Hawaiian Electric Company, Inc.

Docket No. 2006-0386
Application for Approval of Rate Increases and
Revised Rate Schedules and Rules

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HECO T-1
DOCKET NO. 2006-0386

TESTIMONY OF
ROBERT A. ALM

SENIOR VICE PRESIDENT
PUBLIC AFFAIRS
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Introductory Statement

INTRODUCTION

Q. Please state your name and business address.

A. My name is Robert A. Alm and my business address is 900 Richards Street, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Senior Vice President of Public Affairs at Hawaiian Electric Company, Inc. ("HECO"). HECO-100 provides my educational background and experience.

Q. What are your areas of responsibility in this testimony?

A. In this testimony, I will:

1) describe HECO's request in its application in this docket,
2) briefly summarize why there is a need for rate relief,
3) discuss certain policy matters related to this case, and
4) provide certain background information on the justification for the requested rate relief.

Q. Please provide your introduction to this rate case.

A. Rate cases are never easy to file. Disrupting our customers, even a little, is never our goal. We do, however, have obligations that we must meet, even if we cause some level of customer concern. Not to adhere to our obligations is unacceptable.

First and foremost is our obligation to serve. The public expects electrical service consistently and with quality. This may not be the most popular activity but it is our core activity and most of the increases sought are to recover costs incurred to maintain and improve our basic electrical service.

Second, we are also building a wider array of options into our system and in this case these include:

- Providing a direct financial incentive for those who use less electricity. We want and need to reward those who conserve electricity.

- Providing for a more distributed system of generation with smaller units in our system. I will discuss this in more detail below.
- Providing for a continuation of our programs to help our customers save money by operating more efficiently.

Paralleling this case but not directly tied to it are our other pending cases and work which provide for:

1. The biofueling of our proposed new generating unit in Campbell Industrial Park.
2. Our continuing work to site a wind farm in Kahuku.
3. Our work with the City and County of Honolulu on its rebid of the H-Power contract with one clear goal being to increase the level of energy (all renewables) that this plant gives us.
4. Our testing of biofuels in our other units with the goal of biofueling the rest of the Oahu system to the greatest degree possible.

We are in a new day at Hawaiian Electric. It requires us to do two things well, one is to keep the current system providing reliable power to businesses and residences alike and two is to transition the system to one that focuses on conservation, efficiency, renewable energy, and distributed systems. Both are critical, both require support, and we will deliver, on both.

Q. Why is it important for the Company to invest in facilities and expend sufficient amounts to maintain reliability of its electrical system?

A. We are currently living in a state with a robust economy and an ever growing population. However, our State government as well the City, are faced with a number of challenges in managing this growth. An aging infrastructure system (sewer, water, roads, highways, dams) is on the top of their list. We are no different.

As the sole provider of electricity for Oahu, we have an ongoing commitment and responsibility to invest in and maintain our electric system. Our infrastructure is critical to provide the service our customers expect and deserve. "No action" would pose a major risk to the electrical system and ultimately to our customers.

In the business we are in, we literally affect the lives of every single person on this island. We all sometimes take it for granted, but every moment of every day we depend on reliable electric service in our homes and at our place of business. Getting ready for work, from making a cup of coffee or breakfast in the morning to catching an elevator to getting to your workplace, all requires use of electricity.

Reliability of our electric system is also key to the day to day functioning of our public safety and security of our State and City and in emergencies. Reliability is also critical to Oahu's economy. Thriving industries such as tourism, construction, film, and biotech are relying on us to provide the electricity that they need in order to do business here in Hawaii.

