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

March 6, 2006

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PUBLIC UTILITIES COMMISSION

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.

In accordance with paragraph 5.3a. of General Order No. 7, the following information is respectfully submitted[1].

I. Executive Summary

1. Adequacy of Supply – 2005

HECO's 2005 system peak occurred on Wednesday, September 14, 2005 and was 1,273,000 kW-gross or 1,230,000 kW-net based on net HECO generation, net purchased power generation, the peak reduction benefits of energy efficiency demand-side management programs implemented beginning in mid-1996, and with several cogenerators[2] operating at the time. Had these cogenerating units not been operating, the 2005 system peak would have been approximately 1,293,400 kW-gross or 1,250,400 kW-net.

HECO's total generating capability of 1,614,600 kW-net at the time of the system peak included 406,000 kW-net of firm power purchased from (1) Kalaeloa Partners, L.P. ("Kalaeloa"), (2) AES Hawaii, Inc., and (3) H-POWER. Oahu had a reserve margin of approximately 30% over the 2005 system net peak.[3] Subsequent to the 2005 system peak, the Kalaeloa PPA

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[1] HECO's Adequacy of Supply ("AOS") Report is due within 30 days after the end of the year. On January 30, 2006, HECO requested an extension of time, to no later than March 15, 2006, to file the Report. The extension of time was needed to allow HECO to better assess and incorporate the impact of its recent generation availability experience (calendar year 2005) to determine the estimated reserve margin capacity shortfall for the period covered by this letter. The Commission granted HECO's request by letter dated February 1, 2006.

[2] At the time of the peak, certain units at Tesoro, Chevron and Pearl Harbor were generating an estimated 20,400 kW of power for use at their sites.

[3] The reserve margin calculation includes 10,000 kW of interruptible loads served by HECO.

Amendments No. 5 and No. 6 became fully effective on September 28, 2005. As a result, an additional 28 MW are counted from Kalaeloa for planning purposes. In addition, approximately 14.8 MW of distributed generation was installed at three HECO sites on October 26, November 9, and December 16, 2005.

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

A summary of the issues affecting the adequacy of supply will be described in this executive summary, with the details provided in other sections of this document.

2. Reserve Capacity Summary

On March 10, 2005, HECO filed its annual Adequacy of Supply report to the Commission ("2005 AOS") in which HECO concluded that HECO's generation capacity for Oahu would be sufficiently large to meet all reasonably expected demands for service but that it expected a reserve capacity shortfall[4] of 50 to 70 MW in the 2006-2009 period, subject to HECO obtaining timely approval of HECO's two load management DSM program applications and utility CHP program application before the Commission at the time of the 2005 AOS filing. HECO's latest estimates place the reserve capacity shortfall between 170 to 200 MW in the 2006-2009 periods. The reserve capacity shortfall is equivalent in magnitude to the largest generating unit in operation on Oahu (180 MW).

On a day-to-day operational basis, the effect of the reserve capacity shortfall becomes apparent. The number of days when HECO was unable to provide sufficient spinning reserve to cover for the loss of the largest operating unit increased from 3 days in 2003, to 24 days in 2004 to 30 days in 2005, and during the first 10 days in 2006, HECO experienced 4 days of lower-than-desired spinning reserve. (See Figure ES-1). HECO has not had to resort to rolling outages during this time.

HECO notified its customers of its spinning reserve shortfall situation and asked for help through energy conservation on two recent occasions: November 7-10, 2005 and January 10-12, 2006. The spinning reserve shortfalls during these periods were 123 MW-gross and 174 MW-gross, respectively. On both occasions, HECO used the tools approved by the Commission to help mitigate the impact of the shortfall: (1) the operation of its recently installed distributed

[4] "Reserve capacity shortfall" is defined as the amount of additional firm generating capacity or equivalent reductions in load from load management and energy efficiency demand-side management ("DSM") programs and/or combined heat and power ("CHP") installations needed to restore the generating system reliability above HECO's reliability guideline.

generators, and (2) the activation of the residential direct load control program, "EnergyScout", where the power to approximately 5,000 residential water heaters was shutoff for 1-2 hours. The number of reserve capacity shortfalls and calls for conservation will continue to increase in both frequency and duration until reserve capacity margins have returned to desirable levels.

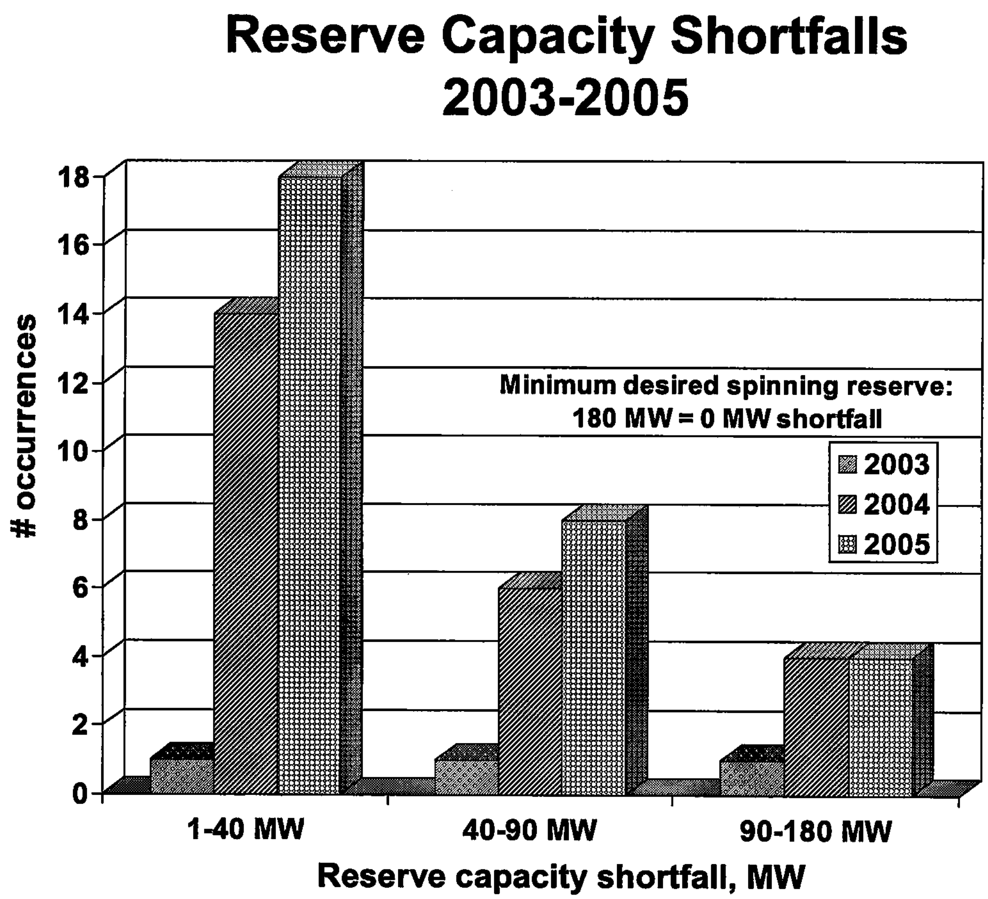

Figure ES-1 Reserve Capacity Shortfall

HECO has been mitigating the effects of the reserve capacity shortfalls by increasing generation reserve margins where possible. For example, in 2005, HECO received Commission approval and has been using the additional 28 MW of firm capacity from Kalaeloa. HECO has so far installed approximately 15 MW of distributed generation at three HECO-owned facilities: the Ewa Nui substation, the Helemano substation, and the Iwilei Tank Farm, and is evaluating further installations for 2006 and beyond. HECO's Demand-Side Management (DSM) programs have contributed 46 MW[5] of peak reduction benefits in 2005, up from 36 MW in 2004. 5,000

[5] Net-to-system level, net of free-riders, at year end, including load management DSM.

customers have participated in the residential direct load control program, EnergyScout, which saves HECO approximately 3-4 MW in the event of a system emergency. HECO continues to sign up more customers and is on target to meet its goal of 25,000 participants by 2008. During the last quarter of 2005 HECO started its "See the Light, Make the Change" campaign, partnering with GE and the local GE distributor Webco Hawaii to encourage residents to buy and install 100,000 compact fluorescent light bulbs (CFL) by December 31, 2005. The promotion increased statewide sales of CFLs to over 100,000. On Oahu, this represents over 1 MW of power savings[6]. HECO is working closely with its IPP partners to maintain or improve the availability of their generating units. HECO has increased operational staff to allow for 24/7 operations of all generating units, is continuing to increase maintenance staff to provide a night shift maintenance crew for its Kahe and Waiau power plants, and is expanding the role of its consultants involved with HECO's current continuous improvement efforts to include assessing the generating unit availability situation. HECO also is making progress with its next combustion turbine peaking generating unit scheduled to be in-service in 2009.

The specific drivers that affect reserve capacity and a discussion of the key issues affecting the adequacy of supply for the 2006 to 2009 period are summarized below.

a) Capacity planning criteria

The level of electric service reliability HECO plans to provide to its customers is established by its capacity planning criteria. The capacity planning criteria establish when and how much generation capacity is needed on the electric system. The inputs to the capacity planning criteria are (1) the projection of load to be served, (2) the reduction in load to be served by firm capacity generation due to the contribution of energy efficiency, energy conservation, and load management programs ("negawatts"), and customer-sited combined heat and power ("CHP") systems, (3) the amount of firm capacity on the system provided by HECO and independent power producer (IPP) generating units, their sizes, and their planned maintenance schedules, and (4) the availability of the existing generating units.

b) Load forecast update

HECO's 2005 system peak was 54 MW-gross (51 MW-net) lower than the system record peak set on October 12, 2004. Had several third-party cogenerators not been running at the time of the peak, HECO's peak would have been approximately 66 MW-net lower than that projected in the June 2004 forecast, and approximately 54 MW-net lower than that projected in the May 2005 forecast.

HECO's lower system peak in 2005 than in 2004 is likely due to a combination of factors. Weather probably contributed as 2005 saw less Kona winds, was less humid, and slightly cooler

[6] Assumes every bulb purchased is installed.

than 2004, which may have resulted in lower air conditioning loads. Consumers also appear to have been generally more price-conscious, particularly since higher gasoline and housing prices were constantly in the news. Some customers may have been responding to this increased visibility and the higher electricity prices by controlling their use of electricity and incurring some inconvenience or discomfort. This voluntary response likely resulted from HECO's energy conservation messages and calls for voluntary reductions in use. Although welcome, experience shows this response is not sustainable over the long term. It is also likely that some customers' use was flat or down simply because of operational differences between 2005 and 2004.

While the 2005 peak did not achieve the level of 2004's record peak, peaks are expected to continue growing during the forecast horizon with the robust local economy and as new construction projects are completed.

The lower-than-projected peak loads in 2005 resulted in a higher generation reserve margin in 2005 than were forecast.

c) Demand-side management, load management, and CHP systems updates

HECO's existing energy efficiency DSM and load management DSM programs in 2005 reduced the demand for electricity by 8 MW[7]. This impact was 3 MW less than the 11 MW projected in the 2005 AOS. The 2005 AOS projected that combined impacts from load management DSM, energy efficiency DSM, and CHP would be approximately 98 MW by 2009. The 2006 AOS projects that the combined impacts will be reduced to approximately 79 MW, as shown in Table ES-1, below.

[7] The 2005 AOS and 2006 AOS both assume that HECO's system peak will occur in the month of October. The 2005 system peak occurred in September, which is approximately one less month for HECO to acquire peak-reducing impacts of energy efficiency and load management DSM. Had the 2005 system peak occurred in October, approximately 9 MW of peak-reducing impacts would have been realized at the time of the system peak.

Table ES-1:
Previous and Current Projections of
Load Management DSM, Rider I, Energy Efficiency DSM, and CHP[8] (MW)

	Load Management		Rider I		Energy Efficiency DSM		CHP		**Total Load Reduction**		
Year	2005 AOS	2006 AOS	2005 AOS	2006 AOS	2005 AOS	2006 AOS	2005 AOS	2006 AOS	**2005 AOS**	**2006 AOS**	**Diff**
2005	6	5	5	5	5	4	0	0	**17**	**14**	**-3**
2006	17	15	5	5	15	9	5	0	**41**	**29**	**-12**
2007	26	22	5	5	24	18	10	1	**65**	**46**	**-19**
2008	34	31	5	5	33	27	15	4	**87**	**67**	**-20**
2009	35	37	5	5	43	36	20	5	**103**	**84**	**-19**
2010	35	42	5	5	52	45	24	7	**116**	**100**	**-16**

These reductions in MW impact are due to a combination of factors, one being that the 2005 AOS assumed a higher level of commercial and industrial load management DSM program participation in 2005 than actually occurred.

At the time of HECO's filing of its 2005 AOS on March 10, 2005, HECO assumed that the five existing energy efficiency programs with enhancements and three additional programs would be bifurcated from the rate case and approved by the Commission on an accelerated schedule separate from the rate case. It was further assumed that an increased rate of acquisition of peak reduction benefits from the eight programs would begin in July 2005. On March 16, 2005 the Commission in Order No. 21698 bifurcated the rate case application creating the Energy Efficiency Docket, Docket No. 05-0069, for the DSM programs. Furthermore, on April 20, 2005, the Commission, in Decision and Order No. 21756, Docket No. 03-0142, denied the RCEA Program, without prejudice. HECO is currently continuing to implement its five existing energy efficiency DSM programs.

[8] To allow equivalent-basis comparison to 2006 AOS projections, 2005 AOS figures are reduced by 2004 Acquired impacts. The 2005 AOS did not present data for year 2010, but it is being included here for comparative purposes. Rider I is not considered a load management program, but is assumed to reduce the peak for planning purposes. Rider I planning assumptions have not changed between the 2005 AOS and the 2006 AOS. Totals may not add, due to rounding.

Since the bifurcation did not result in an accelerated schedule for the complete DSM proposal, HECO proposed a schedule that would permit it to submit the Interim DSM proposals. Following HECO's informal submission of its Interim DSM Program modifications to the parties on October 11, 2005, HECO filed a letter with the Commission on December 5, 2005 requesting modifications to HECO's existing energy efficiency programs and also approval of a new interim DSM program, collectively referred to as HECO's "Interim DSM Proposals". The current assumption is that the Interim DSM Proposal will be approved in July 2006 and that the complete (hereinafter "enhanced") DSM proposal, along with modifications to the load management programs (expected to be filed with the Commission in early 2006) will be approved in January 2007.

HECO is re-evaluating its CHP impact estimates, taking into account the higher prices for diesel and/or synthetic natural gas used by CHP systems, relative to the cost of electricity, which is based on the lower cost of LSFO, as well as HECO's ability to do CHP projects. The impact of CHP is smaller in this AOS compared to the 2005 AOS.

Lower-than-projected reductions from DSM and load management programs, and lower estimated CHP impacts increase the effective load that must be served or backed up by firm capacity generating units, which reduces reserve margins and increases reserve capacity shortfalls.

d) Existing firm capacity update

HECO operates 16 firm generating units at 3 power plants. HECO purchases firm power from 3 independent power producers, including the additional 28 MW of power from Kalaeloa Partners. In 2005, HECO installed 9 distributed generation units totaling approximately 15 MW at three HECO sites on October 26, November 9, and December 16. HECO is looking into installing additional substation distributed generation in 2006.

1. Generating unit availability

In the 2005 AOS, HECO expected that generating unit availability would improve in 2005 and beyond because of the amount and type of work performed in 2004. What we have learned from experience is that 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 generation reserve margins shrink, maintenance scheduling flexibility becomes more difficult. As the generating units age[9], they will need to be maintained more often and for longer periods of time. As the demand for electricity increases, the generating units operate harder, which increases the likelihood of unscheduled

[9] HECO's generating units are between 25 and 59 years old. IPP units are between 14 and 16 years old.

(forced) outages and operations at derated power levels. Generating units that were shutdown unexpectedly generally require immediate maintenance. As resources are shifted to make the emergency repairs, maintenance outage schedules slip, making maintenance scheduling flexibility even more difficult. In addition, generating units operating in a derated capacity cannot be afforded the luxury of a maintenance shutdown to restore the unit to full power operations. These units are generally operated for long periods in a derated state. EFOR[10], 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.

Based on HECO's maintenance experience in 2004 and 2005, lower generating unit availabilities and higher EFOR estimates are expected to continue in the near future. HECO changed its EFOR planning assumption to represent more realistic maintenance assumptions going forward.

Lower generating unit availability and higher EFOR increase reserve capacity shortfalls.

[10] EFOR – equivalent forced outage rate

Table ES-2: Historical and Forward-Looking EFOR

	2000	2001	2002	2003	2004	2005	Forward-Looking EFOR	4 Year Avg EFOR 2002 - 2005	AOS 2005 EFOR
H8	7.2%	10.4%	3.6%	13.0%	23.7%	1.7%	12.8%	10.5%	5.7%
H9	1.4%	3.0%	3.1%	20.0%	1.0%	12.0%	12.8%	9.0%	5.7%
W3	2.0%	1.9%	6.5%	10.9%	24.7%	42.2%	33.5%	21.1%	9.2%
W4	3.0%	14.8%	5.1%	3.4%	13.4%	5.0%	12.8%	6.7%	7.9%
W5	3.6%	0.8%	2.2%	4.1%	1.0%	1.0%	2.9%	2.1%	2.3%
W6	3.8%	3.9%	0.6%	2.8%	0.3%	2.6%	2.9%	1.6%	2.3%
W7	0.7%	1.6%	1.8%	0.7%	1.2%	0.6%	7.7%	1.1%	1.2%
W8	5.3%	1.5%	0.1%	0.0%	7.7%	23.5%	7.7%	7.8%	2.9%
W9	65.7%	4.1%	49.9%	6.9%	63.2%	69.2%	10.0%	47.3%	10.0%
W10	13.4%	5.0%	13.6%	36.0%	4.4%	7.4%	10.0%	15.3%	10.0%
K1	1.2%	0.7%	2.3%	1.2%	2.6%	5.4%	4.3%	2.9%	2.6%
K2	1.7%	3.1%	1.0%	2.2%	2.9%	2.0%	4.3%	2.0%	2.9%
K3	0.3%	3.9%	0.1%	3.5%	8.8%	8.3%	7.7%	5.2%	3.3%
K4	5.7%	0.9%	3.6%	1.3%	1.4%	4.9%	7.7%	2.8%	2.6%
K5	1.7%	0.4%	1.0%	1.1%	7.6%	3.1%	5.5%	3.2%	2.4%
K6	0.9%	0.4%	0.5%	1.9%	3.3%	5.9%	4.9%	2.9%	2.4%
HECO	**2.45%**	**1.6%**	**1.8%**	**2.4%**	**6.2%**	**9.25%**	**6.8%**	**4.0%**	**2.9%**
H-POWER							10.0%	10.0%	10.0%
Kalaeloa							1.0%	1.0%	1.0%
AES							1.0%	1.0%	1.0%

3. Summary of analysis

HECO's 2006 AOS analysis projects reserve capacity shortfalls between 170 to 200 MW in the 2006-2009 periods. This is larger than the 50 to 70MW shortfalls projected in the 2005 AOS.

HECO performed sensitivity analysis using better-than-expected EFORs. Reserve capacity shortfalls between 120 to 160MW resulted.

HECO performed sensitivity analysis using lower-than-expected peak loads. Reserve capacity shortfalls between 110 to 140MW resulted.

HECO performed sensitivity analysis using lower-than-expected DSM. Reserve capacity shortfalls between 180 and 240MW resulted.

The magnitude of the reserve capacity shortfalls are large – about the size of the largest generating unit on Oahu – and indicate that the likelihood for continued calls for public conservation and/or generation-related outages will increase.

The analysis re-confirms the need date of the next generating unit to be 2006 or sooner[11].

4. <u>HECO actions to mitigate projected reserve capacity shortfalls and to increase generating unit availability</u>

HECO has already been involved in a number of projects to improve the availability of the generating units. These include the Power Supply Reliability Optimization (PSRO) program, which seeks to increase the amount of predictive and proactive maintenance items in order to decrease the number of corrective maintenance (forced outage) items; and the Boiler Reliability Optimization (BRO) program, which seeks to closely monitor boiler chemistry control parameters to reduce the number of boiler tube failures. Consultants from EPRI Solutions have been developing and implementing these programs with HECO. In addition, HECO has expanded EPRI Solutions' scope of work to assess the current generating unit availability situation.

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[11] 2009 was identified as the need date for the next generating unit in HECO's second IRP process (IRP-2) filed with the PUC in January 1998. Hawaii was mired in economic slowdown at the time caused by the Asian economic crisis and Japan's 1998 recession. Signs of economic recovery in Japan in 1999 and strong west-bound visitor arrivals led Hawaii to an economic recovery in that year. Immediately following the 9/11/2001 terrorist attacks, economists were predicting a recession lasting until late 2002. However, in the fourth quarter of 2002, economic projections were cautiously optimistic. The need date of the next generating unit was still projected to be 2009 based on the December 2002 IRP-2 Evaluation report, in spite of the uncertainty of the economic projections going forward.

