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PUBLIC UTILITIES
COMMISSION

The Honorable Chair and Members of the
Hawai'i Public Utilities Commission
465 South King Street
Kekuanaoa Building, Room 103
Honolulu, Hawai'i 96813

Dear Commissioners:

Subject: Adequacy of Supply
Hawaiian Electric Company, Inc.

The following information is respectfully submitted in accordance with paragraph 5.3.a of General Order No. 7, which states:

> *The generation capacity of the utility's plant, supplemented by electric power regularly available from other sources, must be sufficiently large to meet all reasonably expectable demands for service and provide a reasonable reserve for emergencies. A Statement shall be filed annually with the Commission within 30 days after the close of the year indicating the adequacy of such capacity and the method used to determine the required reserve capacity which forms the basis for future requirements in generation, transmission, and distribution plant expansion programs required under Rule 2.3h.1.*

2018 Adequacy of Supply Report Summary

- The adequacy of supply ("AOS") of Hawaiian Electric Company, Inc. ("Hawaiian Electric" or the "Company") is based on the Company's June 2017 Sales and Peak Forecast Update and other key assumptions.

- Hawaiian Electric's reserve capacity may not be sufficient to meet the Company's generating system reliability guideline of 4.5 years per day in 2018, 2022, and 2023. However, Hawaiian Electric anticipates that mitigation measures can be implemented to satisfy the projected reserve capacity shortfalls. This assumes the Schofield Generating Station ("SGS") is in service from 2018.

- The adjusted peak load experienced on Oahu in 2017 was 1,209 MW-net, and was served by Hawaiian Electric's total capability of 1,679 MW-net, including firm power purchases. This represents a reserve margin of approximately 41% over the 2017 adjusted system net peak. This reserve margin did not include the capacity of Honolulu Units 8 and 9, which were deactivated in January 2014.

- Honolulu Units 8 and 9 (with a combined rating of 107.3 MW-net) were deactivated on January 31, 2014. The 2018 AOS reference scenario reflects the Honolulu generating units remaining deactivated, and their capacities are not included in the reserve margin calculations.

- Hawaiian Electric is anticipating the addition of approximately 50 MW of utility-owned and operated, firm, dispatchable, generation on federal lands, for the purpose of improving energy security and resiliency for the Hawaiian Electric grid and for the Army facilities in central Oahu, as well as enabling the integration of more variable generation renewable resources. It is estimated that the security project, i.e., the SGS Project, may be in service in the 2018 timeframe and is included in the 2018 AOS reference scenario.

1. Peak Demand and System Capability in 2017

The adjusted peak load experienced on Oahu in 2017 was 1,209 MW-net, and was served by Hawaiian Electric's total capability of 1,679 MW-net, including firm power purchases. This represents a reserve margin of approximately 41%[1] over the 2017 adjusted system net peak. This reserve margin did not include the capacity of Honolulu Units 8 and 9, which were deactivated in January 2014.

The system peak occurred on Wednesday, November 1, 2017 at approximately 6:19 p.m., and was 1,184 MW-net based on net Hawaiian Electric generation, net purchased power generation, the peak reduction benefits of energy efficiency and demand-side management ("DSM") programs, and with several co-generators[2] operating at the time. Had these cogenerating units not been operating, the 2017 system peak would have been approximately 1,209 MW-net.

Hawaiian Electric's 2017 total generating capability of 1,679 MW-net includes 456.5 MW net of firm power purchased from (1) Kalaeloa Partners, L.P. ("KPLP"), (2) AES Hawaii, Inc. ("AES"), and (3) H-POWER.

At times during 2017, Hawaiian Electric received energy from eleven variable generation energy producers (i.e., IES Downstream, Par Hawaii, Kahuku Wind Power, Kapolei Sustainable Energy Park, Kawailoa Wind, Kalaeloa Solar Two, Kalaeloa Renewable Energy Park, Waianae Solar, Waihonu North, Waihonu South, Aloha Solar I). Since these contracts are not for firm capacity, they are not reflected in Hawaiian Electric's total firm generating capability.

[1] The total capability value used in the calculation of this reserve margin does not account for units not available due to maintenance outages, forced outages or derates in unit capacities. The reserve margin calculation takes into account the approximately 18 MW of interruptible load that may be available at system peak. In actual real-time operations, reserves may be reduced due to maintenance, forced outages or deratings.

[2] At the time of the peak, certain units at Par Hawaii, IES Downstream, and Pearl Harbor were generating about 25 MW of power for use at their sites.

2. Estimated Reserve Margins

Appendix 1 shows the forecasted reserve margin over the next six years, 2018-2023, based on Hawaiian Electric's June 2017 Sales and Peak Forecast, and includes estimated energy efficiency impacts and load management impacts. This is based on a Reference Scenario that is described in Section 5.

3. Criteria to Evaluate Hawaiian Electric's Adequacy of Supply

Hawaiian Electric's capacity planning criteria are applied to determine the adequacy of supply and whether or not there is enough generating capacity on the system. Hawaiian Electric's capacity planning criteria take into account that Hawaiian Electric must provide for its own backup generation since, as an island utility, it cannot import emergency power from a neighboring utility. Hawaiian Electric's capacity planning criteria are described in Section 3.1.

The results of the annual analysis of the adequacy of supply on the Hawaiian Electric system are a function of a number of forecasts, such as:

- peak demand, including the forecasted peak reduction benefits of (a) energy efficiency from the Public Benefit Fee Administrator's ("PBFA") programs and changes to codes and standards, and (b) customer-sited-photovoltaic ("PV") with battery installations; [§4.2]
- peak reduction benefits of existing load control programs; [§4.3]
- Equivalent Forced Outage Rate Demand ("EFORd") on the generating units; [§4.4]
- planned maintenance schedules for the generating units on the system; [§4.5]
- additions of firm generating capacity; [§4.7] and
- reductions of firm generating capacity. [§4.8]

Each of the current assumptions for these and other factors is discussed in Section 4.

3.1. Hawaiian Electric's Capacity Planning Criteria

Hawaiian Electric's capacity planning criteria consist of one rule and one reliability guideline. The reserve capacity shortfalls calculated herein are determined by the application of the reliability guideline based on various key inputs such as the EFORds of each generating unit, the load to be served, the amount of capacity on the system, and the availability of the generating units.

