HECO
2004 (for 2003)
2005 (for 2004)

ADEQUACY OF SUPPLY
REPORTS

(SPECIAL REPORTS – PERMANENT)

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

KN
LYK
SI
MS

March 10, 2005

William A. Bonnet
Vice President
Government and Community Affairs

2005 MAR 10 P 3:44

FILED

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
<u>Hawaiian Electric Company, Inc.</u>

In accordance with paragraph 5.3a. of General Order No. 7, HECO's Adequacy of Supply ("AOS") Report is due within 30 days after the end of the year. On January 31, 2005, HECO requested an extension of time, to no later than March 15, 2005, to file the Report. The extension of time was needed to allow HECO to incorporate (1) updated planned maintenance schedules, (2) updates to its expected outage rates for central station generation, (3) updates to its CHP projections, and (4) revisions to the start dates for its enhanced energy efficiency DSM programs. On February 9, 2005, the Commission issued Decision and Order No. 05-ORD-03 approving HECO's request.

HECO respectfully submits the following information pursuant to paragraph 5.3a. of General Order No. 7.

I. Executive Summary

1. Adequacy of Supply – 2004

HECO's 2004 system peak occurred on Tuesday, October 12, 2004 and was 1,327,000 kW-gross or 1,281,000 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[1] operating at the time. Had these cogenerating units not been operating, the 2004 system peak would have been 1,348,000 kW-gross or 1,302,000 kW-net.

[1] At the time of the peak, certain units at Tesoro and Pearl Harbor were generating an estimated 21,000 kW of power for use at their sites.

HECO's 2004 total generating capability of 1,614,600 kW-net includes 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 25% over the 2004 system net peak.[2]

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. Relevant Events Since 2004 Adequacy of Supply Report

On March 31, 2004, HECO filed its annual Adequacy of Supply report to the Commission ("2004 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 30 MW by the end of 2006 and an additional 10 MW (totaling 40 MW) by the end of 2008 subject to the timely approval of HECO's two load management DSM program applications and utility CHP program application before the Commission at the time of the 2004 AOS filing.

Since HECO filed its March 31, 2004 Adequacy of Supply report, several changes have occurred that impact the assessment of the adequacy of supply on Oahu. These changes include (1) the development of a new short-term sales & peak forecast in June of 2004, (2) the setting of a record peak load on October 12, 2004, (3) the delayed start of the load management DSM programs, (4) the development and request for approval of enhanced energy efficiency DSM programs as part of HECO's application for a general rate increase filed on November 12, 2004, (5) the continued delay in the start of HECO's proposed CHP program and the suspension of HECO's application for approval of a Rule 4 CHP agreement with Pacific Allied Products, Limited ("Pacific Allied"), (6) HECO's application for approval of two amendments to its power purchase agreement with Kalaeloa to add up to 29 MW of firm capacity from Kalaeloa's facility, and (7) a decrease in the availability of HECO generating units in 2004.

Forecast Update

In June 2004, HECO updated the 2005-2009 projections of its February 2004 long-term sales and peak forecast. Forecasted peaks are somewhat lower, due to the delays of certain construction projects, but forecasted sales and peak growth rates remain similar to the robust growth rates projected in the February 2004 forecast, reflecting the recent and continued projected strong growth of Hawaii's economy.

2 The reserve margin calculation takes into account 5,200 kW of interruptible loads served by HECO.

On October 12, 2004, HECO experienced a record system peak demand, which (after adjustment to account for cogenerators that were running at the time) was approximately 20 MW higher than the peak projected in the June 2004 forecast and 39 MW higher than the system peak experienced in 2003. It is likely that extremely warm and humid weather, combined with the growing use of air conditioning across the island, contributed to the October 2004 system peak demand.

Load Management DSM Programs

In October 2004, the Commission approved HECO's applications for its Residential Direct Load Control (RDLC) and Commercial and Industrial Direct Load Control (CIDLC) load management programs. Because of the time required to set up the necessary infrastructure and to organize the marketing and installation workforce, both load management programs have modest projected impacts for 2005. While HECO continues to estimate that both programs will be fully subscribed by December 2008, the delays have resulted in reduced estimates of annual load management program impacts forecasted from 2005 through 2009 by 6 to 12 MW.

Enhanced Energy Efficiency Demand-Side Management (DSM)

HECO is currently implementing five approved energy efficiency DSM programs. In HECO's current rate case (HECO Test Year 2005 Rate Case in Docket No. 04-0113), HECO is requesting 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 to increase the rate of acquisition of peak reduction benefits. It is assumed that the benefits from the eight programs will begin in July 2005, but this date is predicated on the assumed bifurcation of the DSM programs from the HECO rate case such that they can be reviewed and approved by the PUC on an accelerated schedule separate from the rate case.

Distributed Generation and Combined Heat and Power (CHP)

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' 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 docket 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." The proceedings for the DG Docket No. 03-0371 are currently in progress, and the matter is expected to be ready for decision by the PUC after briefing is completed at the end of March 2005.

In the meantime, HECO has been developing CHP projects to be submitted to the Commission for approval under Rule 4 of its tariff. In January 2005, the Commission suspended HECO's October 28, 2004, application requesting approval of a CHP agreement with Pacific Allied. By letter dated February 9, 2005, Pacific Allied terminated its CHP Agreement due to schedule uncertainties as a result of the suspension of HECO's Rule 4 Application for its CHP project.

Based upon these events in 2004 and early 2005 related to DG and CHP, and the assumption that HECO will be able to begin installing CHP systems in mid 2006, a revised forecast for CHP was developed that estimates CHP impacts, both utility and non-utility, for the next 20 years, based on the assumption that HECO will be allowed to begin installing CHP systems in 2006. No CHP systems were installed on Oahu in 2004, and one non utility system is expected to be installed in 2005.

3. HECO's Generating Capacity Situation

Kalaeloa Partners, Limited Partnership

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 amendments provide for a firm capacity increase of up to 29 MW from the Kalaeloa facility. Kalaeloa has at its own initiative and sole expense already completed the necessary upgrade to its generating facility resulting in the present availability of additional capacity and energy to the HECO system. However, the additional available capacity will not be counted for planning purposes as a part of HECO's total generating capability unless and until the Commission approves the amendments.

HECO Generating Unit Availabilities

In 2004, outages for planned work and maintenance outages were more numerous and longer in duration than in previous years. In addition, HECO experienced generating unit Equivalent Forced Outage Rates (EFORs) that were higher than in previous years. Much of the higher EFORs were attributable to the need to start cycling and peaking units more often and to run them for more hours than in previous years. Baseload units were 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 and lower Equivalent Availability Factors (EAFs). However, significant overhaul and refurbishment in 2004 and planned for 2005 should improve the condition of the HECO generating units, and the forward looking system average EFOR for the 2005-2009 period is expected to be better than it was in 2004 (although not as low as in earlier years when HECO's reserve margin was larger, and the units experienced less wear and tear).

4. Next Generating Unit Addition

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 DOH deemed the initial application complete in November (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, 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. In 2004, HECO continued 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. These efforts included:

- Continuing to work with the DOH and EPA to facilitate the review of the air permit application.
- Meeting with west Oahu neighborhood boards and community leaders to present HECO's plans.
- Selection of an engineering firm to begin the necessary engineering work to develop conceptual layouts of the next generating unit and to specify and select the combustion turbine package
- Completion of an Environmental Impact Statement Preparation Notice[3].

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.

5. Adequacy of Supply – 2005-2009

HECO expects to have sufficient generation capacity to meet the forecasted peak demands of electricity use. However, HECO anticipates reserve capacity shortfalls in 2005 and

[3] Since the unit addition is planned to be greater than 5 MW, an Environmental Impact Statement is required by HRS Chapter 343. The first step of the EIS process is to draft and publish an EIS Preparation Notice.

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. (The planned generating unit addition is a simple cycle combustion turbine, sized in the 100 MW range, to be located at a site in Campbell Industrial Park.)

Reserve capacity shortfall is 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.

Approximately 60 MW of additional peak load reduction measures and/or generating capacity would be needed in 2005 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, (2) approval for and successful implementation of enhanced energy efficiency DSM programs beginning in July 2005 and (3) the projected approval and availability of up to 29 MW of additional firm capacity from Kalaeloa in 2005. The reserve capacity shortfall is projected to be approximately 50 to 70 MW in the 2006 to 2009 period, assuming that HECO is able to (1) implement the aforementioned DSM programs as planned, and (2) obtain approval for and successfully implement a utility CHP program (and/or individual CHP agreements), and to begin installing CHP systems in mid 2006.

Until sufficient generating capacity can be added to the system, HECO will experience a higher risk of generation-related customer outages. 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 a number of scenarios to analyze the impact if DSM and CHP peak reductions are lower than forecast, and/or generating unit forced outage rates are higher than forecast. One scenario considered the effect of disapproval or delayed implementation of, and lower-than-expected participation in the proposed DSM programs, and disallowance of HECO's participation in the CHP market, which resulted in estimated reserve capacity shortfalls of approximately 60 to 110 MW during the 2005 to 2009 timeframe. If, in addition, forced outage rates are higher than forecast (by 20%), then it is estimated that the HECO system could experience reserve capacity shortfalls of approximately 90 to 130 MW in the 2005 to 2009 period. As these scenarios illustrate, there are scenarios under which generating system reliability would decrease and reserve capacity shortfalls would 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 imports 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.

6. HECO Actions to Mitigate Projected Reserve Capacity Shortfalls

As a result of an increase in the rate of load growth since 2003 HECO has taken a number of actions to minimize the risk of generation-related shortfalls. These include implementing the approved load management DSM programs, filing applications for approval of the enhanced energy-efficiency DSM programs, utility CHP program, and first Rule 4 CHP Agreement, improving the availability of HECO generating units, maintaining or improving the availability of Independent Power Producers generating units, negotiating the Kalaeloa amendments, and initiation of permitting and design of the next generating unit so that it can be installed by 2009.

Given the expected reserve capacity shortfalls it may experience over the next several years, HECO also is working to plan and implement a number of interim mitigation measures. (Examples of measures that are being implemented, developed, or assessed for possible implementation, include installation of portable, leased DG units at HECO-controlled substation sites and other sites, a customer demand response program, incorporation of residential air conditioning loads into HECO's RDLC program, and communications with its customers to voluntarily reduce their electricity use during peak usage times.)

The degree to which these measures can address the reserve capacity shortfall in the 2005 to 2009 period will depend on (1) the time required to obtain the permits and/or approvals that may be necessary to implement the measures, and to obtain and install the measures, (2) the cost to install, operate and maintain the measures, and (3) the extent to which customers agree to participate in the demand-side measures. Thus, HECO projects that there will continue to be some reserve capacity shortfall, even after implementation of mitigation measures, at least until 2009.

7. HECO IRP-3

The AOS Report is intended to address the near-term (i.e., the last year, and next three years) generating capacity situation for the HECO system. HECO's next integrated resource plan ("IRP-3") will address HECO's long-term resource plan (which includes both supply-side and demand-side resources). A final report, which includes the selection of a recommended preferred plan for IRP-3, will be filed with the Commission by October 31, 2005.

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 will 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.

Since the start of the IRP process, several events have occurred in 2004 (see Section 2 above) such that several of the input assumptions to the IRP have changed and have been updated for use in, among other things, HECO's rate case and this AOS filing. These changes will not affect the conclusion of the IRP analysis and further support the determination that additional firm capacity generation is needed (beyond DSM and CHP) before 2009 and that a simple-cycle combustion turbine is the only generation resource that is able to provide the required firm generation capacity within that timeframe.

II. Adequacy of Supply

1. Peak Demand and System Capability in 2004

HECO's 2004 system peak occurred on Tuesday, October 12, 2004 and was 1,327,000 kW-gross or 1,281,000 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[4] operating at the time. Had these cogenerating units not been operating, the 2004 system peak would have been 1,348,000 kW-gross or 1,302,000 kW-net.

HECO's 2004 total generating capability of 1,614,600 kW-net includes 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 25% over the 2004 system net peak.[5]

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.

---

[4] At the time of the peak, certain units at Tesoro and Pearl Harbor were generating an estimated 21,000 kW of power for use at their sites.

[5] The reserve margin calculation takes into account 5,200 kW of interruptible loads served by HECO.

2. Estimated Reserve Margins

Appendix 1 shows the expected reserve margin over the next three years, based on HECO's June 2004 Sales and Peak Forecast, HECO's latest estimate of acquired DSM impacts for 2004, its latest estimate of forecasted enhanced energy efficiency DSM impacts, its latest estimate of forecasted load management DSM impacts, and its latest estimate of forecasted non-utility and utility CHP impacts.

3. Relevant Events Since 2004 Adequacy of Supply Report:

On March 31, 2004, HECO filed its annual Adequacy of Supply report to the Commission ("2004 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 30 MW by the end of 2006 and an additional 10 MW (totaling 40 MW) by the end of 2008 subject to the timely approval of HECO's two load management DSM program applications and utility CHP program application before the Commission at the time of the 2004 AOS filing.

Since HECO filed its March 31, 2004 Adequacy of Supply report, several changes have occurred that impact the assessment of the adequacy of supply on Oahu. These changes include (1) the development of a new short-term sales & peak forecast in June of 2004, (2) the setting of a record peak load on October 12, 2004, (3) the delayed start of the load management DSM programs, (4) the development and request for approval of enhanced energy efficiency DSM programs as part of HECO's application for a general rate increase filed on November 12, 2004, (5) the continued delay in the start of HECO's proposed CHP program and the suspension of HECO's application for approval of a Rule 4 CHP agreement with Pacific Allied Products, Limited ("Pacific Allied"), (6) HECO's application for approval of two amendments to its power purchase agreement with Kalaeloa to add up to 29 MW of firm capacity from Kalaeloa's facility, and (7) a decrease in the availability of HECO generating units in 2004.

3.1. June 2004 Peak Forecast

In June 2004, HECO updated the 2005-2009 projections of its February 2004 long-term sales and peak forecast. This updated sales and peak forecast is used by this Adequacy of Supply Report and is also used as the basis for the test year estimates in the HECO rate case in Docket No. 04-0113.

Monthly peak factors and a historical hourly load profile are used to develop a base hourly peak demand forecast. Daily peaks are determined from this. This forecast is essentially a short-term update to the February 2004 long-term forecast. The February 2004 long-term forecast was utilized in the 2004 AOS report. A comparison between the February 2004 long-term forecast and the June update is included in this report. Short-term updates to the long-term February forecast result from changes in economic outlook, construction project estimates and actual variances from the forecast. As shown in Table 1 below, the forecasted peaks for the period 2005-2009 in the June 2004 forecast are lower than in the February 2004 long-term peak forecast before taking into account projected DSM and CHP system impacts.

Table 1:
Comparison of Forecasted Peak Loads
(Without Future Enhanced Energy Efficiency DSM, Load Management DSM, Utility CHP and Impacts of Non-utility CHP)

Year	February 2004 Forecast System Peak (Net MW)	June 2004 Forecast System Peak (Net MW)	Decrease in Peak Forecast (MW)
2004	1,294	1,286	-8
2005	1,340	1,329	-11
2006	1,380	1,370	-10
2007	1,411	1,399	-12
2008	1,425	1,413	-12
2009	1,453	1,442	-11

One of the primary reasons for the lower forecasted peaks was that actual year-to-date sales at the time the June 2004 forecast was being developed were lower than forecasted in the February long-term forecast. Additionally, expected delays of significant construction projects such as the UH Medical School and Sand Island Waste Water Treatment Plant Phase II resulted in lowering the sales forecast. With reductions of the sales forecast, the forecasted peaks were correspondingly reduced.

Despite the lowering of the peak forecast due to identifiable causes such as those mentioned above, the near-term outlook for the local economy continues to be upbeat. The local economy continues to show strength due to activity in sectors such as real estate and construction. The visitor industry has continued to rebound, providing the final piece to an overall healthy economy. The residential sector especially has grown in response to unprecedented low interest rates. Additionally, military projects are expected to make major contributions to the local economy.

While lowered year-to-date sales were expected to result in a lower forecasted peak for 2004, the June 2004 forecast continued to project sales and peak growth rates that are generally similar to the growth rates projected in the February 2004 forecast. Consequently, the forecasted peaks in the June 2004 forecast are consistently in the range of 10-12 MW less than those previously projected in the February 2004 forecast for the 2005 through 2009 period.

3.2. October 12, 2004 Record Peak

On October 12, 2004, HECO experienced a record system peak demand of 1,327 MW gross or 1,281 MW net. 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 1,348 MW gross or 1,302 MW net. This adjusted record peak of 1,302 MW was approximately 20 MW higher than the peak projected in the June 2004 forecast and 39 MW higher than the system peak experienced in 2003.

The October 12, 2004 record system peak of 1,302 MW was the fourth time in two months that the record peak set in 2003 was surpassed. It is likely that extremely warm and humid weather combined with the growing use of air conditioning across the island contributed to the October 2004 system peak demand and the sensitivity of the peak to weather. Please refer to HECO's response to CA-IR-5, Docket 04-0320, Kalaeloa Partners L. P. Amendment Nos. 5 & 6.

Because forecasted peaks are derived on a weather normalized basis, forecasted 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, including weather related contributions. In addition, Oahu's increasing use of residential air conditioning is increasing the impact of hot and humid weather on actual peaks.

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

The load reducing impact acquired from HECO's existing energy efficiency DSM programs in 2004 was approximately 4 MW. This recorded load reducing impact was 9 MW less than the 13 MW projected in 2004 in the 2004 AOS report for the impacts of HECO's proposed load management DSM, the continuation of existing energy efficiency DSM, and utility and non-utility CHP. With the January 2005 start for its load management DSM programs and the current estimate of a July 2005 start of the enhanced energy efficiency DSM programs and a projected mid 2006 installation of the first utility system under the proposed utility CHP program (and/or individual CHP agreements), 2005 impacts are now collectively projected to be a total of 16 MW (including impacts acquired in 2004), which is 14 MW less than projected for 2005 in the 2004 AOS (See Appendix 2 for a detailed discussion of lower than projected impacts acquired in 2004 and lowered projections of impacts for 2005 for HECO's load management DSM programs, enhanced energy efficiency

DSM programs and utility CHP program). Table 2 below summarizes the collective change in projections of load management DSM, energy efficiency DSM, and CHP (utility and non-utility) impacts assumed for HECO's 2004 AOS versus current estimates forecast in this 2005 AOS report. However, in 2007, the collective projections of load management DSM, energy efficiency DSM, and CHP (utility and non-utility) are near even in both the 2004 and 2005 AOS reports, and in the two years that follow, the 2005 AOS projections exceed those included in the 2004 AOS by as much as 18 MW in 2009. (See Appendix 2 for individual change in projections for HECO's load management DSM programs, enhanced energy efficiency DSM programs, utility CHP program and non-utility CHP annual impacts).

Table 2:
Previous and Current Projections of Load Management DSM, Energy Efficiency DSM, and CHP Combined Cumulative Impact (MW)

Year	2004 AOS Projections	2005 AOS Projections	Difference
2004	13	4 (actual)	-9
2005	30	16	-14
2006	49	40	-9
2007	63	64	1
2008	76	86	9
2009	84	102	18

3.4. Kalaeloa Partners, L. P.

On November 5, 2004, HECO filed a PUC Application for approval of Amendment Nos. 5 and 6 to the Power Purchase Agreement between HECO and Kalaeloa Partners, L. P. in Docket No. 04-0320. As indicated in the PUC Application, Amendment Nos. 5 and 6, among other things, provide for a firm capacity increase of up to 29 MW from the Kalaeloa facility. HECO is currently awaiting a Decision and Order from the Commission, which would follow the Consumer Advocate's review of the application. Kalaeloa has at its own initiative and sole expense already completed the necessary upgrade to its generating facility resulting in the present availability of additional capacity and energy to the HECO system. However, the additional available capacity from Kalaeloa that is the subject of Amendments Nos. 5 and 6 will not be counted for planning purposes as a part of HECO's total firm generating capability unless and until the Commission approves the pending application.

3.5. <u>HECO Generating Unit Availabilities</u>

In 2004, outages for planned work and maintenance outages were more numerous and longer in duration than in previous years. Additional outage time was required to perform several large scope repair and refurbishment projects required as a result of equipment and component repairs. In addition, HECO experienced generating unit Equivalent Forced Outage Rates (EFORs) that were higher than in previous years. The 2004 system average EFOR was 4.98% while the 2000-2004 5-year system average EFOR was 2.63%. Much of the higher EFORs was attributable to the need to start cycling and peaking units more often and to run them for more hours in the year than in previous years. Baseload units were run harder, often with derates due to failed or damaged components because their capacity was required to meet demand and maintain spinning reserve requirements. In combination, the longer outages and higher EFORs resulted in lower unit availabilities and lower Equivalent Availability Factors (EAFs).

For this AOS, forward looking EFORs for each HECO generating unit were developed by reviewing historical EFORs and when applicable, adjusting these EFORs to account for the expected condition of major generating unit components as a result of recently completed or soon-to-be completed overhaul and refurbishment work. Based on this process, the forward looking system average EFOR for the 2005-2009 period is 2.89% (weighted by the estimated 2005 MWh contribution for each generating unit). The forward looking EFOR for each IPP is based on a review of historical EFORs and contractual availability requirements.

3.6. <u>Next Generating Unit Addition</u>

As discussed in HECO's 2004 AOS report, 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 DOH deemed the initial application complete in November (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, or if system demand increased more than projected). The DOH deemed the revised air permit application for two simple-cycle combustion turbines complete in February 2005 and is currently in the process of reviewing the application. In 2004, HECO continued 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. These efforts included:

- Continuing to work with the DOH and EPA to facilitate the review of the air permit application.
- Meeting with west Oahu neighborhood boards and community leaders to present HECO's plans.
- Selection of an engineering firm to begin the necessary engineering work to develop conceptual layouts of the next generating unit and to specify and select the combustion turbine package through a competitive bidding process[6] without commitments to purchase.
- Completion of an Environmental Impact Statement Preparation Notice[7].

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 simple-cycle combustion turbine can be expected to be completed.

4. <u>HECO Capacity Planning</u>

4.1. <u>HECO's Capacity Planning Criteria</u>

HECO's capacity planning criteria consists of two rules.

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.*

---

6 While competitively bidding the combustion turbine package will provide necessary specific information to facilitate permitting, regulatory approvals and engineering design, it will not result in a commitment of funds to manufacture the equipment. It will lock in a price for future purchase of the equipment to allow flexibility of procurement depending upon the status of the necessary permits and approvals.

7 Since the unit addition is planned to be greater than 5 MW, an Environmental Impact Statement is required by HRS Chapter 343. The first step of the EIS process is to draft and publish an EIS Preparation Notice.

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 method used to determine the timing of an additional firm capacity generation unit accounts for interruptible loads. 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.

4.2. <u>HECO's Reliability Guideline: Loss of Load Probability (LOLP)</u>

HECO applies this guideline, in addition to HECO Rule 1 and HECO Rule 2, in determining the need date for new firm capacity.

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."

HECO has a reliability guideline threshold of 4.5 years per day. This means that HECO plans to have sufficient generating capacity to maintain generating system reliability above 4.5 years per day. This threshold means that 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. (See HECO's letter, dated May 14, 2003, to the Division of Consumer Advocacy in response to the Consumer Advocate's Information Request on HECO's Adequacy of Supply dated January 31, 2003, which is attached as Appendix 3).

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 an hour-by-hour 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, so they affect the LOLP calculation as well.

While LOLP gives us 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 unserved kilowatthours (kWh) or customers due to insufficient generation.

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, (3) the actual EFORs for such units, and (4) the addition of firm capacity (Kalaeloa). 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 4 for a detailed discussion of factors affecting 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 2009 under a base set of assumptions including: (1) HECO is able to acquire residential and commercial load management impacts beginning in January 2005; (2) implementation of its enhanced energy efficiency DSM program beginning in July, 2005, (3) approval of HECO's proposed CHP Program (and/or individual CHP agreements) with utility CHP impacts beginning in mid 2006 and an installation rate for non-utility CHP projects that corresponds with the assumption for utility CHP installations, and (4) the inclusion of the additional 29 MW of firm capacity from Kalaeloa. In addition, results in Table 8 are based upon the use of a base composite 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 beginning in 2005 and continuing through 2009. 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 29 MW provided by Kalaeloa, it is noted that Table 4 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)

Year	Generation System Reliability (years/day)
2005	1.2
2006	1.0
2007	0.9
2008	1.6
2009	1.1

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 equal to or greater than the 4.5 years per day reliability guideline. Again, like 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)
2005	-60
2006	-70
2007	-70
2008	-50
2009	-60

The projected level of generation system reliability from 2005 through 2009 is less than desirable, as shown in Tables 3 and 4.

