**Hawaiian Electric Company, Inc.** • PO Box 2750 • Honolulu, HI 96840-0001

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PUBLIC UTILITIES COMMISSION

Darcy L. Endo-Omoto
*Vice President*
*Government & Community Affairs*

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Adequacy of Supply
Hawaiian Electric Company, Inc. ("Hawaiian Electric" or "HECO")

The following information is respectfully submitted in accordance with paragraph 5.3a. of General Order No. 7[1] 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.*

## 1. Peak Demand and System Capability in 2010

Hawaiian Electric's 2010 system peak occurred on Thursday, October 21, 2010, and was 1,200,000 kW-gross or 1,162,000 kW-net based on net Hawaiian Electric generation, net purchased power generation, the peak reduction benefits of energy efficiency demand-side management programs, and with several cogenerators[2] operating at the time. Had these

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[1] Hawaiian Electric's Adequacy of Supply ("AOS") Report is due within 30 days after the end of the year. On January 25, 2011, Hawaiian Electric requested an extension of time, to no later than February 17, 2011, to file its AOS Report to allow it to better assess and incorporate the impacts of its most recent generation availability experience to determine the estimated reserve margin capacity situation for the period covered by this letter. The Commission granted Hawaiian Electric's extension by letter dated January 31, 2011.

[2] At the time of the peak, certain units at Tesoro, Chevron, and Pearl Harbor were generating about 25,000 kW of power for use at their sites.

cogenerating units not been operating, the 2010 system peak would have been approximately 1,225,000 kW-gross or 1,187,000 kW-net.

Hawaiian Electric's 2010 total generating capability of 1,755,600 kW-net includes 434,000 kW-net of firm power purchased from (1) Kalaeloa Partners, L.P. ("Kalaeloa"), (2) AES Hawaii, Inc. ("AES"), and (3) H-POWER.

On April 29, 2010, Hawaiian Electric removed from service 29.5 MW of temporary distributed generation units that were part of the generating fleet since 2005. Oahu had a reserve margin of approximately 53% over the 2010 adjusted system net peak.[3]

Hawaiian Electric also has power purchase contracts with five as-available energy producers. Since these contracts are not for firm capacity, they are not reflected in Hawaiian Electric's total firm generating capability.

2. Estimated Reserve Margins

Appendix 1 shows the expected reserve margin over the next ten years, 2011-2020 based on Hawaiian Electric's May 2010 Sales and Peak Forecast, and includes estimated energy efficiency demand-side management ("DSM") impacts and forecasted load management DSM impacts.

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 demand-side management programs, (b) net energy metering, and (c) customer-site photovoltaic ("PV") installations; [§4.1]
- peak reduction benefits of load control programs; [§4.2]
- planned maintenance schedules for the generating units on the system; [§4.3]
- Equivalent Forced Outage Rates ("EFOR") on the generating units; [§4.3]

[3] The reserve margin calculation takes into account the approximately 38,700 kW of interruptible load at system peak served by Hawaiian Electric.

- additions of firm generating capacity; [§4.4] and
- reductions of firm generating capacity. [§4.5]

Each of the current assumptions for these factors is discussed in Section 4. As with all forecasts, these elements are subject to uncertainties. Therefore, a range of scenarios was considered in the analysis.

3.1 Hawaiian Electric's Capacity Planning Criteria

Hawaiian Electric's capacity planning criteria consist of two rules 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 EFORs of each generating unit, the load to be served, the amount of capacity on the system and the availability of the generating units.

Rule 1:

*The total capability of the system plus the total amount of interruptible loads 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;*

*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.*

Rule 2:

*There must be enough net generation running in economic dispatch so that the sum of the three second quick load pickup power available from all running units, not including the most heavily loaded unit, plus the net loads of all other running units must equal or exceed 95 percent of the hourly system net load (which excludes power plant auxiliary loads but includes T&D losses). This is based on a minimum allowable system frequency of 58.5 Hz and assumes a 2 percent reduction in load for each 1 percent reduction in frequency.*

The two rules include 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.

Rules 1 and 2 are deterministic in nature, meaning that the adequacy of supply can be determined through simple additions or subtractions of capacity without regard to the probability that the capacity will be available at any given time. For example, to determine whether or not Rule 1 would be satisfied at a given point in time, one would take in MW, the total capacity of the system, add the total amount of interruptible loads that would be available for interruption at that time, subtract the capacity of the unit or units that are unavailable due to planned maintenance, subtract the capacity of the largest available unit, and determine whether the result is greater than or less than the system peak at that time. If the result is greater than the system peak, Rule 1 would be satisfied and no additional firm capacity would be needed. If the result is less than the system peak, Rule 1 would not be satisfied and additional firm capacity would be needed. The likelihood (or probability) that the largest unit will be lost from service during the peak is not a factor in the application of this rule.

Rule 2 takes into account the amount of quick load pickup that must be available at the time of the peak to avoid shedding load from the system in the event the largest loaded unit is unexpectedly lost from service. Rule 2 is also deterministic in nature. It does not take into account the probability that the largest unit will be lost from service during the peak.

3.2 Hawaiian Electric's Reliability Guideline: Loss of Load Probability ("LOLP")

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

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 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 ever increasing planning uncertainty and complexity is to revise the capacity planning guideline. If the existing Loss of Load Probability 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 Generating Station and Transmission Additions Project (Docket No. 05-0145), filed on August 17, 2006, the Consumer Advocate stated:

> [HECO'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.

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.

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

## 4. Key Inputs to the 2011 AOS Analysis

### 4.1 May 2010 Sales and Peak Forecast

Hawaiian Electric developed a short-term sales and peak forecast in May 2010 ("May 2010 forecast"), which was subsequently adopted by the company. The system peaks beyond 2015 are extrapolated based on growth rates from Hawaiian Electric's August 2007 long-term forecast.

Figure 1 illustrates Hawaiian Electric's historical system peaks and compares them to the forecast used in the 2010 and 2011 AOS analyses. The analyses contained in the 2010 AOS were based on a December 2009 updated sales and peak forecast.