3.1.1. Hawaiian Electric's Capacity Planning Rule

Rule 1:

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

a. the capacity needed to serve the estimated system peak load, less the total amount of interruptible loads;

b. the capacity of the unit scheduled for maintenance; and

c. the capacity that would be lost by the forced outage of the largest unit in service.

Reserve Margin:

Consideration will be given to maintaining a reserve margin of approximately 20 percent based on Net Top Load Ratings.

Rule 1 includes load reduction benefits from interruptible load customers. Because Hawaiian Electric will not build reserve capacity to serve interruptible loads, interruptible load programs such as Hawaiian Electric's current Rider I and load management programs can have the effect of deferring the need for additional firm capacity generation.

PSIP Update Report Reserve Margin:

In the Hawaiian Electric Companies' Revised and Supplemented Power Supply Improvement Plans ("PSIPs") filed on December 23, 2016 in Docket No. 2014-0183, also referred to as the *PSIP Update Report: December 2016*, the planning reserve margin for O'ahu was assumed to be a minimum of 45% for capacity planning analysis as a proxy for its 4.5 years per day loss of load probability ("LOLP") reliability guideline.[3] The analysis herein uses LOLP calculations rather than the 45% reserve margin proxy value.

3.1.2. Hawaiian Electric's Reliability Guideline: Loss of Load Probability

The application of Hawaiian Electric's generating system reliability guideline does take into account the LOLP that generating units could be unexpectedly lost from service.

[3] Refer to Appendix J of the *PSIP Update Report: December 2016* for reference.

Reliability Guideline:

> *Capacity planning analysis will include a calculation of risk (Loss of Load Probability) in years per day for each year of each plan of the long-range expansion study. In cases where risk is calculated to be less than 4.5 years per day, the plan will be reviewed by the Vice President of Power Supply, Senior Vice President of Operations, and the President for approval of use of the plan in the study.*

In order to determine whether there is enough capacity on the system to account for the probability that multiple units may be unexpectedly lost from service, the result of an LOLP calculation must be compared against Hawaiian Electric's generating system reliability guideline.

Hawaiian Electric has a reliability guideline threshold of 4.5 years per day. Hawaiian Electric plans to have sufficient generating capacity to maintain generating system reliability above 4.5 years per day. There should be enough generating capacity on the system such that the expectation of not being able to satisfy demand due to insufficient generation occurs no more than once every 4.5 years. Values less than 4.5 years per day indicate lower levels of reliability and an increased likelihood of generation-related customer outages.

One potential means to address the planning uncertainty and complexity would be to revise the capacity planning guideline. If the existing LOLP of 4.5 years per day does not provide an adequate cushion to respond to quickly-changing parameters, such as changes in peak demand and individual unit availability factors, many of which may change rapidly from year to year, then the utility could plan for a higher reliability standard similar to that of many mainland utilities. Such an approach would not eliminate quickly-changing parameters, but it would add a measure of conservatism in recognition that the uncertainties undoubtedly exist.

In its direct testimony for the Campbell Industrial Park ("CIP") Generating Station and Transmission Additions Project (Docket No. 05-0145), filed on August 17, 2006, the Consumer Advocate stated:

> [Hawaiian Electric's reliability guideline] is less stringent than the guidelines used by mainland utilities. As will be addressed later in my testimony, this guideline should be re-evaluated to determine if it should be more stringent in the future (e.g., one day in 6 years) to ensure reliable service. However, this determination should be based on analyses that assess the tradeoff between electric service costs to the consumer and the increase in reliability to be gained. CA-T-1 at 32.

The typical reliability standard on the mainland is 10 years per day, which is more stringent than the 6 years per day suggested by the Consumer Advocate and the 4.5 years per day in Hawaiian Electric's reliability guideline. A scenario analysis of the reserve capacity shortfall based on a higher reliability guideline threshold of 10 years per day is included in Section 5. The results of the analysis show the additional amount of firm capacity that would be needed on the Oahu grid to meet a higher, 10 years per day, reliability standard based on the assumptions provided herein.

Please refer to Appendix 3 of the 2005 AOS report for additional information related to Hawaiian Electric's reliability guideline.

3.2. Other Considerations in Determining the Timing of Unit Additions

The need for new generation is not based solely on the application of the criteria previously mentioned. As capacity needs become imminent, it is essential that Hawaiian Electric broaden its consideration to ensure timely installation of generation capacity necessary to meet its customers' energy needs.

Other near-term considerations may include:

1. the current condition and rated capacity of existing units;
2. required power purchase obligations and contract terminations;
3. the uncertainties surrounding non-utility generation resources;
4. transmission system considerations;
5. meeting environmental compliance standards; and
6. system stability considerations for Hawaiian Electric's isolated electrical system.

In the application of Hawaiian Electric's capacity planning criteria that are used to determine its adequacy of supply, the inputs drive the results. Two of the key inputs in the application of the capacity planning criteria are (1) projected peak demand (including the anticipated peak reduction benefits of energy efficiency programs) and (2) the total firm capacity on the system. These key inputs are described in the following sections.

4. Key Inputs to the 2018 AOS Analysis

4.1. Period Under Review

This AOS review covers the period 2018 to 2023, which coincides with the PSIP Near-Term Action Plan period.

4.2. June 2017 Sales and Peak Forecast

Hawaiian Electric developed a sales and peak ("S&P") forecast in June 2017 ("June 2017 S&P forecast"), which was subsequently approved by the Company for future planning purposes. Hawaiian Electric's AOS is based on the Company's June 2017 S&P forecast and other key assumptions.

Figure 1 illustrates Hawaiian Electric's historical system peaks, and compares them to the forecasts used in the 2017 and 2018 AOS analyses. The analyses contained in the 2017 AOS report were based on the October 2016 peak forecast.

