2, AMX-3, Apart, ApartMix, B-1, B-2, BMX-3, BMX-4, I-1, I-2, I-3, IMX-1, Kak, MU, PU, Pub, R-10, R-20, R-3.5, R-5, R-7.5, ResMix, Resort, WI | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | Exclude | exclude | exclude |
| Private Land Use | Golf Courses | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | exclude | exclude |

## 5.1.1 Solar and Wind Potential Assumption for IGP

The grid-scale solar and wind potential assumption garnered much discussion amongst stakeholders, with varying perspectives on what can realistically be built due to land use and community issues.

On the developable resource potential for onshore grid-scale solar and wind, the Company received stakeholder feedback that Federal contracting rules would require that the Department of Defense ("DoD") seek the highest and best use for properties under their control, in addition to deciding whether that land would be made available for renewable energy development. Because of this circumstance, it would be difficult to make a blanket assumption that all DoD lands are available to develop. Further, stakeholders raised concerns on the ease of developing projects at slopes higher than 10% due to the additional work and cost involved. However, other stakeholders felt that higher slopes could be developed, up to 30%, with some additional cost adder. Because some projects have already been developed on steeper slopes.

Taking into consideration the various viewpoints, the Company will use the Alt-1 scenario for wind (no wind speed threshold) and solar potential for various scenarios, shown in Table 5-6. The Company will also use this Alt-1 scenario in developing transmission infrastructure needed to develop renewable energy zones, as discussed in the following Section 5.2. The Alt-1 scenario excludes DoD lands but includes development on land with slopes up to 30% for PV.

It is worth noting that there is substantial overlap between areas with solar resource potential and wind resource potential. And the same system infrastructure can be used to interconnect both wind and solar resources and transfer the renewable energy to the other locations of the system.

However, the Company also recognizes the realities of solar and wind development in the State. To that end, a "Land Constrained" Scenario will reflect the possibility of future limited land availability for solar, wind development and provide a meaningful bookend of analysis that incorporates stakeholder feedback to assume a lower amount of land is available for project development.

## 5.2 RENEWABLE ENERGY ZONES

Hawaiian Electric has commenced a study to identify transmission infrastructure necessary to accommodate the large blocks of grid-scale renewable energy on the islands of O'ahu, Maui, and Hawai'i Island. The objective of this study is to assess the technical feasibility and needs to interconnect high amounts of renewable energy. The study is just one step in the transmission REZ planning process which is shown in Figure 5-1. The Company expects multiple iterations with stakeholder and communities as the process progresses. In this update, key assumptions for this analysis are listed in following sections, as well as a preliminary update on the progress made thus far. This is the Company's first Renewable Energy Zones (REZ) study and will be included in its Grid Needs Review Point.

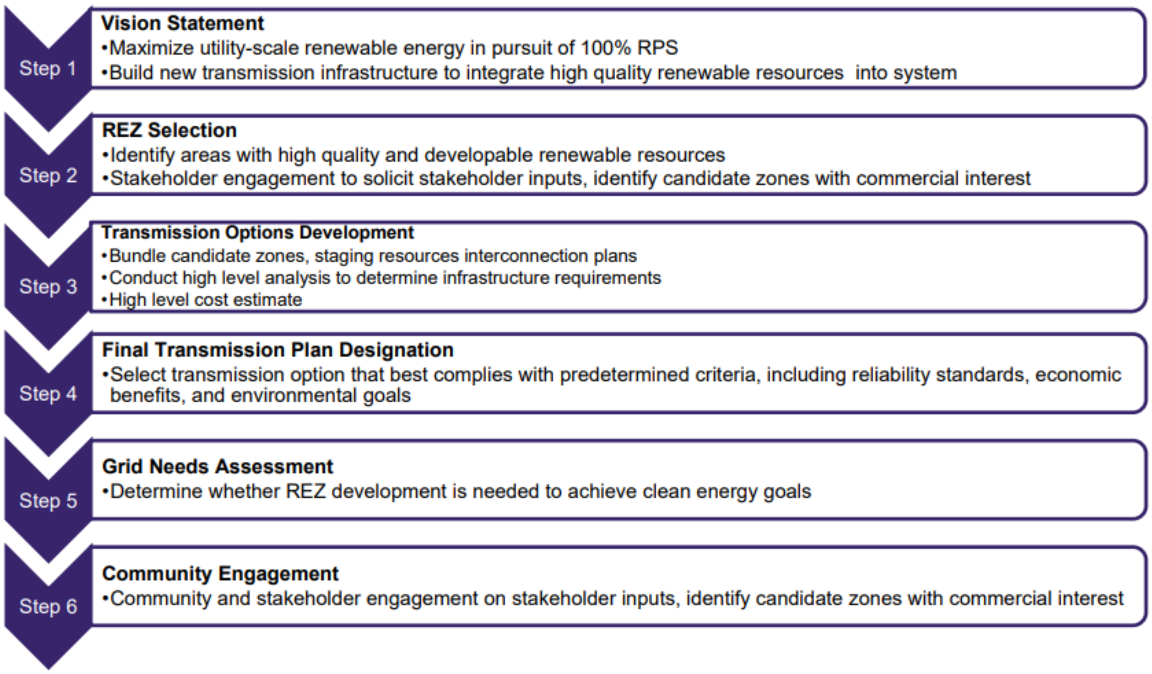



Figure 5-1: Transmission Renewable Energy Zone Planning Process

The study will allow the Company and stakeholders to get an initial understanding of the transmission upgrade options to accommodate future amounts of grid-scale renewable energy, which will be used within the IGP process; including developing future resource costs and schedules, and educating and engaging with communities to gather feedback on these potential plans. As an example, there are high amounts of solar potential on the west and north ends of O'ahu; however, there are currently no transmission lines in those areas. Creating a REZ by bringing out transmission lines to these areas would facilitate further development of renewable energy. These transmission requirements and cost to interconnect various renewable energy zones will serve as an input into the RESOLVE model. The RESOLVE model will then be allowed to select a specific renewable energy zone based on the cost of the solar or wind and associated transmission in that zone.

The study, based on steady-state power flow analyses, assesses the capacity of the existing transmission system and identifies the cost of different transmission upgrade options to interconnect the identified megawatt capacity of each renewable energy zones. The NREL potential study (Scenario Alt-1) described in Section 5.1.1 will be used as an initial target for capacity within the identified zones. The Company acknowledges there are differing opinions from stakeholders regarding these assumptions; however, for purposes of this study, the scenario provides an appropriate energy target to determine the transmission requirements.

The study will identify technology agnostic transmission requirements (i.e., major transmission lines and substations) necessary to facilitate the transfer of power from the REZ to the rest of the system. Costs for interconnection requirements that are developed by specific projects are not included in this analysis (i.e., generation-tie lines).

While Figure 5-1 illustrates the overall REZ process, the general steps to complete the REZ study for the Grid Needs Review Point filing is shown in Figure 5-2.

In this report, the identified REZs based on NREL study results and grouping of REZs for each island are described. In Step 2, the forecasted load for the year 2040 is used to create the power flow study cases for this study.

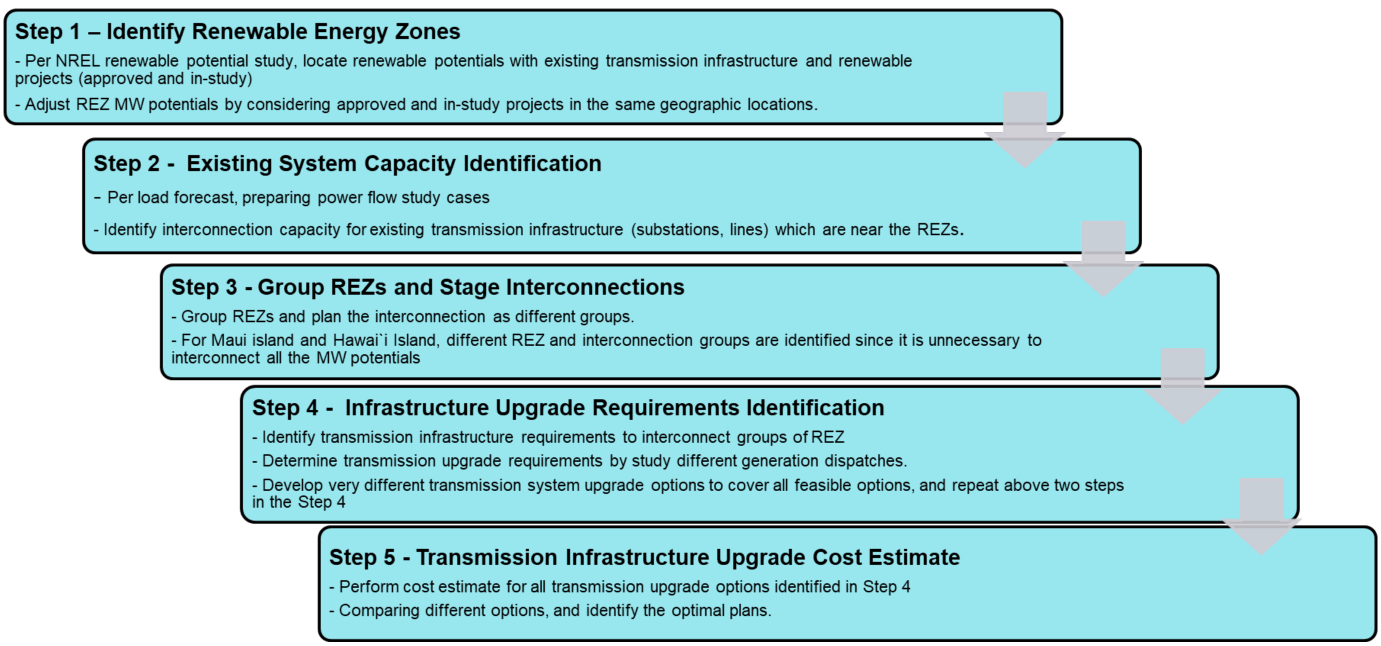



Figure 5-2: Transmission Renewable Energy Zone Study Procedures

The REZ concept was presented to the STWG on July 16, 2021. Hawaiian Electric walked through an illustrative analysis of steps 2-3 of Figure 5-1 for O'ahu to garner discussion and feedback. Stakeholders provided the following comments and feedback:

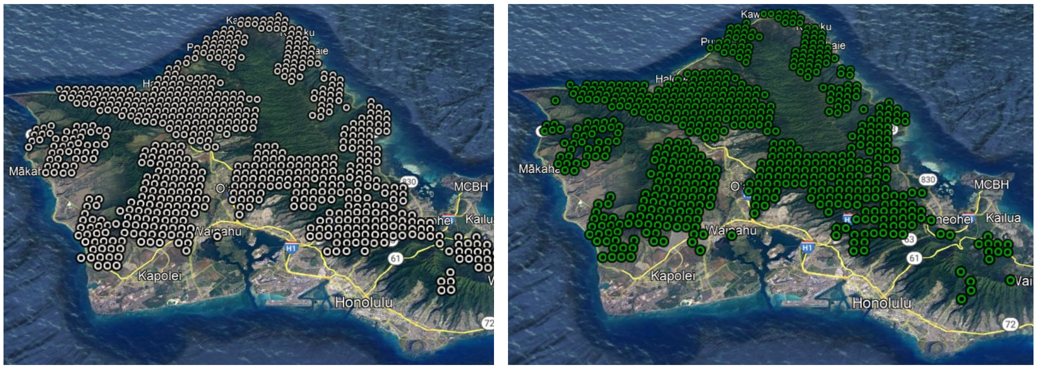
- Incorporate 150MW pumped storage hydro resource in Lake Wilson.
- Include a Community Engagement step earlier in the process.

- Incorporate the updated NREL study (e.g., Alt-1 Scenario) for REZ selection.
- What if the NREL study is overestimating the developable solar?
- In Wahiawa area, Hawaiian Electric was required to bury powerlines due to community concerns.
- Need to take into account transmission routes through conservation lands. EIS/EIA requirements will make new transmission lines difficult to achieve.
- Incorporate capacity requirements to accommodate off-shore wind resources based on BOEM study.
- New 138 kV lines or conversions from 46 kV along the North Shore area should be relocated outside of flood zones.
- Wind resources will mainly be available on the Kahe ridge and Kahuku mountains.
- The Company completed a Land RFI a few years ago which was helpful for developers to understand the available land and interconnections.
- The Company could model transmission between zones as separate investments within RESOLVE.
- The Company could consider awarding RFPs based on location.

Between the presentation on July 16, 2021 and the time of this filing, the Company has completed initial steps in the REZ study. Updates to the Oʻahu, Maui, and Hawaiʻi Island REZs, utilizing the updated NREL scenario Alt-1 are provided below. The Company will provide its final report in the upcoming Grid Needs Review Point.

### *Oʻahu Transmission REZ – Preliminary Update*

According to the NREL study report, the potential Mega Watts ("MW") of grid-scale PV (white circles) and wind (green circles) on Oʻahu island is shown as left and right figures in Figure 5-3.

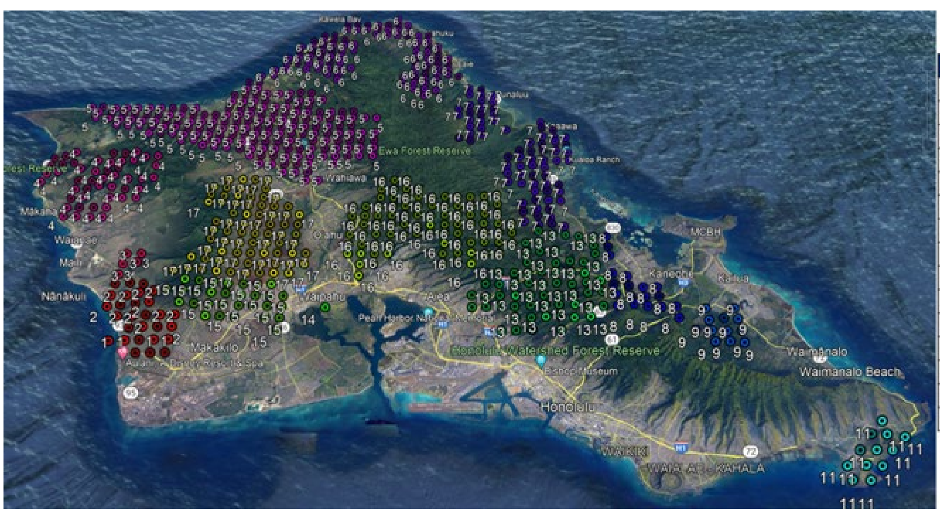



Grid-Scale PV MW Potential Wind MW Potential

Figure 5-3: Grid-scale PV and Wind MW Potential on O‘ahu Island

On O‘ahu, the total grid-scale PV MW potential is 3,810 MW and total wind MW potential is 256 MW. Considering the is large overlap between zones with grid-scale potential and zones with wind potential, and the total wind MW potential is much smaller than the total grid-scale PV MW potential, the grid-scale PV zones identified in the NREL report is used for identifying transmission renewable energy zones and related transmission upgrade.

The grid-scale PV MW potential located on O‘ahu is shown in Figure 5-4. The capacity of each zone was adjusted to subtract the capacity of existing or approved solar projects. For the zones with MW potential below 40 MW, it is assumed that interconnecting those zones via distribution system or sub-transmission system is more cost-effective, and therefore, those zones are removed from the transmission REZ analysis. The total potential MW capacity used for study is 3,344 MW.



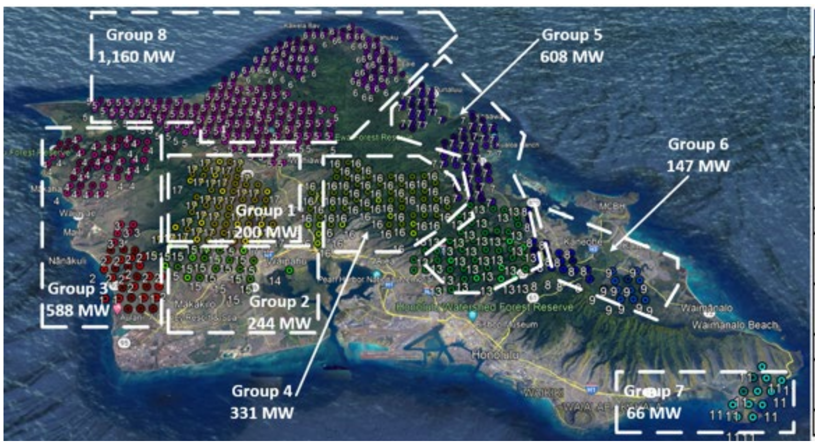

| Zone | Capacity (MW) |
|---|---|
| 1 | 43 |
| 2 | 185 |
| 3 | 42 |
| 4 | 318 |
| 5 | 680 |
| 6 | 480 |
| 7 | 437 |
| 8 | 97 |
| 9 | 50 |
| 11 | 66 |
| 13 | 171 |
| 15 | 106 |
| 16 | 331 |
| 17 | 338 |
| Total | 3,344 |

Figure 5-4: Adjusted Utility Scale PV MW Potential on O‘ahu Island

By considering both grid-scale PV zone, as well as existing O‘ahu island transmission infrastructure, groups of zones are formed, which is shown in

Figure 5-5. Power flow studies for different transmission upgrade options will be performed to determine the estimated transmission infrastructure upgrade requirements for each option. The transmission upgrade options will be designed to export the full potential capacity of the REZ to the rest of the grid. The power flow simulation will assume there is enough reactive power available at vicinity of load center in order to make the power flow problem solvable.

Future analyses will be required to determine if additional reactive sources (and other grid requirements) will be needed. Additionally, there may be other solutions such as grid scale time shift battery energy storage (BESS) that may be considered in future studies as an option to reduce the requirements of transmission upgrade.




| Group | Zone | Capacity (MW) |
|---|---|---|
| 1 | 17 | 200 |
| 2 | 15 | 244 |
| 3 | 1 | 43 |
| | 2 | 185 |
| | 3 | 42 |
| | 4 | 318 |
| 4 | 16 | 331 |
| 5 | 7 | 437 |
| | 13 | 171 |
| 6 | 8 | 97 |
| | 9 | 50 |
| 7 | 11 | 66 |
| 8 | 5 | 680 |
| | 6 | 480 |
| Total | | 3,344 |

Figure 5-5: Group of REZs for O‘ahu Island

For O‘ahu, off-shore wind is also considered as an important renewable resource. Per the NREL off-shore wind study report, it is assumed that there is 600 MW off-shore wind potential available, and can be interconnected to the O‘ahu transmission system via either the Kahe, Iwilei, or Koolau 138 kV buses. Onshore transmission needs for this interconnection will also be evaluated within this study.

### *Maui Island Transmission REZ – Preliminary Update*

According to the NREL study results, Maui has 13,507 MW of grid-scale solar potential (PV-Alt-1, after removing the approved projects and in-study projects) and 767 MW wind potentialWIND-Alt-1. The total potential is 14,274 MW. Compared to O‘ahu, Maui’s total PV and wind potential is much higher than the forecasted 2040 peak load (284 MW). Therefore, the study does not pursue to identify the transmission infrastructure upgrade requirement to interconnect all 14,274 MW of capacity. Instead, the study will identify approximately 1,500 MW of capacity for Maui island (more than 5 times the forecasted peak load MW). It is worth noting that considering the wind potential is much smaller than the grid-scale PV potential, for the area with both PV and wind potential, the study is performed using the grid-scale PV MW potential.

The capacity of each zone was adjusted to subtract the capacity of existing or approved solar projects. The adjusted grid-scale PV potential on Maui island is shown in Figure 5-6.


| Group | Capacity (MW) |
|---|---|
| 1 | 21 |
| 2 | 255 |
| 3 | 609 |
| 4 | 247 |
| 5 | 274 |
| 6 | 153 |
| 7 | 3124 |
| 8 | 1569 |
| 9 | 1947 |
| 10 | 778 |
| 11 | 1341 |
| 12 | 227 |
| 13 | 1 |
| 14 | 1243 |
| 15 | 1007 |
| 16 | 713 |
| Total | 13507 |

Figure 5-6: Adjusted Utility Scale PV MW Potential on Maui Island

Considering the study will only identify infrastructure requirement to interconnect 1,500 MW of potential capacity, zones were removed from consideration based on the following:

1. Zones with low MW potential (such as zone 13)
2. Zones that are far away from existing infrastructure (such as zone 9, 10, 12 and 14)
3. Zones near existing transmission lines with limited capacity ratings (such as zone 15 and 16)

Transmission REZ options on Maui island are shown in Figure 5-7 and Figure 5-8.

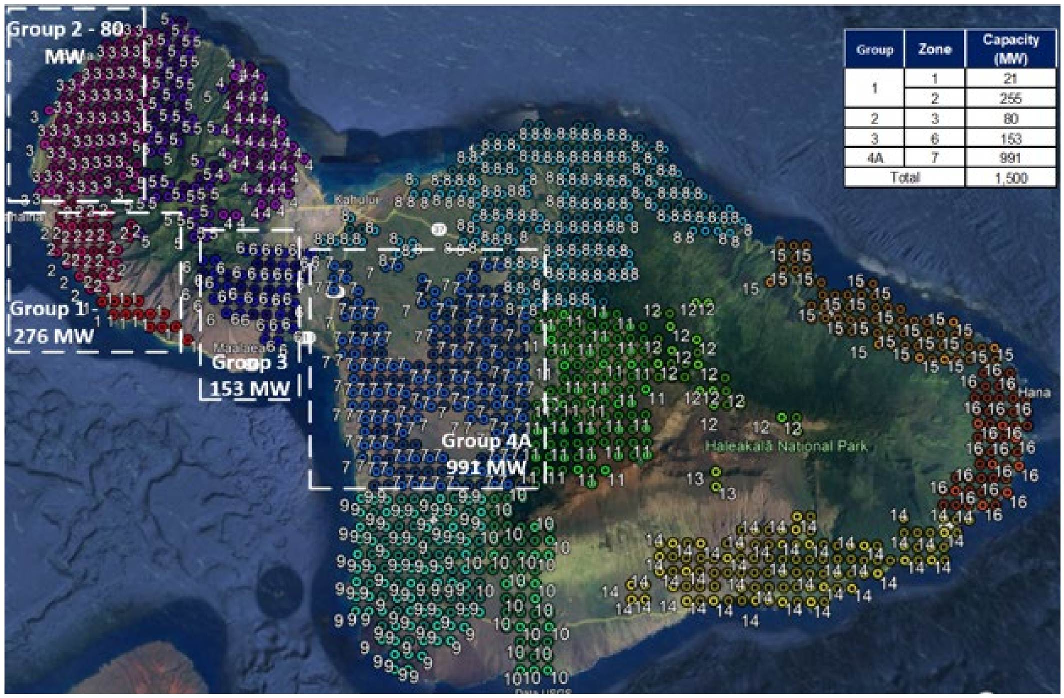



Figure 5-7: Maui Island Transmission REZ – Option 1

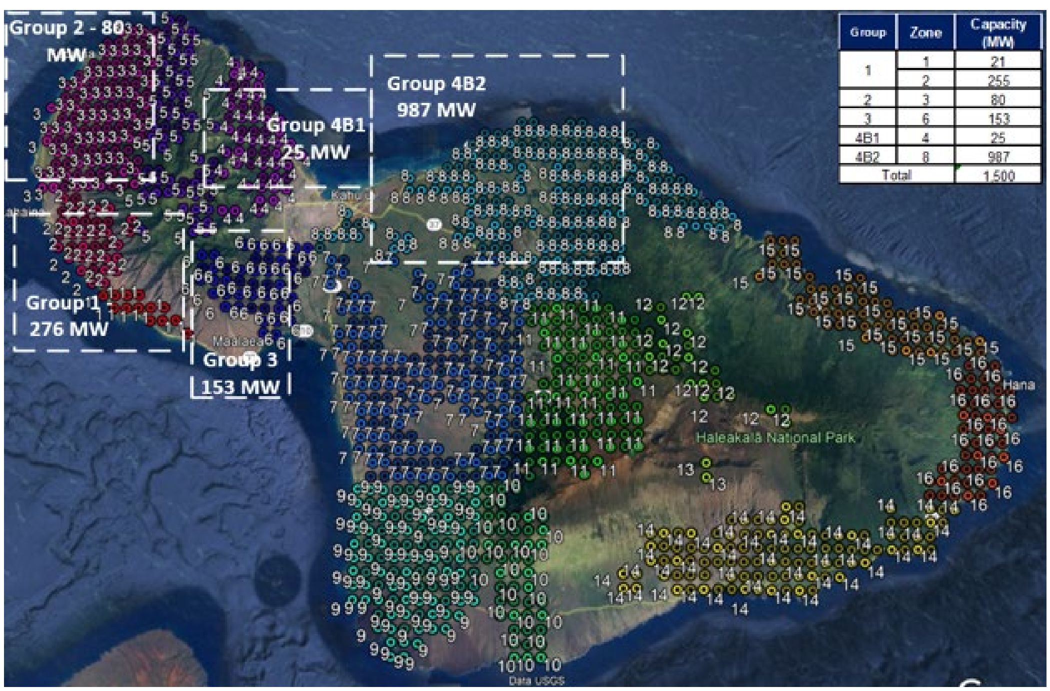
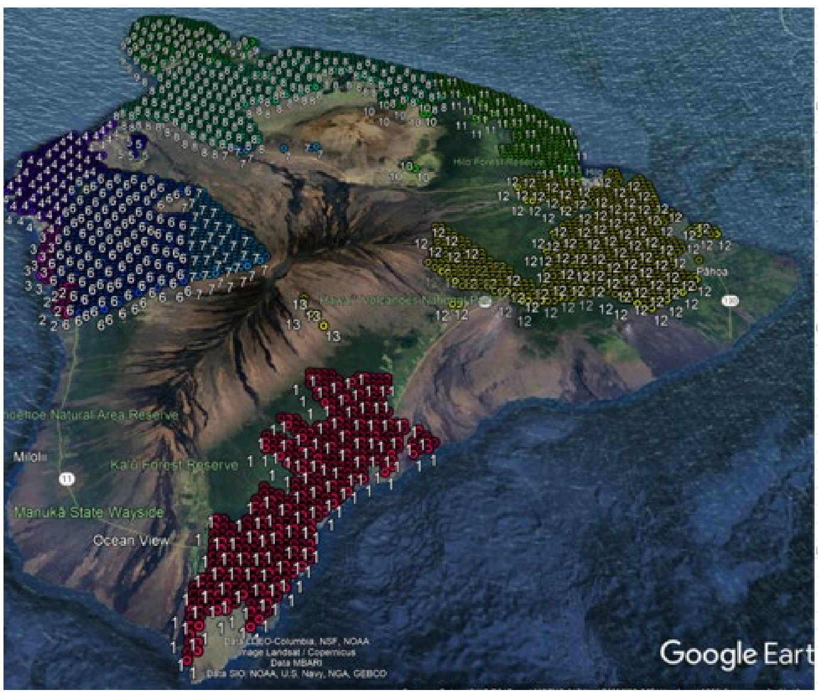


Figure 5-8: Maui Island Transmission REZ – Option 2

### *Hawaiʻi Island Transmission REZ – Preliminary Update*

Similar to Maui island, Hawai'i island also has much larger renewable potential (around 76,000 MW) compared to the forecasted 2040 peak load (5,037 MW). The study will target to interconnect 1,500 MW renewable potential into the system. Also, on Hawaiʻi island, there is a large amount of overlap between grid-scale PV potential zones and wind potential zones, and grid-scale PV potential MW is much larger than the wind potential; therefore, the grid-scale PV MW potential will be used for the study.

The capacity of each zone was adjusted to subtract the capacity of existing or approved solar projects. The adjusted grid-scale PV MW potential on the Hawaiʻi island is shown in Figure 5-9.




| Group | Capacity (MW) |
|---|---|
| 1 | 6011 |
| 2 | 399 |
| 3 | 591 |
| 4 | 5025 |
| 5 | 99 |
| 6 | 17461 |
| 7 | 5509 |
| 8 | 16142 |
| 9 | 5172 |
| 10 | 179 |
| 11 | 4639 |
| 12 | 14829 |
| Total | 76056 |

Figure 5-9: Adjusted Utility Scale PV MW Potential on Hawaiʻi Island

Considering the study will only identify infrastructure requirement to interconnect 1,500 MW potential, and balancing generation in different geographic locations of island, two different Transmission REZ options are developed on Hawai'i island, which are shown in Figure 5-10 and Figure 5-11.

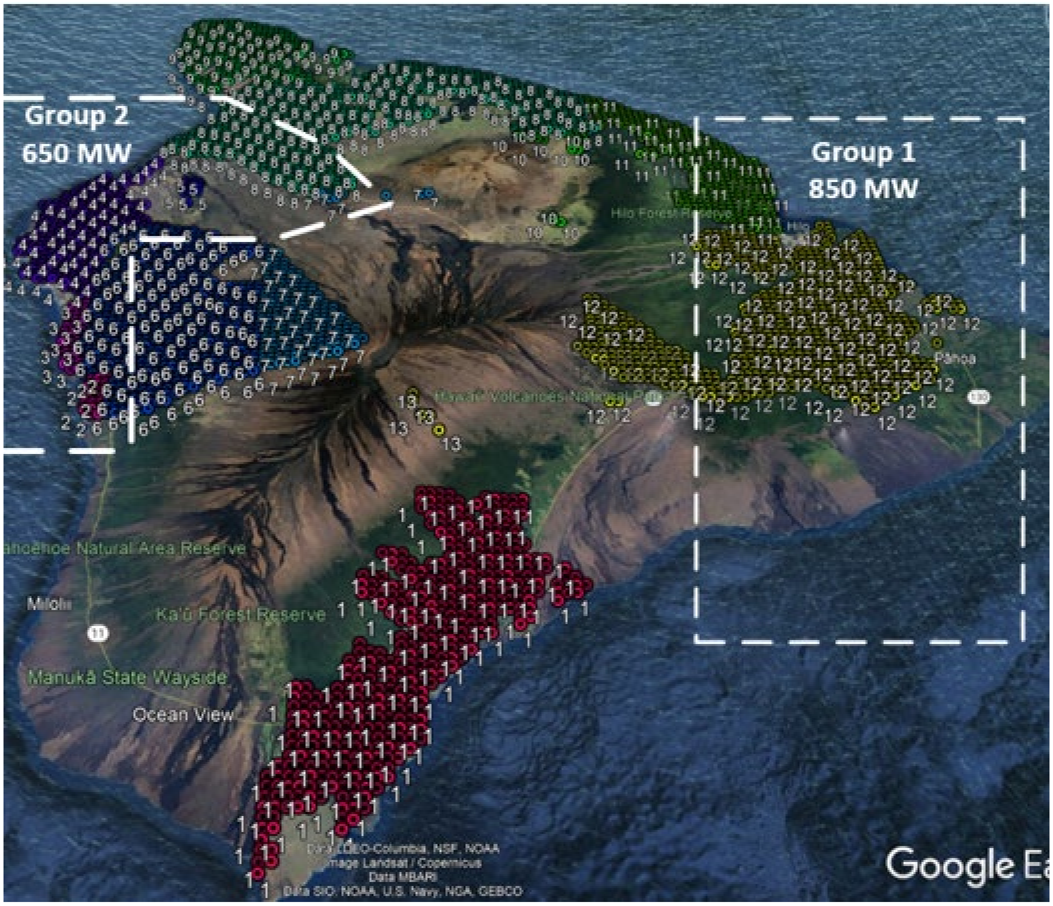



Figure 5-10: Hawai'i Island Transmission REZ – Option 1

In Option 1 (Figure 5-10), two REZs are planned on east and west side of Hawai'i island: Group 1 consists of 850 MW potential from Zone 11 and Zone 12, and Group 2 consists of 650 MW potential from Zone 2, 3, 4, 5, 6 and 8.