Figure 1: Recorded Peaks and Future Year Projections

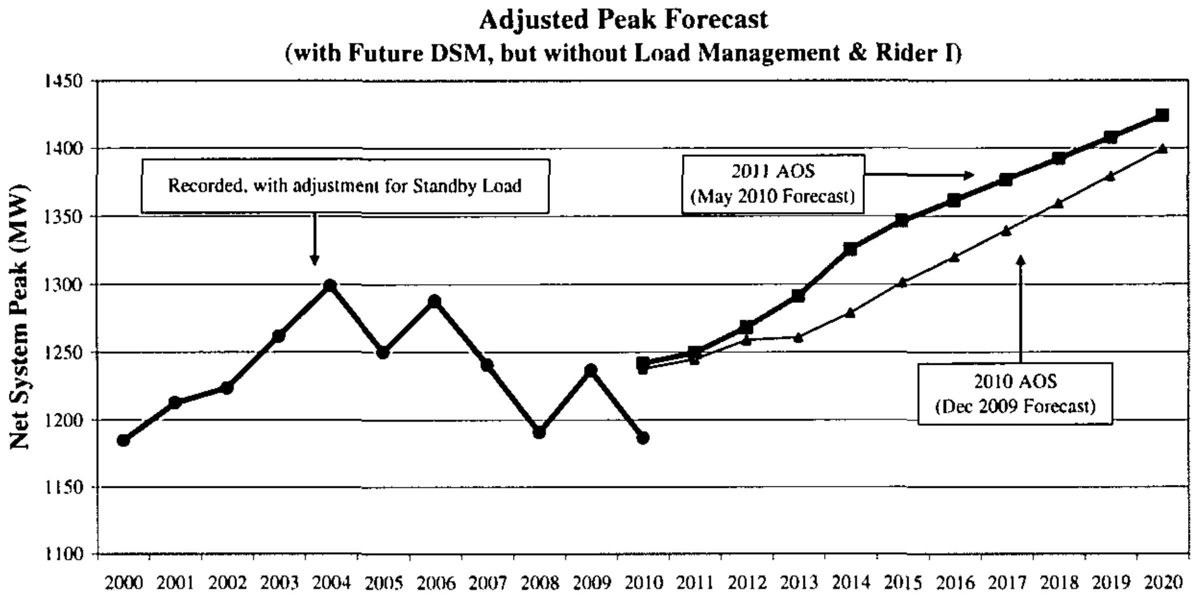


Table 1 compares the historical, 2010 AOS and 2011 AOS forecasts and projections. The comparison between forecasts indicate the degree to which key planning assumptions such as the peak forecast can quickly and unexpectedly change. For both the recorded and forecast data, figures reflect an upward (stand-by) adjustment to account for the potential need to serve certain large customer loads (Chevron, Tesoro and Pearl Harbor) that are frequently served by their own internal generation. Figure 1 includes the peak reduction benefits of energy efficiency DSM programs and naturally occurring conservation. The forecast also includes the impact of customer sited photovoltaic ("PV") and other renewable generation system installations through the Net Energy Metering ("NEM") program and Standard Interconnection Agreements ("SIA") in the derivation of sales. NEM and SIA installations are assumed to reduce sales and day peaks only. The combined NEM and PV forecasts are shown in Table 2 are expected to offset some of the growth from economic recovery. Feed-In Tariff and purchased power agreements were not included in this forecast.

Table 1: Recorded Peaks and Future Year Projections

| **Net System Peak (MW) (with Future DSM, but without Load Management & Rider I)** | | | | | |
|---|---|---|---|---|---|
| Year | Actual | Actual Adj for Standby | 2010 AOS Dec 2009 S&P | 2011 AOS May 2010 S&P | Difference 2011-2010 AOS |
| 2000 | 1164 | 1185 | | | |
| 2001 | 1191 | 1213 | | | |
| 2002 | 1204 | 1224 | | | |
| 2003 | 1242 | 1262 | | | |
| 2004 | 1281 | 1299 | | | |
| 2005 | 1230 | 1250 | | | |
| 2006 | 1265 | 1288 | | | |
| 2007 | 1216 | 1241 | | | |
| 2008 | 1186 | 1191 | | | |
| 2009 | 1213 | 1237 | | | |
| 2010 | 1162 | 1187 | 1,238 | 1,242 | 4 |
| 2011 | | | 1,245 | 1,250 | 5 |
| 2012 | | | 1,259 | 1,268 | 9 |
| 2013 | | | 1,261 | 1,291 | 30 |
| 2014 | | | 1,279 | 1,326 | 47 |
| 2015 | | | 1,301 | 1,347 | 45 |
| 2016 | | | 1,320 | 1,362 | 41 |
| 2017 | | | 1,340 | 1,377 | 37 |
| 2018 | | | 1,359 | 1,392 | 33 |
| 2019 | | | 1,379 | 1,408 | 29 |
| 2020 | | | 1,399 | 1,424 | 24 |

Table 2: Interconnection & NEM Projections
May 2010 Sales Forecast

| | kW Installs * | | Annual (Ramped) |
|---|---|---|---|
| | kW | Cumulative | kWh reduction |
| 2010 | 7,912 | 7,912 | 4,738,792 |
| 2011 | 18,093 | 26,004 | 20,898,188 |
| 2012 | 9,351 | 35,355 | 44,306,182 |
| 2013 | 18,972 | 54,328 | 65,214,706 |
| 2014 | 10,865 | 65,193 | 87,413,899 |
| 2015 | 22,232 | 87,425 | 111,249,106 |

* Note: Peak impact is assumed to be limited to system day peaks.
Assumed a day peak impact of 10% of the total rated array capacity (based on ability of PV systems to generate at least this amount of energy during cloudy periods).

4.2. Projected Peak Reduction Benefits of Load Control Programs

Hawaiian Electric continues to administer the Commercial & Industrial Load Control ("CIDLC") and Residential Direct Load Control ("RDLC") programs. However, in its Decision and Orders in Docket Nos. 2009-0073 and 2009-0097, dated December 29, 2009, for the CIDLC and RDLC Programs, respectively, the Commission extended the programs through December 31, 2012, but denied Hawaiian Electric's request, without prejudice, to expand the programs at that time. Hawaiian Electric intends to request Commission approval for expansion of these and other demand response programs in the near future.

Hawaiian Electric estimates it had approximately 17.8 MW (net generation level) of controlled load under its CIDLC program, and approximately 16.6 MW (net generation level) of controlled load under its RDLC program at the time of the system peak in October 2010. Table 3 shows the forecast of the peak reduction benefits from its existing and future load management programs[4] predicated upon Commission approval of the expansion of these programs.