RATE RELIEF REQUESTED

Q. What are HECO's current effective rates and charges?

A. HECO's current effective rates are the result of our existing "base" rates, plus the interim rate increase approved in HECO's pending 2005 test year rate case, Docket No. 04-0113. HECO's existing base rates are the result of the Commission's Final Decision and Order ("D&O") No. 14412 issued December 11, 1995, in HECO's 1995 test year rate case (Docket No. 7766), and D&O No. 20292 issued July 1, 2003 and Order No. 20310 issued July 9, 2003, in Docket No. 03-0126, which implemented a temporary rate reduction made possible as a result of a capacity charge reduction due to the amendment of HECO's power purchase agreement with AES Hawaii, Inc. The impact of the capacity charge reduction was included in HECO's revenue requirements for the 2005 test year in Docket No. 04-0113, and the temporary rate reduction will be discontinued when new rates are set in that rate case. In addition, the current effective rates include the surcharges resulting from the interim rate increase approved by the Commission in Interim Decision and Order No. 22050 issued September 27, 2005, in Docket No. 04-0113. As of the date of this filing, the final decision and order for Docket No. 04-0113 is pending. Upon issuance of the final decision and order in that proceeding, HECO will terminate the interim rate increase surcharges and implement revised rates in accordance with the Commission's decision and order.

Q. What rate increase is HECO requesting in this rate case?

A. HECO is requesting a revenue increase of $99,556,000 (based on August 1, 2006 fuel oil prices), or 7.1%, over revenues at current effective rates for a normalized 2007 test year.

Q. What would the revenue increase be if revenues from the interim rate increase surcharges were excluded from the rate relief calculation?

A. If the interim rate increase surcharges are excluded from the Company's revenues (i.e., revenues at "present" rates), the revenue increase would be $151,505,000.

Q. What would be a fair and reasonable rate of return on common equity to determine HECO's revenue requirements in this docket?

A. Based on the comprehensive analysis and opinion of Dr. Roger Morin, Professor of Finance at the College of Business, Georgia State University, the expert witness retained by HECO to advise it on this matter, a fair and reasonable return on common equity for HECO for the 2007 test year would be 11.25%.

Q. Please explain any major exclusions from this rate case.

A. The revenue requirements in this rate case exclude incremental demand-side management ("DSM") costs that HECO currently recovers through the DSM component ("DSM surcharge") of the Integrated Resource Planning ("IRP") Cost Recovery Provision. HECO has excluded DSM surcharge revenues and the associated costs from the 2006 test year because Docket No. 05-0069 (the Energy Efficiency proceeding) is currently in progress and is addressing a number of policy issues with respect to DSM programs in the state, including on the island of Oahu. The issues include what the cost recovery mechanism for DSM programs should be (e.g., whether the costs should be recovered through base rates or a separate surcharge). Because of this, HECO has excluded from its 2007 test year revenue requirements the incremental DSM costs currently recovered through the DSM surcharge. Because the DSM costs recovered through the surcharge are excluded, the DSM surcharge revenues are also removed from the case.

Q. How is HECO requesting that the increase be granted?

A. HECO requests that the general increase and revisions to its rate schedules and rules be granted in two steps:

1) An Interim Rate Increase equal to an increase in rates to which the Commission believes HECO is "probably entitled" based on the evidentiary record before it, in accordance with Hawaii Revised Statutes ("H.R.S.") Section 269-16(d). HECO will determine the amount that it is requesting as an interim increase at the close of the evidentiary hearing, based on the evidence before the Commission.

2) A Final Increase when the Commission issues its final decision and order to provide for the amount of the total requested revenue increase not included in the Interim Rate Increase.

HECO requests that the rate design changes requested in the Application, and described in HECO T-20, be implemented when the Final Increase is implemented.

Q. When does HECO anticipate that an Interim Rate Increase would be granted in this proceeding?

A. Based on the processing of prior rate cases, HECO is targeting completion of the evidentiary hearing in the fourth quarter of 2007. HECO requests an Interim Rate Increase as soon as practicable after the evidentiary hearing is held in this proceeding. HECO's Results of Operations show that HECO has a need for a rate increase at the beginning of the 2007 test year. Therefore, HECO requests an expedited processing of this docket, such that the evidentiary hearing is completed and an interim order is rendered as soon as practicable.