In 2003, the Hawaii economy began to bounce back from the post-9/11 concerns. In its March 31, 2004 AOS report, HECO stated "[W]ith the new higher forecast for peak demand, the next generating unit would be needed in 2006 if other measures, such as DSM, distributed generation, CHP or other supply-side resources, are not sufficient to reduce demand or increase supply to maintain generating system reliability at or above the 4.5 years per day threshold. However, given the long lead time to install the next generating unit, it is not possible to have the unit installed by 2006."

In 2004, the Hawaii economy surged forward and began to return to or exceed pre-9/11 levels. Electricity use climbed to a record peak in October 2004. Reserve margins were shrinking more rapidly. HECO activated its public notification plan and issued a call for conservation on October 13, 2004.

In the March 10, 2005 AOS, generating system reliability analysis performed in Section 4.3.1.1 showed that generation reliability is lower than desired levels, affirming that the new generating unit is now needed earlier than 2006 in order to provide established levels of generation reliability. Shrinking reserve margins during this period of strong growth is affecting maintenance by limiting maintenance planning flexibility.

HECO is also working on a number of projects to mitigate the effects of projected reserve capacity shortfalls and increase generating unit availability. These include:

a. Maintaining staffing levels to support 24/7 operations of all HECO generating units;
b. Continuing efforts to implement additional night shift maintenance to allow operational maintenance during off-peak periods;
c. Installing additional distributed generation (DG) at HECO-owned facilities, as well as investigating the feasibility of DG at customer-owned facilities;
d. Creating a demand load response program to seek additional interruptible loads for customers unwilling or unable to participate in the CIDLC load management program;
e. Developing a Residential AC Load Control Program, which will add residential air-conditioner load control to the existing residential direct load control program, which currently focuses solely on water heating;
f. Working with the Consumer Advocate and other parties to allow the enhanced DSM programs to proceed on an interim basis if the final decision on certain issues requires more time;
g. Continuing with capital projects to improve the reliability of generating units and to improve the flexibility in their operations;
h. Continuing to reschedule maintenance when feasible to (1) minimize the occurrence of reserve capacity shortfalls, (2) target maintenance based on the most current assessments of unit component conditions, and (3) adjust for any unanticipated outages of units;
i. Continuing to work with IPP partners to increase availability by careful scheduling and coordination of HECO and IPP maintenance to reduce the impact of IPP maintenance on system reliability; and
j. Accelerating the installation of the next generating unit

In addition, HECO created a public notification program to establish a process to inform and prepare customers for potential generation-related customer outages and to ask for voluntary conservation should a system emergency occur such that HECO anticipates that it may not be able to meet the demand for the day unless immediate action is taken. The public notification program is a tiered, systematic process of notifying the Commission, critical federal, state and local agencies, large customers, and the general public.

HECO has also been reviewing and making modifications to its manual load shedding plans in the event rolling outages become necessary due to temporary generation shortfall situations. Hospitals and other key public health and safety facilities should not be impacted in the event HECO has to initiate rolling outages. HECO divided Oahu into 17 regions, based on the layout of the subtransmission and distribution systems. No region has been pre-identified to go first when rolling outages are first initiated. The region or regions identified to go first will depend on how much load has to be reduced to keep the electric system stable.

5. Conclusion

As the demand for electricity increases, generation reserve margins will get tighter, which will put a strain on maintenance resources, which will lower generating unit availability and increase EFOR. HECO is experiencing this situation now. HECO does not foresee this situation improving in the near-term.

Until sufficient generating capacity can be added to the system, HECO will experience a higher risk of generation-related customer outages, and reserve capacity shortfalls that are more frequent and longer in duration.

The actual risk of generation-related customer outages depends, among other factors, on (1) the actual peaks experienced by the system, (2) success in implementing the DSM programs and utility and non-utility CHP projects, and customer participation in these programs, (3) the ability of HECO and its IPP partners to minimize unplanned or extended outages of existing generating units, and (4) the extent to which mitigation measures can be implemented. If actual peaks, due to weather impacts or other factors, are higher than forecasted, or if generating units experience higher forced outage rates, and/or more and longer maintenance outages, the risk of generation-related customer outages will increase.

HECO has taken a number of steps to mitigate the effects of reserve capacity shortfalls. It cannot, however, completely eliminate them. HECO will operate at lower-than-established reliability levels and take steps to mitigate the reserve capacity shortfall situation until the next generating unit is installed. Given the magnitude of the projected reserve capacity shortfall, HECO also will evaluate the need to file a PUC application for approval to add more firm capacity (a 2nd CT at Campbell Industrial Park).

II. Adequacy of Supply

1. Peak Demand and System Capability in 2005

HECO's 2005 system peak occurred on Wednesday, September 14, 2005 and was 1,273,000 kW-gross or 1,230,000 kW-net based on net HECO generation, net purchased power generation, the peak reduction benefits of energy efficiency demand-side management programs implemented beginning in mid-1996, and with several cogenerators[12] operating at the time. Had

[12] At the time of the peak, certain units at Tesoro and Pearl Harbor were generating an estimated 20,400 kW of power for use at their sites.

these cogenerating units not been operating, the 2005 system peak would have been approximately 1,293,400 kW-gross or 1,250,400 kW-net.

HECO's total generating capability of 1,614,600 kW-net at the time of the 2005 system peak included 406,000 kW-net of firm power purchased from (1) Kalaeloa Partners, L.P. ("Kalaeloa"), (2) AES Hawaii, Inc., and (3) H-POWER. Oahu had a reserve margin of approximately 30% over the 2005 system net peak.[13] Subsequent to the 2005 system peak, the f Kalaeloa PPA Amendments No. 5 and No. 6 became fully effective on September 28, 2005. As a result, an additional 28 MW are counted from Kalaeloa for planning purposes. In addition, approximately 14.8 MW of distributed generation was installed at three HECO sites on October 26, November 9, and December 16, 2005.

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

2. Estimated Reserve Margins

Appendix 1 shows the expected reserve margin over the next three years, based on HECO's May 2005 Sales and Peak Forecast, and HECO's latest estimates of acquired DSM impacts for 2005, forecasted enhanced energy efficiency DSM impacts, forecasted load management DSM impacts, and forecasted non-utility and utility CHP impacts.

3. Relevant Events Since 2005 Adequacy of Supply Report:

On March 10, 2005, HECO filed its annual Adequacy of Supply report with the Commission ("2005 AOS") in which HECO concluded that HECO's generation capacity for Oahu would be sufficiently large to meet all reasonably expected demands for service, but that it expected a reserve capacity shortfall of 70 MW by the end of 2006. Appendix 4 of the 2005 AOS described the uncertainties in HECO's capacity planning, including actual daily load versus forecasted loads, non-dispatchable as-available energy, actual CHP impacts versus forecasted impacts, actual energy efficiency DSM impacts versus forecasted impacts, actual load management DSM impacts versus forecasted impacts, actual outage schedule versus forecasted outage schedule, and assumed Equivalent Forced Outage Rates ("EFORs"). Recognizing the uncertainties in planning assumptions, Appendix 5 of the 2005 AOS provided the results of sensitivity analyses, which illustrated how the capacity shortfall could change under various scenarios. As described below, some of the circumstances that occurred in 2005 were similar to scenarios tested in the 2005 AOS sensitivity analysis. For example, recorded impacts from Energy Efficiency DSM, Load Management DSM, and Combined Heat and Power were less than projected in the 2005 AOS base case. A scenario which illustrated the outcome of this

[13] The reserve margin calculation includes 10,000 kW of interruptible loads served by HECO.

possibility was provided in the AOS (see 2005 AOS, Appendix 5, "Alternate DSM and CHP Scenario").

Since HECO filed its 2005 AOS, there have been changes in certain planning assumptions, and events have occurred that will affect its assessment of the adequacy of supply on Oahu. These include (1) the development of a new short-term sales and peak forecast in May of 2005, (2) determination that forward-looking generating unit availability[14] should reflect more recent operating experience (higher EFORs, lower availability), rather than long-term historical averages (lower EFORs, higher availability), (3) bifurcation of new energy efficiency DSM program proposals from the HECO Test Year 2005 rate case into a separate docket that is currently in progress, and (4) developments that have slowed the expected rate of implementation for customer-sited CHP systems, such as higher prices for the diesel and /or synthetic natural gas used by CHP systems relative to the cost of electricity, which is based on the lower cost LSFO, as well as HECO's ability to do CHP projects.

3.1. <u>Kalaeloa Partners, L. P.</u>

In November 2004, HECO filed an application for approval of Amendment Nos. 5 and 6 to its Power Purchase Agreement with Kalaeloa Partners L. P. ("Kalaeloa") in Docket No. 04-0320. The application was approved by the Commission on May 13, 2005. The full set of benefits and obligations of PPA Amendments No. 5 and No.6 became effective on September 28, 2005.

3.2. <u>May 2005 Peak Forecast</u>

HECO developed a new short-term sales and peak forecast in May 2005 ("May 2005 forecast") which was subsequently adopted for planning purposes in early June 2005. This forecast superseded the June 2004 peak update used in the 2005 AOS.

The near-term outlook for the local economy used as the basis for the May 2005 forecast did <u>not</u> change substantially from the outlook used for the June 2004 update. The economic outlook remains very optimistic, with continued strong activity in real estate and construction, and strong growth in jobs and real personal income. Visitor arrivals are expected to have set a new record in 2005, to continue robust growth through 2006, and to remain growing at a more moderate pace thereafter. Growth in the residential sector is expected to moderate somewhat after strong increases over the last few years, especially as interest rates are expected to climb from historical lows. The military sector is projected to be a major driver of growth in the near future, with projects related to the Stryker Brigade transformation, the C-17 squadron, and military housing privatization.

[14] See Section 3.4 for a discussion on availability.

A comparison of the June 2004 peak update and the May 2005 peak forecast is shown in Table 1 below.

Table 1:
Comparison of Forecasted Peak Loads
(Without impacts of 2005 and thereafter Energy Efficiency DSM, Load Management DSM, Utility CHP and Non-utility CHP)

Year	June 2004 Forecast System Peak (Net MW)	May 2005 Forecast System Peak (Net MW)	Decrease in Peak Forecast (MW)
2005	1,325	1,309	-16
2006	1,366	1,360	-6
2007	1,395	1,394	-1
2008	1,409	1,413	+4
2009	1,438	1,445	+7
2010	Not Available	1,474	N/A

While the local economic outlook remains strong, the May 2005 forecast is lower than the June 2004 update in the earlier years of the forecast horizon because of more pessimistic growth expectations in several commercial sectors due to lower than expected actual sales in early 2005 and anecdotal evidence that suggests many businesses seem to have learned lessons from recent events affecting the local economy, including 9/11, SARS, and the Iraq war. Despite strong job growth and increased business activity, companies appear to be focusing on operational efficiencies including adopting energy efficiency measures and adding less floor space to accommodate new jobs. Re-evaluation of several large commercial projects also resulted in lowered projections due to lower expected loads and slower load build ups. Additionally, commercial sector sales projections were lowered as a result of temporary load decreases from major repair, renovation, and construction projects such as UH Manoa's Hamilton Library and Outrigger's Waikiki Beach Walk project. Lower peak projections in the earlier years of the May 2005 forecast resulted from the lower than previous sales outlook, while stronger sales growth forecast in the latter years of the forecast horizon resulted in slightly higher peak projections. Overall, the May 2005 forecast projections remain within -1.2% to 0.5% of the forecast peaks in the June 2004 update for 2005 - 2009.

3.2.1. 2005 System Peak

HECO's 2005 system peak of 1,273 MW-gross or 1,230 MW-net occurred on September 14, 2005. The 2005 annual peak was 54 MW-gross or 51 MW-net lower than the system record peak of 1,327 MW-gross or 1,281 MW-net set on October 12, 2004. During the time of the peak, several cogenerators were running and either delivering energy (on an as-available basis) to the HECO system or partially offsetting their on-site loads. If these units had not been running, HECO's peak would have been 1,293 MW-gross or 1,250 MW-net. This 2005 adjusted peak was approximately 66 MW-net lower than the peak projected in the June 2004 forecast, and approximately 54 MW-net lower than the peak projected in the May 2005 forecast

HECO's lower system peak in 2005 than in 2004 is likely due to a combination of factors. Weather probably contributed as 2005 saw less Kona winds, was less humid, and slightly cooler than 2004, which may have resulted in lower air conditioning loads. Consumers also appear to be generally more price-conscious, particularly since higher gasoline and housing prices are constantly in the news. Some customers may be responding to this increased visibility and the higher electricity prices by controlling their use of electricity and incurring some inconvenience or discomfort. This voluntary response is likely to have resulted from HECO's energy conservation messages and calls for voluntary reductions in use. Although welcome, experience shows this response is not sustainable over the long term. It is also likely that some customers' use is flat or down simply because of operational differences between 2005 and 2004.

While the 2005 peak did not achieve the level of 2004's record peak, peaks are expected to continue growing during the forecast horizon with the robust local economy and as new construction projects are completed.

Forecast peaks are derived on a weather normalized basis, thus forecast peaks do not represent an "upper bound" of what actual peaks may be. HECO's generation system needs to be able to serve the actual peak, irrespective of the weather situation.

Figure 1 illustrates HECO's historical system peaks and compares them to forecasts used in the 2005 AOS base case and 2006 AOS base case. For the 2006 AOS, a lower load scenario was analyzed, which uses as its starting point the 2005 system peak. 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.

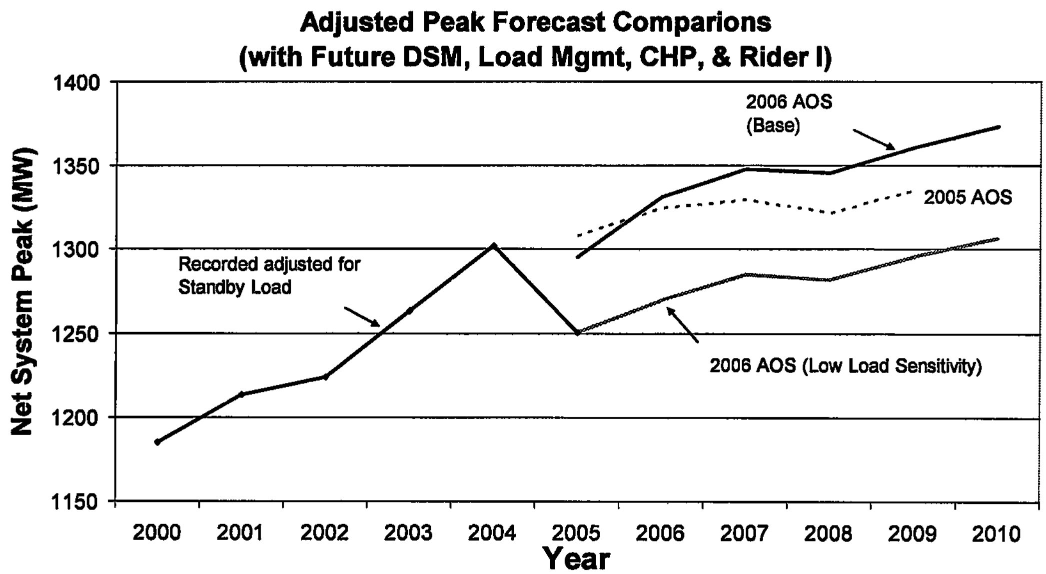

Figure 1: Recorded Peaks and Future Year Projections

One of the consequences of rising peak demand is that the reserve margin (i.e., the reserve capacity, which is the difference between the total installed capacity less the peak demand) will continue to decline. The declining reserve margin will continue to reduce the flexibility HECO has in scheduling outages for maintenance of the generating units, and responding to unanticipated generating unit forced outages or deratings. This is because HECO must try to maintain an amount of spinning reserve necessary to cover for the unexpected loss of the largest unit. The total system capacity less the capacity of the largest unit less the system peak leaves the amount of capacity that can be taken off the system for maintenance. As the peaks increase, the amount of capacity that can be taken off the system decreases.

3.3. Forward-looking EFOR

As explained in Section 4 (HECO Capacity Planning), HECO's capacity planning criteria are applied to determine the adequacy of supply and whether or not there is enough generating capacity on the system. HECO's capacity planning criteria consists of two rules and one reliability guideline. The reserve capacity shortfalls calculated herein are determined by the application of the reliability guideline, which involves a Loss of Load Probability ("LOLP") calculation. The outputs of the LOLP calculation are driven by the input assumptions. The key input assumptions include the load to be served, the amount of firm capacity on the system, and the availabilities of the generating units. The EFOR of a generating unit is one of the key determinants of the availability of the unit.

EFOR, or equivalent forced outage rate, is the rate at which forced outages occur. EFOR is a subset of generating unit availability and accounts for unanticipated shutdowns caused by forced outages and generating unit deratings caused by equipment problems that allow operation of the generating unit, but at a lower level of output. An example of a generating unit derating's impact on EFOR is if a unit is limited to 90% of full power because of an equipment malfunction, its EFOR would be 10% for the duration of the derating.

EFOR is a parameter used in traditional long-term planning and integrated resource planning ("IRP") to determine when and how much capacity is needed to provide established levels of generation-related electric service as determined by HECO's reliability planning guideline. For traditional long-term planning, utilities may average the historical individual unit EFORs by similar unit types and over an extended time period (for example, 5 or 10 years). This method may provide the approximate reliability of each type of generating unit over the long-term. However, past experience is not always an accurate indicator of future performance. EFORs may vary as operating conditions change.

HECO's composite generating unit EFOR has historically compared favorably to the industry average for similar types and sizes of units. As an isolated island utility without interconnections, HECO has had to strive for lower EFORs compared to mainland utilities because HECO cannot rely on neighboring utilities for reserve capacity.

Table 2 below provides recorded HECO EFOR data by unit for the period 2000 to 2005. The estimate of forward-looking EFOR rates is based on a combination of historical data, experience, and operational judgment. In determining the forward-looking EFORs to use in the 2005 AOS report, the focus was on the five-year period 2000-2004. In 2004, the recorded EFOR was considered high given the actual experience in the period 2000 to 2003.

In consideration of the on-going capital and maintenance work that was being performed on the units, the forward-looking EFORs used in the 2005 AOS report (and shown in the right-most column of Table 2, under "AOS 2005 EFOR") reflected optimism that the EFORs could be restored to levels more in line with the 2000 to 2003 experience. For example, at the time the EFOR projection was being developed, substantial progress was made on the Waiau Unit 9 compressor repairs. Also, HECO had a plan to remove the derating on Waiau Unit 3 and restore it to its full capacity. The details of the development of the EFOR projection were provided in response to CA-IR-461 in Docket No. 04-0113 (HECO Test Year 2005 Rate Case).

In 2005, recorded EFORs were even higher than they were in 2004. Two significant events that contributed to the higher EFOR in 2005 were (1) the forced outage of Waiau Unit 8 resulting from the induction of water into the steam turbine and (2) the continued derated operation of Waiau Unit 3 because the low reserve capacity situation constrained HECO's ability to take units such as Waiau Unit 3 out of service for maintenance. The experience in 2005 provided an indication that the 2004 EFOR experience was not unusual and that the 2004-2005 data reflected a higher trend in EFOR. Therefore, in determining the forward-looking EFORs to be used in the analysis for this 2006 AOS, the focus was on the 2004-2005 period. These forward-looking EFORs are shown in Table 2, under the column "Forward-Looking EFOR." This higher EFOR projection (compared to the 2005 AOS projection) reflects an expectation of continued constraints on maintenance flexibility, continued aging of the generating units[15], anticipation of more catastrophic forced outage events and deratings resulting from the cycling operation of certain units and their auxiliary equipment, and more frequent and longer duration overhauls and maintenance outages. The updated EFOR projection reflects HECO's attempt to improve the accuracy of the projection by better taking into account the recent experience and all of the factors that contributed to this experience. A discussion of the derivation of the forward-looking EFORs is provided in Appendix 7. Included in this discussion are actions that HECO will take in effort to improve the EFORs of its generating units.

Estimating forward-looking EFORs is difficult as there are many factors to consider, such as age and condition of the units, the operating stress placed on the units, and the type of maintenance performed. An alternative forward-looking EFOR scenario was considered. This consisted of a four-year (2002-2005) average. This period contained two consecutive years in which EFORs were low and the subsequent two consecutive years in which EFORs were high.

One significant contributing factor to the stress placed on the units is the increasing number of hours that HECO's cycling and peaking units[16] are running as system demand grows. The cycling and peaking units and their associated auxiliary equipment must turn on and off, on a daily basis, and this results in cyclic thermal stresses and accelerated wear on cycled auxiliary equipment, which damage critical parts, and can result in a generating unit forced outage or derating. The increased operating hours add to the stress on the units.

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[15] The average age of HECO's baseload and cycling units is 36 years and 51 years, respectively. The average age of HECO's peaking units is 33 years.