Figure 1: Recorded Peaks and Future Year Projections

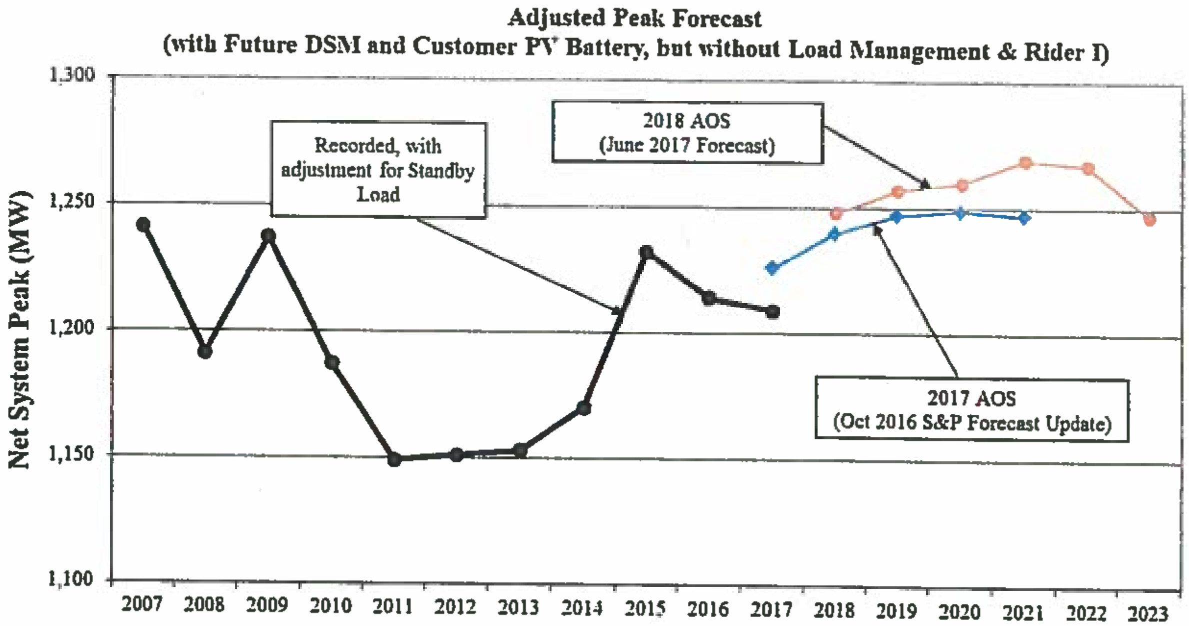

Table 1 below provides the recorded peaks from 2007 and the forecast used in the 2018 AOS analysis.

Table 1: Recorded Peaks and Future Year Projections

Net System Peak (MW) (with Future DSM and Customer PV Battery, but without Load Management & Rider I)			
Year	Actual	Actual Adj for Standby Load	2018 AOS Jun 2017 S&P Forecast
2007	1,216	1,241	
2008	1,186	1,191	
2009	1,213	1,237	
2010	1,162	1,187	
2011	1,141	1,149	
2012	1,141	1,151	
2013	1,144	1,153	
2014	1,165	1,170	
2015	1,206	1,232	
2016	1,192	1,214	
2017	1,184	1,209	
2018			1,248
2019			1,257
2020			1,260
2021			1,269
2022			1,267
2023			1,247

For both the recorded and forecast data (from the June 2017 S&P Forecast), figures reflect an upward (standby) adjustment to account for the potential need to serve certain large customer loads (i.e., IES Downstream, Par Hawaii and Pearl Harbor) that are frequently served by their own internal generation. Figure 1 also includes estimated peak reduction benefits of energy efficiency programs and naturally occurring conservation. With the advent of storage technology (i.e., battery energy storage system ("BESS")) for the consumer market, impacts of customer-sited PV paired with batteries were included in the peak forecast. As solar capacity continues to grow year over year, daytime loads are projected to be reduced and, all else being equal, the average daily load profile is expected to have a more pronounced difference between daytime and evening peak. With an operating assumption of BESS charging during the day time hours, coincident with PV generation, and discharging the stored energy during the system priority peak period, the system peak has been reduced for this type of energy storage operation.

4.3. Projected Peak Reduction Benefits of Load Control Programs

Hawaiian Electric is committed to pursuing demand response ("DR") programs designed to provide cost-effective resource options to meet the capacity needs and support the reliable operation of the system, as identified in the Integrated Demand Response Portfolio Plan ("IDRPP") filed with the Commission on July 28, 2014, Update filed March 31, 2015, and Supplement filed November 20, 2015, in Docket No. 2007-0341.

On December 30, 2015, the Hawaiian Electric Companies submitted to the Commission for approval a DR Portfolio Application requesting approval of:

- a proposed tariff structure for DR programs;
- a cost recovery mechanism;
- a two-year program and budget approval cycle; and
- the Companies' proposed reporting structure.

A Revised DR Portfolio was filed on February 10, 2017, which provided modified approval requests and DR program design and targets (MW) consistent with the DR Portfolio used in the *PSIP Update Report: December 2016*. On January 25, 2018 the Commission issued Decision and Order No. 35238, approving the Companies Revised DR Portfolio tariff structure framework. Hawaiian Electric will continue to implement DR in accordance future targets. For the purposes of this analysis, *PSIP Update Report: December 2016* DR targets (MW) will shift targets two years. For example, 2017 targets are now 2019 targets.

Table 2 shows the forecast of the peak reduction benefits towards Rule 1 and reserve margin calculations from the *PSIP Update Report: December 2016* high distributed generation ("DG")-PV DR forecast.

Table 2: DR Impacts for Capacity Planning Purposes (MW)

Year	DR Total	Rider I	Total
2018	14.0	4.3	18.3
2019	22.3	4.3	26.6
2020	44.1	4.3	48.4
2021	69.3	4.3	73.6
2022	93.9	4.3	98.2
2023	109.8	4.3	114.1

4.4. Hawaiian Electric Generating Unit Forced Outages

Forced outages and deratings reduce generating unit availability and are accounted for in the EFORd statistic. EFORd, a measure of forced outages and operations in derated conditions, is a subcomponent of generating unit availability – and a key driver in the capacity planning criteria and reserve capacity shortfall calculations. Lower generating unit availability and higher EFORd both contribute to an increase in reserve capacity shortfalls. The definition of EFORd and an example of the application of the EFORd formula is provided in Appendix 2.