4.3.1.2. HECO Rule 1 and HECO 2 Analysis

Table 5 shows the load service capability shortfalls relative to HECO's Rule 1 and Rule 2 criteria.

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

Year	Rule 1 Shortfall (MW)	Rule 2 Shortfall (MW)
2005	-23	-63
2006	-1	-41
2007	-7	-47
2008	4	-36
2009	-7	-47

In 2005, HECO anticipates a 23 MW 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.

The 23 MW Rule 1 reserve capacity shortfall in 2005 is due to the coincident outages currently planned for Waiau 10, H-POWER, and Kalaeloa. The combined unavailability of all three units during the late April to early May 2005 period results in insufficient reserve generation available to cover the loss of AES. The coincident outage of these three units is a result of maintenance interval and run-hour requirements from H-POWER and Kalaeloa and the need to inspect and overhaul Waiau 10 as a result of the forced outage experienced on Waiau 9 in 2004. HECO is currently examining whether or not the planned Waiau 10 outage can be deferred to later in 2005 to avoid or mitigate the Rule 1 shortfall. However, while HECO has some flexibility to revise the schedule, such flexibility is limited by operating permit restrictions, requirements for maintenance intervals, material lead times, manpower constraints and how changes to this year's outage schedule impact outage schedules in future years.

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

4.3.2. Alternate DSM and CHP Scenario and Sensitivity Analysis

Because there continues to be significant uncertainty about 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) that are part of HECO's base analysis, HECO evaluated a scenario where the impacts occur later and are lower than currently estimated.

The alternative DSM and CHP scenario uses the assumption that residential and commercial load management impacts are lower than those acquired in the base case by 25% and 20% respectively. Such a scenario could arise, for example, if (1) customer acceptance and/or awareness is less than expected in the case of the residential programs, and permitting constraints limit the use of emergency generators in the commercial 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; and (3) HECO's participation in the CHP market is not allowed. 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 Scenarios

	Cumulative Impact (MW)		
Year	Base	Alternate	Difference
2005	16	12	-4
2006	40	28	-13
2007	64	40	-24
2008	86	52	-34
2009	102	58	-44

As mentioned previously, HECO's generating system reliability guideline is affected by the EFOR assumed for each existing generating unit. As discussed in Appendix 4, Section 6, it is difficult to forecast EFOR. Because of the uncertainty of future EFORs based on aging units, longer planned maintenance schedules, and less "room" to accommodate unplanned generating unit outages, HECO evaluated a sensitivity scenario where forecasted EFORs for existing generating units (both HECO owned and IPP) are increased by 20%.

Table 7 shows the generating system reliability and reserve capacity shortfalls for the base scenario, alternate DSM and CHP scenario, and the alternate DSM and CHP scenario with high EFOR.

Table 7:
Reserve Capacity Shortfall, MW

Year	Base Scenario	Alternate DSM and CHP Scenario	Alternate DSM and CHP Scenario with high EFOR
2005	-60	-60	-90
2006	-70	-80	-110
2007	-70	-100	-120
2008	-50	-80	-110
2009	-60	-110	-130

Table 8 below shows Rule 1 planning criteria reserve capacity shortfalls in the alternate DSM and CHP scenario with and without the high EFOR sensitivity. Because HECO's Rule 1 planning criteria is a deterministic criteria that does not take into account the probability of generating unit outages, the high EFOR sensitivity does not increase the reserve capacity shortfall to meet the Rule 1 criteria.

Table 8:
Rule 1 Reserve Capacity Shortfall, MW

Year	Base Scenario	Alternate DSM and CHP Scenario	Alternate DSM and CHP Scenario with high EFOR
2005	-23	-24	-24
2006	-1	-7	-7
2007	-7	-30	-30
2008	4	-30	-30
2009	-7	-51	-51

(See Appendix 5 for a detailed discussion of alternate scenario and sensitivity analysis of system risk).

Tables 4 through 8 show that, even with the successful implementation of residential and commercial load management DSM, approval for and implementation of enhanced energy efficiency DSM beginning in July 2005, approval for and implementation of a utility CHP Program in mid 2006, and implementation of existing generating maintenance schedules and EFORs forecasted for the base scenario, these actions are not enough to eliminate the projected reserve margin shortfalls. HECO is exploring ways to shorten the CIP generating unit schedule, but it is unlikely that it could be placed into service earlier than 2009. Under certain scenarios, such as the scenario that assumes that the enhanced energy-efficiency DSM program and utility CHP Program applications are disapproved, customer participation in HECO's two load management programs is less than forecast, and unit EFORs are higher than forecast, generating system reliability could decrease and reserve capacity shortfalls could 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. <u>HECO IRP-3</u>

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 will 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, will be filed with the Commission by October, 31 2005.

The IRP process, to date, has 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 meets the six resource plan concepts developed in conjunction with the Advisory Group and Technical Committees. Each of these six proposed resource plans developed in the IPR process to date includes 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). Although the 20-year resource plan is still being developed, the utility's efforts towards DSM, CHP, and combustion turbine installation as outlined in the previous sections of this document will be consistent with the 20-year resource plan as each of the proposed resource plans in the IRP process include these resources.

Since the start of the IRP process, several events have occurred in 2004 (see Section 3.0 above) such that several of the input assumptions to the IRP have changed and have been updated for use in, among other things, HECO's rate case and this AOS filing. These changes will not affect the conclusion of the IRP analysis and further support the determination that additional firm capacity generation is needed (beyond DSM and CHP) before 2009 and that a simple-cycle combustion turbine is the only generation resource that is able to provide the required firm generation capacity within that timeframe.

4.5. <u>Reserve Capacity Shortfalls and Generation Shortfalls</u>

Quantifying the risk of generation-related customer outages is difficult. Many factors cannot be quantified. A qualitative analysis can be performed, but in the end, only assessments can be made of what can and cannot be done. (See Appendix 6 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 enhanced energy efficiency DSM program and 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 rates for existing generating resources. To counter this risk, HECO has a series of action plans, including the addition of generation, to restore HECO's system reliability above the 4.5 years per day reliability guideline.

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. It is nonetheless, a necessary alternative.

5. Action Plan and Mitigation Measures

The analysis shows there may be reserve capacity shortfalls ranging from 50 MW to 130 MW from 2005 until the next generating unit can be added.

HECO has been undertaking several actions to increase its reserve capacity and/or reduce demand to restore system reliability above the 4.5 years per day reliability guideline. This section of the report addresses specific action plans already undertaken and planned for by HECO in order to provide reliable service. These actions include:

5.1. 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 PUC on an accelerated schedule separate from the rate case).
- 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.

5.2. Implement Utility CHP Program

- 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.

5.3. Improve Availability of HECO Generating Units

- 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.
- Continue the addition of a night shift maintenance crew 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. This additional staffing, along with 24/7 operational staffing, will allow HECO additional flexibility to respond to unplanned outages and unforeseen maintenance requirements.

- Continue with capital projects to improve the reliability of generating units and to improve the flexibility in their operations. Projects include the rehabilitation of Waiau 9 compressor and exhaust structure, any rehabilitation work resulting from an upcoming inspection of Waiau 10, separation of the bus between Waiau 9 and Waiau 10, Waiau 3 main transformer replacement, upgrades to the Waiau 5 annunciator and data acquisition system, Kahe 4 voltage regulator and exciter upgrades, turbine blade replacements for Honolulu 8, Honolulu 9, Waiau 5, Waiau 8, and Kahe 4, the rotor rewind to rehabilitate the Waiau 5 generator, repair of Honolulu 8 and Honolulu 9 generator rotors, HECO's new Waiau fuel pipeline, and renovations of Waiau low sulfur fuel oil storage tank Nos. 1, 4 & 5 and diesel oil storage tanks Nos. 1 & 2. Additional capital projects completed which are projected to help improve unit availability are listed in HECO response to CA-IR-129, in HECO's rate case, Docket No. 04-0113.
- 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.

5.4. <u>Maintain or Improve Availability of Independent Power Producers</u>

- 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.
- 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.

5.5. <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.
- 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.

5.6. Additional Mitigation Measures Under Consideration

HECO is also evaluating additional mitigation measures to reduce the likelihood or impact of the reserve capacity shortfalls. 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 nor 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.

5.6.1. Installation of distributed generators (DG) at various HECO substations, and evaluation 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. Substation sites currently under consideration include transmission and distribution substation sites that have sufficient space, access, land use and zoning classifications, and compatibility with adjacent properties. HECO is examining the viability of installing DG on a temporary basis, targeting three to four substation sites beginning in 2005, and will evaluate further opportunities for installation in 2006 and beyond. At this time, the full potential for HECO-sited DG is unknown as it is highly dependent upon site specific factors.

5.6.2. A demand load response program to seek additional interruptible loads for customers unwilling or unable to participate in the CIDLC load management program. HECO believes that some commercial customers have loads or operations that make the recently approved CIDLC load management program unattractive. These customers may feel uneasy about committing a portion of their load to interruption under a long term contract with the utility. HECO is considering the addition of a demand load response program to target these customers. HECO has conceptualized a program in which HECO calls for voluntary reductions in load and program participants may elect to voluntarily participate, but once committed, are required to reduce their demand accordingly. In return, participants are compensated for reducing their load. HECO has begun a process of retaining a consultant to develop a demand load response program and expects to file a PUC application by mid 2005.

5.6.3. 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.

5.6.4. 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. The public notification program is a tiered, systematic process of notifying the PUC, 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. On October 13, 2004, HECO executed the notification program by informing the PUC and the Consumer Advocate of the possibility of not having sufficient generation to meet the day's demand. Subsequent to their notification, HECO, with consideration of the expected growth in demand that morning, began notifying major customers and later the media calling for voluntary conservation by commercial and residential customers.

HECO's action plans 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.

6. Conclusion

HECO expects to have sufficient generation capacity to meet the forecasted peak demands of electricity use. However, HECO anticipates reserve capacity shortfalls in 2005 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 60 MW of additional peak load reduction measures and/or generating capacity would be needed in 2005 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, (2) approval for and successful implementation of enhanced energy efficiency DSM programs beginning in July 2005, and (3) the projected approval and availability of up to 29 MW of additional firm capacity from Kalaeloa in 2005. The reserve capacity shortfall is projected to be approximately 50 to 70 MW in the 2006 to 2009 period, assuming that HECO is able to implement the aforementioned DSM programs as planned and obtains approval for and successfully implements a utility CHP Program (and/or individual CHP agreements), and to begin installing CHP systems beginning in mid 2006.

Until sufficient generating capacity can be added to the system, HECO will experience a higher risk of generation-related customer outages. 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 two scenarios to analyze the impact if DSM and CHP peak reductions are lower than forecast, and/or generating unit forced outage rates are higher than forecast. One scenario considered the effect of disapproval or delayed implementation of, and lower-than-expected participation in the proposed DSM programs, and disallowance of HECO's participation in the CHP market, which resulted in estimated reserve capacity shortfalls of approximately 60 to 110 MW during the 2005 to 2009 timeframe. If, in addition, forced outage rates are higher than forecast (by 20%), then it is estimated that the HECO system could experience reserve capacity shortfalls of approximately 90 to 130 MW in the 2005 to 2009 period. As these scenarios illustrate, there are scenarios under which generating system reliability would decrease and reserve capacity shortfalls would 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 result of an increase in the rate of load growth since 2003, 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 applications for approval of the enhanced energy-efficiency DSM programs, utility CHP program, and first Rule 4 CHP Agreement, improving the availability of HECO generating units, maintaining or improving the availability of Independent Power Producers generating units, negotiating the Kalaeloa amendments, and initiation of permitting and design of the next generating unit so that it can be installed by 2009.

Given the expected reserve capacity shortfalls it may experience over the next several years, HECO also is working to plan and implement a number of interim mitigation measures. (Examples of measures that are being implemented, developed, or assessed for possible implementation, include installation of portable, leased DG units at HECO-controlled substation sites and other sites, a customer demand response program, incorporation of residential air conditioning loads into HECO's RDLC program, and communications with its customers to voluntarily reduce their electricity use during peak usage times.)

The degree to which these measures can address the reserve capacity shortfall in the 2005 to 2009 period will depend on (1) the time required to obtain the permits and/or approvals that may be necessary to implement the measures, and to obtain and install the measures, (2) the cost to install, operate and maintain the measures, and (3) the extent to which customers agree to participate in the demand-side measures. Thus, HECO projects that there will continue to be some reserve capacity shortfall, even after implementation of mitigation measures, at least until 2009.

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							
2004	1,614,600	1,302,000	5,200	25%	N/A	5,200	N/A
Future							
2005	1,643,600	1,324,500	5,200	25%	1,318,700	11,300	26%
2006	1,643,600	1,361,500	5,200	21%	1,346,300	22,200	24%
2007	1,643,600	1,385,000	5,200	19%	1,360,400	31,400	24%

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 2005-2007 include the actual peak reduction benefits acquired in 1996 – 2003 and also include the peak reduction benefits acquired in 2004 of approximately 4,100 net-kW (net of free riders). Without this 2004 peak reduction benefit, the recorded system net peak of 1,302,000 kW in 2004, which includes 21,000 kW of standby load, would have been 1,306,100 kW.

II. System Capability includes:

- HECO units at a total normal capability of 1,208,600 kW-net or 1,263,000 kW-gross.
- For 2004, firm power purchase contracts have 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 November 5, 2004 HECO filed an application in Docket No. 04-0320 requesting approval of Amendment No. 5 and No. 6 to Kalaeloa's purchase power agreement, which would increase Kalaeloa's capacity to 209,000 kW. The 29,000 kW of additional capacity is expected to be available beginning in 2005. For 2005 – 2007 the firm power purchase contracts will have a combined net total of 435,000 kW

from Kalaeloa (209,000 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 2005-2007 annual forecasted system peaks are based on HECO's mid 2004 Sales and Peak Forecast.
- Forecasted system peaks include the peak reducing impacts of future utility CHP impacts[8] and future non-utility CHP impacts.
- Peaks include 21,000 kW of standby load for the following cogenerators:

Tesoro	19.0
Chevron	0.0
Pearl Harbor	2.0
	21.0 MW

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

IV. Interruptible Load[9] (Without Future Peak Reduction Benefits of DSM Programs):

- Interruptible Load include 5,200 kW of the peak reduction benefits from Rider I customer contracts.

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

- The 2005-2007 annual forecasted system peaks are based on HECO's mid 2004 Sales and Peak Update.
- The forecasted System Peaks for 2005-2007 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[10] and future non-utility CHP impacts.
- Peaks include 21,000 kW of standby load for the following cogenerators:

Tesoro	19.0

---

8 Utility CHP impacts are from a CHP forecast dated February 7, 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 outages and maintenance.

9 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.

10 Utility CHP impacts are from a CHP forecast dated February 7, 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.

Chevron	0.0
Pearl Harbor	2.0
	21.0 MW

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

VI. Interruptible Load[11] (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 estimated peak reductions for these programs begin in 2005.

[11] 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:

Relevant Events Since the March 31, 2004 Adequacy of Supply Report

1. Load Management DSM Programs

On October 14, 2004, the Commission issued Decision and Order No. 21415 and on October 19, 2004, issued Decision and Order No. 21421 approving HECO's applications for a Residential Direct Load Control (RDLC) and Commercial and Industrial Direct Load Control (CIDLC) load management program, respectively. At the time of HECO's filing of its 2004 AOS report on March 31, 2004, HECO estimated that approval of these programs would be received in the mid 2004 timeframe to allow for the implementation of these programs to start and peak reduction benefits to be realized before the end of the year. With the later than anticipated approval of these two load management programs, implementation of these two programs began in January 2005. Because of the time required to set up the necessary infrastructure and to organize the marketing and installation workforce, both load management programs have modest projected impacts for 2005. While HECO continues to estimate that both programs will be fully subscribed in December 2008, the delays have resulted in reduced estimates of annual load management program impacts forecasted from 2005 through 2009 by 6 to 12 MW. Table A2 below provides a comparison of load management program impacts assumed for HECO's 2004 AOS with current estimates for impacts for both load management programs.

Table A2:
Previous & Current Projections of Load Management Impacts

Year	RDLC			CIDLC		
	2004 Projections (MW)	2005 Projections (MW)	Difference	2004 Projections (MW)	2005 Projections (MW)	Difference
2004	3	0	-3	4	0	-4
2005	8	3	-5	10	4	-6
2006	13	8	-5	16	9	-7
2007	16	13	-3	20	13	-6
2008	17	16	-1	24	18	-6
2009	17	16	-1	24	19	-5

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

HECO is currently implementing five approved energy efficiency DSM programs. In HECO's current rate case (HECO Test Year 2005 Rate Case in Docket No. 04-0113), HECO is requesting 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. At the time of HECO's filing of its 2004 Adequacy of Supply ("AOS") report on March 31, 2004, HECO assumed that its existing DSM programs would continue until the end of 2005[12]. It was further assumed that the programs would be allowed to continue in 2006 and beyond with the same rate of acquisition of peak reduction impacts. HECO's current assumption is that the five existing energy efficiency programs will be enhanced to increase the rate of acquisition of peak reduction benefits and that the three additional programs will provide additional peak reduction benefits. It is further assumed that the increased rate of acquisition of peak reduction benefits from the eight programs combined will begin in July 2005. This date is predicated on the assumed bifurcation of the DSM programs from the HECO rate case such that they can be reviewed and approved by the PUC on an accelerated schedule separate from the rate case.

Table A3 below provides a comparison of energy efficiency DSM program impacts assumed for HECO's 2004 AOS with current estimates of impacts for an enhanced energy efficiency program starting in July, 2005 as assumed for this AOS report.

[12] In the Commission's Order No. 19019 in Docket No. 00-0169 (Commercial and Industrial DSM Program) and Order No. 19020 in Docket No. 00-0209 (Residential DSM Program), both filed on November 15, 2001, the Commission approved the agreements, terms and conditions of the Stipulation, dated October 12, 2001, between HECO and the Consumer Advocate, subject to certain conditions. In the Stipulation, HECO and the CA agreed to the temporary continuation of HECO's two existing residential DSM programs and three Commercial and Industrial DSM programs in place of implementing new consolidated programs for five years, until HECO's next rate case. On November 9, 2004, HECO filed an application with the Commission for a rate increase in Docket No. 04-0113 with a test year of 2005.

Table A3:
Prior & Current Projections of Energy Efficiency
DSM

Year	2004 Projections (MW)	2005 Projections (MW)	Difference
2004	3	4	1
2005	7	9	2
2006	11	19	8
2007	15	28	13
2008	19	37	18
2009	22	47	25

3. Distributed Generation and Combined Heat and Power (CHP)

On October 10, 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. Implementation of a CHP Program was scheduled to begin in 2004, if authorized by the Commission[13]. The utilities' 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. As indicated in the PUC Application, HECO developed a forecast of utility CHP systems for Oahu (dated August 20, 2003).

CHP systems can also be owned and operated by third parties (non-utility entities). HECO developed forecasts for non-utility CHP systems with and without the utility CHP Program (dated August 20, 2003). Both utility and non-utility CHP systems have the potential to defer the installation of traditional centralized generation. The rate of installation of CHP systems is estimated to be significantly greater with the utility CHP Program[14].

---

13 The utilities requested approval of each of their proposed CHP Program and related tariff provisions (Schedule CHP, Customer-Sited Utility-Owned Cogeneration Service). Under the CHP Program and Schedule CHP, the utilities propose to offer CHP systems to eligible utility customers on the islands of Oahu, Maui, and Hawaii as a regulated utility service. The utilities also indicated that they would request approval on a contract-by-contract basis for CHP system projects that fall outside the scope of the proposed program.

14 For purposes of this report, utility-owned CHP systems are included as reductions in the System Peak numbers (based on the net equivalent capacity of the CHP system, taking into account the electrical capacity supplied to a customer, the reduction of the customer's electrical load through waste heat application for the system, and a

On March 2, 2004, by Order No. 20831, the Commission suspended the Companies' CHP Program application, indicating that its DG docket is intended to "form the basis for rules and regulations deemed necessary to govern participation into Hawaii's electricity market through distributed generation." The proceedings for the DG Docket No. 03-0371 are currently in progress. The evidentiary hearing was completed on December 10, 2004, and the parties to the docket filed Opening Briefs with the Commission on March 7, 2005. Reply briefs are scheduled to be filed on March 28, 2005

In the meantime, HECO has been developing CHP projects to be submitted to the Commission for approval under Rule 4 of its tariff. On January 21, 2005, the Commission issued Order No. 21555 in Docket No. 04-0314 suspending HECO's application requesting approval of a CHP agreement with Pacific Allied Products, Limited (On January 21, 2005, the Commission also issued Order No. 21554 in Docket No. 04-0366 suspending HELCO's application requesting approval of a combined heat and power agreement with Koa Hotel, LLC). By letter dated February 9, 2005, Pacific Allied Products informed HECO of the termination of the CHP Agreement due to schedule uncertainties as a result of the suspension HECO's Rule 4 Application for its CHP project. With the continued suspension of HECO's CHP program application and the recent suspension of HECO's applications for individual CHP projects, there is significant uncertainty as to when the benefits of utility CHP can begin to be realized.

Table A4 below provides a comparison of utility CHP Program impacts assumed for HECO's 2004 AOS with current estimates of impacts for a utility CHP Program.

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

	2004 Projections (MW)			2005 Projections (MW)			Diff. in
Year	Utility	Non-utility	Total	Utility	Non-utility	Total	Total
2004	3	0	3	0	0	0	-3
2005	4	1	5	0	0*	0	-5
2006	7	2	9	3	1	4	-5
2007	10	3	13	9	1	10	-3
2008	13	4	17	13	2	15	-2
2009	17	4	21	18	2	20	-1

*Rounded to 0. HECO anticipates the installation of a 300 kW non utility CHP system in mid 2005

---

reduction in line losses). The load reduction impacts of CHP systems and/or DG owned by third parties are reflected in the System Peak numbers.

4. Load Management DSM, Energy Efficiency DSM, and CHP

Table A5 below summarizes the collective change in projections of load management DSM, energy efficiency DSM, and CHP (utility and non-utility) impacts assumed for HECO's 2004 AOS with current estimates.

Table A5:
Previous and Current Projections of Load Management DSM, Energy Efficiency DSM, and CHP

Year	2004 Projections (MW)	2005 Projections (MW)	Difference
2004	13	4	-9
2005	30	16	-14
2006	49	40	-9
2007	63	64	1
2008	76	86	9
2009	84	102	18

5. Kalaeloa Partners, L. P.

On November 5, 2004, HECO filed a PUC Application for approval of Amendment Nos. 5 and 6 to the Power Purchase Agreement between HECO and Kalaeloa Partners, L. P. in Docket No. 04-0320. As indicated in the PUC Application, Amendment Nos. 5 and 6, among other things, provide for a firm capacity increase of up to 29 MW from the Kalaeloa facility. HECO is currently awaiting a Decision and Order from the Commission, which would follow the Consumer Advocate's review of the application. Kalaeloa has at its own initiative and sole expense already completed the necessary upgrade to its generating facility resulting in the present availability of additional capacity and energy to the HECO system. However, the additional available capacity from Kalaeloa that is the subject of Amendments Nos. 5 and 6 will not be counted for planning purposes as a part of HECO's total firm generating capability unless and until the Commission approves the pending application.

6. Availability of HECO Generating Units in 2004

Availability of HECO generating units is impacted by unavailable times for (1) planned outages, in which relatively long multi-week outages are planned in advance to perform scheduled work, (2) unplanned outages, usually shorter maintenance outages to perform repair work, and (3) forced outages, in which a unit must be immediately brought offline, trips or shuts itself down, or when a component of the unit fails causing a "derate" of the unit's capacity output.