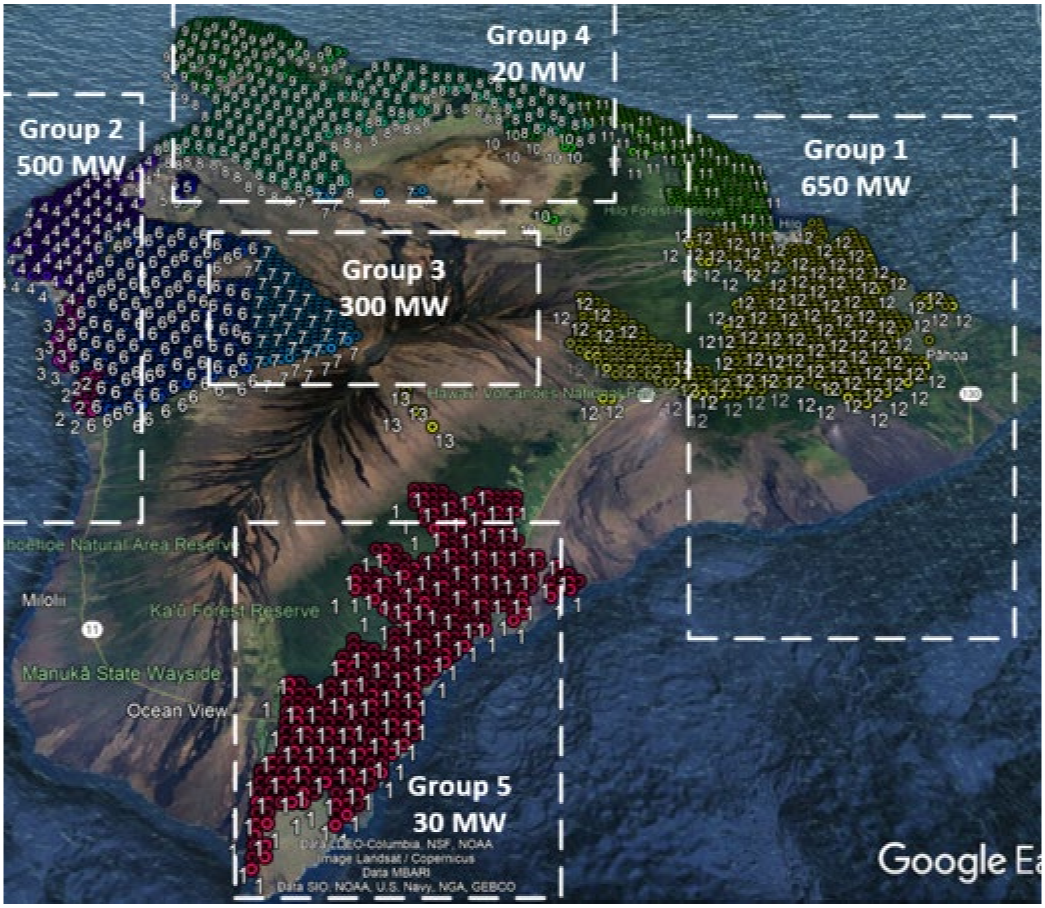



Figure 5-11: Hawai`i Island Transmission REZ - Option 2

In Option 2 (Figure 5-11), five REZs are planned on east, west, north, south side and central of Hawai`i island: Group 1 consists of 650 MW potential from Zone 11 and Zone 12, Group 2 consists of 500 MW potential from Zone 2, 3, 4 and 6, Group 3 consists of 300 MW from Zone 6 and 7, Group 4 consists of 20 MW from Zone 8 and 10, and Group 5 has 30 MW from Zone 1.

# 6 Modeling Scenarios and Sensitivities

Scenarios and 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.

The scenarios and sensitivities have evolved throughout the IGP process, reflecting stakeholder feedback from the Stakeholder Council, SEOWG, and TAP. At the March 12, 2020 Stakeholder Council meeting, the Company shared the four sensitivities that it proposed, and an additional six sensitivities proposed by stakeholders. The four proposed by the Company included:

- Sensitivity #1: Value of Market DER ("DER Freeze")
    - Determine the system value of the forecasted market DER uptake by running a case where no incremental DERs are added beyond 2020 levels.
- Sensitivity #2: No Future Transmission Infrastructure
    - Determine the system value of expanding the DER uptake by limiting new transmission infrastructure and shifting the generation options to future DER resources
- Sensitivity #3: High Energy Efficiency
    - Understand the system value of increased efficiency, above what is assumed in the sales forecast
- Sensitivity #4: No State Investment Tax Credit
    - Understand the impact of no State ITC for PV on the future resource portfolio

The six sensitivities proposed by stakeholders included:

- Sensitivity #5: Non Grid-Participating Customer Storage
    - Determine the system value of existing net energy metering customers adopting storage and operating as a non-export load shift resource
- Sensitivity #6: Grid-Participating Customer Storage
    - Determine the system value of additional distributed storage that is able to charge from / export to the grid and be capable of providing grid services
- Sensitivity #7: Customer Controlled EV Charging
    - Understand the system value of customers using behind the meter storage to charge their electric vehicles
- Sensitivity #8: Grid-Participating, Managed EV Charging
    - Understand the system value of managing EV charging and moving that portion of load to other times of day

- Sensitivity #9: Offshore Wind Only
  - Understand the impact of limiting future renewable resource options to offshore wind on the future resource portfolio
- Sensitivity #10: Low Renewable Generation
  - Understand the impact of low renewable generation from wind and PV resources for an extended period (1 week+)

Subsequently, the TAP's review of the inputs and assumptions led to their recommendation that the Company consider testing the sensitivity of models and resulting portfolios by running bookend scenarios that utilize the cumulative potential high and low load forecasts for each layer. To that end, the Company should also consider wider adoption forecast of customer technologies. The Company's March 2021 update to the I&A reflected the addition of bookend scenarios and changes to the customer adoption forecasts as described throughout this document. Considerable time was spent with stakeholders discussing the development and updates to the customer technology forecasts, for which stakeholders have made significant contributions in this area.

Through STWG meetings, stakeholders suggested that additional "freeze" cases should be considered, for example, EE freeze and EV freeze to approximate the value of those forecast layers compared to the load being served by other sources of generation. In response to Review Point Guidance, the Company also added a high fuel sensitivity.

This section describes the sensitivities that will be evaluated throughout the IGP process, with a clear explanation of the assumptions used for each sensitivity. In developing these revised sensitivities, the Company considered all of the stakeholder feedback received to date, while balancing where meaningful learnings can take place to help inform robust decision making.

## 6.1 RESOLVE MODELING SCENARIOS AND SENSITIVITIES

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

### 6.1.1 Scenario and 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 and STWG provide feedback and suggestions for each sensitivity. The SEOWG and more recently the STWG have 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 and STWG reviews the grid service needs assessment and sensitivities. The Stakeholder Council and STWG members will have an advance opportunity to review and comment on the Grid Needs Assessment and sensitivity analyses prior to the review point filing.

### 6.1.2 Revised Sensitivities and Scenarios

Table 6-1 describes the original set of sensitivities proposed and the disposition of each.

Table 6-1 Original proposed sensitivities

| Sensitivity Name | Disposition |
|---|---|
| 1. **DER Freeze** | Modeled as part of the DER freeze scenarios in the DER Docket. An updated sensitivity will be run using revised forecasts and inputs and assumptions to help inform future program design. |

| Sensitivity Name | Disposition |
|---|---|
| 2. No Future Transmission Infrastructure | This sensitivity will be combined with the offshore wind sensitivity, and also include lower renewable development potential estimates based on stakeholder feedback. The combination of these factors will be a new sensitivity called, Land Constrained, where development of onshore resources are limited by land constraints, including new transmission. |
| 3. High Energy Efficiency | High energy efficiency will be incorporated as part of the bookend scenarios. |
| 4. No State ITC for PV | No changes are being made for this sensitivity. |
| 5. Non Grid-Participating Customer Storage | This scenario informs program design rather than resource plans. To that end, the DER Parties modeled this sensitivity as part of their "Load Shift Scenario in the DER docket. Additionally, the bookend analysis should capture any impacts this sensitivity would have on the load served by the Company. |
| 6. Grid-Participating Customer Storage | See sensitivity #5 above. The Company also modeled a version of this sensitivity as part of the Company's proposal for emergency demand response in the DER docket. |
| 7. Customer Controlled EV Charging | The bookend analysis should capture any impacts this sensitivity would have on the load served by the Company. |
| 8. Grid-Participating, Managed EV Charging | The bookend analysis should capture any impacts this sensitivity would have on the load served by the Company. |
| 9. Offshore Wind Only | See sensitivity #2, above. |
| 10. Low Renewable Generation | No changes are being made to this sensitivity. |

| Sensitivity Name | Disposition |
|---|---|
| 11. **Higher Customer Technology Adoption Bookend** | The Company reviewed the various combinations of the updated forecast layers. As shown in Figure XX, the high and low customer adoption does not offer a significantly different demand than the base case. Therefore, the Company will run a high and low load case, as shown in Figure XX, instead of high and low customer adoption cases. |
| | |
| 13. **High Load** | The Company will proceed with a high load sensitivity based on the combination of forecast layers that result in the highest demand served by the Company. |

Based on stakeholder discussions and to meet the intent and objective of sensitivities, the revised sensitivities are provided in Table 6-2.

Table 6-2: Table of Proposed Sensitivities

| Sensitivity Name | Purpose |
|---|---|
| 1. **High Load Customer Technology Adoption Bookend** | Understand the impact of customer adoption of technologies for DER, electric vehicles, energy efficiency, and time-of-use rates that lead to higher loads. |
| 2. **Low Load Customer Technology Adoption Bookend** | Understand the impact of customer adoption of technologies for DER, electric vehicles, energy efficiency, and time-of-use rates that leads to lower loads. |
| 3. **DER Freeze** | Understand the value of the distributed PV and BESS uptake in the Base forecast. Informative for program design and solution sourcing. |
| 4. **EV Freeze** | Understand the value of the electric vehicles uptake in the Base forecast. Informative for program design and solution sourcing. |
| 5. **EE Freeze** | Understand the value of the energy efficiency uptake in the Base forecast. Informative for program design and solution sourcing. |

| Sensitivity Name | Purpose |
|---|---|
| **6. Land Constrained** | Understand the impact of limited availability of land for future solar, onshore wind, and biomass development. |
| **7. No State ITC for PV** | Understand the impact of removing the state ITC for PV. |
| **8. Low Renewable Generation** | Understand the value of the resource portfolio during periods of low renewable production and additional forced outage combinations. |
| **9. High Fuel Price** | Understand the impact of higher fuel prices on the resource plan. |

Table 6-3 provides a high level mapping of the various forecast layers being used for each of the scenario and sensitivity analyses.

Table 6-3: Forecast Layer Mapping of Modeling Scenarios and Sensitivities

| No. | Modeling Case | DER Forecast | EV Forecast | EE Forecast | TOU Load Shape | Fuel Price Forecast | Resource Cost Forecast | Resource Potential |
|---|---|---|---|---|---|---|---|---|
| 1 | Base | Base Forecast | Base Forecast | Base Forecast | Managed EV Charging | Base Forecast | Base Forecast | NREL Alt-1 |
| 2 | High Load Customer Technology Adoption Bookend | Low Forecast | High Forecast | Low Forecast | Unmanaged EV Charging | Base Forecast | Base Forecast | NREL Alt-1 |
| 3 | Low Load Customer Technology Adoption Bookend | High Forecast | Low Forecast | High Forecast | Managed EV Charging | Base Forecast | Base Forecast | NREL Alt-1 |
| 4 | DER Freeze | DER Freeze | Base Forecast | Base Forecast | Managed EV Charging | Base Forecast | Base Forecast | NREL Alt-1 |
| 5 | EV Freeze | Base Forecast | EV Freeze | Base Forecast | Managed EV Charging | Base Forecast | Base Forecast | NREL Alt-1 |

| No. | Modeling Case | DER Forecast | EV Forecast | EE Forecast | TOU Load Shape | Fuel Price Forecast | Resource Cost Forecast | Resource Potential |
|---|---|---|---|---|---|---|---|---|
| 6 | EE Freeze | Base Forecast | Base Forecast | EE Freeze | Managed EV Charging | Base Forecast | Base Forecast | NREL Alt-1 |
| 7 | Land Constrained | Base Forecast | Base Forecast | Base Forecast | Managed EV Charging | Base Forecast | Base Forecast | Land Constrained Resource Potential |
| 8 | No State ITC for PV | No State ITC Forecast | Base Forecast | Base Forecast | Managed EV Charging | Base Forecast | No State ITC applied to PV resources | NREL Alt-1 |
| 9 | Low Renewable Generation | Base Forecast | Base Forecast | Base Forecast | Managed EV Charging | Base Forecast | Base Forecast | NREL Alt-1 |
| | High Fuel Price | Base Forecast | Base Forecast | Base Forecast | Managed EV Charging | EIA High Fuel Price Forecast | Base Forecast | NREL Alt-1 |

### *Sensitivity #2, #3: Bookends for Customer Technology Adoption*

Bookends will be evaluated as a scenario around the reference forecast, to establish a plausible set of assumptions for each of the layers within the load forecast that define a cumulative high forecast and cumulative low load forecast for customer technology adoption. 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 that are purposefully combined to create proper high and low load bookends, which all combinations of the load layers would reside within. While the base 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.

### *Sensitivity #4: DER Freeze*

The purpose of this sensitivity is to determine the value of the base case 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 base DER forecast and a lower bound on the value of DER in the portfolio. This sensitivity can be used to determine the appropriate mechanism for solution sourcing and program design.

### *Sensitivity #5: EV Freeze*

The purpose of this sensitivity is to determine the value of the base case EV uptake that is already assumed in the reference portfolio by evaluating a case where no incremental EV is added beyond 2021 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 base EV forecast and a lower bound on the value of EV in the portfolio. This sensitivity can be used to determine the appropriate mechanism for solution sourcing and program design.

### *Sensitivity #6: EE Freeze*

The purpose of this sensitivity is to determine the value of the base case EE uptake that is already assumed in the reference portfolio by evaluating a case where no incremental EE is added beyond 2021 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 base EE forecast and a lower bound on the value of EE in the portfolio. This sensitivity can be used to determine the appropriate mechanism for solution sourcing and program design.

### *Sensitivity #7: Land Constrained*

The purpose of this sensitivity is to understand the impact of limited land availability to develop future solar, onshore wind, and biomass resources. Biomass will be removed as a resource option in RESOLVE and the land availability for development of wind, solar and new transmission lines will be limited based on stakeholder feedback. This sensitivity will use a lessor resource potential than the PV-Alt-1 case from the NREL resource potential study. RPS and grid needs will be met by developing offshore resources or additional DER above the base forecast through a DER aggregator.

### *Sensitivity #8: No State ITC 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 for PV against the reference case.

### *Sensitivity #9: 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. Low PV and wind generation as well as increased forced outages of thermal generation will be examined as a stress test of the base case portfolio. Low PV and wind profiles will be defined using historical production as well as production profiles developed through NREL's System Advisory Model and data provided in NREL's National Solar Radiation Database.

### *Sensitivity #10: High Fuel Price*

The purpose of this sensitivity is to understand the impact of a higher fuel forecast on the resource portfolio. RESOLVE will be allowed to optimize the retirement of the thermal generating units compared to the base case where a fixed removal from service schedule is assumed.

# 7 Thermal Generating Unit Portfolios

Hawaiian Electric's thermal generating unit capacity is provided by a mix of utility-owned generation and independent power producers (IPPs). Key inputs to characterize the operation of the utility-owned generation include the minimum and maximum capacity, heat rate coefficients, planned maintenance outages, forced outage rates, and maintenance outage rates.

Minimum and Maximum Capacity

The minimum and maximum capacity of a generating unit define its dispatchable range.

Heat Rate Coefficients

The heat rate coefficients define the heat input function $y = cx^2 + bx + a$ where y is the amount of fuel consumed to produce at the megawatt level x for one hour.

Maintenance Outages

Maintenance outages can be defined as discrete occurrences with a start date and duration or can be defined as a percentage of the year that the unit will be out of service on maintenance. Maintenance outages can remove an entire unit from service or reduce the generating unit's capacity that is available for service.

Forced Outages

Forced outages are unexpected and unplanned generating unit outages and are defined as a percentage of the year that the unit may experience an outage based on historical data.

## *O'ahu*

Table 7-1: O'ahu Minimum and Maximum Capacity for Thermal Resources

| Unit | Operating Minimum (Net MW) | Normal Top Load (Net MW) | Fuel Type |
|---|---|---|---|
| **Kahe 1** | 23.2 | 82.6 | LSFO |
| **Kahe 2** | 23.3 | 82.4 | LSFO |
| **Kahe 3** | 23.1 | 86.1 | LSFO |
| **Kahe 4** | 23.1 | 85.4 | LSFO |
| **Kahe 5** | 50.4 | 134.9 | LSFO |
| **Kahe 6** | 50.4 | 134.7 | LSFO |

| Unit | Operating Minimum (Net MW) | Normal Top Load (Net MW) | Fuel Type |
|---|---|---|---|
| Waiau 3 | 23.5 | 47.1 | LSFO |
| | | | |
| Waiau 5 | 23.4 | 54.4 | LSFO |
| | | | |
| Waiau 7 | 23.1 | 82.9 | LSFO |
| | | | |
| Waiau 9 | 5.9 | 52.9 | Diesel |
| | | | |
| Campbell Industrial Park | 41.2 | 129.0 | Diesel |
| | | | |
| AES | 63.0 | 180.0 | Coal |
| | | | |
| Airport DSG | 4.0 | 8.0 | Biodiesel |
| | | | |
| Schofield 2 | 4.0 | 8.1 | ULSD / Biodiesel |
| | | | |
| Schofield 4 | 4.0 | 8.1 | ULSD / Biodiesel |
| | | | |
| Schofield 6 | 4.0 | 8.1 | ULSD / Biodiesel |

Table 7-2: O‘ahu Heat Rate Coefficients for Thermal Resources

| Unit | A Coefficient (MMBTU/hr) | B Coefficient (MMBTU/hr MW) | C Coefficient (MMBTU/hr MW^2) |
|---|---|---|---|
| Kahe 1 | 72.1042 | 9.1921 | 0.0022 |
| Kahe 2 | 72.0121 | 8.3600 | 0.0118 |
| Kahe 3 | 73.2636 | 8.1711 | 0.0167 |
| Kahe 4 | 116.5162 | 6.5015 | 0.0264 |
| Kahe 5 | 113.3406 | 7.9454 | 0.0106 |
| Kahe 6 | 59.8050 | 9.4934 | 0.0031 |

| Unit | A Coefficient (MMBTU/hr) | B Coefficient (MMBTU/hr MW) | C Coefficient (MMBTU/hr MW^2) |
|---|---|---|---|
| Waiau 3 | 60.8508 | 8.5429 | 0.0309 |
| | | | |
| Waiau 5 | 37.8539 | 10.2088 | 0.0019 |
| | | | |
| Waiau 7 | 101.1916 | 7.4411 | 0.0174 |
| | | | |
| Waiau 9 | 206.3054 | 7.0804 | 0.0249 |
| | | | |
| Campbell Industrial Park | 271.1301 | 8.6971 | 0.0050 |
| | | | |
| AES | 258.7479 | 14.9713 | 0.0051 |
| | | | |
| Airport DSG | 0.0000 | 10.2090 | 0.0000 |
| | | | |
| Schofield 2 | 8.4677 | 6.7967 | 0.0614 |
| | | | |
| Schofield 4 | 8.5071 | 6.6227 | 0.0814 |
| | | | |
| Schofield 6 | 7.6438 | 7.0152 | 0.0513 |

| Year % | Waiau 3 | Waiau 4 | Waiau 5 | Waiau 6 | Waiau 7 | Waiau 8 | Waiau 9 | Waiau 10 |
|---|---|---|---|---|---|---|---|---|
| 2021 | 7 | 7 | 4.5 | 4.5 | 4.5 | 4.5 | 4 | 4 |
| 2022 | 7 | 7 | 4.5 | 4.5 | 4.5 | 4.5 | 4 | 4 |
| 2023 | 7 | 7 | 4.5 | 4.5 | 4.5 | 4.5 | 4 | 4 |
| 2024 | 7 | 7 | 4.5 | 4.5 | 4.5 | 4.5 | 4 | 4 |
| 2025 | 9 | 9 | 5 | 5 | 4.5 | 4.5 | 4 | 4 |

| Year | Waiau 3 | Waiau 4 | Waiau 5 | Waiau 6 | Waiau 7 | Waiau 8 | Waiau 9 | Waiau 10 |
|---|---|---|---|---|---|---|---|---|
| % | | | | | | | | |
| 2026 | 9 | 9 | 5 | 5 | 4.5 | 4.5 | 4 | 4 |
| | | | | | | | | |
| 2028 | 9 | 9 | 5 | 5 | 4.5 | 4.5 | 4 | 4 |
| | | | | | | | | |
| 2030 | 9 | 9 | 6 | 6 | 5.5 | 5.5 | 4 | 4 |
| | | | | | | | | |
| 2032 | 9 | 9 | 6 | 6 | 5.5 | 5.5 | 4 | 4 |
| | | | | | | | | |
| 2034 | 9 | 9 | 6 | 6 | 5.5 | 5.5 | 4 | 4 |
| 2035 | | | | | | | | |
| 2036 | 9 | 9 | 6 | 6 | 5.5 | 5.5 | 4 | 4 |
| | | | | | | | | |
| 2038 | 9 | 9 | 6 | 6 | 5.5 | 5.5 | 4 | 4 |
| | | | | | | | | |
| 2040 | 9 | 9 | 6 | 6 | 5.5 | 5.5 | 4 | 4 |
| | | | | | | | | |
| 2042 | 9 | 9 | 6 | 6 | 5.5 | 5.5 | 4 | 4 |
| | | | | | | | | |
| 2044 | 9 | 9 | 6 | 6 | 5.5 | 5.5 | 4 | 4 |
| 2045 | | | | | | | | |
| 2046 | 9 | 9 | 6 | 6 | 5.5 | 5.5 | 4 | 4 |
| | | | | | | | | |
| 2048 | 9 | 9 | 6 | 6 | 5.5 | 5.5 | 4 | 4 |
| | | | | | | | | |
| 2050 | 9 | 9 | 6 | 6 | 5.5 | 5.5 | 4 | 4 |

| Year | Kahe 1 | Kahe 2 | Kahe 3 | Kahe 4 | Kahe 5 | Kahe 6 | CIP CT 1 |
|---|---|---|---|---|---|---|---|
| % | | | | | | | |
| 2021 | 4.5 | 4.5 | 4.5 | 4.5 | 5 | 5 | 3 |

| Year<br>% | Kahe 1 | Kahe 2 | Kahe 3 | Kahe 4 | Kahe 5 | Kahe 6 | CIP CT 1 |
|---|---|---|---|---|---|---|---|
| 2022 | 4.5 | 4.5 | 4.5 | 4.5 | 5 | 5 | 3 |
| 2023 | 4.5 | 4.5 | 4.5 | 4.5 | 5 | 5 | 3 |
| 2024 | 4.5 | 4.5 | 4.5 | 4.5 | 5 | 5 | 3 |
| 2025 | 4.5 | 4.5 | 4.5 | 4.5 | 5 | 5 | 3 |
| 2026 | 4.5 | 4.5 | 4.5 | 4.5 | 5 | 5 | 3 |
| 2027 | 4.5 | 4.5 | 4.5 | 4.5 | 5 | 5 | 3 |
| 2028 | 4.5 | 4.5 | 4.5 | 4.5 | 5 | 5 | 3 |
| 2029 | 4.5 | 4.5 | 4.5 | 4.5 | 5 | 5 | 3 |
| 2030 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2031 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2032 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2033 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2034 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2035 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2036 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2037 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2038 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2039 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2040 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2041 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2042 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2043 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2044 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2045 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2046 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2047 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2048 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2049 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |
| 2050 | 5.5 | 5.5 | 5 | 5 | 5 | 5 | 3 |

Table 7-5: O'ahu Forced Outage Rates for Thermal Resources (3 of 4)

| Year<br>% | Airport DSG | Schofield 1 | Schofield 2 | Schofield 3 | Schofield 4 | Schofield 5 | Schofield 6 |
|---|---|---|---|---|---|---|---|
| 2021 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2022 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2023 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2024 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2025 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2026 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2027 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2028 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2029 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2030 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2031 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2032 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2033 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2034 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2035 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2036 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2037 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2038 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2039 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2040 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2041 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2042 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2043 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2044 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2045 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2046 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2047 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2048 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |
| 2049 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |

| Year<br>% | Airport DSG | Schofield 1 | Schofield 2 | Schofield 3 | Schofield 4 | Schofield 5 | Schofield 6 |
|---|---|---|---|---|---|---|---|
| 2050 | 5 | 2 | 2 | 2 | 2 | 2 | 2 |

Table 7-6: O‘ahu Forced Outage Rates for Thermal Resources (4 of 4)

| Year<br>% | H POWER | Kalaeloa | AES |
|---|---|---|---|
| 2021 | 3 | 1.5 | 1.5 |
| 2022 | 3 | 1.5 | 1.5 |
| 2023 | 3 | 1.5 | |
| 2024 | 3 | 1.5 | |
| 2025 | 3 | 1.5 | |
| 2026 | 3 | 1.5 | |
| 2027 | 3 | 1.5 | |
| 2028 | 3 | 1.5 | |
| 2029 | 3 | 1.5 | |
| 2030 | 3 | 1.5 | |
| 2031 | 3 | 1.5 | |
| 2032 | 3 | 1.5 | |
| 2033 | 3 | 1.5 | |
| 2034 | 3 | 1.5 | |
| 2035 | 3 | 1.5 | |
| 2036 | 3 | 1.5 | |
| 2037 | 3 | 1.5 | |
| 2038 | 3 | 1.5 | |
| 2039 | 3 | 1.5 | |
| 2040 | 3 | 1.5 | |
| 2041 | 3 | 1.5 | |
| 2042 | 3 | 1.5 | |
| 2043 | 3 | 1.5 | |
| 2044 | 3 | 1.5 | |
| 2045 | 3 | 1.5 | |

| Year | H POWER | Kalaeloa | AES |
|---|---|---|---|
| % | | | |
| 2046 | 3 | 1.5 | |
| | | 1.5 | |
| 2048 | 3 | 1.5 | |
| | | 1.5 | |
| 2050 | 3 | 1.5 | |

| Year | Waiau 3 | Waiau 4 | Waiau 5 | Waiau 6 | Waiau 7 | Waiau 8 | Waiau 9 | Waiau 10 |
|---|---|---|---|---|---|---|---|---|
| % | | | | | | | | |
| 2021 | 1.92 | 1.92 | 5.75 | 5.75 | 7.67 | 7.67 | 3.84 | 15.34 |
| 2022 | 13.42 | 1.92 | 21.10 | 13.42 | 3.84 | 3.84 | 3.84 | 3.84 |
| 2023 | 1.92 | 13.42 | 3.84 | 3.84 | 13.42 | 13.42 | 3.84 | 3.84 |
| 2024 | 3.84 | 3.84 | 5.75 | 5.75 | 7.67 | 7.67 | 3.84 | 3.84 |
| 2025 | 13.42 | 1.92 | 13.42 | 13.42 | 1.92 | 1.92 | 3.84 | 3.84 |
| 2026 | 0.00 | 13.42 | 0.00 | 0.00 | 17.26 | 13.42 | 26.85 | 3.84 |
| 2027 | 3.84 | 3.84 | 5.75 | 5.75 | 5.75 | 5.75 | 3.84 | 26.85 |
| 2028 | 13.42 | 1.92 | 13.42 | 21.10 | 3.84 | 3.84 | 3.84 | 3.84 |
| 2029 | 1.92 | 13.42 | 1.92 | 1.92 | 13.42 | 21.10 | 3.84 | 3.84 |
| 2030 | 1.92 | 1.92 | 3.84 | 3.84 | 5.75 | 5.75 | 3.84 | 3.84 |
| 2031 | 13.42 | 1.92 | 21.10 | 13.42 | 1.92 | 1.92 | 3.84 | 3.84 |
| 2032 | 1.92 | 13.42 | 1.92 | 1.92 | 13.42 | 13.42 | 15.34 | 3.84 |
| 2033 | 1.92 | 1.92 | 5.75 | 5.75 | 5.75 | 5.75 | 3.84 | 15.34 |
| 2034 | 13.42 | 1.92 | 13.42 | 13.42 | 5.75 | 5.75 | 3.84 | 3.84 |
| 2035 | 0.00 | 13.42 | 0.00 | 0.00 | 17.26 | 13.42 | 3.84 | 3.84 |
| 2036 | 1.92 | 1.92 | 5.75 | 5.75 | 5.75 | 5.75 | 3.84 | 3.84 |
| 2037 | 13.42 | 0.00 | 13.42 | 21.10 | 1.92 | 1.92 | 3.84 | 3.84 |
| 2038 | 0.00 | 13.42 | 1.92 | 1.92 | 13.42 | 21.10 | 26.85 | 3.84 |
| 2039 | 1.92 | 1.92 | 5.75 | 5.75 | 3.84 | 3.84 | 3.84 | 26.85 |
| 2040 | 13.42 | 1.92 | 13.42 | 13.42 | 3.84 | 3.84 | 3.84 | 3.84 |

| Year | Waiau 3 | Waiau 4 | Waiau 5 | Waiau 6 | Waiau 7 | Waiau 8 | Waiau 9 | Waiau 10 |
|---|---|---|---|---|---|---|---|---|
| % | | | | | | | | |
| 2041 | 1.92 | 13.42 | 5.75 | 5.75 | 13.42 | 13.42 | 3.84 | 3.84 |
| 2042 | 1.92 | 1.92 | 5.75 | 5.75 | 5.75 | 5.75 | 5.75 | 5.75 |
| | | | | | | | | |
| 2044 | 1.92 | 1.92 | 5.75 | 5.75 | 5.75 | 5.75 | 5.75 | 5.75 |
| | | | | | | | | |
| 2046 | 1.92 | 1.92 | 5.75 | 5.75 | 5.75 | 5.75 | 5.75 | 5.75 |
| | | | | | | | | |
| 2048 | 1.92 | 1.92 | 5.75 | 5.75 | 5.75 | 5.75 | 5.75 | 5.75 |
| | | | | | | | | |
| 2050 | 1.92 | 1.92 | 5.75 | 5.75 | 5.75 | 5.75 | 5.75 | 5.75 |

| Year | Kahe 1 | Kahe 2 | Kahe 3 | Kahe 4 | Kahe 5 | Kahe 6 | CIP CT 1 |
|---|---|---|---|---|---|---|---|
| % | | | | | | | |
| 2021 | 21.10 | 5.75 | 5.75 | 5.75 | 5.75 | 5.75 | 3.84 |
| 2022 | 3.84 | 17.26 | 3.84 | 13.42 | 13.42 | 3.84 | 3.84 |
| 2023 | 3.84 | 5.75 | 13.42 | 5.75 | 3.84 | 13.42 | 3.84 |
| 2024 | 13.42 | 7.67 | 7.67 | 7.67 | 5.75 | 5.75 | 15.34 |
| 2025 | 1.92 | 13.42 | 3.84 | 13.42 | 19.18 | 1.92 | 3.84 |
| 2026 | 0.00 | 0.00 | 17.26 | 0.00 | 0.00 | 23.01 | 3.84 |
| 2027 | 13.42 | 7.67 | 7.67 | 7.67 | 5.75 | 5.75 | 3.84 |
| 2028 | 1.92 | 13.42 | 1.92 | 21.10 | 13.42 | 3.84 | 3.84 |
| 2029 | 3.84 | 3.84 | 13.42 | 3.84 | 1.92 | 13.42 | 3.84 |
| 2030 | 21.10 | 5.75 | 5.75 | 5.75 | 5.75 | 5.75 | 19.18 |
| 2031 | 3.84 | 17.26 | 1.92 | 13.42 | 13.42 | 1.92 | 3.84 |
| 2032 | 3.84 | 3.84 | 21.10 | 3.84 | 3.84 | 13.42 | 3.84 |
| 2033 | 13.42 | 7.67 | 7.67 | 7.67 | 7.67 | 7.67 | 3.84 |
| 2034 | 5.75 | 13.42 | 5.75 | 13.42 | 13.42 | 3.84 | 3.84 |
| 2035 | 0.00 | 0.00 | 13.42 | 1.92 | 1.92 | 23.01 | 3.84 |
| 2036 | 13.42 | 7.67 | 7.67 | 7.67 | 7.67 | 5.75 | 15.34 |

| Year % | Kahe 1 | Kahe 2 | Kahe 3 | Kahe 4 | Kahe 5 | Kahe 6 | CIP CT 1 |
|---|---|---|---|---|---|---|---|
| 2037 | 1.92 | 13.42 | 1.92 | 21.10 | 13.42 | 1.92 | 3.84 |
| 2038 | 3.84 | 3.84 | 13.42 | 1.92 | 1.92 | 13.42 | 3.84 |
| | | | | | | | |
| 2040 | 5.75 | 17.26 | 5.75 | 13.42 | 13.42 | 3.84 | 3.84 |
| | | | | | | | |
| 2042 | 7.67 | 7.67 | 7.67 | 7.67 | 7.67 | 7.67 | 5.75 |
| | | | | | | | |
| 2044 | 7.67 | 7.67 | 7.67 | 7.67 | 7.67 | 7.67 | 5.75 |
| | | | | | | | |
| 2046 | 7.67 | 7.67 | 7.67 | 7.67 | 7.67 | 7.67 | 5.75 |
| | | | | | | | |
| 2048 | 7.67 | 7.67 | 7.67 | 7.67 | 7.67 | 7.67 | 5.75 |
| | | | | | | | |
| 2050 | 7.67 | 7.67 | 7.67 | 7.67 | 7.67 | 7.67 | 5.75 |

| Year % | Airport DSG | Schofield 1 | Schofield 2 | Schofield 3 | Schofield 4 | Schofield 5 | Schofield 6 |
|---|---|---|---|---|---|---|---|
| 2021 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2022 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2023 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2024 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2025 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2026 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2027 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2028 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2029 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2030 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2031 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2032 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |

| Year<br>% | Airport DSG | Schofield 1 | Schofield 2 | Schofield 3 | Schofield 4 | Schofield 5 | Schofield 6 |
|---|---|---|---|---|---|---|---|
| 2033 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2034 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2035 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2036 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2037 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2038 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2039 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2040 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2041 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2042 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2043 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2044 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2045 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2046 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2047 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2048 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2049 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |
| 2050 | 1.92 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 |