Outages for planned work and maintenance will continue to be more numerous and longer in duration than in previous years. Maintenance will continue to be a challenge for the existing units. As the generating units age,[4] they will need to be maintained more often and for longer periods of time. As the demands on existing generating units change to mitigate different resources on the system such as variable generation resources, the generating units operate harder to counteract the increasingly dynamic changes, which increase the likelihood of unscheduled (forced) outages and operations at derated power levels. Generating units that are shut down unexpectedly generally require immediate maintenance. As resources shift to make the emergency repairs, maintenance outage schedules slip, making maintenance scheduling flexibility difficult. In addition, generating units operating in a derated capacity typically cannot be afforded the luxury of a maintenance shutdown to restore the units to full power operations. These units are generally operated for long periods in a derated state.

Table 3 provides the forward looking Hawaiian Electric EFORd data by unit. The forward looking EFORd values utilized in the 2018 AOS analysis are forecasted EFORd expectations for planning purposes based on a combination of historical data, experience, and operational judgment. The EFORd assumption generally reflects the five-year average of the specific unit, or group of similar units. EFORd projections are not certain, however, and actual experience may differ from the projections. It is difficult to forecast EFORd due to unforeseen conditions of aging units, longer planned maintenance schedules, and the operating stress placed on the units. Refer to Appendix 3 for specific generating unit information on EFORd.

[4] Hawaiian Electric's generating units (not including the Campbell Industrial Park combustion turbine installed in 2009) are between 37 and 71 years old. Firm capacity independent power producer ("IPP") units are between 26 and 28 years old excluding Airport DSG.

Table 3: Forward-looking EFORd

AOS EFORd Rates	
	2018 Forward Looking
Honolulu 8	8.5%
Honolulu 9	8.5%
Waiau 3	7.0%
Waiau 4	7.0%
Waiau 5	4.5%
Waiau 6	4.5%
Waiau 7	4.5%
Waiau 8	4.5%
Waiau 9	4.0%
Waiau 10	4.0%
Kahe 1	3.0%
Kahe 2	4.5%
Kahe 3	4.5%
Kahe 4	4.5%
Kahe 5	5.0%
Kahe 6	5.0%
CIP CT-1	3.0%
Schofield	2.0%
HECO	**4.6%**

(Note: Honolulu units 8 and 9 were deactivated in 2014. Forward looking EFORd values for these units are based on historical data and shown for comparison purposes.)

4.5. Planned Maintenance Schedules for the Generating Units on the System

Planned outages and maintenance outages reduce generating unit availabilities. The schedules for planned overhaul and maintenance outages change frequently due to unforeseeable findings during outage inspections or to changes in priorities due to unforeseeable problems. When major revisions to planned and/or maintenance outages occur, the Planned Maintenance Schedule is revised. The uncertainty of future maintenance schedules contributes to future planning uncertainty and may influence the magnitude of reserve capacity surplus or shortfalls.

4.6. Other Inputs

For the purposes of the analysis, DG-PV additions and demand response impacts were included. No future firm or variable resource additions were included, except for the SGS because the project has been approved by the Commission, so that capacity needs could be examined without the addition of future resources. Any future resources to be acquired could contribute to meeting the needs.

4.7. Additions of Capacity

4.7.1. Firm Capacity Additions

The DOT, 8 MW Airport DSG facility was placed in-service and available for Hawaiian Electric's dispatch on June 23, 2017. This capacity was included in the AOS analysis.

On September 30, 2015, in Decision and Order No. 33178 ("D&O 33178"), the Commission approved the SGS project with certain conditions and modifications. It is anticipated that this project will be in service in the 2018 timeframe. This capacity was included in the AOS analysis.

On October 29, 2015, Hawaiian Electric submitted a letter to the Commission providing its detailed outline of tasks necessary to shift its biodiesel use from the CIP Combustion Turbine 1 ("CT-1") to the SGS project in accordance with ordering paragraph 6 of D&O 33178. Following the shift of biodiesel use, Hawaiian Electric intends to use diesel at CIP CT-1. The operating capacity of CIP CT-1 using diesel may increase, subject to performance testing.

4.7.2. Non-Firm Additions

In addition to firm generation power projects, Hawaiian Electric purchases energy on an as-available basis from eleven producers and anticipates adding additional variable generation renewable energy projects to the Hawaiian Electric system in the near future as these facilities achieve commercial operation.

Several variable generation IPPs have power purchase agreements ("PPAs") with Hawaiian Electric and others are in various stages of Commission approval. For example:

On December 12, 2013, in Docket No. 2013-0423, Hawaiian Electric submitted an application for Commission approval of a waiver from the Framework for Competitive Bidding and approval of a PPA with Na Pua Makani Power Partners, LLC, for up to 24 MW of wind power. On December 31, 2014 in Decision and Order No. 32600, the Commission approved a waiver from the Framework for Competitive Bidding, subject to certain conditions set forth therein.

On October 3, 2016, in Docket No. 2016-0342, Hawaiian Electric submitted an application for the development and operation of the 20 MW West Loch PV project. The facility is planned to be located on property leased from the United States Navy in West Loch Annex area of O'ahu. In Decision and Order No. 34676, filed June 30, 2017, the Commission approved the Company's request for a waiver from the Framework for Competitive Bidding for the West Loch PV project, subject to certain conditions set forth therein.

On May 10, 2017, the Commission opened Docket No. 2017-0108 to consolidate three separate letter requests seeking approval of amended and restated power purchase agreements between Hawaiian Electric and NRG Renew LLC for the following projects: (1) 49 MW Kawailoa Solar; (2) 14.7 MW Lanikuhana Solar; and (3) 45.9 MW Waipio PV. On July 27, 2017, in Decision and Order No. 34714, the Commission approved these PPAs, subject to certain conditions set forth therein.