[16] The cycling units are Waiau Units 3 to 6 and Honolulu Units 8 and 9. The peaking units are Waiau Units 9 and 10, which are combustion turbines.

The ages of the units also played a large role in the higher EFORs in last two years. Generating units are made up of very complex systems and equipment that wear and tear at different rates as they age. Older mechanical and electrical equipment are prone to break down more frequently than newer equipment.

The EFOR values in the row titled "HECO" represent a HECO-system composite EFOR that takes into account the size and operating hours on each unit.

Table 2: Historical and Forward-looking EFORs

	2000	2001	2002	2003	2004	2005	Forward-Looking EFOR	4 Year Avg EFOR 2002 - 2005	AOS 2005 EFOR
H8	7.2%	10.4%	3.6%	13.0%	23.7%	1.7%	12.8%	10.5%	5.7%
H9	1.4%	3.0%	3.1%	20.0%	1.0%	12.0%	12.8%	9.0%	5.7%
W3	2.0%	1.9%	6.5%	10.9%	24.7%	42.2%	33.5%	21.1%	9.2%
W4	3.0%	14.8%	5.1%	3.4%	13.4%	5.0%	12.8%	6.7%	7.9%
W5	3.6%	0.8%	2.2%	4.1%	1.0%	1.0%	2.9%	2.1%	2.3%
W6	3.8%	3.9%	0.6%	2.8%	0.3%	2.6%	2.9%	1.6%	2.3%
W7	0.7%	1.6%	1.8%	0.7%	1.2%	0.6%	7.7%	1.1%	1.2%
W8	5.3%	1.5%	0.1%	0.0%	7.7%	23.5%	7.7%	7.8%	2.9%
W9	65.7%	4.1%	49.9%	6.9%	63.2%	69.2%	10.0%	47.3%	10.0%
W10	13.4%	5.0%	13.6%	36.0%	4.4%	7.4%	10.0%	15.3%	10.0%
K1	1.2%	0.7%	2.3%	1.2%	2.6%	5.4%	4.3%	2.9%	2.6%
K2	1.7%	3.1%	1.0%	2.2%	2.9%	2.0%	4.3%	2.0%	2.9%
K3	0.3%	3.9%	0.1%	3.5%	8.8%	8.3%	7.7%	5.2%	3.3%
K4	5.7%	0.9%	3.6%	1.3%	1.4%	4.9%	7.7%	2.8%	2.6%
K5	1.7%	0.4%	1.0%	1.1%	7.6%	3.1%	5.5%	3.2%	2.4%
K6	0.9%	0.4%	0.5%	1.9%	3.3%	5.9%	4.9%	2.9%	2.4%
HECO	**2.45%**	**1.6%**	**1.8%**	**2.4%**	**6.2%**	**9.25%**	**6.8%**	**4.0%**	**2.9%**
H-POWER							10.0%	10.0%	10.0%
Kalaeloa							1.0%	1.0%	1.0%
AES							1.0%	1.0%	1.0%

3.4. <u>HECO Generating Unit Planned Outages and Maintenance Outages</u>

Each generating unit has two possible states: either it is available (i.e., it is operating or on stand-by, ready to serve load) or unavailable. When a unit is available, it can be fully available (i.e., it is able to operate at its full capability) or partially available (i.e., it is derated or able to operate only at less that its full capability).

A unit may be unavailable for three reasons: (a) it is on planned outage (i.e., on scheduled overhaul); (b) it is on a maintenance outage (i.e., out of service on a scheduled basis to repair a problem on the unit); or (c) it is on forced outage (i.e., unexpectedly forced out of service).

One measure of generating unit availability is the Equivalent Availability Factor ("EAF"). It can generally be thought of as the percent of the time a unit is available to serve demand, taking into account periods of time when the unit is only partially available.

HECO's composite generating unit EAF has historically compared favorably to the industry average for similar types and sizes of units. As an isolated island utility without interconnections, HECO has had to maintain a higher EAF than mainland utilities because HECO cannot rely on neighboring utilities for reserve capacity.

Forced outages and deratings reduce generating unit availability and are accounted for in the EFOR statistic. Planned outages and maintenance outages also reduce generating unit availabilities. As reserve margins continue to shrink, it becomes more challenging to take units out of service for planned or maintenance outages or to provide maintenance scheduling flexibility.

The scheduling of planned overhaul and maintenance outages, is very dynamic in nature. When forced outages occur, or potential problems are discovered such that an outage is needed to address it, the outage schedule must be rearranged. As explained in Section 3.2.1, as peak demand increases, reserve capacity decreases, and the amount of capacity that can be taken off the system for maintenance decreases. This reduces the flexibility in rearranging the outage schedule. The dynamic nature of scheduling outages was discussed in HECO's Test Year 2005 Rate Case.

Notwithstanding the dynamic nature of maintenance scheduling, for the 2006 AOS, additional emphasis was placed on developing an assumption for planned outages and maintenance outages in which the unavailable MWh due to these two types of outages was better levelized over the forward-looking period 2006-2010. In the 2005 AOS, then-current outage schedules were used. These planned and maintenance outage schedules identified year-ahead outage requirements (and unavailable MWh) more completely than in the period two to four years into the future. This drop-off in unavailable MWh is similar to a drop-off in forecast capital expenditures that might be seen in a 5-year capital budget, where years further in the future often have the appearance of lower capital expenditures because much of the work cannot be precisely defined at the time the budget is developed. To adjust for this phenomenon, trending is sometimes used as a technique to account for projects that will be eventually identified with the passage of time. In terms of planned outages and maintenance outages, historical outage requirements were scrutinized to ensure that the forecast for future outages to perform maintenance work two to four years in the future was not understated. This should help improve the accuracy of the forecast for unavailability attributable to planned and maintenance outages.

3.5. Load Management DSM, Energy Efficiency DSM and CHP Impacts

The load reducing impact acquired from HECO's existing energy efficiency DSM and load management DSM programs in 2005 was approximately 8 MW[17]. This recorded load reducing impact was 3 MW less than the 11 MW projected for 2005 in the 2005 AOS report for the impacts of HECO's proposed load management DSM and the continuation of existing energy efficiency DSM. The 2005 AOS report did not project any 2005 impacts for CHP, and none were acquired. Further, the 2005 AOS projected that combined impacts from load management DSM, energy efficiency DSM, and CHP would be approximately 98 MW by 2009. The 2006 AOS projects that the combined impacts will be reduced to approximately 79 MW, as shown in Table 2, below.

Table 2:
Previous and Current Projections of
Load Management DSM, Rider I, Energy Efficiency DSM, and CHP[18] (MW)

	Load Management		Rider I		Energy Efficiency DSM		CHP		**Total Load Reduction**		
Year	2005 AOS	2006 AOS	2005 AOS	2006 AOS	2005 AOS	2006 AOS	2005 AOS	2006 AOS	**2005 AOS**	**2006 AOS**	**Diff**
2005	6	5	5	5	5	4	0	0	**17**	**14**	**-3**
2006	17	15	5	5	15	9	5	0	**41**	**29**	**-12**
2007	26	22	5	5	24	18	10	1	**65**	**46**	**-19**
2008	34	31	5	5	33	27	15	4	**87**	**67**	**-20**
2009	35	37	5	5	43	36	20	5	**103**	**84**	**-19**
2010	35	42	5	5	52	45	24	7	**116**	**100**	**-16**

These reductions in MW impact are due to a combination of factors. The 2005 AOS assumed that the load management DSM programs would start in January 2005.

17 The 2005 AOS and 2006 AOS both assume that HECO's system peak will occur in the month of October. The 2005 system peak occurred in September, which is approximately one less month for HECO to acquire peak-reducing impacts of energy efficiency and load management DSM. Had the 2005 system peak occurred in October, approximately 9 MW of peak-reducing impacts would have been realized at the time of the system peak.

18 To allow equivalent-basis comparison to 2006 AOS projections, 2005 AOS figures are reduced by 2004 Acquired impacts. The 2005 AOS did not present data for year 2010, but it is being included here for comparative purposes. Rider I is not considered a load management program, but is assumed to reduce the peak for planning purposes. Rider I planning assumptions have not changed between the 2005 AOS and the 2006 AOS. Totals may not add, due to rounding.

Participation in the Residential Direct Load Control ("RDLC") program was better than expected and continued as such throughout 2005. However, lower than expected customer acceptance of the CIDLC Program and the efforts to seek agreement with the Hawaii State Department of Health to allow the use of customer-owned stand by generators led to load management impacts that are lower than was forecast in the 2005 AOS through 2008. The projections for HECO's load management DSM programs assume that modifications to the RDLC and CIDLC Programs to include residential air-conditioning load control and add a commercial and industrial demand load response components are implemented in January 2007. The proposed demand load response components are expected to decrease load reduction impacts in the short-term, but increase load reduction impacts thereafter. In addition, in contrast to maintaining the amount of load reductions after 2009 as assumed in the 2005 AOS, the projections reflect HECO's intention to increase load reduction acquisition beyond 2009.

At the time of HECO's filing of its 2005 AOS on March 10, 2005, HECO assumed that the five existing energy efficiency programs with enhancements and three additional programs would be bifurcated from the rate case and approved by the Commission on an accelerated schedule separate from the rate case. It was further assumed that an increased rate of acquisition of peak reduction benefits from the eight programs would begin in July 2005. On March 16, 2005 the Commission in Order No. 21698 bifurcated the rate case application creating the Energy Efficiency Docket, Docket No. 05-0069, for the DSM programs. Furthermore, on April 20, 2005, the Commission, in Decision and Order No. 21756, Docket No. 03-0142, denied the RCEA Program, without prejudice. HECO is currently continuing to implement its five existing energy efficiency DSM programs.

Since the bifurcation did not result in an accelerated schedule for the complete DSM proposal, HECO proposed a schedule that would permit it to submit the Interim DSM proposals. Following HECO's informal submission of its Interim DSM Program modifications to the parties on October 11, 2005, HECO filed a letter with the Commission on December 5, 2005 requesting modifications to HECO's existing energy efficiency programs and also approval of a new interim DSM program, collectively referred to as HECO's "Interim DSM Proposals". The current assumption is that the Interim DSM Proposal will be approved in July 2006 and that the complete (hereinafter "enhanced") DSM proposal, along with modifications to the load management programs (expected to be filed with the Commission in early 2006) will be approved by January 2007. However, the actual timing for the approval of these proposals is uncertain.

The 2005 AOS also projected a mid-2006 installation of the first utility system under the proposed utility CHP program (and/or individual CHP agreements); whereas HECO currently does not expect that any CHP impacts will be realized in 2006.

There are indications that CHP development in Hawaii in general, and on Oahu in particular, is being affected by macro-scale economics. Specifically, the economic viability of CHP is highly sensitive to fuel and electricity prices. The energy efficiency benefits of a CHP system may not translate to overall cost savings for a customer if the CHP fuel cost is significantly higher than the cost of fuel used to generate grid electricity, as is the situation currently on Oahu.

Please refer to Appendix 2 for individual changes in projections for HECO's load management DSM programs, enhanced energy efficiency DSM programs, utility CHP program and non-utility CHP annual impacts.

The net result of these reductions is that the hourly load that must be served by central-station generation and non-CHP distributed generation is increased.

3.6. Next Generating Unit Addition

2009 was identified as the need date for the next generating unit in HECO's second IRP process (IRP-2) filed with the Commission in January 1998. Hawaii was mired in economic slowdown at the time, caused by the Asian economic crisis and Japan's 1998 recession[19]. Signs of economic recovery in Japan in 1999 and strong west-bound visitor arrivals led Hawaii to an economic recovery in that year. Immediately following the 9/11/2001 terrorist attacks, economists were predicting a recession lasting until late 2002[20]. However, in the fourth quarter of 2002, economic projections were cautiously optimistic. The need date of the next generating unit was still projected to be 2009 based on the December 2002 IRP-2 Evaluation report.

In 2003, the Hawaii economy began to bounce back from the post-9/11 concerns. In its March 31, 2004 AOS report, HECO stated "[W]ith the new higher forecast for peak demand, the next generating unit would be needed in 2006 if other measures, such as DSM, distributed generation, CHP or other supply-side resources, are not sufficient to reduce demand or increase supply to maintain generating system reliability at or above the 4.5 years per day threshold. However, given the long lead time to install the next generating unit, it is not possible to have the unit installed by 2006."

In 2004, the Hawaii economy surged forward and began to return or exceed pre-9/11 levels. Electricity use climbed to a record peak in October 2004. Reserve margins were shrinking more rapidly. HECO activated its public notification plan and issued a call for conservation on October 13, 2004.

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[19] HECO IRP-2 Evaluation Report, December 2002, Chapter 2
[20] ibid

In the 2005 AOS, generating system reliability analysis performed in Section 4.3.1.1 show that generation reliability is lower than desired levels, affirming that the new generating unit is now needed earlier than 2006 in order to provide established levels of generation reliability. Shrinking reserve margins during this period of strong growth is affecting maintenance by limiting maintenance planning flexibility.

HECO estimates that the lead time to install a simple-cycle combustion turbine is approximately seven years. Given this lead time, HECO began the process of preliminary engineering work in 2002 and began efforts to obtain the Covered Source Permit ("air permit") for a nominal 100 MW simple-cycle combustion turbine in January 2003. HECO submitted an initial application for the air permit with the State of Hawaii Department of Health ("DOH") in October 2003. The air permit contains provisions to use alternate fuels such as ethanol. The DOH deemed the initial application complete in November 2003. The HECO IRP-3 Advisory Group was informed of the air permit application at the October 7, 2003 IRP Advisory Group meeting. In December 2004, HECO submitted an amendment to its initial air permit application, in part to allow for the possibility that a second simple-cycle combustion turbine may be needed sooner than projected (for example, if energy efficiency and load management DSM, CHP and renewable energy program imports are not fully realized, delayed from the projected timeline, or if system demand increased more than projected). The DOH deemed the revised air permit application complete in February 2005 and is currently in the process of reviewing the application. HECO continues with efforts to permit, design, and install its next generating unit and a 2-mile long 138 kV transmission line between the AES substation and CEIP substation. To date, these efforts include:

- Through meetings with West Oahu/Waianae Coast community leaders in 2005, developed a proposed community benefits package in recognition of this project being sited in their community.
- On June 17, 2005, filed applications with the Commission for approval to commit funds in excess of $2.5 million for both the project and the community benefits package.
- Through a competitive bid process, selected the combustion turbine to be used for this project (Siemens SGT6-3000E) in December 2005.
- Continuing to work with the DOH and EPA to develop a draft air permit for public review and comment.
- Completed the Draft Environmental Impact Statement (DEIS) in January 2006[21]. Announcement of the DEIS availability was made in the February 8, 2006 *Environmental Notice.*

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[21] Since the unit addition is planned to be greater than 5 MW, an Environmental Impact Statement is required by HRS Chapter 343.

- Continuing to meet with west Oahu neighborhood boards and community leaders to present HECO's plans.
- Started detailed engineering design to support long lead time "ministerial permits", such as the building permit and grubbing and grading permit.

However, given the long lead time of the permitting, engineering, equipment procurement and construction activities, it appears that 2009 is still the earliest that permitting and installation of the planned simple-cycle combustion turbine can be expected to be completed.

4. HECO Capacity Planning

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

4.1. HECO's Capacity Planning Criteria

HECO's capacity planning criteria consists of two rules and one reliability guideline. As noted in Section 3.3 (Forward-looking EFOR), the reserve capacity shortfalls calculated herein are determined by the application of the reliability guideline, where the key inputs to the application of the reliability guideline are the EFORs of each generating unit.

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 HECO will not build reserve capacity to serve interruptible loads, interruptible load programs such as HECO's current Rider I and recently approved RDLC and CIDLC programs 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 the total capacity of the system, in MW, add the total amount of interruptible loads, in MW, that would be available for interruption at that time, subtract the capacity, in MW, of the unit or units that are unavailable due to planned maintenance, subtract the capacity, in MW, of the largest available unit, and determine whether the result is greater than or less than the system peak, in MW, 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.

4.2. HECO's Reliability Guideline: Loss of Load Probability

The application of HECO's generating system reliability guideline does take into account the probabilities that generating units could be unexpectedly lost from service. The EFORs of the generating units are key inputs to the LOLP calculation in the application of the guideline.

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 HECO's generating system reliability guideline.

HECO has a reliability guideline threshold of 4.5 years per day. HECO 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. Please refer to Appendix 3 of the 2005 AOS for additional information related to HECO's reliability guideline.

LOLP is a measure of the probability on a given day of not having sufficient generation available to serve the system load, due to forced outages of one or multiple generating units (owned by HECO or IPPs). LOLP is computed using a day-by-day computer simulation that takes into account projected system daily peak loads to be served by central station generation, scheduled maintenance, and unit forced outage rates (expressed as equivalent forced outage rate, or EFOR). Energy efficiency DSM programs, interruptible load management DSM programs, and customer-sited CHP resource also have an effect of reducing the daily peak load that has to be served, so they affect the LOLP calculation as well.

While LOLP provides an indication of the probability that the peak demand may or may not be served, it does not provide a measure of the expected duration of outages due to insufficient generation, the magnitude (in MW) of the outage, or the projected number of unnerved kilowatthours (kWh) or customers due to insufficient generation.

In addition, probabilistic results are a mathematical expectation that may differ from observed results. For example, the probability that a tossed coin will land on "Tails" is 50%. However, this is no guarantee that a coin tossed 10 times will result in 5 Tails. Similarly, a system with an expected LOLP of 4.5 years per day could experience two generation shortfall incidents in a single year (an observed LOLP = 0.5), or it could experience one incident in five years (an observed LOLP = 5.0), or it could experience one incident in ten years (an observed LOLP = 10.0). The fact that an observable generation shortfall incident did not occur precisely at the expected interval should not lead one to conclude that the system has become more or less reliable than calculated, it merely confirms that random events like forced outages – even when characterized as mathematical probabilities – are still random.

Other reasons for the variance between mathematical expectation and observable generation shortfall incidents include actual conditions, such as actual load being lower than projected load, as was the case in 2005, or the degree to which critical situations are managed to address the shortfall. For example, HECO's recent calls for extra conservation helped to reduce the electrical load on the system, however, the impacts of this community response cannot be assumed for capacity planning purposes. The consumer is under no obligation to undertake emergency conservation measures on a routine basis or when asked by the utility (the utility encourages all customers to practice conservation). This reduction in load would be an example of events that may occur, but are not "counted on" when calculating the mathematical expectation for insufficient generation events. In general, the application of HECO's reliability guideline results in a need for more generating capacity on the system compared to that required by the HECO Rule 1 or HECO Rule 2 planning criteria. The reliability guideline is probabilistic - it takes into consideration that forced outages from one or more generating units may result in not having sufficient generation capacity to meet the peak load demand. HECO Rule 1 and HECO Rule 2 criteria are deterministic – they only take into consideration that the forced outage from the largest generating unit may result in not having sufficient capacity to meet the peak load demand.

Whether or not there are actual outages due to insufficient generation as projected by the HECO reliability guideline will depend on factors that impact (1) the actual system load to be served by central station generation, (2) the actual scheduled maintenance of generating units, and (3) the actual EFORs for such units. The actual system load to be served by central station generation will be affected by (1) actual daily loads (versus forecasted loads and load profiles), (2) non-dispatchable as-available energy contributions, (3) actual CHP impacts (versus forecasted impacts), and (4) actual energy efficiency DSM and load management DSM peak impacts (versus forecasted impacts). (See Appendix 5 for a detailed discussion of uncertainties in HECO capacity planning).

4.3. Analysis Results

4.3.1. Base Scenario

4.3.1.1. Generating System Reliability Analysis

Table 3 below provides the LOLP calculated using a production simulation model for each year through 2010 under a base set of assumptions including: (1) continued acquisition of residential and commercial load management impacts, including modifications to these programs to add residential air-conditioning load control and commercial and industrial demand load response elements; (2) implementation of its Interim DSM Proposals in July 2006 and its enhanced energy efficiency DSM program beginning in 2007, (3) modest impacts from utility and non-utility CHP installations, beginning in 2007 and continuing through 2010, and (4) the inclusion of the additional 28 MW of firm capacity from Kalaeloa. In addition, the results in Table 3 are based upon the use of a forward-looking EFOR for all existing generating units, both HECO-owned and IPP. Table 3 projects that generating system reliability will be less than the 4.5 years per day reliability guideline in 2006 and continuing through 2010. Under these projections, a generation-related customer outage is likely to occur more frequently than that provided for in the reliability guideline. To determine the level of generating system reliability without the addition of new firm capacity beyond the 28 MW provided by Kalaeloa, Table 3 does not include the addition of the CIP simple–cycle combustion turbine in 2009.