## *Hawai'i Island*

Table 7-10: Hawai'i Island Minimum and Maximum Capacity for Thermal Resources

| Unit | Operating Minimum (Net MW) | Normal Top Load (Net MW) | Fuel Type |
|---|---|---|---|
| PGV (2024) | 20 | 46 | Geothermal |
| PGV (2021, off-peak) | 22.0 | 38.0 | Geothermal |
| PGV (2021, on-peak) | 33.9 | 38.0 | Geothermal |
| Hill 5 | 5.0 | 13.8 | IFO (2021-2024) / ULSD(2025+) |
| Hill 6 | 8.0 | 20.0 | IFO (2021-2024) / ULSD(2025+) |

| Unit | Operating Minimum (Net MW) | Normal Top Load (Net MW) | Fuel Type |
|---|---|---|---|
| Kanoelehua CT1 | 2.0 | 10.3 | Diesel |
| Kanoelehua D11 | 2.0 | 2.0 | ULSD |
| Kanoelehua D15 | 2.4 | 2.5 | ULSD |
| Kanoelehua D16 | 2.4 | 2.5 | ULSD |
| Kanoelehua D17 | 2.4 | 2.5 | ULSD |
| Kapua D27 | 1.3 | 1.3 | ULSD |
| Keahole CT2 | 6.0 | 13.8 | Diesel |
| Keahole D21 | 2.4 | 2.5 | ULSD |
| Keahole D22 | 2.4 | 2.5 | ULSD |
| Keahole D23 | 2.4 | 2.5 | ULSD |
| Ouli D25 | 1.3 | 1.3 | ULSD |
| Panaewa D24 | 1.3 | 1.3 | ULSD |
| Puna | 6.0 | 15.5 | IFO |
| Puna CT3 | 8.0 | 20.0 | Diesel |
| Punaluu D26 | 1.3 | 1.3 | ULSD |
| Waimea D12 | 2.4 | 2.5 | ULSD |
| Waimea D13 | 2.4 | 2.5 | ULSD |
| Waimea D14 | 2.4 | 2.5 | ULSD |
| Keahole CT4 | 8.0 | 20.5 | Diesel |
| Keahole CT5 | 8.0 | 20.5 | Diesel |
| Keahole ST7 | 1.0 | 9.5 | – |
| HEP CT1 | 7.0 | 20.8 | 80% Naphtha / 20% Biodiesel |
| HEP CT2 | 7.0 | 20.8 | 80% Naphtha / 20% Biodiesel |
| HEP ST | 5.5 | 16.4 | – |

Table 7-11: Hawai'i Island Heat Rate Coefficients for Thermal Resources

| Unit | A Coefficient (MMBTU/hr) | B Coefficient (MMBTU/hr MW) | C Coefficient (MMBTU/hr MW^2) |
|---|---|---|---|
| Hill 5 | 24.6229 | 8699.0000 | 0.2033 |
| Hill 6 | 64.0000 | 4000.0000 | 0.2550 |
| Kanoelehua CT1 | 74.0422 | 9150.1300 | 0.1272 |
| Kanoelehua D11 | 6.1493 | 4323.1400 | 1.5805 |
| Kanoelehua D15 | 7.6830 | 4326.1600 | 1.2637 |
| Kanoelehua D16 | 7.6830 | 4326.1700 | 1.2637 |
| Kanoelehua D17 | 7.6830 | 4326.1800 | 1.2637 |
| Kapua D27 | 2.8000 | 3200.0300 | 3.2800 |
| Keahole CT2 | 56.9838 | 8864.6600 | 0.0040 |
| Keahole D21 | 7.6834 | 4326.1500 | 1.2637 |
| Keahole D22 | 7.6834 | 4326.1400 | 1.2637 |
| Keahole D23 | 7.6834 | 4326.1300 | 1.2637 |
| Ouli D25 | 2.8000 | 3200.0400 | 3.2800 |
| Panaewa D24 | 2.8000 | 3200.0100 | 3.2800 |
| Puna | 41.8152 | 7738.1000 | 0.2001 |
| Puna CT3 | 49.3842 | 7680.7600 | 0.0310 |
| Punaluu D26 | 2.8000 | 3200.0200 | 3.2800 |
| Waimea D12 | 7.6830 | 4326.1600 | 1.2637 |
| Waimea D13 | 7.6830 | 4326.1700 | 1.2637 |
| Waimea D14 | 7.6830 | 4326.1500 | 1.2637 |
| Keahole CT4 | 49.3842 | 7680.7600 | 0.0310 |
| Keahole CT5 | 53.1791 | 6858.6800 | 0.0689 |
| Keahole ST7 | 59.8609 | 20348.8000 | 0.0000 |
| HEP CT1 | 56.5930 | 7544.0000 | 0.0504 |
| HEP CT2 | 56.5930 | 7544.0000 | 0.0504 |
| HEP ST | 49.1130 | 14653.0000 | 0.0000 |

Table 7-12: Hawai'i Island Forced Outage Rates for Thermal Resources (1 of 4)

| Year<br>% | Hill 5 | Hill 6 | Puna Steam | Kanoelehua D11 | Waimea D12 | Waimea D13 | Waimea D14 | Kanoelehua D15 |
|---|---|---|---|---|---|---|---|---|
| 2021 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2022 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2023 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2024 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2025 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2026 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2027 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2028 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2029 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2030 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2031 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2032 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2033 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2034 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2035 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2036 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2037 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2038 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2039 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2040 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2041 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2042 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2043 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2044 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2045 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2046 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2047 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2048 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |
| 2049 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |

| Year % | Hill 5 | Hill 6 | Puna Steam | Kanoelehua D11 | Waimea D12 | Waimea D13 | Waimea D14 | Kanoelehua D15 |
|---|---|---|---|---|---|---|---|---|
| 2050 | 1.78 | 1.38 | 1.58 | 17.31 | 19.44 | 12.04 | 14.85 | 0.50 |

Table 7-13: Hawai‘i Island Forced Outage Rates for Thermal Resources (2 of 4)

| Year % | Kanoelehua D16 | Kanoelehua D17 | Keahole D21 | Keahole D22 | Keahole D23 | Panaewa D24 | Ouli D25 | Punaluu D26 |
|---|---|---|---|---|---|---|---|---|
| 2021 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2022 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2023 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2024 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2025 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2026 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2027 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2028 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2029 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2030 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2031 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2032 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2033 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2034 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2035 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2036 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2037 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2038 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2039 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2040 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2041 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2042 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2043 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2044 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| 2045 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |

| Year<br>% | Kanoelehua D16 | Kanoelehua D17 | Keahole D21 | Keahole D22 | Keahole D23 | Panaewa D24 | Ouli D25 | Punaluu D26 |
|---|---|---|---|---|---|---|---|---|
| 2046 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| | | | | | | | | |
| 2048 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |
| | | | | | | | 1.65 | |
| 2050 | 17.65 | 7.09 | 6.73 | 8.33 | 7.99 | 4.14 | 1.65 | 6.40 |

Table 7-14: Hawai'i Island Forced Outage Rates for Thermal Resources (3 of 4)

| Year<br>% | Kapua D27 | Kanoelehua CT1 | Keahole CT2 | Puna CT3 | Keahole CT4 | Keahole CT5 | Keahole ST | HEP CT1 |
|---|---|---|---|---|---|---|---|---|
| 2021 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2022 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2023 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2024 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2025 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2026 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2027 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2028 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2029 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2030 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2031 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2032 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2033 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2034 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2035 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2036 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2037 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2038 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2039 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2040 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| 2041 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |

| Year<br>% | Kapua D27 | Kanoelehua | Keahole | Puna | Keahole | Keahole | Keahole | HEP CT1 |
|---|---|---|---|---|---|---|---|---|
| 2042 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| | | | | | | | | |
| 2044 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| | | | | | | | | |
| 2046 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| | | | | | | | | |
| 2048 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |
| | | | | | | | | |
| 2050 | 0.61 | 0.94 | 4.18 | 1.81 | 4.68 | 6.30 | 2.93 | 2.05 |

| Year<br>% | HEP CT2 | HEP ST | PGV |
|---|---|---|---|
| 2021 | 4.22 | 2.52 | 3.85 |
| 2022 | 4.22 | 2.52 | 3.85 |
| 2023 | 4.22 | 2.52 | 3.85 |
| 2024 | 4.22 | 2.52 | 3.85 |
| 2025 | 4.22 | 2.52 | 3.85 |
| 2026 | 4.22 | 2.52 | 3.85 |
| 2027 | 4.22 | 2.52 | 3.85 |
| 2028 | 4.22 | 2.52 | 3.85 |
| 2029 | 4.22 | 2.52 | 3.85 |
| 2030 | 4.22 | 2.52 | 3.85 |
| 2031 | 4.22 | 2.52 | 3.85 |
| 2032 | 4.22 | 2.52 | 3.85 |
| 2033 | 4.22 | 2.52 | 3.85 |
| 2034 | 4.22 | 2.52 | 3.85 |
| 2035 | 4.22 | 2.52 | 3.85 |
| 2036 | 4.22 | 2.52 | 3.85 |
| 2037 | 4.22 | 2.52 | 3.85 |

| Year<br>% | HEP CT2 | HEP ST | PGV |
|---|---|---|---|
| 2038 | 4.22 | 2.52 | 3.85 |
| | | | |
| 2040 | 4.22 | 2.52 | 3.85 |
| | | | |
| 2042 | 4.22 | 2.52 | 3.85 |
| | | | |
| 2044 | 4.22 | 2.52 | 3.85 |
| | | | |
| 2046 | 4.22 | 2.52 | 3.85 |
| | | | |
| 2048 | 4.22 | 2.52 | 3.85 |
| | | 2.52 | |
| 2050 | 4.22 | 2.52 | 3.85 |

Table 7-16: Hawai'i Island Maintenance Outage Rates for Thermal Resources (1 of 4)

| Year<br>% | Hill 5 | Hill 6 | Puna Steam | Kanoelehua D11 | Waimea D12 | Waimea D13 | Waimea D14 | Kanoelehua D15 |
|---|---|---|---|---|---|---|---|---|
| 2021 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| 2022 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| 2023 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| 2024 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| 2025 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| 2026 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| 2027 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| 2028 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| 2029 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| 2030 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| 2031 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| 2032 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| 2033 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |

| Year<br>% | Hill 5 | Hill 6 | Puna Steam | Kanoelehua D11 | Waimea D12 | Waimea D13 | Waimea D14 | Kanoelehua D15 |
|---|---|---|---|---|---|---|---|---|
| 2034 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| | | | | | | | | |
| 2036 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| | | | | | | | | |
| 2038 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| | | | | | | | | |
| 2040 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| | | | | | | | | |
| 2042 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| | | | | | | | | |
| 2044 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| | | | | | | | | |
| 2046 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| | | | | | | | | |
| 2048 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |
| | | | | | | | | |
| 2050 | 5.33 | 9.83 | 10.77 | 4.76 | 0.17 | 0.32 | 0.12 | 1.04 |

Table 7-17: Hawai‘i Island Maintenance Outage Rates for Thermal Resources (2 of 4)

| Year<br>% | Kanoelehua D16 | Kanoelehua D17 | Keahole D21 | Keahole D22 | Keahole D23 | Panaewa D24 | Ouli D25 | Punaluu D26 |
|---|---|---|---|---|---|---|---|---|
| 2021 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |
| 2022 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |
| 2023 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |
| 2024 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |
| 2025 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |
| 2026 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |
| 2027 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |
| 2028 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |
| 2029 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |

| Year<br>% | Kanoelehua D16 | Kanoelehua D17 | Keahole D21 | Keahole D22 | Keahole D23 | Panaewa D24 | Ouli D25 | Punaluu D26 |
|---|---|---|---|---|---|---|---|---|
| 2030 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |
| | | | | | | | | |
| 2032 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |
| | | | | | | | | |
| 2034 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |
| | | | | | | | | |
| 2036 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |
| | | | | | | | | |
| 2038 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |
| | | | | | | | | |
| 2040 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |
| | | | | | | | | |
| 2042 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |
| | | | | | | | | |
| 2044 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |
| | | | | | | | | |
| 2046 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |
| | | | | | | | | |
| 2048 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |
| | | | | | | | | |
| 2050 | 0.42 | 0.99 | 1.11 | 0.93 | 0.79 | 0.72 | 0.22 | 0.17 |

Table 7-18: Hawai'i Island Maintenance Outage Rates for Thermal Resources (3 of 4)

| Year<br>% | Kapua D27 | Kanoelehua CT1 | Keahole CT2 | Puna CT3 | Keahole CT4 | Keahole CT5 | Keahole ST | HEP CT1 |
|---|---|---|---|---|---|---|---|---|
| 2021 | 0.29 | 2.64 | 1.79 | 2.65 | 2.96 | 3.09 | 1.09 | 2.46 |
| 2022 | 0.29 | 2.64 | 1.79 | 2.65 | 2.96 | 3.09 | 1.09 | 2.46 |
| 2023 | | | | | | | | |
| 2024 | 0.29 | 2.64 | 1.79 | 2.65 | 2.96 | 3.09 | 1.09 | 2.46 |
| 2025 | 0.29 | 2.64 | 1.79 | 2.65 | 2.96 | 3.09 | 1.09 | 2.46 |

| Year<br>% | Kapua D27 | Kanoelehua | Keahole | Puna | Keahole | Keahole | Keahole | HEP CT1 |
|---|---|---|---|---|---|---|---|---|
| 2026 | 0.29 | 2.64 | 1.79 | 2.65 | 2.96 | 3.09 | 1.09 | 2.46 |
| | | | | | | | | |
| 2028 | 0.29 | 2.64 | 1.79 | 2.65 | 2.96 | 3.09 | 1.09 | 2.46 |
| | | | | | | | | |
| 2030 | 0.29 | 2.64 | 1.79 | 2.65 | 2.96 | 3.09 | 1.09 | 2.46 |
| | | | | | | | | |
| 2032 | 0.29 | 2.64 | 1.79 | 2.65 | 2.96 | 3.09 | 1.09 | 2.46 |
| | | | | | | | | |
| 2034 | 0.29 | 2.64 | 1.79 | 2.65 | 2.96 | 3.09 | 1.09 | 2.46 |
| 2035 | | | | | | | | |
| 2036 | 0.29 | 2.64 | 1.79 | 2.65 | 2.96 | 3.09 | 1.09 | 2.46 |
| | | | | | | | | |
| 2038 | 0.29 | 2.64 | 1.79 | 2.65 | 2.96 | 3.09 | 1.09 | 2.46 |
| | | | | | | | | |
| 2040 | 0.29 | 2.64 | 1.79 | 2.65 | 2.96 | 3.09 | 1.09 | 2.46 |
| | | | | | | | | |
| 2042 | 0.29 | 2.64 | 1.79 | 2.65 | 2.96 | 3.09 | 1.09 | 2.46 |
| | | | | | | | | |
| 2044 | 0.29 | 2.64 | 1.79 | 2.65 | 2.96 | 3.09 | 1.09 | 2.46 |
| 2045 | | | | | | | | |
| 2046 | 0.29 | 2.64 | 1.79 | 2.65 | 2.96 | 3.09 | 1.09 | 2.46 |
| | | | | | | | | |
| 2048 | 0.29 | 2.64 | 1.79 | 2.65 | 2.96 | 3.09 | 1.09 | 2.46 |
| | | | | | | | | |
| 2050 | 0.29 | 2.64 | 1.79 | 2.65 | 2.96 | 3.09 | 1.09 | 2.46 |

| Year<br>% | HEP CT2 | HEP ST | PGV |
|---|---|---|---|
| 2021 | 2.93 | 1.07 | 3.84 |

| Year<br>% | HEP CT2 | HEP ST | PGV |
|---|---|---|---|
| 2022 | 2.93 | 1.07 | 3.84 |
| 2023 | 2.93 | 1.07 | 3.84 |
| 2024 | 2.93 | 1.07 | 3.84 |
| 2025 | 2.93 | 1.07 | 3.84 |
| 2026 | 2.93 | 1.07 | 3.84 |
| 2027 | 2.93 | 1.07 | 3.84 |
| 2028 | 2.93 | 1.07 | 3.84 |
| 2029 | 2.93 | 1.07 | 3.84 |
| 2030 | 2.93 | 1.07 | 3.84 |
| 2031 | 2.93 | 1.07 | 3.84 |
| 2032 | 2.93 | 1.07 | 3.84 |
| 2033 | 2.93 | 1.07 | 3.84 |
| 2034 | 2.93 | 1.07 | 3.84 |
| 2035 | 2.93 | 1.07 | 3.84 |
| 2036 | 2.93 | 1.07 | 3.84 |
| 2037 | 2.93 | 1.07 | 3.84 |
| 2038 | 2.93 | 1.07 | 3.84 |
| 2039 | 2.93 | 1.07 | 3.84 |
| 2040 | 2.93 | 1.07 | 3.84 |
| 2041 | 2.93 | 1.07 | 3.84 |
| 2042 | 2.93 | 1.07 | 3.84 |
| 2043 | 2.93 | 1.07 | 3.84 |
| 2044 | 2.93 | 1.07 | 3.84 |
| 2045 | 2.93 | 1.07 | 3.84 |
| 2046 | 2.93 | 1.07 | 3.84 |
| 2047 | 2.93 | 1.07 | 3.84 |
| 2048 | 2.93 | 1.07 | 3.84 |
| 2049 | 2.93 | 1.07 | 3.84 |
| 2050 | 2.93 | 1.07 | 3.84 |

## *Maui*

Table 7-20: Maui Minimum and Maximum Capacity for Thermal Resources

| Unit[89] | Operating Minimum (Net MW) | Normal Top Load (Net MW) | Fuel Type |
|---|---|---|---|
| Kahului 1 | 2.26 | 4.71 | IFO |
| Kahului 2 | 2.28 | 4.76 | IFO |
| Kahului 3 | 3.00 | 11.50 | IFO |
| Kahului 4 | 3.00 | 11.50 | IFO |
| Maalaea 1 | 2.50 | 2.50 | ULSD |
| Maalaea 2 | 2.50 | 2.50 | ULSD |
| Maalaea 3 | 2.50 | 2.50 | ULSD |
| Maalaea 4 | 1.86 | 5.51 | Diesel |
| Maalaea 5 | 1.86 | 5.51 | Diesel |
| Maalaea 6 | 1.86 | 5.51 | Diesel |
| Maalaea 7 | 1.86 | 5.51 | Diesel |
| Maalaea 8 | 1.86 | 5.48 | Diesel |
| Maalaea 9 | 1.86 | 5.48 | Diesel |
| Maalaea 10 | 7.87 | 12.34 | Diesel |
| Maalaea 11 | 7.87 | 12.34 | Diesel |
| Maalaea 12 | 7.87 | 12.34 | Diesel |
| Maalaea 13 | 7.87 | 12.34 | Diesel |
| Maalaea X1 | 2.50 | 2.50 | ULSD |
| Maalaea X2 | 2.50 | 2.50 | ULSD |
| Maalaea 14 | 5.88 | 21.13 | Diesel |
| Maalaea 15 | 3.73 | 13.38 | - |
| Maalaea 16 | 5.88 | 21.13 | Diesel |
| Maalaea 17 | 5.93 | 21.47 | Diesel |
| Maalaea 18 | 2.96 | 12.99 | - |
| Maalaea 19 | 5.93 | 21.47 | Diesel |
| Hana 1 | 0.00 | 0.97 | ULSD |

[89] Kahului 1-4 units plan to retire in 24.

| Unit[89] | Operating Minimum (Net MW) | Normal Top Load (Net MW) | Fuel Type |
|---|---|---|---|
| Hana 2 | 0.00 | 0.97 | ULSD |

Table 7-21: Maui Heat Rate Coefficients for Thermal Resources

| Unit | A Coefficient (MMBTU/hr) | B Coefficient (MMBTU/hr MW) | C Coefficient (MMBTU/hr MW^2) | Average Heat Rate (BTU/KWH) [90] |
|---|---|---|---|---|
| Kahului 1 | 13.909 | 10.485 | 0.529 | |
| | | | | |
| Kahului 3 | 28.226 | 8.566 | 0.187 | |
| | | | | |
| Maalaea 1 | 0.000 | 10.288 | 0.000 | |
| | | | | |
| Maalaea 3 | 0.000 | 10.288 | 0.000 | |
| | | | | |
| Maalaea 5 | 7.643 | 6.53 | 0.412 | |
| | | | | |
| Maalaea 7 | 8.411 | 6.222 | 0.431 | |
| | | | | |
| Maalaea 9 | 7.325 | 5.249 | 0.412 | |
| | | | | |
| Maalaea 11 | 16.865 | 5.471 | 0.196 | |
| | | | | |
| Maalaea 13 | 5.163 | 8.286 | 0.034 | |
| | | | | |
| Maalaea X2 | 0.000 | 10.288 | 0.000 | |
| | | | | |
| Maalaea 15 | 74.702 | 7.046 | 0 | |
| Maalaea 16 | 51.685 | 5.891 | 0.033 | |

[90] Hana 1 and 2 are primarily used as backup generation only for line maintenance and repair work in Hana. Therefore, they are modeled using an average heat rate, which is based on the maximum monthly usage over a 5-year historical period.

| | | | | |
|---|---|---|---|---|
| Maalaea 17 | 57.1744 | 6.4611 | -0.0002 | |
| | | | | |
| Maalaea 19 | 58.5869 | 6.4094 | 0.0013 | |
| | | | | |
| Hana 2 | - | - | - | 11532.0000 |

Table 7-22: Maui Forced Outage Rates for Thermal Resources (1 of 3)

| Year<br>% | Kahului 1 | Kahului 2 | Kahului 3 | Kahului 4 | Maalaea 1 | Maalaea 2 | Maalaea 3 | Maalaea 4 |
|---|---|---|---|---|---|---|---|---|
| 2021 | | | 0.08 | 0.34 | 3.93 | 3.93 | 3.93 | 1.45 |
| 2022 | | | 0.08 | 0.34 | 3.93 | 3.93 | 3.93 | 1.45 |
| 2023 | | | | | | | | |
| 2024 | | | | | 3.93 | 3.93 | 3.93 | 1.45 |
| 2025 | | | | | 3.93 | | | |
| 2026 | | | | | 3.93 | 3.93 | 3.93 | 1.45 |
| 2027 | | | | | 3.93 | | | |
| 2028 | | | | | 3.93 | 3.93 | 3.93 | 1.45 |
| 2029 | | | | | 3.93 | | | |
| 2030 | | | | | 3.93 | 3.93 | 3.93 | 1.45 |
| 2031 | | | | | 3.93 | | | |
| 2032 | | | | | 3.93 | 3.93 | 3.93 | 1.45 |
| 2033 | | | | | 3.93 | | | |
| 2034 | | | | | 3.93 | 3.93 | 3.93 | 1.45 |
| 2035 | | | | | 3.93 | | | |
| 2036 | | | | | 3.93 | 3.93 | 3.93 | 1.45 |
| 2037 | | | | | 3.93 | | | |
| 2038 | | | | | 3.93 | 3.93 | 3.93 | 1.45 |
| 2039 | | | | | 3.93 | | | |
| 2040 | | | | | 3.93 | 3.93 | 3.93 | 1.45 |
| 2041 | | | | | 3.93 | | | |
| 2042 | | | | | 3.93 | 3.93 | 3.93 | 1.45 |

| Year<br>% | Kahului 1 | Kahului 2 | Kahului 3 | Kahului 4 | Maalaea 1 | Maalaea 2 | Maalaea 3 | Maalaea 4 |
|---|---|---|---|---|---|---|---|---|
| 2043 | | | | | 3.93 | 3.93 | 3.93 | 1.45 |
| 2044 | | | | | 3.93 | 3.93 | 3.93 | 1.45 |
| 2045 | | | | | 3.93 | 3.93 | 3.93 | 1.45 |
| 2046 | | | | | 3.93 | 3.93 | 3.93 | 1.45 |
| 2047 | | | | | 3.93 | 3.93 | 3.93 | 1.45 |
| 2048 | | | | | 3.93 | 3.93 | 3.93 | 1.45 |
| 2049 | | | | | 3.93 | 3.93 | 3.93 | 1.45 |
| 2050 | | | | | 3.93 | 3.93 | 3.93 | 1.45 |

| Year<br>% | Maalaea 5 | Maalaea 6 | Maalaea 7 | Maalaea 8 | Maalaea 9 | Maalaea 10 | Maalaea 11 | Maalaea 12 |
|---|---|---|---|---|---|---|---|---|
| 2021 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2022 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2023 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2024 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2025 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2026 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2027 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2028 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2029 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2030 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2031 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2032 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2033 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2034 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2035 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2036 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2037 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2038 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |

| Year<br>% | Maalaea 5 | Maalaea 6 | Maalaea 7 | Maalaea 8 | Maalaea 9 | Maalaea 10 | Maalaea 11 | Maalaea 12 |
|---|---|---|---|---|---|---|---|---|
| 2039 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2040 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2041 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2042 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2043 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2044 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2045 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2046 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2047 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2048 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2049 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |
| 2050 | 1.45 | 1.45 | 1.45 | 2.36 | 2.36 | 0.63 | 0.63 | 0.63 |

Table 7-24: Maui Forced Outage Rates for Thermal Resources (3 of 3)

| Year<br>% | Maalaea 13 | Maalaea X1 | Maalaea X2 | Maalaea 14 | Maalaea 15 | Maalaea 16 | Maalaea 17 | Maalaea 18 | Maalaea 19 |
|---|---|---|---|---|---|---|---|---|---|
| 2021 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2022 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2023 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2024 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2025 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2026 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2027 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2028 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2029 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2030 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2031 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2032 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2033 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2034 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |

| Year<br>% | Maalaea 13 | Maalaea X1 | Maalaea X2 | Maalaea 14 | Maalaea 15 | Maalaea 16 | Maalaea 17 | Maalaea 18 | Maalaea 19 |
|---|---|---|---|---|---|---|---|---|---|
| 2035 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2036 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2037 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2038 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2039 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2040 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2041 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2042 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2043 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2044 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2045 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2046 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2047 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2048 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2049 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |
| 2050 | 0.63 | 3.93 | 3.93 | 0.16 | 0.41 | 0.16 | 0.49 | 0.30 | 0.49 |