On June 6, 2016, Hawaiian Electric filed a letter with the Commission requesting to open a docket and appointment of an Independent Observer to seek proposals for new renewable energy generation with a target installation date of 2022. On October 6, 2017, the Commission opened Docket 2017-0352 to receive filings, review approval requests, and resolve disputes, if necessary, related to the Company's plan to proceed with a competitive bidding process of variable renewable generation on O'ahu. On October 23, 2017, the Hawaiian Electric Companies filed a draft request for proposals for the equivalent of 220 MW of renewable generation on O'ahu, assumed to be in service by the end of 2022. On January 12, 2018, in Order No. 35224, the Commission provided guidance on the request for proposals process. However, none of this variable renewable generation was assumed in the calculation of reserve margin.

In the *PSIP Update Report: December 2016*, the resource plans show community based renewable energy (CBRE) additions of 15 MW of PV and 10 MW of wind by the end of 2018. On December 22, 2017 the Commission issued Decision and Order No. 35137, in Docket No. 2015-0389 indicating a 5 MW PV block for the first phase of a CBRE program for O'ahu. However, this addition was not assumed in the calculation of reserve margin.

4.8. Reductions of Firm Generating Capacity

4.8.1. Honolulu Units 8 and 9 Deactivation

Honolulu Units 8 and 9 (with a combined rating of 107.3 MW-net) were deactivated on January 31, 2014. The 2018 AOS reference scenario reflects the Honolulu generating units remaining deactivated, and their capacities are not included in the analysis.

4.8.1.1 Reactivation Option

Deactivated units may be reactivated in the event of an emergency and/or to mitigate reserve capacity shortfalls. Reserve capacity shortfalls may occur for a variety of reasons including unexpected long-term outages of generating units or existing PPAs with IPPs for firm capacity being terminated or not being renegotiated and extended. In the case of Honolulu Units 8 and 9, reactivation would take approximately three months. In the event a situation warranted the reactivation of any deactivated units, the Company would inform the Commission accordingly and provide details supporting the basis for the need for such reactivation and its planned course of action.

4.8.3. Capacity from AES Hawaii, Inc.

The existing PPA with AES expires on September 1, 2022. For the purposes of the 2018 AOS analysis, it is assumed that the capacity from AES is 180 MW through the end of the contract term.

4.9. Capacity from Kalaeloa Partners, L.P., Combined Cycle Unit

The existing PPA with KPLP expired on May 23, 2016. The PPA states:

> *[S]hould the original Term end with the parties hereto actively negotiating for the purchase of the Facility or the Net Electric Energy Output of the Facility, then such Term shall be automatically extended on a month-to-month basis under the same terms and conditions as contained in this Agreement for so long as said negotiations continue in good faith. The month-to-month term extensions shall end sixty (60) days after either party notifies the other in writing that said negotiations have terminated.*

On November 10, 2011, Hawaiian Electric submitted to the Commission a Petition for Declaratory Order regarding the Exemption of KPLP's project from the Framework for Competitive Bidding, or in the alternative, Approval of Application for Waiver from the Framework for Competitive Bidding. On May 14, 2012, in Decision and Order No. 30380, the Commission declared that the proposed renegotiation of the amended PPA is exempt from the competitive bidding process. The PPA, as amended, automatically extends on a month-to-month basis as long as the parties are still negotiating in good faith. Hawaiian Electric and Kalaeloa have agreed that neither party will terminate the PPA prior to October 31, 2018.

For the purposes of the 2018 AOS analysis, it is assumed that the 208 MW of capacity provided by KPLP remains in service beyond 2017.

5. Scenario Analysis

5.1. Description of Scenarios

In energy planning uncertainty is an important aspect. Therefore, a range of forecasts was considered in the analysis. Descriptions of the various planning scenarios are provided below:

- Reference Scenario
- Higher load forecast (60 MW increase in peak load)
- Revised system reliability guideline – Increased stringency of Hawaiian Electric's generating system reliability guideline from 4.5 years per day to 10 years per day

A scenario using a lower load forecast was not performed in the analysis. However, should lower loads occur in the future, it may provide more certainty regarding decisions to deactivate or decommission existing generation units.

A reference scenario consisting of assumptions such as Honolulu Units 8 and 9 remaining deactivated and are not counted towards capacity, no other unit deactivations, KPLP remaining in service, and SGS included from May 2018, serves as the resource plan to which the following scenarios can be compared.

5.1.1. Higher Load Forecast

The Higher Load Scenario uses the assumption that the system peaks are higher by 60 MW. Such a scenario is possible if energy usage is higher than projected due to hotter or more humid than average weather conditions, lower than anticipated adoption of energy efficient measures and practices and/or an upswing in the economy as compared to the forecast occurs in the future. A 60 MW higher peak load is roughly equivalent to one standard deviation over a 20-year period of historical peaks. Table 4 summarizes the Higher Load Scenario peak requirements.

Table 4: Higher Load Scenario

Year	2018 AOS Jun 2017 S&P Forecast Update (MW)	60 MW higher Jun 2017 S&P Forecast Update (MW)	Difference (MW)
2018	1,248	1,308	60
2019	1,257	1,317	60
2020	1,260	1,320	60
2021	1,269	1,329	60
2022	1,267	1,327	60
2023	1,247	1,307	60

5.1.2. Revised System Reliability Guideline

Another potential means to address the ever-increasing planning uncertainty and complexity is to revise the capacity planning guideline. As explained in Section 3.1.2, Hawaiian Electric currently uses a reliability guideline threshold of 4.5 years per day. If the existing LOLP of 4.5 years per day does not provide an adequate cushion to respond to quickly-changing parameters, such as changes in peak demand and individual unit availability factors, many of which may change rapidly from year to year, then the utility could plan for a higher reliability standard similar to that of many mainland utilities. Such an approach would not eliminate quickly-changing parameters, but it would add a measure of conservatism in recognition that the uncertainties undoubtedly exist.

Hawaiian Electric performed a high-level evaluation using a more stringent reliability guideline of 10 years per day. The purpose of this analysis was to determine the amount of firm capacity that would be required to meet this higher reliability guideline. The results of this high-level evaluation are shown in Section 5.2.