In 2004, outages for planned work and maintenance were more numerous and longer in duration than in previous years. Additional outage time was required to perform several large scope repair and refurbishment projects required as a result of equipment and component repairs. In addition, HECO experienced generating unit Equivalent Forced Outage Rates (EFORs) that were higher than in previous years. The 2004 system average EFOR was 4.98% while the 2000-2004 5-year system average EFOR was 2.63%. Much of the reason for the higher EFORs was attributable to the need to start cycling and peaking units more often and to run them for more hours in the year than in previous years. Baseload units were run harder, often with derates due to failed or damaged components because their capacity was required to meet demand and maintain spinning reserve requirements. In combination, the longer outages and higher EFORs resulted in lower unit availabilities and lower Equivalent Availability Factors (EAFs). (See response to Rate Case Docket 04-0113, CA-IR-28 through 31 for detailed outage statistics.)

While the number of starts and run hours for cycling and peaking units are expected to continue to be high over the next several years, at least until additional capacity is added to the system, HECO expects the numerous repair and refurbishment projects completed in 2004 and planned in 2005 to improve the overall condition of HECO's generating units and, therefore, it is expected that forward looking availabilities for HECO generation will improve relative to 2004 recorded availability.

Appendix 3:

HECO letter dated May 14, 2003, to the Division of Consumer Advocacy, in response to the Consumer Advocate's Information Request on HECO's Adequacy of Supply dated January 31, 2003

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

May 14, 2003

William A. Bonnet
Vice President
Government and Community Affairs

Department of Commerce and
Consumer Affairs
Division of Consumer Advocacy
250 S. King Street, 8th Floor
Honolulu, Hawaii 96813

Attention: Ms. Cheryl Kikuta

Subject: HECO Adequacy of Supply dated January 31, 2003

Dear Ms. Kikuta:

Attached are HECO's responses to the Consumer Advocate's information requests submitted by letter dated March 17, 2003.

CA-IR-1 Ref: Adequacy of Supply report, dated January 31, 2003.

Footnote 3, page 2 of HECO's Adequacy of Supply report, dated January 31, 2003, states that:

> Also included in HECO's capacity planning criteria is a reliability guideline. The guideline states: *"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."*

a. Please provide a discussion on the following aspects of the Company's use of "loss of load probability":

1. Please confirm that HECO's use of a 4.5 years per day factor for loss of load probability represents the threshold of an allowable instance of at least one day every 4.5 years where system peak exceeds the system generation capacity.

2. Please confirm that HECO's criteria means that, if the resulting loss of load probability is less than 4.5 years per day, the Vice President of Power Supply and President of HECO must approve the plan before it is used because that lower factor (which translates into higher reliability) would probably entail greater capital investment costs or capital investments being spent sooner than under HECO's other generation planning criteria.

3. Please provide examples using actual or hypothetical examples of HECO's loss of load probability calculations.

b. Please explain how the Company determined the threshold for the loss of load probability of 4.5 years per day. Please include the workpapers and/or documentation used to determine the threshold as well as industry standards relied upon, if any.

c. Please explain why HECO has included this reliability guideline in its capacity planning criteria.

d. In response to TGC-RIR-1001e. in Docket No. 99-0207, HELCO stated that:

> A Loss of Load Probability (LOLP) guideline would be expected to result in generating units being added sooner than with [HELCO's] current criterion. Sooner unit additions, while increasing the reliability of the generating system by reducing the probability of loss of load, would result in higher costs for customers. HELCO has not made a determination that the cost to its customers of adding generation based on an LOLP guideline is necessary at this time, or that the benefits would outweigh the cost.

1. Please confirm that HECO's Loss of Load Probability guideline is still not part of HELCO's capacity planning criteria for the reasons discussed in the response to TGC-RIR-1001e., in Docket No. 99-0207.

2. Please confirm that HECO's Loss of Load Probability guideline is not part of MECO's capacity planning criteria and, if so, please explain why HECO's Loss of Load Probability guideline is not part of MECO's capacity planning criteria.

3. HECO's 2002 Evaluation Report Regarding Integrated Resource Planning, dated December 2002 filed in Docket No. 95-0347 concluded that the next generating unit is still projected to be required in 2009.

(a) Please confirm that the Loss of Load Probability guideline was used in HECO's capacity planning criteria to determine that the next generating unit is projected to be required in 2009.

(b) Please confirm that HECO's generation planning criteria consists of the factors listed in response to TGC-RIR-1007a. If HECO's generation planning criteria have been revised, please provide the revised criteria.

(c) Please identify when the next generating unit would be required in HECO's system if the Loss of Load Probability guideline was excluded from HECO's generation planning criteria.

4. Please identify when the Company included the reliability guideline listed above in its capacity planning criteria.

Response: a. 1. HECO's use of 4.5 years per day loss of load probability represents the threshold of an allowable instance of a maximum of one day every 4.5 years where the system peak exceeds <u>available</u> generation.

2. A loss of load probability (LOLP) value lower than 4.5 years per day would mean that the system is <u>less</u> reliable than it would be if the LOLP were at 4.5 years per day. For example, if the LOLP value is 2.0 instead of 4.5 years per day, there is a probability that the system peak would exceed available generation (due to forced outages of multiple units) once every 2.0 years instead of once every 4.5 years. Therefore, the system is less reliable.

If the LOLP value is forecasted to be less than 4.5 years per day, the Vice President of Power Supply and President of HECO must approve the plan before it is used because there is a higher risk that customers may experience an interruption in service compared to when the LOLP is at 4.5 years per day.

3. Please see Attachment 1 for a numerical example.

b. In the late 1950s and early 1960s, the electric utility industry began using probability methods in generation planning, in addition to providing for the loss of largest unit and a minimum amount of margin. In 1962, HECO commissioned Commonwealth Associates, Inc., to conduct a study of the HECO system and to recommend the criteria to be used for planning generating unit additions. In its report, Commonwealth Associates recommended the Company work toward an index of reliability of seven to ten years per one day loss of load but not less than two in any year. This was considered acceptable by much of the utility industry on the mainland.

In 1965, the probability criterion for HECO generation planning was added, which specified a minimum risk of two years per day. In 1968, in an effort to move toward the recommended reliability level of seven to ten years per one day loss of load, the reliability level was increased to 4.5 years per day.

Increasing the reliability level from 4.5 years per day to seven to ten years per day would require that generation capacity be added to the system sooner such that reserve margins could be increased. Doing so would require a higher commitment of financial resources and would result in higher rates for consumers.

Since 1968, the HECO generation planning reliability threshold has remained at 4.5 years per day.

Please see attached reference materials for more detailed information:

i) Generation Planning Criteria History, Presentation to PUC Staff, May 19, 1972. (See Attachment 2.)
ii) Testimony of J. F. Richardson, Jr., Public Utilities Commission Hearing, 1975 Hawaiian Electric Company, Inc. Capital Budget, March 18, 1975. (See Attachment 3.)
iii) Commonwealth Associates, Inc., System Generation Reserve Study, Hawaiian Electric Company, Limited, Engineering Report R-920, July 1962. (See Attachment 4.)

c. HECO included a reliability guideline in its capacity planning criteria because (1) probabilistic analyses provided a more comprehensive means of assessing generation system reliability and (2) probabilistic planning methodologies for capacity planning were commonly being used in the electric utility industry on the mainland.

d. 1. Yes, HECO's Loss of Load Probability guideline is still not part of HELCO's capacity planning criteria for the reasons discussed in the response to TGC-RIR-1001, subpart e, in Docket No. 99-0207.

2. Yes, HECO's Loss of Load Probability guideline is not part of MECO's capacity planning criteria for the reasons discussed in the response to TGC-RIR-1001, subpart e, in Docket No. 99-0207.

3. (a) Yes, the Loss of Load Probability guideline of 4.5 years per day in HECO's capacity planning criteria was used to determine that the next generating unit is projected to be required in 2009.

   (b) HELCO's response to TGC-RIR-1007, subpart a, indicated that HECO's capacity planning criteria included a Load Service Capability Criterion, a Quick Load Pickup Criterion and a Reliability Guideline. These components are still included in HECO's capacity planning criteria.

   (c) If the Loss of Load Probability guideline were excluded from HECO's generation planning criteria, it is estimated that the next generating unit would be needed in 2012.

4. Please refer to the response to subpart b above.

Sincerely,

Attachments

cc: Public Utilities Commission

HECO Response to CA-IR-1, subpart a.3.
HECO Adequacy of Supply, Dated January 31, 2003

Sample Calculation of Loss of Load Probability for HECO

The Loss of Load Probability (LOLP) calculation quantifies the probability that a particular generating system will be unable to serve a given demand. The calculation uses the following inputs:

- normal capability rating of each generating unit;
- equivalent force outage rate (EFOR) for each generating unit;
- maintenance schedule for each generating unit and
- peak demand in each day.

The calculation treats the forced outages of generating units as random and independent events.

To illustrate the calculation, consider a system consisting of three generating units (for simplicity, maintenance schedules are not considered):

Table 1
Characteristics of Generating Units in a Hypothetical System

	Capacity, MW	Equivalent Forced Outage Rate (EFOR)	In-Service Rate (1 – EFOR)
Unit A	50	0.05	0.95
Unit B	100	0.07	0.93
Unit C	200	0.10	0.90
Total	350		

Table 2
All Possible Forced Outage States on the System

Units on Forced Outage			MW on Forced Outage	Units in Service			Probability of Particular State	
A	B	C		A	B	C		
None			0	X	X	X	0.95 x 0.93 x 0.90 =	0.7952
X			50		X	X	0.05 x 0.93 x 0.90 =	0.0419
	X		100	X		X	0.95 x 0.07 x 0.90 =	0.0599
		X	200	X	X		0.95 x 0.93 x 0.10 =	0.0884
X	X		150			X	0.05 x 0.07 x 0.90 =	0.0032
X		X	250		X		0.05 x 0.93 x 0.10 =	0.0047
	X	X	300	X			0.95 x 0.07 x 0.10 =	0.0067
X	X	X	350	None			0.05 x 0.07 x 0.10 =	0.0004
							Sum =	1.0000

Suppose a determination must be made of the probability that a 220 MW peak demand could not be served with the given system on a particular day. First, all states in which there are less than 220 MW in service must be identified. Then the probabilities of those states must be summed.

Table 3
Probability that a 220 MW Peak Demand Could Not Be Served

MW on Forced Outage	MW in Service	Probability of State	220 MW in Service?	Probability
0	350	0.7952	Yes	
50	300	0.0419	Yes	
100	250	0.0599	Yes	
200	150	0.0884	No	0.0884
150	200	0.0032	No	0.0032
250	100	0.0047	No	0.0047
300	50	0.0067	No	0.0067
350	0	0.0004	No	0.0004
		1.0000	Total =	0.1032

Therefore, there is a probability of 0.1032, or about a 10% chance, that a 220 MW peak demand on a particular day could not be served.

The above example illustrates the calculation for a particular day. The resulting probability value can be interpreted to mean 0.1032 days per day that a 220 MW demand could not be served. The concept can be expanded to cover a series of days.

Suppose a series of days, each with a particular peak demand is considered, as shown in Table 4. The calculation would be as follows:

Table 4
Probability that Peak Demand Could Not Be Served

Day	Peak Demand, MW	Probability of State												
Sunday	140							0.0047	+	0.0067	+	0.0004	=	0.0117
Monday	280	0.0599	+	0.0884	+	0.0032	+	0.0047	+	0.0067	+	0.0004	=	0.1630
Tuesday	240			0.0884	+	0.0032	+	0.0047	+	0.0067	+	0.0004	=	0.1032
Wednesday	220			0.0884	+	0.0032	+	0.0047	+	0.0067	+	0.0004	=	0.1032
Thursday	260	0.0599	+	0.0884	+	0.0032	+	0.0047	+	0.0067	+	0.0004	=	0.1630
Friday	290	0.0599	+	0.0884	+	0.0032	+	0.0047	+	0.0067	+	0.0004	=	0.1630
Saturday	130							0.0047	+	0.0067	+	0.0004	=	0.0117
	Total =													0.7186

The calculation indicates there is probability of about 0.72 days over a period of seven days (or 0.72 days per week) that the demand will not be served. This is about equal to 0.72 / 7 = 0.103 or about a 10% chance over the seven-day period.

If the peak demand for every day of an entire year is known, then the calculation can be performed for the entire year. The result would be expressed in terms of days per year.

HECO uses a program, called PREL, to perform this type of LOLP calculations for its system. PREL is a module of PMONTH, which is a production simulation computer model used by HECO, HELCO and MECO, and which was developed by PPlus Corporation.

Typical values resulting from the LOLP calculations are fractions of a day per year. HECO long ago adopted a convention of taking the inverse of the result such that the units would be in years per day. This is primarily because greater reliability values resulted in higher values so that people could more easily understand the reliability numbers in terms of "bigger is better." For example, a system may have an LOLP of 10.0 years per day under a given set of conditions and an LOLP of 5.0 years per day under another set of conditions. The system with an LOLP of 10.0 years per day is more reliable than the system with an LOLP of 5.0 years per day.

System Planning Department

Generation Planning Criteria History
Presentation to PUC Staff May 19, 1972

The criteria used for planning the generating capability to serve the predicted load has varied considerably over the years. With each change the system was planned to have greater reliability. Each of these changes instituted additional capital cost to the company.

During World War II some of the company's load was served by Pearl Harbor Naval Shipyard and by a power barge, the Jacona. From 1947 until about 1955, generation capability of the system was adequate only to serve the peak load and provide for maintenance or overhaul of each generating unit two to six weeks each year. This does not provided for a very reliable system because at any time one of the generating units may have a forced outage.

Beginning in 1956 we began to add capability to the system such that with the forced outage of a unit in service at the time of the evening peak we would still be able to carry system load. At the beginning of this period we provided for the loss of about 25 mw, or the capability of our smallest unit, and gradually increased this so that by 1964 we were providing for the loss of 83 mw, the maximum capability of any unit at that time. During this period the system load grew from 204 mw to 426 mw.

The criterion of providing for the loss of the largest unit was used by mainland utilities of comparable size (1957 EEI publication on system planning practices). Small utilities tended to use a loss of largest unit while large companies tended to use a percentage margin.

In the late 1950's and early '60's the industry began using probability methods in generation planning, in addition to providing for the loss of the largest unit and a minimum amount of margin. Utilizing probability mathematics, the probability of simultaneous combinations of units being out of service due to forced outage such that insufficient generating capability will be available to meet the system peak load is computed to give the Reliability Index. The Index is stated in years per day.

In 1962 we requested the consulting firm, Commonwealth Associates, Inc., of Jackson, Michigan, to make a study of the Hawaiian Electric system and recommend the criteria to be used for planning generating unit additions. In their report, Commonwealth Associates recommended the company work toward an index of reliability of seven to ten years per one day loss of load but not less than two in any year.

In 1965 the probability criterion for generation planning was added, which specified a minimum risk of two years per day. This meant that multiple outages of generating units might necessitate interruption of load one day every two years. Or, the chances of having to drop load were one in 520 on any week day.

Since 1968, generation planning has been at a level of reliability of 4.5 years per day. We planned (in 1972) to increase the level of reliability to between 7.0 and 10.0, as recommended by Commonwealth Associates, and as considered acceptable by much of the utility industry on the mainland, as our company financing and earnings will permit us to do so.

TESTIMONY OF J. F. RICHARDSON, Jr.
PUBLIC UTILITIES COMMISSION HEARING
1975 HAWAIIAN ELECTRIC COMPANY, INC. CAPITAL BUDGET
MARCH 18, 1975

At the end of 1974, the total generating capacity on the Hawaiian Electric Company system was 1,209,400 kw. Approximately 15% of this capacity is installed at the Honolulu plant, 41% at the Kahe plant, and 44% at the Waiau plant. With the present predicted system peaks through 1979, as discussed by Ken Stretch, we will not require additional generating capacity until 1979.

Over the years, Hawaiian Electric has developed criteria for determining when new generation should be added to the system. These criteria have been changed periodically as the total system load has grown and as it has become more critical that a higher degree of reliability of service should be maintained. Because of the isolation of our system from neighboring utilities for interconnection purposes, it has been necessary to maintain considerably more generation margin than mainland utilities.

The two basic criteria now being used for planning the installation of additional generating capacity on the Hawaiian Electric system are as follows:

1. Total system capacity must be equal to or greater than the sum of the peak load, the capacity of units scheduled for maintenance, and the capacity lost by the forced outage of the largest operating unit.

2. Total system capacity must be sufficient to provide an Index of Reliability of at least 4.5 years per day.

The Index of Reliability is derived from probability mathematics and gives an indication of the relative probability that there will be insufficient generating capability to meet the system peak load due to the simultaneous combination of units being out of service due to forced outage. The Index is stated in years per day. An Index of Reliability of 4.5 years per day means that there is a probability that there will be insufficient generation to meet system peak load once in 4.5 years.

F

In 1962 we requested the consulting firm of Commonwealth Associates, Inc., of Jackson, Michigan, to make a study of the Hawaiian Electric system and recommend the criteria to be used for planning generating unit additions. In their report, a copy of which was made available to the Commission, Commonwealth Associates recommended the company work toward an Index of Reliability of seven to ten years per one day loss of load but not less than two in any year.

Generation planning has two basic objectives. The first is to determine how much generation will be needed in future years, and this is where the generation criteria come into play. This objective is largely a matter of establishing sufficient future generation reserve capacity to give adequate system reliability.

The second objective is to establish what kinds of generation should be added, the mix of different kinds, and the sizes of individual units. The choice is a matter of economics, the combination resulting in the lowest cost of electricity to the customer being the plan followed.

Generation planning methods revolve around three basic processes: first, capacity and probability calculations by which the reliability of a system can be measured and planned; second, production costing simulation techniques which allow an estimate to be made of future fuel, operation, and maintenance costs; and third, a calculation of the fixed carrying charges on investment in new generation. These methods have been developed to a high degree of sophistication within the industry, and Hawaiian Electric has developed its own computer program models to take into account the uniqueness of an isolated system.

During the next five years the generation margin will decrease from 34% in 1975 to 15% in 1978, and increase to 22% in 1979 when Kahe 6 is included. During this period it is anticipated that our index of reliability will stay above the 4.5 years per day we have been able to maintain beginning in 1970.

SYSTEM GENERATION RESERVE STUDY

HAWAIIAN ELECTRIC COMPANY, LIMITED

Engineering Report R-920

COMMONWEALTH
ASSOCIATES · INC

209 E. WASHINGTON AVE.
JACKSON, MICHIGAN
STATE 4-6111

July 20, 1962

Mr. Ralph B. Johnson, President
The Hawaiian Electric Company
Box 2750
Honolulu 3, Hawaii, USA

Dear Mr. Johnson:

In response to your letter of April 24, 1962, to Mr. W. B. Tippy, we have made a study of your generating reserves in accordance with the scope which was discussed with Mr. C. H. Williams and confirmed in my letter to him on May 1, 1962. It was also agreed that we should use the computer programs and services of the Westinghouse Manufacturing Company. Attached are five copies of Report R-920 covering the results of this study.

The use of probability methods for studying plans of generation additions results in an index of reliability which must be compared with costs to evaluate the various plans. While this is the most comprehensive approach to the problem and the method which is gaining greater acceptance, there is still a great deal of judgment left to determine the critical value of a satisfactory reliability index. A review of experience and practice indicates a rather wide range of index values from 2 to 30 (years for one-day loss of load) being used by various utilities. A range of 7 to 10 appears to be the mode and this has been used as a reference in the report.

The conclusions given in the report are as follows:

1. The Hawaiian Electric Company has experienced forced outage rates which are much lower than the national average.

2. Forced outage rates over the long term for The Hawaiian Electric Company are not expected to be significantly different from the national averages on the United States mainland for oil-fired units of similar design. Therefore, higher forced outage rates should be anticipated and generation planning should be based on these rates.

3. The Hawaiian Electric Company index of reliability for the 1956-1961 period based on the expected forced outage rates as derived in this report was lower than that normally considered adequate. Likewise, the reliability based on the lower experienced forced outage rates was also inadequate.

4. Based on the expected outage rates, Budget Plans 1 and 2 for the 1962-1970 period yield a higher index of reliability than has been experienced in the past; however, the system reliability provided by all plans is below the index generally considered acceptable.

5. If generating units that are large with respect to system load are installed as proposed in the four budget plans, a low index of reliability must be anticipated unless additional reserve capacity is installed.

It is our understanding that this report may be considered preliminary or Phase 1 to be followed by studies of alternate plans, depending on your decision as to whether the reserves provided by any of the plans are considered as satisfactory. As a result of this study it appears that the system reliability may be improved by the installation of peaking capacity. It may even be possible to reduce the capital expenditures during this period while increasing the system reliability. This would involve a study comparing the economics and index of reliability of alternate plans of generation expansion.

We should be glad to discuss this with you further at your convenience.

Yours very truly,

M. C. Westrate

M. C. Westrate

MCW/mhn

SYSTEM GENERATION RESERVE STUDY

THE HAWAIIAN ELECTRIC COMPANY, LIMITED

Prepared by
Commonwealth Associates Inc.
Jackson, Michigan
July 1962
mhn

Engineering Report R-920

TABLE OF CONTENTS

APPENDIX

SYSTEM GENERATION RESERVE STUDY

A study has been made comparing The Hawaiian Electric Company generating reserves and system characteristics with mainland utility reserve criteria. Generation reserves for a 15-year period from 1956 through 1970 were analyzed utilizing the four proposed budget plans of generator additions in the future years.

SCOPE

The Scope of this study includes the following:

1. Discussion of current system planning practices used on the United States mainland for determining required generation reserves.

2. Determination of expected forced outage rates for The Hawaiian Electric Company's present and future generators.

3. Determination of loss of load probabilities for a 15-year period from 1956 through 1970, using the Westinghouse Powercasting Program, for each of the four budget plans of future generator additions.

4. Preparation of a report analyzing the results of the study and including conclusions.

SITUATION

The Hawaiian Electric Company supplies power to the Island of Oahu. In 1961, the system peak load was 341 megawatts. The system generation is located at the Honolulu and Waiau Stations. Following the 1961 installation of Waiau Unit 6, a 50 megawatt unit, the system net generating capability was 457 megawatts, as shown on Exhibit 1. With the exception of ties to several plantations which have small turbine-generators and to the generating station which supplies a portion of the Pearl Harbor load (the remaining requirements are purchased from The Hawaiian Electric Company), there are no interconnections with outside sources of power.

The annual peak loads that occurred during the 1956-1961 portion of the study period are shown on Exhibit 2. During this period, 50 megawatt units were installed in 1957, 1959 and 1961, and the generation reserves at the time of system peak varied from 28 percent to 50 percent as shown on Exhibit 2.

BASIS OF STUDY

The predicted peak loads, four budget plans of generator additions, and maintenance schedule for this study were supplied by The Hawaiian Electric Company.

PREDICTED PEAK LOADS

The predicted peak loads for the years 1962 through 1970 are as follows:

Year	Predicted Peak Load - Mw
1962	369
1963	399
1964	430
1965	465
1966	502
1967	542
1968	585
1969	632
1970	683

BUDGET PLANS OF GENERATOR ADDITIONS

All of the budget plans schedule commercial operation of Kahe Unit 1, a 75 megawatt unit, March 1, 1963. Following the installation of this unit, the various plans install three additional 75 megawatt units or a second 75 megawatt unit and two 100 megawatt units. The 75 megawatt and 100 megawatt units are expected to have a maximum net capability of 82.5 megawatts and 110 megawatts, respectively.

Budget Plan 1, as shown on Exhibit 3, places a second 75 megawatt unit, Kahe 2, in commercial operation November 1, 1964. Kahe Units 3 and 4 are rated 100 megawatts each and are scheduled for commercial operation November 1, 1966, and November 1, 1968, respectively. Exhibit 3 indicates that generation reserves increase from about 24 percent in 1962 to 46 percent following the installation of Kahe 3 in 1966 and subsequently decrease to about 23 percent in 1970.