Q. If the Commission were to grant an Interim Rate Increase in the fourth quarter of 2007, will HECO be in a position to earn the return found to be reasonable by the Commission?

A. No. In 2007, HECO will not have a realistic opportunity to earn the return found to be reasonable by the Commission, because by the time the hearings are held, the year will be near its conclusion. Under the test year concept, the amount of the rate increase approved by the Commission in a general rate case, which uses an average rate base, generally is the increase in revenues necessary <u>at the beginning of the test year</u>. Unless a rate increase is effective at the beginning of a test year, the utility <u>will not</u> have an opportunity to earn the fair rate of return on rate base determined to be fair and reasonable by the Commission, based on the estimated results of operations for the normalized test year. If the rate increase is received later in the test year, the amount of the rate relief <u>actually</u> received in the test year will be proportionately lower than that determined to be necessary.

Q. What does Section 269-16(d) provide with respect to the timing of an interim increase?

A. Section 269-16(d) contemplates that the Commission "shall make every effort to complete its deliberations and issue its decision as expeditiously as possible and before nine months from the date the public utility filed its completed application … " If the Commission has not issued a <u>final</u> decision on a public utility's rate application within the nine-month period, the Commission "shall render an interim decision" within one month after the expiration of the nine-month period. The Commission may postpone its interim rate decision 30 days if the Commission considers the evidentiary hearing incomplete. Thus, Section 269-16(d) contemplates that:

1) the normal time to complete the evidentiary hearing and to issue a final decision in a rate case will be nine months or less,
2) an interim decision normally must be issued within ten months if a final decision is not issued within nine months, and
3) an interim decision must be issued within 11 months even if the evidentiary hearing takes more than 10 months to complete.

Q. Can the Commission render an interim decision and grant an interim rate increase prior to expiration of the nine-month period?

A. Yes. The Commission issued Interim Decision and Order No. 13431 ("Interim D&O 13431") on August 8, 1994 in Docket No. 7764, Hawaii Electric Light

Company, Inc.'s ("HELCO") 1994 test year rate case, just over eight months after the filing of HELCO's completed application on November 30, 1993. In Interim D&O 13431, the Commission found that:

> "HELCO filed its application in this docket on November 30, 1993. Thus, the nine-month period in this proceeding will expire on August 31, 1994. Although this period has not yet expired, the commission will now issue an interim decision, since the parties agree that, based on the record adduced at the evidentiary hearing held on July 26 and 29, 1994, it is probable that HELCO is entitled to some rate relief and it is unlikely that the commission will be able to complete its deliberations or issue a final decision and order in this proceeding by August 31, 1994. Further, the test year in this rate proceeding is calendar year 1994. Seven months of the test year have already expired. Unless interim rate relief is granted now, HELCO will not secure the degree of benefit that it would otherwise derive from any rate relief the commission may ultimately grant.
>
> The commission does not read HRS §269-16(d) as prohibiting the issuance of interim relief prior to the expiration of the nine-month period. The statute simply requires that an interim decision be issued, if commission deliberations are not concluded within the nine-month period."

Q. What will HECO's return on rate base be in 2007 without rate relief?

A. Absent rate relief, HECO's return on rate base is expected to be 4.36% for the normalized test year, assuming the interim rate increase surcharges continue to be in effect (or 1.98% without the revenues from the interim rate increase surcharges). In HECO's last rate case, Docket No. 04-0113, which used a 2005 test year, the Commission found an 8.66% return on rate base to be reasonable for interim decision purposes.

<u>Implementation of Rate Increase</u>

Q. How does HECO propose to implement the proposed rate increase?

A. HECO is proposing that only the Final Increase in this proceeding involve base rate changes. The Interim Rate Increase implemented prior to the final step would be structured as a surcharge to the various classes based on a percentage of the customer's bill (exclusive of Energy Cost Adjustment Charges and other surcharges). The allocation to each rate schedule would be on an equal percentage increase. The allocation of the proposed increase over present rates to each rate schedule is shown on HECO-111. The allocation of the proposed increase over current effective rates to each rate schedule is shown on HECO-112.