[4] Forecasted impacts available at system peak at the net-to-system level.

Table 3: Projected Commercial, Residential and Rider I Impacts (MW)[5]

| Year | Residential | Commercial | Rider I | Total |
|---|---|---|---|---|
| 2011 | 17 | 21 | 4 | 42 |
| 2012 | 17 | 24 | 4 | 45 |
| 2013 | 20 | 31 | 4 | 56 |
| 2014 | 24 | 37 | 4 | 66 |
| 2015 | 28 | 42 | 4 | 74 |
| 2016 | 28 | 38 | 4 | 70 |
| 2017 | 28 | 38 | 4 | 70 |
| 2018 | 28 | 38 | 4 | 70 |
| 2019 | 28 | 38 | 4 | 70 |
| 2020 | 28 | 38 | 4 | 70 |

4.3. Hawaiian Electric Generating Unit Forced, Planned and Maintenance Outages

Forced outages and de-ratings reduce generating unit availability and are accounted for in the EFOR statistic. Planned outages and maintenance outages also 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 extensions to planned outages occur, or problems are discovered such that an outage is needed to address it, or if forced outages occur, the Planned Maintenance Schedule must be revised.

Table 4 provides recorded Hawaiian Electric EFOR data by unit for the period 2006-2010. These EFOR values are utilized in the 2011 AOS analysis, and are based on a combination of historical data, experience, and operational judgment. Table 4 also illustrates the EFOR projections for the Independent Power Producers used in the 2011 AOS analysis. The EFOR assumption generally reflects the 5-year average of the specific unit, or group of similar units. EFOR projections are uncertain, however, and actual experience may differ from the projections made. Refer to Appendix 2 for additional information on EFOR.

[5] The values in Table 2 reflect, for planning purposes, the cumulative amount of load available for interruption at the net-to-system level. The CIDLC program has a limit of 300 cumulative hours that each contracted load can be interrupted in a year, which is taken into account in the loss of load probability calculations reflected in Table 8.

Table 4: Historical and Forward-looking EFOR

| | Recorded | | | | | AOS EFOR Rates |
|---|---|---|---|---|---|---|
| | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** Forward Looking |
| **Honolulu 8** | 3.1% | 2.0% | 17.8% | 4.1% | 33.1% | 15.1% |
| **Honolulu 9** | 25.8% | 25.3% | 11.1% | 6.6% | 21.9% | 15.1% |
| **Waiau 3** | 24.0% | 19.6% | 23.3% | 1.4% | 6.7% | 15.0% |
| **Waiau 4** | 27.2% | 7.9% | 13.7% | 9.6% | 1.4% | 12.0% |
| **Waiau 5** | 1.7% | 4.3% | 11.7% | 4.1% | 2.5% | 4.7% |
| **Waiau 6** | 9.2% | 11.2% | 1.2% | 0.0% | 0.3% | 4.7% |
| **Waiau 7** | 1.1% | 4.2% | 20.7% | 2.4% | 0.1% | 5.2% |
| **Waiau 8** | 18.5% | 3.9% | 2.9% | 1.9% | 1.3% | 5.2% |
| **Waiau 9** | 14.5% | 11.7% | 24.3% | 6.2% | 0.9% | 10.9% |
| **Waiau 10** | 26.2% | 7.6% | 14.3% | 1.6% | 1.6% | 10.9% |
| **Kahe 1** | 1.6% | 0.4% | 4.6% | 2.3% | 0.7% | 3.6% |
| **Kahe 2** | 0.9% | 7.5% | 1.6% | 7.6% | 8.8% | 3.6% |
| **Kahe 3** | 2.1% | 7.7% | 0.7% | 3.8% | 3.9% | 5.2% |
| **Kahe 4** | 1.4% | 6.1% | 4.7% | 7.0% | 10.3% | 5.2% |
| **Kahe 5** | 3.1% | 2.5% | 0.3% | 9.0% | 1.1% | 3.2% |
| **Kahe 6** | 2.8% | 0.4% | 2.1% | 3.3% | 1.9% | 2.1% |
| **CIP CT-1** | | | | 22.0% | 16.0% | 15.0% |
| **HECO** | **5.3%** | **5.1%** | **5.6%** | **5.0%** | **4.5%** | **~4.8%** |

| | |
|---|---|
| **H-POWER** | 10.0% |
| **Kalaeloa** | 1.5% |
| **AES** | 1.5% |

4.4. Additions of Firm Generating Capacity

The Campbell Industrial Park CT-1, a 113 MW net simple-cycle combustion turbine, was placed in service on August 3, 2009.

The State of Hawaii Department of Transportation, Airports Division ("DOT"), plans to install approximately 8 MW of distributed standby generation ("Airport DSG") in July 2012. Under an agreement between Hawaiian Electric and DOT ("Airport DSG Agreement"), Hawaiian Electric will be able to use the Airport DSG to serve system needs under certain conditions. Nearly all of the generation provided by the Airport DSG will be dispatchable by Hawaiian Electric under the conditions given in the agreement. The Commission approved the Airport DSG Agreement on March 2, 2010 in Docket No. 2009-0317.

On December 15, 2009 in Docket No. 2009-0291 (Hawaiian Electric's petition for a declaratory order regarding the exemption of the proposed H-Power project from the Framework for Competitive Bidding ("Framework")), the Commission issued an Order that the project is exempt from the Framework. Hawaiian Electric is currently in discussions with the City & County of Honolulu to purchase up to an additional 27 MW of power from an expansion of the existing waste-to-energy facility, which is currently under construction and is forecasted to begin commercial operation in 2012.

The addition of these firm capacity projects is included in the generating system reliability analyses contained herein.

In addition to these firm generation power projects, Hawaiian Electric also anticipates adding renewable as-available energy projects to the Hawaiian Electric system. For example, on May 12, 2010 the Commission approved a power purchase agreement ("PPA") with Kahuku Wind Power, LLC for up to 30 MW of as-available wind energy starting in early 2011. On January 19, 2011, the Commission approved a power purchase contract with Honua Power, LLC, to purchase approximately 6.6 MW of as-available energy from a biomass gasification facility.