Budget Plan 2, shown on Exhibit 4, is based on Kahe Units 2, 3 and 4 being 75 megawatt units placed in commercial operation November 1, 1964, 1966 and 1968, respectively. During the period 1962-1970, see

Exhibit 4, generation reserves increase to a maximum of about 45 percent, following the installation of Kahe Unit 2 in 1964. In succeeding years, this plan's generation reserves decrease to about 15 percent in 1970 if no generation is installed in that year.

Budget Plan 3, as shown on Exhibit 5, places a second 75 megawatt Kahe Unit 2 in commercial operation March 1, 1965. Kahe Units 3 and 4 are scheduled for commercial operation March 1, 1967, and March 1, 1969, respectively, and are 100 megawatt units. In this plan, generation reserves for the 1962-1970 period vary from a maximum of about 35 percent, following the installation of Kahe Unit 1, to a minimum of 23 percent in 1970.

Budget Plan 4 is based on the installation of 75 megawatt generators for Kahe Units 2, 3 and 4. These units are to be placed in commercial operation March 1, 1965, 1967 and 1969. As shown on Exhibit 6, the maximum reserve at the time of system peak is 35 percent, following the installation of Kahe Unit 1 in 1963, and subsequently decreases to a minimum reserve of about 15 percent if no generation is installed in 1970.

MAINTENANCE SCHEDULE

In the determination of the loss of load probabilities for the four budget plans of generator additions, using the Westinghouse Powercasting Program, maintenance can be based on a fixed schedule, or the computer program can develop a maintenance schedule on a constant or minimum risk basis. After considering these methods of handling maintenance, it was decided to use a fixed maintenance schedule because it eliminated any variation in the comparison and would not penalize any of the plans. Therefore the fixed maintenance schedule shown on Exhibit 7 was used in this study.

GENERATION RESERVE PLANNING PRACTICES

On electric utility systems, it is generally the practice to provide sufficient generation to supply the system load with an adequate margin to allow for scheduled and reasonable unscheduled generator outages. In system planning, one of the fundamental problems is the determination of the amount of reserve capacity that is required to yield an acceptable index of reliability. On the U. S. mainland, several criteria are used by the major utilities to determine the required system generation reserves. The three basic methods used for this purpose are (1) largest unit, (2) percentage reserve and (3) probability.

LARGEST UNIT METHOD

One criterion for determining the proper generation reserve is based on maintaining sufficient generating capacity to provide for the loss of some multiple of the largest unit at any time. Historically, this is perhaps the oldest criterion used for generation planning purposes. At first, all companies were isolated or loosely interconnected and had to supply their own generation reserves to provide backup for forced and scheduled maintenance outages. At that time, it was not economically feasible for an individual company to supply backup for units that were large in relation to the total installed capacity. Therefore, small units were installed to hold reserves to a minimum while providing for the loss of some multiple of the largest unit. Also, as long as the largest units available were moderately sized and the dollars per kilowatt savings were not appreciable, it was economical for many companies to utilize smaller units. However, with the dollar per kilowatt savings now available, there appears to be a trend toward installing larger units and reducing the multiple of the largest unit planned for as reserve capacity. This has been made possible by many of the companies becoming interconnected or by strengthening existing interconnections to permit sharing installed reserves.

A survey of a number of the major utilities indicated that about 15 percent still use some multiple of the largest unit for determining reserve requirements. In some cases, planning is based on a multiple of the largest unit plus a fixed percentage (2 to 3 percent) of the estimated peak load. Approximately 9 percent consider the largest unit out of service, and about 4 percent utilize 1-1/2 times the largest unit. Most of these companies are well interconnected with neighboring utilities. Only 2 percent plan system generation on the basis of the two largest units out of service, and in these cases they are not as well interconnected.

PERCENTAGE RESERVE METHOD

In the percentage reserve method the determination of the proper generation reserve is based on maintaining a certain minimum percentage of the estimated peak load as reserve capacity. As companies became more closely interconnected to permit sharing of reserve capacity, it became feasible to utilize the percentage method. This sharing allowed companies to install larger units without the inherent disadvantage of increasing their installed reserves.

The percentage reserve method provides a means for determining the relative reserves for all companies in an interconnected group or pool where the size of new units will greatly exceed the reserve of the individual companies. The actual percentage selected is based on the number and size of units, load diversity and experience of the interconnected companies. The percentage is generally between 10 and 15 percent for well interconnected systems. The survey shows that approximately 55 percent of the utilities on the U. S. mainland use the percentage reserve method for capacity planning purposes.

PROBABILITY METHOD

The complexity of the generation reserve problem has resulted in the development of methods of analysis which permit a systematic evaluation of all important factors. Probability mathematics allow the system planner to acknowledge forced outages of generation to evaluate the relationship between system reliability and such factors as the size and timing of generation additions, the accuracy of load forecasts, load duration characteristics and maintenance schedules.

The survey indicated that about 30 percent of the utilities use probability methods to determine system capacity requirements. Some of these use probability in combination with some type of percentage reserve method as the basis of capacity planning. It appears that probability methods have obtained wide acceptance in the industry, and that the trend is toward the application of this method to system planning problems.

In the survey, the standard of service reliability used to determine the required reserves varies from 2 years to 30 years for one-day loss of load. At the present time the most generally accepted range appears to be from 7 to 10 years for one-day loss of load. However, on utility systems that have a relatively small number of generating units, with the largest unit being about 20 to 30 percent of the annual peak load, the index of reliability can be expected to vary considerably from year to year. In this case, an average reliability of 7 to 10 years per one-day loss of load is considered adequate, provided that the minimum index in any one year is no lower than 2 years per day.

COMPARISON OF METHODS

Of the three criteria described, the largest unit and percentage reserve methods of generation planning are based on rules of thumb and experience, which have been found to yield an acceptable level of service reliability. While these methods provide a straightforward approach, they do not permit evaluation of the important factors in the complex generation reserve problem.

Probability methods allow the system planner to systematically analyze various plans of generator additions to determine which plan will yield an acceptable standard of service most economically. The application of this relatively new technique should lead to generation planning that is better than can be expected by the application of rule of thumb methods.

APPLICATION TO THE HAWAIIAN ELECTRIC COMPANY

In the past, The Hawaiian Electric Company generation planning has been based on the largest unit method. Generation additions were installed to maintain sufficient generating capacity to supply the system load with an adequate margin of reserve to allow for one unit on scheduled maintenance and the loss of the largest remaining unit. This method does not permit analysis of the relationship between system reliability and such factors as the size and timing of generator additions.

The use of probability methods will allow The Hawaiian Electric Company to evaluate the effect of system variables on the required reserves. Probability analysis will also facilitate investigation of the economic balance between installed reserves and system reliability.

FORCED OUTAGE RATES

The value of probability calculations depends materially on the reliability of the forced outage rates used. The forced outage rate is the fundamental quantity on which predictions of the future performance of the equipment are based and must necessarily be obtained from previous experience with similar equipment. Therefore, it is important that sufficient data is available to obtain stable forced outage values so that the inclusion of additional unit data would not result in a significant change in the forced outage rate.

PAST EXPERIENCE

The average forced outage experience for The Hawaiian Electric Company units is shown on Exhibit 8. This data has been accumulated for a seven-year period from 1955 through 1961, for all units installed prior to 1954, and for shorter periods for all subsequent units. As indicated on Exhibit 8, The Hawaiian Electric Company has experienced very low forced outage rates.

Several of the present units have experienced forced outages due to stator coil failures and the manufacturer indicates that these failures can be expected to continue. Thus far, the failures have occurred in the top coils which are relatively easily repaired. However, failure of a bottom coil would result in a forced outage of considerable duration. Also, all units have integral steam chests and nozzle chambers. The manufacturer has indicated that units of this design and operating at steam temperatures of 850 F and higher are subject to cylinder cracking. Mainland experience indicates that cylinder cracking can be expected to occur regardless of whether the unit is operated as a base load unit or is cycled frequently. While no forced outages have been experienced due to cylinder cracking, approximately 80 percent of the total system generating capability is susceptible to this type of outage.

In view of the relatively short historical record and the above possible causes of forced outages, the forced outage record in the future will undoubtedly be higher than past experience. In fact, over the life of the units, the forced outage rates for The Hawaiian Electric Company units should not be expected to be significantly different from the industry experience on the U. S. mainland for oil-fired units of similar design.

EXPECTED FORCED OUTAGE RATES

The expected forced outage rates for the turbine-generator-condenser portion of The Hawaiian Electric Company units were derived from outage data compiled by EEI for the period 1956 through 1960.

The boiler outage data that is readily available does not distinguish between the various methods of firing. Therefore, data from a recent EEI survey of oil-fired units was obtained and used to determine the expected forced outage rates. Also utilities in New England, Florida and Southern California were contacted to obtain additional outage data for oil-fired boilers.

The expected outage rates for the present and future generating units shown on Exhibit 9 were developed from the data for turbine-generator-condenser group and oil-fired boilers. Exhibit 10 graphically compares the expected outage rates with the 1955-1961 Hawaiian Electric Company experience and the experience of the industry regardless of the type of fuel.

It is understood that Honolulu 1 and 5 are multiple turbine and boiler installations, but were considered to be unit type installations when the probability portion of the Powercasting Program for The Hawaiian Electric Company was developed. Correspondingly, the forced

CORRECTION

THE PRECEDING DOCUMENT(S) HAS BEEN REPHOTOGRAPHED TO ASSURE LEGIBILITY
SEE FRAME(S)
IMMEDIATELY FOLLOWING

Several of the present units have experienced forced outages due to stator coil failures and the manufacturer indicates that these failures can be expected to continue. Thus far, the failures have occurred in the top coils which are relatively easily repaired. However, failure of a bottom coil would result in a forced outage of considerable duration. Also, all units have integral steam chests and nozzle chambers. The manufacturer has indicated that units of this design and operating at steam temperatures of 850 F and higher are subject to cylinder cracking. Mainland experience indicates that cylinder cracking can be expected to occur regardless of whether the unit is operated as a base load unit or is cycled frequently. While no forced outages have been experienced due to cylinder cracking, approximately 80 percent of the total system generating capability is susceptible to this type of outage.

In view of the relatively short historical record and the above possible causes of forced outages, the forced outage record in the future will undoubtedly be higher than past experience. In fact, over the life of the units, the forced outage rates for The Hawaiian Electric Company units should not be expected to be significantly different from the industry experience on the U. S. mainland for oil-fired units of similar design.

EXPECTED FORCED OUTAGE RATES

The expected forced outage rates for the turbine-generator-condenser portion of The Hawaiian Electric Company units were derived from outage data compiled by EEI for the period 1956 through 1960.

The boiler outage data that is readily available does not distinguish between the various methods of firing. Therefore, data from a recent EEI survey of oil-fired units was obtained and used to determine the expected forced outage rates. Also utilities in New England, Florida and Southern California were contacted to obtain additional outage data for oil-fired boilers.

The expected outage rates for the present and future generating units shown on Exhibit 9 were developed from the data for turbine-generator-condenser group and oil-fired boilers. Exhibit 10 graphically compares the expected outage rates with the 1955-1961 Hawaiian Electric Company experience and the experience of the industry regardless of the type of fuel.

It is understood that Honolulu 1 and 5 are multiple turbine and boiler installations, but were considered to be unit type installations when the probability portion of the Powercasting Program for The Hawaiian Electric Company was developed. Correspondingly, the forced outage rates shown on Exhibit 9 for Honolulu 1 and 5 were derived by considering the various capacity outage factors for each plant. While the unit approach for these plants is not correct, it does not appear that this will materially affect the results of the study since this capacity represents a small and ever-decreasing percentage of the total installed capacity and is presumably operated as peaking capacity.

IMMATURE OUTAGE RATES

The application of probability methods to power system problems is an analytical approach based on best available statistical data. It must be realized that forced outages of system components are assumed to be random events independent from one another and governed by the laws of chance. Also, probability theory only predicts the average performance of system components over a long period of time. It cannot predict the performance of a given unit in a specific year.

Previous studies that have been made for The Hawaiian Electric Company by Westinghouse, using the Powercasting Program, considered that new units were immature for one year after installation. During this period the outage rates were considered to be twice the mature outage rate.

In this study only average outage rates were used. This was done since the period of the study is short compared to the life of the units, and the expected forced outage rates were derived based on the average experience during their life. Therefore, the reduced reliability of the units during their early life is reflected in the average outage rate selected.

SYSTEM RELIABILITY

In this study, the system reliability was calculated using the probability portion of the Westinghouse Powercasting Program. In this program, the determination of the system reliability is based on the probability of the available installed capacity being adequate to meet the system load requirements. The measure of reliability is expressed in years per day or the average interval in years per one-day loss of load.

1956-1961 RELIABILITY

The system reliability for the historical period was calculated using the actual forced outage rates that were experienced during the period (see Exhibit 8) and the expected forced outage rates derived in this report and shown on Exhibit 9. The results of these probability calculations are tabulated on Exhibit 11 and shown graphically on Exhibit 13. The system reliability during these years can be summarized as follows:

	Reliability - Years Per One-Day Loss of Load	
	Using Experienced Forced Outage Rates	Using Expected Forced Outage Rates
Minimum	0.51	0.23
Maximum	7.65	2.88
Average	2.87	1.01

Based on the expected forced outage rates derived in this report, the probability study indicated that the system reliability would have been very low and a loss of load would have been expected to occur on the average of once each year. The experienced forced outage rates during this relatively short period were lower than the national average and correspondingly the index of reliability was higher. However, the index was still lower than normally considered adequate.

1962-1970 RELIABILITY

The system reliability provided by the four budget plans of generator additions during this period is tabulated on Exhibit 12 and shown graphically on Exhibit 13. The following is a summary of the data shown on these exhibits:

	Reliability - Years Per One-Day Loss of Load			
	Plan 1	Plan 2	Plan 3	Plan 4
Minimum	2.12	1.88	0.96	0.75
Maximum	8.02	5.90	4.22	3.55
Average	4.13	3.43	2.45	2.11

The system reliability in 1970 is not included in the above summary, since it appears that additional generating capacity may be required in that year.

Based on the outage rates derived in this report, the results of the probability study indicate that none of the four plans yields an index of reliability that would normally be considered adequate. Only Plans 1 and 2 yield a higher average index of reliability than has been actually experienced in the past. However, each of the four budget plans yields a higher index of reliability based on national averages than would have been expected during the 1956-1961 period.

DISCUSSION

The primary factors which influence system reliability in addition to the forced outage rates are (1) number and size of generating units, (2) amount of reserve generating capacity, and (3) scheduled maintenance time. On The Hawaiian Electric Company system a large portion of the generating capacity is concentrated in a few large units which tends to decrease the system reliability. At the present time, 65 percent of the generation consists of units that range in size from 15 to 18 percent of the system peak. This can be compared to the practices of isolated mainland systems where the largest unit is only about 10 percent of the peak load and only a few units this large are installed.

The Hawaiian Electric Company generation planning has been based on maintaining reserves equal to a maintenance outage of 25 megawatts plus the largest unit at the time of system peak. Isolated mainland systems generally plan reserves equal to twice the largest unit at the time of system peak which will increase the relative reliability of these systems. Also, The Hawaiian Electric Company's peak load variation curve is relatively flat compared to similar winter or summer peaking systems on the mainland. If the annual valley were more pronounced the reliability would be improved because of higher reserves during the maintenance period.

In view of the relatively low reliability provided by each of the budget plans, an additional case was run for comparison purposes and to demonstrate the effect of increasing generation reserves. Plan 4 was rerun and increased reserves were simulated by reducing the annual peak loads by 10 percent. In this case designated Plan 5, the reliability during the 1962-1970 period as shown on Exhibit 12 varied from a minimum of 8.25 to a maximum of 64.81 years per one-day loss of load. The average reliability during the period was about 24 years per day which indicates that the additional reserves were greater than required to provide an average reliability of 7 to 10 years per one-day loss of load.

CONCLUSIONS

As a result of this study, it is concluded that:

1. The Hawaiian Electric Company has experienced forced outage rates which are much lower than the national average.

2. Forced outage rates over the long term for The Hawaiian Electric Company are not expected to be significantly different from the national averages on the U.S. mainland for oil-fired units of similar design. Therefore, higher forced outage rates should be anticipated and generation planning should be based on these rates.

3. The Hawaiian Electric Company index of reliability for the 1956-1961 period based on the expected forced outage rates as derived in this report was lower than that normally considered adequate. Likewise, the reliability based on the lower experienced forced outage rates was also inadequate.

4. Based on expected forced outage rates Budget Plans 1 and 2 for the 1962-1970 period yield a higher index of reliability than has been experienced in the past. However, the system reliability provided by all plans is below the index generally considered acceptable.

5. If generating units that are large with respect to system load are installed as proposed in the four budget plans, a low index of reliability must be anticipated unless additional reserve capacity is installed.

APPENDIX

Exhibit 1

1962 GENERATING CAPABILITY
Megawatts

Plant	Unit	Throttle Temperature And Pressure Degrees F	Psig	Turbine Name Plate Rating	Net Capability
Honolulu	1	651.4	265	40(a)	30
	5	700	430	20	23
	7	900	650	35	42
	8	950	1250	40	55
	9	950	1250	50	60
Plant Total					210
Waiau	1	825	650	7.5	8
	2	825	650	15	18
	3	900	850	40	52
	4	900	850	40	52
	5	950	1250	50	60
	6	950	1250	50	57
Plant Total					247
Total System Capability					457

(a) 4 - 10 megawatt turbines (Units 1, 2, 3 and 6)

Exhibit 2

1956 - 1961
GENERATION, LOAD AND RESERVE CAPACITY

Year	Unit Addition				System Net Capability	Peak Load	Reserve Capacity	
	Unit	Date	Rating Mw	Capability Mw	Mw	Mw	Mw	% of Peak
1956					280	204	76	37.2
1957	Honolulu 9	12/9	50	60	340	227	113	49.8
1958					340	248	92	37.1
1959	Waiau 5	10/9	50	60	400	287	113	39.4
1960					400	313	87	27.8
1961	Waiau 6	7/28	50	57	457	341	116	34.0

Exhibit 3

BUDGET PLAN 1
Generation Expansion Pattern

Year	Unit Addition: Unit	Date	Rating Mw	Capability Mw	System Net Capability Mw	Peak Load Mw	Reserve Capacity Mw	% of Peak
1962					457	369	88	23.8
1963	Kahe 1	3/1	75	82.5	539.5	399	140.5	35.2
1964	Kahe 2	11/1	75	82.5	622	430	192	44.6
1965					622	465	157	33.8
1966	Kahe 3	11/1	100	110	732	502	230	45.8
1967					732	542	190	35.1
1968	Kahe 4	11/1	100	110	842	585	257	43.9
1969					842	632	210	33.2
1970					842	683	159	23.3

Exhibit 4

BUDGET PLAN 2
Generation Expansion Pattern

	Unit Addition				System Net	Peak	Reserve Capacity	
Year	Unit	Date	Rating Mw	Capability Mw	Capability Mw	Load Mw	Mw	% of Peak
1962					457	369	88	23.8
1963	Kahe 1	3/1	75	82.5	539.5	399	140.5	35.2
1964	Kahe 2	11/1	75	82.5	622	430	192	44.6
1965					622	465	157	33.8
1966	Kahe 3	11/1	75	82.5	704.5	502	202.5	40.3
1967					704.5	542	162.5	30.0
1968	Kahe 4	11/1	75	82.5	787	585	202	34.5
1969					787	632	155	24.5
1970					787	683	104	15.2

Exhibit 5

BUDGET PLAN 3
Generation Expansion Pattern

Year	Unit Addition: Unit	Date	Rating Mw	Capability Mw	System Net Capability Mw	Peak Load Mw	Reserve Capacity: Mw	% of Peak
1962					457	369	88	23.8
1963	Kahe 1	3/1	75	82.5	539.5	399	140.5	35.2
1964					539.5	430	109.5	25.4
1965	Kahe 2	3/1	75	82.5	622	465	157	33.8
1966					622	502	120	23.9
1967	Kahe 3	3/1	100	110	732	542	190	35.1
1968					732	585	147	25.1
1969	Kahe 4	3/1	100	110	842	632	210	33.2
1970					842	683	159	23.3

Exhibit 6

BUDGET PLAN 4
Generation Expansion Pattern

Year	Unit Addition: Unit	Date	Rating Mw	Capability Mw	System Net Capability Mw	Peak Load Mw	Reserve Capacity: Mw	% of Peak
1962					457	369	88	23.8
1963	Kahe 1	3/1	75	82.5	539.5	399	140.5	35.2
1964					539.5	430	109.5	25.4
1965	Kahe 2	3/1	75	82.5	622	465	157	33.8
1966					622	502	120	23.9
1967	Kahe 3	3/1	75	82.5	704.5	542	162.5	30.0
1968					704.5	585	119.5	20.4
1969	Kahe 4	3/1	75	82.5	787	632	155	24.5
1970					787	683	104	15.2

Exhibit 7
Sheet 1 of 2

1956 - 1961
MAINTENANCE SCHEDULE
Week Numbers (a)

Plant	Unit	1956	1957	1958	1959	1960	1961
Honolulu	1	29-32	33-34	33-34 42-43	0	1-4	9-11
	5	34-36	30-32	37-40	0	5-8	6-8 12
	7	22-27	24-29	9-16	0	25-30	30 49-52
	8	15-20	23	17-19	8-12	9-10	31
	9	-	0	0	3-6	11-14	0
Waiau	1	41-42	11-13	33	30-31	48-50	0
	2	38-39	14-15	31-32	30-31	36-40	0
	3	10-13	19-21	26-30	13-20	16-19	41-45
	4	5-8	16-18	6-8 20-25	22-28	20-23	35-40
	5	-	-	-	0	31-35	33-34
	6	-	-	-	-	-	0

(a) For example Honolulu Unit 1 is on scheduled maintenance for the period starting the 29th week and extending through the 32nd week in 1956.