Q. Is this proposed implementation of the Interim Rate Increase consistent with past practice before the Commission?

A. Yes. This implementation method was used for recent interim increases for HECO in Docket No. 04-0113, HELCO in Docket Nos. 99-0207 and 94-0140 and for Maui Electric Company, Limited ("MECO") in Docket Nos. 94-0345 and 97-0346.

NEED FOR RATE RELIEF

Q. What are the principal factors driving the need for HECO to increase its rates?

A. The rate case is primarily driven by the need for the following:

1) Fulfill the capacity needs of Oahu's customers
2) Maintain service quality and fulfill infrastructure needs
3) Maintain the Company's financial integrity

Fulfilling the Capacity Needs of Oahu's Customers

Q. Please describe HECO's ability to fulfill the electrical capacity needs of Oahu's customers.

A. As explained in other filings before the Commission, HECO has sufficient generation capacity, both from its generating units and those from independent power producers ("IPPs"), to meet the forecasted peak demands of electricity use on Oahu. However, the demand for electricity on Oahu has increased to the point that HECO is experiencing a reserve capacity shortfall. "Reserve capacity shortfall" is defined as the amount of additional firm generating capacity or equivalent reductions in load from load management and energy efficiency demand-side management ("DSM") programs and/or combined heat and power ("CHP") installations needed to restore the generating system reliability above HECO's reliability guideline of 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. Although HECO may have enough generation capacity to satisfy electrical demand on a day-to-day basis, if there is a forced outage of one or multiple generating units (owned by HECO or an IPP), there may not be enough reserve capacity in other units to make up for that sudden loss of generation and avoid a major outage.

Q. What is the current reserve capacity shortfall projection?

A. HECO's Adequacy of Supply ("AOS") Report, filed on March 6, 2006, projected a reserve capacity shortfall of approximately 170 to 200 megawatts ("MW") in the 2007 to 2009 period. As explained by Mr. Ross Sakuda in HECO T-4, the Company updated its generating system reliability analysis and concluded that even with a lower peak forecast, issued in August 2006, and an additional amount of distributed generation ("DG") units, the reserve capacity shortfall would range from 90 to 130 MW in the 2006 to 2010 timeframe.

Q. How does HECO plan to address the reserve capacity shortfall and the energy demands of Oahu's consumers?

A. In HECO T-4, Mr. Sakuda explains that HECO plans to address these capacity needs through a portfolio of energy solutions. The solutions that have the greatest impact on the test year revenue requirement are the following:

1) Maintaining and improving the availability of HECO's existing generation as addressed by Mr. Dan Giovanni in HECO T-6.
2) Installation of distributed generation ("DG") units at HECO sites and distributed standby generators ("DSG") at customer sites, as discussed by Mr. Giovanni in HECO T-6.

The other solutions in the portfolio that have lesser impact on the 2007 test year but that are nonetheless crucial to meeting Oahu's capacity needs are:

3) Continuation of the energy efficiency DSM and load control programs as discussed by Mr. Alan Hee in HECO T-9.
4) Implementation of renewable energy projects.
5) Installation of a 113 MW simple cycle combustion turbine in 2009.

I will discuss each of these solutions below and describe the impact on the 2007 test year.

<u>Maintaining and Improving the Availability of HECO's Existing Generation</u>

Q. Please describe HECO's generation reliability performance.

A. In 2006, EPRI Solutions, Inc. ("ESI") issued a report on HECO's Power Supply operations, maintenance and outage management programs and observed that over the past two decades the HECO steam fleet has performed exceptionally well in terms of equivalent availability factor ("EAF") and equivalent forced outage rate ("EFOR") measures compared to industry averages but there has been a trend of decreasing availability and reliability within the past five years, up to 2005.