Table 3:
Generation System Reliability
(Base Load Management DSM, Enhanced Energy Efficiency DSM, CHP, and EFOR)
HECO Reliability Guideline: 4.5 years/day

Year	Generation System Reliability (years/day)
2006	0.2
2007	0.1
2008	0.1
2009	0.1
2010	0.1

Table 4 shows the reserve capacity shortfall corresponding to the calculated reliability shown in Table 3. Reserve capacity shortfall is the amount of additional firm generating capacity needed to restore the generating system LOLP to be greater than the 4.5 years per day reliability guideline. Again, as in Table 3, it is noted that Table 4 does not include the addition of the CIP combustion turbine in 2009 to assess the reserve capacity shortfall.

Table 4:
Reserve Capacity Shortfall
(Base Load Management DSM, Enhanced Energy Efficiency DSM, CHP, and EFOR)

Year	Reserve Capacity Shortfall (MW)
2006	-170
2007	-170
2008	-180
2009	-200
2010	-200

The projected level of generation system reliability from 2005 through 2009 is significantly less than desirable, as shown in Tables 3 and 4. These shortfalls are approximately 100 to 150 MW worse than the reserve capacity shortfalls projected in the 2005 AOS.

4.3.1.2. HECO Rule 1 and HECO 2 Analysis

Table 5 shows the reserve capacity shortfalls relative to HECO's Rule 1 and Rule 2 criteria.

Table 5:
Rule 1 and Rule 2 Reserve Capacity Shortfalls
(Base Load Management DSM, Enhanced Energy Efficiency DSM, and CHP)

Year	Rule 1 Shortfall (MW)	Rule 2 Shortfall (MW)
2006	-7	-47
2007	18	-22
2008	-13	-53
2009	-28	-68
2010	-27	-67

In 2006, HECO anticipates a 7 MW reserve capacity shortfall for HECO Rule 1. Reserve capacity, at times, will be insufficient to meet HECO's projected spinning reserve and quick load pickup requirement (HECO Rule 2) in each of the next five years. Unplanned outages, unit deratings, and higher-than-forecasted electricity use would exacerbate the situation.

Reserve capacity shortfalls are still projected under these less stringent deterministic criteria.

Table 5 does not include the effects of the addition of the CIP combustion turbine in 2009.

4.3.2. Alternate Load Scenarios and Sensitivity Analysis

As discussed in Section 3.5, the timing and magnitude of the combined peak reduction benefits from HECO's proposed enhanced energy efficiency DSM programs, the load management DSM programs, and the proposed CHP Program (and/or individual CHP agreements) are uncertain. HECO evaluated a scenario where the impacts occur later and are lower than currently estimated. Because these programs affect peak demand and energy use, this scenario is also equivalent to higher-than-projected load growth.

The alternative higher load scenario uses the assumption that energy efficiency DSM, load management DSM, and CHP impacts are 50% of those acquired in the base case. Such a scenario is possible, for example, if (1) customer acceptance and/or awareness is less than expected in the case of the residential and commercial and industrial programs; (2) HECO's proposed enhanced energy efficiency DSM programs are not approved and, in their place, DSM programs with lower impacts (similar to impacts estimated for its existing programs) are continued; (3) HECO's participation in the CHP market is not forthcoming; and (4) electricity use is higher than that projected by the May 2005 sales and peak forecast . The combined peak reduction benefits would be reduced significantly in this scenario. Table 6 below summarizes the cumulative impact under this alternate scenario.

Table 6:
Comparison of the Base and Alternate DSM and CHP Scenario
(Higher Load)

	Cumulative Impact (MW)		
Year	Base	Lower-than-projected DSM, LM, CHP by 50% Alternate Scenario (Higher Load)	Difference
2006	24	12	-12
2007	41	20	-20
2008	62	31	-31
2009	79	39	-39
2010	95	47	-47

As explained in Section 3.2.1, HECO experienced a lower system peak in 2005 than in 2004. HECO performed a sensitivity analysis using lower peaks by starting with the 2005 recorded peak (adjusted upward for stand-by loads) and applying escalation factors from the May 2005 sales and peak forecast. The resulting peaks for this Lower Load sensitivity are illustrated in Figure 1 and tabulated in Table 7.

Table 7:

Comparison of the Peaks: Base versus Lower Load Sensitivity

	System Peak (MW)		
Year	Base	Lower Load	Difference
2006	1331	1270	-61
2007	1348	1285	-63
2008	1346	1282	-64
2009	1361	1296	-65
2010	1373	1307	-66

HECO performed a sensitivity analysis on EFOR by using a 4-year average EFOR, using historical data from 2002 through 2005. This average is designed to include a blend of two "better" years (2002 & 2003) and two "worse" years (2004 & 2005). The unit-specific EFOR values are provided in Table ES-2.

Table 7 shows the generating system reliability and reserve capacity shortfalls for the base scenario, alternate higher load scenario, and the alternate lower EFOR sensitivity.

Table 7:
Reserve Capacity Shortfall, MW

Year	Base Scenario	Alternate Scenario (Higher Load)	Alternate Scenario (Lower Load)	Alternate Scenario (Lower EFOR)
2006	-170	-180	-110	-120
2007	-170	-190	-120	-130
2008	-180	-210	-120	-140
2009	-200	-230	-140	-160
2010	-200	-240	-140	-160

Table 8 below shows Rule 1 planning criteria reserve capacity shortfalls for the alternate high load, low load, and lower EFOR scenarios. Because HECO's Rule 1 is a deterministic planning criterion that does not take into account the probability of generating unit outages, the lower EFOR sensitivity does not decrease the reserve capacity shortfall to meet the Rule 1 criterion.

Table 8:
Rule 1 Reserve Capacity Shortfall, MW

Year	Base Scenario	Alternate Scenario (Higher Load)	Alternate Scenario (Lower Load)	Alternate Scenario (Lower EFOR)
2006	-7	-17	54	-7
2007	18	0	81	18
2008	-13	-41	50	-13
2009	-28	-65	38	-28
2010	-27	-73	38	-27

(See Appendix 6 for additional quantifiable results for the Alternate Scenarios.

Tables 4 through 8 show that, even with the successful implementation of residential and commercial load management DSM, approval for and implementation of the Interim DSM Proposals in July 2006, and the enhanced energy efficiency DSM and load management modifications beginning in 2007, approval for and implementation of a revised utility CHP Program in 2007, and implementation of existing generating maintenance schedules and EFORs forecasted for the base scenario, there are still expected to be projected reserve capacity shortfalls in the 2006 – 2009 period. HECO is exploring ways to shorten the CIP generating unit schedule, but, as mentioned in Section 3.6, it is not expected to be placed into service earlier than 2009.

Under a scenario in which higher loads on the order of 40 MW are encountered (either through greater than projected load growth, and/or less than anticipated impacts of energy efficiency DSM, load management DSM, and CHP) the reserve capacity shortfalls are estimated to be approximately 210 MW by 2008.

If HECO unit EFOR rates are reduced to levels indicated by longer-term averages, reserve capacity shortfalls could decrease to 140 MW by 2008. These reductions are units specific, but in aggregate, would represent a reduction of approximately 40% in EFORs.

Under base case, alternate higher load, and alternate lower EFOR scenarios, reserve capacity shortfalls will increase to a level such that the nominal 100 MW capacity of the next generating unit will not be sufficient to restore HECO's generating system reliability above the 4.5 years per day reliability guideline in 2009 and beyond. Additional peak reduction impacts and/or firm capacity generation beyond what is already planned for in HECO's base plan would be required to restore generating system reliability to a desirable level pursuant to HECO's reliability guideline.

4.4. HECO IRP-3

HECO began the process for its third major integrated resource planning cycle (IRP-3) in July 2003. The IRP process develops a 20-year resource plan and a 5-year action plan based upon relevant forecast, financial, demand-side and supply-side (including renewable resource, distributed and central-station) assumptions that are developed for use in this process. The 20-year resource plan is intended to identify the appropriate characteristics, timing and size of demand-side and supply-side resources to meet near- and long-term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost. Consideration is given to life cycle costs and the plan's impact upon the utility's consumers, the environment, culture, community lifestyles, the state's economy, and society. A final report, which includes the selection of a recommended preferred plan for IRP-3, was filed with the Commission on October 28, 2005.

The IRP process identified six proposed resource plans with various combinations of demand-side, central-station supply side, renewable, and distributed generation in the form of CHP that meet the six resource plan concepts developed in conjunction with the Advisory Group and Technical Committees. Each of these six resource plans developed in the IRP included the implementation of an aggressive level of DSM, a large market potential for CHP, and the addition of a simple-cycle combustion turbine in 2009 (the earliest date that a simple-cycle combustion turbine can be permitted, constructed and placed into service). Scenarios for higher than projected fuel oil prices were performed for LSFO in the $70 to $119/bbl range. The IRP Supply-side Action Plan included activities to support installation of a 100 MW class simple-cycle combustion turbine generating unit in 2009. The Supply-side Risk Mitigation Measures noted that HECO is considering ways to accelerate the installation of this unit. In addition, because of long lead-times, preliminary activities to preserve the option, if needed, of installing additional firm capacity such as a second combustion turbine generating unit need to take place during the Action Plan period.

4.5. Reserve Capacity Shortfalls and Generation Shortfalls

Quantifying the risk of generation-related customer outages is difficult. Many factors cannot be quantified. (See Appendix 5 for a discussion of factors that affect the calculation of reserve capacity shortfalls and factors that affect generation shortfalls).

HECO has sufficient firm generating capacity on its system to meet the forecasted load. HECO may not, at times, have sufficient capacity to cover for the loss of the largest unit or for multiple generating unit outages.

Until sufficient capacity can be added to the system, the likelihood of generation-related customer outages exists. The risk of generation-related customer outages is also dependent on the success of implementing various demand side programs, including the residential and commercial load management DSM programs, the interim and enhanced energy efficiency DSM programs, the load management program modifications, and utility and non-utility CHP projects, and customer participation in these programs. In addition, the risk of generation-related customer outages is dependent on the ability of HECO and its IPP partners to maintain the availability of existing generating resources.

Several mitigation measures have been identified to best manage the increasing risk of reliability brought on by the shortfall in reserve capacity while the process to add a simple-cycle combustion turbine in 2009 continues. However, the interim mitigation measures do not provide the same level of reliability as a large increment of firm capacity.

5. Action Plan and Mitigation Measures

The 2005 AOS provided extensive Action Plan and Mitigation Measures, including efforts to (1) implement enhanced energy efficiency DSM programs, (2) implement a utility CHP program, (3) improve availability of HECO generating units, (4) maintain or improve the availability of independent power producers, (5) accelerate the installation of the next generating unit, (6) install DG, (7) refine the Commercial and Industrial Load Control program, (8) refine the Residential Direct Load Control program, and (9) implement a public notification program. A review of these items is presented in Appendix 3.

The 2006 AOS base case analysis projects reserve capacity shortfalls ranging from 170 MW to 200 MW from 2006 until the next generating unit can be added. HECO has developed an Action Plan and Mitigation Measures for this AOS, which includes efforts to (1) pursue accelerated installation of the next generating unit, (2) sustain operational staff to allow for 24 hours a day, 7 days a week operation of all generating units, (3) pursue the staffing plan for night maintenance, (4) continue to reschedule maintenance of generating units when feasible, (5) continue to work with independent power producer partners to increase availability, (6) pursue initiatives that improve EFOR for HECO generating units, (7) evaluate filing of a request to commit funds in excess of $2.5 million for a 2nd CT at Campbell Industrial Park, (8) evaluate additional DG opportunities, (9) expand peak-shifting strategies, (10) move forward on renewable proposals submitted to HECO and RHI, (11) support sea water air conditioning, (12) implement PV, and (13) prepare for potential outages. A description of the 2006 AOS Action Plan and Mitigation Measures is provided in Appendix 4.

6. Conclusion

HECO anticipates reserve capacity shortfalls in 2006 and projects these shortfalls to continue at least until 2009, which is the earliest that HECO expects to be able to permit, acquire, install and place into commercial operation its next central station generating unit.

Approximately 170 MW of additional peak load reduction measures and/or generating capacity would be needed in 2006 in order to maintain generating system reliability at or above HECO's reliability guideline. This is in addition to (1) the projected successful implementation of the residential and commercial load management DSM programs for which HECO has already obtained approval, and (2) approval for, and successful implementation of, the Interim DSM Proposals in July 2006 and the enhanced energy efficiency DSM programs and load management program modifications beginning in 2007. The reserve capacity shortfall is projected to be approximately 170 to 200 MW in the2007 to 2009 period

Until sufficient generating capacity can be added to the system, HECO will experience a higher risk of generation-related customer outages, and more frequent, longer duration reserve capacity shortfalls. The actual risk of generation-related customer outages depends, among other factors, on (1) the actual peaks experienced by the system, (2) success in implementing the DSM programs and utility CHP projects, and customer participation in these programs, (3) the ability of HECO and its IPP partners to minimize unplanned or extended outages of existing generating units, and (4) the extent to which mitigation measures can be implemented. If actual peaks, due to weather impacts or other factors, are higher than forecasted, or if generating units experience higher forced outage rates, and/or more and longer maintenance outages, the risk of generation-related customer outages will increase.

HECO considered three alternate scenarios in addition to the base case. Under the alternate higher load scenario, higher than forecast load growth and/or less than anticipated impacts of energy efficiency DSM, load management DSM, and CHP will cause the reserve capacity shortfall to increase, reaching approximately 180 MW in 2006, and 230 MW in 2009. Under the alternate lower load scenario, lower than forecast load growth and/or more than anticipated impacts of energy efficiency DSM, load management DSM, and CHP will cause the reserve capacity shortfall to decrease, reaching approximately 110 MW in 2006, and 140MW in 2009. With the better EFOR scenario, efforts to improve HECO generating unit EFOR rates will cause the reserve capacity shortfall to decrease, to approximately 120 MW in 2006, and 160 MW in 2009.

As the base case and both alternate scenarios illustrate, reserve capacity shortfalls are expected to increase to levels such that the nominal 100 MW capacity of the peaking unit planned for 2009 would not be sufficient to fully offset the shortfall in reserve capacity. In such scenarios, larger peak reduction impacts from measures such as these in the DSM and CHP programs would have to be obtained, and/or more firm capacity than that to be provided by the peaking unit planned for 2009, would be required to restore generating system reliability to an acceptable level that meets HECO's reliability guideline.

As a follow-up to the 2005 AOS, HECO has taken a number of actions to minimize the risk of generation-related shortfalls, which include implementing the approved load management DSM programs, filing interim DSM proposals for Commission approval in advance of the Commission's ultimate ruling on the enhanced energy efficiency DSM programs proposed in Docket No. 05-0069, a utility CHP program and a Rule 4 CHP Agreement, working to maintain or improve the availability of HECO generating units, working to maintain or improve the availability of Independent Power Producers generating units, negotiating and obtaining approval of the Kalaeloa amendments, and initiation of permitting and design of the next generating unit so that it can be installed by 2009. A review of the 2005 AOS action plan and mitigation measures is provided in Appendix 3.

As described in Appendix 3, HECO was able to successfully complete several of the key action plan and mitigation measures described in the 2005 AOS. However, the reserve capacity shortfall has increased, and HECO has again developed an action plan and mitigation measures in an attempt to address it. These include efforts to accelerate the installation of the next generating unit, sustained staffing to allow 24 hours a day, 7 days a week operation of all generating units, pursuit of night maintenance staffing, continued rescheduling of generating units when feasible, working with IPP partners to increase availability, pursuit of initiatives to improve the EFOR of HECO generating units, evaluation of additional DG opportunities, and evaluating the need to file a request to commit funds for the 2nd CT at Campbell Industrial Park. A description of the 2006 AOS action plan and mitigation measures is provided in Appendix 4.

The magnitude of the reserve capacity shortfall is large – about the size of the largest generating unit on Oahu – and while HECO will work to implement the action plan and mitigation measures described in Appendix 4, it is unrealistic to expect the reserve capacity shortfall to reduce to zero. Therefore, although HECO will be striving to do what it can to keep the lights on, the likelihood for continued calls for public conservation and/or generation-related outages will increase; at least until the simple-cycle combustion turbine at Campbell Industrial Park is placed into service.

Very truly yours,

Attachments

cc: Division of Consumer Advocacy

Table A1:
Projected Reserve Margins with and without Future DSM

		Without Future DSM (Includes Acquired DSM[I])			With Future DSM (Includes Acquired DSM[I])		
Year	System Capability at Annual Peak Load (net kW) [A] [II]	System Peak (net kW) [B] [III]	Interruptible Load (net kW) [C][IV]	Reserve Margin (%) [A-(B-C)] (B-C)	System Peak (net kW) [D] [V]	Interruptible Load (net kW) [E][VI]	Reserve Margin (%) [A-(D-E)] (D-E)
Recorded 2005	1,614,600	1,250,400	9,800	30%	N/A	9,800	N/A
Future 2006	1,657,400	1,355,300	11,000	23%	1,350,900	20,000	25%
2007	1,657,400	1,388,700	11,000	20%	1,375,400	27,400	23%
2008	1,657,400	1,404,700	11,000	19%	1,382,000	36,000	23%

Notes:

I. Acquired DSM

- Implementation of full-scale DSM programs began in the second half of 1996 following Commission approval of the programs. The forecasted system peak values for the years 2006-2008 include the actual peak reduction benefits acquired in 1996 – 2004 and also include the peak reduction benefits acquired in 2005 of approximately 4,700 net-kW (net of free riders) by year end.
- Without this 2005 peak reduction benefit, the recorded system net peak of 1,250,400 kW in 2005, which includes 26,000 kW of stand-by load, and 3,000 kW of energy efficiency DSM, would have been 1,253,400 kW.

II. System Capability includes:

- HECO central station units at a total normal capability of 1,208,600 kW-net or 1,263,000 kW-gross.
- In 2005, HECO installed 14,800 kW-net of distributed generation units. Since these units were installed after the 2005 system peak, the distributed generation capability was reflected beginning in 2006.
- For the early part of 2005, firm power purchase contracts had a combined net total of 406,000 kW from Kalaeloa (180,000 kW), AES Hawaii (180,000 kW), and H-POWER (46,000 kW). On September 28, 2005, Amendments No. 5 and No. 6 to

Kalaeloa's purchase power agreement (Docket No. 04-0320), which increased Kalaeloa's firm capacity to 208,000 kW, became effective. Since the 2005 system peak occurred on September 14th, prior to Amendments No. 5 and No. 6 becoming effective, Kalaeloa's increased capacity was reflected beginning in 2006. For 2006-2008 the firm power purchase contracts will have a combined net total of 434,000 kW from Kalaeloa (208,000 kW), AES Hawaii (180,000 kW), and H-POWER (46,000 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.

III. System Peak (Without Future Peak Reduction Benefits of DSM Programs):

- The 2006-2008 annual forecasted system peaks are based on HECO's May 2005 Sales and Peak Forecast.
- Forecasted system peaks include the peak reducing impacts of future utility CHP impacts[22] and future non-utility CHP impacts.
- Peaks include 26,000 kW of stand-by load for the following cogenerators:

Tesoro	20.0
Chevron	4.0
Pearl Harbor	2.0
	26.0 MW

- The HECO annual forecasted system peak is expected to occur in the month of October.

IV. Interruptible Load[23] (Without Future Peak Reduction Benefits of DSM Programs):

- Interruptible Load include 5,200 kW of the peak reduction benefits from Rider I customer contracts.
- Load management DSM impacts from the RDLC and CIDLC Programs acquired in 2005 total 5,800 kW. At the time of the 2005 system peak, there was approximately 4,600 kW of peak reduction benefit.

V. System Peaks (With Future Peak Reduction Benefits of DSM Programs)

- The 2006-2008 annual forecasted system peaks are based on HECO's May 2005 Sales and Peak Update.

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22 Utility CHP impacts are from a CHP forecast dated January 9, 2006. These impacts are at system level based on a T&D loss factor of 4.864%. For capacity planning analysis, an availability factor is also included to account for periods when the utility CHP is unavailable due to forced outages and maintenance.

23 The Interruptible Load impacts are at the system level (based on a T&D loss factor of 4.864%) and are coincident with the expected system peak month.

- The forecasted System Peaks for 2006-2008 include the peak reduction benefits of HECO's energy efficiency DSM programs (acquired and future).
- Forecasted system peaks include the peak reducing impacts of future utility CHP impacts[24] and future non-utility CHP impacts.
- Peaks include 26,000 kW of stand-by load for the following cogenerators:

Tesoro	20.0
Chevron	4.0
Pearl Harbor	2.0
	26.0 MW

- The HECO annual forecasted system peak is expected to occur in the month of October.

VI. Interruptible Load[25] (With Future Peak Reduction Benefits of DSM Programs):

- Interruptible Load includes 5,200 kW of the peak reduction benefits from Rider I customer contracts.
- On June 6, 2003, HECO filed an Application in Docket No. 03-0166 requesting approval for a proposed residential direct load control program ("RDLC"). On December 11, 2003, HECO filed an Application in Docket No. 03-0415, requesting approval for a proposed Commercial & Industrial Dispatchable Load Control ("CIDLC") program. On October 14, 2004, the Commission issued Decision and Order No. 21415 approving HECO's RDLC program. On October 19, 2004, the Commission issued Decision and Order No. 21421 approving HECO's CIDLC program. The peak reductions for these programs began in 2005.