1962 - 1970
MAINTENANCE SCHEDULE
Week Numbers

Plant	Unit	1962	1963	1964	1965	1966	1967	1968	1969	1970
Honolulu	1	0	6-9	6-9	5-8	5-8	5-8	5-8	5-8	4-6
	5	32-37	1-5	1-5	1-4	1-4	1-4	1-4	1-4	1-3
	7	0	10-13	48-52	41-46	47-52	41-46	49-52	45-48	37-39
	8	8-13	14-18	10-14	9-13	9-12	9-12	9-12	9-12	7-10
	9	14-17	25-31	20-23	20-23	17-20	17-20	17-20	17-20	15-18
Waiau	1	3-7	49-52	40-43	47-52	40-46	47-52	40-43	49-52	40-44
	2	3-7	49-52	36-39	47-52	40-46	47-52	40-43	49-52	40-44
	3	0	39-43	32-35	33-36	33-36	33-36	37-39	37-40	45-48
	4	0	44-48	44-47	37-40	37-39	37-40	44-48	41-44	49-52
	5	0	32-38	28-31	29-32	29-32	29-32	33-36	33-36	34-36
	6	19-25	19-24	15-19	14-19	13-16	13-16	13-16	13-16	11-14
Kahe	1	-	0	24-27	24-28	21-24	21-24	21-24	21-24	19-22
	2	-	-	-	-	25-28	25-28	25-28	25-28	23-26
	3	-	-	-	-	-	-	29-32	29-32	27-30
	4	-	-	-	-	-	-	-	-	31-33

Exhibit 8

1955 - 1961
EXPERIENCED FORCED OUTAGE RATES
PERCENT

Plant	Unit	Annual Outage Rate 1955	1956	1957	1958	1959	1960	1961	Average Outage Rate
Honolulu	1	10.00	6.75	0	0	0	72.05	0	12.70
	5	0	0.82	0	2.62	0	0	0	0.49
	7	0	0.86	0	0.92	8.53	0	0.83	1.59
	8	-	0	0.77	0	1.27	0	0	0.34
	9	-	-	-	-	0	1.22	1.15	0.79
Waiau	1	0	0	0	0	0	1.10	0	0.16
	2	0.48	0	2.86	0	0.41	0	0	0.54
	3	0	0	0.41	0.44	0.90	0.41	3.00	0.74
	4	0	0	0.83	0.94	0	0.82	0	0.37
	5	-	-	-	-	-	-	0.40	0.40

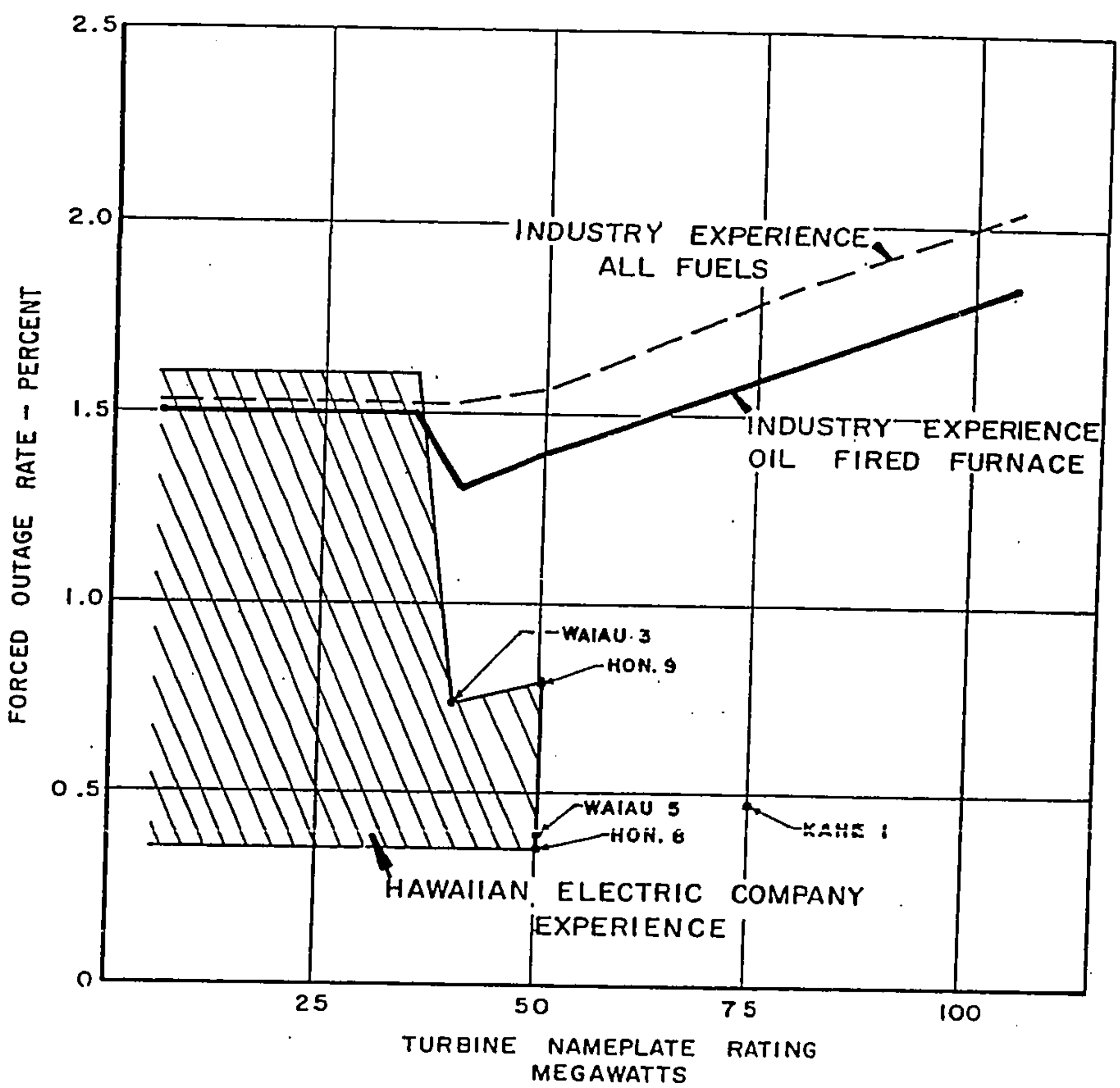
Exhibit 9

EXPECTED FORCED OUTAGE RATES

Plant	Unit	Turbine Name Plate Rating - Mw	Net Capability Mw	Forced Outage Rate - %
Honolulu	1	40	30	1.6
	5	20	23	1.6
	7	35	42	1.5
	8	40	55	1.4
	9	50	60	1.4
Waiau	1	7.5	8	1.5
	2	15	18	1.5
	3	40	52	1.3
	4	40	52	1.3
	5	50	60	1.4
	6	50	57	1.4
Kahe	1	75	83	1.6
	2	75	83	1.6
	3	75	83	1.6
	3	100	110	1.8
	4	75	83	1.6
	4	100	110	1.8

Exhibit 10

COMPARISON OF FORCED OUTAGE RATES



CA Inc. R-920

Exhibit 11

1956 - 1961
SYSTEM RELIABILITY

	Years Per One Day Loss of Load	
Year	Experienced Outage Rates	Expected Outage Rates
1956	1.70	0.63
1957	0.97	0.37
1958	7.65	2.88
1959	0.59	0.23
1960	5.82	1.63
1961	0.51	0.30

Exhibit 12

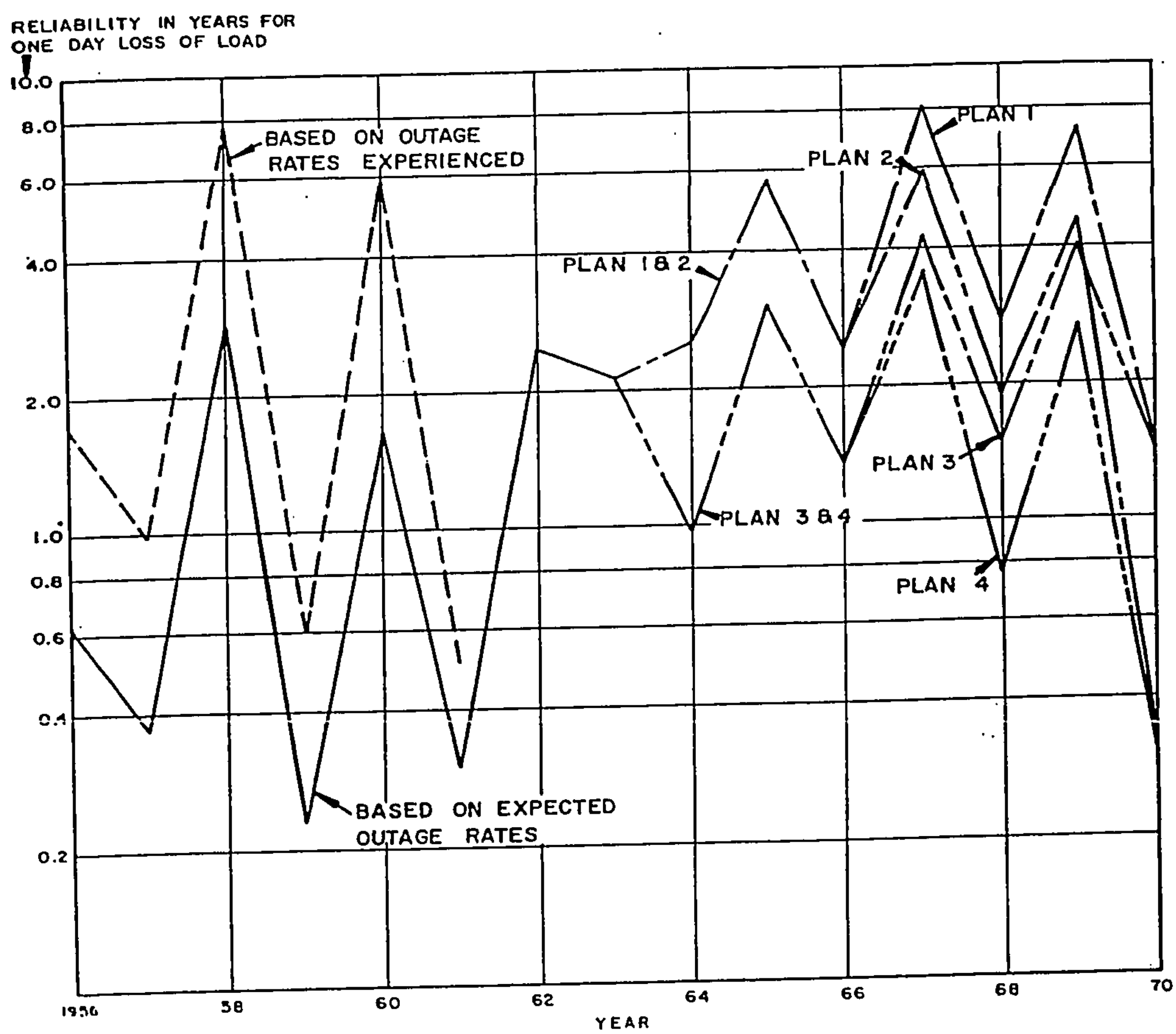
1962 - 1970
SYSTEM RELIABILITY

Year	Years Per One Day Loss of Load: Plan 1	Plan 2	Plan 3	Plan 4	Plan 5 (a)
1962	2.48	2.48	2.48	2.48	17.57
1963	2.12	2.12	2.12	2.12	13.20
1964	2.51	2.51	0.96	0.96	11.12
1965	5.62	5.62	3.02	3.02	29.87
1966	2.42	2.41	1.33	1.33	11.22
1967	8.02	5.90	4.22	3.55	64.81
1968	2.73	1.88	1.49	0.75	9.44
1969	7.13	4.50	3.99	2.68	50.25
1970	1.35	0.29	1.35	0.29	8.25

(a) Plan 5 is the same as Plan 4 except that peaking capacity equal to ten percent of the annual peak load has been installed.

Exhibit 13

1956 - 1970
SYSTEM RELIABILITY



C A Inc R-920

Appendix 4:

Factors Affecting HECO Capacity Planning

1. Actual Daily Load Versus Forecasted Loads

As mentioned in Section 3.2, 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.

2. 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.

3. Actual CHP Impacts Versus Forecasted Impacts

Through market analysis, discussions with prospective CHP customers, and estimates of regulatory review and approval times, HECO developed a forecast of utility CHP program impacts. With this forecast, along with estimates of the overall potential CHP market, a complementary forecast of non-utility CHP projects was also developed. There is a significant degree of uncertainty in forecasting the CHP market, whether it is for HECO CHP projects or non-utility CHP projects. All prospective CHP projects are subject to customer desire and support, which can be extremely variable. 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, evidence that CHP projects are subject to changes in customer sentiment.

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.

In addition, the ability of the utility to offer CHP to customers on a regulated basis has not been determined. While the Commission considers distributed generation policy issues in Docket No. 03-0371, the resulting uncertainty can affect customer support for a utility CHP system, as was the case with Pacific Allied. HECO's first proposed CHP project, for Pacific Allied Products, was terminated by the customer on February 9, 2005 due to schedule uncertainties resulting from suspension of HECO's application (see Order No. 21555, issued January 21, 2005, suspending HECO's Rule 4 Application for its CHP project with Pacific Allied Products). No utility CHP was installed in 2004, and it is unlikely that any HECO CHP will be installed in 2005.

However, notwithstanding the aforementioned uncertainties negatively impacting the CHP forecast for 2005, short-term CHP forecasts in the years beyond may also move in the positive direction driven primarily by proposed major new facility developments. For example, the recent announcement of major development in the Ko Olina area, including several hotels and an aquarium, present significant additional CHP potential for Oahu.

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.

5. 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 to the Residential Direct Load Control program due to factors such as inadequate awareness and/or the risk of lower customer participation in the Commercial & Industrial Direct Load Control program due to 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.

6. 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. (HECO plans to provide in its response to CA-IR-42 in the Rate Case Docket 04-0113, an example of how the actual maintenance schedule can be substantially different from the planned maintenance schedule.)

In addition, as the overhaul and capital replacement work for Waiau 9 continues, findings that could only be made during the disassembly of the turbine have resulted in unanticipated additions to the scope of work. Further, HECO has experienced several material delivery delays for the exhaust duct refurbishment work. As a result, HECO now estimates that the outage for Waiau 9 will continue through the end of March. The longer than planned outage of Waiau 9 will have an impact on the scheduling of other generating units for the remainder of the year. The Power Supply Operations and Maintenance Department is evaluating adjustments to the overhaul schedule to accommodate the overhaul extension of Waiau 9.

7. 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.

In 2004, recorded system average EFOR for all HECO units was 4.98 % on a weighted average basis for actual MWh contribution for each generating unit. This recorded system average was higher than the average of the five prior years (1999-2003) of 2.34 %. Several extended deratings of Honolulu 8, Kahe 3, Kahe 5 and Waiau 8 were significant contributors to the 2004 system average EFOR. These derates were longer than normal because HECO could not afford to take these derated units out of service immediately due to the tight capacity situation encountered throughout 2004.

For this AOS, forward looking EFORs for each HECO generating unit were developed by reviewing historical EFORs and when applicable, adjusting these EFORs to account for the expected condition of major generating unit components as a result of recently completed or soon-to-be completed overhaul and refurbishment work. Based on this process, the forward looking system average EFOR for the 2005-2009 period is 2.89% (weighted by the estimated 2005 MWh contribution for each generating unit). The forward looking EFOR for each IPP is based on a review of historical EFORs and contractual availability requirements for IPPs. (HECO plans to provide additional details on how it establishes projections for forward looking EFORs in response to CA-IR-130, in HECO's rate case, Docket 04-0113.) Collectively, these individual unit EFORs represent the base composite EFOR used for this AOS.

Appendix 5:

Alternate Scenario & Sensitivity Analysis of System Risk

1. Alternate DSM and CHP Scenario

Because there continues to be significant uncertainty regarding the timing and magnitude of the peak reduction benefits of HECO's proposed enhanced energy efficiency DSM program, the load management DSM programs and the proposed CHP program, HECO considered a scenario where the impacts occur later and are lower than currently estimated.

HECO developed an alternative DSM and CHP scenario that uses the assumption that residential and commercial load management impacts are lower than those acquired in the base case by 25% and 20% respectively. Such a scenario could arise, for example, if (1) customer acceptance and/or awareness is less than expected in the case of the residential programs, and permitting constraints limit the use of emergency generators in the commercial 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; and (3) HECO's participation in the CHP market is not allowed. The combined peak reduction benefits would be reduced significantly in this scenario. Table A6 below provides the cumulative difference in load reducing impact under this alternate scenario. It results in a decrease in generating system reliability and an increase in reserve capacity shortfalls.

Table A6:

Comparison of the Base and Alternate DSM and CHP Scenarios

	Cumulative Impact (MW)		
Year	Base	Alternate DSM and CHP Scenario	Difference
2004	4	4	0
2005	16	12	-4
2006	40	28	-13
2007	64	40	-24
2008	86	52	-34
2009	102	58	-44

1.1. Alternate DSM and CHP Scenario Generation System Reliability Analysis

Table A7 provides the generating system reliability and reserve capacity shortfall under this alternate DSM and CHP scenario.

Table A7:

Generation System Reliability and Reserve Capacity Shortfall for the Alternate DSM and CHP Scenario

Year	Generation System Reliability (years/day)	Reserve Capacity Shortfall (MW)
2005	1.1	-60
2006	0.8	-80
2007	0.5	-100
2008	0.7	-80
2009	0.4	-110

It should be noted that Table A7 does not include the effects of the addition of the CIP combustion turbine in 2009 to assess the generation system reliability and reserve capacity shortfall.

1.2. <u>Alternate DSM and CHP Scenario Rule 1 & Rule 2 Analysis</u>

Table A8 below provides reserve capacity shortfalls to meet the Rule 1 and Rule 2 planning criteria for the Alternate DSM and CHP scenario.

Table A8:

HECO Rule 1 and Rule 2 Capacity Shortfalls
(Alternate DSM and CHP scenario)

Year	HECO Rule 1 Shortfall (MW)	HECO Rule 2 Shortfall (MW)
2005	-24	-65
2006	-7	-47
2007	-30	-70
2008	-30	-70
2009	-51	-91

As shown in Table A8 for this scenario, beginning in 2005 there would be occasions in which there is an insufficient amount of reserve capacity to meet HECO's loss of largest unit requirement (Rule 1). The 24 MW HECO Rule 1 reserve capacity shortfall and 65MW HECO Rule 2 reserve capacity shortfall are due to coincident outages planned for Waiau 10, H-POWER, and Kalaeloa (see page 14 of the report). These values are similar to those provided in Table 6 as load reducing impacts from energy efficiency DSM, load management DSM and CHP are very similar in base and alternate cases for 2005. However, the reserve capacity shortfalls grow faster in this lower DSM and CHP scenario as a result of the higher peaks projected for this scenario.

It should be noted that Table A8 does not include the effects the addition of the CIP combustion turbine in 2009 to determine the Rule 1 and Rule 2 shortfall.

2. Alternate DSM and CHP Scenario with EFOR Sensitivity Analysis

2.1. Alternate DSM and CHP Scenario with EFOR Sensitivity Reliability Guideline Analysis

As mentioned previously, HECO's generating system reliability guideline is affected by the EFOR assumed for each existing generating unit. As discussed in Appendix 4, Section 7, it is difficult to forecast EFOR. Because of the uncertainty of future EFORs, HECO evaluated a scenario based on a higher EFOR.

Table A9 below provides the impact to generating system reliability and reserve capacity shortfall if forecasted EFORs for existing generating units (both HECO owned and IPP) are increased by 20%. It should be noted, as Table A9 illustrates, that the relationship between EFOR of units and generating system reliability is non-linear and that increase in EFOR results in a comparatively larger reserve capacity shortfall. This is due to the actual calculation involved in determining LOLP.

Table A9:

Reserve Capacity Shortfall, low load management DSM, energy efficiency DSM, no utility CHP, and 20% higher EFOR

Year	Generation System Reliability (years/day)	Reserve Capacity Shortfall (MW)
2005	0.7	-90
2006	0.5	-110
2007	0.3	-120
2008	0.5	-110
2009	0.3	-130

Table A9 does not include the effects the addition of the CIP combustion turbine in 2009 to assess the generation system reliability and reserve capacity shortfall.

2.2. Alternate DSM and CHP Scenario with EFOR Sensitivity Rule 1 and Rule 2 Analysis

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.

Appendix 6:

Reserve Capacity Shortfalls and Generation Shortfalls

1. Reserve Capacity Shortfalls

Reserve capacity shortfall is defined as not having enough reserve capacity from firm capacity resources on the system to maintain generating system reliability at or above 4.5 years per day reliability guideline in a given year. It is equal to the amount of additional firm capacity required in a given year to restore generating system reliability above the 4.5 years per day reliability guideline. A reserve capacity shortfall does not equate to a generation-related customer outage. However it does increase the likelihood of a customer outage due to generation shortages.

For planning purposes, projections are used to forecast the need for additional generation and the timing of future resource additions. Factors that affect these projections include (1) actual versus forecasted peak demand, (2) actual versus forecasted energy efficiency DSM, load management DSM, and CHP impacts, (3) planned maintenance schedules and how actual maintenance schedules deviate from forecasted plans due to operational and condition assessment factors, and (4) the actual condition and reliability of existing generating units.

The calculation of reserve capacity shortfalls does not take into account the availability of as-available resources such as intermittent output from the Tesoro or Chevron refineries.

As indicated in Section 4.2, the LOLP analysis takes into account factors such as expected daily peak demand, number and sizes of generating units, the planned maintenance schedule, and the forced outage rates of each generating unit. The LOLP analysis takes into account the possibility of multiple unit outages

For planning purposes, projections are used to forecast the timing of future resource additions. The following factors affect reserve capacity projections:

- Daily Peak Forecast
- Normal Top Load Ratings and Number of Generating Units
- Planned Maintenance Schedule
- Equivalent Forced Outage Rates ("EFOR") of Each Generating Unit

2. Generation Shortfalls

Generation shortfall is defined as not having sufficient capacity on the system to meet the expected load. Outages due to generation shortages may occur with generation shortfalls, but other factors need to be considered before any assessment of outages due to generation shortages can be made.

Other factors must be considered when making an assessment of the possibility that available generation will be insufficient to serve the system load (i.e., that rolling blackouts will have to be implemented). These factors include the availability of non-firm resources (such as the output of the Tesoro and Chevron refineries), differences between actual and forecast peaks (which are impacted by factors such as weather), differences between actual and normal unit capabilities (due to such factors as temporary unit deratings, ambient conditions in the case of Waiau Units 9 and 10, and the overall condition of the units), and differences between actual and planned maintenance schedules (maintenance outages may be extended or shortened, depending on circumstances).

For planning purposes, projections are used to forecast the timing of future resource additions. Factors that affect whether or not there is adequate generation to meet the load are more complex than those that affect reserve margin shortfalls. These factors include the following:

- Actual versus Forecasted Peak and Actual load management DSM and energy efficiency DSM Penetration
- Condition and Reliability of Existing Units
- Availability of Non-Dispatchable As-Available Resources

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

William A. Bonnet
Vice President
Government and Community Affairs

January 31, 2005

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 Report") is due within 30 days after the end of the year. HECO respectfully requests an extension to no later than March 15, 2005 in which to submit its AOS Report.

In general, the AOS Report assesses the adequacy of central station generation (including firm purchased power) 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"), during the next three years. HECO requests a delay to file its AOS Report until no later than March 15, 2005, because HECO is in the process of updating (1) the planned maintenance schedules for 2005-2007 (which affect the availability of central station generation), (2) the expected outage rates for central station generation (which affect the adequacy of reserve margins), (3) its CHP projections (given the current state of the proposed CHP program, Rule 4 contract applications and generic distributed generation docket), and (4) the start dates for its enhanced energy efficiency DSM programs (which are the subject of its pending rate case.) The Consumer Advocate does not object to this request.

Very truly yours,

cc: Division of Consumer Advocacy

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

March 31, 2004

William A. Bonnet
Vice President
Government and Community Affairs

FILED
2004 MAR 31 P 4: 17
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 is due within 30 days after the end of the year. On January 30, 2004, HECO requested an extension of time, to no later than March 31, 2004, to file the Report. The extension of time was needed to allow HECO to incorporate the results of its new sales and peak load forecast, which was under development at the time in conjunction with its Integrated Resource Planning process, in the reserve margin estimates for the 2004 – 2006 future period covered by the Adequacy of Supply Report. The Commission granted HECO's request for extension of time on February 9, 2004. This report incorporates the results of HECO's February 2004 long-term sales and peak forecast.[1]

HECO respectfully submits the following information pursuant to paragraph 5.3a. of General Order No. 7.

Peak Demand and System Capability in 2003

HECO's 2003 system peak occurred on Monday, October 27, 2003 and was 1,284,000 kW-gross or 1,242,000 kW-net based on net HECO generation, net purchased power generation, the peak reduction benefits of energy efficiency demand-side management programs implemented in mid-1996, and with several cogenerators[2] operating at the time. Had these cogenerating units not been operating, the 2003 system peak would have been 1,305,000 kW-gross or 1,263,000 kW-net.

[1] A summary of the February sales and peak forecast is shown in Attachment 1, page 1.
[2] At the time of the peak, certain units at Tesoro, Chevron, and Pearl Harbor were generating an estimated 21,000 kW of power.

HECO's 2003 total generating capability of 1,615,000 kW-net includes 406,000 kW-net of firm power purchased from (1) Kalaeloa Partners, L.P., (2) AES Hawaii, Inc., and (3) H-POWER. Oahu had a reserve margin of approximately 28% over the 2003 system net peak.[3]

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.

February 2004 Peak Forecast

As indicated in HECO's letter, dated January 30, 2004, requesting an extension of time to file this report, load is expected to grow at a rate faster than previously forecasted over the next five-year period, although there may be a temporary lag due to the deployment of troops from the 25th Infantry Division at Schofield to Iraq. Table 1 shows a comparison of the forecasted peaks for the period 2004–2006 in the August 2002 long-term peak forecast and the February 2004 long-term peak forecast.