In its March 6, 2006 AOS Report, HECO projected higher EFORs than those achieved historically based on recent experience and due to an expectation of continued constraints on maintenance flexibility, continued aging of the generating units, anticipation of more catastrophic forced outage events and deratings resulting from the cycling operation of certain units and their auxiliary equipment, and more frequent and longer duration overhauls and maintenance outages.

Q. What has HECO's EAF and EFOR performance been in 2006?

A. HECO's EAF and EFOR measures improved in 2006 to levels better than the measures in recent years.

Q. What will HECO need to do to continue to achieve its desired levels of reliability?

A. To maintain service reliability, Mr. Giovanni explains in HECO T-6 that among other things, the Company needs to increase its operational staff to allow for 24 hours a day, 7 days a week operation of all steam generating units and to bolster the station and travel maintenance crews to take care of HECO's aging fleet of generators.

Q. Has HECO implemented 24x7 operations for all of its steam generating units?

A. Yes. HECO returned Waiau 3 and 4 to 24x7 operations on March 21, 2005 and Honolulu 8 and 9 to 24x7 operations on June 27, 2005. As a result, all fourteen of its steam-electric generating units are on 24x7 operations.

Q Will HECO need to increase its staffing to operate all steam-electric units 24x7?

A. Yes. The Company requires 156 employees in its Power Supply Operations Division to support 24x7 operation of all of its steam-electric units. The average number of employees in the Operations Division in 2005 and 2006 was about 144. Operating without the needed level of employees would mean requiring existing personnel to work excessive overtime and deferring training and vacation. The vacant positions cannot be filled by outside contractors because of the unit-specific training and qualification that are required for operators.

Q. Will there be increases in staffing in other departments at HECO for the 2007 test year?

A. Yes. Ms. Faye Chiogioji will provide an overview of the staffing increases in HECO T-14. Various witnesses will discuss the need for staffing increases in their departments in their respective testimonies.

Q. You earlier mentioned the continuing age of the generating units. Please describe the age of the generating units and associated infrastructure on Oahu.

A. As described in the testimony of Mr. Dan Giovanni, HECO T-6, the average age of HECO's six cycling steam units and eight baseload steam units are 51.3 years and 36.3 years, respectively. HECO's two peaking combustion turbines, Waiau 9 and 10, are 33 years of age. The IPP facilities, H-Power, Kalaeloa and AES are 16, 15, and 14 years of age, respectively. Some of the Waiau Power Plant infrastructure still in use today dates back to 1938. The Honolulu Power Plant infrastructure dates back to 1930.

Q. What has been the impact of running aging units harder?

A. As the units become older and the operating duties become more severe, the wear and tear on the equipment increases and the maintenance required to sustain acceptable levels of performance becomes more costly. HECO is managing the effects of its aging equipment through a comprehensive maintenance program that includes planned and unplanned maintenance work and has been able to operate these units with a relatively high degree of reliability. This will increase the cost of operating and maintaining these units but it avoids the more costly alternative of replacing existing generating capacity.

Q. Has HECO determined what would be required to adequately maintain its aging fleet of generators?

A. Yes. Based, in part on the ESI study, HECO has concluded that it can more effectively perform all the required maintenance, day and night, by bolstering its existing station and travel maintenance crews instead of creating a new night maintenance crew. Any and all maintenance personnel will be scheduled to work night shifts as necessary to perform critical station and planned maintenance work. Thus, durations of planned and maintenance outages will be less in the future with a full complement of maintenance personnel.

Q. What are the staffing requirements for a full complement of maintenance personnel?

A. Based on the maintenance work load over the past few years, the long-term planned maintenance schedules, experience using contractors, the backlog of maintenance work orders, and the anticipated work for future years, HECO requires 161 maintenance positions in the 2007 test year. As of September 2006, there were 134 employees in this area.