On January 19, 2011, Hawaiian Electric submitted an application for Commission approval of a PPA with IC Sunshine LLC, for up to 5 MW of photovoltaic power, and anticipates additional power purchase contract applications will be submitted in 2011.

Because these as-available generating units cannot be dispatched to provide a specified level of power upon demand to serve the peak load, power from these units are not included in the planning criteria and reliability guideline calculations.

4.5. Reductions of Firm Generating Capacity

On April 29, 2010, Hawaiian Electric removed from service 29.5 MW of temporary distributed generation units that were part of the generating fleet since 2005. The units were no longer needed to enhance generating system reliability.

Waiau Units 3 and 4, and Honolulu Units 8 and 9 are candidates for retirement in the next 10 years.[6] The decision on whether to continue operating these units or retire them would depend largely on other factors, such as operation and maintenance costs, environmental regulations, replacement capacity, and transmission infrastructure improvements. For the purposes of the 2011 AOS analysis, the reference scenario forecasts Waiau units 3 and 4 to be removed from service in 2017, and Honolulu Units 8 and 9 removed from service in 2020.

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

The existing PPA with Kalaeloa Partners, L.P. ("Kalaeloa") expires on May 23, 2016. A new PPA is being negotiated between Hawaiian Electric and Kalaeloa.

6 See Section 6.2.2 below.

Hawaiian Electric intends to seek a declaratory order from the Commission regarding the exemption of the renegotiated PPA from competitive bidding.

For the purposes of the 2011 AOS analysis, it is assumed that the 208 MW of capacity provided by Kalaeloa remains in service beyond May 23, 2016.

## 5. Scenario Analysis

### 5.1 Description of Scenarios

Forecasts of the inputs to the analysis are subject to uncertainties. Therefore, a range of forecasts was considered in the analysis. Descriptions of the various planning scenarios are provided below:

- Energy Efficiency Portfolio Standards ("EEPS") forecast
- Higher load forecast (60 MW increase in peak load);
- Waiau 3 and 4, and Honolulu 8 and 9 generating units remain in service
- Increased stringency of Hawaiian Electric's generating system reliability guideline from 4.5 years per day to 10 years per day.

#### 5.1.1 EEPS Forecast

On March 8, 2010, the Commission initiated an investigation to examine establishing energy efficiency portfolio standards ("EEPS") for the State of Hawaii, pursuant to Act 155, Session Laws of Hawaii 2009 ("Act 155") and Hawaii Revised Statues §269-96. The EEPS will be designed to achieve 4,300 GWh of electricity use reductions statewide by 2030 or to achieve some other level of reduction as may be determined in the proceeding. For the purposes of the 2011 AOS scenario analysis, a hypothetical sales and peak forecast was developed by Hawaiian Electric based on its May 2010 sales and peak forecast to assess the potential impact of EEPS on the need for additional firm capacity. Table 5 summarizes the EEPS peak scenario estimates.

Table 5: EEPS Peak Scenario

| **Net System Peak (MW) (with Future DSM, but without Load Management & Rider I)** | | | | | |
|---|---|---|---|---|---|
| Year | Actual | Actual Adj for Standby | 2011 AOS May 2010 S&P | EEPS Forecast | Difference May2010 S&P - EEPS Fcst |
| 2000 | 1164 | 1185 | | | |
| 2001 | 1191 | 1213 | | | |
| 2002 | 1204 | 1224 | | | |
| 2003 | 1242 | 1262 | | | |
| 2004 | 1281 | 1299 | | | |
| 2005 | 1230 | 1250 | | | |
| 2006 | 1265 | 1288 | | | |
| 2007 | 1216 | 1241 | | | |
| 2008 | 1186 | 1191 | | | |
| 2009 | 1213 | 1237 | | | |
| 2010 | 1162 | 1187 | 1,242 | 1,226 | -16 |
| 2011 | | | 1,250 | 1,222 | -28 |
| 2012 | | | 1,268 | 1,226 | -42 |
| 2013 | | | 1,291 | 1,236 | -55 |
| 2014 | | | 1,326 | 1,262 | -63 |
| 2015 | | | 1,347 | 1,275 | -72 |
| 2016 | | | 1,362 | 1,279 | -83 |
| 2017 | | | 1,377 | 1,282 | -95 |
| 2018 | | | 1,392 | 1,289 | -103 |
| 2019 | | | 1,408 | 1,300 | -108 |
| 2020 | | | 1,424 | 1,318 | -106 |

### 5.1.2 Higher Load Forecast

The higher load scenario uses the assumption that the system peaks are higher by 60 MW. Such a scenario is possible, for example if, (1) customer acceptance and/or awareness is less than expected in the case of the load management DSM programs, or energy efficiency DSM programs; (2) electricity use is higher than that projected by the Hawaiian Electric sales and peak forecast due to a recovering economy; or (3) a combination of these or other factors occur in the future. A 60 MW higher peak load is roughly equivalent to one standard deviation over a 20 year period of historical peaks (peak 1990-2009). Table 6 summarizes the higher load scenario.

Table 6: Higher Load Scenario

| Year | 2011 AOS May 2010 S&P Forecast (MW) | 60 MW higher May 2010 S&P Forecast (MW) | Difference (MW) |
|---|---|---|---|
| 2011 | 1,250 | 1,310 | 60 |
| 2012 | 1,268 | 1,328 | 60 |
| 2013 | 1,291 | 1,351 | 60 |
| 2014 | 1,326 | 1,386 | 60 |
| 2015 | 1,347 | 1,407 | 60 |
| 2016 | 1,362 | 1,422 | 60 |
| 2017 | 1,377 | 1,437 | 60 |
| 2018 | 1,392 | 1,452 | 60 |
| 2019 | 1,408 | 1,468 | 60 |
| 2020 | 1,424 | 1,484 | 60 |

5.1.3 Waiau 3 and 4; Honolulu 8 and 9

The scenario of Waiau Units 3 and 4 and Honolulu 8 and 9 remaining in service examines the generating system reliability if these units are not removed from service in 2017, and 2020, respectively.