Table 1
Comparison of Forecasted Peak Loads
(With Future DSM[4] and Utility CHP and Impacts of Third Party CHP and Rider I)

Year	August 2002 Forecast System Peak (net kW)	February 2004 Forecast System Peak (net kW)	Increase in Peak Forecast (kW)
2004	1,263,000	1,279,500	16,200
2005	1,273,900	1,309,000	35,100
2006	1,286,100	1,334,200	48,100

The major reasons for the higher forecast peaks are a more optimistic near-term economic outlook and substantial new project loads associated with military forward deployment, transformation, and housing privatization. As shown in Attachment 1, pages 2-3, the local economic outlook has improved since the summer of 2002. Major military forward deployment and transformation projects are shown in Attachment 1, page 4. The August 2002 forecast did not include these new military project loads.

The year 2003 provided a solid foundation for economic growth. However, while housing construction and consumer spending were sources of strength, tourism provided only

3 The reserve margin calculation takes into account the 4,000 kW interruptible load served by HECO.
4 HECO's energy efficiency DSM and load management programs.

nominal growth. With a rebound in visitor figures expected this year, all three major sectors (tourism, construction, and military spending) are forecasted to contribute to economic growth in 2004 and beyond.

Strong U.S. economic growth, as shown in Attachment 1 page 5, should support an expansion of domestic visitors to the islands. Visitors from Japan should grow in double digits since even the continuation of late year 2003 visitor levels would be much improved from the depths experienced just prior to and during last year's war in Iraq.

Construction should be even better than last year. With a growing economy, interest rates projected to rise only slightly (as shown in Attachment 1, page 6), and a shortage of housing, the residential market for new and re-sold properties will remain hot. In addition, at least four high-rise condominiums will be under construction. Construction began on the Hokua Condo in Kakaako in November and was expected to start on the Koolani, Moana Pacific, and Lanikea in early 2004. Waikiki is also undergoing revitalization as older apartments and older, off-beach, hotels are renovated into residential and time-share properties.

Military housing will provide another huge boost. Not only will current military construction quality of life projects continue at Schofield and Pearl Harbor, but also the military's housing privatization projects, worth $3.5 billion in construction alone, will start gearing up this year. Actus Lend Lease won both the Army's contract to renovate and replace 7,700 homes over 10 years, and the Air Force's contract for 1,350 homes over a period of 5 years. Hawaii Military Communities won the Navy's contract to renovate and replace more than 1,900 homes over 4 years. Fluor Hawaii also is working with the Navy to provide about $85 million in design-build projects on Ford Island, and will oversee rental property at Iroquois Point, Puuloa, and Kalaeloa. All of these contracts are particularly favorable to the developers because the source of funding is secure, construction is not subject to the vagaries of interest rates, and being on federal land, entitlements are not an issue. Construction is expected to begin as early as April 2004.

The military is preparing for the basing of a squadron of eight C-17 cargo planes at Hickam Air Force Base, and the transformation of one brigade of soldiers into a Stryker Brigade Combat Team at Schofield. Congress and the President have already approved funding for the first phase of infrastructure and facilities construction to accommodate the new missions. Subsequent phases of construction are included in the proposed FY05 military construction budget.

In contrast, the decision to homeport an aircraft carrier at Pearl Harbor has not been made. There are several reasons why a carrier homeport will not likely occur soon: the location of the carrier air wing remains unresolved, an EIS process and infrastructure improvements must be completed, and housing for the crew and families must be identified. Therefore, a homeported carrier is not expected for another 5 years.

The impact of the military construction program on the economy will be immense. State construction put-in-place is expected to grow over 17% in 2004 after a 7% increase last year. It has been estimated that over time, more than 12,000 direct blue and white collar jobs will be added. Furthermore, this does not include the trickle down effect in other sectors that will result from the additional spending by the new job holders.

On the other hand, the military will also have a temporary negative effect on the economy when over 8,000 soldiers deploy to Iraq and Afghanistan this year for 12 months. An unknown number of families also will depart for the mainland when their spouses are deployed. Estimates of the number of families that will leave range from 10% to 40%.

Schofield Barracks is not the only base affected by deployments. Kaneohe Marine Corps Base Hawaii has a "steady state" deployment of approximately 2,000 Marines and expects another 500 this year. Nearly 400 Hawaii Army reservists are expected to leave for Iraq in March 2004. According to the Hawaii National Guard, about 2,100 Hawaii Guardsmen may be sent to Iraq sometime in 2005. The 8,000 Schofield soldiers are scheduled to return to Hawaii early that year.

Overall, however, the outlook for tourism, construction and the military results in an optimistic forecast for the Hawaii economy and related growing demand for electricity. Attachment 1, page 7, compares the forecasts from a number of local economists for 2004. Note that all agree that (1) the visitor industry will rebound this year, (2) job growth will continue to grow at around 2%, and (3) real personal income will grow about 3% or better. Although none of the forecasts shown venture beyond 2004, one thing is certain – military construction will contribute billions of dollars to the economy for many years to come, providing stability in a sector that has traditionally been strongly cyclical and adding to the increasing demand for electricity. DBEDT's economic projections (Attachment 1, page 2) also point to a positive outlook for the local economy. Low interest rates continue to drive a boom in housing and commercial construction. This will boost the demand for electricity both during the construction phase and later when the facilities are occupied. Combined with a national economy that is expected to accelerate, and barring the occurrence of domestic terrorist activity or another SARS scare, the outlook for the local economy is very good and electrical load is expected to grow faster than previously forecasted.

Estimated Reserve Margins

Attachment 2 shows the expected reserve margin over the next three years, based on HECO's Sales and Peak Forecast, dated February 26, 2004, and on HECO's latest estimate of forecasted DSM impacts for 2003.

Impact of Higher Peak Demand Forecast

The following method is used to determine the timing of an additional generation unit:

> *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.*

The method used to determine the timing of an additional generation unit accounts for interruptible loads. HECO will not build reserve capacity to serve interruptible loads.

Also included in HECO's capacity planning criteria is a reliability guideline. The guideline states:

> *"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."*

HECO applies this guideline in determining the need date for new firm capacity.

In HECO's IRP-2 Evaluation Report, filed with the Commission on December 31, 2002, pursuant to PUC Order No. 19689, in Docket No. 95-0347, a modified preferred plan was established. The modified preferred plan reflected the effects of changes in assumptions that occurred between January 1998, when HECO's IRP-2 was filed, and December 2002, when HECO's IRP-2 Evaluation Report was filed. The supply-side of the modified preferred plan called for, among other things, installation of a simple cycle combustion turbine in 2009. The 2009 need date was determined using the August 2002 forecast, part of which is shown in Table 1 above, and by the application of the reliability guideline.

With the February 2004 forecast, which is higher than the August 2002 forecast as indicated in Table 1, HECO's analysis indicates that generating system reliability will fall below the 4.5 years per day reliability guideline beginning in 2006, assuming that no new central-station generating capacity is added from 2004 through 2006, even if:

1. forecasted peak reduction benefits (estimated at 11 MW for 2004 – 2006) from continuation of existing energy efficiency DSM programs are acquired,
2. proposed peak reduction benefits (estimated at 28 MW for 2004 – 2006) from the two load management programs[5] are acquired, as forecasted in their respective applications; and
3. proposed utility CHP impacts (estimated at 8 MW for 2004 – 2006) occur as forecasted in Docket No. 03-0366.

Should the forecasted peak reduction benefits from these programs not occur, then the generating system reliability is expected to fall below the 4.5 years per day reliability guideline threshold sooner than 2006.

Assuming that the aforementioned forecasted peak reduction benefits from these programs do occur, it is estimated that about 30 MW of additional peak reduction benefits, or equivalent capacity additions, would be needed from 2004 through 2006, over and above these programs, to maintain generating system reliability above the 4.5 years per day guideline to 2007. It is also estimated that an additional 10 MW (over and above the 30 MW) of peak reduction benefits, or equivalent capacity additions, would be needed from 2004 through 2008 to maintain generating system reliability above the guideline to 2009.

Utility Combined Heat and Power Program Impacts

On October 10, 2003, HECO (along with MECO and HELCO) filed a PUC Application for approval of a proposed utility-owned Combined Heat and Power ("CHP") Program in Docket No. 03-0366. Implementation of a CHP Program was scheduled to begin in 2004, if authorized by the Commission[6]. The utilities' program involves the installation of small, distributed generating ("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. As indicated in the PUC Application, HECO developed a forecast of utility CHP systems for Oahu (dated August 20, 2003).

CHP systems can also be owned and operated by third-parties (non-utility entities). HECO developed forecasts for third-party CHP systems with and without the utility CHP

[5] HECO filed an application for a Residential Direct Load Control Program in May 2003 in Docket No. 03-0166 and an application for a Commercial & Industrial Dispatchable Load Control Program in December 2003, in Docket No. 03-0415.

[6] The utilities requested approval of each of their proposed CHP Program and related tariff provisions (Schedule CHP, Customer-Sited Utility-Owned Cogeneration Service). Under the CHP Program and Schedule CHP, the utilities propose to offer CHP systems to eligible utility customers on the islands of Oahu, Maui, and Hawaii as a regulated utility service. The utilities also indicated that they would request approval on a contract-by-contract basis for CHP system projects that fall outside the scope of the proposed program.

Program (dated August 20, 2003). Both utility and third-party CHP systems have the potential to defer the installation of traditional centralized generation. The rate of installation of CHP systems is estimated to be significantly greater with the utility CHP Program[7].

On October 21, 2003, the Commission issued Order No. 20582 in Docket No. 03-0371, which initiated a proceeding to investigate DG in Hawaii. The Commission anticipated that other matters related to the DG generic proceeding may be considered on a "case-by-case basis". Issues to be addressed in the DG docket included: (1) addressing interconnection matters, (2) determining who should own and operate distributed generation projects, (3) identifying what impacts, if any, distributed generation will have on Hawaii's electric distribution systems and market, (4) defining the role of regulated electric utility distribution companies and the commission in the deployment of distributed generation in Hawaii, (5) identifying the rate design and cost allocation issues associated with the deployment of distributed generation facilities, and (6) developing revisions to the integrated resource planning process, if necessary.

On October 31, 2003, the Consumer Advocate filed a Statement of Position (SOP) in Docket No. 03-0366, in which it recommended that the CHP Program docket be consolidated with the DG docket, or in the alternative, be suspended so as to not "affect the Commission's analysis" in the DG docket. The Consumer Advocate proposed that the Commission analyze situations "where an existing end-user may leave the grid to pursue non-utility options" on a "case-by-case" basis.

In their reply to the SOP, filed December 26, 2003, the utilities opposed consolidation of the CHP Program docket with the DG docket, or deferral (i.e., suspension) of the CHP Program docket[8]. . The utilities also indicated that, as soon as is practicable after the parties and participants are set in the CHP Program docket, or in the Generic DG Docket if the two dockets are consolidated, the utilities intended to file an appropriate motion requesting that their CHP Programs be allowed to go into effect on an interim basis.

[7] For purposes of this report, utility-owned CHP systems are included in the System Capability numbers (based on the net equivalent capacity of the CHP system, taking into account the electrical capacity supplied to a customer, the reduction of the customer's electrical load through waste heat application for the system, and a reduction in line losses). The load reduction impacts of CHP systems and/or DG owned by third parties are reflected in the System Peak numbers. Since there are expected to be more CHP systems installed with a utility CHP Program, the Reserve Margins (System Capability less System Peak divided by System Peak) are greater with the utility CHP Program, although the System Peaks appear to be higher because there are estimated to be somewhat fewer third party CHP systems/DG installed with a utility CHP Program.

[8] The Reply indicated that delaying the start of the program would be contrary to (1) State energy policy, (2) the utilities' need to address load growth with all cost-effective means at their disposal, and (3) the reasonable desire of and need for utility customers to implement energy and cost effective measures when appropriate opportunities arise. The Reply pointed out that load is growing faster than was anticipated, particularly on Oahu, (1) without the central station deferral benefits expected from their CHP Program, the need dates for new generation may well occur sooner than the forecasted need date of 2009 for HECO, and (2) the utilities are not in a position to accelerate the installation dates for new generation, and the installation of utility-owned CHP systems can help avoid reserve margin shortfalls.

By Order No. 20831, issued March 2, 2004 in Docket No. 03-0366, the Commission ordered that the CHP Program application "is suspended until further order of the Commission." The Commission indicated that its DG docket is intended to "form the basis for rules and regulations deemed necessary to govern participation into Hawaii's electricity market through distributed generation." The Commission noted that "[e]very effort will be made to hold hearings on Docket No. 03-0371 by the end of 2004 and immediately issue a decision and order in that docket."

As a result, HECO's opportunity to file a motion requesting that its CHP Program be allowed to go into effect on an interim basis has been foreclosed. Thus, HECO will have to file applications for approval of contracts entered into under Rule 4 of its Tariffs for the installation of CHP projects on a customer-by-customer basis. It is very difficult for HECO to forecast the rate at which customer-cited CHP projects will proceed, although the pace will undoubtedly be slower than if HECO was authorized to proceed with its CHP Program at this time.

With the suspension of HECO's CHP Program application, there is greater uncertainty as to how soon utility CHP systems can be installed. HECO's estimated future reserve margins, shown in Attachment 2, page 1, include the amount of CHP impacts forecasted in HECO's CHP Program application. If a lower amount of CHP impacts is realized, or if the forecasted impacts are delayed, estimated future reserve margins will be lower than those shown in the table.

Next Generating Unit and Integrated Resource Planning

HECO estimates that the lead time to install a simple cycle combustion turbine is approximately seven years. This duration includes the time necessary to perform necessary preliminary engineering activities, obtain all permits and approvals, procure long lead time equipment, and install and test the unit. Given this lead time, HECO began the process of preliminary engineering work in 2002 and began work to obtain the Covered Source Permit ("air permit") for a nominal 100 MW simple cycle combustion turbine in January 2003. HECO submitted the application for the air permit with the State of Hawaii Department of Health ("DOH") in October 2003. The DOH deemed the application complete in November 2003 and is currently reviewing the application. The HECO IRP-3 Advisory Group was informed of the air permit application at the October 7, 2003 meeting.

With 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, including renewable 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 and operating by 2006.

HECO began meetings for its third major integrated resource planning cycle in July 2003. In this third cycle, relevant forecast, financial, demand-side and supply-side (including renewable resource) assumptions will be re-examined in accordance with the Commission's IRP Framework. A resource integration process will be performed, with Advisory Group input, to develop an updated preferred resource plan in accordance with the IRP Framework. The updated resource plan will 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. HECO must file its IRP-3 plan with the Commission no later than October 31, 2005, but filed a schedule with the PUC to file by March 31, 2005.

Given the long lead time to install a generating unit and the associated uncertainties, HECO believed it was prudent to proceed, in parallel with the on-going IRP process, with at least the early steps involved in permitting the unit. Accordingly, HECO has begun the process to obtain the air permit. This will help preserve the viability of installing additional generating capacity on the system by 2009. Should the IRP-3 process find that the characteristics, timing or size of the next increment of supply-side capacity are different from those currently being pursued, the circumstances will need to be examined at that time to determine an appropriate course of action.

Mitigation Measures

Given that the next generating unit cannot be installed in 2006, HECO is exploring several other options to mitigate the effects of the higher forecast on generating system reliability. These options include, but are not limited to, more aggressive energy and load management DSM programs that acquire increased and accelerated impacts, identification and implementation of CHP projects in addition to those included in HECO's proposed CHP Program, increased output from HECO's existing units within the limits of existing permits, increased output from existing Independent Power Producers, and the installation of DG. HECO is currently evaluating the cost, permitting, schedule and regulatory requirements for these options.

Since the next generating unit cannot be installed by 2006, it is important that the regulatory proceedings for HECO's proposed load management programs and any proposed individual CHP projects move as quickly as possible[9]. Expeditious approval of these initiatives will enable HECO to begin its implementation efforts to begin acquiring the peak reduction benefits of these initiatives in order to mitigate the effect of the higher peak forecast on generating system reliability.

[9] In the near future, HECO plans to request interim approval of its proposed load management programs.

Conclusion

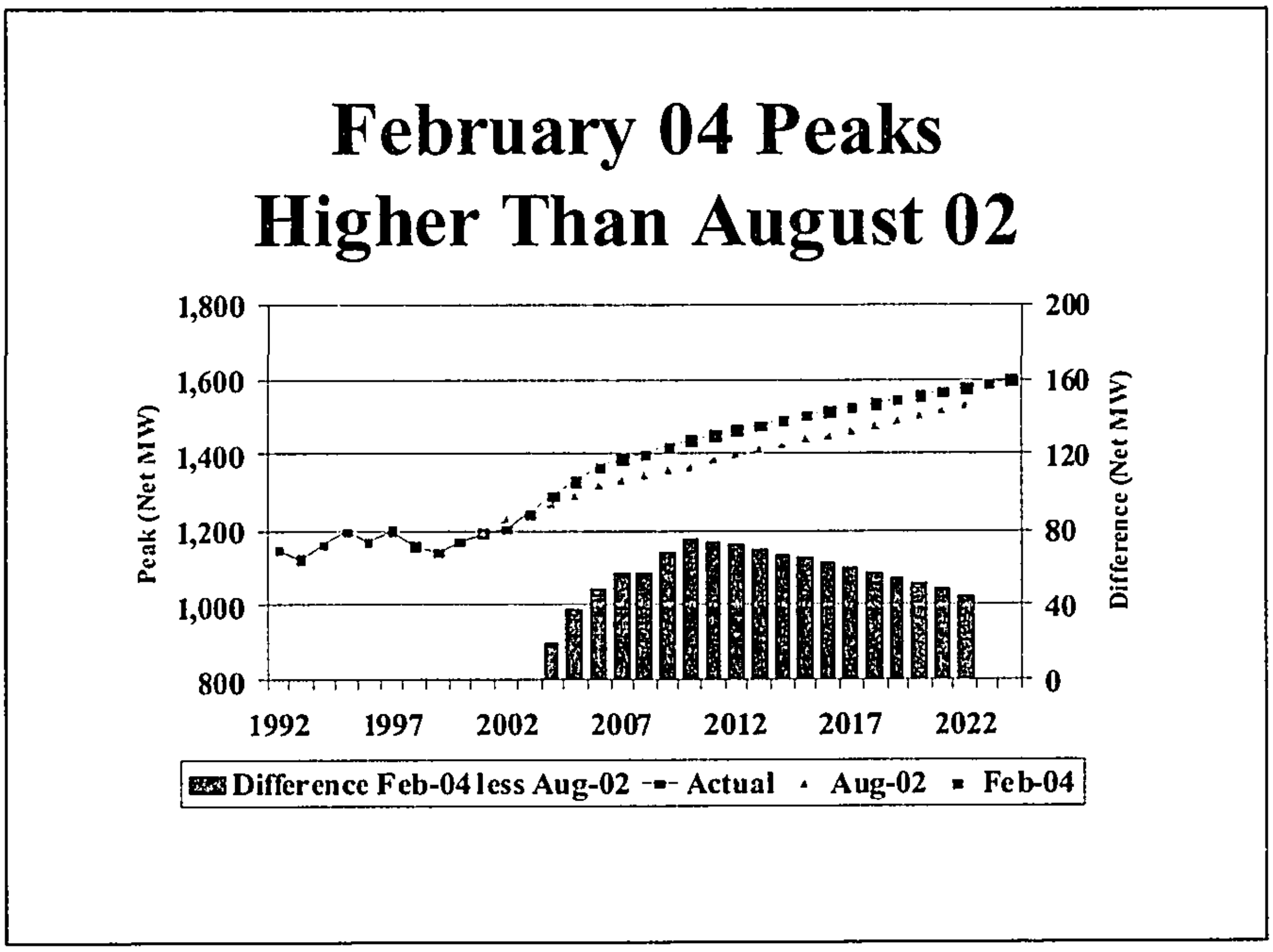
HECO's generation capacity for Oahu for the next three years will be sufficiently large to meet all reasonably expected demands for service, contingent upon an expeditious review and approval of the DSM load management programs and CHP Program (or individual contracts, given suspension of the program) now pending with the Commission. Further, given the brighter economic outlook driving a forecast of increased demand for electricity in the three to six year period, HECO anticipates filings for additional measures, including more aggressive DSM programs and individual CHP project applications in the future as well as a request for approval for a new central-station generating unit with a service date of 2009. Expressing this in terms of megawatts, HECO already has planned for, subject to regulatory approval, acquiring the impacts of approximately 78 MWs from DSM energy efficiency programs, DSM load management programs, and utility-sponsored CHP projects through 2008. In addition, HECO anticipates seeking another 40 MW (specifically 30 MW before 2007 and an additional 10 MW before 2009) of combined additional capacity and load reductions through a mix of generation alternatives and demand-side management programs that are critical to maintain HECO's generation system reliability above the reliability guideline until firm capacity from the new central-station generating unit is added in 2009.

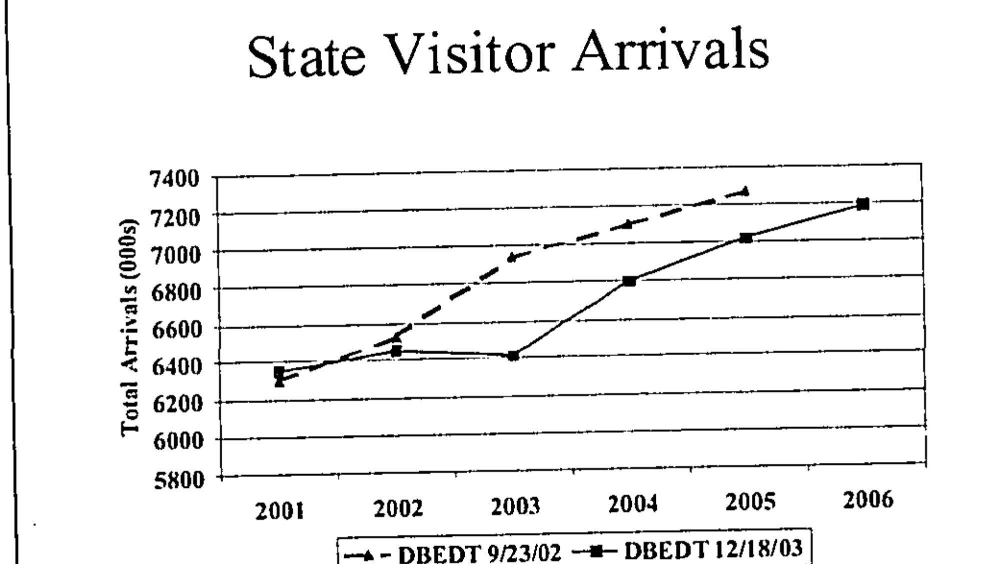
As noted, since firm capacity from the new central-station generating unit will not be in place before 2009, HECO's generating system reliability could fall below the 4.5 years per day threshold in 2006 and beyond if other firm generating capacity is not installed by then, or if the peak reduction benefits of additional or accelerated energy efficiency and load management DSM programs and those of CHP or DG are not realized, beginning in 2005.