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24 Utility CHP impacts are from a CHP forecast dated November 4, 2005. These impacts are at system level based on a T&D loss factor of 4.864%. For capacity planning analysis, an availability factor is also included to account for periods when the utility CHP is unavailable due to forced outage and maintenance.

25 The Interruptible Load impacts are at the system level (based on a T&D loss factor of 4.864%) and are coincident with the expected system peak month.

Appendix 2:

Additional Detail Regarding Relevant Events
Since the March 10, 2005 Adequacy of Supply Report

1. Load Management DSM Programs

As explained in Section 3.5, a combination of factors has led to revisions in the timing of expected load management DSM impacts. Table A2 compares the 2005 AOS assumptions for residential and commercial load management DSM impacts with the 2006 AOS assumptions.

Table A2:
Previous & Current Projections of Load Management Impacts

Year	RDLC			CIDLC		
	2005 Projections (MW)	2006 Projections (MW)	Difference	2005 Projections (MW)	2006 Projections (MW)	Difference
2005	3	3	0	4	2	-2
2006	8	9	1	9	6	-3
2007	13	13	0	13	9	-4
2008	16	17	1	18	14	-4
2009	16	17	1	19	20	1
2010	16	17	1	19	25	6

HECO has taken steps to accelerate the marketing and installation of the Residential Direct Load Control (RDLC), for which approval was obtained in Docket No. 03-0166, and the Commercial & Industrial Direct Load Control Program (CIDLC) Programs, for which approval was obtained in Docket No. 03-0415, as explained in the response to CA-IR-566 in Docket No. 04-0113. Nonetheless, there are uncertainties associated with obtaining the peak reduction impacts from the load management programs. For example, there is a risk of lower customer participation to the Residential Direct Load Control program due to factors such as inadequate awareness. Lower customer participation in the Commercial & Industrial Direct Load Control program could result from factors such as the challenges of acquiring the necessary permits for the use of customer-owned emergency generators, to provide stand-by generation to backup their interruptible loads. Thus, HECO has found it necessary to adjust the mechanics and promotion of these programs to achieve the planned results.

With respect to the marketing of the programs, HECO proposed to increase its estimate of RDLC advertising expenses in its 2005 test year rate case by $275,000 to reflect a full year direct mail campaign, telemarketing, and the addition of a customer recognition campaign to retain previously enrolled customers, and to add an advertising component (increasing test year rate case expenses by $25,000) to the CIDLC budget included in base rates. The parties in the rate case stipulated that HECO could request approval for the $300,000 through the Annual DSM Program Modification and Evaluation ("M&E") Report mechanism or in a program modification letter. HECO included the request in its M&E Report filed December 2, 2005.

Since the load management programs are new, customer acceptance of the programs, particularly the CIDLC Program, has not been immediate. Business customers are understandably concerned about how service interruptions may affect their operations. HECO's account managers and technical engineers have been working with customers to discuss these concerns and meet customer needs. In addition, gaining environmental approval to use customer owned stand-by generators to accomplish customer load reductions under the CIDLC Program took most of 2005 to complete. This effort did result in the Generator Reporting Agreement and approval by the Hawaii Department of Health allowing customer stand-by generators to operate during a system emergency for up to 500 hours per year. This agreement, however, may not encompass every customer's generator permitting requirements and these requirements will continue to be addressed as necessary. Customer acceptance and the effort to seek agreement with the State Department of Health are two reasons why the load management impacts are expected to be lower than as forecasted in the 2005 AOS through 2008.

To address the unwillingness or inability of some customers to participate in the CIDLC program, HECO intends to file modifications to the program with the Commission in early 2006, as described in Appendix 3. The base load management projections assume that these modifications are approved by January 2007 and that the program will continue to increase customer participation beyond 2009. The 2005 AOS did not include the load reduction impacts of these modifications and assumed that 2009 impacts of the CIDLC program were maintained thereafter. One of the modifications is to offer an option that does not require an under-frequency relay. Another modification is to offer a Voluntary Load Curtailment (VLC) option which provides customers the ability to participate in the program, but with no firm commitment of load. Neither option provides spinning reserve, but they can enhance system reliability in situations in which short-term generation shortfalls are anticipated. With these options more customers are expected to participate in the program. However, customers who might have participated under the original CIDLC program may initially choose one of these options instead, temporarily decreasing the amount of load reductions that count as spinning reserve. This effect contributes to the lower load management impacts through 2008 shown in Table A2. On the other hand, HECO expects that, with experience under these two options, customers will recognize that they can cope with service interruptions and will switch to the CIDLC program options that contribute to spinning reserve in order to receive the higher incentives. As shown in Table A2, this is expected to result in increased load management impacts in 2009 and beyond.

2. Enhanced Energy Efficiency Demand-Side Management (DSM)

As explained in Section 3.5, a change in the estimated schedule for regulatory proceedings has led to revisions in the energy efficiency DSM impacts. Table A3 compares the 2005 AOS assumptions for energy efficiency DSM impacts with the 2006 AOS assumptions.

Table A3:

Prior & Current Projections of Energy Efficiency DSM

Year	2005 Projections[26] (MW)	2006 Projections (MW)	Difference
2005	5	4	-1
2006	15	9	-6
2007	24	18	-6
2008	33	27	-6
2009	43	36	-7
2010	52	45	-7

The uncertainties associated with obtaining the peak reduction impacts from the energy efficiency DSM programs include time lags in the regulatory approval process and lower customer participation in the programs due to factors such as inadequate awareness about their energy options and about the urgency of the capacity situation. If approvals to implement the enhanced energy efficiency DSM program are delayed and/or customer participation in these programs is lower than estimated, impacts from these DSM programs will be delayed and will be lower than estimated, ultimately resulting in higher peak loads.

HECO has attempted to accelerate the enhanced DSM programs as much as it could, while still complying with mandated regulatory and planning processes. The programs were developed in the on-going IRP-3 process. The entire process of developing the changes to HECO's portfolio of programs began nearly two years earlier with the initiation of a DSM potential study in July 2003 and the organization of a DSM Technical Committee under IRP auspices in December 2003. The DSM Technical Committee provided valuable input into the

[26] To allow equivalent-basis comparison to 2006 AOS projections, 2005 AOS figures are reduced by 2004 Acquired impacts. The 2005 AOS did not present data for year 2010, but it is being included here for comparative purposes.

design of the DSM programs. The last meeting of the Committee was held on April 21, 2004 and culminated in the portfolio of 10 DSM programs. They were fully documented and filed with HECO's rate case filed in November 2004, as required by HECO's Commission -approved stipulations with the Consumer Advocate (for the C&I DSM programs) and with the Consumer Advocate and other parties (for the Residential DSM programs). The Commission must approve the modifications to these existing programs and the new DSM programs before the modifications and new programs are implemented. Prior to 2005, HECO also had taken steps to accelerate the acquisition of demand reductions through its existing energy efficiency (REWH, RNC, CIEE, CINC, and CICR) programs, as explained in the response to CA-IR-567 in Docket No. 04-0113.

By Order 21698, issued March 16, 2005, the Commission separated HECO's request for approval and/or modification of demand-side and load management programs and recovery of program costs and DSM utility incentives (the "Proposed DSM Programs") from the Rate Case Docket, and opened Docket No. 05-0069 (the "Energy Efficiency Docket").

Since the bifurcation did not result in an accelerated schedule for the complete DSM proposal, HECO proposed a schedule that would permit it to submit the Interim DSM proposals. Following HECO's informal submission of its Interim DSM Program modifications to the parties on October 11, 2005, HECO filed a letter with the Commission on December 5, 2005 requesting modifications to HECO's existing energy efficiency programs and also approval of a new interim DSM program, collectively referred to as HECO's "Interim DSM Proposals". The current assumption is that the Interim DSM proposal will be approved by July 2006, and that the complete DSM proposal will be approved by January 2007.

HECO's plan to expedite realization of some of the increased peak reduction benefits that were expected to result from the enhanced EE DSM programs, pending final resolution of the Energy Efficiency Docket, is to propose that certain measures included in the proposed enhanced EE DSM Programs (such as CFLs for Residential customers) be allowed to be implemented on an interim basis in the EE Docket, and an expanded advertising "budget" be included in its pending rate case to be used (in conjunction with much of the existing corporate advertising "budget") to encourage energy conservation, through "behavioral changes" on the part of residential customers, in addition to their implementation of DSM measures included in the Residential DSM Programs. Following HECO's informal submission of its Interim DSM Program modifications to the parties on October 11, 2005, HECO filed a letter with the Commission on December 5, 2005 requesting modifications to HECO's existing energy efficiency programs and also approval of a new interim DSM program, collectively referred to as HECO's "Interim DSM Proposals". The current assumption is that the Interim DSM proposal will be approved by July 2006, and that the complete DSM proposal will be approved by January 2007. The net result, however, would still be somewhat lower impacts than if the Enhanced EE DSM Programs had been implemented beginning in July 2005, as was assumed for purposes of the 2005 AOS report.

3. <u>Distributed Generation and Combined Heat and Power (CHP)</u>

On January 27, 2006, the Commission issued a decision and order ("D&O") in its Distributed Generation Investigative Docket No. 03-0371. The Commission D&O established three criteria under which HECO could provide a DG system at a customer site: (1) the DG must resolve a legitimate system need; (2) it should be the least cost alternative to meet that need; and (3) the customer, via an open and competitive process, is not able to secure the DG service from another entity at a price and quality that is comparable to the utility's offering. The Commission D&O allows HECO to pursue approval of a CHP program and/or projects, with approval subject to whether these criteria can be met.

The Commission D&O also directed the utility to establish new standards and procedures for DG interconnection, reliability, and safety. The utility must also establish new cost-based stand-by rates for customer-generators who want access to utility systems for stand-by services and backup power.

On March 1, 2006, the electric utilities filed a Motion for Clarification and/or Partial Reconsideration to the Commission in order to better determine the impacts the D&O may have on the electric utilities' DG plans.

Finally, there is anecdotal evidence that CHP development in Hawaii is being affected by macro-scale economics. Specifically, the economic viability of CHP is highly sensitive to CHP fuel costs and electricity prices. The energy efficiency benefits of a CHP system may not translate to overall cost savings for a customer if the CHP fuel cost is significantly higher than the cost of fuel used to generate grid electricity.

Depending on the outcome of HECO's Motion for Clarification and/or Partial Reconsideration in the DG Investigative Docket, and on other factors impacting the viability of CHP on Oahu, HECO's ability to install CHP systems at customer sites may be impacted.

Based on the above events and uncertainties, a revised 20-year forecast for CHP was developed that reflects that CHP penetration is expected to be more limited compared to previous forecasts. No new CHP systems were commissioned on Oahu in 2005. HECO had anticipated one non-utility CHP system to be placed in service in 2005, but now expects that system to be started up in 2006. No HECO CHP will be installed in 2006.

Table A4 below provides a comparison of CHP system impacts assumed for HECO's 2005 AOS with current estimates of impacts for a utility CHP Program.

Table A4:
Prior and Current Cumulative Projections of Utility and Non-utility CHP

	2005 Projections (MW)			2006 Projections (MW)			Diff. in
Year	Utility	Non-utility	Total	Utility	Non-utility	Total	Total
2005	0	0	0	0	0	0	0
2006	3	1	4	0	0	0	-4
2007	9	1	10	1	0	1	-9
2008	13	2	15	3	1	4	-11
2009	18	2	20	5	1	6	-14
2010	Not	Provided		6	1	7	N/A

Appendix 3:

Review of 2005 AOS Action Plan and Mitigation Measures

The 2005 AOS described Action Plan and Mitigation Measures that HECO would employ in order to provide reliable service (refer to Section II.5, pages 24-27). HECO's action plan and mitigation measures are not intended to be a single plan of action. Instead, HECO's action plan and mitigation measures are meant to be part of a process to continuously re-evaluate, re-assess, and modify the appropriate actions and measures that should be planned for in response to changing circumstances. This Appendix reviews the status of these items.

Action Plan

1. Implement Enhanced Energy Efficiency DSM Program

- Work to bifurcate the enhanced energy efficiency DSM programs from the remainder of the rate case proceeding (so they can be reviewed and approved by the Commission on an accelerated schedule separate from the rate case).

  Status: Bifurcation was completed

  HECO is currently implementing five approved energy efficiency DSM programs. In HECO's rate case (HECO Test Year 2005 Rate Case in Docket No. 04-0113), HECO requested approval for three new programs (Residential Customer Energy Awareness, Residential Energy Solutions for the Home, and Residential Low Income), enhancements to the five existing energy efficiency programs, and approval to implement all eight programs. On March 16, 2005 the Commission in Order No. 21698 bifurcated the rate case application creating the Energy Efficiency Docket, Docket No. 05-0069, for the DSM programs. On April 20, 2005, the Commission, in Decision and Order No. 21756, Docket No. 03-0142, denied the RCEA Program, without prejudice.

- Work with the Consumer Advocate and other parties to allow the enhanced DSM programs to proceed on an interim basis if the final decision on certain issues requires more time.

  Status: On-going

  Since the bifurcation did not result in an accelerated schedule for the complete DSM proposal, HECO proposed a schedule that would permit it to submit the Interim DSM proposals. Following HECO's informal submission of its Interim DSM Program modifications to the parties on October 11, 2005, HECO filed a letter with the Commission on December 5, 2005 requesting modifications to HECO's existing energy efficiency programs and also approval of a new interim DSM program, collectively referred to as HECO's "Interim DSM Proposals". The Interim DSM Proposals include increases in the customer incentive levels for prescriptive energy efficiency measures in the CIEE and CINC Programs, the elimination of the 2-year payback threshold in the CICR Program, and an interim ESH Program consisting of customer incentives for the retail purchase of compact fluorescent lamps.

The current assumption is that the Interim DSM Proposal will be approved in July 2006 and that the complete DSM proposal, along with modifications to the load management programs (expected to be filed with the Commission in early 2006) will be approved in January 2007.

2. <u>Implement Utility CHP Program</u>

- Continue to seek Commission approval of the utility's ability to provide customer-sited CHP in the DG Docket, and subsequently, Commission approval of Rule 4 CHP applications and approval of HECO's proposed CHP Program and Schedule CHP tariff.

Status: On-going

In October 2003, HECO (along with MECO and HELCO) filed a PUC Application for approval of a proposed utility-owned CHP Program in Docket No. 03-0366. The utilities' proposed program involves the installation of small, distributed generation ("DG") units at selected customer sites. The waste heat from the DG units at these selected customer sites would be used for the customers' heating and/or cooling purposes.

In March 2004, the Commission suspended the Companies' CHP Program application, indicating that its DG Investigative Docket No. 03-0371 opened in October 2003 was intended to "form the basis for rules and regulations deemed necessary to govern participation into Hawaii's electricity market through distributed generation."

In January 2005, the Commission suspended HECO's October 28, 2004, Rule 4 application requesting approval of a CHP agreement with Pacific Allied Products. By letter dated February 9, 2005, Pacific Allied Products terminated its

CHP Agreement due to schedule uncertainties as a result of the suspension of the PUC application for its CHP project.

On January 27, 2006, the Commission issued a decision and order ("D&O") in its Distributed Generation Investigative Docket No. 03-0371. The Commission D&O established three criteria under which HECO could provide a DG system at a customer site: (1) the DG must resolve a legitimate system need; (2) it should be the least cost alternative to meet that need; and (3) the customer, via an open and competitive process, is not able to secure the DG service from another entity at a price and quality that is comparable to the utility's offering. The Commission D&O allows HECO to pursue approval of a CHP program and/or projects, with approval subject to whether these criteria can be met.

The Commission D&O also directed the utility to establish new standards and procedures for DG interconnection, reliability, and safety. The utility must also establish new cost-based stand-by rates for customer-generators who want access to utility systems for stand-by services and backup power.

On March 1, 2006, the electric utilities filed a Motion for Clarification and/or Partial Reconsideration to the Commission in order to better determine the impacts the D&O may have on the electric utilities' DG plans.

Finally, there is anecdotal evidence that CHP development in Hawaii is being affected by macro-scale economics. Specifically, the economic viability of CHP is highly sensitive to fuel and electricity prices. The energy efficiency benefits of a CHP system may not translate to overall cost savings for a customer if the CHP fuel cost is significantly higher than the cost of fuel used to generate grid electricity.

Depending on the outcome of HECO's Motion for Clarification and/or Partial Reconsideration in the DG Investigative Docket, and on other factors impacting the viability of CHP on Oahu, HECO's ability to install CHP systems at customer sites may be impacted.

Based on the above events and uncertainties, a revised 20-year forecast for CHP was developed that reflects that the penetration of CHP systems is expected to be more limited compared to previous forecasts. No new CHP systems were commissioned on Oahu in 2005. HECO had anticipated one non-utility CHP system to be placed in service in 2005, but now expects that system to be started up in 2006. No HECO CHP will be installed in 2006.

There is a significant degree of uncertainty in forecasting the CHP market, whether it is for HECO CHP projects or non-utility CHP projects. On a macro-scale, the economic viability of CHP is highly sensitive to fuel and electricity prices. The energy efficiency benefits of a CHP system may not translate to overall cost savings for a customer if the CHP fuel cost is significantly higher than the cost of fuel used to generate grid electricity.

Furthermore, all prospective CHP projects are subject to customer desire and support, which can be extremely variable. For example, a CHP system under development by the City and County of Honolulu for their Kapolei Hale facility was cancelled in January 2005 by the City

Site-specific factors also add uncertainty, as they may affect the feasibility of moving forward on a project even when the desire for CHP is strong. As an example, the largest potential HECO CHP project that was included in the June 2004 IRP-3 CHP forecast, the Outrigger Beachwalk CHP project, was determined to be infeasible in late 2004 due to technical and economic reasons.

3. <u>Improve Availability of HECO Generating Units</u>

- Continue the addition of operational staff to allow for 24 hours a day, 7 days a week operation of all generating units. The additional staffing to allow for 24 hours a day, 7 days a week operation of Honolulu 8 & 9 and Waiau 3 & 4 by mid 2005 will allow for greater flexibility in performing maintenance on other units while having sufficient generation manned for operation.

  Status: Complete

  Additional staffing is now in place to allow for 24 hours a day, 7 days a week operation of Honolulu 8 & 9 and Waiau 3 & 4.

- Continue efforts to implement night shift maintenance at Kahe and Waiau power plants and expansion of day shift maintenance crews. Additional maintenance staffing will allow for the flexibility of performing more maintenance within the same period of time, or allow for a shorter outage to perform the same maintenance when compared with having only a single day shift.

  Status: On-going

  The establishment of a permanent night maintenance crew has taken longer than expected, due to the complex work force issues that had to be resolved, and the on-going difficulty in finding the qualified and certified journeymen needed to perform this type of work. Currently, process negotiations with HECO's bargaining unit to address known concerns have been completed, and hiring is currently in progress to staff the night maintenance crew. However, with local unemployment running at very low levels, HECO has found it very difficult to find the qualified and certified journeymen needed for this type of work and has to resort to other alternatives such as:

  - Filling these positions with mainland candidates with possible retention challenges;
  - Performing temporary night shift maintenance supplemented with outside contractors. This alternative is available but limited to performing only breakdown maintenance as required. Also, contractor-to-employee ratios must be maintained for safety and environmental compliance management reasons.

  Developing a 5-7 year apprentice program that will meet longer term needs, but will not meet near-term needs.

- Continue with capital projects to improve the reliability of generating units and to improve the flexibility in their operations.

  Status: On-going

  Completed capital projects that are projected to help maintain or improve unit availability include the rehabilitation of Waiau 9 compressor and exhaust structure, Waiau 3 main and auxiliary transformer replacements, upgrades to the Waiau 5 annunciator system, turbine blade replacements for Honolulu 8, Honolulu 9, Waiau 5, Waiau 8, and Kahe 4, the rotor rewind to rehabilitate the Waiau 5 generator, Kahe 4 voltage regulator and exciter upgrades, repair of Honolulu 8 generator rotor, HECO's new Waiau fuel pipeline, renovations of Waiau low sulfur fuel oil storage tank Nos. 1, 4 & 5 and diesel oil storage tanks

Nos. 1 & 2, and replacements of the Kahe 5 reheater and Kahe 6 secondary superheater.

Efforts continue with capital projects to improve the reliability of generating units and to improve the flexibility in their operations. Projects include any rehabilitation work resulting from an upcoming inspection of Waiau 10, Waiau 10 exhaust duct replacement, separation of the bus between Waiau 9 and Waiau 10, Kahe 4 Boiler controls upgrade, Waiau 4 main transformer replacement, Waiau 4 exciter upgrade, Honolulu 9 generator rotor rewind, Honolulu 9 voltage regulator and exciter replacement, Honolulu 9 secondary superheater replacement, Kahe 1 reheater section replacement, Kahe 1 excitation system and Kahe 1 main steam line replacement.