5.2. Results of Analysis

Table 5 shows the capacity, in MW, in excess of the amount needed to satisfy Rule 1 of the capacity planning criteria. The analysis shows that Rule 1 is satisfied for the reference scenario for each year through 2023 under a reference set of assumptions including, but not limited to: (1) continued residential and commercial load management impacts at the levels described in Table 2; and (2) continued acquisition of third-party energy efficiency. However, as previously explained, Rule 1 results are deterministic and do not incorporate unit specific EFORd rates in their calculation.

Table 5: Rule 1 Analysis

Year	Rule 1 Results (MW)
2018	30
2019	117
2020	50
2021	98
2022	51
2023	96

The LOLPs for the reference and planning scenarios were calculated using a production simulation model for each year.

In 2018, 2022, and 2023, the generating system reliability is projected to be less than 4.5 years per day in the reference scenario. Based on the Company's June 2017 S&P forecast, Hawaiian Electric's firm generating capacity, which does not include intermittent energy sources such as wind and solar, may not be sufficient to meet projected peak demand in 2018, 2022, and 2023. Reactivation of Honolulu Units 8 and 9 may alleviate, or remove, the future projected reserve capacity shortfalls.

Table 6 shows the results of the Generation System Reliability analysis. The system reliability in the scenarios shown varies depending on the firm generating units available, and the planned maintenance schedules.

Table 6: Generation System Reliability Guideline (years/day)

Generation System Reliability (years/day)			
Year	Reference Scenario	Higher Load (Add 60 MW)	10 yrs/day reliability scenario
2018	1.5	0.4	1.5
2019	5.0	1.3	5.0
2020	6.2	1.7	6.2
2021	12.3	3.1	12.3
2022	1.7	0.5	1.7
2023	2.1	0.5	2.1

Table 7 shows the reserve capacity surpluses or shortfalls corresponding to the calculated reliability shown in Table 6. Reserve capacity shortfall, shown as a negative number, is the approximate amount of additional firm capacity needed to restore the generating system LOLP to be greater than the 4.5 years per day reliability guideline. A positive number indicates the amount of capacity over and above that amount needed to satisfy the 4.5 years per day reliability guideline. For example, in the reference scenario for 2022, the number -50 would indicate that about 50 MW of firm generating capacity would have to be added, in order for the expectation of not being able to satisfy demand due to insufficient generation occurs no more than once every 4.5 years.

Table 7: Reserve Capacity Shortfall for reference and planning scenarios (MW)

		Alternate Scenario	
Year	Reference Scenario	Higher Load (Add 60 MW)	10 yrs/day reliability scenario
2018	-60	-120	-90
2019	0	-60	-40
2020	10	-50	-30
2021	40	-20	0
2022	-50	-110	-80
2023	-40	-100	-70

(Note: Negative values indicate a shortfall of generating capacity; positive values indicate a surplus of generating capacity)

The forecasts and analysis for 2018, 2022, and 2023 indicate that there may be insufficient generation available for reasonable emergencies and reserve capacity.

The results indicated for the 2018-2023 timeframe are based on present day assumptions, and will change as the Hawaiian Electric system transforms into the future. The capacity shortfalls identified in this period are influenced by a set of assumptions, including but not limited to: (1)

continued implementation of third party energy efficiency; (2) forward-looking maintenance schedules and unit availability that will change in the years ahead; and (3) the extent to which new generating capacity is added.

The analysis shows that the reserve capacity shortfall is sensitive to the load forecast. In the case of the Higher Load Scenario, a nominal 60 MW increase in the forecasted load resulted in a 60 MW reduction to projected reserve capacity for all years (2018-2023). Expectations regarding future loads can change quickly, and Hawaiian Electric may not be able to respond quickly to increases in demand. This illustrates the importance of using scenario analysis as a planning tool.

Table 7 further projects that approximately 120 MW of firm capacity would have to be added to the Hawaiian Electric system to achieve a higher reliability guideline of 10 years/day. The approximate 30 to 40 MW difference between the 4.5 years/day reference scenario and the 10 years/day Scenario to achieve higher levels of reliability is a non-linear relationship between MW capacity added and improvement in LOLP.

6. Mitigation Measures for Near-Term Reserve Capacity Shortfall (2018)

As a result of the projected reserve capacity shortfalls, Hawaiian Electric has considered a number of actions to minimize the risk of generation-related shortfalls. These include implementing expanded DR programs once approved, refinement of maintenance schedules, issuing calls for conservation, reactivation of the Honolulu Units 8 and 9, and procurement of temporary generation.

6.1. Implement Demand Response Programs

Hawaiian Electric will implement its DR portfolio plan in accordance with Docket No. 2015-0412, and as discussed in Section 4.3 above.

6.2. Refinement of Maintenance Schedule

Scheduling maintenance requires consideration of many different operational factors. Maintenance scheduling can be expected to be adjusted several times over the year due to changing operational factors. In the event of reserve capacity shortfalls, rearranging maintenance schedules should be considered as a mitigation measure.

6.3. Call for Conservation

Hawaiian Electric may request voluntary customer curtailment of demand during capacity reserve shortfall conditions.

6.4. Reactivation of Honolulu 8 & 9

Honolulu Units 8 and 9 are currently in a deactivated state. Hawaiian Electric may consider reactivation of these steam generating units in the event that system conditions warrant such measures. In their current deactivated state, the generating units would require several months to restore them to operating conditions.

6.5. Temporary Generation

In the event that severe or prolonged reserve capacity shortfalls are anticipated, temporary emergency DG could be installed. In the mid-2000s, Hawaiian Electric experienced significant reserve capacity shortfalls and installed 30 MW of DG at substation and other sites. These temporary units were removed after the installation of CIP CT-1.

7. Conclusions

Hawaiian Electric's reserve capacity may not be sufficient to meet the Company's generating system reliability guideline of 4.5 years per day in 2018, 2022, and 2023. However, Hawaiian Electric anticipates that mitigation measures can be implemented to satisfy the projected reserve capacity shortfalls. This assumes the SGS is in service from 2018.

As indicated in Section 4.5, Hawaiian Electric is anticipating the addition of approximately 50 MW of utility owned and operated, firm, dispatchable generation (SGS) in 2018.