Table 7-25: Maui Maintenance Outage Rates for Thermal Resources (1 of 3)

| Year<br>% | Kahului 1 | Kahului 2 | Kahului 3 | Kahului 4 | Maalaea 1 | Maalaea 2 | Maalaea 3 | Maalaea 4 |
|---|---|---|---|---|---|---|---|---|
| 2021 | | | 12.35 | 10.98 | 2.4 | 2.4 | 2.4 | 2.63 |
| 2022 | | | 10.98 | 10.98 | 2.4 | 2.4 | 2.4 | 2.63 |
| 2023 | | | | | 4.04 | 4.04 | 2.4 | 2.63 |
| 2024 | | | | | 2.4 | 2.4 | 2.4 | 2.63 |
| 2025 | | | | | 2.4 | 2.4 | 2.4 | 2.63 |
| 2026 | | | | | 2.4 | 7.88 | 2.4 | 2.63 |
| 2027 | | | | | 2.4 | 2.4 | 7.88 | 2.63 |
| 2028 | | | | | 2.4 | 2.4 | 2.4 | 2.63 |
| 2029 | | | | | 2.4 | 2.4 | 2.4 | 2.63 |

| Year % | Kahului 1 | Kahului 2 | Kahului 3 | Kahului 4 | Maalaea 1 | Maalaea 2 | Maalaea 3 | Maalaea 4 |
|---|---|---|---|---|---|---|---|---|
| 2030 | | | | | 2.4 | 2.4 | 5.96 | 2.63 |
| 2031 | | | | | 2.4 | 2.4 | 2.4 | 25.37 |
| 2032 | | | | | 2.4 | 2.4 | 2.4 | 2.63 |
| 2033 | | | | | 7.88 | 2.4 | 2.4 | 2.63 |
| 2034 | | | | | 2.4 | 2.4 | 2.4 | 2.63 |
| 2035 | | | | | 2.4 | 2.4 | 2.4 | 2.63 |
| 2036 | | | | | 2.4 | 7.88 | 2.4 | 2.63 |
| 2037 | | | | | 2.4 | 2.4 | 7.88 | 2.63 |
| 2038 | | | | | 2.4 | 2.4 | 2.4 | 2.63 |
| 2039 | | | | | 2.4 | 2.4 | 2.4 | 2.63 |
| 2040 | | | | | 2.4 | 2.4 | 2.4 | 2.63 |
| 2041 | | | | | 2.4 | 2.4 | 2.4 | 2.63 |
| 2042 | | | | | 2.4 | 2.4 | 2.4 | 2.63 |
| 2043 | | | | | 7.88 | 2.4 | 2.4 | 2.63 |
| 2044 | | | | | 2.4 | 2.4 | 2.4 | 2.63 |
| 2045 | | | | | 2.4 | 2.4 | 2.4 | 2.63 |
| 2046 | | | | | 2.4 | 2.4 | 2.4 | 2.63 |
| 2047 | | | | | 2.4 | 2.4 | 2.4 | 2.63 |
| 2048 | | | | | 2.4 | 2.4 | 2.4 | 2.63 |
| 2049 | | | | | 2.4 | 2.4 | 2.4 | 2.63 |
| 2050 | | | | | 2.4 | 2.4 | 2.4 | 2.63 |

Table 7-26: Maui Maintenance Outage Rates for Thermal Resources (2 of 3)

| Year % | Maalaea 5 | Maalaea 6 | Maalaea 7 | Maalaea 8 | Maalaea 9 | Maalaea 10 | Maalaea 11 | Maalaea 12 |
|---|---|---|---|---|---|---|---|---|
| 2021 | 2.63 | 10.3 | 2.63 | 1.24 | 1.24 | 2.54 | 18.98 | 25.28 |
| 2022 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 25.28 | 2.54 | 2.54 |
| 2023 | 2.63 | 19.62 | 2.63 | 1.24 | 1.24 | 2.54 | 2.54 | 2.54 |
| 2024 | 19.62 | 2.63 | 2.63 | 1.24 | 1.24 | 2.54 | 19.52 | 17.61 |

| Year<br>% | Maalaea 5 | Maalaea 6 | Maalaea 7 | Maalaea 8 | Maalaea 9 | Maalaea 10 | Maalaea 11 | Maalaea 12 |
|---|---|---|---|---|---|---|---|---|
| 2025 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 17.61 | 2.54 | 2.54 |
| 2026 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 2.54 | 2.54 | 2.54 |
| 2027 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 2.54 | 19.52 | 17.61 |
| 2028 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 17.61 | 2.54 | 2.54 |
| 2029 | 2.63 | 2.63 | 19.62 | 1.24 | 1.24 | 2.54 | 2.54 | 2.54 |
| 2030 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 2.54 | 19.52 | 17.61 |
| 2031 | 2.63 | 2.63 | 2.63 | 16.3 | 18.22 | 17.61 | 2.54 | 2.54 |
| 2032 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 2.54 | 2.54 | 17.61 |
| 2033 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 17.61 | 19.52 | 2.54 |
| 2034 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 2.54 | 2.54 | 2.54 |
| 2035 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 2.54 | 2.54 | 17.61 |
| 2036 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 17.61 | 19.52 | 2.54 |
| 2037 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 2.54 | 2.54 | 2.54 |
| 2038 | 2.63 | 19.62 | 2.63 | 1.24 | 1.24 | 2.54 | 19.52 | 17.61 |
| 2039 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 17.61 | 2.54 | 2.54 |
| 2040 | 19.62 | 2.63 | 2.63 | 1.24 | 1.24 | 2.54 | 2.54 | 2.54 |
| 2041 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 2.54 | 17.61 | 17.61 |
| 2042 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 17.61 | 2.54 | 2.54 |
| 2043 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 2.54 | 2.54 | 2.54 |
| 2044 | 2.63 | 2.63 | 19.62 | 16.3 | 18.22 | 2.54 | 17.61 | 17.61 |
| 2045 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 17.61 | 2.54 | 2.54 |
| 2046 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 17.61 | 2.54 | 2.54 |
| 2047 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 17.61 | 2.54 | 2.54 |
| 2048 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 17.61 | 2.54 | 2.54 |
| 2049 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 17.61 | 2.54 | 2.54 |
| 2050 | 2.63 | 2.63 | 2.63 | 1.24 | 1.24 | 17.61 | 2.54 | 2.54 |

Table 7-27: Maui Maintenance Outage Rates for Thermal Resources (3 of 3)

| Year<br>% | Maalaea 13 | Maalaea X1 | Maalaea X2 | Maalaea 14 | Maalaea 15 | Maalaea 16 | Maalaea 17 | Maalaea 18 | Maalaea 19 |
|---|---|---|---|---|---|---|---|---|---|
| 2021 | 2.54 | 2.4 | 2.4 | 5.65 | 4.35 | 6.2 | 6.34 | 5.2 | 4.42 |
| 2022 | 25.28 | 2.4 | 2.4 | 5.65 | 12.02 | 5.65 | 4.42 | 5.2 | 4.42 |
| 2023 | 2.54 | 2.4 | 2.4 | 11.41 | 4.35 | 12.78 | 4.42 | 5.2 | 4.42 |
| 2024 | 2.54 | 2.4 | 2.4 | 7.3 | 4.35 | 5.65 | 4.42 | 5.2 | 4.42 |
| 2025 | 2.54 | 2.4 | 2.4 | 5.65 | 4.35 | 5.65 | 4.7 | 5.2 | 4.42 |
| 2026 | 17.61 | 2.4 | 2.4 | 5.65 | 13.94 | 5.65 | 4.42 | 5.2 | 4.42 |
| 2027 | 2.54 | 2.4 | 2.4 | 5.65 | 4.35 | 8.12 | 4.42 | 14.51 | 6.07 |
| 2028 | 2.54 | 5.69 | 5.69 | 9.22 | 4.35 | 12.78 | 6.34 | 5.2 | 4.42 |
| 2029 | 17.61 | 2.4 | 2.4 | 5.65 | 4.35 | 5.65 | 4.42 | 5.2 | 4.42 |
| 2030 | 2.54 | 2.4 | 2.4 | 6.48 | 4.35 | 5.65 | 4.42 | 5.2 | 7.98 |
| 2031 | 2.54 | 2.4 | 2.4 | 9.22 | 13.94 | 5.65 | 4.42 | 5.2 | 4.42 |
| 2032 | 17.61 | 2.4 | 2.4 | 5.65 | 4.35 | 5.65 | 4.42 | 14.51 | 4.42 |
| 2033 | 2.54 | 2.4 | 2.4 | 5.65 | 4.35 | 9.22 | 4.42 | 5.2 | 5.24 |
| 2034 | 2.54 | 2.4 | 2.4 | 5.65 | 4.35 | 6.48 | 4.42 | 5.2 | 4.42 |
| 2035 | 17.61 | 2.4 | 2.4 | 5.65 | 4.35 | 5.65 | 10.18 | 5.2 | 6.07 |
| 2036 | 2.54 | 2.4 | 2.4 | 8.12 | 13.94 | 5.65 | 4.42 | 5.2 | 4.42 |
| 2037 | 17.61 | 2.4 | 2.4 | 9.22 | 4.35 | 5.65 | 4.42 | 14.51 | 4.42 |
| 2038 | 2.54 | 5.69 | 4.04 | 5.65 | 4.35 | 9.22 | 4.42 | 5.2 | 4.42 |
| 2039 | 2.54 | 2.4 | 2.4 | 5.65 | 4.35 | 7.3 | 4.42 | 5.2 | 4.42 |
| 2040 | 17.61 | 2.4 | 2.4 | 5.65 | 4.35 | 5.65 | 7.98 | 5.2 | 5.24 |
| 2041 | 2.54 | 2.4 | 2.4 | 5.65 | 13.94 | 5.65 | 4.42 | 5.2 | 4.42 |
| 2042 | 2.54 | 2.4 | 2.4 | 9.22 | 4.35 | 5.65 | 4.42 | 12.87 | 4.42 |
| 2043 | 17.61 | 2.4 | 2.4 | 5.65 | 4.35 | 9.22 | 4.42 | 5.2 | 4.42 |
| 2044 | 2.54 | 2.4 | 2.4 | 5.65 | 4.35 | 5.65 | 4.42 | 5.2 | 4.42 |
| 2045 | 2.54 | 2.4 | 2.4 | 5.65 | 4.35 | 5.65 | 4.42 | 5.2 | 4.42 |
| 2046 | 2.54 | 2.4 | 2.4 | 5.65 | 4.35 | 5.65 | 4.42 | 5.2 | 4.42 |
| 2047 | 2.54 | 2.4 | 2.4 | 5.65 | 4.35 | 5.65 | 4.42 | 5.2 | 4.42 |
| 2048 | 2.54 | 2.4 | 2.4 | 5.65 | 4.35 | 5.65 | 4.42 | 5.2 | 4.42 |
| 2049 | 2.54 | 2.4 | 2.4 | 5.65 | 4.35 | 5.65 | 4.42 | 5.2 | 4.42 |

| Year<br>% | Maalaea 13 | Maalaea X1 | Maalaea X2 | Maalaea 14 | Maalaea 15 | Maalaea 16 | Maalaea 17 | Maalaea 18 | Maalaea 19 |
|---|---|---|---|---|---|---|---|---|---|
| 2050 | 2.54 | 2.4 | 2.4 | 5.65 | 4.35 | 5.65 | 4.42 | 5.2 | 4.42 |

## *Molokaʻi*

Table 7-28: Molokaʻi Minimum and Maximum Capacity for Thermal Resources

| Unit | Operating Minimum (Net MW) | Normal Top Load (Net MW) | Fuel Type |
|---|---|---|---|
| Palaau 01 | 0.31 | 1.25 | ULSD |
| | | | |
| Palaau 03 | 0.25 | 0.97 | ULSD |
| | | | |
| Palaau 05 | 0.25 | 0.97 | ULSD |
| | | | |
| Palaau 07 | 0.66 | 2.20 | ULSD |
| | | | |
| Palaau 09 | 0.66 | 2.20 | ULSD |
| | | | |

Table 7-29: Molokaʻi Heat Rate Coefficients for Thermal Resources

| Unit | A Coefficient (MMBTU/hr) | B Coefficient (MMBTU/hr MW) | C Coefficient (MMBTU/hr MW^2) |
|---|---|---|---|
| Palaau 01 | 1.3894 | 9.6947 | -0.8835 |
| Palaau 02 | 0.8831 | 10.4922 | -1.7433 |
| Palaau 03 | 5.4111 | -4.6487 | 10.2493 |
| Palaau 04 | 4.5017 | 1.8072 | 5.8410 |
| Palaau 05 | 1.3975 | 9.3826 | -0.3959 |
| Palaau 06 | 1.5392 | 8.5616 | 0.1192 |
| Palaau 07 | 3.1052 | 6.6925 | 0.8483 |
| Palaau 08 | 2.0900 | 8.2860 | 0.2125 |
| Palaau 09 | 2.1250 | 8.0170 | 0.3328 |

| Unit | A Coefficient (MMBTU/hr) | B Coefficient (MMBTU/hr MW) | C Coefficient (MMBTU/hr MW^2) |
|---|---|---|---|
| Palaau GT1 | 0.0000 | 18.8310 | 0.0000 |

Table 7-30: Moloka‘i Forced Outage Rates for Thermal Resources

| Year<br>% | Palaau 01 | Palaau 02 | Palaau 03 | Palaau 04 | Palaau 05 | Palaau 06 | Palaau 07 | Palaau 08 | Palaau 09 | Palaau GT1 |
|---|---|---|---|---|---|---|---|---|---|---|
| 2021 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2022 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2023 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2024 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2025 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2026 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2027 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2028 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2029 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2030 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2031 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2032 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2033 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2034 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2035 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2036 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2037 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2038 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2039 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2040 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2041 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2042 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2043 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2044 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| 2045 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |

| Year % | Palaau 01 | Palaau 02 | Palaau 03 | Palaau 04 | Palaau 05 | Palaau 06 | Palaau 07 | Palaau 08 | Palaau 09 | Palaau GT1 |
|---|---|---|---|---|---|---|---|---|---|---|
| 2046 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| | | | | | | | | | | |
| 2048 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |
| | | | | | | | | | 0.36 | |
| 2050 | 2.69 | 2.69 | 0.45 | 0.45 | 0.45 | 0.45 | 0.36 | 0.36 | 0.36 | 0 |

Table 7-31: Moloka'i Maintenance Outage Rates for Thermal Resources

| Year % | Palaau 01 | Palaau 02 | Palaau 03 | Palaau 04 | Palaau 05 | Palaau 06 | Palaau 07 | Palaau 08 | Palaau 09 | Palaau GT1 |
|---|---|---|---|---|---|---|---|---|---|---|
| 2021 | 6.1 | 2.54 | 5.06 | 5.06 | 5.06 | 5.06 | 2.04 | 2.04 | 2.04 | 0 |
| 2022 | 2.54 | 13.77 | 5.06 | 5.06 | 5.06 | 5.06 | 2.04 | 2.04 | 13.27 | 1.64 |
| 2023 | 2.54 | 2.54 | 10.54 | 10.54 | 16.29 | 8.62 | 2.04 | 16.56 | 2.04 | 0 |
| 2024 | 8.02 | 2.54 | 5.06 | 5.06 | 5.06 | 10.54 | 16.56 | 2.04 | 2.04 | 0 |
| 2025 | 2.54 | 2.54 | 5.06 | 5.06 | 10.54 | 5.06 | 2.04 | 5.6 | 5.6 | 1.37 |
| 2026 | 2.54 | 8.02 | 5.06 | 8.62 | 5.06 | 5.06 | 5.6 | 2.04 | 2.04 | 0 |
| 2027 | 6.1 | 2.54 | 8.62 | 5.06 | 5.06 | 8.62 | 2.04 | 2.04 | 2.04 | 0 |
| 2028 | 2.54 | 2.54 | 5.06 | 5.06 | 8.62 | 5.06 | 2.04 | 5.6 | 5.6 | 0 |
| 2029 | 2.54 | 6.1 | 5.06 | 14.38 | 5.06 | 5.06 | 5.6 | 2.04 | 2.04 | 0 |
| 2030 | 8.02 | 2.54 | 10.54 | 5.06 | 5.06 | 10.54 | 2.04 | 2.04 | 2.04 | 1.37 |
| 2031 | 2.54 | 2.54 | 5.06 | 5.06 | 10.54 | 5.06 | 2.04 | 5.6 | 5.6 | 0 |
| 2032 | 2.54 | 8.02 | 5.06 | 8.62 | 5.06 | 5.06 | 5.6 | 2.04 | 2.04 | 0 |
| 2033 | 6.1 | 2.54 | 8.62 | 5.06 | 5.06 | 8.62 | 2.04 | 2.04 | 2.04 | 0 |
| 2034 | 2.54 | 2.54 | 5.06 | 5.06 | 8.62 | 5.06 | 2.04 | 5.6 | 5.6 | 0 |
| 2035 | 2.54 | 6.1 | 5.06 | 17.94 | 5.06 | 5.06 | 5.6 | 2.04 | 2.04 | 1.37 |
| 2036 | 11.58 | 2.54 | 10.54 | 5.06 | 5.06 | 14.1 | 2.04 | 2.04 | 2.04 | 0 |
| 2037 | 2.54 | 2.54 | 5.06 | 5.06 | 14.1 | 5.06 | 2.04 | 5.6 | 5.6 | 0 |
| 2038 | 2.54 | 8.02 | 5.06 | 8.62 | 5.06 | 5.06 | 5.6 | 2.04 | 2.04 | 0 |
| 2039 | 6.1 | 2.54 | 8.62 | 5.06 | 5.06 | 8.62 | 2.04 | 2.04 | 2.04 | 0 |
| 2040 | 2.54 | 2.54 | 5.06 | 5.06 | 8.62 | 5.06 | 2.04 | 5.6 | 5.6 | 1.37 |

| Year<br>% | Palaau 01 | Palaau 02 | Palaau 03 | Palaau 04 | Palaau 05 | Palaau 06 | Palaau 07 | Palaau 08 | Palaau 09 | Palaau GT1 |
|---|---|---|---|---|---|---|---|---|---|---|
| 2041 | 2.54 | 6.1 | 5.06 | 17.94 | 5.06 | 5.06 | 5.6 | 2.04 | 2.04 | 0 |
| 2042 | 11.58 | 2.54 | 10.54 | 5.06 | 5.06 | 10.54 | 2.04 | 2.04 | 2.04 | 0 |
| 2043 | 2.54 | 2.54 | 5.06 | 5.06 | 14.1 | 5.06 | 2.04 | 5.6 | 5.6 | 0 |
| 2044 | 2.54 | 8.02 | 5.06 | 8.62 | 5.06 | 5.06 | 5.6 | 2.04 | 2.04 | 0 |
| 2045 | 6.1 | 2.54 | 8.62 | 5.06 | 5.06 | 8.62 | 2.04 | 2.04 | 2.04 | 1.37 |
| 2046 | 2.54 | 2.54 | 5.06 | 5.06 | 5.06 | 5.06 | 2.04 | 2.04 | 2.04 | 0 |
| 2047 | 2.54 | 2.54 | 5.06 | 5.06 | 5.06 | 5.06 | 2.04 | 2.04 | 2.04 | 0 |
| 2048 | 2.54 | 2.54 | 5.06 | 5.06 | 5.06 | 5.06 | 2.04 | 2.04 | 2.04 | 0 |
| 2049 | 2.54 | 2.54 | 5.06 | 5.06 | 5.06 | 5.06 | 2.04 | 2.04 | 2.04 | 0 |
| 2050 | 2.54 | 2.54 | 5.06 | 5.06 | 5.06 | 5.06 | 2.04 | 2.04 | 2.04 | 0 |

### *Lānaʻi*

Table 7-32: Lānaʻi Minimum and Maximum Capacity for Thermal Resources

| Unit | Operating Minimum (Net MW) | Normal Top Load (Net MW) | Fuel Type |
|---|---|---|---|
| LL 1 | 0.5 | 1.0 | ULSD |
| LL 2 | 0.5 | 1.0 | ULSD |
| LL 3 | 0.5 | 1.0 | ULSD |
| LL 4 | 0.5 | 1.0 | ULSD |
| LL 5 | 0.5 | 1.0 | ULSD |
| LL 6 | 0.5 | 1.0 | ULSD |
| LL 7 | 0.3 | 2.2 | ULSD |
| LL 8 | 0.3 | 2.2 | ULSD |
| CHP | 0.83 | 0.83 | ULSD |

| Unit | A Coefficient (MMBTU/hr) | B Coefficient (MMBTU/hr MW) | C Coefficient (MMBTU/hr MW^2) |
|---|---|---|---|
| LL 1 | 1.9016 | 6.6910 | 1.9235 |
| | | | |
| LL 3 | 0.9656 | 10.5671 | -0.8720 |
| | | | |
| LL 5 | 1.2913 | 9.0183 | 0.3364 |
| | | | |
| LL 7 | 3.4169 | 6.6148 | 0.6626 |
| | | | |
| CHP | 0 | 11.380 | 0 |

Table 7-34: Lānaʻi Forced Outage Rates for Thermal Resources

| Year<br>% | LL 1 | LL 2 | LL 3 | LL 4 | LL 5 | LL 6 | LL 7 | LL 8 | CHP |
|---|---|---|---|---|---|---|---|---|---|
| 2021 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| 2022 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| 2023 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| 2024 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| 2025 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| 2026 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| 2027 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| 2028 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| 2029 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| 2030 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| 2031 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| 2032 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| 2033 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| 2034 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| 2035 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| 2036 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |

| Year<br>% | LL 1 | LL 2 | LL 3 | LL 4 | LL 5 | LL 6 | LL 7 | LL 8 | CHP |
|---|---|---|---|---|---|---|---|---|---|
| 2037 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| 2038 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| | | | | | | | | | |
| 2040 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| | | | | | | | | | |
| 2042 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| | | | | | | | | | |
| 2044 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| | | | | | | | | | |
| 2046 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| | | | | | | | | | |
| 2048 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |
| | | | | | | | | | |
| 2050 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.93 | 4.30 | 4.30 | 16.35 |

| Year<br>% | LL 1 | LL 2 | LL 3 | LL 4 | LL 5 | LL 6 | LL 7 | LL 8 | CHP |
|---|---|---|---|---|---|---|---|---|---|
| 2021 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2022 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2023 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2024 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2025 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2026 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2027 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04% | 3.04 | 8.12 |
| 2028 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2029 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2030 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2031 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2032 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |

| Year | LL 1 | LL 2 | LL 3 | LL 4 | LL 5 | LL 6 | LL 7 | LL 8 | CHP |
|---|---|---|---|---|---|---|---|---|---|
| % | | | | | | | | | |
| 2033 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2034 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2035 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2036 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2037 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2038 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2039 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2040 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2041 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2042 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2043 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2044 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2045 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2046 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2047 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2048 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2049 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |
| 2050 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 1.57 | 3.04 | 3.04 | 8.12 |

# 8 Thermal Generating Unit Removal from Service Schedules

The planned removal from service schedules for O'ahu, Hawai'i Island, and Maui are provided below in Table 8-1. These schedules represent initial assumptions made on the timing for the removal of utility-owned, thermal generating units. This does not imply that the Company will retire these units in the years in which the model does not dispatch them. Actual retirement decisions are operational decisions that will be made at a later date based on a number of factors, including whether sufficient resources have been acquired and are in service, ancillary services provided by these generators have been sufficiently replaced, and after consideration for reliability and resilience factors, among others.

The planning analyses in the Grid Needs Assessment may deem it prudent to delay certain units' removal to address shortfalls in grid services, including Energy Reserve Margin. The order in which units are removed may be further adjusted to account for flexibility needs and unit age.

Table 8-1: Planned Removal from Service Assumptions for O'ahu, Hawai'i Island, and Maui

| Island | O'ahu | Hawai'i Island | Maui |
|---|---|---|---|
| **2024** | Waiau 3-4 Removed from Service | | |
| | | Puna Steam Removed from Service | |
| **2027** | Waiau 5-6 Removed from Service | Hill 5-6 Removed from Service | |
| | | | |
| **2030** | | | Maalaea 4-9 Removed from Service |
| | | | |
| **2037** | Kahe 3-4 Removed from Service | | |
| | | | |

# 9 Variable Renewable, Storage, and Grid Service Resource Portfolios

In addition to the thermal generating units, Hawaiian Electric has a diverse range of variable renewable resources including wind, solar, and hydro in its portfolio. Several upcoming projects will also add storage to the resource mix, paired with solar or as a standalone resource. The following resources are assumed to be online in the RESOLVE and PLEXOS models and are either existing resources that are currently online or have had an application submitted for approval. The year in service shown for the Stage 1 and Stage 2 RFP projects have been rounded to the nearest beginning of year. The planned resource portfolio will be updated for the projects resulting from the Community-Based Renewable Energy (CBRE) Phase 2 once they are known. Grid Services RFP projects noted below are assumed to be online at partial capacity in 2021 and ramp to their full capacity by 2023.

### *O'ahu*

Table 9-1: O'ahu Variable Renewable, Storage, and Grid Service Resources

| Unit | Year in Service | Capacity (MW) | Storage Capacity (MWh) | Capacity Factor (%) |
|---|---|---|---|---|
| Kapolei Sustainable Energy Park | 2012 | 1.0 | - | 21.9% |
| Kalaeloa Solar Two | 2013 | 5.0 | - | 25.7% |
| Kalaeloa Renewable Energy Park | 2014 | 5.0 | - | 20.5% |
| Kahuku Wind | 2011 | 30.0 | - | 27.2% |
| Kawailoa Wind | 2013 | 69.0 | - | 19.7% |
| West Loch | 2019 | 20.0 | - | 25.1% |
| Lanikuhana Solar | 2019 | 14.7 | - | 27.1% |
| Waipio PV | 2019 | 45.9 | - | 27.1% |
| Kawailoa Solar | 2019 | 49.0 | - | 27.1% |
| Na Pua Makani | 2020 | 24.0 | - | 42.5% |
| Waianae Solar | 2017 | 27.6 | - | 27.1% |
| Feed-In-Tariff Tier 1 and 2 | | 24.8 | - | 19.3% |
| Feed-In-Tariff Tier 3 | | 20.0 | - | |
| Aloha Solar Energy Fund 1 & 2 | 2020 | 10.0 | - | 19.3% |

| Unit | Year in Service | Capacity (MW) | Storage Capacity (MWh) | Capacity Factor (%) |
|---|---|---|---|---|
| Mauka FIT 1 | 2020 | 3.5 | – | 19.3% |
| Waihonu Solar | 2016 | 6.5 | – | 19.3% |
| CBRE Phase 1 | 2021 | 5.0 | – | 24.5% |
| CBRE Phase 2 | 2026 | 180.0 | – | – |
| Stage 1 | | | | |
| Hoohana Solar 1 | 2024 | 52.0 | 208.0 | 25.1% |
| AES West Oahu Solar | 2023 | 12.5 | 50.0 | 25.2% |
| Mililani 1 Solar | 2023 | 39.0 | 156.0 | 27.2% |
| Waiawa Solar Power | 2023 | 36.0 | 144.0 | 27.9% |
| Stage 2 | | | | |
| Kupehau Solar | 2022 | 60.0 | 240.0 | 21.2% |
| Waiawa Phase 2 Solar | 2024 | 30.0 | 240.0 | 20.5% |
| Mountain View Solar | 2023 | 7.0 | 35.0 | 17.3% |
| Barber's Point Solar | 2024 | 15.0 | 60.0 | 22.2% |
| Mahi Solar | 2024 | 120.0 | 480.0 | 25.8% |
| Kapolei Energy Storage | 2022 | 185.0 | 565.0 | – |
| Grid Services RFP | | | | |
| Load Build | 2021 | 14.8 | – | – |
| Load Reduce | 2021 | 26.3 | – | – |
| FFR | 2021 | 37.3 | – | – |
| Load Build 3 | 2023 | 60 | – | – |
| Load Reduce 3 | 2023 | 60 | – | – |
| FFR 3 | 2023 | 12 | – | – |
| Demand Response | | | | |
| Fast Demand Response (FDR) | 2018 | 5.5 | – | – |
| Residential Direct Load Control | 2018 | 13.2 | – | – |
| Commercial Direct Load Control | 2018 | 7.8 | – | – |

| Unit | Year in Service | Capacity (MW) | Storage Capacity (MWh) | Capacity Factor (%) |
|---|---|---|---|---|
| Small Business Direct Load Control | 2018 | 1.6 | - | - |

## *Hawai'i Island*

Table 9-2: Hawai'i Island Variable Renewable, Storage, and Grid Service Resources

| Unit | Year in Service | Capacity (MW) | Storage Capacity (MWh) | Capacity Factor (%) |
|---|---|---|---|---|
| Small Hydros | | 0.2 | - | 85.7% |
| Wailuku Hydro | 1993 | 12.1 | - | 18.9% |
| HRD Wind | 2006 | 10.5 | - | 42.4% |
| Tawhiri | 2007 | 20.5 | | 63.6% |
| SIA Wind | | 3.5 | - | 30.3% |
| Feed-In-Tariff | | 9.1 | | 18.1% |
| Puueo Hydro | 2005 | 3.3 | - | 54.8% |
| Waiau Hydro | 1920 | 2.0 | - | 53.2% |
| CBRE Phase 1 | 2023 | 0.75 | - | 16.9% |
| CBRE Phase 2 | 2026 | 32.5 | - | - |
| Stage 1 RFP | | | | |
| Hale Kuawehi Solar | 2023 | 30.0 | 120.0 | 33.2% |
| Waikoloa Solar | 2023 | 30.0 | 120.0 | 30.9% |
| Stage 2 RFP | | | | |
| Puako Solar | 2024 | 60.0 | 240.0 | 32.2% |
| Keahole Battery Energy Storage | 2023 | 12.0 | 12.0 | - |
| Grid Services RFP | | | | |
| FFR | 2023 | 6.0 | - | - |
| Load Reduce | 2023 | 4.0 | - | - |
| Load Build | 2023 | 3.2 | - | - |

### *Maui*

Table 9-3: Maui Variable Renewable, Storage, and Grid Service Resources

| Unit | Year in Service | Capacity (MW) | Storage Capacity (MWh) | Capacity Factor (%) |
|---|---|---|---|---|
| Feed-In-Tariff | | 6.75 | - | 17% |
| | | | | |
| Kaheawa Wind Farm II | 2012 | 21.0 | - | 47% |
| | | | | |
| South Maui Renewable Resources | 2018 | 2.9 | - | 29% |
| | | | | |
| CBRE Phase 1 | 2021 | 0.02832 | - | 28% |
| | | | | |
| Stage 1 RFP | | | | |
| | | | | |
| Paeahu Solar | 2023 | 15.0 | 60.0 | 31% |
| Stage 2 RFP | | | | |
| Kahana Solar | 2024 | 20.0 | 80.0 | 33% |
| Pulehu Solar | 2023 | 40.0 | 160.0 | 31% |
| Kamaole Solar | 2023 | 40.0 | 160.0 | 35% |
| Waena BESS | 2023 | 40.0 | 160.0 | - |
| Grid Services RFP | | | | |
| Load Build | 2023 | 2.0 | - | - |
| Load Reduce | 2023 | 7.2 | - | - |
| FFR1 | 2023 | 6.1 | - | - |
| Demand Response | | | | |
| Fast Demand Response | 2021 | 4.9 | - | - |

### *Moloka'i*

| Unit | Year in Service | Capacity (MW) | Storage Capacity (MWh) | Capacity |
|---|---|---|---|---|
| CBRE Phase 1 | 2023 | 0.25 | – | 21.8% |
| | | | | |
| Molokai RFP | 2026 | 4.40 | 17.60 | 25.7% |

### *Lāna'i*

| Unit | Year in Service | Capacity (MW) | Storage Capacity (MWh) | Capacity Factor (%) |
|---|---|---|---|---|
| Lanai Sustainability Research | 2009 | 1.2 | – | 26.15% |
| CBRE Phase 2 | 2026 | 15.8 | 63.2 | 25.8% |

# 10 Location-Based Forecasts

To develop location-based circuit level load and DER technology forecasts, the Company has adopted LoadSEER as a key component to advancing the distribution planning methodology. On O'ahu, LoadSEER is already being used to develop distribution-level circuit forecasts, and the Company targets deployment on Maui and Hawai'i Island in early 2022. This electric load forecasting software uses the Company's corporate load forecasts and a multitude of other geospatial inputs to create forecasts at the circuit and transformer level. The Company's use of LoadSEER is discussed in the Distribution Planning Methodology[91] developed in collaboration with stakeholder and customer engagement through the Distribution Planning Working Group.