- Continue to reschedule maintenance when feasible to (1) minimize the occurrence of reserve capacity shortfalls, (2) target maintenance based on the most current assessments of unit component conditions, and (3) adjust for any unanticipated outages of units.

Status: On-going

As described in Section 3.4, the flexibility HECO has in rearranging the generating unit maintenance schedule decreases as reserve capacity decreases. However, current assessments of generating unit and system conditions (e.g., anticipated load) are used to adjust maintenance schedules, when feasible.

4. Maintain or Improve Availability of Independent Power Producers

- Continue to work with IPP partners to increase availability by careful scheduling and coordination of HECO and IPP maintenance to reduce the impact of IPP maintenance on system reliability.

Status: On-going

HECO continued to coordinate the maintenance of utility and IPP generating units during 2005. For example, HECO subject matter experts and engineers worked closely with H-Power, Kalaeloa and AES to understand various system and equipment problems to ensure identified items were satisfactorily repaired during their respective planned outages. Specific examples include H-Power's superheater replacement; Kalaeloa's economizer tube leak concern; AES's boiler stop valve leak, etc. Efforts in this area will continue, though tight reserves can constrain the opportunities for rescheduling the maintenance of both utility and IPP generating units.

As the IPPs contribute about 25% of the system capacity, it is important that they contribute positively to system reliability. This notion is already recognized in PPAs. For example, the Kalaeloa PPA requires Kalaeloa to use all reasonable measures to maximize the reliability of the facility, the AES Hawaii PPA requires AES Hawaii to use all reasonable measures to maximize the overall HECO system reliability, and the HPOWER PPA requires HPOWER to operate and maintain its facility in accordance with accepted good engineering practices in the electric industry.

The IPPs are required under their contracts to provide HECO with their planned maintenance schedules, which HECO considers for integration into its master maintenance schedule. To provide for overall system reliability, it is sometimes necessary to require the IPPs, similar to the requirement on HECO's own units, to adjust their planned maintenance schedule. As an example, HECO worked with HPOWER to separate HPOWER's planned maintenance schedule in 2006 into two periods from an originally approved single maintenance outage to accommodate other unit maintenance and generation reserve margin needs.

Although the IPPs are motivated by the financial terms of their contracts to maximize their availability to HECO, to further strengthen the objective of maximum availability, HECO has initiated enhanced communications, sharing of technical expertise, and training. A hot line was recently installed to HPOWER's control room to improve communications between system dispatchers and control room operators. In addition, HECO and the IPPs have scheduled cross visitations between system dispatchers and control room operators at each other's facilities. Periodic meetings between HECO and IPP personnel have been scheduled to discuss 'state of the system' issues.

Further, in the area of communications, HECO has implemented additional channels of communications with the IPPs to gather information during system emergency or forced outage conditions. HECO also has increased communications with the IPPs on a routine basis by providing them with access to daily system condition reports and by clearly communicating HECO's reliability goals and how the IPPs support these goals. The objective of enhanced communications is to ensure that the IPPs are cognizant of HECO system conditions and their contributions to system reliability. The fact that during recent generation margin shortfalls, Kalaeloa and HPOWER took extra efforts to provide additional power to the system demonstrates their willingness to help.

For many years, HECO has shared its technical expertise with the IPPs. The objective is not to tell the IPPs how to run their facilities, but to provide useful information, for example in the area of maintenance practices. The IPPs have welcomed this information. For example, HECO has sent its technical experts to review the condition of the IPPs' facilities during planned maintenance and forced outages and to provide advice.

HECO has also included the IPPs in internal training exercises for system emergencies. For example, the IPPs have been included in yearly emergency response drills.

Close coordination with the IPPs is essential to maximizing system reliability. Enhanced communications and cooperation in all operational aspects as noted above cannot be achieved without the foundation of good business relationships with the IPPs. In HECO's estimation, there is generally a good working relationship between HECO and its IPP partners.

- Negotiate increased availability provisions in the HECO and Kalaeloa Amendments Nos. 5 and 6 with more defined terms of full plant trips and stiffer financial penalties for failing to meet availability requirements.

  Status: Complete

  The Commission approved HECO's application for approval of Amendment Nos. 5 and 6 to its Power Purchase Agreement with Kalaeloa Partners L. P. ("Kalaeloa") on May 13, 2005, and the Amendments became effective on September 28, 2005. These Amendments provide specific provisions related to penalties for a full plant trip involving more than 180 MW and also specific availability standards and associated liquidated damages that pertain to the additional 28 MW.

5. <u>Accelerate the Installation of the Next Generating Unit</u>

- Continue to work with stakeholders and the community to expedite the schedule of the various permits required for the Campbell Industrial Park simple-cycle combustion turbine units.

Status: On-going

Through meetings with West Oahu/Waianae Coast community leaders, HECO developed a proposed community benefits package in recognition of this project being sited in their community. HECO filed applications with the Commission for approval to commit funds in excess of $2.5 million for both the project and the community benefits package in June 2005.

HECO and its consultants developed a Draft Environmental Impact Statement, which was submitted to the Department of Planning and Permitting, City and County of Honolulu, on January 18, 2006. Notice of its availability was published in the February 8, 2006 *Environmental Notice*, starting a 45-day public comment period ending on March 28, 2006.

HECO expects to file an application for a Public Infrastructure Map Amendment to the Department of Planning and Permitting for their review and eventual City Council approval in the first quarter of 2006.

HECO is continuing to work with the DOH and EPA to develop a draft air permit for public review and comment, and is also continuing to meet with west Oahu neighborhood boards and community leaders to present HECO's plans.

- Proceed with issuance of a Request for Proposal for the combustion turbine generator and proceed with engineering, without a commitment to purchase the combustion turbine, in order to obtain information to support our permit applications in a timely manner and to be prepared to take advantage of any permit schedule accelerations.

  Status: Complete

  Through a competitive bid process, HECO selected the combustion turbine to be used for this project (Siemens SGT6-3000E). Detailed engineering design to support long lead time "ministerial permits", such as the building permit and grubbing and grading permit, is in progress. Additional information on this project is provided in Appendix 4.

Mitigation Measures

These mitigation measures are short-term programs or efforts limited to actions which can be implemented in order to provide near term relief until sufficient generation is added to the HECO system. These programs cannot provide permanent or complete relief from a reserve capacity shortfall and are efforts separate from and in addition to the action items mentioned above. In addition, these mitigation measures, like the action items, have their own share of uncertainties and risks.

1. Installation of distributed generation (DG) at various HECO substations, and evaluation of other possible sites. HECO has begun to screen various company controlled sites for the viability of adding leased or owned DG units to provide additional generation capacity to serve the peak load.

   Status: On-going

   Between October 26, 2005 and December 16, 2005, HECO placed into service a total of approximately 14.8 MW of temporary DG. Three leased diesel engine generators were installed at each of the following HECO sites: Ewa Nui substation, Iwilei tank farm, and Helemano substation. Refer to Appendix 4 for HECO's on-going DG efforts.

2. A demand load response program to seek additional interruptible loads for customers unwilling or unable to participate in the CIDLC load management program.

   Status: On-going

   Soliciting participation in the CIDLC Program continues to be difficult. Therefore, based on feedback and suggestions received from current and prospective CIDLC Program customers, HECO Account Managers, and technical staff working on the CIDLC Program, HECO is currently in the process of proposing five modifications to the existing CIDLC Program designed to increase interest and participation.

   In early 2006, HECO expects to submit to the Commission under a separate transmittal a request for approval of the following:

   2.1. A reduction in the minimum kilowatt requirement for qualification to participate in the program from 200 kW to 50 kW. This modification will help to increase the number of facilities that qualify for participation in the CIDLC Program.

   2.2. Due to the reluctance of customers to enter into the current 5 year contract, HECO will propose offering an option to opt out of the program after one year. This reduces the participant's objections and serves to make the CIDLC Program more attractive. Customers choosing this option to opt out after one year will have to reimburse HECO for any installation expenses and potentially any incentives paid during the year.

2.3. The addition of an option for CIDLC that does not require an under-frequency relay. While the additional loads enrolled under the non-under frequency relay option will not count as spinning reserve, they may enhance system reliability in situations in which short-term generation shortfalls are anticipated.

2.4. The addition of a Voluntary Load Curtailment (VLC) option. The VLC option provides customers the ability to participate in the program, but with no firm commitment of load. The incentive is only paid for actual kWh reduced during an event.

2.5. The addition of a small business program similar to the RDLC Program.

3. A Residential AC Load Control Program, which will add residential air-conditioner load control to the existing residential direct load control program, which currently focuses solely on water heating.

Status: On-going

In early 2006, HECO expects to submit to the Commission under a separate transmittal a request for approval of a direct load control option for residential central ducted air conditioning systems in the RDLC program.

4. A public notification program. HECO has created a public notification program to establish a process to inform and prepare customers of a potential generation-related customer outage and to ask for voluntary conservation should a system emergency occur such that HECO anticipates that it may not be able to meet the demand for the day unless immediate action is taken.

Status: On-going

HECO created a public notification program to establish a process to inform and prepare customers of potential generation-related customer outages and to ask for voluntary conservation should a system emergency occur such that HECO anticipates that it may not be able to meet the demand for the day unless immediate action is taken. The public notification program is a tiered, systematic process of notifying the Commission, critical federal, state and local agencies, large customers, and the general public upon various generating conditions. The worse the generating condition, the broader the notification and requests for conservation.

HECO used the public notification program and asked for help through energy conservation on two recent occasions: November 7-10, 2005 and January 10-12, 2006. In addition to notifying the public, HECO used the tools approved by the Commission to help mitigate the impact of the shortfall: (1) the operation of its recently installed distributed generators, and (2) the activation of the residential direct load control program, "EnergyScout", where the power to approximately 5,000 residential water heaters were shutoff for 1-2 hours.

HECO informed the Commission and the Consumer Advocate of HECO's generating situation in the March 31, 2004 and March 10, 2005 Adequacy of Supply letters. In addition, from November 2004 to March 2005 HECO gave presentations to the Governor and her staff, the Commission, DOH, DBEDT, State Civil Defense, HPD, key lawmakers, and the US Attorney General informing them of the generation situation.

HECO is also in the process of developing a customer notification system to support a rolling outage plan. The steps involved in developing this system require HECO to modify its customer databases to include more detailed information to enable HECO to let customers know ahead of time when they could be affected.

With respect to the public notification program, the potential contribution will depend upon the success of HECO's integrated advertising campaign to encourage energy conservation and efficiency (see responses to CA-IR-446.a and CA-IR-533, Docket No. 04-0113), and the conditions that exist at the time public notification is made. These conditions include, but are not limited to, the time of year, time of day, weather conditions (e.g., ambient temperature, wind speed, humidity), system demand, the success of HECO's direct load control programs, and the willingness and ability of our customers to reduce load at the time the public notification is given.

Appendix 4:

Description of 2006 AOS Action Plan and Mitigation Measures

HECO's action plan and mitigation measures are not intended to be a single plan of action. Instead, HECO's action plans and mitigation measures are meant to be part of a process to continuously re-evaluate, re-assess, and modify the appropriate actions and measures that should be planned for in response to changing circumstances.

Action Plan

1. Pursue Accelerated Installation of Next Generating Unit

Given the critical nature of HECO's reserve capacity shortfall, all efforts are being made to pursue practical opportunities to accelerate the installation of the next generating unit. HECO has already incorporated efforts to expedite the unit installation, and therefore, opportunities to compress the schedule even further are limited. HECO's efforts thus far, and potential opportunities for additional project acceleration, are described in the following paragraphs.

The project to install a new simple-cycle combustion turbine in Campbell Industrial Park consists of four major phases:

1. Permits and Approvals;
2. Material Procurement;
3. Construction; and
4. Startup and Testing.

Although these phases will essentially be completed on a sequential basis, overlap between these phases has been incorporated into the project where feasible in order to accelerate project completion.

Phase 1 - Permits and Approvals

Obtaining the necessary permits and approvals for construction and operation of a generation unit addition project has typically been the longest phase and the one with the most uncertainty from a scheduling standpoint. Many of the processes for obtaining these permits and approvals do not have statutory time limits for review and approval by the regulatory agencies. Once HECO submits the applications and required information to the regulatory agencies, the agencies control the schedule for this phase.

To account for the uncertainty in processing time, efforts to initiate some of the permitting and approval processes for this project were started very early. The initial Covered Source Permit application was submitted in October 2003 (six years prior to anticipated commercial operation date). The application to the PUC to commit funds in excess of $2.5 million was filed in June 2005 (four years prior to the anticipated commercial operation date).

The Covered Source Permit and the PUC approval are currently parallel critical path[27] items in the project schedule. The amount of time that the schedule would be shortened is dependent upon whether the Covered Source Permit and the PUC approval can be obtained sooner than scheduled as well as whether other approvals or tasks would then become part of the critical path.

Phase 2 - Material Procurement

Following receipt of the critical path discretionary permits and approvals (i.e. Covered Source Permit and PUC approval), material procurement is scheduled to commence[28]. The key component and critical path item for this phase of the project is the delivery schedule for the combustion turbine-generator package itself.

After a competitive bid process, HECO placed a conditional purchase order for a combustion turbine from Siemens with a guaranteed delivery date thirteen (13) months following the final notice to proceed. This shorter than normal delivery date is made possible by the fact that the major components (turbine and generator) were previously manufactured and are being stored in environmentally controlled warehouses. Any delays past this delivery date would result in late fees assessed against Siemens.

Delivery of the combustion turbine-generator package in less than thirteen (13) months could potentially result in an earlier commercial operation date. However, this delivery timeframe is already tight and there are not likely to be opportunities to accelerate it.

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[27] Within every project schedule, there are items that make up the critical path. Critical path items are those that cannot be delayed without delaying the finish time for the entire project.

[28] One exception to this sequence of events is that the combustion turbine has already been selected through a competitive bidding process to facilitate receipt of the Covered Source Permit. Final notice to proceed with manufacture and delivery of the combustion turbine package will not be made until the discretionary permits are received.

Phase 3 - Construction

The construction phase of this project can be broken into two (2) parts: construction prior to delivery of the combustion turbine; and construction after delivery of the combustion turbine.

To provide for the shortest possible overall construction phase, the goal is to complete as much construction as possible prior to the delivery of the combustion turbine to the project site. Then, all the construction work that requires that the combustion turbine be in place would be completed.

The construction schedule for the work prior to combustion turbine delivery is not part of the critical path. Therefore, taking less time to do that work or starting earlier will not affect the commercial operation date of the project.

The construction schedule for the work following the combustion turbine delivery is part of the critical path and is estimated to take six (6) months. There may be opportunities to shorten this part of the construction schedule by working more hours of the day or possibly using larger crews.

Phase 4 - Startup and Testing

Startup and testing of the unit is part of the critical path and cannot be done prior to completion of construction. This part of the schedule is estimated to take approximately two (2) months and does not have opportunities for acceleration.

2. Sustain Operational Staff to Allow for 24 hours a day, 7 days a week Operation of all Generating Units.

As described in Appendix 3, HECO has hired operational staff which serves to improve the availability of HECO generating units. Efforts will now be made to sustain the operational staffing levels achieved in 2005, including hiring replacements to fill any vacancies caused by attrition. Hiring operational staff has been challenging, but not as difficult in the tight local labor market as finding skilled journeymen for night shift maintenance, because the entry level requirements for operators are not as stringent.

3. Pursue Staffing Plan for Night Maintenance

As described in Appendix 3, HECO has laid the foundation for establishing a night maintenance crew, which serves to improve the availability of HECO generating units. However, as previously explained, HECO has been experiencing significant challenges in implementing this measure. HECO will continue its hiring efforts and exploration of alternatives in 2006.

4. Continue to Reschedule Maintenance of Generating Units when Feasible

As described in Appendix 3, adjustments to the maintenance schedule are an on-going activity that HECO will continue to pursue, though tight reserves can constrain the opportunities for rescheduling maintenance.

5. Continue to Work with IPP Partners to Increase Availability

HECO will continue work in this area, pursuing opportunities that increase IPP availability without triggering FIN46R consolidation, which can have negative economic impacts on ratepayers. See Appendix 3 for a description of ongoing activities in this regard.

6. Evaluate Opportunities for Purchase of Additional Firm Capacity and Energy

HECO continues to explore opportunities to purchase additional firm capacity and energy from independent power producers, taking into consideration the full scope of all relevant issues, which includes among others maintaining or improving the reliability of Oahu's isolated electrical system, avoiding potential impacts arising from purchased power that may be detrimental to the financial integrity of the utility, impacts to the environment and neighboring communities, and the cost impact to ratepayers. Such factors were considered in the recent success found in the contracting for an additional 28 MW of firm capacity and energy from Kalaeloa Partners, L.P., which was approved by the Commission on May 13, 2005. The full set of benefits and obligations of PPA Amendments No. 5 and No. 6 became effective on September 28, 2005.

HECO has had discussions with other existing providers of firm capacity, such as H-Power, and is aware of their capabilities and plans. However, the time to add firm capacity in Hawaii (unless it can be done without a major air permit modification, as Kalaeloa was able to do through its "M" upgrade) is substantial, due to the time required to do air permitting, the need for an EIS for generation greater than 5 MW, the need for land use permits and approvals at many sites, and the time required for other regulatory approval proceedings. (HECO does not have the option of "importing" power from other jurisdictions.)

HECO has also engaged in substantive discussions with AES Hawaii regarding its desired sale to HECO of up to 9 MW of additional firm capacity and/or energy. As was the case with the recent Kalaeloa PPA Amendments, any modification to the current power purchase arrangement with AES Hawaii will require an amendment to the existing AES Hawaii PPA and related Commission approval. Any amendment to the PPA, however, will trigger a review under accounting standards EITF No. 01-8 and SFAS No. 13, as to capital lease treatment of the supply arrangement. With regard to the AES proposal, HECO remains concerned with the negative impact to HECO and its ratepayers of treating the AES Hawaii PPA as a capital lease. The significant debt in AES Hawaii's capitalization after its recent refinancing may result in significantly more debt being shown on HECO's financial statements. HECO also remains concerned that a PPA amendment might trigger the consolidation of AES Hawaii on HECO's books under another accounting standard, FIN 46R. Moreover, HECO's spinning reserve and quick load pickup (QLPU) requirements are based on AES Hawaii's committed capacity of 180 MW, the largest single electrical generator on the HECO system. Any increase in AES Hawaii's output above 180 MW would impact HECO spinning reserve and QLPU requirements, and the resulting system operational and reliability impacts, as well as the increase in costs has to be considered.

These substantial hurdles must be overcome before any amendment of the AES Hawaii PPA to purchase up to 9 MW of additional firm capacity and/or energy could prove to be in the public interest and just and reasonable from the ratepayer perspective. HECO must take all cost impacts into account, including those arising out of new accounting standards and/or interpretations. Nonetheless, HECO remains interested in purchasing additional capacity and/or energy from AES Hawaii if the financial, operational and contractual issues can be addressed. Unfortunately, at this time, that does not appear to be the case.

7. Pursue Initiatives that Improve the EFOR of HECO Generating Units

A discussion of HECO generating unit EFOR is provided in Appendix 7. Included in this discussion are actions that HECO will take in effort to improve the EFOR rate of its generating units.

8. Evaluate Filing of Request to Commit Funds in Excess of $2.5 million for 2nd CT at Campbell Industrial Park Site

The base case AOS assumptions illustrate that the additional capacity from a single CT in the 2009 timeframe will not allow HECO to meet its reliability guideline. Reserve capacity shortfalls of approximately 200 MW are anticipated by the year 2009, whereas the capacity from a single CT is approximately 113 MW.

These results are consistent with, but more pronounced than, scenarios analyzed in the 2005 AOS, as described on pages 6 and 7 on that filing. Specifically, with lower-than-expected DSM and CHP impacts, and with higher than forecast forced outage rates, the 2005 AOS noted that the nominal 100 MW capacity of the peaking unit planned for 2009 would not be sufficient to fully offset the shortfall in reserve capacity.

While it is certainly not expected, it is possible that a convergence of factors, such as a pronounced and sustained decrease in peak electricity usage, combined with significant improvement in HECO generating unit EFOR, could reduce the urgent need for a 2nd CT.

HECO will work to implement the Action Plan and Mitigation Measures described in this appendix, in an effort to address the estimated near-term decrease in system reliability. However, these actions will not negate the need for another large increment of firm capacity. HECO must therefore initiate long-lead items, such as evaluating the need to file a PUC application for the 2nd CT at Campbell Industrial Park.

Mitigation Measures

1. Evaluate Additional DG Opportunities

As described in Appendix 3, HECO installed 14.8 MW of utility-sited DG units in 2005. HECO is developing plans to install additional temporary DG units at HECO sites, targeting up to three sites in 2006. HECO will evaluate further opportunities for installation of temporary DG in 2007 and beyond. At this time, the full potential for temporary DG is unknown, as it is highly dependent upon site specific factors.