The scenario analysis indicates that depending on system conditions, Hawaiian Electric may experience anywhere from a 60 MW reserve capacity shortfall under the reference scenario to a 120 MW reserve capacity shortfall in the Higher Load Scenario in the timeframe analyzed. Hawaiian Electric may seek to mitigate future capacity needs in 2022 and beyond by increasing DR programs, refining maintenance schedules, reactivating units that are currently deactivated, or acquiring additional firm capacity.

Hawaiian Electric will continue its portfolio approach to meet its obligation to serve, which includes increased renewable energy contributions, DSM programs, energy storage resources, and the pursuit of firm capacity and non-firm supply side options. Hawaiian Electric also recognizes that the environment for resource planning has increased in complexity and uncertainty.

Very truly yours,

Joseph P. Viola
Vice President
Regulatory Affairs

Attachments
c: Division of Consumer Advocacy (with Attachments)

Table A1:
Projected Reserve Margins for the Reference Case

Year	System Capability at Annual Peak Load (net MW) [A] (I)	System Peak (net MW) [B] (II)	Interruptible Load (net MW) [C] (III)	Reserve Margin (%) [A-(B-C)] / (B-C)
2017	1,679	1,209	18	41%
2018	1,745	1,248	18	42%
2019	1,745	1,257	27	42%
2020	1,745	1,260	48	44%
2021	1,745	1,269	74	46%
2022	1,565	1,267	98	34%
2023	1,565	1,247	114	38%

Notes:

I. System Capability includes:
- Hawaiian Electric central station units at total normal capability in 2017 was 1,214.3 MW-net.
- Airport DSG (8 MW).
- Firm power purchase contracts with a combined net total of 465.5 MW in 2017 from KPLP (208 MW), AES Hawaii (180 MW), and H-POWER (68.5 MW.
- Honolulu Units 8 and 9 were deactivated in 2014 (-107.3 MW)
- KPLP assumed to continue in service after 2017
- Expected addition of the SGS project in 2018 (48.8 MW)
- Following the addition of the SGS project in 2018, CIP CT-1 is anticipated to switch its primary fuel to diesel. The unit rating for CIP CT-1 consuming diesel is expected to increase from 113 MW to 130 MW subject to testing.

II. System Peaks
- The 2018-2023 annual forecasted system peaks are based on Hawaiian Electric's June 2017 S&P Forecast.
- The forecasted System Peaks for 2018-2023 include the estimated peak reduction benefits of third-party energy efficiency DSM programs.
- The peak for 2018-2023 includes approximately 27 MW of stand-by load
- The Hawaiian Electric annual forecasted system peak is expected to occur in the month of October.

III. Interruptible Load:
- Interruptible Load impacts are at the net-to-system level, and are approximate impacts at the system peak.

Equivalent Demand Forced Outage Rate Definition and Formula

As defined in IEEE Std-762-2006,[5] Section 3.8:

Equivalent Demand Forced Outage Rate (EFORd): A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.

EFORd is defined in the NERC GADS Data Reporting Instructions,[6] Appendix F as:

$$\text{EFORd} = \frac{[\text{FOHd} + (\text{EFDHd})]}{[\text{SH} + \text{FOHd}]} \times 100\%$$

where

FOHd = f x FOH
EFDHd = (EFDH – EFDHRS) if reserve shutdown events reported, or
= (fp x EFDH) if no reserve shutdown events reported – an approximation.
fp = (SH/AH)

$$f = \left(\frac{1}{r} + \frac{1}{T}\right) / \left(\frac{1}{r} + \frac{1}{T} + \frac{1}{D}\right)$$

r=Average Forced outage deration = (FOH) / (# of FO occurrences)
D=Average demand time = (SH) / (# of unit actual starts)
T=Average reserve shutdown time = (RSH) / (# of unit attempted starts)

An example of the application of the EFORd formula to Hawaiian Electric's Waiau 9 generating unit in 2012 is shown below:

	Service Hours	Reserve Shutdown Hours	Available Hours				Equivalent Forced Derated Hours	Forced Outage Hours	
Capacity	SH	RSH	AH	Actual Starts	Attempted Starts	Failed Starts	EFDH	FOH	FO Events
53	67	7002.14	7069	26	27	1	0.00	1,067.26	5

=1/(1067/5)	=1/(7002/27)	=1/(67/26)		=0.021397 *1067	=67/7069	=0.009416*0		=(22.84/(67+22.84)) *100	=(1067/(1067+67)) *100
1/r	1/T	1/D	f	fxFOH	fp	fp x EFDH	EFORd x MW	**EFORd**	**EFOR**
0.004685	0.003856	0.390625	0.021397	22.83591142	0.009416	0	1,353.87	**25.54**	**94.1**

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[5] http://www.nerc.com/docs/pc/gadstf/ieee762tf/762-2006.pdf
[6] http://www.nerc.com/page.php?cid=4|43|45

Hawaiian Electric Equivalent Demand Forced Outage Rate ("EFORd") Discussion

It is extremely difficult to predict unit-specific EFORd rates, as indicated by the variation in historical data. Nonetheless, for planning purposes it is necessary to estimate forward-looking EFORd rates. This is accomplished using a blend of historical data, experience, and judgment. Hawaiian Electric has used a few different methods in determining unit specific EFORd numbers. Generating units are, at any giving time, in various stages of their maintenance plan. Different outage rates are expected following unit overhauls compared to the period prior to unit overalls. Similarly due to changing system needs, Hawaiian Electric responds differently to forced outages/derates. When forced outages or derates occur, Power Supply evaluates the impacts to the system and responds accordingly. For example, when forced outages or derates do not impact system reliability, Power Supply will not expend significant amount of overtime to restore the unit. These decisions impact actual EFORd, but not actual material condition of the plants. Therefore, Hawaiian Electric has attempted to normalize variations by comparing similar generating units over a five year period, with some exceptions, consider the cause/remedy of actual events, and consider actual unit material condition. Hawaiian Electric retains the ability to respond to forced outages/derates as has been done historically. Therefore, from an adequacy of supply perspective, historic EFORd alone does not represent an appropriate forward looking number for planning purposes. Table A2 provides recorded Hawaiian Electric EFORd data used as the basis for forward looking EFORd. The rationalization for the selection of EFORd numbers to be used in the 2018 AOS analysis is discussed below:

Table A2:
Historical EFORd

	Recorded EFORd				
	2013	**2014**	**2015**	**2016**	**2017**
Honolulu 8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Honolulu 9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Waiau 3	13.7%	33.2%	37.4%	4.4%	3.8%
Waiau 4	1.7%	5.0%	5.5%	11.3%	11.7%
Waiau 5	1.4%	3.5%	6.3%	7.2%	18.0%
Waiau 6	2.4%	7.2%	24.2%	4.9%	2.8%
Waiau 7	1.6%	0.0%	1.0%	12.0%	6.7%
Waiau 8	4.7%	6.7%	5.0%	7.2%	16.4%
Waiau 9	2.1%	0.9%	12.5%	12.0%	4.3%
Waiau 10	7.1%	3.4%	3.1%	9.4%	2.9%
Kahe 1	0.6%	2.8%	5.1%	3.3%	2.4%
Kahe 2	3.1%	10.6%	8.4%	11.4%	15.7%
Kahe 3	1.3%	2.2%	9.3%	5.3%	11.3%
Kahe 4	2.3%	9.0%	4.1%	2.6%	4.4%
Kahe 5	2.3%	6.1%	14.1%	4.0%	3.5%
Kahe 6	12.8%	1.8%	29.1%	3.9%	3.3%
CIP CT-1	0.7%	9.0%	0.6%	3.2%	3.3%
HECO	**3.4%**	**5.9%**	**10.2%**	**5.2%**	**6.0%**

1. Honolulu Units 8 and 9

In the 2015 AOS analysis, the forward looking EFORd of 8.5% included the actual average of 5 years for both Honolulu Units 8 and 9. Honolulu Units 8 and 9 are similar units at a similar juncture in their maintenance strategy. Honolulu Units 8 and 9 are in a deactivated state. It is assumed that if they were to be reactivated they would operate and be maintained in a similar to that of pre-deactivation. Therefore, Honolulu Units 8 and 9 will have an EFORd of 8.5% for forwarding looking analysis and are shown for comparison purposes.

2. Waiau Units 3 and 4

The actual EFORds in 2017 for Waiau Unit 3 & 4 was 3.8 % and 11.7 %, respectively. Waiau Units 3 and 4 are classified as limited use units under our compliance plan with Mercury and Air Toxic Standards (MATS) compliance plans. Hawaiian Electric attempts to keep the capacity factors of Waiau Units 3 and 4 below 8%. This status can and will be changed if system requirements dictate. Nonetheless, with the limited use intentions, age, material condition of these units and planned deactivation, Hawaiian Electric believes a forward looking EFORd of 7% for AOS purposes is appropriate.

3. Waiau Units 5 and 6

The actual EFORds in 2017 for Waiau Units 5 and 6 were 18.0% and 2.8%, respectively. Waiau 5 experienced equipment failure that resulted in a long outage. The condition is considered a onetime event and therefore discounted in consideration of forward looking EFORd for AOS purposes. Based on age, material condition, number of anticipated starts, and increased "cycling rate"[7] Hawaiian Electric believes a forward looking EFORd of 4.5% for AOS purposes is appropriate.

4. Waiau Unit 7, Waiau Unit 8, Kahe Unit 3, and Kahe Unit 4

These four units are of similar size, design, and vintage, and are dispatched as baseloaded units with similar duty cycles. They also have a similar maintenance strategy although each unit is at a different spot in its maintenance cycle. The actual 2017 EFORd for Waiau 7, Waiau 8, Kahe 3, and Kahe 4 was 6.7%, 16.4%, 11.3%, and 4.4% respectively. With the increased penetration of variable renewable generation these units have lower capacity factors, operate at new low loads, and have increased ramp rates. It is expected that this more severe service coupled with the units age and material condition may result in more force outage and forced derate events. Additional potential complications with MATS may also affect EFORd. Therefore, a forward looking EFORd of 4.5% for AOS purposes is appropriate.

[7] Cycling Rate is defined as the number of starts per 1,000 service hours.

5. Waiau Units 9 and 10

The actual EFORds in 2017 for Waiau Units 9 and 10 were 4.3% and 2.9%, respectively. Hawaiian Electric places higher degree of focus on reliably of CTs as a result of changing system needs. Based on age, anticipated starts, and service conditions Hawaiian Electric believes a forward looking EFORd of 4.0 for AOS purposes is appropriate.

6. Kahe Units 1 and 2

The actual EFORds in 2017 for Kahe Unit 1 and 2 were 2.4% and 15.7%, respectively. Kahe 2 experienced equipment failure that was corrected and considered a onetime event. Therefore the 15.7% EFORd is being discounted in the consideration of forward looking EFORd for AOS purposes. With the increased penetration of variable renewable generation these units have lower capacity factors, operate at new low loads, and have increased ramp rates. It is expected that this more severe service coupled with the units age and material condition may result in more force outage and forced derate events. Additional potential complications with MATS may also affect EFORd. Therefore, a forward looking EFORd for Kahe 1 and 2 of 3.0% and 4.5% is appropriate. Kahe 1 has a lower forward looking EFORd due to the fact that it will undergo a turbine/boiler overhaul in 2018. Additionally, the unit has boiler feed pump variable frequency drives which may assist in minimizing some of the effects of low load operation to associated pumps and valves.

7. Kahe Units 5 and 6

The actual EFORds in 2017 for Kahe Units 5 and 6 were 3.5% and 3.3%, respectively. Kahe 5 and 6 will experience lower capacity factors associated with the increased penetration of variable renewable generation. The increased time at lower load affects these units more than the others due in part to the challenges associated with MATS. Therefore, a forward looking EFORd more consistent with historic operations is considered appropriate. The forward looking EFORd for Kahe units 5 and 6 of 5% is appropriate for AOS purposes...

8. CIP CT-1

The actual EFORd in 2017 for CIP CT-1 was 3.3%. For the 2018 AOS analysis, it was recognized that CTs continue to play an increasingly important role in system reliability. After considering material condition and focus on CTs, Hawaiian Electric believes the forward looking 3.0% EFORd for AOS purposes is appropriate.