Very truly yours,

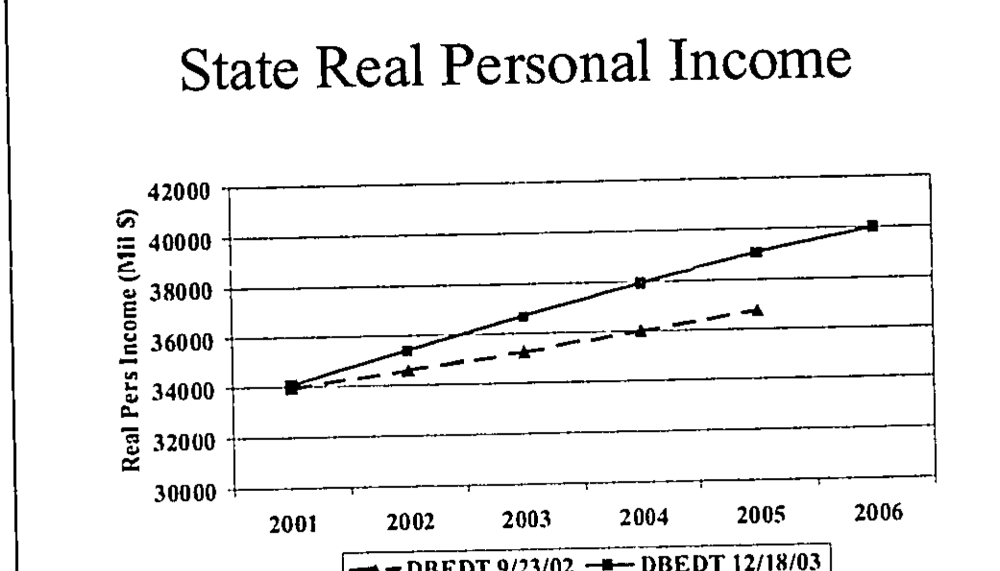
Attachment

cc: Division of Consumer Advocacy

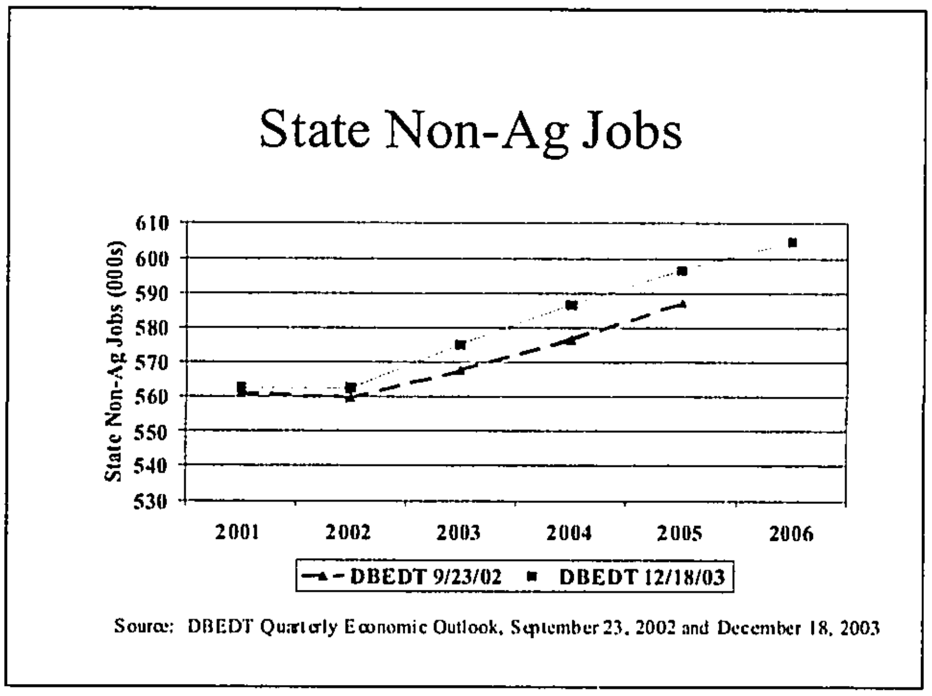

February 04 Peaks
Higher Than August 02
Peak (Net MW)
Difference (Net MW)
1,800
1,600
1,400
1,200
1,000
800
200
160
120
80
40
0
1992
1997
2002
2007
2012
2017
2022
Difference Feb-04 less Aug-02
Actual
Aug-02
Feb-04

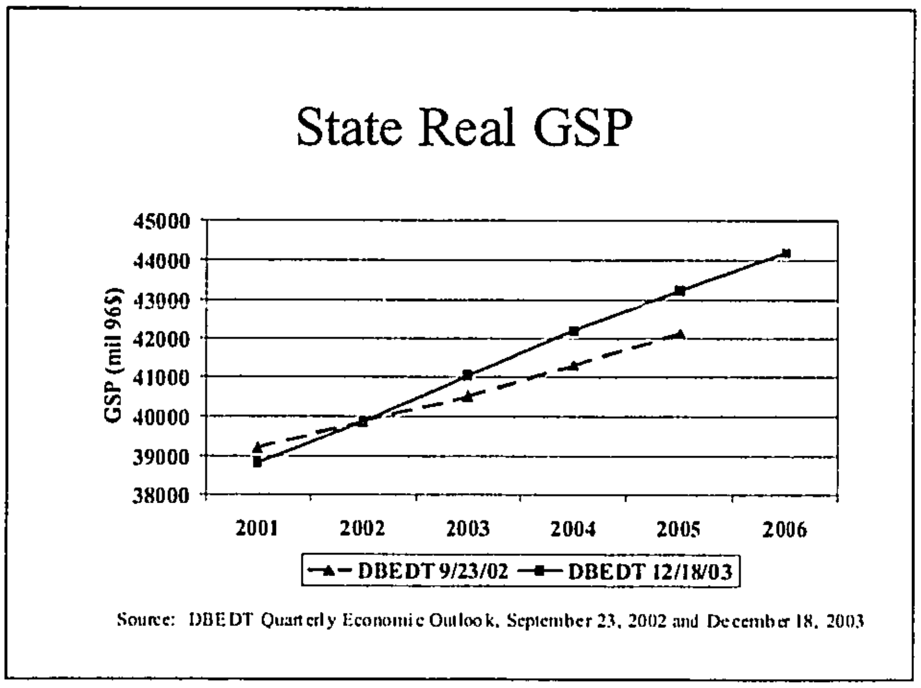


Source: DBEDT Quarterly Economic Outlook, September 23, 2002 and December 18, 2003



Source: DBEDT Quarterly Economic Outlook, September 23, 2002 and December 18, 2003

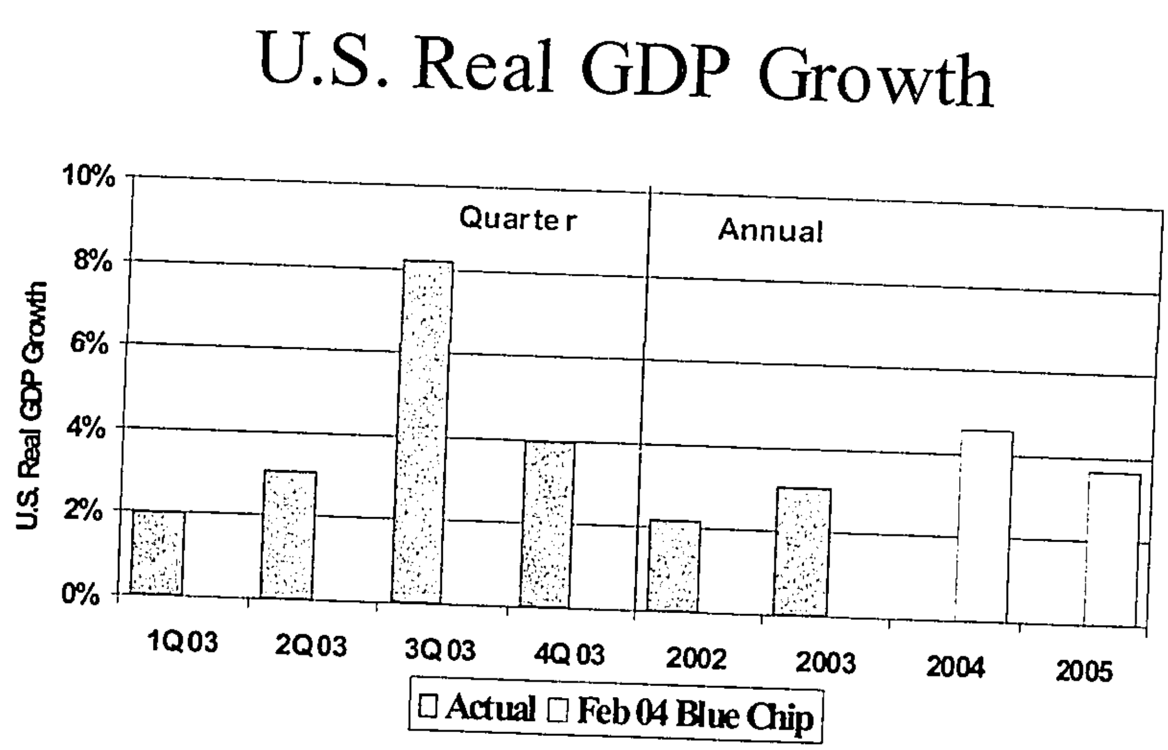

State Non-Ag Jobs
State Non-Ag Jobs (000s)
610
600
590
580
570
560
550
540
530
2001
2002
2003
2004
2005
2006
DBEDT 9/23/02
DBEDT 12/18/03
Source: DBEDT Quarterly Economic Outlook, September 23, 2002 and December 18, 2003


State Real GSP
GSP (mil 96$)
45000
44000
43000
42000
41000
40000
39000
38000
2001
2002
2003
2004
2005
2006
DBEDT 9/23/02
DBEDT 12/18/03
Source: DBEDT Quarterly Economic Outlook, September 23, 2002 and December 18, 2003

Military Forward Deployment/ Transformation Projects

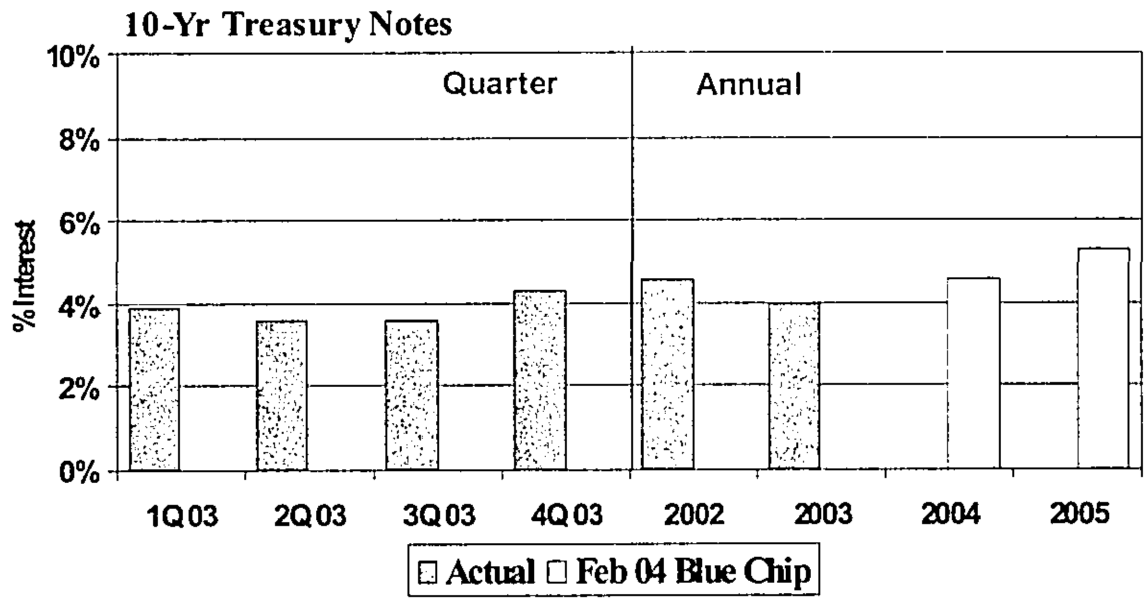
Description	No. of Personnel	No. of Dependents	Date
Stryker Brigade, Schofield	500-800	1600	May 2005
C-17s, Hickam	500	1000	Dec 2005
Aircraft Carrier, Pearl Harbor	3200	4800	July 2009
Carrier Air Wing, Barbers Point	2300	3450	2010

Reference: Projects, personnel, dependents: July 28, 2003, Honolulu Advertiser. Dates: Stryker – FY 2004 Military construction sheet, Information System Facility, p. 61, (http://www.asafm.army.mil/budget/fybm/fy04-05/mca fhha.pdf). C-17s – Sept 24, 2003, Honolulu Advert. Aircraft Carrier and Air Wing – Conversation with Rear Adm. Greenert, Deputy Cmdr. US Pacific Fleet, who indicated that the earliest a carrier could be homeported in Hawaii would be in 5 years.



Source: Blue Chip Economic Indicators, Vol. 29, No. 2, February 10, 2004

Interest Rates



Source: Blue Chip Economic Indicators, Vol. 29, No. 2, February 10, 2004

COMPARISON OF 2003 AND 2004 HAWAII ECONOMIC FORECASTS

	Jobs			Employment			Real Pers Income			CPI		
	2002	2003	2004	2002	2003	2004	2002 [5]	2003	2004	2002	2003	2004
Actual (p)	0.1	2.2		0.3			3.9			1.1	2.3	
BOH [1]		2.3	1.8					3.5	4.0		1.8	1.7
UHERO [2]		2.3	2.0		4.0	2.3		3.4	3.2		1.7	2.5
Laney [3]		2.5	2.0					3.5	2.7		1.8	2.1
DBEDT [4]		2.2	2.0					3.5	3.4		1.8	2.0

	Construction (Current $) [6]			Total Visitor Arrivals			Domestic Arrivals [7]			International Arrivals [8]		
	2002	2003	2004	2002	2003	2004	2002	2003	2004	2002	2003	2004
Actual (p)	13.5			1.4	-0.7		3.2	3.2		-1.4	-9.0	
BOH [1]					1.3	8.3		4.5	3.7		-6.3	14.7
UHERO [2]		7.3	17.4		-0.3	8.7		3.9	4.0		-13.5	24.0
Laney [3]					0.2	3.0						
DBEDT [4]					-0.6	6.0						

[1] Paul Brewbaker, Chief Economist (Bank of Hawaii), September 8, 2003, www.boh.com/econ/pdfs/econ1103.pdf
[2] Professors Carl Bonham and Byron Gangnes (University of Hawaii Economic Research Organization), November 12, 2003
[3] Professor Leroy Laney (Hawaii Pacific University) as reported from FHB annual economic forum, November 20, 2003
[4] Hawaii DBEDT Quarterly Forecast, December 18, 2003
[5] Using Honolulu CPI-U as deflator
[6] UHERO, UHERO Construction Outlook, Construction Put In Place, November 19, 2003
[7] UHERO projections for U.S. arrivals
[8] UHERO projections for Japan arrivals

ADEQUACY OF SUPPLY
Hawaiian Electric Company, Inc.
March 31, 2004

		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)	Reserve Margin (%) [[A-B]/B]	System Peak (net kW) [C] (IV)	Reserve Margin (%) [[A-C]/C]
Recorded					
2003	1,614,600	1,263,000	28%	N/A	N/A
Future					
2004	1,616,800 (V)	1,289,800	25%	1,279,500	26%
2005	1,619,800 (VI)	1,334,200	21%	1,309,000	24%
2006	1,622,400 (VII)	1,374,300	18%	1,334,200	22%

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 peaks values for the years 2004-2006 include the actual peak reduction benefits acquired in 1996 - 2002 and also include the peak reduction benefits acquired in 2003 of approximately 4,000 net-kW (net of free riders). Without this 2003 peak reduction benefit, the recorded system net peak of 1,263,000 kW in 2003, which includes 21,000 kW of standby load, would have been 1,267,000 kW.

(II) System Capability includes:

- HECO units at a total normal capability of 1,209,000 kW-net or 1,263,000 kW-gross.
- Firm power purchase contracts have a combined net total of 406,000 kW from Kalaeloa (180,000 kW), AES Hawaii (180,000 kW), and H-POWER (46,000 kW).
- Forecasted utility CHP impacts.[10] Without utility CHP Program impacts, annual system capabilities and corresponding annual reserve margins would be lower.
- 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.

[10] Utility CHP impacts are from a CHP forecast dated August 20, 2003. These impacts are at system level based on a T&D loss factor of 4.95%. 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.

(III) System Peak (Without Future DSM):

- The 2004-2006 annual forecasted system peaks are based on HECO's February 2004 Long Term Sales and Peak Forecast.
- Forecasted system peaks include the peak reducing impacts of third-party CHP (with utility CHP Program).
- Peaks include 21,000 kW of standby load for the following cogenerators:

Tesoro	19.0
Chevron	0.0
Pearl Harbor	2.0
	21.0 MW

- The HECO annual forecasted system peak is expected to occur in the month of October.
- In addition to acquired DSM, the forecasted system peaks are reduced by 4,000 kW of existing Rider I interruptible loads.

(IV) System Peak (With Future DSM):

- The 2004-2006 annual forecasted system peaks are based on HECO's February 2004 Long Term Sales and Peak Forecast.
- Forecasted system peaks include the peak reducing impacts of third-party CHP (with utility CHP Program).
- Peaks include 21,000 kW of standby load for the following cogenerators:

Tesoro	19.0
Chevron	0.0
Pearl Harbor	2.0
	21.0 MW

- The HECO annual forecasted system peak is expected to occur in the month of October.
- In addition to the acquired DSM, the forecasted system peaks for 2004-2006 include the peak reduction benefits of HECO's energy efficiency DSM programs, load management programs, and Rider I program. 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. The estimated peak reductions for these programs begin in 2004.

(V) System Capability at the end of 2004 is 1,617,700 kW (net), which includes additional CHP resources installed after the annual peak and prior to the end of the 2004.

(VI) System Capability at the end of 2005 is 1,620,300 kW (net), which includes additional CHP resources installed after the annual peak and prior to the end of the 2005.

(VII) System Capability at the end of 2006 is 1,623,500 kW (net), which includes additional CHP resources installed after the annual peak and prior to the end of the 2006.

LINDA LINGLE
GOVERNOR

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

CARLITO P. CALIBOSO
CHAIRMAN

WAYNE H. KIMURA
COMMISSIONER

JANET E. KAWELO
COMMISSIONER

February 9, 2004

William A. Bonnet
Vice President, Government and Community Affairs
Hawaiian Electric Company, Inc.
P. O. Box 2750
Honolulu, Hawaii 96840

Dear Mr. Bonnet:

Re: January 30, 2004 Request for Extension in filing the Adequacy of Supply Report

We received your letter, dated and filed on January 30, 2004, requesting an extension of time to file your 2004 Adequacy of Supply Report which is due on January 30, 2004 in accordance with paragraph 5.3a of General Order No. 7 ("G.O. No. 7"). You represent, among other things, that the extension of the filing date "will allow HECO to incorporate the results of its new sales and peak load forecast, that is currently under development and review in conjunction with its [IRP] process, in the reserve margin estimates for 2004-2006 future period to be covered by the 2004 Adequacy of Supply Report." You further represent that the Consumer Advocate does not object to this request.

We will treat your January 30, 2004 request as a motion for an extension of time ("Motion"), pursuant to Hawaii Administrative Rules ("HAR") §§ 6-61-23[1] and 6-61-41.[2]

Upon review of your Motion, we will grant your Motion, thereby approving your request for an extension of time (from January 30, 2004 to no later than March 31, 2004). Should you have any questions, please contact Kris Nakagawa at 586-2180.

Sincerely,

Carlito P. Caliboso
Chairman

CPC:KN:sl

c: Consumer Advocate

[1]Pursuant to HAR § 6-61-23(a)(1), the commission for good cause shown may order a period enlarged if a written request is made before the expiration of the period originally prescribed. Paragraph 1.2e of G.O. No. 7 further provides, in relevant part, that"[n]o electric utility shall deviate from these rules without specific authorization from the Commission except as herein provided."

[2]Pursuant to HAR § 6-61-41(e), motions that do not involve the final determination of a proceeding may be determined by the chairperson or a commissioner.

CORRECTION

THE PRECEDING DOCUMENT(S) HAS
BEEN REPHOTOGRAPHED TO ASSURE
LEGIBILITY
SEE FRAME(S)
IMMEDIATELY FOLLOWING

LINDA LINGLE
GOVERNOR

CARLITO P. CALIBOSO
CHAIRMAN

WAYNE H. KIMURA
COMMISSIONER

JANET E. KAWELO
COMMISSIONER

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

February 9, 2004

William A. Bonnet
Vice President, Government and Community Affairs
Hawaiian Electric Company, Inc.
P. O. Box 2750
Honolulu, Hawaii 96840

Dear Mr. Bonnet:

Re: January 30, 2004 Request for Extension in filing the Adequacy of Supply Report

We received your letter, dated and filed on January 30, 2004, requesting an extension of time to file your 2004 Adequacy of Supply Report which is due on January 30, 2004 in accordance with paragraph 5.3a of General Order No. 7 ("G.O. No. 7"). You represent, among other things, that the extension of the filing date "will allow HECO to incorporate the results of its new sales and peak load forecast, that is currently under development and review in conjunction with its [IRP] process, in the reserve margin estimates for 2004-2006 future period to be covered by the 2004 Adequacy of Supply Report." You further represent that the Consumer Advocate does not object to this request.

We will treat your January 30, 2004 request as a motion for an extension of time ("Motion"), pursuant to Hawaii Administrative Rules ("HAR") §§ 6-61-23[1] and 6-61-41.[2]

Upon review of your Motion, we will grant your Motion, thereby approving your request for an extension of time (from January 30, 2004 to no later than March 31, 2004). Should you have any questions, please contact Kris Nakagawa at 586-2180.

Sincerely,

Carlito P. Caliboso
Chairman

CPC:KN:sl

c: Consumer Advocate

---

[1]Pursuant to HAR § 6-61-23(a)(1), the commission for good cause shown may order a period enlarged if a written request is made before the expiration of the period originally prescribed. Paragraph 1.2e of G.O. No. 7 further provides, in relevant part, that"[n]o electric utility shall deviate from these rules without specific authorization from the Commission except as herein provided."

[2]Pursuant to HAR § 6-61-41(e), motions that do not involve the final determination of a proceeding may be determined by the chairperson or a commissioner.

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

bulgen file

c: 3Cs
KN
SI
LYK
RVD

January 30, 2004

William A. Bonnet
Vice President
Government and Community Affairs

FILED
2004 JAN 30 P 4: 23
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 is due within 30 days after the end of the year. HECO respectfully requests an extension to no later than March 31, 2004 in which to submit this report. The Consumer Advocate does not object to this request.

Extension of the filing date will allow HECO to incorporate the results of its new sales and peak load forecast, that is currently under development and review in conjunction with its Integrated Reserve Planning ("IRP") process, in the reserve margin estimates for the 2004 – 2006 future period to be covered by the 2004 Adequacy of Supply Report. Based on the preliminary results of the forecast process, there is a trend towards higher peaks (than those forecast in HECO's most recent long-term sales and peak load forecast), caused by higher expectations for local economic growth and by planned military forward deployments to Hawaii.

HECO's forecasted peak load for 2003 was 1289 MW, including 20 MW of standby load (or 1269 MW without the standby load). The evening peak on October 27, 2003 was 1284 MW without the standby load, or 15 MW more than the 2003 peak forecast, based on the August 2002 Sales and Peak Load Forecast, as reflected in the December 2002 Evaluation Report for HECO's 2nd Integrated Resource Plan ("IRP Plan"), which Report was filed December 31, 2002 in Docket No. 95-0347.

Load is expected to grow at a rate that is faster than previously forecasted over the next five-year period, although there may be a temporary lag due to the deployment of troops from the 25th Infantry Division at Schofield to Iraq. The higher rate of load growth should result from the improved economic outlook for the U.S. and Hawaii economies, a continuation of low interest rates, and a substantial increase in the amount of construction. Exhibit 1 shows the rising expectations for the U.S. economy in 2004 and for Hawaii real personal income and job growth for the 2001-2006 period, based on forecasts from the Blue Chip Economic Indicators ("Blue Chip") and the Department of Business, Economic Development and Tourism ("DBEDT"). Exhibit 2 shows the current expectation that interest rates will continue to be low through 2004, based on Blue Chip forecasts. Exhibit 3 shows that construction will increase substantially based on a forecast by Paul Brewbaker and Carl Bonham of the University of Hawaii Economic Research Organization ("UHERO"). The UHERO forecast cites the acceleration of private commitments to build and the rising importance of military-related housing construction as sources of growth.

The planned forward deployment of military units to Hawaii should further boost the Hawaii economy. As shown in Exhibit 4, the planned forward deployments include the formation of a Stryker brigade in May 2005, and the basing of eight C-17 jet transports at Hickam AFB in December 2005. At the far end of the next five-year period is the possible home porting of a Nimitz-class aircraft carrier at Pearl Harbor in 2009, and the possible basing of an air carrier wing at Barbers Point in 2010. The additions of military personnel and dependents could exceed 17,000.