## 10.1 STAGES OF THE DISTRIBUTION PLANNING PROCESS

The Distribution Planning Methodology is comprised of four stages: forecast, analysis, solution options, and evaluation.

1. **Forecast Stage**: Develop circuit-level forecasts based on the corporate demand forecast.
2. **Analysis Stage**: Determine the adequacy of the distribution system.
3. **Solution Options Stage**: Identify the grid needs requirements.
4. **Evaluation Stage**: Evaluation of solutions.

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

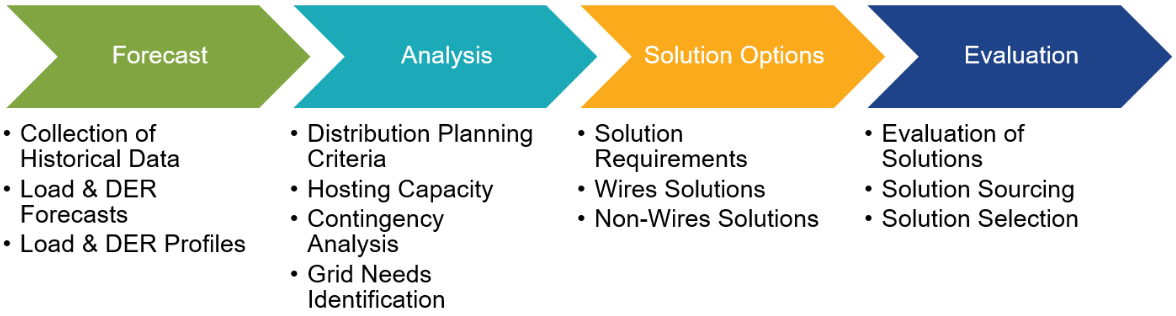



Figure 10-1 : Stages of the Distribution Planning Process

## 10.2 LOADSEER FORECASTING ENGINE

LoadSEER is an electric load forecasting software that creates circuit-level forecasts by combining historical SCADA and weather data along with forecasted new load, DER, EV, and EE spatially allocated throughout the system. LoadSEER spatially allocates these layers at the distribution level through an agent-based simulation that determines the likelihood that each of these types will be adopted at each service point. This process refines the system level forecast and provides location information such as customer consumption, historical DER adoption, census tract data, among others, with circuit-level forecasts. LoadSEER constrains the total amount that gets allocated for each of these layers by an incremental system level limit for each layer. The system level constraint is based on the corporate DER forecast. The resulting DER forecast allocation provides the feeder-level forecasted DER growth that is needed to calculate the adjusted DER forecast and thus the total anticipated DER by feeder.

As shown in Figure 10-2, LoadSEER is used in the Forecast and Analysis stages within the distribution planning process. As described above and presented in the June 4, 2021 IGP Technical Conference and June 17, 2021 Stakeholder Technical Working Group meetings, the Corporate forecast is used as an input to the LoadSEER circuit-forecasting process. The Corporate forecasted load, DER, EV, and EE layers are spatially allocated to the distribution circuits (see Figure 10-3). The hosting capacity analysis provided in the *Distribution DER Hosting Capacity Grid Needs* report disaggregated DER layers by residential and commercial for its analysis. System load layers used in LoadSEER are split by rate classes[92] R, DS, F, G, J, and P, and will be included in the process for the Grid Needs Review Point filing.

[92] *See* https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/oahu-rates

The resulting circuit level forecasts are the basis for distribution planning analyses. Currently the resulting circuit level forecasts are not used to inform the Corporate-level forecast. However, the circuit-level forecast is used as part of the hosting capacity analysis to determine the distribution grid needs to accommodate the corporate-level DER forecast.

A hosting capacity analysis was completed based on the 5-year forecasted DER, which is discussed in Section 11 and the Company's *Distribution DER Hosting Capacity Grid Needs* report. The Distribution DER Hosting Capacity Grid Needs report explains how LoadSEER is used to allocate the Corporate DER forecast to the circuit level to perform the circuit level hosting capacity analysis. A circuit-level load forecast for all islands[93] will be provided on October 1, 2021 in the Grid Needs Review Point.

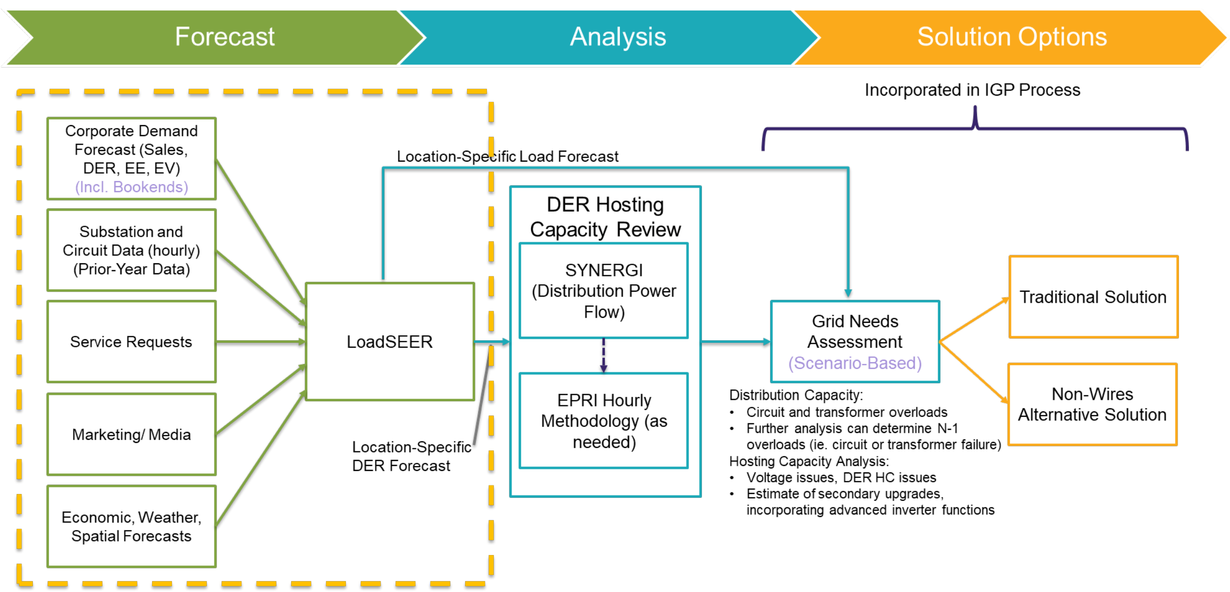



Figure 10-2: LoadSEER in Distribution Planning Process

[93] LoadSEER implemented on O'ahu only.


Figure 10-3: LoadSEER Layers

# 11 Hosting Capacity Analysis

Filed alongside this report is the Company's *Distribution DER Hosting Capacity Grid Needs* report, which is a wide-scale distribution-level analysis that focuses on hosting capacity grid needs identified for the next five years (year 2021 through 2025) driven by the anticipated increase in DER on distribution circuits based on the current market DER forecast provided the 2020 Integrated Grid Planning Inputs and Assumptions March 2021 Update.[94] The intent of the analysis is to update circuit hosting capacities and identify the grid needs at the local distribution level to accommodate the market DER forecast at the system level allocated down to the circuit level. The effort to complete the analysis was performed in parallel with ongoing stakeholder engagement and IGP working group discussions, as discussed in Section 2, and therefore does not reflect the latest forecast assumptions discussed in Section 4.1.1.

As a result of this analysis:

- 576 circuits do not require grid needs:
  - 511 circuits can accommodate the 5-year DER forecast with existing hosting capacity.
  - 65 circuits are can accommodate the 5-year DER forecast through updated hosting capacity without modifications.
- 44 circuits require grid needs at the primary distribution circuit-level:
  - 32 circuits can accommodate through minimal investment (e.g., LTC setting changes).
  - 12 circuits require solutions/mitigations, which will serve as an input to the Grid Needs Assessment stage of the IGP process. Total estimated costs for traditional solutions on all islands is $2.7 M.

Updated hosting capacities and implementation of the above mitigations and solutions will provide an increase of hosting capacity of 16 MW on O'ahu, 18 MW on Hawai'i Island, 37 MW on Maui Island, 0.02 MW on Lāna'i, and 0.5 MW on Moloka'i.

Consistent with the *Non-Wires Opportunity Evaluation Methodology*[95], cost estimates are developed for solutions that require significant upgrades. These

---

[94] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20210330_wg_fa_deliverable_draft.pdf

[95] Hawaiian Electric, Non-Wires Opportunity Evaluation Methodology June 2020, 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

estimates will be used as inputs to the Grid Needs Assessment stage of the IGP process to evaluate if they qualify as an NWA opportunity, and if so, be procured as part of the overarching IGP process where a portfolio of solutions will be selected to address the identified grid needs.

As described in the June 2021 Work Plan[96], the Company anticipates filing a Grid Needs Assessment update deliverable by October 1, 2021 that includes a refresh of the hosting capacity analysis using the updated forecast assumptions as well as additional modeling and analysis to identify grid needs driven by other DER forecast sensitivities, such as the high and low DER bookends currently being developed.

[96] Hawaiian Electric Updated Timeline and Stakeholder Engagement Plan filed on June 18, 2021 in Docket No. 2018-0165 at page 7.

# Appendix A: Nominal Resource Cost Forecasts (2020 – 2050)

Table A-1: Capital and O&M Costs for Resource Options (Paired Grid-Scale PV, Standalone Grid-Scale PV, Commercial-Scale PV)

| Year | Paired Grid Scale PV (Single axis tracking) | | Standalone Grid Scale PV (Single axis tracking) | | Commercial Scale PV | |
|---|---|---|---|---|---|---|
| | Capital ($/kW) | O&M ($/kW-year) | Capital ($/kW) | O&M ($/kW-year) | Capital ($/kW) | O&M ($/kW-year) |
| 2020 | 1,381 | 28 | | | 2,067 | |
| 2021 | 1,343 | 28 | 2,048 | 28 | 2,004 | 25 |
| 2022 | 1,303 | 28 | 1,986 | 28 | 1,936 | 25 |
| 2023 | 1,348 | 28 | 2,056 | 28 | 1,984 | 25 |
| 2024 | 1,629 | 27 | 2,484 | 27 | 2,252 | 24 |
| 2025 | 1,579 | 27 | 2,408 | 27 | 2,153 | 24 |
| 2026 | 1,526 | 27 | 2,326 | 27 | 2,048 | 23 |
| 2027 | 1,539 | 27 | 2,346 | 27 | 2,021 | 22 |
| 2028 | 1,476 | 26 | 2,250 | 26 | 1,918 | 22 |
| 2029 | 1,409 | 26 | 2,148 | 26 | 1,808 | 21 |
| 2030 | 1,338 | 25 | 2,040 | 25 | 1,692 | 20 |
| 2031 | 1,357 | 26 | 2,069 | 26 | 1,712 | 21 |
| 2032 | 1,376 | 26 | 2,098 | 26 | 1,731 | 21 |
| 2033 | 1,396 | 27 | 2,128 | 27 | 1,750 | 21 |
| 2034 | 1,415 | 27 | 2,157 | 27 | 1,769 | 22 |
| 2035 | 1,435 | 28 | 2,187 | 28 | 1,789 | 22 |
| 2036 | 1,454 | 28 | 2,217 | 28 | 1,808 | 22 |
| 2037 | 1,474 | 29 | 2,247 | 29 | 1,827 | 23 |
| 2038 | 1,494 | 29 | 2,278 | 29 | 1,846 | 23 |
| 2039 | 1,514 | 30 | 2,309 | 30 | 1,864 | 23 |
| 2040 | 1,535 | 30 | 2,339 | 30 | 1,883 | 24 |
| 2041 | 1,555 | 31 | 2,370 | 31 | 1,902 | 24 |
| 2042 | 1,575 | 31 | 2,402 | 31 | 1,920 | 24 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2043 | 1,596 | 32 | 2,433 | 32 | 1,938 | 25 |
| | | | | | | |
| 2045 | 1,637 | 33 | 2,496 | 33 | 1,974 | 26 |
| | | | | | | |
| 2047 | 1,679 | 34 | 2,560 | 34 | 2,009 | 26 |
| | | | | | | |
| 2049 | 1,721 | 36 | 2,624 | 36 | 2,042 | 27 |
| | | | | | | |

Table A-2: Capital and O&M Costs for Resource Options (Residential PV, Onshore Wind,

| Year | Residential PV | | Onshore Wind | | Distributed Wind | |
|---|---|---|---|---|---|---|
| | Capital ($/kW) | O&M ($/kW-year) | Capital ($/kW) | O&M ($/kW-year) | Capital ($/kW) | O&M ($/kW-year) |
| 2020 | 2,923 | | | | | |
| 2021 | 2,766 | 39 | 9,530 | 52 | 7,761 | 50 |
| | 2,730 | 38 | 11,944 | 53 | 7,682 | 51 |
| 2023 | 2,749 | 36 | 11,807 | 54 | 8,005 | 51 |
| 2024 | 3,628 | 35 | 11,658 | 55 | 10,136 | 52 |
| 2025 | 3,400 | 33 | 11,496 | 55 | 9,995 | 53 |
| 2026 | 3,160 | 31 | 11,320 | 56 | 9,841 | 54 |
| 2027 | 3,028 | 30 | 11,597 | 57 | 9,676 | 54 |
| 2028 | 2,750 | 28 | 11,383 | 58 | 9,497 | 55 |
| 2029 | 2,457 | 26 | 11,152 | 59 | 9,304 | 56 |
| 2030 | 2,149 | 24 | 10,905 | 59 | 9,097 | 57 |
| 2031 | 2,175 | 24 | 11,047 | 60 | 9,216 | 57 |
| 2032 | 2,201 | 24 | 11,190 | 61 | 9,335 | 58 |
| 2033 | 2,226 | 25 | 11,334 | 62 | 9,455 | 59 |
| 2034 | 2,252 | 25 | 11,478 | 63 | 9,576 | 60 |
| 2035 | 2,278 | 25 | 11,623 | 64 | 9,697 | 61 |
| 2036 | 2,303 | 26 | 11,768 | 65 | 9,818 | 62 |
| 2037 | 2,329 | 26 | 11,914 | 66 | 9,940 | 63 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | |
| **2039** | 2,380 | 27 | 12,207 | 68 | 10,185 | 65 |
| | | | | | | |
| **2041** | 2,431 | 28 | 12,501 | 70 | 10,431 | 67 |
| | | | | | | |
| **2043** | 2,481 | 29 | 12,796 | 72 | 10,677 | 69 |
| | | | | | | |
| **2045** | 2,531 | 30 | 13,091 | 75 | 10,923 | 71 |
| | | | | | | |
| **2047** | 2,579 | 30 | 13,385 | 77 | 11,169 | 73 |
| | | | | | | |
| **2049** | 2,627 | 31 | 13,678 | 79 | 11,413 | 75 |
| | | | | | | |

Table A-3: Capital and O&M Costs for Resource Options (Offshore Wind North, Offshore

| Year | Offshore Wind North | | Offshore Wind East | | Offshore Wind South | |
|---|---|---|---|---|---|---|
| | Capital ($/kW) | O&M ($/kW-year) | Capital ($/kW) | O&M ($/kW-year) | Capital ($/kW) | O&M ($/kW-year) |
| **2020** | 2,976 | | | | | |
| **2021** | 2,863 | 68 | 2,597 | 69 | 2,501 | 65 |
| | 2,800 | 65 | 2,536 | 65 | 2,441 | 62 |
| **2023** | 2,764 | 63 | 2,501 | 63 | 2,406 | 60 |
| **2024** | 2,745 | 61 | 2,481 | 62 | 2,386 | 58 |
| **2025** | 2,738 | 60 | 2,472 | 60 | 2,377 | 57 |
| **2026** | 4,069 | 59 | 3,686 | 59 | 3,549 | 56 |
| **2027** | 4,082 | 58 | 3,695 | 58 | 3,557 | 55 |
| **2028** | 4,102 | 58 | 3,711 | 58 | 3,572 | 55 |
| **2029** | 4,129 | 57 | 3,734 | 57 | 3,593 | 54 |
| **2030** | 4,162 | 57 | 3,761 | 57 | 3,619 | 54 |
| **2031** | 4,200 | 57 | 3,794 | 57 | 3,649 | 54 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | |
| 2033 | 4,288 | 56 | 3,871 | 56 | 3,722 | 54 |
| | | | | | | |
| 2035 | 4,391 | 56 | 3,961 | 56 | 3,808 | 53 |
| | | | | | | |
| 2037 | 4,508 | 56 | 4,063 | 56 | 3,906 | 54 |
| | | | | | | |
| 2039 | 4,635 | 56 | 4,176 | 57 | 4,014 | 54 |
| | | | | | | |
| 2041 | 4,774 | 57 | 4,299 | 57 | 4,131 | 54 |
| | | | | | | |
| 2043 | 4,923 | 57 | 4,431 | 57 | 4,257 | 55 |
| | | | | | | |
| 2045 | 5,083 | 58 | 4,572 | 58 | 4,393 | 55 |
| | | | | | | |
| 2047 | 5,252 | 58 | 4,722 | 59 | 4,537 | 56 |
| | | | | | | |
| 2049 | 5,431 | 59 | 4,882 | 59 | 4,689 | 57 |
| | | | | | | |

Table A-4: Capital and O&M Costs for Resource Options (Grid-Scale Storage, Pumped

| Year | Grid Scale Storage | | | Pumped Storage Hydro | | |
|---|---|---|---|---|---|---|
| | Balance of System ($/kW) | Modules ($/kWh) | O&M ($/kW-year) | Capital ($/kW) | O&M ($/kW-year) | Var O&M ($/MWH) |
| 2020 | 365 | | | | | |
| 2021 | 356 | 377 | 40 | 2,919 | 37 | 1 |
| 2022 | 347 | 360 | 38 | 2,987 | 38 | 1 |
| 2023 | 337 | 342 | 36 | 3,056 | 39 | 1 |
| 2024 | 327 | 322 | 34 | 3,127 | 39 | 1 |
| 2025 | 315 | 302 | 33 | 3,200 | 40 | 1 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | |
| 2027 | 330 | 288 | 32 | 3,351 | 42 | 1 |
| | | | | | | |
| 2029 | 345 | 272 | 31 | 3,509 | 44 | 1 |
| | | | | | | |
| 2031 | 359 | 265 | 30 | 3,674 | 46 | 1 |
| | | | | | | |
| 2033 | 373 | 268 | 31 | 3,847 | 49 | 1 |
| | | | | | | |
| 2035 | 388 | 272 | 31 | 4,028 | 51 | 1 |
| | | | | | | |
| 2037 | 403 | 275 | 32 | 4,218 | 53 | 1 |
| | | | | | | |
| 2039 | 418 | 278 | 33 | 4,417 | 56 | 1 |
| | | | | | | |
| 2041 | 434 | 281 | 33 | 4,625 | 58 | 1 |
| | | | | | | |
| 2043 | 451 | 283 | 34 | 4,842 | 61 | 1 |
| | | | | | | |
| 2045 | 468 | 285 | 34 | 5,071 | 64 | 1 |
| | | | | | | |
| 2047 | 486 | 287 | 35 | 5,309 | 67 | 1 |
| | | | | | | |
| 2049 | 505 | 288 | 35 | 5,559 | 70 | 1 |
| | | | | | | |

Table A-5: Capital and O&M Costs for Resource Options (Paired Grid-Scale Storage (2hrs),

| Year | Paired Grid Scale Storage (2hr) | | Paired Grid Scale Storage (4hr) | |
|---|---|---|---|---|
| | Capital ($/kW) | O&M ($/kW-year) | Capital ($/kW) | O&M ($/kW-year) |
| 2020 | 858 | | | |

| | | | | |
|---|---|---|---|---|
| 2021 | 827 | 40 | 1,389 | 40 |
| 2022 | | | | |
| 2023 | 802 | 36 | 1,339 | 36 |
| 2024 | | | | |
| 2025 | 753 | 33 | 1,301 | 33 |
| 2026 | | | | |
| 2027 | 722 | 32 | 1,182 | 32 |
| 2028 | | | | |
| 2029 | 708 | 31 | 1,141 | 31 |
| 2030 | | | | |
| 2031 | 709 | 30 | 1,131 | 30 |
| 2032 | | | | |
| 2033 | 726 | 31 | 1,154 | 31 |
| 2034 | | | | |
| 2035 | 743 | 31 | 1,177 | 31 |
| 2036 | | | | |
| 2037 | 760 | 32 | 1,200 | 32 |
| 2038 | | | | |
| 2039 | 778 | 33 | 1,222 | 33 |
| 2040 | | | | |
| 2041 | 795 | 33 | 1,243 | 33 |
| 2042 | | | | |
| 2043 | 812 | 34 | 1,272 | 34 |
| 2044 | | | | |
| 2045 | 829 | 34 | 1,301 | 34 |
| 2046 | | | | |
| 2047 | 846 | 35 | 1,328 | 35 |
| 2048 | | | | |
| 2049 | 862 | 35 | 1,355 | 35 |
| 2050 | | | | |

Table A-6: Capital and O&M Costs for Resource Options (Paired Grid-Scale Storage (6hrs), Paired Grid-Scale Storage (8hrs), DER Aggregator)

| Year | Paired Grid Scale Storage (6hr) | | Paired Grid Scale Storage (8hr) | | DER Aggregator PV+Storage | |
|---|---|---|---|---|---|---|
| | Capital ($/kW) | O&M ($/kW-year) | Capital ($/kW) | O&M ($/kW-year) | Capital ($/kW) | O&M ($/kW-year) |
| 2020 | 2,030 | 41 | 2,616 | 41 | 5,836 | |
| 2021 | 1,951 | 40 | 2,513 | 40 | 5,578 | 79 |
| 2022 | 1,868 | 38 | 2,404 | 38 | 5,303 | 76 |
| 2023 | 1,875 | 36 | 2,412 | 36 | 5,354 | 73 |
| 2024 | 1,979 | 34 | 2,564 | 34 | 6,843 | 69 |
| 2025 | 1,849 | 33 | 2,397 | 33 | 6,480 | 66 |
| 2026 | 1,808 | 32 | 2,343 | 32 | 6,162 | 64 |
| 2027 | 1,693 | 32 | 2,215 | 32 | 5,968 | 61 |
| 2028 | 1,648 | 31 | 2,156 | 31 | 5,652 | 59 |
| 2029 | 1,600 | 31 | 2,092 | 31 | 5,320 | 56 |
| 2030 | 1,549 | 30 | 2,025 | 30 | 4,976 | 53 |
| 2031 | 1,568 | 30 | 2,048 | 30 | 5,032 | 54 |
| 2032 | 1,588 | 31 | 2,071 | 31 | 5,087 | 55 |
| 2033 | 1,607 | 31 | 2,093 | 31 | 5,143 | 56 |
| 2034 | 1,626 | 31 | 2,116 | 31 | 5,198 | 56 |
| 2035 | 1,645 | 31 | 2,138 | 31 | 5,253 | 57 |
| 2036 | 1,663 | 32 | 2,160 | 32 | 5,307 | 58 |
| 2037 | 1,682 | 32 | 2,181 | 32 | 5,362 | 58 |
| 2038 | 1,700 | 32 | 2,202 | 32 | 5,416 | 59 |
| 2039 | 1,718 | 33 | 2,222 | 33 | 5,470 | 60 |
| 2040 | 1,735 | 33 | 2,243 | 33 | 5,523 | 60 |
| 2041 | 1,753 | 33 | 2,262 | 33 | 5,576 | 61 |
| 2042 | 1,770 | 34 | 2,281 | 34 | 5,628 | 62 |
| 2043 | 1,786 | 34 | 2,300 | 34 | 5,680 | 62 |
| 2044 | 1,802 | 34 | 2,318 | 34 | 5,731 | 63 |
| 2045 | 1,818 | 34 | 2,336 | 34 | 5,781 | 64 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | |
| 2047 | 1,848 | 35 | 2,368 | 35 | 5,879 | 65 |
| | | | | | | |
| 2049 | 1,876 | 35 | 2,398 | 35 | 5,974 | 67 |
| | | | | | 6,020 | |

Table A-7: Capital and O&M Costs for Resource Options (Synchronous Condenser,

| Year | Synchronous Condenser | Geothermal | | Municipal Solid Waste (MSW) | | |
|---|---|---|---|---|---|---|
| | Capital ($/kVar) | Capital ($/kW) | O&M ($/kW-year) | Capital ($/kW) | O&M ($/kW-year) | Var O&M ($/MWH) |
| 2020 | 1,255 | 8,869 | | | | |
| 2021 | 1,272 | 8,989 | 223 | 1,908 | 24 | 8 |
| 2022 | 1,296 | 9,109 | 226 | 1,946 | 25 | 8 |
| 2023 | 1,299 | 9,230 | 230 | 1,979 | 26 | 8 |
| 2024 | 1,314 | 9,352 | 234 | 2,023 | 26 | 8 |
| 2025 | 1,340 | 9,475 | 238 | 2,071 | 27 | 8 |
| 2026 | 1,361 | 9,598 | 242 | 2,108 | 27 | 8 |
| 2027 | 1,372 | 9,722 | 246 | 2,146 | 28 | 9 |
| 2028 | 1,393 | 9,847 | 250 | 2,184 | 29 | 9 |
| 2029 | 1,416 | 9,972 | 254 | 2,222 | 29 | 9 |
| 2030 | 1,442 | 10,097 | 258 | 2,259 | 30 | 9 |
| 2031 | 1,470 | 10,281 | 264 | 2,298 | 31 | 10 |
| 2032 | 1,494 | 10,467 | 270 | 2,334 | 32 | 10 |
| 2033 | 1,519 | 10,658 | 276 | 2,368 | 32 | 10 |
| 2034 | 1,546 | 10,851 | 283 | 2,407 | 33 | 10 |
| 2035 | 1,574 | 11,048 | 290 | 2,446 | 34 | 10 |
| 2036 | 1,600 | 11,249 | 296 | 2,484 | 35 | 11 |
| 2037 | 1,628 | 11,453 | 303 | 2,523 | 35 | 11 |
| 2038 | 1,657 | 11,661 | 310 | 2,564 | 36 | 11 |
| 2039 | 1,689 | 11,873 | 317 | 2,607 | 37 | 11 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | |
| **2041** | 1,747 | 12,309 | 332 | 2,688 | 39 | 12 |
| | | | | | | |
| **2043** | 1,809 | 12,760 | 348 | 2,776 | 41 | 13 |
| | | | | | | |
| **2045** | 1,875 | 13,228 | 364 | 2,869 | 43 | 13 |
| | | | | | | |
| **2047** | 1,942 | 13,712 | 382 | 2,959 | 45 | 14 |
| | | | | | | |
| **2049** | 2,007 | 14,215 | 400 | 3,049 | 47 | 14 |
| | | | | | | |

| Year | Biomass | | | |
|---|---|---|---|---|
| | Capital ($/kW) | O&M ($/kW-year) | Var O&M ($/MWH) | Fuel Cost ($/MWH) |
| **2020** | 5,985 | 182 | 6 | 4 |
| **2021** | 6,106 | 186 | 6 | 4 |
| **2022** | 6,228 | 190 | 6 | 4 |
| **2023** | 6,331 | 195 | 6 | 4 |
| **2024** | 6,475 | 199 | 6 | 4 |
| **2025** | 6,626 | 204 | 7 | 4 |
| **2026** | 6,745 | 209 | 7 | 4 |
| **2027** | 6,868 | 213 | 7 | 5 |
| **2028** | 6,990 | 218 | 7 | 5 |
| **2029** | 7,111 | 224 | 7 | 5 |
| **2030** | 7,227 | 229 | 7 | 5 |
| **2031** | 7,353 | 234 | 7 | 5 |
| **2032** | 7,468 | 239 | 8 | 5 |
| **2033** | 7,579 | 245 | 8 | 5 |
| **2034** | 7,703 | 251 | 8 | 5 |
| **2035** | 7,827 | 257 | 8 | 5 |

| | | | | |
|---|---|---|---|---|
| | | | | |
| 2037 | 8,075 | 269 | 9 | 6 |
| | | | | |
| 2039 | 8,342 | 281 | 9 | 6 |
| | | | | |
| 2041 | 8,602 | 295 | 9 | 6 |
| | | | | |
| 2043 | 8,883 | 308 | 10 | 7 |
| | | | | |
| 2045 | 9,180 | 323 | 10 | 7 |
| | | | | |
| 2047 | 9,468 | 338 | 11 | 7 |
| | | | | |
| 2049 | 9,757 | 354 | 11 | 8 |
| | | | | |

| Year | Concentrated Solar | | | Combined Cycle | | |
|---|---|---|---|---|---|---|
| | Capital ($/kW) | O&M ($/kW-year) | Var O&M ($/MWH) | Capital ($/kW) | O&M ($/kW-year) | Var O&M ($/MWH) |
| 2020 | 7,425 | | | | | |
| 2021 | 7,284 | 81 | 4 | 1,445 | 34 | 2 |
| | 7,105 | 81 | 4 | 1,476 | 35 | 2 |
| 2023 | 7,344 | 81 | 4 | 1,493 | 35 | 2 |
| 2024 | 8,366 | 81 | 4 | 1,521 | 36 | 2 |
| 2025 | 8,231 | 80 | 4 | 1,557 | 37 | 2 |
| 2026 | 8,124 | 80 | 4 | 1,586 | 38 | 2 |
| 2027 | 8,044 | 79 | 4 | 1,609 | 39 | 2 |
| 2028 | 7,992 | 78 | 4 | 1,639 | 40 | 3 |
| 2029 | 7,968 | 78 | 4 | 1,670 | 41 | 3 |
| 2030 | 7,971 | 77 | 4 | 1,702 | 42 | 3 |

| | | | | | | |
|---|---|---|---|---|---|---|
| **2031** | 8,000 | 79 | 5 | 1,735 | 43 | 3 |
| | | | | | | |
| **2033** | 8,137 | 83 | 5 | 1,797 | 45 | 3 |
| | | | | | | |
| **2035** | 8,372 | 86 | 5 | 1,867 | 47 | 3 |
| | | | | | | |
| **2037** | 8,697 | 90 | 5 | 1,935 | 49 | 3 |
| | | | | | | |
| **2039** | 9,099 | 95 | 5 | 2,010 | 51 | 3 |
| | | | | | | |
| **2041** | 9,532 | 99 | 6 | 2,086 | 54 | 3 |
| | | | | | | |
| **2043** | 9,986 | 104 | 6 | 2,166 | 56 | 4 |
| | | | | | | |
| **2045** | 10,461 | 109 | 6 | 2,250 | 59 | 4 |
| | | | | | | |
| **2047** | 10,957 | 114 | 7 | 2,337 | 62 | 4 |
| | | | | | | |
| **2049** | 11,476 | 119 | 7 | 2,421 | 65 | 4 |
| | | | | | | |

| Year | Combustion Turbine | | | Internal Combustion Engine | | |
|---|---|---|---|---|---|---|
| | Capital ($/kW) | O&M ($/kW-year) | Var O&M ($/MWH) | Capital ($/kW) | O&M ($/kW-year) | Var O&M ($/MWH) |
| **2020** | 1,255 | | | | | |
| **2021** | 1,272 | 26 | 6 | 2,684 | 38 | 29 |
| **2022** | 1,296 | 27 | 6 | 2,734 | 39 | 29 |
| **2023** | 1,299 | 27 | 6 | 2,740 | 40 | 30 |
| **2024** | 1,314 | 28 | 7 | 2,773 | 41 | 31 |
| **2025** | 1,340 | 28 | 7 | 2,827 | 42 | 31 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2026 | | | | | | |
| 2027 | 1,372 | 30 | 7 | 2,894 | 44 | 33 |
| 2028 | 1,393 | | | | 45 | |
| 2029 | 1,416 | 31 | 7 | 2,988 | 46 | 34 |
| 2030 | 1,442 | 32 | 8 | 3,042 | 47 | 35 |
| 2031 | 1,470 | 33 | 8 | 3,101 | 48 | 36 |
| 2032 | 1,494 | 33 | 8 | 3,153 | 49 | 37 |
| 2033 | 1,519 | 34 | 8 | 3,205 | 50 | 38 |
| 2034 | 1,546 | 35 | 8 | 3,262 | 51 | 39 |
| 2035 | 1,574 | 36 | 8 | 3,320 | 53 | 40 |
| 2036 | 1,600 | 37 | 9 | 3,375 | 54 | 40 |
| 2037 | 1,628 | 37 | 9 | 3,435 | 55 | 41 |
| 2038 | 1,657 | 38 | 9 | 3,496 | 56 | 42 |
| 2039 | 1,689 | 39 | 9 | 3,563 | 58 | 43 |
| 2040 | 1,716 | 40 | 9 | 3,621 | 59 | 44 |
| 2041 | 1,747 | 41 | 10 | 3,685 | 60 | 45 |
| 2042 | 1,777 | 42 | 10 | 3,750 | 62 | 46 |
| 2043 | 1,809 | 43 | 10 | 3,816 | 63 | 48 |
| 2044 | 1,841 | 44 | 10 | 3,883 | 65 | 49 |
| 2045 | 1,875 | 45 | 11 | 3,957 | 66 | 50 |
| 2046 | 1,908 | 46 | 11 | 4,026 | 68 | 51 |
| 2047 | 1,942 | 47 | 11 | 4,097 | 69 | 52 |
| 2048 | 1,976 | 48 | 11 | 4,168 | 71 | 53 |
| 2049 | 2,007 | 49 | 12 | 4,235 | 73 | 55 |
| 2050 | 2,030 | 51 | 12 | 4,284 | 74 | 56 |