Q. What have been the consequences of operating with less than a full complement of maintenance personnel?

A. HECO has had to use contractors and increase the amount of overtime but this has not been sufficient as the backlog of lower priority work has grown considerably. There is a need to hire the appropriate number of employees in both the Operations and Maintenance Divisions in order to maintain service reliability at acceptable levels.

<u>Installation of Distributed Generation Units</u>

Q. How do DG units help mitigate the reserve capacity shortfall?

A. DG units provide HECO with dispatchable, firm generating capacity for peaking purposes.

Q. Please describe HECO's efforts to install DG units on Oahu.

A. HECO has aggressively pursued the installation of DG units. The installations include the following:

1) Nine leased 1.64 MW diesel generating units totaling 14.76 MW installed at HECO's Ewa Nui Substation, Helemano Substation, and Iwilei Tank Farm and placed in service in 2005;
2) Three leased 1.64 MW diesel generating units totaling 4.92 MW installed at HECO's Campbell Estates Industrial Park ("CEIP") Substation and placed in service in November 2006;
3) Three leased 1.64 MW diesel generating units being installed at HECO's Kalaeloa Poleyard that are projected to be in service in December 2006;
4) Three leased 1.64 MW diesel generating units totaling 4.92 MW to be installed at HECO's Ewa Nui Substation in the first quarter of 2007; and
5) One 1.64 MW utility-dispatchable, customer-owned standby generator unit to be installed at Kaiser Foundation Hospital Moanalua Medical Center ("Kaiser Hospital") in the third quarter of 2007.

The costs associated with these units are included in the revenue requirements of this rate case.

Q. Did the interim rate increase awarded by the Commission in Docket No. 04-0113 provide recovery for the costs of any of these DG units?

A. Yes. As part of a September 16, 2005 stipulated settlement, HECO, the Division of Consumer Advocacy and the Department of Defense agreed to include one-half of the annual costs of the nine DG units installed in 2005 as the test year estimate for substation distributed generation expenses. Interim Decision and Order No. 22050 accepted the parties' agreements, including the agreement on DG expenses, for the purposes of calculating the interim rate increase. In this proceeding, the total annual costs of these units and the units added in 2006, as well as the partial year costs for the units to be added in 2007, are included in the test year revenue requirement.

Continuation of the Energy Efficiency DSM And Load Control Programs

Q. What is the impact of HECO's DSM and load management programs on the 2007 test year.

A. As I explained earlier, the Company has excluded from the 2007 test year the incremental DSM and load management program costs that are currently recovered through the DSM surcharge and the associated DSM surcharge revenues, because recovery of DSM and load management program costs is one of the issues currently being addressed in the Energy Efficiency proceeding (Docket No. 05-0069). HECO recovers almost all of the total DSM and load management program costs through the DSM surcharge. However, HECO recovers the remaining DSM and load management program costs through base rates and as a result these costs are reflected in the 2007 test year revenue requirement.

Q. Were incremental DSM and load management costs included in the test year revenue requirement of HECO's last rate case?

A. Initially, yes. In HECO's 2005 test year rate case (Docket No. 04-0113), DSM and load management were essential components of the Company's application for a general rate increase. The Commission subsequently issued Order No. 21698 that bifurcated the proceeding by initiating a separate Docket No.05-0069 to address statewide DSM and load management issues, including the recovery of the program costs. As a result, the Company adjusted its test year revenue requirement in Docket No. 04-0113 by excluding the incremental DSM and load management program costs. A decision and order in Docket No. 05-0069 is pending.