5.1.4 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 3.2, Hawaiian Electric currently uses a reliability guideline threshold of 4.5 years per day. If the existing Loss of Load Probability 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 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

### 5.2. Other Planning Considerations

In order to continue satisfying Hawaiian Electric's capacity planning criteria, replacement firm capacity must be installed if existing firm capacity will be removed from service. The replacement capacity must be installed prior to the removal of service of existing generation. The lead time to install new, firm generating capacity may be seven to 10 years, depending on the length of time needed to obtain permits, procure major equipment, and construct the facilities. Given the anticipated reserve capacity shortfalls in the timeframes described below, Hawaiian Electric plans to issue a Request For Proposals ("RFP") in 2011 to acquire additional firm capacity. The proposed scope of the RFP is provided in Section 6.2 below.

The risks associated with action and inaction are not symmetrical. While Hawaiian Electric has the ability to delay the execution of its resource plans when circumstances, such as an economic slump resulting in reduced load growth, lead to a reduction in urgency, it has very limited ability or no ability to accelerate the addition of *significant generation resources if unanticipated changes in key drivers require that firm* capacity be added sooner than anticipated. This is because Hawaiian Electric has little control over the rate at which major equipment can be manufactured and the speed of the permitting and regulatory review process . This asymmetrical risk profile is considered when determining the date at which new capacity should be added for any of the reasons cited in Section 4 above.

### 5.3 Results of Analysis

Table 7 shows that the Rule 1 and Rule 2 criteria are satisfied for the Reference Scenario for each year through 2015 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 3; and (2) continued acquisition of energy efficiency DSM programs but by a third party. However, as previously explained, Rule 1 and Rule 2 results are deterministic and do not incorporate unit specific EFOR rates in their calculation.

Table 7: Rule 1 and Rule 2 Analysis

| Year | Rule 1 Results (MW) | Rule 2 Results (MW) |
|---|---|---|
| 2011 | 232 | 192 |
| 2012 | 196 | 156 |
| 2013 | 201 | 161 |
| 2014 | 221 | 181 |
| 2015 | 238 | 198 |

The LOLP for the Reference and Planning Scenarios were calculated using a production simulation model for each year through 2020 under reference and variable sets of assumptions described in Section 4.

For the years 2011 to 2015, the generating system's 4.5 years per day reliability guideline is projected to be met in the reference scenario, but will be less than the 4.5 years per day reliability guideline in the higher load scenario, and under the higher generating system reliability scenario of 10 years per day. A reserve capacity shortfall may occur in 2016 under all scenarios except the EEPS scenario which indicates that reserve capability shortfalls may occur from 2017. Table 8 shows the results of the reliability analysis.

Table 8: Generation System Reliability Guideline (years/day)

| Generation System Reliability (years/day) | | | | | |
|---|---|---|---|---|---|
| Year | Reference Scenario | Higher Load (Add 60 MW) | EEPS Forecast | No Retirements | 10 yrs/day reliability scenario |
| 2011 | 6.4 | 1.4 | 9.1 | 6.4 | 6.4 |
| 2012 | 7.1 | 1.6 | 13.7 | 7.1 | 7.1 |
| 2013 | 10.4 | 2.3 | 25.6 | 10.4 | 10.4 |
| 2014 | 4.9 | 1.1 | 13.5 | 4.9 | 4.9 |
| 2015 | 5.5 | 1.3 | 17.9 | 5.5 | 5.5 |
| 2016 | 2.0 | 0.7 | 10.6 | 2.0 | 2.0 |
| 2017 | 0.6 | 0.2 | 2.1 | 2.4 | 0.6 |
| 2018 | 0.3 | 0.1 | 1.6 | 1.1 | 0.3 |
| 2019 | 0.2 | 0.1 | 1.1 | 1.0 | 0.2 |
| 2020 | 0.1 | 0.0 | 0.2 | 0.7 | 0.1 |

Table 9 shows the reserve capacity surpluses or shortfalls corresponding to the calculated reliability shown in Table 8. Reserve capacity shortfall 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. For example in the Higher Load scenario for 2011, the number -60 would indicate that about 60 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. A positive number indicates the amount of capacity over and above that amount needed to satisfy the 4.5 years per day reliability guideline. A negative number indicates the amount of capacity below the amount needed to satisfy the 4.5 years per day reliability guideline.

Table 9: Reserve Capacity Shortfall for Reference and Planning Scenarios (MW)

| Year | Reference Scenario | Alternate Scenarios | | | |
|---|---|---|---|---|---|
| | | Higher Load (Add 60 MW) | EEPS Forecast | No Retirements | 10 yrs/day reliability scenario |
| 2011 | 10 | -60 | 30 | 10 | -20 |
| 2012 | 20 | -50 | 40 | 20 | -20 |
| 2013 | 30 | -40 | 70 | 30 | 0 |
| 2014 | 0 | -70 | 40 | 0 | -40 |
| 2015 | 0 | -60 | 50 | 0 | -30 |
| 2016 | -40 | -100 | 30 | -40 | -80 |
| 2017 | -110 | -180 | -40 | -40 | -140 |
| 2018 | -150 | -220 | -50 | -70 | -180 |
| 2019 | -150 | -220 | -70 | -80 | -190 |
| 2020 | -240 | -310 | -150 | -90 | -270 |

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

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 to 70 MW change to the results, indicating a reserve capacity shortfall in all years analyzed in contrast to no reserve capacity shortfall projected in the Reference Scenario in 2011-2015. 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.

The analysis also shows that a reserve capacity shortfall occurs in 2016, and continues to increase in all scenarios, and may occur as early as 2011 in the high load scenario. Additional demand-side resources, including additional load management, can benefit generation system reliability over this short-term horizon.

Table 9 further projects that for the years 2011 to 2015, approximately 20 MW to 40 MW of firm capacity must be added to the Hawaiian Electric system to achieve a higher reliability guideline of 10 years/day in the near term. The approximately 30-40 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. Acquisition of Additional Firm Capacity

### 6.1 Competitive Bidding is the Required Acquisition Mechanism

On December 8, 2006, the Framework for Competitive Bidding ("CB Framework") was adopted by the Commission in Decision and Order No. 23121, in Docket No. 03-0372, pursuant to HRS §§ 269-7 and 269-15 and Hawaii Administrative Rules § 6-61-71. The Commission's CB Framework states that "[c]ompetitive bidding, unless the Commission finds it to be unsuitable, is established as the required mechanism for acquiring a future generation resource or a block of generation resources, whether or not such resource has been identified in a utility's IRP."[7]

As indicated above, Hawaiian Electric will need additional firm capacity in the 2016 timeframe. Hawaiian Electric will seek to acquire the additional capacity through a competitive bidding process.