# Appendix B: Distributed Energy Resource Forecasts (2020 – 2050)

Table B-1: Cumulative Distributed PV Capacity (kW)

| Year | O'ahu | Hawai i Island | Maui | Moloka'i | Lāna'i | Consolidated |
|---|---|---|---|---|---|---|
| MW | A | B | C | D | E | F =A + B + C + D +E |
| 2020 | 534,704 | 110,108 | 119,232 | 2,678 | 832.72 | 767,555 |
| 2021 | 578,150 | 118,086 | 129,449 | 2,836 | 868.72 | 829,389 |
| 2022 | 644,017 | 124,018 | 138,586 | 2,936 | 900.72 | 910,458 |
| 2023 | 681,381 | 130,519 | 147,329 | 3,100 | 1005.72 | 963,335 |
| 2024 | 701,907 | 134,421 | 152,758 | 3,152 | 1025.72 | 993,264 |
| 2025 | 723,234 | 138,801 | 158,260 | 3,200 | 1,050 | 1,024,545 |
| 2026 | 744,949 | 143,671 | 163,786 | 3,268 | 1,091 | 1,056,764 |
| 2027 | 766,577 | 148,742 | 169,165 | 3,400 | 1,179 | 1,089,063 |
| 2028 | 788,306 | 153,820 | 174,641 | 3,476 | 1,211 | 1,121,454 |
| 2029 | 809,690 | 159,053 | 180,120 | 3,548 | 1,260 | 1,153,671 |
| 2030 | 830,974 | 164,392 | 185,501 | 3,696 | 1,356 | 1,185,919 |
| 2031 | 851,110 | 169,563 | 190,787 | 3,776 | 1,405 | 1,216,641 |
| 2032 | 870,093 | 174,395 | 195,679 | 3,856 | 1,437 | 1,245,460 |
| 2033 | 887,886 | 179,126 | 200,340 | 3,928 | 1,469 | 1,272,749 |
| 2034 | 905,021 | 183,812 | 204,847 | 4,060 | 1,574 | 1,299,314 |
| 2035 | 921,457 | 188,390 | 209,200 | 4,116 | 1,602 | 1,324,765 |
| 2036 | 936,961 | 192,830 | 213,399 | 4,180 | 1,630 | 1,349,000 |
| 2037 | 951,843 | 197,150 | 217,465 | 4,244 | 1,731 | 1,372,433 |
| 2038 | 966,214 | 201,392 | 221,405 | 4,292 | 1,759 | 1,395,062 |
| 2039 | 980,005 | 205,496 | 224,746 | 4,416 | 1,787 | 1,416,450 |
| 2040 | 993,411 | 209,179 | 227,968 | 4,476 | 1,888 | 1,436,922 |
| 2041 | 1,006,467 | 213,179 | 231,325 | 4,520 | 1,916 | 1,457,407 |
| 2042 | 1,019,145 | 216,764 | 234,337 | 4,576 | 1,940 | 1,476,762 |
| 2043 | 1,031,362 | 220,530 | 237,470 | 4,616 | 1,964 | 1,495,942 |
| 2044 | 1,042,809 | 224,193 | 240,272 | 4,732 | 2,001 | 1,514,007 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2045 | 1,053,934 | 227,449 | 242,917 | 4,768 | 2,085 | 1,531,153 |
| | | | | | | |
| 2047 | 1,075,171 | 233,953 | 248,174 | 4,848 | 2,146 | 1,564,292 |
| | | | | | | |
| 2049 | 1,095,227 | 240,131 | 253,102 | 4,924 | 2,186 | 1,595,570 |
| | | | | | | |

| Year | O'ahu | Hawai i Island | Maui | Moloka'i | Lāna'i | Consolidated |
|---|---|---|---|---|---|---|
| MW | A | B | C | D | E | F =A + B + C + D +E |
| 2020 | 54,034 | 37,313 | 41,409 | 173 | 114.05 | 133,043 |
| 2021 | 99,912 | 50,066 | 65,335 | 443 | 251.3 | 216,007 |
| 2022 | 179,528 | 55,880 | 89,495 | 819.5 | 343.55 | 326,067 |
| 2023 | 252,823 | 70,465 | 107,323 | 1083.5 | 415.55 | 432,111 |
| 2024 | 284,230 | 76,961 | 117,759 | 1203.5 | 460.55 | 480,615 |
| 2025 | 317,754 | 84,230 | 128,263 | 1347.5 | 514.55 | 532,110 |
| 2026 | 352,482 | 92,294 | 138,731 | 1515.5 | 577.55 | 585,601 |
| 2027 | 387,489 | 100,626 | 148,874 | 1,684 | 640.55 | 639,314 |
| 2028 | 423,066 | 108,969 | 159,054 | 1,876 | 712.55 | 693,677 |
| 2029 | 458,478 | 117,597 | 169,152 | 2,092 | 793.55 | 748,112 |
| 2030 | 493,412 | 126,316 | 179,030 | 2,308 | 874.55 | 801,941 |
| 2031 | 526,663 | 134,728 | 188,609 | 2,512 | 955.55 | 853,467 |
| 2032 | 557,885 | 142,412 | 197,427 | 2,716 | 1027.55 | 901,468 |
| 2033 | 587,332 | 149,910 | 205,740 | 2,896 | 1099.55 | 946,977 |
| 2034 | 615,321 | 157,223 | 213,711 | 3,064 | 1171.55 | 990,491 |
| 2035 | 641,891 | 164,338 | 221,342 | 3,232 | 1234.55 | 1,032,037 |
| 2036 | 667,128 | 171,200 | 228,634 | 3,388 | 1297.55 | 1,071,648 |
| 2037 | 691,116 | 177,842 | 235,632 | 3,544 | 1360.55 | 1,109,495 |
| 2038 | 713,973 | 184,341 | 242,351 | 3,688 | 1423.55 | 1,145,776 |
| 2039 | 735,673 | 190,587 | 248,779 | 3,832 | 1,487 | 1,180,357 |
| 2040 | 756,521 | 196,611 | 254,943 | 3,976 | 1,550 | 1,213,601 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2041 | 776,594 | 202,563 | 260,890 | 4,108 | 1,613 | 1,245,767 |
| 2042 | 795,830 | 208,305 | 266,589 | 4,240 | 1,667 | 1,276,631 |
| 2043 | 814,174 | 213,828 | 272,043 | 4,360 | 1,721 | 1,306,125 |
| 2044 | 831,671 | 219,163 | 277,280 | 4,480 | 1,775 | 1,334,369 |
| 2045 | 848,456 | 224,301 | 282,258 | 4,588 | 1,829 | 1,361,431 |
| 2046 | 864,549 | 229,250 | 287,034 | 4,696 | 1,883 | 1,387,412 |
| 2047 | 880,038 | 234,012 | 291,625 | 4,792 | 1,937 | 1,412,403 |
| 2048 | 894,914 | 238,598 | 296,032 | 4,888 | 1,982 | 1,436,413 |
| 2049 | 909,265 | 243,023 | 299,549 | 4,984 | 2,027 | 1,458,848 |
| 2050 | 923,096 | 247,272 | 303,603 | 5,068 | 2,072 | 1,481,111 |

# Appendix C: Forecast Methodologies

## UNDERLYING FORECAST METHODOLOGIES

The sales forecasts were developed for each of the five islands and began with the development of the sales forecast by rate class (residential, commercial and street lighting) and by layer (underlying load forecast and adjusting layers – energy efficiency, distributed energy resources, and electrification of transportation). Key factors that affect sales in the future are identified such as the economic outlook, analysis of existing and proposed large customer loads, and impacts of customer-sited technologies such as energy efficiency measures, distributed energy resources and emerging technologies such as electric vehicles. This section focuses on the development of the underlying sales forecast which excludes impacts from previously installed and future DER, EE and EVs.

Multiple methods and models were analyzed to develop the underlying forecast as one model does not fit all. The methods are described below and were presented in the July 17, 2019 FAWG meeting, slides 10-12.[97] More than one model or method may be used to blend together a short term forecast with a long term forecast. Methods for the underlying layer include:

- Market analysis - a ground up forecast evaluating individual customers, particularly large commercial customers, forecasting individual projects or awareness of events that may merit a specific carve out if significant, i.e. new large projects or loss of large loads.
- Customer service - analysis of recent trends in customer counts, sales and use per customer and applies knowledge of local conditions such as construction activity, state of the visitor industry, trends in weather including impacts of storms and volcanic eruptions.
- Trending models – uses historical data series to project future sales or customer counts. Works well when historical data series has identifiable patterns and future trends aren't expected to vary from the past.
- Econometric models – relates sales or customers' use of electricity to macroeconomic variables such as personal income, jobs, population

[97] Available at, https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20190717_wg_fa_meeting_presentation_materials.pdf

and visitor arrivals as well as other variables such as temperature, humidity or electricity price. Econometric models may also incorporate time series parameters such as lagged dependent variables or an autoregressive term. The quantification of the impact of changes in the economic and other variables on use is the strength of these models.

The econometric model is specified in the following form:

$$Y = \beta 0 + \sum_{i=1}^{n} (\beta i \; x \; Xi)$$

where the dependent variable, Y, is kWh sales or use per customer and is related to the independent (explanatory) variables, X*i*, which represent economic or other variables. Variables β*i* represent the regression model coefficients. The constant variable $\beta_o$ represents the Y-intercept.

Various models are evaluated for best fit and explanatory power however, it is important to assess if the models make sense. Is it reasonable to believe that electricity sales are related to the external variables in the model? Is the direction of the relationship plausible?

A description of the assumptions and models used to develop the underlying forecasts presented at the March 3, 2020 FAWG meeting and described in the response to PUC-HECO-IR-1[98] by rate class for Oʻahu, Hawaiʻi, Maui, Molokaʻi and Lānaʻi are provided below under each island's section.

Leading up to the March 3rd FAWG meeting, local economists were describing Hawai'i's economy as being on an expected slowing trend for the past several years even prior to the spread of the coronavirus ("COVID-19"). Immediately following the March 3rd meeting economic scenarios about the impact of COVID-19 were being developed with very limited information. The COVID-19 pandemic resulted in unprecedented disruptions to global travel, local resident behavior, economic activity and as a result, electricity consumption. State and county emergency orders beginning with stay-at-home orders and mandatory post-arrival travel quarantines in March 2020 basically shutdown the Hawaiʻi economy, especially the tourism industry. Electricity usage was severely impacted, although in different ways depending on the sector. Several economic updates were issued in the following months by the University of

[98] Available at, https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/dkt_20180165_20200702_HECO_response_to_PUC_IRs_1-2.pdf

Hawaiʻi Economic Research Organization ("UHERO"), with the outlook rapidly changing as new emergency orders went into effect.

The Company's updated forecast was informed by multiple types of data to provide numerous sources of insight into this unprecedented time. Customer information was analyzed including available customer-level consumption data from before and after the governments' emergency orders went into effect, customers' public announcements regarding closures and reopening plans, feedback from customers to their Hawaiian Electric account managers, distribution circuit data from before and after emergency orders went into effect, and customer billing data. Local economists, organizations and businesses in Hawai'i discussed impacts to the local economy and their perspectives on recovery in multiple public forums. Information from other utilities on Covid-19 related impacts to electricity consumption and methods for projecting recovery was also considered. The Company updated its underlying forecasts to account for the impacts of COVID-19 and anticipated recovery as presented in the August 31, 2020 FAWG meeting[99] and are also described for each island below.

## Oʻahu Underlying Forecast

Econometric methods were used for deriving the underlying sales for both the residential and commercial sectors. Historical recorded sales used in econometric models were adjusted to remove sales impact of DER, EE and EoT, which are treated as separate layers.

Residential Sales

The residential econometric equation was specified using a monthly use per residential customer in kilowatt-hours ("kWh"). The monthly econometric model describes residential electricity use per customer as a function of temperature, humidity, electricity price and real personal income per capita as these variables were all found to have relationships with residential use per customer. In addition, a simple trend variable and a monthly dummy variable were included in the models. The trend variable which increases by 1 was used as a proxy for growth and the binary dummy variable representing January or August (1 if January or August; 0 otherwise) improves the model statistics. Additional details on each variable, dependent and independent, used in deriving the monthly use per residential customer including the name of the variable and the source of the information are shown below. The values of the

[99] Available at, https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20200831_wg_fa_meeting_presentation_materials_HECO.pdf

variables fed into the econometric modeling tool and the output from the model are contained in the Excel file "Appendix C Att 1 HE Underlying Inputs and Predicted.xlsx".[100]

The specification and evaluation of the hypothetical relationships was performed using a proprietary software package, MetrixND from Itron, Inc. MetrixND is a statistical analysis package which allows Hawaiian Electric to conduct analyses and statistical testing of econometric models. Many hypothetical relationships were considered, tested, and rejected until econometric equations for residential use per customer and commercial kWh sales were identified for use in Hawaiian Electric's sales projections.

[100] See https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/forecast-assumptions-documents

Table C-1: O‘ahu Residential Customer Econometric Sales Model Variables

| Variables | Description | Source | Variable Labels |
|---|---|---|---|
| *Dependent Variable:* | | | |
| Monthly Residential Use Per Customer | Monthly residential recorded kWh sales divided by Monthly residential recorded customers | Hawaiian Electric's monthly reports filed with the Commission | Res_rcd_adj divided by Res_Cust_rcd |
| *Weather Variables:* | | | |
| Cooling Degree Days | 1999 – 2018 average + warming trend | Historical HNL airport data from NOAA, see FAWG presentation on August 27, 2019. | cdd_99_18add |
| Dewpoint Temperature | 1999 – 2018 average | Historical HNL airport data from NOAA | dewpt_99_18 |
| *Economic Variables:* | | | |
| Real Residential electricity price | Real Residential $ (1982-84=100) per kWh | See FAWG presentation on August 27, 2019 | Res_rprc_rcd |
| Real personal income per capita | Real personal income (1982-84=100) ÷ Resident population | UHERO updated forecast dated October 2019 | ypc_r_hon = y_r_hon ÷ respop_hon |
| *Trend & Dummy Variables:* | | | |
| Trend variable | Growth proxy | Trend variable that increases by 1 per month | mo_yr_time |
| Monthly dummy variables | January and August | Improves model statistics | m_1 and m_8 |

To arrive at sales per month, the monthly use per residential customer derived in MetrixND was multiplied by the number of residential customers. The number of customers per month was derived using a linear trend time series model based on historical residential customer data from January 1980 through December 2018. The trending model used the maximum data points available to incorporate historical trends since residential customer growth is relatively stable.

The resulting residential GWh underlying sales forecast is residential kWh use per customer ÷ $10^6$ x number of customers (Res_rcd_adj ÷ $10^6$ x Res_Cust_rcd). An adjustment was made to include an extra day for leap year.

Commercial Sales

The econometric model used for underlying commercial sales was run for the combined rate schedules applied to small, medium and large commercial customers excluding street lighting rather than for individual rate schedules (Schedules G, J, P, DS and U) as it had stronger explanatory relationships since Oʻahu commercial customers historically tend to transfer between commercial rate schedules on a regular basis (based on tariff requirements). The underlying commercial sales econometric equation was specified using monthly sales in kilowatt-hours. The monthly econometric model describes electricity sales as a function of temperature, humidity, electricity price and non-agricultural jobs as these variables were all found to have relationships with commercial sales. In addition, monthly binary dummy variables representing February, August or October (1 if February, August or October; 0 otherwise) and another dummy variable for months starting from January 2015 and onwards which reflect a change in the relationship between non-agricultural jobs and sales improve the model statistics. Additional details on each variable, dependent and independent, used in deriving the monthly sales including the name of the variable and the source of the information are shown below. The values of the variables fed into the econometric modeling tool (independent variables) and the output from the model are contained in the Excel file "Appendix C Att 1 HE Underlying Inputs and Predicted.xlsx".[101]

Table C-2: Oʻahu Commercial Customer Econometric Sales Model Variables

| Variable | Description | Source | Variable Labels |
|---|---|---|---|
| *Dependent Variable:* | | | |
| Commercial Sales | Commercial recorded kWh sales (1984 - 2018) | Hawaiian Electric's monthly reports filed with the Commission | Com_rcd_adj |

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

| | | | |
|---|---|---|---|
| *Weather Variables:* | | | |
| Cooling Degree Days | 1999 – 2018 average + warming trend | Historical HNL airport data from NOAA see FAWG presentation on August 27, 2019 | cdd_99_18add |
| Dewpoint Temperature | 1999 – 2018 average | Historical HNL airport data from NOAA | dewpt_99_18 |
| *Economic Variables:* | | | |
| Real commercial electricity price | Real commercial $ (1982-84=100) per kWh | See FAWG presentation on August 27, 2019 | Com_rprc_rcd |
| Non-Ag Jobs | Non-agricultural job counts | UHERO, October 2019 | E_NF_Hon |
| *Trend Variable:* | | | |
| Trend variable | Growth proxy | Trend variable that increases by 1 per month | mo_yr_time |
| Monthly dummy variables | February, August, and October | Improves model statistics | m_2, m_8, m_10 |
| Dummy variable | For all months starting in January 2015 and continuing through December 2050 | Relationship between non-ag jobs and commercial kWh appeared to change beginning in 2015, addition of this variable improved model statistics. | d_15on |

The resulting commercial GWh sales forecast is commercial kWh underlying sales forecast ÷ $10^6$. (Com_rcd_adj ÷ $10^6$). Adjustments were made to include an extra day for leap year and for known large projects.

Street Lighting Sales

Sales for street lighting are less sensitive to changes in economic and weather drivers than sales in other rate schedules and represent less than 0.5% of Hawaiian Electric's sales. Consequently, an econometric or modeled approach to forecasting Schedule F sales was not developed. The average 2013 – 2018 growth rate in the underlying Schedule F kWh sales (excluding EE impacts) was applied as year-over-year growth for the forecast horizon. Additional growth was included for new unmetered pole attachments (e.g., third party telecom and network devices) based on market projections for number of attachments and existing attachments' kWh use.

The resulting street lighting GWh sales forecast is the underlying street lighting commercial kWh underlying sales forecast ÷ $10^6$ (f_rcd_adj ÷ $10^6$). An adjustment was made to include an extra day for leap year.

The values of the underlying street lighting in kWh are contained in the Excel file "Appendix C Att 1 HE Underlying Inputs and Predicted.xlsx".[102]

COVID-19 Update to the Underlying Sales for Oʻahu

Oʻahu's stay-at-home orders went into effect on March 23, 2020. Under Mayor Caldwell's Emergency Order No. 2020-02, "All persons may leave their residences only for Essential Activities, Essential Governmental Functions, or to operate Essential Businesses…." This order basically shutdown the Oʻahu economy, especially the tourism industry. This unprecedented shutdown was a shock to Hawaiʻi's economy that has never been experienced before. Electricity usage was severely impacted, although in different ways depending on the sector. The economic impact and uncertainty about the length of the shutdown added to the confusion. Several economic updates were issued in the following month or two by UHERO, rapidly changing as new emergency orders went into effect.

Hawaiian Electric's econometric models were unable to incorporate the changes in the economic outlook because there had never been a period in history that could establish what the relationship between the economic shock and electricity use might be. Stay-at home orders basically shutdown hotels, office buildings, schools, retail and other building types where occupants could work from home or were not providing an essential service (including restaurants, bars, movie theaters, and most small businesses). On the other hand, residential usage increased as people were forced to stay home 24 hours a day.

The economic information and updates were rapidly changing and did not have as much detail as would normally be used in the sales forecast, in addition, customer behavior changed immediately and drastically in response to emergency orders and fears of the new unknown virus. As a result, a sales

102 *See* https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/forecast-assumptions-documents

forecast update for the very near-term (2020 – 2021) was developed using more judgmental techniques to update the very near-term forecast, then blended with more traditional econometric models using updated economic outlooks (covering 2 – 5 years) as they became available.

For the very near-term forecast, current to 18 months ahead, the Oʻahu forecast was developed by analyzing very limited data for specific customers in Itron Inc.'s MV-Web billing system. Using available customer data for before and after the shutdown orders went into effect (only 3 – 4 weeks of post COVID data was available when the analysis was done), an estimate of the immediate impact (percentage change) was developed to use as a proxy for the commercial sectors by business types (e.g., hotel, office, retail, education). UHERO updates were used to estimate the length of time the lowest economic activity would continue and the how long it would take to see some recovery.

The residential sector was even more difficult to estimate because meter reads were stopped due to safety concerns for customers and meter readers. Residential customers' bills were estimated from late March until mid-May 2020 using previous consumption patterns which were low relative to stay-at-home COVID usage. There was no billing data beyond anecdotal stories about how residential usage was affected by the stay-at-home orders. The Distribution Planning Department assisted in obtaining real time circuit level energy data from the Company's PI system for specific residential areas. This data was used to derive a high-level impact factor to apply to total residential sales.

Information on data and trends in other jurisdictions were obtained from webinars, meetings, blogs, email blasts, and publications, primarily from EEI and other utilities. This information was used to help validate the projections the Company was developing for Oʻahu. Of particular interest were the trends from other utilities that had more granular data from widely deployed AMI meters. UHERO, DBEDT, and other economists discussed the local economy in multiple meetings with the State Legislature, business groups, and in the news which provided rapidly changing outlooks that influenced forecast assumptions.

In the longer run (2 – 5) years, UHERO provided an April 2020 economic outlook that was used to develop econometric models for the commercial sectors. The econometric relationship for the residential sector remained undeterminable, so a year-over-year percentage growth from the IGP forecast was used. After 5 years, the impact of the COVID pandemic had dissipated (assuming a vaccine was developed) and the more normal economic trends resumed. As a result, the IGP forecast was used for the long-term.

## Hawai'i Underlying Forecast

For Hawai'i Island the underlying forecast is developed by rate class - residential, small and medium commercial, large power and street lighting. Similar to O'ahu, historical recorded sales used in the models were adjusted to remove sales impact of DER, EE and EoT.

Residential Sales

The residential underlying sales forecast is developed using a combination of two forecast methods, the customer service method in the near term (2019-2020) and then an econometric model for the remainder of the forecast period. The customer service method allows for factors including knowledge of local economic conditions such as construction activity, the state of the visitor industry and a review of weather conditions as well as other island specific circumstances such as the volcano eruption on Hawai'i Island in 2018 to be considered in the analysis. At the time the underlying forecast was developed, actual Schedule R data was available through October 2019, which was used to inform the forecasts for 2019 and 2020.

The customer service method for residential sales examines historical and recent trends in customer count growth and underlying average use (kWh sales) per customer. In forecasting 2019 and 2020, this analysis also needed to take into consideration the residential customer losses that occurred in 2018 when homes were destroyed by the volcano eruption. October 2019 year-to-date year-over-year growth in customer count excluding eruption losses was used as the basis for projecting 2019 and 2020 residential customers. Similarly, careful analysis of underlying average use through October 2019 looking at both year-to-date and recent monthly trends in year-over-year changes was undertaken. This analysis included factoring in unusual circumstances from 2018 such as eruption losses, impacts of transfers from Schedule G to Schedule R and poor air quality in the summer as a result of the eruption as well as weather impacts in 2019. Forecasted 2019 and 2020 underlying average use was forecasted taking these factors into consideration. The forecasted number of customers multiplied by the forecasted average use per customer results in the forecasted residential underlying sales for 2019 and 2020.

The residential econometric equation is specified using adjusted residential class sales per month in megawatt-hours (MWh). The adjusted sales are the monthly residential MWh sales excluding the historical estimated impacts from each of the layers (DER, EE and EV) to result in underlying residential sales. This also includes impacts from significant transfers between rate classes, to reflect the accounts currently in the rate class.

The monthly econometric model describes residential electricity sales as a function of resident population, real personal income per capita, monthly visitor arrivals to the County, electricity price and weather variables (temperature humidity index and precipitation). In recognition of the climate differences between the Hilo and Kona sides of the island, the Hilo and Kona weather data is weighted based on historical sales by region and weighted weather variables are utilized in the model. For the forecast years, the weighting is a five-year historical average (2014-2018). These variables were all found to have relationships with residential sales. In addition, three sets of binary dummy variables were created – 1) monthly dummy variables representing individual months of the year, excluding February, used to account for seasonal variations, 2) a dummy variable to account for the significant amount of air conditioner installs starting in June 2015 and 3) a monthly dummy variable from October 2017 onwards in recognition of the policy change in the timing of transferring customers from a temporary service under commercial rate Schedule G to the residential rate Schedule R.

The specification and evaluation of the hypothetical relationships was performed using a proprietary software package, MetrixND from Itron, Inc. Many hypothetical relationships were considered, tested, and rejected until econometric equations for residential use per customer and commercial kWh sales were identified for use in Hawaiian Electric's sales projections.

Additional details on each variable, dependent and independent, used in deriving the monthly residential customer sales including the name of the variable and the source of the information are shown below. The values of the variables fed into the econometric modeling tool and the output from the model are contained in the Excel file "Appendix C Att 2 HL Underlying Inputs and Predicted.xlsx".[103]

Table C-3: Hawai'i Residential Econometric Sales Model Variables

| Variable | Description | Source | Variable Labels |
|---|---|---|---|
| *Dependent Variable:* | | | |
| Residential Sales | Adjusted Schedule R Sales (MWh) | Hawaiian Electric's monthly reports filed with the Commission | Adjusted R Sales (MWh) |
| *Economic Variables:* | | | |
| Monthly Resident Population | Resident Population, Hawai'i County. | UHERO, October 2019 | Monthly Resident Population |

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

| | | | |
|---|---|---|---|
| | Allocated to monthly values using straight-line approach with annual values assumed to be in July of each year | | |
| Real Annual Income Per Capita | Real Personal Income (1982-84 = 100) ÷ Resident Population (Hawai'i County) | UHERO, October 2019 | Annual Income Per Capita ($82-84) |
| Monthly Visitor Arrivals | Visitor Arrivals (Hawai'i County), allocated to monthly values using historical patterns | UHERO, October 2019 | Monthly Visitor Arrivals |
| Real Monthly Residential Electricity Price, one-month lag | Real residential dollars per kwh (1982-84=100) (Hawai'i Island) | see FAWG presentation on August 27, 2019 | R Electricity Price ($82-84) (1-month lag) |
| *Weather Variables:* | | | |
| Monthly Weighted THI (temperature humidity index) | Composite weather variable to incorporate both temperature and humidity.<br><br>Wtd THI = 17.5 + (0.55 * Wtd Avg Temperature) + (0.20 * Wtd Dewpoint)<br><br>Forecast uses 20-year average (1999-2018) of weighted average | Historical airport weather data (Hilo and Kona) from NOAA | Weighted THI |

| | | | |
|---|---|---|---|
| | temperature and weighted dewpoint to calculate THI. Warming trend included in forecasted average temperatures. | | |
| Monthly Weighted Precipitation | Rainfall in inches | Historical airport weather data (Hilo and Kona) from NOAA | Weighted Precipitation |
| *Dummy Variables:* | | | |
| Monthly dummy variables | Dummy variable for each individual month to account for seasonal variation, excluding February | Improves model statistics | Dmy Jan, Dmy Mar…Dmy Dec |
| Dummy variable starting in June 2015 | Proxy for impacts of increased a/c installs | Improves model statistics | Dmy 615-on |
| Dummy variable for Schedule G to Schedule R transfers | October 2017-on, proxy for policy change for transfer of temporary Schedule G (construction accounts) to Schedule R | The historical sales data series was adjusted for known transfers, but the dummy variable reflects the change in the transfer process and picks up additional effects | Dmy GtoR TFR |

The resulting monthly sales from the econometric model are then summed to annual sales forecast values. The year-over-year growth rates from the annual sales are then applied to the 2020 customer service forecast to extend the forecast out to the full 30-year range. Adjustments are made to include an extra day in leap years.