Q. What is the status of HECO's provision of DSM and load management programs?

A. As Mr. Alan Hee describes in HECO T-9, there are nine DSM programs:

1) Commercial and Industrial Energy Efficiency ("CIEE")
2) Commercial and Industrial New Construction ("CINC")
3) Commercial and Industrial Customized Rebate ("CICR")
4) Residential Efficient Water Heating ("REWH")
5) Residential New Construction ("RNC")
6) Energy Solutions for the Home ("ESH")
7) Commercial and Industrial Direct Load Control ("CIDLC")
8) Residential Direct Load Control ("RDLC")
9) Residential Low Income ("RLI")

The first eight programs are existing programs (CIEE, CINC, CICR, REWH, RNC, ESH, CIDLC, and RDLC), while the last program (RLI) is new. HECO has requested Commission approval of enhancements to the CIEE, CINC, CICR, REWH, RNC, and ESH programs, and approval of the new RLI program in the Energy Efficiency Docket. Interim Decision and Order No. 22420, issued on April 26, 2006, approved on an interm basis the compact fluorescent lamp ("CFL") rebate component of the ESH program. The 2007 test year sales impact of these programs is a reduction of about 54 gigawatt-hours.

HECO filed a RDLC program modification with the Commission on November 22, 2006, requesting approval to add a residential central air-conditioning load control program element to the program. HECO plans to file modifications to the CIDLC program by the end of 2006.

Continuation of the energy efficiency DSM and load control programs is an important part of HECO's energy portfolio.

Implementation of Renewable Energy Projects

Q. Please explain the Company's position on the implementation of renewable energy in Hawaii.

A. HECO recognizes the importance of renewable energy to Hawaii's future and has intensified its efforts to introduce renewable energy projects in this state. These efforts extend well beyond the 2007 test year and will include projects of major importance such as the use of biofuels at the new generating station at Campbell Industrial Park and a wind farm in Kahuku. HECO is also aware of renewable projects being considered by independent power producers such as the possible expansion of the City and County of Honolulu's H-Power municipal solid waste power plant, possible wind farm projects and an ocean thermal energy conversion project on Oahu. These projects are in the initial stages and will not come to fruition until after the 2007 test year but they will affect future rate cases.

Q. Are there any renewable energy-related costs in HECO's 2007 test year revenue requirement?

A. Yes. There are a number of renewable-related initiatives that are included in the 2007 test year revenue requirement, such as a 155 kilowatt photovoltaic system at HECO's Ward Avenue facility, which Mr. Daniel Ching discusses in HECO T-5. Mr. Dan Giovanni in HECO T-6 and Mr. Bruce Tamashiro in HECO T-13 discuss the renewable research and development projects that the Company has included in its 2007 test year estimates.

Installation of a 113 MW Simple Cycle Combustion Turbine in 2009

Q. What is the status of installing a new combustion turbine generating unit at

Campbell Industrial Park?

A. In June 2005, HECO filed an application for the installation of the new generating unit in Docket No. 05-0145. The Commission held evidentiary hearings in December 2006. The Company also filed an application in Docket No. 05-0146 for a package of community benefit measures to mitigate the impact of the new generating unit on the surrounding communities. The Commission held evidentiary hearings in November 2006. The new unit is scheduled to go into service in 2009.

Q. Will the installation of the new unit have any impact on the 2007 test year?

A. Yes. As indicated in the direct testimony of Mr. Ken Morikami (HECO T-16), the 2007 test year includes in property held for future use the cost of purchasing the property for the new generating station.

Q. Please summarize HECO's efforts to meet the electrical capacity needs of Oahu's customers.

A. HECO must utilize a portfolio of solutions to fulfill Oahu's capacity needs and to address the current reserve capacity shortfall. These solutions extend beyond the test year and the impacts of some of them will not be realized for a number of years. However, in the 2007 test year it will be critical for the Company to have the needed resources to operate and maintain its generating units at desired levels of reliability and to utilize DG units to help mitigate capacity needs.

<u>Maintaining Service Quality and Fulfilling Infrastructure Needs</u>

Q. In the preceding section you discussed how the Company is addressing capacity needs on Oahu. What else is HECO doing in the 2007 test year to maintain service quality and reliability of its electrical service to its customers?