In addition to the temporary DGs installed at utility sites, HECO is exploring other options for DG, as described below:

1.1. Dispatchable Stand-by Generation

HECO is evaluating the feasibility of a dispatchable stand-by generation program similar to that established as a regulated utility service by Portland General Electric ("PGE"). By letter agreement executed with the State of Hawaii Department of Transportation Airports Division ("DOT Airports") on December 21, 2005, HECO and the DOT Airports agreed to jointly study whether a dispatchable stand-by generation arrangement is feasible for implementation in the 2007-2008 timeframe at the Honolulu International Airport.

In the PGE dispatchable stand-by generation program, the electric utility is allowed to remotely dispatch customer-owned stand-by generators for limited peaking duty purposes. PGE provides financial payment to the customer for various costs incurred by the customer to enable utility dispatch. According to PGE, the dispatchable stand-by generation program is one of the most cost-effective resource options for peaking capacity.

The HECO feasibility study will evaluate technical, economic, permitting, and regulatory factors and allow both HECO and DOT Airports to decide whether to proceed with an actual one-off project at the Honolulu Airport. Should dispatchable stand-by generation appear viable on a more general scale, HECO will consider additional applications of this DG model to other large customers. At this time, the full potential of a dispatchable stand-by generation program is unknown.

1.2. Department of Defense ("DOD") DG Evaluation

In June 2005, HECO and the DOD agreed to conduct an evaluation of DG opportunities on Oahu military sites. The objectives being pursued include (1) enhancement of energy security and reliability for the DOD; (2) energy cost savings; (3) reduced use of fossil fuel; and (4) provision of benefits to HECO's system and ratepayers. Based on study results so far, technical potential exists for the installation of peaking DG at various military bases. However, actual DG development will depend on economic, permitting, and regulatory factors, including compliance with the PUC's recent decision and order in Docket No. 03-0371 governing utility-owned DG at customer sites, and on DOD contracting requirements. HECO anticipates completion of the DOD DG evaluation during the second quarter of 2006.

2. Expand Peak-Shifting Strategies

While actual generation shortfall incidents are not restricted to peak load conditions, reducing the system peak by shifting a portion of the load will generally improve system reliability, everything else being equal. HECO currently offers three optional rate riders (Rider M, Rider T, and Schedule U) to commercial demand service customers who can reduce their bills by shifting load out of priority peak and on-peak hours. There are 54 customers currently served under these rate riders. In addition, in HECO's current rate case, Docket No. 04-0113, HECO proposes to expand its offering of optional time-of-use rates to residential and small commercial non-demand service customers.

3. Move Forward on Renewable Proposals Submitted to HECO and RHI

Renewable Hawaii, Inc. ("RHI"), a non-regulated subsidiary of HECO, has issued RFPs to seek passive investment opportunities in commercial renewable energy projects greater than 1 MW in Hawaii (which could include firm capacity and as-available energy). RHI issued its first RFP in May 2003 for renewable energy projects on the island of Oahu. Copies of the May 2003 RFP, entitled "Renewable Energy Request for Project Proposals (RE RFPP)", and associated "Frequently Asked Questions (FAQ)" document issued by Renewable Hawaii, Inc. were provided in Attachments 1 and 2 to HECO's response to CA-IR-446 in Docket No. 04-0113. RHI released its second round RE RFPP on March 28, 2005 (for all islands). The RE RFPP can be viewed at RHI's website – www.renewablehawaii.com. The intent of the renewable energy RFPs is to stimulate the addition of cost-effective renewable energy in Hawaii, promote viable projects that will integrate positively with the utility grid on Oahu, and encourage renewable energy generation activity where such activity is lacking in targeted categories.

HECO will continue to support renewable energy, and continues to discuss proposals for potential projects with developers. However, in order to address the reserve capacity shortfall situation described in this AOS, HECO requires large increments of firm capacity, in the near term. Although RHI has issued two requests for project proposals for the island of Oahu, this process has not yet identified any candidate renewable projects that are large, firm, and can be installed in the near term. For example, a wind power project, while it may supply a significant block of energy when the wind is blowing, is not a dispatchable firm capacity resource. Nonetheless, cost-effective renewables are attractive supply-side resources, and HECO will move forward on viable renewable proposals.

4. Support Sea Water Air Conditioning

Seawater Air Conditioning (SWAC) is a renewable energy technology that is emerging as a possible energy option for reducing the electricity requirement for air conditioning for commercial customers. Honolulu Seawater Air Conditioning, LLC plans to develop this resource for use in downtown Honolulu, Waikiki and Kakaako. Like other emerging technologies it is difficult to assess the timing of the commercial viability of the technology in specific location. The status of the numerous permits, environmental assessments, site acquisitions necessary for the primary pumping stations, and easement and rights-of-way needed to implement the project are uncertain. Thus, it is not certain at this time whether SWAC will be installed in Hawaii and what the date of commercial operation will be. However, should the technology become commercially available, HECO's existing DSM CICR program has the flexibility to provide incentive for customers to install systems using the SWAC technology.

5. Implement PV

Photovoltaic ("PV") systems do not meet firm capacity needs, but do provide energy and value to the utility in terms of meeting renewable portfolio standards requirements. Consistent with its IRP-3 preferred plan, HECO has performed preliminary engineering for development of approximately 300 kW of photovolatics ("PV") at HECO's Ward Avenue facility. HECO is currently determining its options with regard to financing the PV systems. The timing of the installations is identified in the IRP plan as 2007, but will ultimately depend on the acquisition of required permits and regulatory approvals.

Recent developments at the federal level may contribute to increased installations of PV systems by HECO's customers. The federal government recently increased the tax credit incentives for PV systems. Beginning January 1, 2006, the federal tax credit for commercial PV systems increased from 10% to 30% with no cap and there is a new 30% credit up to $2,000 for residential PV systems. The federal and state tax credits end December 31, 2007 and the fate of the tax credits after expiration is uncertain at this time. While State tax credits for PV systems so far remain unchanged, the changes in federal incentives may stimulate market response to PV systems. HECO anticipates that some customers may install PV systems during the forecast period, however, the amount and timing of such installations is indeterminate.

As for utility involvement in customer-sited PV, initial development and ownership of PV systems is generally not cost-effective for the electric utility, since regulated electric utilities are not eligible for federal renewable energy investment tax credits. The utility is evaluating how it might support the installation of PV systems at customer sites in partnership with third party PV developers.

6. Preparations for Potential Outages

HECO has been reviewing and making modifications to its manual load shedding plans in the event rolling outages become necessary. Hospitals and other key public health and safety facilities should not be impacted in the event HECO has to initiate rolling outages. HECO divided Oahu into 17 sections, based on the layout of the subtransmission and distribution systems. No section has been pre-identified to go first when rolling outages are first initiated. The section or sections identified to go first will depend on how much load has to be reduced to keep the electric system stable.

Appendix 5:

Uncertainties in HECO Capacity Planning

Any planning activity relies on certain assumptions. For example, when individuals plan for retirement, they may forecast future revenues, expenses, length of retirement, and many other items. Each of these planning assumptions contains an element of uncertainty. Similarly, when HECO performs its capacity planning, it employs assumptions about the future that may turn out to be different from actual results. Described below are some of the key uncertainties related to HECO's capacity planning.

Actual Daily Load versus Forecasted Loads

As mentioned in Section 3, factors such as the schedule for implementing large commercial and residential development projects, the time of year, weather variables (such as rainfall, cloud cover, humidity, winds, and temperature) and their load impacts, and changes in residential and commercial use affect the actual daily load.

HECO does not forecast its load to be an "upper bound" of what future loads could be. HECO's actual load may be higher than the forecasted load.

Non Dispatchable As-available Energy

Resources in this category include the energy provided under as-available energy contracts, such as those between HECO and the Tesoro and Chevron refineries. A key characteristic of non-dispatchable as-available resources is their unpredictable variability. Because energy providers are not under contract to provide specific amounts of capacity or energy at scheduled times, the amount of capacity they will provide at a given time cannot be quantified.

Because a portion of Tesoro, Chevron and Pearl Harbor's load is served by their as-available generators at the time of the system peak and because HECO would need to serve that load had their generators not been running, HECO includes this additional load in its peaks for capacity planning purposes.

Actual CHP Impacts Versus Forecasted Impacts

There is a significant degree of uncertainty in forecasting the CHP market, whether the forecast is for HECO-owned CHP projects or non-utility CHP projects. On a macro-scale, the economic viability of CHP is highly sensitive to fuel and electricity prices. The energy efficiency benefits of a CHP system may not translate to overall cost savings for a customer if the CHP fuel cost (for diesel fuel oil, propane or synthetic natural gas) is significantly higher than the cost of fuel used to generate grid electricity, which is currently the situation on Oahu. Furthermore, prospective CHP projects are subject to customer desire and support, which can be extremely variable. For example, a CHP project under development by the City and County of Honolulu for its Kapolei Hale facility was cancelled in January 2005 by the City and County. Site-specific factors also add uncertainty, as they may affect the feasibility of moving forward with a project even when the desire for CHP is strong. The largest potential HECO CHP project that was included in the CHP forecast used in the 2005 AOS, the Outrigger Beachwalk CHP project, was determined to be infeasible in late 2004 due to technical and economic reasons.

In addition, HECO's proposals to implement utility-owned CHP projects were delayed by the suspension of the CHP program application and its first "Rule 4" contract application, pending resolution of the Commission's DG investigation. The Rule 4 contract was then terminated by the customer. The 2005 AOS assumed that HECO's ability to install customer-sited CHP as a utility service would be delayed pending resolution of the Commission's DG investigation initiated in October 2003, but that such installations would commence in 2006.

On January 27, 2006, the PUC issued its decision and order ("D&O") in the DG proceeding. The D&O affirmed the ability of electric utilities to procure and operate DG for utility purposes <u>at utility sites</u>. The Commission also indicated its desire to promote the development of a competitive market <u>for customer-sited DG</u>. In weighing the general advantages and disadvantages of allowing a utility to provide DG services on a customer's site, the PUC found that the "disadvantages outweigh the advantages." However, the PUC also found that the utility "is the most informed potential provider of DG" and it would not be in the public interest to exclude the HECO Utilities from providing DG services at this early stage of DG market development. The D&O allows utilities to provide DG services on a customer-owned site as a regulated service when (1) the DG resolves a legitimate system need; (2) the DG is the least cost alternative to meet that need; and (3) it can be shown that in an open and competitive process acceptable to the PUC, the customer operator was unable to find another entity ready and able to supply the proposed DG service at a price and quality comparable to the utility's offering.

The D&O allows HECO to pursue its CHP Program application submitted in October 2003 in Docket No. 03-0366, but requires that the application be amended to provide facts relevant to the three conditions. As a practical matter, however, the conditions may limit the Companies' ability to provide CHP systems on a programmatic or regulated basis, depending on how the conditions are applied. On March 1, 2006, the electric utilities filed a Motion for Clarification and/or Partial Reconsideration requesting clarification as to how these conditions will be applied.

As a result of the change in the economic outlook for CHP projects on Oahu, and uncertainties as to the ability of HECO to provide CHP projects on a regulated utility basis, the updated CHP forecast used for the 2006 AOS projects that the peak reduction impacts of both utility and non-utility CHP installations will be significantly lower than the impacts projected for the 2005 AOS, with peak reduction impacts of 1 MW in 2007 and 7 MW in 2010. At the same time, HECO is focusing on other potential DG projects, as indicated in Appendix 4.

Actual Energy Efficiency DSM Impacts Versus Forecasted Impacts

There are risks that the Company's enhanced energy efficiency DSM programs will not achieve projected peak load reductions. Those risks include time lags in the regulatory approval process and lower customer participation in the programs due to factors such as inadequate awareness about their energy options and about the urgency of the capacity situation. If approvals to implement the enhanced energy efficiency DSM program are delayed and/or customer participation in these programs is lower than estimated, impacts from these DSM programs will be delayed and lower than estimated, ultimately resulting in higher peak loads.

Actual Load Management DSM Impacts Versus Forecasted Impacts:

There are risks that the Company's load management DSM programs will not achieve projected peak load reductions. There is a risk of lower customer participation in the Residential Direct Load Control program due to factors such as inadequate awareness. Lower customer participation in the Commercial & Industrial Direct Load Control program could be due to factors such as the challenges of acquiring the necessary permits for the use of customer-owned emergency generators, to provide stand-by generation to backup their interruptible loads.

Actual Outage Schedule versus Forecasted Schedule

Maintenance scheduling is performed by the HECO Power Supply Operations and Maintenance Department. Maintenance scheduling can be expected to change several times over the year because of operational factors. Each year, a five-year schedule is developed to plan for generating unit outages required to complete necessary maintenance, overhauls, inspections, and capital project installations. Throughout the year, as equipment components fail such that corrective maintenance needs to be performed, additional maintenance or repair beyond what was originally planned is required, resulting in the need to revise and update outage schedules. However, revisions to the schedule are limited by constraints in manpower availability to perform the repair work, material and replacement equipment fabrication and delivery lead times, regulatory constraints which require periodic inspections within a set timeframe, and the need to have enough generation available to meet the expected load. Depending on the magnitude and timing of the additional outages required, changes in the outage schedule may result in higher risk to the system by having less than desired generation reserves available to meet HECO's spinning reserve and quick load pickup needs or to keep the LOLP above the 4.5 days per year reliability guideline. In the event planned capacity is delayed, rearranging maintenance schedules should be considered as a measure to mitigate the effects of delays in installing generation or acquiring the peak reduction benefits of energy efficiency DSM, load management

DSM or CHP. However, deferring maintenance or rearranging maintenance schedules cannot avoid or permanently defer the need for additional generation under a reserve capacity shortfall situation and, despite short-term benefits, may over time increase generating unit EFOR with a resulting decrease in generation system reliability in the long run. Please refer to HECO's response to CA-IR-42 in the Rate Case Docket No. 04-0113, for an example of how the actual maintenance schedule can be substantially different from the planned maintenance schedule.

Assumed EFOR

Even with timely and prudent maintenance practices, all generating units are subject to forced outages. There is also a risk of multiple forced outages on a given day. Statistical or stochastic analysis may be appropriate for longer-term analyses; however, on a day-to-day basis, forecasting whether or not forced outages are likely to occur is very difficult to quantify.

EFOR is an indication of the probability that a generating unit will be unexpectedly forced out of service due to an unforeseen problem with the unit. Projections of EFOR for each unit are based on factors such as the historical EFOR of the unit and maintenance work that was recently done or will be done to improve the expected reliability of the unit.

A discussion of HECO generating unit EFOR is provided in Appendix 7. Included in this discussion are actions that HECO will take in effort to improve the EFOR rate of its generating units.

Appendix 6:

Additional Sensitivity Analysis of Alternate Scenarios

Section 4.3.2 provides the basic information regarding alternate scenarios to the base case. Additional quantifiable results for these scenarios are provided in this Appendix. Explanations for HECO's generating system reliability guideline and Rule 2 planning criteria can be found in Sections 4.2 and 4.1, respectively.

1. Alternate High Load Scenario

Table A6-1 provides the generating system reliability in years per day for this scenario. It should be noted that Table A6-1 does not include the effects of the addition of the CIP combustion turbine in 2009. The results are significantly lower than HECO's reliability guideline of 4.5 years per day, in all years.

Table A6-1:

Generation System Reliability Shortfall for the Alternate High Load Scenario

Year	Generation System Reliability (years/day)
2006	0.1
2007	0.1
2008	0.1
2009	0.1
2010	0.0

Table A6-2 provides the reserve capacity shortfall in meeting HECO's Rule 2 planning criteria. It should be noted that Table A6-2 does not include the effects of the addition of the CIP combustion turbine in 2009. Since Rule 2 results are deterministic, these alternative high load scenario results indicate that approximately 105 MW of firm capacity would be needed by 2009, regardless of any improvement in HECO generating unit EFORs.

Table A6-2:

HECO Rule 2 Reserve Capacity Shortfall for the Alternate High Load Scenario

Year	MW
2006	-57
2007	40
2008	-81
2009	-105
2010	-113

2. <u>Alternate Low Load Scenario</u>

Table A6-3 provides the generating system reliability in years per day for this scenario. It should be noted that Table A6-3 does not include the effects of the addition of the CIP combustion turbine in 2009. The results are significantly lower than HECO's reliability guideline of 4.5 years per day, in all years.

Table A6-3:

Generation System Reliability Shortfall for the Alternate Low Load Scenario

Year	Generation System Reliability (years/day)
2006	0.5
2007	0.4
2008	0.4
2009	0.3
2010	0.3

Table A6-4 provides the reserve capacity shortfall in meeting HECO's Rule 2 planning criteria. It should be noted that Table A6-4 does not include the effects of the addition of the CIP combustion turbine in 2009. Since Rule 2 results are deterministic, these alternative low load scenario results indicate that approximately 3 MW of firm capacity would be needed by 2009, regardless of any improvement in HECO generating unit EFORs.

Table A6-4:

HECO Rule 2 Capacity Shortfall for the Alternate Low Load Scenario

Year	MW
2006	14
2007	41
2008	10
2009	-3
2010	-2

3. Alternate Lower EFOR Scenario

Table A6-5 provides the generating system reliability in years per day for this scenario. It should be noted that Table A6-5 does not include the effects of the addition of the CIP combustion turbine in 2009. The results are significantly lower than HECO's reliability guideline of 4.5 years per day, in all years.

Table A6-5

Generation System Reliability Shortfall for the Lower EFOR Scenario

Year	Generation System Reliability (years/day)
	Lower EFOR, 2002-2005 Avg
2006	0.3
2007	0.3
2008	0.2
2009	0.2
2010	0.2

Because HECO's Rule 1 and Rule 2 criteria are deterministic and do not take into account the reliability of each unit, a high EFOR sensitivity analysis has no impact on the amount of excess or deficit capacity available on the HECO system to meet Rules 1 and 2. Therefore, the Rule 2 results for the Alternate Lower EFOR scenario are not illustrated here.

Appendix 7:

HECO Equivalent Forced Outage Rate (EFOR) Discussion

1. Introduction

EFOR is a unit-specific measure of lost megawatt hours due to forced outages or unplanned unit deratings

- "Forced Outages" are unplanned unit shutdown caused by a number of factors, e.g., automatic or programmed protective trips, operator-initiated trips due to equipment malfunction or maintaining compliance with established permits, or operator error.

- "Deratings" are unplanned unit events caused by equipment malfunction or deterioration such that full load cannot be achieved. For example, a generating unit that can only produce 78 MW of its 90 MW normal capacity is considered derated.

2. Factors Affecting EFOR

Major factors contributing to EFOR include unit and equipment age (older units tend to have higher EFOR than newer units), operating duty (i.e., minimum load, on/off cycling, etc.), human factors, compliance with environmental restrictions, and safety. The severity of unit operating duty (running units harder) increases as the units age, because the older units, over time, become less efficient than the newer units. Another way of understanding this is that new units in a particular class, i.e., non-reheat steam units, started out as base loaded units when they were first placed on line, because they tended to be the largest and most efficient. Over time, newer, larger and more efficient units were added to the HECO system, i.e., reheat steam units, and were baseloaded, leaving the relatively less efficient non-reheat units to cycle. As a consequence of shifting mode of operation from baseload when they were new (least severe on equipment), to cycling when they were older (most severe on equipment), wear and tear on equipment increased as the units got older. HECO baseloaded reheat steam units are also being affected by the impact of daily minimum loads on their respective auxiliary equipment. The cause is attributed to the addition of IPP baseloaded capacity in the early 90's that required HECO baseload units to share the minimum load with IPP baseload units. Due to the relative differences in efficiency between the HECO reheat units and the IPP units, HECO baseload units are operated down their respective minimum loads to meet system requirements while IPP baseloaded units operate close to their maximum output. In order to operate safely at minimum loads, HECO baseload units must cycle (on/off operation) critical auxiliaries on a daily basis.

This mode of operation increases the wear and tear on critical auxiliaries and increases the potential for breakdown and subsequent operation with a derating.

One significant contributing factor to the stress placed on the units is the increasing number of hours that HECO's cycling and peaking units[29] are running as system demand grows. The cycling and peaking units and their associated auxiliary equipment must turn on and off, on a daily basis, and this results in cyclic thermal stresses and accelerated wear on cycled auxiliary equipment, which damage critical parts, and can result in a generating unit forced outage or derating. The increased operating hours add to the stress on the units.

All of HECO's steam units were originally designed to operate in baseload duty, i.e., operate 24 hours a day. They were not designed to withstand the stresses of daily starting and stopping. However, as the larger, more efficient units, such as Kahe Units 1 to 6 came into service, they were placed into baseload duty, and the smaller, less efficient units, such as Waiau Units 3 to 6, were placed into cycling duty to support the daily changes in peak loads.

One example of the consequence of placing a unit designed for baseload duty into cycling duty is the severe cracking of the turbine cylinder[30] experienced on Waiau Unit 4 in the 1980s due to the thermal cycling fatigue. (The unit was built in 1950.) The cylinder needed to be completely replaced because at the time, crack mapping technologies and weld repair techniques were not available to effect a reliable repair.