Small and Medium Commercial Sales (Rate Schedules G and J)

The small/medium commercial underlying sales forecast is developed using a combination of two forecast methods, the customer service method in the near term (2019-2020) and then applying year over year growth rates from an econometric model for the remainder of the forecast period. The customer service method allows for factors including knowledge of local economic conditions such as construction activity, the state of the visitor industry and a review of weather conditions as well as other island specific circumstances such as the volcano eruption on Hawaiʻi Island in 2018 to be considered in the analysis. At the time the underlying forecast was developed, actual Schedule G/J data was available through October 2019, which was used to inform the forecasts for 2019 and 2020.

The customer service method for small/medium commercial sales examines historical and recent trends in customer count growth and underlying average use (kWh sales) per customer similar to the approach for residential sales. In forecasting 2019 and 2020, this analysis also needed to take into consideration the small commercial customer account losses that occurred in 2018 as a result of the volcano eruption and account transfers from Schedule G to Schedule R. Careful analysis of both customer counts underlying average use through October 2019 examining both year-to-date and recent monthly trends in year-over-year changes was undertaken. Forecasted 2019 and 2020 underlying average use was forecasted taking these factors into consideration. The forecasted number of customers multiplied by the forecasted average use per customer results in the forecasted small/medium commercial underlying sales for 2019 and 2020.

The Schedule G/J econometric equation is specified using adjusted small/medium commercial class sales per month in megawatt-hours (MWh). The adjusted sales are the monthly Schedule G/J MWh sales excluding the historical estimated impacts from each of the layers (DER, EE and EV) to result in underlying Schedule G/J sales. This also includes impacts from significant transfers between rate classes, to reflect the accounts currently in the rate class.

The monthly econometric model describes Schedule G/J electricity sales as a function of resident population, real personal income per capita, monthly visitor arrivals to the County and weather variables (cooling degree days and precipitation). In recognition of the climate differences between the Hilo and Kona sides of the island, the Hilo and Kona weather data is weighted based on historical sales by region and weighted weather variables are utilized in the model. For the forecast years, the weighting is a five-year historical average (2014-2018). These variables were all found to have relationships with Schedule G/J sales. In addition, three sets of binary dummy variables were created – 1) monthly dummy variables representing individual months of the year, excluding February, used to account for seasonal variations, 2) a monthly dummy variable from September 2001 to September 2002 as a proxy for 9/11 impacts and 3) a dummy variable in February of leap years to account for leap day.

Additional details on each variable, dependent and independent, used in deriving the monthly small/medium commercial sales including the name of the variable and the source of the information are shown below. The values of the variables fed into the econometric modeling tool and the output from the model are contained in the Excel file "Appendix C Att 2 HL Underlying Inputs and Forecast.xlsx ".[104]

Table C-4: Hawai'i Small and Medium Commercial Customer Econometric Sales Model Variables

| Variable | Description | Source | Variable Labels |
|---|---|---|---|
| *Dependent Variable:* | | | |
| Small/Medium Commercial Sales | Adjusted Schedule G/J Sales (MWh) | Hawaiian Electric's monthly reports filed with the Commission | Adjusted GJ Sales (MWh) |
| *Economic Variables:* | | | |
| Monthly Resident Population | Resident Population, Hawai'i County. Allocated to monthly values using straight-line approach with annual values assumed to be in July of each year | UHERO, October 2019 | Monthly Resident Population |
| Real Annual Income Per Capita | Real Personal Income (1982-84 = 100) ÷ Resident Population (Hawai'i County) | UHERO, October 2019 | Annual Income Per Capita ($82-84) |
| Monthly Visitor Arrivals | Visitor Arrivals (Hawai'i County), | UHERO, October 2019 | Monthly Visitor Arrivals |

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

| | | | |
|---|---|---|---|
| | allocated to monthly values using historical patterns | | |
| *Weather Variables:* | | | |
| Monthly Weighted CDD (cooling degree days) | Cooling degree days (CDD) are the difference between the daily mean temperature (F) and 65 degrees, which are summed over the month.<br><br>Forecast uses 20-year average (1999-2018) of cooling degree days. Warming trend included in forecasted CDD. | Historical airport weather data (Hilo and Kona) from NOAA | Weighted CDD |
| Monthly Weighted Precipitation, one-month lag | Rainfall in inches lagged by one month | Historical airport weather data (Hilo and Kona) from NOAA | Weighted Precipitation |
| *Dummy Variables:* | | | |
| Monthly dummy variables | Dummy variable for each individual month to account for seasonal variation, excluding February | Improves model statistics | Dmy Jan, Dmy Mar…Dmy Dec |
| Dummy variable September 2001 through September 2002 | Proxy for 9/11 impacts | Improves model statistics | Dmy 911 |
| Dummy variable for leap day | Dummy variable for February in leap years (historical only) | Improves model statistics | Dmy leap day |

The resulting monthly sales from the econometric model are then summed to annual sales forecast values. The year-over-year growth rates from the annual sales are then applied to the 2020 customer service forecast to extend the forecast out to the full 30-year range. Adjustments are made to include new projects and an extra day in leap years.

Large Power Sales (Rate Schedule P)

The large power (Schedule P) sales forecast is developed using a combination of two forecast methods, the market analysis method in the near term (2019-2021) and an econometric model for the remainder of the forecast (2022-2050). The market analysis method is based on an analysis of the market conditions influencing different rate schedules with special emphasis on customer-by-customer accounting of loads in Large Power Schedule P services. Market analysis is the primary accepted near-term forecasting method for Schedule P services for Hawai'i Island, because the small number of large power customers (less than 100) allows for in-depth customer-by-customer analysis by the Company's Commercial Account Managers. The expected addition or loss of specific Schedule P customers is also accounted for.

The large power econometric equation is specified using adjusted annual large power class sales in megawatt-hours (MWh). The adjusted sales are the annual large power MWh sales excluding the historical estimated impacts from each of the layers (DER, EE and EV) to result in underlying large power sales. This also includes impacts from significant transfers between rate classes, to reflect the accounts currently in the rate class.

The annual econometric model describes large power electricity sales as a function of large power electricity sales lagged by one year, non-farm jobs and two sets of binary dummy variables – 1) a dummy variable in 2001 and 2002 to account for impacts to large power sales from 9/11 and the lingering economic impacts and 2) a dummy variable for years with a U.S. recession in at least six months of the year. These variables were all found to have relationships with large power sales.

Additional details on each variable, dependent and independent, used in deriving the annual large power sales including the name of the variable and the source of the information are shown below. The values of the variables fed into the econometric modeling tool and the output from the model are contained in the Excel file "Appendix C Att 2 HL Underlying Inputs and Forecast.xlsx ".[105]

[105] See https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/forecast-assumptions-documents

Table C-5: Hawai'i Large Power Customer Econometric Sales Model Variables

| Variable | Description | Source | Variable Labels |
|---|---|---|---|
| *Dependent Variable:* | | | |
| Large Power Sales | Adjusted P Sales (MWh) | Hawaiian Electric's monthly reports filed with the Commission | Adjusted P Sales (MWh) |
| *Lagged Dependent Variable:* | | | |
| Lagged Dependent Variable | Adjusted Schedule P Sales with one-year lag | | Lagged Dependant - Adjusted P Sales (MWh) (1-year lag) |
| *Economic Variables:* | | | |
| Annual Non-Farm Jobs | Non-Farm Jobs, Hawai'i County | UHERO, October 2019 | Annual Non-Farm Jobs |
| *Dummy Variables:* | | | |
| Dummy variable 2001-2002 | Proxy for 9/11 impacts | Improves model statistics | Dmy 911 |
| Dummy variable for recessions | Dummy variable for years with a U.S. recession in at least 6 months | Improves model statistics | Dmy Recession |

The resulting year-over-year growth rates from the annual sales econometric model are then applied to the 2020 customer service forecast to extend the forecast out to the full 30 year range . Adjustments are made to include large new projects and an extra day in leap years.

<u>Street Lighting Sales (Schedule F)</u>

The Schedule F forecast is developed using the customer service method for the duration of the forecast. Schedule F makes up a small portion (0.2-0.3%) of total Hawai'i Island sales and is less sensitive to economic drivers than the other rate schedules.

The trend in average annual kWh sales for new Schedule F customers in recent history (2016-2019) and the average number of new customers was analyzed, and those averages were applied to determine annual incremental kWh sales.

The annual incremental kWh sales are then applied as year-over-year growth for the forecast horizon.

COVID-19 Update to the Underlying Sales for Hawai'i Island

Hawai'i Island stay-at-home orders went into effect on March 25, 2020 in conjunction with Governor Ige's initial statewide stay at home orders effective through April 30, 2020. Similar to O'ahu this order shutdown the visitor industry, schools and all but essential businesses.

A sales forecast update for the very near-term (2020 – 2021) was developed within the first month of the stay at home orders. This forecast used more judgmental techniques to update the very near-term forecast. More traditional econometric models using updated economic outlooks were developed for the years 2022-2025 assuming that more traditional economic relationships would resume even though the economy was expected to remain below pre-pandemic levels. UHERO's forecast update as of May 8, 2020 was utilized in developing the forecast update.

The 2020 update for Hawai'i Island was developed within less than two weeks of the shutdown. To develop the update, an analysis was done of daily system load after the shutdown compared to the same day in the prior year as well as in the weeks prior to the shutdown. This provided an estimate of total sales reductions on a percentage basis that were occurring under the stay-at-home orders and served as the lower bound of the monthly forecast. Based on the fast and furious changes in economic outlooks and information that could be gathered from various news sources, a corporate assumption of visitor arrivals beginning to resume in August became another bound of the forecast in that some recovery in electric sales would begin in August. The assumptions by customer class as describe below were assumed to be in place from April to July, with incremental recovery in August through October and an additional increment of recovery in November through December.

To assist in forecasting the different customer classes, hourly circuit data was obtained for selected circuits on Hawai'i Island that would be representative of heavily impacted sectors such as hotels, airports, retail and residential. The year-over-year changes as well as comparisons to before the shutdown from selected circuits helped to inform assumptions for residential and commercial sales reductions.

For residential sales, Hawai'i Island is unique compared to other islands in having a higher percentage of visitors reporting accommodations as rental homes or staying with family and friends. Also, there is a higher portion of service jobs and fewer traditional office jobs, where working from home may not be an option. The analysis of selected circuits serving predominantly residential customers across the island showed a mix of increased and decreased electricity usage. This supported the assumption that no changes would be made to the residential sales forecast in 2020.

For both large power and small/medium commercial sales, circuit analysis provided some guidance to potential sales losses in certain business sectors. In addition, estimated sales reductions by business sector were informed by judgmental analysis of sectors most likely to be impacted by the shutdown, the degree to which they would be impacted and recognizing that large power customers would be impacted differently than medium and small commercial customers in the same sector. These estimated reductions by sector were applied to the Schedule P customer by customer forecast to estimate the overall Schedule P sales reductions by month. Small commercial (Schedule G) and medium commercial (Schedule J) sales were analyzed separately with estimated percentage reductions applied to 2019 sales for the impacted sectors to determine estimated total year-over-year percentage reductions. These reductions were used as a guideline for the "all-in" forecast reductions for Schedule G and Schedule J. No forecast changes were made to Street Lighting (Schedule F). The total resulting reduction in the "all-in" forecast for April through July was compared to the average overall daily year-over-year system load reductions that were seen in the first few weeks after the shutdown to assess the reasonableness of the reductions. These reductions were then scaled back in three month increments over the remainder of the year. No changes were assumed to the layers, so underlying sales was derived by taking the revised "all-in" sales by

The 2021 forecast was developed by incorporating an analysis of the losses in underlying sales by rate class during the Great Recession (2009 vs 2007) while also looking at the corresponding forecasted economic impacts compared to the Great Recession economic impacts. This was used to inform the forecast reductions by rate class.

From 2022-2025, the economic forecast data from the May 8, 2020 UHERO forecast update was used to rerun the econometric models for all rate classes. The resulting growth rates in underlying sales from these updated forecasts were applied to the 2021 forecast update underlying sales in order to derive the 2022-2025 forecasts. For all rate schedules except Schedule P, the forecast rejoined the original IGP forecast in 2026. For Schedule P the forecast update included an assumption that several new projects would each be delayed by a year, so the return to the IGP forecast did not occur until 2028.

## Maui Island Underlying Forecast

For Maui Island, the underlying forecast is developed by rate class - residential, small and medium commercial, large power and street lighting. Maui Island also used historical recorded sales in the models adjusted to remove sales impact of DER, EE and EoT.

Residential Sales

The residential underlying sales forecast is developed using the customer service method in 2019 and an econometric model for the remainder of the forecast period. The customer service method allows for factors including 2019 year to date sales, knowledge of local economic conditions such as construction activity, the state of the visitor industry and a review of short-term weather trends and conditions. The residential sales forecast for 2019 included actual Schedule R sales through September 2019 and a use per customer model for October through December.

The residential econometric equation specified using a residential class use per customer per month in kilowatt-hours. The monthly econometric model describes residential electricity use per customer as a function of real personal income per capita, electricity price, visitor arrivals and average billed days along with temperature humidity index interaction terms, dummy variables and moving average error terms. The model includes two interaction terms, one between real personal income per capita and temperature humidity index and the another between electricity price and temperature humidity index. There are also six monthly dummy variables included in the model used to account for seasonal variations in residential use per customer. In addition, there is a dummy variable that is used to calibrate 1995 with the other years in the historical data There are also three moving average error terms that are used to improve the fit of the model.

The specification and evaluation of the hypothetical relationships was performed using a proprietary software package, MetrixND from Itron, Inc. Many hypothetical relationships were considered, tested, and rejected until econometric equations for residential use per customer and commercial kWh sales were identified for use in Hawaiian Electric's sales projections.

Additional details on each variable, dependent and independent, used in deriving the monthly use per residential customer including the name of the variable and the source of the information are shown below. The values of the variables fed into the econometric modeling tool and the output from the model are contained in the Excel file "Appendix C Att 3 Maui Underlying Inputs and Predicted.xlsx".[106]

Table C-6: Maui Residential Customer Econometric Sales Model Variables

| Variable | Description | Source | Variable Labels |
|---|---|---|---|
| *Dependent Variable:* | | | |
| Use per Customer | Adjusted Underlying Residential Sales ÷ Monthly Total Residential Customer Count | Hawaiian Electric's monthly reports filed with the Commission | Adjusted Billed R Use Per Customer kWh |
| *Economic Variables:* | | | |
| 12-Month Moving Average Real Personal Income Per Capita | Real Personal Income (1982-84 = 100) ÷ Resident Population (Maui County) | UHERO, October 2019 | Adjusted Billed R Use Per Customer kWh |
| 6-Month Moving Average Real Residential Electricity Price | Real residential dollars per kwh (1982-84=100) (Maui Island) | Internal Records, see FAWG presentation on August 27, 2019 | Maui Island R Electricity Price 82-84$/kWh, 6 Month Moving Average |
| Monthly Visitor Arrivals | Visitor Arrivals (Maui Island), allocated to monthly values using historical patterns | UHERO, October 2019 | Maui County Visitor Arrivals |
| Average Billed Days | Monthly Average Number of Billed Days | Internal Records | Days |

[106] See https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/forecast-assumptions-documents

| | | | |
|---|---|---|---|
| *Weather Interaction Variables**:* | | | |
| 12-Month Moving Average Real Personal Income Per Capita × Monthly THI | See Variable Descriptions | UHERO and NOAA | Real Income Per Capita - THI Degree Days Interaction |
| 6-Month Moving Average Real Residential Electricity Price × Monthly THI | See Variable Descriptions | Internal Records and NOAA | Maui Island R Electricity Price 82-84$/kWh - THI Degree Day Interaction |
| *Dummy Variables:* | | | |
| Monthly Dummy Variables | Dummy variable for six months found to seasonally differ from the base case, excluding Apr, Jul, Sep - Dec | Improves model statistics | Jan…Mar, May, June, Aug |
| Dummy Variable for All of 1995 | Calibration factor for 1995 | Improves model statistics | 1995 |

To arrive at sales per month, the monthly use per residential customer derived in MetrixND was multiplied by the number of residential customers. The resulting residential GWh underlying sales forecast is residential kWh use per customer ÷ $10^6$ x number of customers (Res_rcd_adj ÷ $10^6$ x Res_Cust_rcd). An adjustment was made to include an extra day for leap year.

Growth rates from the econometric model are applied to the 2019 forecast to extend the forecast out to the full 30 year range.

<u>Small and Medium Commercial Sales</u>

The Maui Island the small and medium commercial underlying sales forecast is developed using the customer service method in 2019 and an econometric model for the remainder of the forecast period. Similarly, the small and medium commercial sales forecast for 2019 included actual Schedule G and Schedule J sales through September 2019 and a monthly customer service model for October through December.

The econometric model used for underlying small and medium commercial sales was modeled together since there are a significant number of rate transfers between the two commercial rate schedules on a regular basis (based on tariff requirements). The underlying small and medium commercial sales econometric equation was specified using monthly sales in kilowatt-hours. The monthly econometric model describes electricity sales as a function of real personal income, temperature humidity index, precipitation, Itron's Statistically Adjusted End-Use ("SAE") model's monthly energy intensity index, and average billed days along with several monthly dummy variables and moving average error terms. There are seven consecutive monthly dummy variables included in the model used to account for seasonal variations in monthly underlying sales. There are also six moving average error terms that are used to improve the fit of the model.

Additional details on each variable, dependent and independent, used in deriving the monthly small and medium commercial customer sales including the name of the variable and the source of the information are shown below. The values of the variables fed into the econometric modeling tool and the output from the model are also contained in the Excel file "Appendix C Att 3 Maui Underlying Inputs and Predicted.xlsx".[107]

Table C-7: Maui Small and Medium Commercial Customer Econometric Sales Model Variables

| Variable | Description | Source | Variable Labels |
|---|---|---|---|
| *Dependent Variable:* | | | |
| Underlying Small and Medium Commercial Sales | Monthly Adjusted Underlying Small and Medium Commercial Sales | Hawaiian Electric's monthly reports filed with the Commission | Adjusted Billed GJ Sales MWh |
| *Economic Variables:* | | | |
| 12-Month Moving Average Real Personal Income | Real Personal Income (1982-84 = 100) | UHERO, October 2019 | Maui Island Personal Income<br>Mil 82-84$, 12 Month Moving Average |
| Itron SAE Monthly | Energy Intensity Index to | Itron, 2019 SAE Pacific Region | Monthly Commercial Energy Intensity |

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

| | | | |
|---|---|---|---|
| Commercial Energy Intensity | Calibrate Historical Energy Usage | | |
| Average Billed Days | Monthly Average Number of Billed Days | Internal Records | Days |
| *Weather Variables**: | | | |
| Monthly THI (temperature humidity index) | Composite weather variable to incorporate both temperature and humidity.<br><br>Wtd THI = 17.5 + (0.55 * Wtd Avg Temperature) + (0.20 * Wtd Dewpoint)<br><br>Forecast uses 20-year average (1999-2018) of weighted average temperature and weighted dewpoint to calculate THI. Warming trend included in forecasted average temperatures. | Historical Kahului airport weather data from NOAA | THI Degree Days |
| Monthly Precipitation | Current month's rainfall in inches | Historical Kahului airport weather data from NOAA | Precipitation |
| 1-Month Lagged Monthly Precipitation | Previous month's rainfall in inches | Historical Kahului airport weather data from NOAA | Precipitation Lag 1 Month |
| *Interaction Variables**: | | | |

| | | | |
|---|---|---|---|
| Itron SAE Monthly Energy Intensity multiplied by Dummy variable for October 2017 forward | Energy Intensity Index to Calibrate Historical Energy Usage × Dummy for the months of October 2017 forward | Itron, 2019 SAE Pacific Region | Monthly Commercial Energy Intensity - October 2017 Forward Interaction |
| *Dummy Variables:* | | | |
| Monthly Dummy Variables | Dummy variable for seven consecutive months found to seasonally differ from the base case, excluding Jan-Apr, Dec | Improves model statistics | May - Nov |

Growth rates from the econometric model are applied to the 2019 forecast to extend the forecast out to the full 30 year range.

<u>Large Commercial Sales</u>

The large commercial sales forecast is developed using market analysis techniques for the first three years and an econometric model for the forecast period after 2021. The market analysis is developed through ground up forecasting of each customer in the rate class. Commercial Account Managers ("CAMs") work with customers in the rate class to forecast customer usage; accounting for individual projects, renovations, expansions, and changes in customer equipment. Within the market analysis, CAMs forecast customers' underlying load, additional DER equipment, and energy efficiencies independently. Engineering requests for service, news articles, and county permitting information is also used to help forecast potential additions of new large loads or loss of large loads. Rate transfers between large commercial rate schedules and small and medium rate schedules along with impending future transfers are also factored into the market analysis forecast.

In 2022, growth rates from the econometric model for underlying large commercial sales is used to forecast the remainder of the forecast period. This model is specified using monthly adjusted sales as a factor of real personal income, average billed days, and Itron's SAE commercial energy intensity index, temperature humidity index, and precipitation along with one structural break interaction term and several dummy variables and moving average error terms. The model includes one interaction terms, between a structural break dummy from October 2017 forward and Itron's SAE commercial energy intensity index. There are also six monthly dummy variables included in the model used to account for seasonal variations in large commercial sales. There are six moving average error terms that are used to improve the fit of the model.

Additional details on each variable, dependent and independent, used in deriving the monthly large commercial sales including the name of the variable and the source of the information are shown below. The values of the variables fed into the econometric modeling tool and the output from the model are also contained in the Excel file "Appendix C Att 3 Maui Underlying Inputs and Predicted.xlsx".[108]

Table C-8: Maui Large Power Customer Econometric Sales Model Variables

| Variable | Description | Source | Variable Labels |
|---|---|---|---|
| *Dependent Variable:* | | | |
| Underlying Large Commercial Sales | Monthly Adjusted Underlying Large Commercial Sales | Hawaiian Electric's monthly reports filed with the Commission | Adjusted Billed P Sales MWh |
| *Economic Variables:* | | | |
| 12-Month Moving Average Real Personal Income | 12-Month Moving Average Real Personal Income (1982-84 = 100) (Maui County) | UHERO, October 2019 | Maui Island Personal Income<br>Mil 82-84$, 12 Month Moving Average |
| Itron SAE Monthly Commercial Energy Intensity | Energy Intensity Index to Calibrate Historical Energy Usage | Itron, 2019 SAE Pacific Region | Monthly Commercial Energy Intensity |
| Average Billed Days | Monthly Average Number of Billed Days | Hawaiian Electric's monthly reports filed | Days |

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

| | | | |
|---|---|---|---|
| | | with the Commission | |
| *Weather Variables*:* | | | |
| Maui Temperature-Humidity Cooling Degree Days | Annual sum of daily temperature-humidity index in excess of 85 | Historical Kahului airport weather data from NOAA | THI Degree Days |
| Monthly Precipitation | Current month's rainfall in inches | Historical Kahului airport weather data from NOAA | Precipitation |
| *Structural Break Interaction Variables*:* | | | |
| Itron SAE Monthly Energy Intensity multiplied by Dummy variable for October 2017 forward | Energy Intensity Index to Calibrate Historical Energy Usage × Dummy for the months of October 2017 forward | Itron, 2019 SAE Pacific Region | Monthly Commercial Energy Intensity - October 2017 Forward Interaction |
| *Dummy Variables:* | | | |
| Monthly Dummy Variables | Dummy variable for six months found to seasonally differ from the base case, excluding Jan, Mar-May, Sep, Dec | Improves model statistics | Feb, Jun… Aug, Oct, Nov |

<u>Street Lighting Sales (Schedule F)</u>

The Schedule F forecast is developed using the customer service method for 2019 to 2023 and a trending model for the remaining duration of the forecast period. Schedule F makes up a small portion (0.4-0.6%) of total Maui Island sales and is less sensitive to economic drivers than the other rate schedules. While historical schedule F sales have been relatively flat, the customer service portion of the forecast reflects a significant decline in sales, as the planned replacement of existing streetlight fixtures with LED fixtures are executed. The customer service approach takes into consideration the information and replacement schedule provided by the engineering department tasked with the conversion. Schedule F sales are expected to decrease to less than half of the historical level during the years of the customer service portion of the forecast. Thereafter, growth rates from the linear trend model that accounts for monthly seasonality are applied to forecast the remaining years of the forecast period.

COVID-19 Update to the Underlying Sales

Stay-at-home orders went into effect on March 25, 2020 in conjunction with Governor Ige's initial statewide stay at home orders effective through April 30, 2020. Similar to the other islands this order shutdown the visitor industry, schools and all but essential businesses.

For the very near term, 2020-2021, the commercial forecast was developed using several sources of information. Where available, customer data from before and after the shutdown orders went into effect, customer announcements regarding closures, and feedback from customers to their Hawaiian Electric account managers were analyzed to produce an estimate of the immediate impact (percent change). The impacts were used as a proxy for the commercial sectors by business types (e.g., hotel, office, retail, education). UHERO updates were used to estimate the length of time the lowest economic activity would continue and how long it would take to see recovery.

The residential sector was initially difficult to estimate because meter reads were halted due to safety concerns for customers and meter readers. Residential customers' bills were estimated from late March until mid-May 2020 using prior consumption, which was low relative to residential usage under the stay-at-home order. Real time circuit level energy data for a sample of residential areas was used to help derive a high-level impact factor to apply to total residential sales. As billing data became available, the initial forecast was refined and updated.

In the longer run (2022-2025), the economic outlook from UHERO was used to update econometric models. For 2022, results from the econometric models were averaged with the 2021 forecast in order to smooth the transition from the near-term forecast and the econometric models. Following 2025, the forecast transitions to the previously developed IGP forecast. Smoothing of the transition was performed by applying adjustment factors of 0.985-0.995 to the underlying sales from 2026-2028.

## Lānaʻi Island Underlying Forecast

The Lānaʻi underlying forecast is developed by rate class - residential, small and medium commercial, large power and street lighting. Lānaʻi also used historical recorded sales in the models adjusted to remove sales impact of DER, EE and EoT.

Residential Sales

The residential underlying sales forecast is developed using the customer service method for 2019 to 2022 and an econometric model for the remainder of the forecast period. The customer service method allows for factors including 2019 year to date sales, knowledge of local economic conditions such as construction activity, the state of the visitor industry and a review of short-term weather trends and conditions. The residential sales forecast for 2019 included actual Schedule R sales through September 2019 and a use per customer model for October through December. This portion of the forecast was primarily derived from an analysis on forecasted customer count and average use per customer trends.

The residential econometric equation is specified using a residential class annual sales model in megawatt-hours. The annual econometric model describes adjusted underlying residential electricity sales as a function of customer counts, previous year's real electricity price, a dummy variable for 2007, and a 1-year lagged dependent variable.

Additional details on each variable, dependent and independent, used in deriving the monthly use per residential customer including the name of the variable and the source of the information are shown below. The values of the variables fed into the econometric modeling tool and the output from the model are contained in the Excel file "Appendix C Att 4 Lanai Underlying Inputs and Predicted.xlsx".[109]

Table C-9: Lāna'i Residential Customer Econometric Sales Model Variables

| Variable | Description | Source | Variable Labels |
|---|---|---|---|
| *Dependent Variable:* | | | |
| Annual Adjusted Underlying Sales | Adjusted underlying residential sales | Internal Records | Adjusted Billed R Sales MWh |

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

| | | | |
|---|---|---|---|
| *Economic Variables:* | | | |
| Annual Residential Customer Counts | Number of customers in the residential rate class by year | Hawaiian Electric's monthly reports filed with the Commission | Residential class customer count |
| 1-Year Lagged Real Residential Electricity Price | Average annual real residential dollars per kwh from previous year (1982-84=100) (Lāna'i) | Internal Records, see FAWG presentation on August 27, 2019 | Real residential electricity price lag one year |
| 1-Year Lagged Dependent | Adjusted underlying residential sales from previous year (MWH) | Internal Records | Lagged Dependent |
| *Dummy Variables:* | | | |
| 2007 Calibration Dummy Variable | Binary variable coded as 1 for year 2007 and 0 for all other years | Calibrates 2007 and improves model statistics | Dummy 2007 |

Growth rates from the econometric model are applied to the 2022 forecast to extend the forecast out to the full 30 year range.

Small and Medium Commercial Sales

The Lānaʻi small and medium commercial underlying sales forecast is developed using the customer service method in 2019 through 2021 and a trending model for the remainder of the forecast period. Similarly, the small and medium commercial sales forecast for 2019 included actual Schedule G and Schedule J sales through September 2019 and a monthly customer service model for October through December. The opening of The Lodge at Koele has stimulated and supported growth in small and medium commercial sales in 2019 and expected to continue for a portion of 2020. The customer service model assumed a leveling-off in growth for 202l sales to the 5-Year (2014-2018) historical average growth rate for the small and medium commercial sectors.

After 2021, the trending model used growth rates from a damped exponential smoothing function to forecast the small and medium commercial sales to 2050.

Large Commercial Sales

The large commercial sales forecast is developed using market analysis techniques for the first three years and the customer service method for the forecast period after 2021. The market analysis is developed through ground up forecasting of each customer in the rate class. CAMs develop sales forecast with customers in the rate class to forecast underlying usage and sales to account for individual projects, renovations, expansions, and changes in customer equipment. Like the market analysis for Maui Island, CAMs forecast Lāna'i customers' underlying load, additional DER equipment, and energy efficiencies independent and alongside the underlying sales. Engineering request, news articles, and county permitting information is also used to help forecast potential additions or loss of large loads. Rate transfers between large commercial rate schedules and small and medium rate schedules along with impending future transfers are also factored into the market analysis forecast. With the launch of Sensei Lāna'i, A Four Seasons Resort (formerly The Lodge at Koele), sales for the large commercial sector on Lāna'i are expected to increase substantially in the near term. This expected growth is captured in the market analysis portion of the forecast.

For 2022 forward, the customer service method is used to forecast underlying sales in the large commercial sector for Lāna'i. In 2022 with Sensei Lāna'i fully operational, growth in the sector is expected to level off. A growth rate of 0.2% annual increase in underlying sales was applied to carry the market analysis forecast out to 2050.