### 6.2 Foundation for the RFP

#### 6.2.1 Integrated Resource Planning

The CB Frameworks states "Any electric utility's IRP shall specify the proposed scope of the RFP for any specific generation resource or block of generation resources that the IRP states will be subject to competitive bidding."[8]

On September 30, 2008, Hawaiian Electric filed its fourth integrated resource plan ("IRP-4") in Docket No. 2007-0084. The IRP-4 preferred plan indicated, among other things, that a 100 MW block of firm capacity would be needed in 2011 and that Waiau

[7] CB Framework, Section II.A.3. on page 3.

[8] Id., Section II.B.1., on page 7

Unit 3 would be either retired or placed on emergency reserve status once that additional capacity was operational.

The next firm capacity resource (subsequent to the 100 MW block of firm capacity) identified in the IRP-4 plan was a 50 MW resource in the 2014 timeframe. The IRP-4 report indicated that this resource block of firm capacity is needed to maintain the generation planning criteria and will also allow, once operational, the placement of Waiau 4 generating unit into a status similar to Waiau 3.

Since Hawaiian Electric filed its IRP-4 report in 2008, updated annual sales and peak forecasts were developed. These updated forecasts projected lower system peaks in the near term due primarily to lower economic activity. This resulted in deferral of the need for capacity from the 2011 timeframe.

On November 26, 2008, the Commission issued an Order Closing Docket in Docket No. 2007-0084 (Hawaiian Electric IRP-4).

Despite the suspension of the HECO IRP-4 process, Hawaiian Electric continues its planning work in the normal course of conducting its business. As part of its normal planning work, Hawaiian Electric assesses the adequacy of its generating resources to provide reliable service and files Adequacy of Supply reports annually. The current analysis provided herein indicates that additional firm generating capacity is needed in the 2016 timeframe to accommodate load growth.

As provided above, the CB Framework states that the utility's IRP shall specify the scope of the RFP for any specific generation resource or block of generation resources that the IRP states will be subject to competitive bidding. Since Hawaiian Electric's IRP-4 process has been suspended, Hawaiian Electric is providing the scope of the RFP herein.

6.2.2 Evaluation of Existing Hawaiian Electric Generating Units

On October 12, 2010, Hawaiian Electric filed with the Commission a report titled *Evaluation of Hawaiian Electric Company, Inc.'s Existing Generating Units* in Docket No. 2010-0286 (Barbers Point Fuel Oil Tank 132 Renovation). The report indicated that Waiau Units 3 and 4 are candidates for retirement because of potential risks associated with their age and that Honolulu Units 8 and 9 are candidates for retirement because retirement may be the only viable option to comply with various evolving environmental regulations. The potential retirement of these generating units is a factor in the scope of the RFP. Section 12, on page 44, of the report described the anticipated scope of the RFP in terms of the size (in MW) being sought, the timing of the need for capacity, and the attributes needed from the new generating unit(s). A refinement of the scope of the RFP is provided herein.

6.3 Scope of RFP

6.3.1 Size (in MW) of RFP

Hawaiian Electric plans to seek up to 300 MW in firm capacity to accommodate anticipated load growth and the retirement of up to four existing generating units. The RFP will be prepared in such a manner as to allow bidders to participate in two distinct bidding options aligned with the firm capacity needs for Hawaiian Electric. The first option will be related to the capacity needed in 2016 to accommodate load growth and the potential retirement of Waiau Units 3 and 4. The second option will be related to an additional increment of capacity needed to replace the capacity of Honolulu Units 8 and 9, which may need to be retired.

6.3.2 Timing of Firm Capacity Needs

The first 200 MW need to be in service by 2016 to accommodate anticipated load growth and the retirement of the first two generating units (Waiau Units 3 and 4). The next 100 MW need to be in service by 2020 to accommodate the retirement of the next two generating units (Honolulu Units 8 and 9).

6.3.3 Attributes of New Generation

The attributes of desired future firm generating capacity are described below. Definitions of the terminology are described in Appendix 3. The description of the attributes and the definitions of the terminology will be refined as needed in the draft and final RFPs.

- The capacity to be provided may come from multiple generating units.
- Each generating resource must provide firm capacity.
- Each generating resource must be dispatchable.
- The size, in MW, of any one generating resource shall not exceed 150 MW.
- The input energy (such as the fuel supply) to the generating units must be renewable and sustainable.
- Each generating resource must be quick-starting, i.e., the time between the start signal and synchronizing the generator to the system, closing the breaker and reaching minimum load shall be 10 minutes or fewer.
- Each generating resource must be able to cycle on and off multiple times per day.

- Each generating resource must be able to help regulate system frequency.
- Each generating resource must be able to help regulate voltage.
- Each generating resource must be able to increase or decrease their power output at a rate equal to or greater than 5 MW per minute.
- Each generating resource must use commercially available and proven technology.
- Each generating resource site must have black-start capability (i.e., capable of starting up on a completely de-energized utility grid).

### 6.4 Competitive Bidding Process

#### 6.4.1 Request Commission Open a Docket

In February 2011, Hawaiian Electric will submit a request to the Commission to open a new docket to receive filings, review approval requests, and resolve disputes, if necessary, related to Hawaiian Electric's proposal to proceed with a competitive bidding process to acquire new firm capacity generation.

#### 6.4.2 Request Commission Approval of Independent Observer Contract

In February 2011, Hawaiian Electric will also submit a request to the Commission to approve the contract for an Independent Observer. The Commission's Framework for Competitive Bidding requires the use of an Independent Observer when the utility seeks to advance a project proposal.

#### 6.4.3 Timeline

The proposed timeline for the competitive bidding process is anticipated to take between 12 and 18 months from the issuance of the Draft Request for Proposals to selection of the Final Award Group. The actual timeline will be influenced by the number of bids received and the complexity of any issues that may be raised by participants.

## 7. Conclusions

Under the Reference Scenario, Hawaiian Electric's generation capacity for the next five years (2011-2015) will be sufficient to meet reasonably expected demands for service and provide reasonable reserves for emergencies. Hawaiian Electric will need additional firm capacity in the 2016 timeframe, and will seek to acquire the additional capacity through a competitive bidding process.