With respect to the peaking units, they were designed to start and stop daily and operate only a few hours a day to serve the peak demand period, which occurs usually between the hours of 5:00 pm to 9:00 pm. From 1993 to the late 1990s when HECO enjoyed a higher reserve margin, the peaking units generally operated between 100 and 200 hours each, which is typical for peaking units. Over the past two years, they have been averaging over 1,000 hours each. This operation is more like cycling duty, and the longer operating hours is increasing the "wear and tear" on these units. In 2004, Waiau Unit 9 experienced a forced outage of long duration resulting from the catastrophic failure of some of its compressor blades.

Even critical auxiliary equipment, such as various pumps and motors, on HECO's baseload units[31] experience cycling stresses from daily on/off operation. While these units run 24 hours a day, seven days a week, they must increase their output during the high demand daytime hours and reduce their output during the low demand night-time hours. During the low demand periods, some of the critical auxiliary equipment must be turned off to support stable and

[29] The cycling units are Waiau Units 3 to 6 and Honolulu Units 8 and 9. The peaking units are Waiau Units 9 and 10, which are combustion turbines.
[30] The turbine cylinder is the casing that contains the extremely high pressure, high temperature steam.
[31] HECO's baseload units include Kahe Units 1 to 6 and Waiau Units 7 and 8. The Kalaeloa, AES and H-Power units are also baseload units.

reliable low load operation. As demand increases at the start of the day, they must be turned on again. This daily on/off cycling of critical auxiliary causes thermal, mechanical and electrical stresses that can result in unanticipated breakdowns and unit deratings. The auxiliary equipment on the Independent Power Producer ("IPP") units do not cycle on and off or experience duty as severe as HECO units because they tend to operate closer to their full outputs 24 hours a day.

The ages of the units also played a large role in the higher EFORs in last two years. Generating units are made up of very complex systems and equipment that wear and tear at different rates as they age. Older mechanical and electrical equipment are prone to break down more frequently than newer equipment. Oftentimes, imminent breakdowns cannot be detected despite best efforts to regularly inspect and maintain the equipment. Also, acquiring replacement parts on older equipment become more challenging due to obsolescence, and substitute parts that are often reengineered by other than the original equipment manufacturer (OEM) require several iterations to refine the design. This can increase the amount of time a unit remains out of service, thereby increasing the EFOR statistic. One example is the Waiau Unit 3 outage which required 2 outages (planned outage of 18 weeks and forced outage of 10.5 weeks) to permanently correct a design flaw in the replacement condenser waterbox.

3. Unpredictable Nature of EFOR

Unplanned deratings and/or unit trips are difficult to predict as evidenced by the erratic nature of observed EFOR. The erratic nature of EFOR is related to how hard HECO's aging units are operated, and the amount of reserve margin available to perform repairs while minimizing risk to the system. When problems are detected, corrective action is taken as soon as possible once the root cause is identified. In the case of unplanned deratings, corrective action may be delayed depending on expected system demand, available reserve margin, outage priorities on other units, and parts/materials availability.

4. Forward-looking EFOR Rates used in the 2006 AOS

As explained above, it is difficult to predict EFOR rates, especially under changing operating conditions. Nonetheless, simultaneous unplanned outages and unit deratings are both real-life occurrences, and efforts are made to estimate forward-looking EFOR rates using a blend of historical data, experience, and judgment. The rationale for the estimated EFOR rates used in the 2006 AOS analysis is described in the following paragraphs.

4.1. Honolulu Units 8 and 9

Honolulu Unit 8 experienced an EFOR of 23.7% in 2004, and 1.7% in 2005. The 2004 EFOR of 23.7% was mainly attributed to a capacity derating caused by an abnormal

#1 turbine bearing oil drain temperature. A maintenance outage was performed in July, 2004, and external cooling was added to remove the derating in August, 2004. The 2005 EFOR of 1.7% was attributed to five incidents that required either a derating or resulted in a forced outage. In general the unit performed reliably in 2005. Due to the age and increase in operation since the shift from 16x5 to 24x7 availability, a 2-year average EFOR of 12.8% is recommended for forecasting purposes.

Honolulu Unit 9 had an EFOR of 1% in 2004, and 12.0% in 2005. The 2004 EFOR of 1% was attributed to substantial amount of refurbishment work performed on both Honolulu units. The 2005 EFOR of 12% was attributed to 12 incidents - 7 derates and 5 forced outages. The forced outages were attributed to boiler tube leaks, turbine governor valve controls, exciter, and attemperation repairs. Due to the age and increase in operation since the shift from 16x5 to 24x7 availability, and similarity to Honolulu Unit 8, the EFOR of 12.8% used for Honolulu Unit 8 is recommended for forecasting purposes.

4.2. <u>Waiau Units 3 and 4</u>

Waiau Unit 3 experienced an EFOR of 24.7% in 2004, and 42.2% in 2005. In 2004, Waiau Unit 3 underwent an 18-week major overhaul to inspect and refurbish the turbine, boiler, generator, and balance of plant equipment. Even with the scheduled planned outages in 2004 and maintenance outages in 2005, W3 continued to experience derates and forced outages. The 2005 EFOR of 42.2% was attributed to 14 incidents of deratings and forced outages – 3 deratings and 11 forced outages. The unit will continue to operate with a derating until reserve margins allow a maintenance outage in 2006 to investigate the cause of the derate. The forced outages on W3 were caused by various problems on the boiler, turbine, generator and balance of plant equipment. Waiau Unit 3 is the oldest active unit in the HECO fleet, and will be 59 years old in 2006. Due to the age and increase in operation since the shift from 16x5 to 24x7 availability, a 2-year average EFOR of 33.5% is recommended for forecasting purposes.

Waiau Unit 4 experienced an EFOR of 13.4% in 2004, and 5% in 2005. The 2005 EFOR of 5% was attributed to 11 incidents of deratings and forced outages – 3 deratings and 8 forced outages. The forced outages were caused by various problems on the boiler, generator and balance of plant equipment. The Waiau Unit 4 planned outage scheduled in October, 2005, had to be rescheduled in 2006 due to a forced outage on Waiau Unit 8 that occurred on October 15, 2005. Due to the age and increase in operation since the shift from 16x5 to 24x7 availability, and similarity to Honolulu Unit 8, the EFOR of 12.8% used for Honolulu Unit 8 is recommended for forecasting purposes.

4.3. Waiau Units 5 and 6

Waiau Unit 5 experienced an EFOR of 1.0% in 2004, and 1% in 2005. The 2004 EFOR of 1% resulted from substantial refurbishment work that was performed on Waiau Unit 5 during a 27-week major overhaul from September, 2002, through March, 2003. The 2005 EFOR of 1% was attributed to five incidents of deratings and forced outage – 4 derating and 1 forced outage. Waiau Unit 5 continues to perform reliably, however, as the unit approaches its next overhaul, and considering the unit's age and operating duty, an EFOR of 2.9% based on its sister unit, Waiau Unit 6, is recommended for forecasting purposes.

Waiau Unit 6 experienced an EFOR of 0.3% in 2004, and 2.6% in 2005. The 2004 EFOR of 0.3% is considered excellent considering the age of the unit and operating duty. The 2005 EFOR of 2.6% is attributed to four incidents of deratings and forced outage – 3 derating and 1 forced outage. HECO expects that the EFOR will remain at the level of the latest data and subsequent operating reliability following a major overhaul that was completed in April 2005, despite diligent maintenance, due to the increasing unit age and reduced scheduling flexibility caused by tight reserve margins. EFORs of 2.9% are expected to be reasonably representative of the future EFOR.

4.4. Waiau Units 7 and 8

Waiau Unit 7 experienced an EFOR of 1.2% in 2004, and 0.6% in 2005. The 2005 EFOR was attributed to four incidents of deratings and forced outage – 3 derating and 1 forced outage. It is expected that Waiau Unit 7 continue to experience higher levels of deratings and forced outages because its condenser tubes are scheduled for replacement in 2008.

Waiau Unit 8 experienced an EFOR of 7.7% in 2004, and 23.5% in 2005. The 2005 EFOR was attributed to 10 incidents of deratings and force outages – 6 derating and 4 forced outages. Waiau Unit 8 underwent a 10.5-week major overhaul in 2004, and experienced a forced outage in October, 2005 due to a feedwater heater failure that also damaged the turbine. Forced outage repairs were completed in February, 2006.

The EFORs for these units may move upward some from their historical averages, despite diligent maintenance, due to their increasing age and reduced scheduling flexibility caused by tight reserve margins. EFORs of 7.7% are expected to be reasonably representative of the future EFOR on both Waiau Unit 7 and Waiau Unit 8 considering the scope of the recent overhauls, repairs on the Waiau Unit 8 feedwater heater and turbine, and the general condition of the units.

4.5. Waiau Units 9 and 10

Waiau Unit 9 experienced EFORs of 63.2% in 2004 and 69.2% in 2005. Both EFOR results were heavily influenced by the W9 forced outage that straddled both 2004 and 2005. W9 was placed into service following forced outage repairs in April, 2005. Since then Waiau Unit 9 experienced 12 forced outage incidents caused by combustion, turbine vibration, and generator instrumentation problems.

Waiau Unit 10 experienced an EFOR of 4.4% in 2004, and 7.4% in 2005. The 2005 EFOR of 7.4% was attributed to 13 forced outage incidents caused by combustion, and miscellaneous control and instrumentation problems. Waiau Unit 10 is currently scheduled for a major overhaul beginning in February, 2006. The overhaul, originally scheduled to follow the Waiau Unit 9 outage in 2005, was rescheduled due to other unit outage requirements and reserve margin considerations.

Even after the completion of both overhauls, EFORs of 10% for Waiau Units 9 and 10 are reasonable when considering the age of the units and the significantly higher service hours and peaking duty anticipated.

4.6. Kahe Units 1 and 2

Kahe Unit 1 experienced EFORs of 2.6% in 2004 and 5.4% in 2005. The 2005 EFOR of 5.4% was attributed to 18 incidents of deratings and no forced outages. However, one of the major contributors of the higher EFOR in 2005 was a boiler reheater tube leak. Repairs on similar condition tubes are not scheduled until the latter part of 2006. Until then, there is a possibility of experiencing more reheater tube leaks.

Kahe Unit 2 experienced EFORs of 2.9% in 2004 and 2.0% in 2005. The 2005 EFOR of 2.0% was attributed to 12 incidents of deratings and forced outages – 9 deratings and 3 forced outages.

The EFORs for these units may move upward some from their historical averages, despite diligent maintenance, due to their increasing age and reduced scheduling flexibility caused by tight reserve margins. Therefore, EFORs of 4.3% based on the higher 2-year average of Kahe 1 are expected to be reasonably representative of the future EFOR on both Kahe Units 1 and 2.

4.7. Kahe Units 3 and 4

Kahe Unit 3 experienced EFORs of 8.8% in 2004 and 8.3% in 2005. The 2004 EFOR of 8.8% was due to a capacity derating from 90 MW down to lower capacities depending on furnace pressure limitations caused by clogged sections of air preheater baskets. The 2005 EFOR of 8.3% was attributed to seven incidents of deratings and no forced outages.

Kahe Unit 4 experienced EFORs of 1.4% in 2004 and 4.9% in 2005. The 2005 EFOR of 4.9% was attributed to seven incidents of deratings and forced outages – 5 derating and 2 forced outages.

The EFORs on both Kahe Unit 3 and Kahe Unit 4 are expected to be similar to the EFORs for Waiau Unit 7 and Waiau Unit 8, due to the similarities in boiler design and mode of operation. Therefore, EFORs of 7.7%, as used for Waiau Unit 7 and Waiau Unit 8, are expected to be reasonably representative of the future EFORs for both Kahe Units 3 and 4.

4.8. <u>Kahe Units 5 and 6</u>

Kahe Unit 5 experienced EFORs of 7.6% in 2004 and 3.1% in 2005. The 2004 EFOR of 7.6% was due to a capacity derating from 142 MW (gross) down to lower capacities based on problems with the superheat attemporator which controls steam temperature to the turbine. The control issues were resolved and the unit returned to its normal capability of 142 MW (gross). The 2005 EFOR of 3.1% was attributed to seven incidents of deratings and forced outages. The most significant was a forced outage caused by a boiler hotspot in November, 2005. An EFOR based on the 2-year average EFOR of 5.5% for Kahe Unit 5 is expected to be reasonably representative of the future EFOR.

Kahe Unit 6 experienced EFORs of 3.3% in 2004 and 5.9% in 2005. The 2004 EFOR of 3.2% was due to a derating caused by partial air preheater pluggage that results in high furnace pressure. The 2005 EFOR of 5.9% was attributed to 11 incidents of deratings and forced outage – 10 deratings and 1 forced outage. An EFOR based on the 2-year average EFOR of 4.9% for Kahe Unit 6 is expected to be reasonably representative of the future EFOR.

5. <u>Evaluate an Expanded Inventory of Critical Spare Parts</u>

Availability of spare parts can impact the duration of an unplanned outage. The benefits of having a vast inventory of spare parts readily available must be balanced against the likelihood that the spare part will be needed, and the carrying cost of the inventory. Estimated delivery times for items that are not kept in inventory must also be considered. HECO will evaluate an expanded inventory of critical spare parts for its generating units.

6. HECO Generating Unit Maintenance Program Review and Evaluation

Over the years HECO has conducted studies through its maintenance programs, practices and application of various technologies and testing techniques. The studies and programs primarily focus on critical pieces of equipment such as the boiler, generator and turbine that significantly impact unit availability. For example HECO pioneered turbine cylinder crack repair procedures on Honolulu Units 8 & 9, in 2002 and 2003, with a high degree of success by combining selected non-destructive testing techniques with in-house expertise to avoid purchasing long lead (up to 2 years) replacement turbine cylinders. From that time to date no problems attributed to turbine cylinder cracks have been experienced. Further elaboration on other examples is given in HECO's response to CA-IR-439 in HECO's Test Year 2005 Rate Case (Docket No. 04-0113).

In addition to HECO's internal continuous improvement efforts, HECO has retained consultants from EPRI Solutions to review HECO's operating, maintenance and outage practices, processes, and policies to look for untapped opportunities to improve its generation assets' availability and reliability. This review and evaluation will include the following actions:

6.1. Review studies, recommendations, reports and other documents related to generating unit maintenance practices.

6.2. Evaluate unit-specific and system EFOR/EAF trends and events.

6.3. Review HECO maintenance capabilities, limitations, and opportunities as they relate to HECO's generating units

In addition, the consultants will evaluate HECO's 5-year maintenance plan and verify ways in which it can be cost-effectively and practically improved. It is anticipated that this review and evaluation will be completed by mid-2006.

HECO selected EPRI Solutions because HECO has, in the past, benefited from the expertise of the Electric Power Research Institute ("EPRI") on improving the reliability of its generating units. One example is the design of HECO's Boiler Reliability Optimization program, started in late 1998, and finalized in November 2001, with the issuing of a Boiler Reliability Optimization Procedures Manual. The effectiveness of the program has resulted in reducing forced outages caused by boiler tube leaks from a high of 59 forced outages in 1999 to a manageable 7 to 11 forced outages between 2001 to 2005, and has elevated HECO's industry ranking to "world class" status. Further elaboration is given in HECO's response to CA-IR-50 in HECO's Test Year 2005 Rate Case (Docket No. 04-0113).

In the late 1990s and early 2000s, HECO also developed a Power Supply Reliability Optimization (PSRO) Program under the guidance of EPRI Solutions. The goal of this program

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STATE OF HAWAII
PUBLIC UTILITIES COMMISSION
DEPARTMENT OF BUDGET AND FINANCE
465 S. KING STREET, #103
HONOLULU, HAWAII 96813

February 1, 2006

Mr. William A. Bonnett
Vice President, Government &
Community Affairs
Hawaiian Electric Company, Inc.
PO Box 2750
Honolulu, Hawaii 96840-0001

Mr. Edward L. Reinhardt
President
Maui Electric Company, Ltd.
PO Box 398
Kahului, Hawaii 96733-6898

Mr. Warren H. W. Lee
President
Hawaii Electric Light Company, Inc.
PO Box 1027
Hilo, Hawaii 96721-1027

Re: Extension for Adequacy of Supply Reports

Dear Messrs. Bonnett, Reinhardt, and Lee:

By separate letters dated and filed on January 30, 2006, Hawaiian Electric Company, Inc. ("HECO") and Maui Electric Company, Ltd. ("MECO") requested extensions to file their respective Adequacy of Supply Reports ("AOS"), which are due thirty (30) days after the end of the year, pursuant to paragraph 5.3a of General Order No. 7. According to HECO and MECO, an extension will allow them to better assess and incorporate the impact of their most recent generation availability experience (for the calendar year 2005) in determining their reserve capacity for the period covered by the 2006 AOS. HECO requested an extension until March 15, 2006, to submit its AOS, and MECO requested an extension until February 28, 2006, to complete its AOS.

By letter dated and filed on January 31, 2006, Hawaii Electric Light Company, Inc. ("HELCO") requested an extension to file its AOS, the day after the deadline to file the AOS. According to HELCO, an extension is required to allow it to incorporate into its AOS "the impacts of the Commission's recent decision and order in the Distributed Generation proceeding (Docket No 03-0371)."

The commission will treat HECO, MECO and HELCO's letter requests as motions for extension of time under Hawaii Administrative Rules ("HAR") §§ 6-61-23 and 6-61-41. HAR § 6-61-23(a)(1) allows the commission to enlarge a period by which a required act must be completed upon a showing of good cause provided that a written request is made before the expiration of the period originally prescribed.[1] If the period originally prescribed has expired, the commission may only grant the request upon a showing that the "failure to act was the result of excusable neglect." HAR § 6-61-23(a)(2).

After reviewing the entire record, the commission grants HECO and MECO's extension requests. HECO's AOS is due no later than March 15, 2006, and MECO's AOS is due no later than February 28, 2006.

HELCO, however, has not demonstrated the requisite "excusable neglect" required by HAR § 6-61-23(a)(2). Accordingly, HELCO's motion is denied.

If you have any questions or concerns, please contact Stacey Kawasaki Djou at 586-2180.

Sincerely,

Carlito P. Caliboso
Chairman

CPC:SKD:eh

c: Division of Consumer Advocacy

[1]Motions that do not involve the final determination of a proceeding may be determined by the chairperson or commissioner. See HAR § 6-61-41(e).

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

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January 30, 2006

William A. Bonnet
Vice President
Government & Community Affairs

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PUBLIC UTILITIES
COMMISSION

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.

In accordance with paragraph 5.3a of General Order No. 7, HECO's Adequacy of Supply Report ("AOS") is due within 30 days after the end of the year. HECO respectfully requests an extension to no later than March 15, 2006 to submit its report.[1]

In general, the AOS assesses the adequacy of central station generation (including firm purchased power from Independent Power Producers, or "IPPs") to serve forecasted loads, as those loads are reduced due to the projected impacts of energy efficiency demand-side management ("DSM") programs, load management programs, and customer-sited combined heat and power systems ("CHP").

Extension of the filing date for the 2006 report will allow HECO to better assess and incorporate the impact of its most recent generation availability experience (for the calendar year 2005) in determining the estimated reserve margin capacity shortfall for the future period to be covered by the 2006 AOS.[2]

In the last two years, as HECO's generation reserve margin has shrunk due to customer load growth as the economy has improved, HECO has experienced higher equivalent forced outage rates ("EFORs" – the rate of unplanned outages and deratings for the generating units), as well as the need for more frequent and longer planned outages. The higher EFORs are attributable, in large part, to the need to start cycling and peaking units more often and to run them for more hours than in previous years, in order to serve higher customer loads. Baseload

[1] HECO filed its 2005 AOS on March 10, 2005 and 2004 AOS on March 31, 2004.

[2] In its 2005 AOS, HECO reported that it anticipated a reserve capacity shortfall in 2005, and projected that the shortfall would continue at least until 2009, which was the earliest that HECO expected to be able to permit, acquire, install and place into commercial operation its next central station generating unit.

units are run harder, and sometimes at lower-than-normal capacity due to failed or damaged components. In combination, the longer outages and higher EFORs resulted in lower unit availabilities. Thus, considered in isolation, higher EFORs will tend to increase the reserve margin shortfall. (However, in the AOS, the EFORs should and will be considered in conjunction with other factors that affect the sufficiency of the reserve capacity margin.)

In its 2005 AOS, HECO also identified actions that had been or were being implemented, developed, or assessed for possible implementation to minimize the risk of generation-related shortfalls. The extension will allow HECO to provide details as to additional measures (i.e., measures in addition to those that have already been successfully implemented by HECO or that are awaiting regulatory action) that are being evaluated or implemented to help address the reserve margin shortfall situation.

The Consumer Advocate does not object to this request.

Very truly yours,

cc: Division of Consumer Advocacy