The next long-term sales and peak load forecast for HECO is under development in conjunction with HECO's 3rd IRP cycle. HECO's IRP Load Forecasting Committee [which includes representatives from the Consumer Advocate, University of Hawaii College of Business Administration, DBEDT (Energy Resources & Technology and Research & Economic Analysis Divisions), and Life of the Land[1], among others] reviewed a preliminary long-term forecast on January 26, 2004. The preliminary forecast, which is subject to change based on new factual information obtained during the rest of the review process, projected that the system peak could be nearly 60 MW higher than the 2006 peak included in the August 2002 forecast, as shown in Exhibit 5. The review process is expected to be completed by February 20, 2004. A short time thereafter the forecast will be disseminated to HECO's IRP Advisory Group.

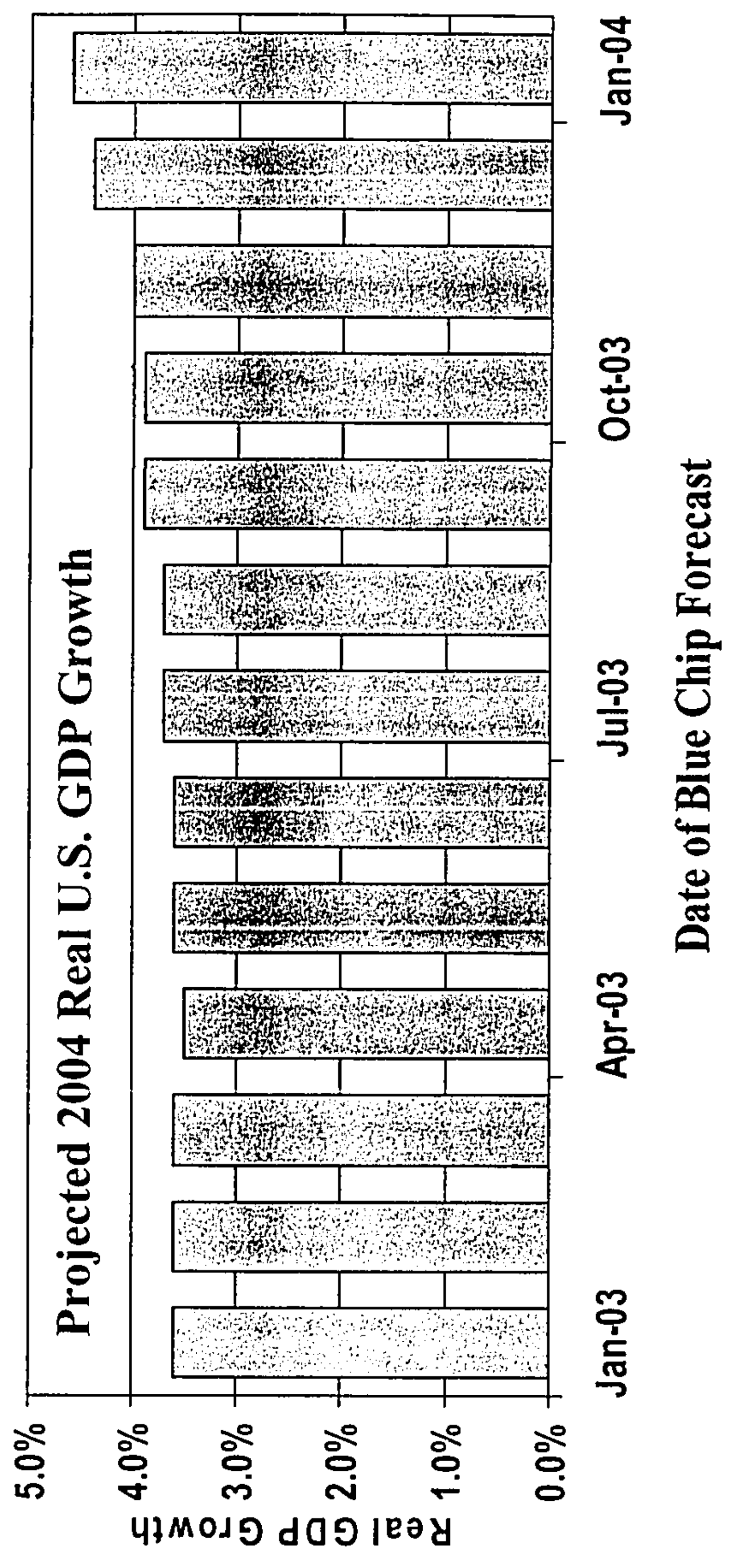
Very truly yours,

[signature]

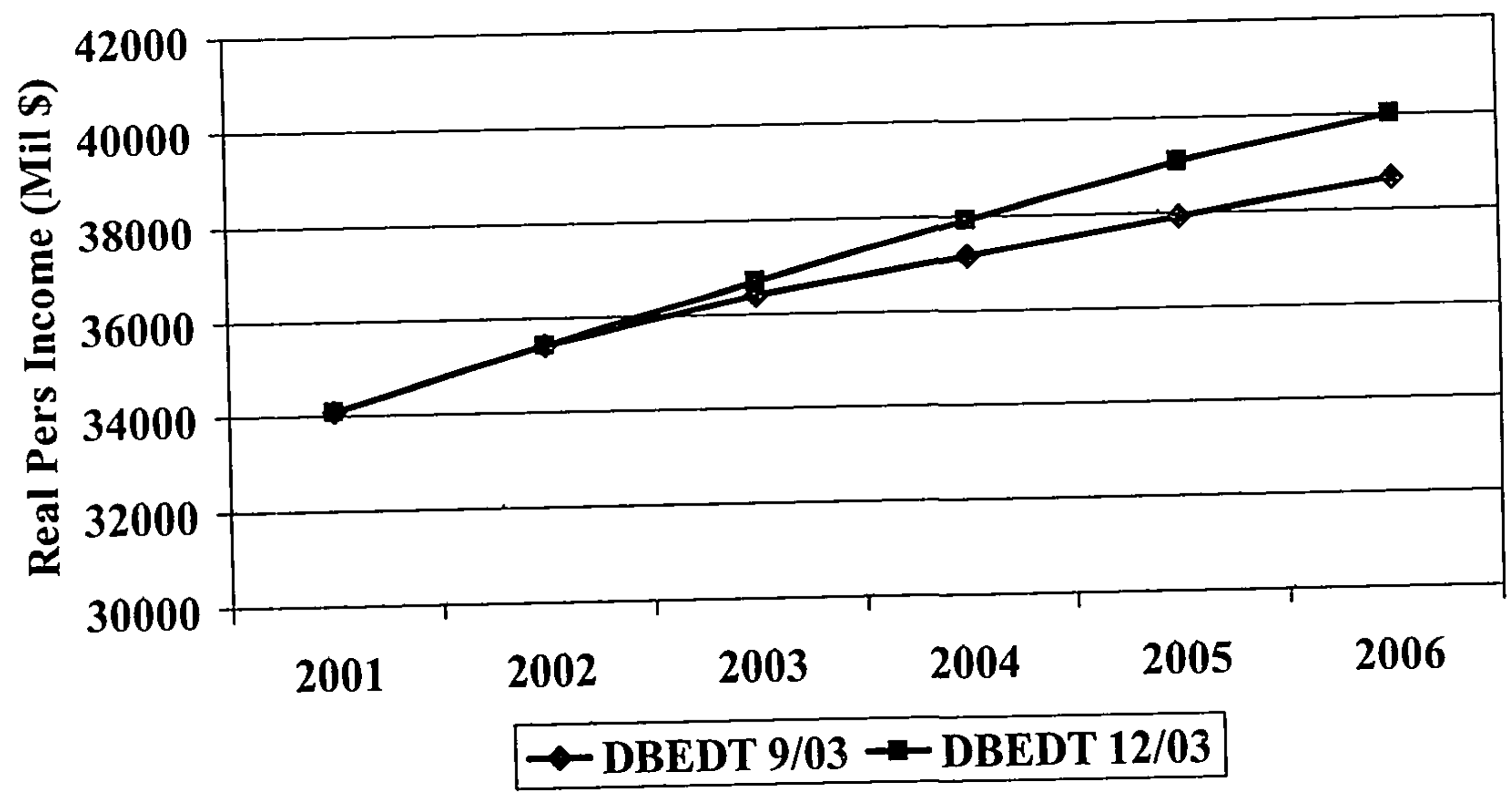
cc: Division of Consumer Advocacy

[1] Life of the Land is a member of the HECO IRP Load Forecasting Committee, but was not in attendance at the January 26, 2004 meeting.

Expectations for 2004 Rising

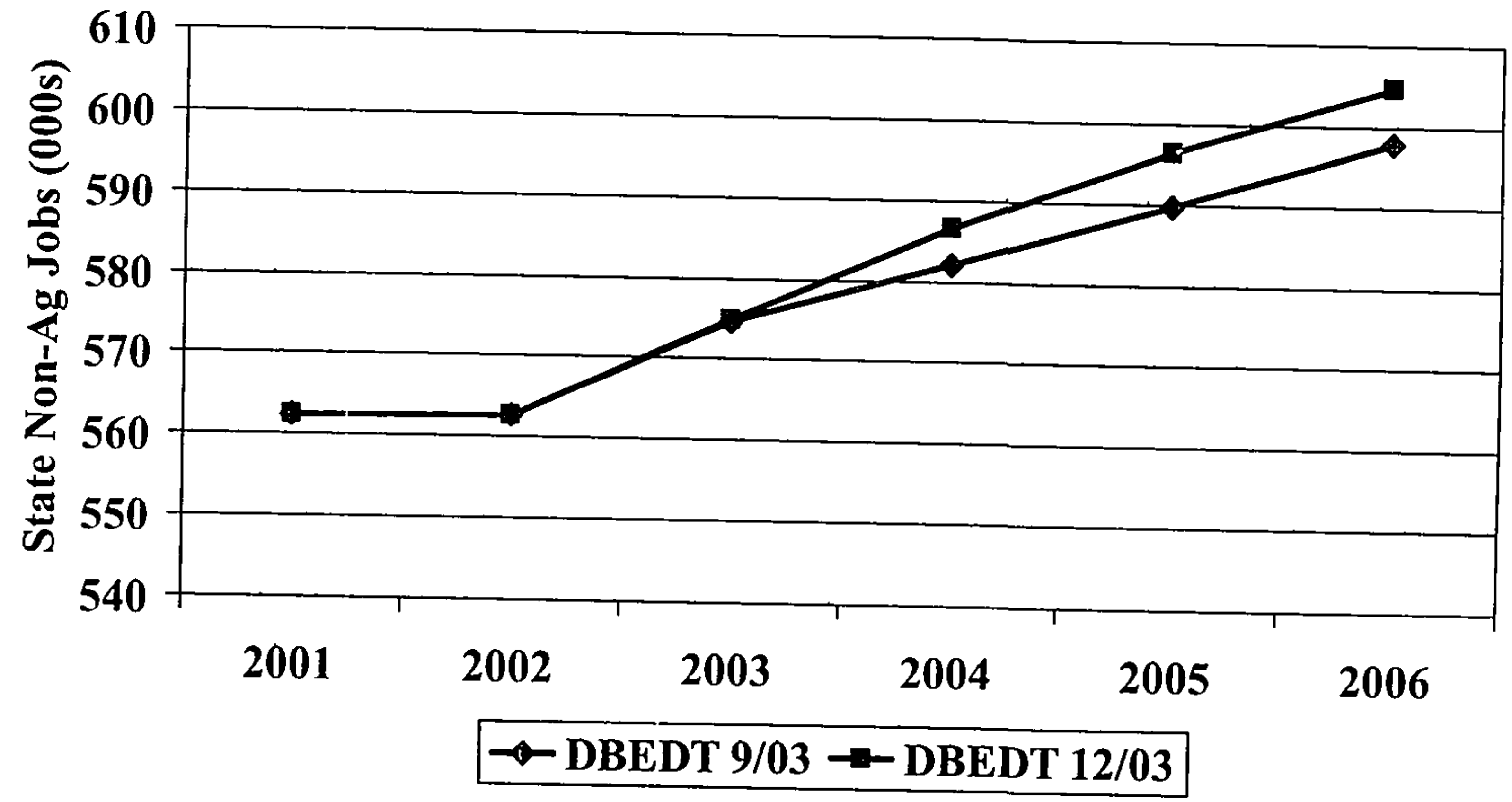


State Real Personal Income Outlook



Source: DBEDT Quarterly Economic Outlook

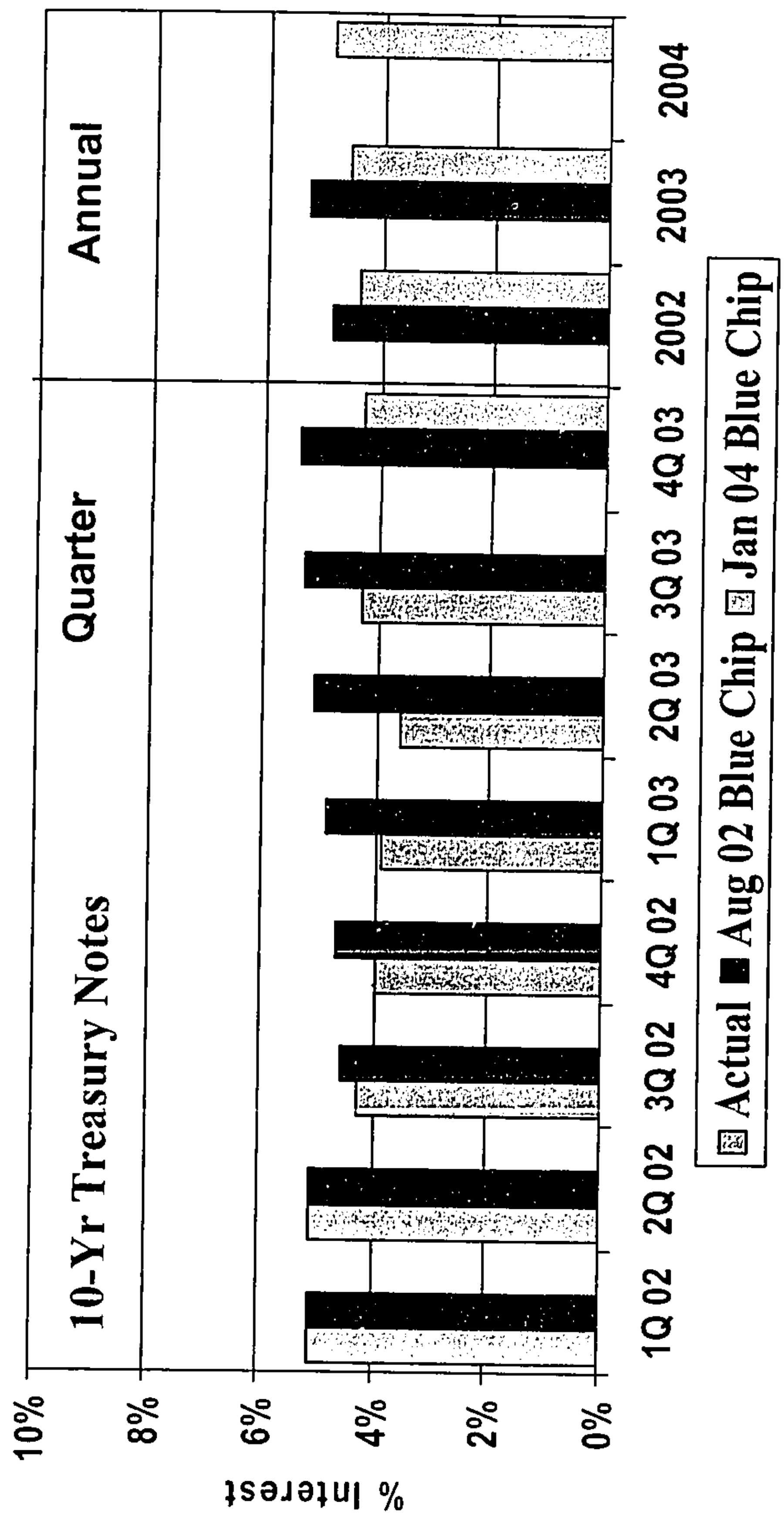
State Job Count Outlook



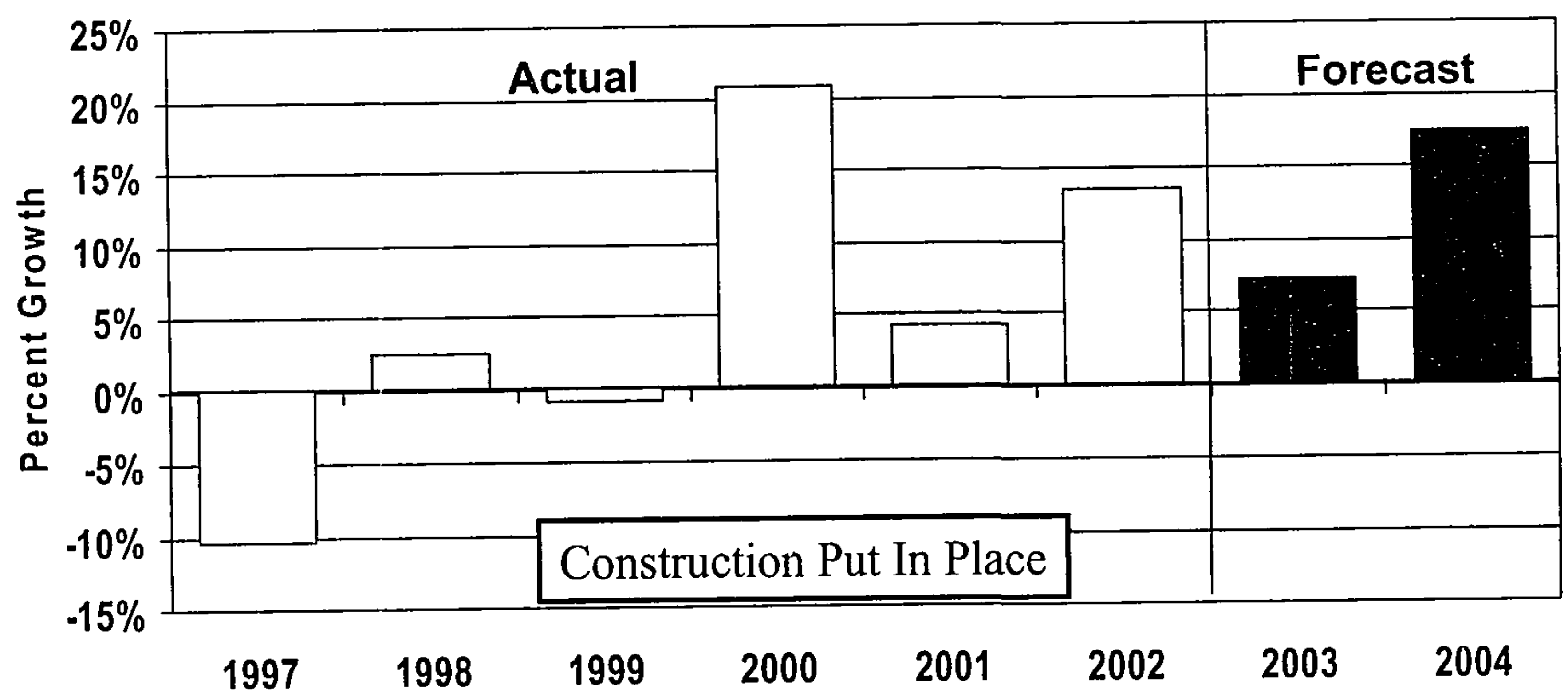
Source: DBEDT Quarterly Economic Outlook

EXHIBIT 2
PAGE 1 OF 1

Continued Low Interest Rates



Construction Booming



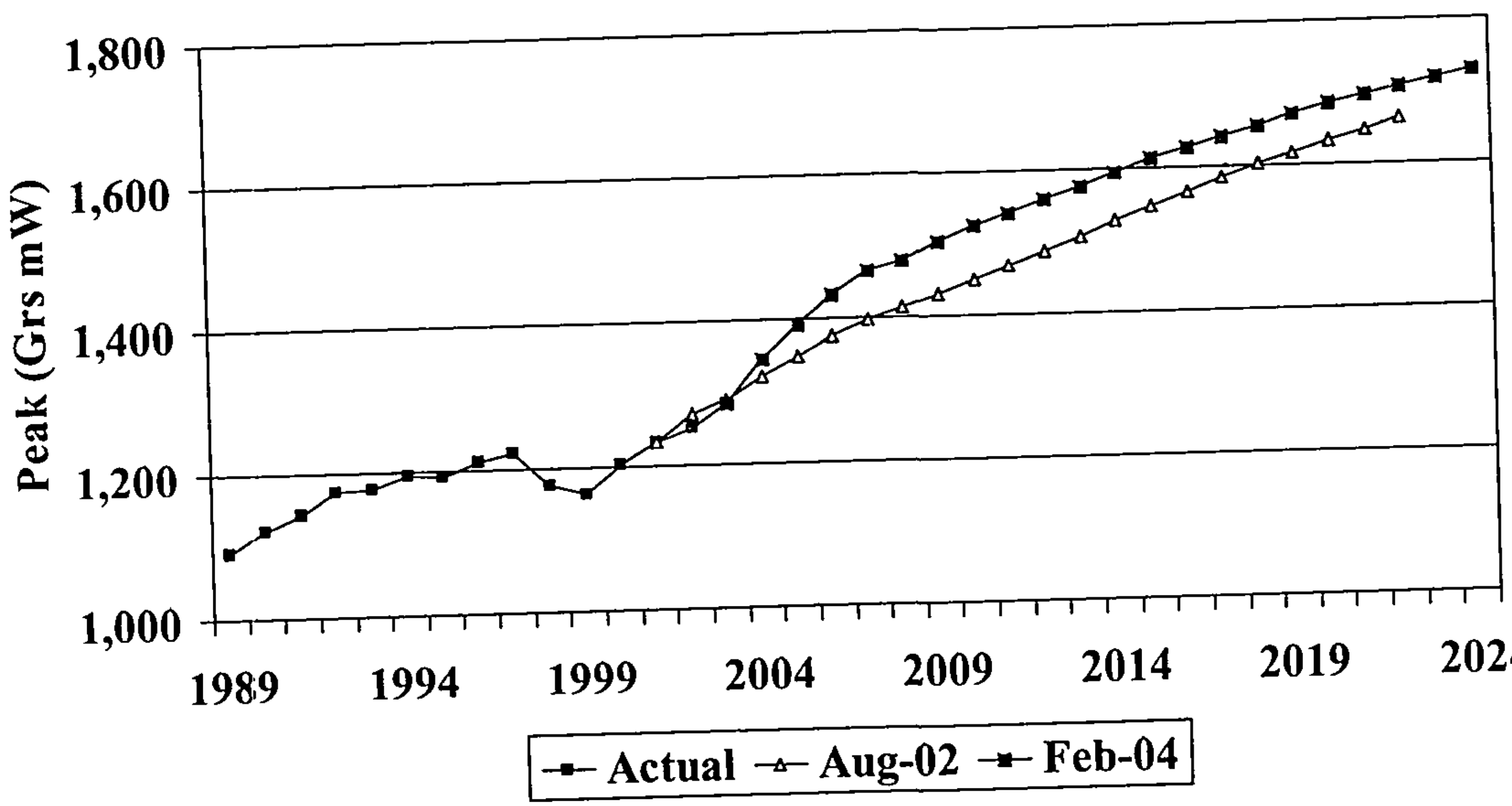
Source: UHERO, Nov 2003.

Military Forward Deployment

Description	No. of Personnel	No. of Dependents	Date
Stryker Brigade, Schofield	500-800	1600	May 2005
C-17s, Hickam	500	1000	Dec 2005
Aircraft Carrier, Pearl Harbor	3200	4800	July 2009
Carrier Air Wing, Barbers Point	2300	3450	2010

Reference: Projects, personnel, dependents: July 28, 2003, Honolulu Advertiser. Dates: Stryker – FY 2004 Military construction sheet, Information System Facility, p. 61, (http://www.asafm.army.mil/budget/fybm/fy04-05/mcafhha.pdf). C-17s – Sept 24, 2003, Honolulu Advert. Aircraft Carrier and Air Wing – Conversation with Rear Adm. Greenert, Deputy Cmdr. US Pacific Fleet, who indicated that the earliest a carrier could be homeported in Hawaii would be in 5 years.

Feb 04 Peak Higher Than Aug 02



Note: Reduced by Future DSM and CHP