Street Lighting Sales (Schedule F)

The Schedule F forecast is developed using the customer service method for 2019 to 2023 and a trending model for the remaining duration of the forecast period. Schedule F makes up a small portion (0.4-0.6%) of total Lāna'i. The customer service portion of the forecast reflects a significant decline in sales, as the planned replacement of existing streetlight fixtures with LED fixtures are executed. The customer service approach takes into consideration the information and replacement schedule provided by the engineering department tasked with the conversion. Schedule F sales are expected to decrease to less than half of the historical level (114-137 MWh annually) during the years of the customer service portion of the forecast. Thereafter, sales are expected to remain flat at 42 MWh annually for the remained of the forecast.

**Moloka'i Island Underlying Forecast**

The Moloka'i underlying forecast is developed by rate class - residential, small and medium commercial, large power and street lighting. Moloka'i also used historical recorded sales in the models adjusted to remove sales impact of DER, EE and EoT.

Residential Sales

The residential underlying sales forecast is developed using the customer service method for 2019 to 2023 and an econometric model for the remainder of the forecast period. The customer service method allows for factors including 2019 year to date sales, knowledge of local economic conditions such as construction activity, the state of the visitor industry and a review of short-term weather trends and conditions. The residential sales forecast for 2019 included actual Schedule R sales through September 2019 and a use per customer derived forecast for October through December. The customer service portion of the forecast was primarily derived from an analysis on forecasted customer count and use per customer trends.

The residential econometric equation is specified using a residential class annual sales model in megawatt-hours. The annual econometric model describes adjusted underlying residential electricity sales as a function of real personal income, real electricity price, the annual sum of cooling degree days from Maui's temperature-humidity index, and a 1-year lagged dependent variable.

Additional details on each variable, dependent and independent, used in deriving the monthly use per residential customer including the name of the variable and the source of the information are shown below. The values of the variables fed into the econometric modeling tool and the output from the model are contained in the Excel file "Appendix C Att 5 Molokai Underlying Inputs and Predicted.xlsx".[110]

Table C-10: Moloka'i Residential Customer Econometric Sales Model Variables

| Variable | Description | Source | Variable Labels |
|---|---|---|---|
| *Dependent Variable:* | | | |
| Annual Adjusted Underlying Sales | Adjusted underlying residential sales | Hawaiian Electric's monthly reports filed with the Commission | Adjusted Billed R Sales MWh |

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

| | | | |
|---|---|---|---|
| *Economic Variables:* | | | |
| Real Personal Income | Real Personal Income (1982-84 = 100) | UHERO, October 2019 | Molokai Personal Income Mil 82-84$ |
| Real Residential Electricity Price | Average annual real residential dollars per kwh from previous year (1982-84=100) (Molokaʻi) | Internal Records, see FAWG presentation on August 27, 2019 | Molokai R Electricity Price 82-84cents/kWh |
| 1-Year Lagged Dependent | Adjusted underlying residential sales from previous year (MWH) | Internal Records | Lagged Dependent |
| *Weather Variables*:* | | | |
| Maui Temperature-Humidity Cooling Degree Days | Annual sum of daily temperature-humidity index in excess of 85 | Historical Kahului airport weather data from NOAA | THI Degree Days |

Growth rates from the econometric model are applied to the 2020 forecast to extend the forecast out to the full 30 year range.

<u>Small and Medium Commercial Sales</u>

The Molokaʻi small and medium commercial underlying sales forecast is developed using the customer service method for the entire forecast period. Actual sales through September 2019 were used, with a monthly forecast for October through December of 2019 and an annual growth model thereafter. Without the advent of large changes in load for the small and medium commercial sector in the foreseeable future, a growth rate of 0.2% was assumed for 2020 to 2050.

<u>Large Commercial Sales</u>

The large commercial sales forecast is developed using market analysis techniques for the first three years and a trending model for the forecast period after 2021. The market analysis is developed through ground up forecasting of each customer in the rate class. CAMs develop sales forecast with customers in the rate class to forecast underlying usage and sales to account for individual projects, renovations, expansions, and changes in customer equipment. CAMs forecast Molokaʻi customers' underlying load, additional DER equipment, and energy efficiencies independent and alongside the underlying sales. Engineering request, news articles, and county permitting information is also used to help forecast potential additions or loss of large loads. Rate transfers between large commercial rate schedules and small and medium rate schedules along with impending future transfers are also factored into the market analysis forecast.

For 2022 forward, the trend analysis is used to forecast underlying sales in the large commercial sector for Molokaʻi. The 5-year average growth rate of 0.18% annual increase in underlying sale was applied to carry the market analysis forecast out to 2050.

Street Lighting Sales (Schedule F)

The Schedule F forecast is developed using the customer service method for 2019 to 2023 and a trending model for the remaining duration of the forecast period. Schedule F makes up a small portion (1.3-2.0%) of total Molokaʻi. The customer service portion of the forecast reflects a significant decline in sales, as the planned replacement of existing streetlight fixtures with LED fixtures are executed. The customer service approach takes into consideration the information and replacement schedule provided by the engineering department tasked with the conversion. Schedule F sales are expected to decrease to less than half of the historical level (450-560 MWh annually) during the years of the customer service portion of the forecast. Thereafter, sales are expected to remain flat at 240 MWh annually for the remained of the forecast.

COVID-19 Update to the Underlying Sales for Lānaʻi and Molokaʻi

The unique character of each island has to be considered when choosing methods for forecasting the impact of a major disruption such as the Covid-19 pandemic. The impact of Covid to 2020 sales has varied significantly among the islands. The most likely explanation is the relative dependency of each island's economy on tourism. Molokaʻi, being the least tourism dependent, exhibited little to no impact in total kWh sales from the Covid shutdowns. Maui and Lānaʻi, being the most dependent on tourism, experienced the largest impacts to total kWh sales.

On Lānaʻi, the Pulama Lānaʻi resorts are the most significant driver of the island's electricity consumption. The forecast for Lānaʻi assumes that the resorts would resume operation as soon as travel to the island was allowed without post-travel quarantine. Therefore, Covid-19 impacts to the Lānaʻi underlying forecast were limited to 2020 with no change to the forecast thereafter.

On Moloka‘i, the forecast for 2020 was updated to include an increase in residential kWh sales and reduction to commercial sales due to stay-at-home orders. The Covid-19 impacts in the forecast for Moloka‘i were limited to 2020 with no change to the forecast thereafter.

# Appendix D: Sales Forecasts (2020 – 2050)

Table D-1: Oʻahu Sales Forecast

| Year | Underlying | DER (PV and BESS) | Energy Efficiency | Electric Vehicles | Customer Level Sales Forecast |
|---|---|---|---|---|---|
| GWH | A | B | C | D | E =A + B + C + D |
| 2020 | 8,106 | (936) | (1,396) | 30 | 5,805 |
| 2021 | 8,690 | (991) | (1,509) | 38 | 6,228 |
| 2022 | 8,936 | (1,093) | (1,613) | 49 | 6,279 |
| 2023 | 9,094 | (1,179) | (1,703) | 61 | 6,274 |
| 2024 | 9,276 | (1,226) | (1,793) | 75 | 6,332 |
| 2025 | 9,456 | (1,255) | (1,887) | 92 | 6,407 |
| 2026 | 9,638 | (1,287) | (1,980) | 111 | 6,482 |
| 2027 | 9,745 | (1,319) | (2,067) | 134 | 6,493 |
| 2028 | 9,873 | (1,355) | (2,153) | 159 | 6,524 |
| 2029 | 9,988 | (1,384) | (2,232) | 187 | 6,561 |
| 2030 | 10,133 | (1,415) | (2,307) | 221 | 6,632 |
| 2031 | 10,237 | (1,445) | (2,383) | 257 | 6,666 |
| 2032 | 10,345 | (1,478) | (2,462) | 297 | 6,702 |
| 2033 | 10,447 | (1,500) | (2,530) | 342 | 6,759 |
| 2034 | 10,533 | (1,524) | (2,595) | 392 | 6,805 |
| 2035 | 10,617 | (1,547) | (2,654) | 447 | 6,863 |
| 2036 | 10,731 | (1,571) | (2,713) | 501 | 6,948 |
| 2037 | 10,792 | (1,587) | (2,760) | 561 | 7,007 |
| 2038 | 10,875 | (1,605) | (2,809) | 624 | 7,085 |
| 2039 | 10,972 | (1,622) | (2,860) | 700 | 7,190 |
| 2040 | 11,110 | (1,642) | (2,917) | 789 | 7,341 |
| 2041 | 11,152 | (1,653) | (2,963) | 892 | 7,427 |
| 2042 | 11,232 | (1,668) | (3,012) | 1,006 | 7,557 |
| 2043 | 11,322 | (1,682) | (3,057) | 1,120 | 7,703 |
| 2044 | 11,443 | (1,699) | (3,105) | 1,238 | 7,877 |

| Year | Underlying | DER (PV and BESS) | Energy Efficiency | Electric Vehicles | Customer Level Sales Forecast |
|---|---|---|---|---|---|
| 2045 | 11,499 | (1,707) | (3,142) | 1,366 | 8,016 |
| | | | | | |
| 2047 | 11,662 | (1,728) | (3,223) | 1,631 | 8,343 |
| | | | | | |
| 2049 | 11,823 | (1,747) | (3,297) | 1,871 | 8,650 |
| | | | | | |

| Year | Underlying | DER (PV and BESS) | Energy Efficiency | Electric Vehicles | Customer Level Sales Forecast |
|---|---|---|---|---|---|
| GWH | A | B | C | D | E =A + B + C + D |
| 2020 | 1,345 | (179) | (185) | 2 | 983 |
| 2021 | 1,373 | (195) | (204) | 3 | 978 |
| 2022 | 1,410 | (205) | (221) | 4 | 987 |
| 2023 | 1,433 | (214) | (237) | 5 | 986 |
| 2024 | 1,456 | (222) | (253) | 6 | 988 |
| 2025 | 1,471 | (228) | (268) | 10 | 986 |
| 2026 | 1,483 | (234) | (284) | 15 | 980 |
| 2027 | 1,496 | (241) | (300) | 19 | 974 |
| 2028 | 1,516 | (249) | (316) | 25 | 976 |
| 2029 | 1,524 | (256) | (331) | 32 | 969 |
| 2030 | 1,535 | (263) | (345) | 39 | 967 |
| 2031 | 1,547 | (271) | (359) | 47 | 964 |
| 2032 | 1,561 | (278) | (374) | 56 | 965 |
| 2033 | 1,566 | (284) | (387) | 66 | 961 |
| 2034 | 1,575 | (291) | (400) | 77 | 963 |
| 2035 | 1,584 | (297) | (411) | 93 | 970 |
| 2036 | 1,598 | (304) | (422) | 107 | 979 |
| 2037 | 1,603 | (308) | (431) | 121 | 985 |

| | | | | | |
|---|---|---|---|---|---|
| | | | | | |
| **2039** | 1,621 | (319) | (450) | 154 | 1,005 |
| | | | | | |
| **2041** | 1,637 | (329) | (469) | 192 | 1,031 |
| | | | | | |
| **2043** | 1,654 | (338) | (486) | 238 | 1,068 |
| | | | | | |
| **2045** | 1,670 | (346) | (501) | 288 | 1,110 |
| | | | | | |
| **2047** | 1,685 | (354) | (516) | 345 | 1,160 |
| | | | | | |
| **2049** | 1,700 | (361) | (529) | 404 | 1,214 |
| | | | | | |

| Year | Underlying | DER (PV and BESS) | Energy Efficiency | Electric Vehicles | Customer Level Sales Forecast |
|---|---|---|---|---|---|
| GWH | A | B | C | D | E =A + B + C + D |
| 2020 | 1,343 | (202) | (219) | 3 | 925 |
| 2021 | 1,409 | (222) | (238) | 4 | 953 |
| 2022 | 1,415 | (237) | (255) | 6 | 928 |
| 2023 | 1,425 | (252) | (270) | 8 | 911 |
| 2024 | 1,453 | (263) | (285) | 10 | 914 |
| 2025 | 1,474 | (271) | (300) | 14 | 917 |
| 2026 | 1,499 | (280) | (315) | 20 | 924 |
| 2027 | 1,521 | (288) | (329) | 28 | 932 |
| 2028 | 1,542 | (297) | (344) | 37 | 938 |
| 2029 | 1,556 | (304) | (358) | 46 | 939 |
| 2030 | 1,572 | (312) | (371) | 56 | 945 |
| 2031 | 1,586 | (320) | (384) | 70 | 952 |

| | | | | | |
|---|---|---|---|---|---|
| 2032 | 1,606 | (329) | (397) | 87 | 967 |
| 2033 | 1,620 | (335) | (409) | 107 | 982 |
| | | | | | |
| 2035 | 1,649 | (347) | (431) | 147 | 1,018 |
| | | | | | |
| 2037 | 1,678 | (359) | (448) | 189 | 1,060 |
| | | | | | |
| 2039 | 1,707 | (369) | (464) | 233 | 1,107 |
| | | | | | |
| 2041 | 1,733 | (377) | (480) | 277 | 1,153 |
| | | | | | |
| 2043 | 1,760 | (384) | (493) | 319 | 1,203 |
| | | | | | |
| 2045 | 1,787 | (390) | (505) | 357 | 1,248 |
| | | | | | |
| 2047 | 1,813 | (396) | (516) | 392 | 1,294 |
| | | | | | |
| 2049 | 1,839 | (401) | (525) | 426 | 1,339 |
| | | | | | |

| Year | Underlying | DER (PV and BESS) | Energy Efficiency | Electric Vehicles | Customer Level Sales Forecast |
|---|---|---|---|---|---|
| GWH | A | B | C | D | E =A + B + C + D |
| 2020 | 35.6 | (4.6) | (2.7) | 0.1 | 28.4 |
| 2021 | 36.2 | (5.1) | (2.8) | 0.1 | 28.4 |
| 2022 | 36.0 | (5.3) | (2.9) | 0.1 | 27.9 |
| 2023 | 36.0 | (5.5) | (2.9) | 0.1 | 27.6 |
| 2024 | 36.1 | (5.7) | (3.0) | 0.1 | 27.4 |
| 2025 | 36.0 | (5.8) | (3.1) | 0.1 | 27.2 |

| | | | | | |
|---|---|---|---|---|---|
| | | | | | |
| 2027 | 36.2 | (6.0) | (3.3) | 0.2 | 27.0 |
| | | | | | |
| 2029 | 36.3 | (6.3) | (3.5) | 0.2 | 26.7 |
| | | | | | |
| 2031 | 36.5 | (6.6) | (3.7) | 0.3 | 26.5 |
| | | | | | |
| 2033 | 36.8 | (6.9) | (3.8) | 0.4 | 26.5 |
| | | | | | |
| 2035 | 37.1 | (7.2) | (4.0) | 0.5 | 26.5 |
| | | | | | |
| 2037 | 37.4 | (7.3) | (4.1) | 0.7 | 26.7 |
| | | | | | |
| 2039 | 37.6 | (7.5) | (4.2) | 0.9 | 26.9 |
| | | | | | |
| 2041 | 37.8 | (7.7) | (4.3) | 1.3 | 27.1 |
| | | | | | |
| 2043 | 38.1 | (7.8) | (4.4) | 1.7 | 27.5 |
| | | | | | |
| 2045 | 38.3 | (8.0) | (4.5) | 2.1 | 27.9 |
| | | | | | |
| 2047 | 38.5 | (8.1) | (4.6) | 2.6 | 28.4 |
| | | | | | |
| 2049 | 38.8 | (8.2) | (4.7) | 3.0 | 29.0 |
| | | | | | |

| Year | Underlying | DER (PV and BESS) | Energy Efficiency | Electric Vehicles | Customer Level Sales Forecast |
|---|---|---|---|---|---|
| GWH | A | B | C | D | E =A + B + C + D |
| 2020 | 34.3 | (1.4) | (1.1) | 0.1 | 31.9 |

| | | | | | |
|---|---|---|---|---|---|
| 2021 | 40.0 | (1.4) | (1.2) | 0.1 | 37.5 |
| 2022 | 40.1 | (1.5) | (1.3) | 0.1 | 37.4 |
| 2023 | 40.2 | (1.6) | (1.4) | 0.1 | 37.3 |
| 2024 | 40.6 | (1.7) | (1.5) | 0.1 | 37.5 |
| 2025 | 40.8 | (1.7) | (1.6) | 0.1 | 37.6 |
| 2026 | 41.1 | (1.8) | (1.7) | 0.1 | 37.8 |
| 2027 | 41.4 | (1.9) | (1.8) | 0.1 | 37.9 |
| 2028 | 41.9 | (2.0) | (1.9) | 0.1 | 38.2 |
| 2029 | 42.0 | (2.0) | (1.9) | 0.1 | 38.2 |
| 2030 | 42.2 | (2.1) | (2.0) | 0.2 | 38.2 |
| 2031 | 42.4 | (2.2) | (2.1) | 0.2 | 38.2 |
| 2032 | 42.7 | (2.3) | (2.2) | 0.2 | 38.4 |
| 2033 | 42.8 | (2.4) | (2.3) | 0.3 | 38.4 |
| 2034 | 43.0 | (2.5) | (2.4) | 0.3 | 38.4 |
| 2035 | 43.1 | (2.6) | (2.4) | 0.4 | 38.5 |
| 2036 | 43.4 | (2.6) | (2.5) | 0.4 | 38.8 |
| 2037 | 43.5 | (2.7) | (2.6) | 0.5 | 38.7 |
| 2038 | 43.6 | (2.8) | (2.6) | 0.5 | 38.8 |
| 2039 | 43.8 | (2.8) | (2.7) | 0.6 | 38.9 |
| 2040 | 44.1 | (2.9) | (2.8) | 0.7 | 39.1 |
| 2041 | 44.1 | (3.0) | (2.8) | 0.8 | 39.1 |
| 2042 | 44.3 | (3.0) | (2.9) | 0.9 | 39.3 |
| 2043 | 44.4 | (3.1) | (2.9) | 1.0 | 39.5 |
| 2044 | 44.7 | (3.1) | (3.0) | 1.1 | 39.8 |
| 2045 | 44.7 | (3.2) | (3.0) | 1.3 | 39.8 |
| 2046 | 44.9 | (3.3) | (3.1) | 1.4 | 40.0 |
| 2047 | 45.1 | (3.3) | (3.2) | 1.6 | 40.2 |
| 2048 | 45.3 | (3.3) | (3.2) | 1.7 | 40.5 |
| 2049 | 45.4 | (3.3) | (3.3) | 1.8 | 40.6 |
| 2050 | 45.6 | (3.4) | (3.3) | 1.9 | 40.8 |

# Appendix E: Peak Forecasts (2020 – 2050)

Table E-1: O‘ahu Peak Forecast (MW)

| Year | Underlying | DER (PV and BESS) | Energy Efficiency | Electric Vehicles | Peak Forecast |
|---|---|---|---|---|---|
| MW | A | B | C | D | E =A + B + C + D |
| 2020 | 1,330 | (5) | (258) | 6 | 1,072 |
| 2021 | 1,405 | (13) | (282) | 8 | 1,117 |
| 2022 | 1,496 | (30) | (297) | 9 | 1,178 |
| 2023 | 1,517 | (47) | (310) | 11 | 1,170 |
| 2024 | 1,552 | (58) | (335) | 13 | 1,173 |
| 2025 | 1,579 | (60) | (339) | 16 | 1,196 |
| 2026 | 1,569 | (66) | (351) | 19 | 1,171 |
| 2027 | 1,589 | (75) | (366) | 23 | 1,173 |
| 2028 | 1,590 | (69) | (381) | 29 | 1,169 |
| 2029 | 1,617 | (91) | (388) | 33 | 1,171 |
| 2030 | 1,642 | (95) | (402) | 39 | 1,184 |
| 2031 | 1,667 | (97) | (414) | 46 | 1,202 |
| 2032 | 1,683 | (99) | (424) | 54 | 1,214 |
| 2033 | 1,703 | (95) | (434) | 62 | 1,236 |
| 2034 | 1,712 | (101) | (440) | 72 | 1,243 |
| 2035 | 1,718 | (104) | (448) | 82 | 1,248 |
| 2036 | 1,738 | (106) | (455) | 94 | 1,271 |
| 2037 | 1,762 | (117) | (465) | 106 | 1,286 |
| 2038 | 1,780 | (120) | (476) | 121 | 1,305 |
| 2039 | 1,792 | (121) | (483) | 135 | 1,323 |
| 2040 | 1,736 | (87) | (454) | 145 | 1,339 |
| 2041 | 1,747 | (90) | (466) | 177 | 1,369 |
| 2042 | 1,639 | (43) | (437) | 237 | 1,396 |
| 2043 | 1,852 | (140) | (508) | 223 | 1,427 |
| 2044 | 1,800 | (97) | (474) | 241 | 1,470 |

| | | | | | |
|---|---|---|---|---|---|
| 2045 | 1,702 | (43) | (452) | 286 | 1,493 |
| | | | | | |
| 2047 | 1,704 | (49) | (464) | 392 | 1,582 |
| | | | | | |
| 2049 | 1,712 | (52) | (473) | 453 | 1,640 |
| | | | | 473 | |

Table E-2: Hawai'i Island Peak Forecast (MW)

| Year | Underlying | DER (PV and BESS) | Energy Efficiency | Electric Vehicles | Peak Forecast |
|---|---|---|---|---|---|
| MW | A | B | C | D | E =A + B + C + D |
| 2020 | 221.6 | (0.8) | (29.5) | 0.4 | 191.8 |
| 2021 | 218.8 | (2.8) | (36.8) | 0.6 | 179.8 |
| 2022 | 219.8 | (4.2) | (35.7) | 0.8 | 180.8 |
| 2023 | 228.1 | (6.1) | (43.0) | 1.1 | 180.1 |
| 2024 | 224.2 | (6.6) | (41.0) | 1.5 | 178.1 |
| 2025 | 229.5 | (10.0) | (42.6) | 2.1 | 178.9 |
| 2026 | 229.4 | (7.2) | (45.8) | 3.2 | 179.6 |
| 2027 | 234.2 | (12.2) | (47.8) | 4.2 | 178.3 |
| 2028 | 234.5 | (10.4) | (50.7) | 5.0 | 178.5 |
| 2029 | 250.1 | (21.0) | (58.1) | 7.1 | 178.1 |
| 2030 | 236.8 | (12.5) | (55.5) | 8.7 | 177.5 |
| 2031 | 241.1 | (17.9) | (57.0) | 10.3 | 176.5 |
| 2032 | 239.3 | (12.1) | (60.7) | 11.5 | 178.1 |
| 2033 | 243.8 | (15.5) | (62.3) | 15.3 | 181.2 |
| 2034 | 233.6 | (3.2) | (68.9) | 17.5 | 178.9 |
| 2035 | 243.0 | (9.0) | (74.7) | 21.3 | 180.6 |
| 2036 | 247.4 | (23.4) | (67.1) | 23.6 | 180.6 |
| 2037 | 240.2 | (3.3) | (72.8) | 26.0 | 190.2 |
| 2038 | 240.1 | (3.3) | (74.0) | 27.8 | 190.5 |
| 2039 | 240.4 | (5.4) | (76.1) | 35.4 | 194.3 |

| | | | | | |
|---|---|---|---|---|---|
| | | | | | |
| **2041** | 252.3 | (22.2) | (75.7) | 42.2 | 196.6 |
| | | | | | |
| **2043** | 247.7 | (3.4) | (82.2) | 51.5 | 213.6 |
| | | | | | |
| **2045** | 247.2 | (3.4) | (85.3) | 64.5 | 223.1 |
| | | | | | |
| **2047** | 218.1 | (2.8) | (73.1) | 88.0 | 230.1 |
| | | | | | |
| **2049** | 253.1 | (9.1) | (93.6) | 91.2 | 241.6 |
| | | | | | |

| Year | Underlying | DER (PV and BESS) | Energy Efficiency | Electric Vehicles | Peak Forecast |
|---|---|---|---|---|---|
| **MW** | A | B | C | D | E =A + B + C + D |
| **2020** | 229.7 | (1.7) | (34.1) | 0.1 | 194.0 |
| **2021** | 237.2 | (3.2) | (38.5) | 0.2 | 195.7 |
| **2022** | 236.9 | (8.5) | (41.5) | 0.6 | 187.5 |
| **2023** | 238.0 | (12.4) | (42.4) | 1.0 | 184.2 |
| **2024** | 242.4 | (16.2) | (44.7) | 1.5 | 183.0 |
| **2025** | 246.7 | (18.0) | (47.3) | 2.2 | 183.6 |
| **2026** | 250.8 | (20.0) | (52.1) | 3.6 | 182.3 |
| **2027** | 250.2 | (15.6) | (55.8) | 5.5 | 184.3 |
| **2028** | 252.5 | (16.2) | (59.2) | 7.2 | 184.3 |
| **2029** | 259.5 | (26.6) | (56.6) | 8.7 | 185.0 |
| **2030** | 261.1 | (29.2) | (58.1) | 11.4 | 185.2 |
| **2031** | 254.0 | (22.9) | (58.0) | 13.1 | 186.2 |
| **2032** | 246.6 | (11.3) | (59.8) | 16.3 | 191.8 |
| **2033** | 250.0 | (11.5) | (61.6) | 21.0 | 197.9 |
| **2034** | 252.8 | (11.8) | (63.1) | 26.4 | 204.2 |

| | | | | | |
|---|---|---|---|---|---|
| **2035** | 231.7 | (3.8) | (58.9) | 36.4 | 205.4 |
| | | | | | |
| **2037** | 257.2 | (13.0) | (66.5) | 37.8 | 215.5 |
| | | | | | |
| **2039** | 263.0 | (13.6) | (68.9) | 46.5 | 226.9 |
| | | | | | |
| **2041** | 243.6 | (5.8) | (64.3) | 69.1 | 242.6 |
| | | | | | |
| **2043** | 273.2 | (14.8) | (72.5) | 64.0 | 249.9 |
| | | | | | |
| **2045** | 255.4 | (4.1) | (67.7) | 77.8 | 261.4 |
| | | | | | |
| **2047** | 254.5 | (6.0) | (69.4) | 98.1 | 277.1 |
| | | | | | |
| **2049** | 258.8 | (16.7) | (70.7) | 107.7 | 279.2 |
| | | | | | |

| Year | Underlying | DER (PV and BESS) | Energy Efficiency | Electric Vehicles | Peak Forecast |
|---|---|---|---|---|---|
| **MW** | A | B | C | D | E =A + B + C + D |
| **2020** | 5.7 | (0.0) | 0.0 | 0.0 | 5.7 |
| **2021** | 5.7 | (0.0) | (0.0) | 0.0 | 5.6 |
| **2022** | 5.7 | (0.0) | (0.1) | 0.0 | 5.6 |
| **2023** | 5.7 | (0.1) | (0.1) | 0.0 | 5.5 |
| **2024** | 5.7 | (0.1) | (0.1) | 0.0 | 5.6 |
| **2025** | 5.8 | (0.1) | (0.1) | 0.0 | 5.6 |
| **2026** | 5.8 | (0.1) | (0.1) | 0.0 | 5.6 |
| **2027** | 5.7 | (0.1) | (0.2) | 0.0 | 5.5 |
| **2028** | 5.8 | (0.1) | (0.1) | 0.0 | 5.5 |
| **2029** | 5.8 | (0.2) | (0.2) | 0.0 | 5.6 |

| | | | | | |
|---|---|---|---|---|---|
| | | | | | |
| **2031** | 5.9 | (0.2) | (0.2) | 0.1 | 5.6 |
| | | | | | |
| **2033** | 5.9 | (0.2) | (0.3) | 0.1 | 5.6 |
| | | | | | |
| **2035** | 6.1 | (0.2) | (0.3) | 0.1 | 5.7 |
| | | | | | |
| **2037** | 6.0 | (0.2) | (0.2) | 0.2 | 5.7 |
| | | | | | |
| **2039** | 6.1 | (0.2) | (0.2) | 0.2 | 5.9 |
| | | | | | |
| **2041** | 6.1 | (0.3) | (0.2) | 0.3 | 5.9 |
| | | | | | |
| **2043** | 6.2 | (0.3) | (0.2) | 0.4 | 6.1 |
| | | | | | |
| **2045** | 6.3 | (0.3) | (0.2) | 0.5 | 6.3 |
| | | | | | |
| **2047** | 6.4 | (0.3) | (0.2) | 0.6 | 6.5 |
| | | | | | |
| **2049** | 6.4 | (0.3) | (0.2) | 0.7 | 6.6 |
| | | | | | |

| Year | Underlying | DER (PV and BESS) | Energy Efficiency | Electric Vehicles | Peak Forecast |
|---|---|---|---|---|---|
| **MW** | A | B | C | D | E =A + B + C + D |
| **2020** | 5.9 | – | – | – | 5.9 |
| **2021** | 6.3 | – | – | – | 6.3 |
| **2022** | 6.3 | – | – | – | 6.3 |
| **2023** | 6.5 | – | (0.1) | – | 6.4 |
| **2024** | 6.5 | – | (0.1) | – | 6.4 |

| | | | | | |
|---|---|---|---|---|---|
| **2025** | 6.5 | – | (0.1) | – | 6.4 |
| **2026** | 6.5 | – | (0.1) | – | 6.4 |
| **2027** | 6.6 | – | (0.1) | – | 6.5 |
| **2028** | 6.7 | – | (0.2) | – | 6.5 |
| **2029** | 6.8 | (0.1) | (0.2) | – | 6.5 |
| **2030** | 6.8 | (0.1) | (0.2) | – | 6.6 |
| **2031** | 6.8 | (0.1) | (0.2) | – | 6.5 |
| **2032** | 6.8 | (0.1) | (0.2) | – | 6.5 |
| **2033** | 6.8 | (0.1) | (0.2) | – | 6.5 |
| **2034** | 6.9 | (0.1) | (0.3) | 0.1 | 6.6 |
| **2035** | 7.0 | (0.1) | (0.3) | 0.1 | 6.7 |
| **2036** | 7.0 | (0.1) | (0.2) | 0.1 | 6.7 |
| **2037** | 7.0 | (0.1) | (0.3) | 0.1 | 6.7 |
| **2038** | 7.0 | (0.1) | (0.3) | 0.1 | 6.7 |
| **2039** | 7.1 | (0.1) | (0.3) | 0.1 | 6.8 |
| **2040** | 7.2 | (0.1) | (0.3) | 0.1 | 6.9 |
| **2041** | 7.2 | (0.1) | (0.3) | 0.2 | 6.9 |
| **2042** | 7.2 | (0.2) | (0.3) | 0.2 | 6.9 |
| **2043** | 7.3 | (0.2) | (0.3) | 0.2 | 7.0 |
| **2044** | 7.2 | (0.1) | (0.4) | 0.2 | 7.0 |
| **2045** | 7.3 | (0.2) | (0.4) | 0.3 | 7.0 |
| **2046** | 7.4 | (0.2) | (0.4) | 0.3 | 7.1 |
| **2047** | 7.5 | (0.2) | (0.4) | 0.3 | 7.2 |
| **2048** | 7.4 | (0.2) | (0.4) | 0.3 | 7.2 |
| **2049** | 7.3 | (0.2) | (0.4) | 0.3 | 7.1 |
| **2050** | 7.5 | (0.2) | (0.4) | 0.4 | 7.3 |