The scenario analysis indicates that in 2011, Hawaiian Electric may experience anywhere from a 60 MW reserve capacity shortfall under the higher load scenario to a 10 MW reserve capacity surplus in the Reference Scenario. By 2015, Hawaiian Electric may experience anywhere from a 50 MW surplus to 60 MW capacity shortfall under various scenarios. The range of potential reserve capacity shortfalls can be addressed through the acquisition of additional energy efficiency and load management resources over the near-term (if approved by the Commission).

Hawaiian Electric will continue its portfolio approach to meet its obligation to serve, which includes demand-side management programs and the pursuit of firm capacity renewable supply side options. Hawaiian Electric also recognizes that the environment for resource planning has increased in complexity and uncertainty. Hawaiian Electric must therefore be proactive, anticipating the what-ifs, and cannot bank on the Reference Scenario occurring.

Very truly yours,

Darcy L. Endo-Omoto
Vice President
Government & Community Affairs

Attachments

c: Division of Consumer Advocacy (with Attachments)

Table A1:
Projected Reserve Margins

| Year | System Capability at Annual Peak Load (net kW) [A] (I) | System Peak (net kW) [D] (II) | Interruptible Load (net kW) [E] (III) | Reserve Margin (%) [A-(D-E)] / (D-E) |
|---|---|---|---|---|
| 2010 | 1,755,600 | 1,187,000 | 38,700 | 53% |
| 2011 | 1,755,600 | 1,249,800 | 42,200 | 45% |
| 2012 | 1,790,600 | 1,268,400 | 45,300 | 46% |
| 2013 | 1,790,600 | 1,291,400 | 55,800 | 45% |
| 2014 | 1,790,600 | 1,325,600 | 65,500 | 42% |
| 2015 | 1,790,600 | 1,346,600 | 74,200 | 41% |
| 2016 | 1,790,600 | 1,361,700 | 69,800 | 39% |
| 2017 | 1,698,000 | 1,376,900 | 69,800 | 30% |
| 2018 | 1,698,000 | 1,392,400 | 69,800 | 28% |
| 2019 | 1,590,700 | 1,408,000 | 69,800 | 19% |
| 2020 | 1,590,700 | 1,423,900 | 69,800 | 17% |

Notes:

I. System Capability includes:
- Hawaiian Electric central station units at total normal capability is 1,321,600 kW-net or 1,383,000 kW-gross.
- Temporary, Hawaiian Electric-sited distributed generating units with a total capability of 29,500 kW-net were removed from service on April 28, 2010.
- Firm power purchase contracts with a combined net total of 434,000 kW from Kalaeloa (208,000 kW), AES Hawaii (180,000 kW), and H-POWER (46,000 kW).
- Expected expansion of H-POWER in 2012 (+27,000 kW)
- Airport DSG in 2012 (8,000 kW)
- Waiau Units 3 and 4 are removed from service in 2017 (-92,600 kW)
- Honolulu Units 8 and 9 are removed from service in 2020 (-107,300 kW)
- When the system capability at the time of the system peak differs from the year-end system capability, an applicable note will indicate the year-end system capability.

II. System Peaks
- The 2011-2015 annual forecasted system peaks are based on Hawaiian Electric's May 2010 Sales and Peak Forecast.
- The forecasted System Peaks for 2011-2015 include the estimated peak reduction benefits of third-party energy efficiency DSM programs.

The peak for 2011-2015 includes approximately 25,000 kW 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, (based on a T&D loss factor of 4.95%) and are approximate impacts at the system peak.

Hawaiian Electric Equivalent Forced Outage Rate ("EFOR") Discussion

It is extremely difficult to predict unit-specific EFOR rates, as indicated by the variation in historical data. Nonetheless, for planning purposes it is necessary to estimate forward-looking EFOR rates. This is accomplished using a blend of historical data, experience, and judgment. Accordingly, the estimated EFOR rates used in the 2011 AOS analysis and the rationale for them are described in the following paragraphs.

1. Honolulu Units 8 and 9

   In the 2010 AOS, the forward looking EFOR of 10.9% included the actual average of 5 years for both H8 and H9. The actual EFOR for 2010 for Honolulu Units 8 & 9 were 33.1% and 21.9%, respectively, and averaged 15.1% for the two units. For the 2011 AOS analysis, it was decided to continue to utilize the average of the actual EFOR for both units for the past 5 years. This approach recognizes that these units will be dispatched and operated similarly in 2011 as they were in recent years. As a result, an EFOR of 15.1%, 4.2% higher than that utilized for the 2010 AOS analysis, is recommended for the 2011 AOS forward looking EFOR for both Honolulu Units 8 and 9.

2. Waiau Units 3 and 4

   In the 2010 AOS, the forward looking EFOR for Waiau Unit 3 was 22.1%. The actual EFOR for 2010 for Waiau Unit 3 was 6.7%. The actual EFOR was significantly lower than the forecast. For the 2011 AOS analysis, it was decided to continue to use the average of the actual EFOR rates for the past 5 years. This approach recognizes that Waiau Unit 3 will be dispatched and operated similarly in 2011 as it was in recent years. Thus, for Waiau Unit 3, an EFOR of 15.0%, 7.1% lower than that utilized for the 2010 AOS analysis, is recommended for the 2011 AOS forward looking EFOR.

   In the 2010 AOS, the forward looking EFOR for Waiau Unit 4 was 12.7%. The actual EFOR for 2010 for Waiau Unit 4 was 1.4%. The actual EFOR was significantly lower than the forecast. For the 2011 AOS analysis, it was decided to continue and utilize the average of the actual EFOR of the unit for the recent 5 years. This approach recognizes that Waiau Unit 4 will be dispatched and operated similarly in 2011 as it was in recent years. Thus, for Waiau Unit 4, an EFOR of 12.0%, 0.7% lower than that utilized for the 2010 AOS analysis, is recommended for the 2011 AOS forward looking EFOR.

3. Waiau Units 5 and 6

In the 2010 AOS, the forward looking EFORs for Waiau Units 5 and 6 were 4.7% based on the average actual EFORs for both units for the recent 5 years. The actual EFOR for 2010 for Waiau Units 5 and 6 were 2.5% and 0.3%, respectively. For both units, actual EFORs were below forecast. For the 2011 AOS analysis, it was decided to continue to use the average of the actual EFOR rates for the past 5 years. This approach also recognizes that the units will be dispatched and operated similarly in 2011 as they were in recent years. As a result, an EFOR of 4.7%, 0.1% lower than that utilized for the 2010 AOS analysis is recommended for the 2011 AOS forward looking EFOR for both Waiau 5 and 6.

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. Accordingly, in the 2010 AOS, the forward looking EFOR rate of 6.3% was used for these four units. The actual EFOR for 2010 for Waiau 7, Waiau 8, Kahe 3, and Kahe 4 were 0.1%, 1.3%, 3.9%, 10.3%, respectively, with an average of 3.9%. For the 2011 AOS analysis, it was decided to continue to use the average of the actual EFOR rates for the four units for the past 5 years. This approach also recognizes that these units will be dispatched and operated similarly in 2011 as they were in recent years. As a result, an EFOR of 5.2%, 1.1% lower than that utilized for the 2010 AOS analysis is recommended for the 2011 AOS forward looking EFOR for Waiau Units 7 and 8, and Kahe Units 3 and 4.

5. Waiau Units 9 and 10

In the 2010 AOS, the forward looking EFORs for Waiau Units 9 and 10 were 11.4% based on the average of the actual EFORs for both units for the recent 5 years. The actual EFOR in 2010 for Waiau Units 9 and 10 were 0.9% and 1.6%, respectively, and averaged 1.3% for the two units. The reliability for both units were compared closely with the forecast. For the 2011 AOS analysis, it was decided to continue to use the average of the actual EFOR rates for both units for the past 5 years. This approach also recognizes that these units will be dispatched and operated similarly in 2011 as they were in recent years. As a result, an EFOR of 10.9%, 0.5% lower than that utilized for the 2010 AOS analysis is recommended for the 2011 AOS forward looking EFOR for Waiau 9 and 10.

6. Kahe Units 1 and 2

In the 2010 AOS, the forward looking EFORs for Kahe Units 1 and 2 were 3.4% based on the average of the actual EFORs for both units for the recent 5 years. The actual EFOR in 2010 for Kahe Unit 1 and 2 were 0.7% and 8.8%, respectively, and averaged 4.8% for both units. For the 2011 AOS analysis, it was decided to continue to use the average of the actual EFOR rates for both units for the past 5 years. This approach also recognizes that these units will be dispatched and operated similarly in 2011 as they were in recent years. As a result, an EFOR of 3.6%, 0.2% higher than that utilized for the 2010 AOS analysis is recommended for the 2011 AOS forward looking EFOR for Kahe 1 and 2.

7. Kahe Unit 5

In the 2010 AOS, the forward looking EFOR for Kahe Unit 5 was 3.6% based on the average of the actual EFOR for the recent 5 years. The actual EFOR of 1.1% was higher than the forecast. For the 2011 AOS analysis, it was decided to continue to use the average of the actual EFOR rate for the past 5 years. This approach recognizes that this unit will be dispatched and operated similarly in 2011 as it was in recent years. As a result, an EFOR of 3.2%, 0.4% lower than that utilized for the 2010 AOS analysis is recommended for the 2011 AOS forward looking EFOR for Kahe 5.

8. Kahe Unit 6

In the 2010 AOS, the forward looking EFOR for Kahe Unit 6 was 2.9% based on the average of Kahe Unit 6 actual EFOR for the recent 5 years. The actual EFOR for 2010 for Kahe Unit 6 was 1.9%. For the 2011 AOS analysis, it was decided to continue to use the average of the actual EFOR rate for the past 5 years. This approach also recognizes that Kahe Unit 6 will be dispatched and operated similarly in 2011 as it was in recent years. As a result, an EFOR of 2.1%, 0.8% lower from that utilized for the 2010 analysis is recommended for the 2011 AOS forward looking EFOR for Kahe Unit 6.

9. CIP CT-1

On August 3, 2009, CIP CT-1 was placed in service (e.g. tied into the electrical grid and producing power). The actual EFOR for 2009 and 2010, was 22.0% and 16.0%, respectively. It is typical for the EFOR new generating units to decline over the first few years of operation as problems are identified and resolved. For example, for the Hamakua Energy Partners, L.P. naphtha-fired combined cycle unit, which was commissioned in 2002, its EFOR in 2002, 2003 and 2004 were 6.72%, 3.08% and 1.5%, respectively. The Kalaeloa combined cycle unit began operating in May 1991. In its first four contract years[9], Kalaeloa's EFOR for its Low Sulfur Fuel Oil-fired combined cycle unit were 1.90%, 12.75%, 6.61% and 0.82%, respectively. While Kalaeloa's EFOR was low in the first contract year, it increased in the second year and declined progressively in the next two years. It is anticipated that the EFOR for CIP CT-1 will decline over time as problems related to its initial operation are resolved. Its EFOR has already declined from the first year to the second year of its operation. Therefore, for the purposes of this 2011 AOS analysis, the forward-looking EFOR for CIP CT-1 was assumed to be 15%. Adjustments will be made to this EFOR projection as more operating experience is acquired on the unit.

[9] The first contract year was from May 23, 1991 to May 30, 1992. The second contract year was from June 1, 1992 to May 31, 1993. Subsequent contract years covered June 1st of one year to May 31st of the succeeding year.

## Terminology for New Generating Unit Attributes

Firm Capacity – The amount of energy producing capacity which can be guaranteed to be available at a given time.

Dispatchable – The ability to turn on or turn off a generating resource at the request of the utility's system operators, or the ability to increase or decrease the output of a generating resource from moment to moment in response to signals from a utility's Automatic Generation Control System, Energy Management System or similar control system, or at the request of the utility's system operators.

Renewable Energy – Energy generated or produced using the following sources:

1. Wind
2. The sun
3. Falling water
4. Biogas, including landfill and sewage-based digester gas
5. Geothermal
6. Ocean water, currents, and waves, including ocean thermal energy conversion
7. Biomass, including biomass crops, agricultural and animal residues and wastes, and municipal solid waste and other solid waste
8. Biofuels
9. Hydrogen produced from renewable sources

Sustainable Fuel Supply – Lasting and stable fuel supply, including transportation and fuel related services if applicable.

Commercially Available and Proven Technology – Technology that has been commercially operating for at least five years, with capacity factors within design and dispatch parameters, and at a scale of 100 KW or larger and be scalable to produce energy on a commercial level submitted.