A. First, the Company is continuing to invest in the electrical infrastructure on this island. As discussed by Mr. Ken Morikami in HECO T-16, HECO projects its plant additions to be in excess of $200 million in 2006 and 2007.

Q. What projects are included in the plant additions for 2006 and 2007.

A. There are more than 300 projects in the 2006 and 2007 plant additions which impact all facets of the Company's operations. These include the following:

- Dispatch Center and Energy Management System ("EMS") - The Dispatch Center and EMS project provide a more robust and technically advanced EMS that supplies better and more complete information needed to operate HECO's generation and delivery systems. The Dispatch Center furnishes physical safeguards to ensure better protection from natural or terroristic incidents.
- Waikiki Rehabilitation Program, Project One – This project addresses deteriorated underground cable in targeted areas of Waikiki. Numerous cable failures in the Waikiki Project One area pointed to the need for planned cable replacement. Since the completion of the Project One cable replacements, there have been no cable failures in the Project One area.
- New substations and related subtransmission lines at Ford Island (Pearl Harbor) to support military requests for redevelopment of the island, Mamala to support upgrades of electrical facilities at Hickam Air Force Base and Ocean Pointe for new residential development in Ewa Beach.
- Boiler control upgrades to the Kahe 3 and Kahe 4 generating units to increase the reliability of these units.

- Equipment upgrade and replacement projects for the Waiau 4, 7, 8 and 10, Kahe 1 and 3, and Honolulu 9 generating units to maintain the reliability of HECO's aging units.

Q. What other items are included in the 2006 and 2007 plant additions?

A. The 2006 and 2007 plant additions also include investments to replace overhead and underground transmission and distribution cables, transformers, utility poles, meter equipment, service connections and other facilities. Similar to the Company's generating units, the transmission and distribution plant is also aging. These investments are necessary to maintain reliable service to existing customers and fulfill new customer installations.

Q. Does the 2007 test year include other programs and activities that will support reliable electrical service to customers?

A. Yes. In HECO T-7, Mr. Robert Young describes the following:

- Vegetation Management – The Company will be increasing its efforts to keep corridors clear of vegetation that could come into contact with the Company's transmission and distribution lines and cause service outages. Since 2003, precipitation has been above normal in the state and has had long term effects on vegetation growth because of water retention in the vegetation and the ground. This has caused the need for more frequent inspections and trimmings to keep the lines clear.
- Inspections – HECO is expanding its inspection programs to identify needed repairs and replacements before there is an impact on service to customers. Increased inspections of both overhead and underground transmission and distribution lines, substations and poles will improve the reliability of the system and service to customers.

- Improved Systems – In addition to the EMS described above, the Company will implement an Outage Management System ("OMS") which will automate service restoration functions and assist in the dispatch and management of repair crews.

Maintaining Financial Integrity

Q. What is meant by maintaining financial integrity?

A. As explained by Ms. Tayne Sekimura in HECO T-19, financial integrity refers to the financial health of the company – having sufficient funds to fulfill the electrical needs of its customers and prudently plan for future needs, while at the same time providing a reasonable rate of return for its shareholder and ability to attract new capital on reasonable terms. As long as there is inflation and new plant must be added at today's prices to replace older plant and to serve new loads, electric rates will have to increase from time to time. In timing its applications for rate increases, HECO has tried to strike a reasonable balance between maintaining its financial integrity and the impact of a rate increase on its customers.

Q. Are HECO's current effective rates sufficient for the Company to maintain its financial integrity?

A. No, they are not. As shown on HECO-2301, even with the revenues from the interim rate increase surcharges, HECO's current effective rates would result in a rate of return on average rate base of 4.36% in the normalized test year. As I mentioned earlier, a fair and reasonable rate of return on average rate base for HECO in the 2007 test year would be 8.92%. This return is based on a return on common equity of 11.25%. Thus, a 4.36% return on average rate base would result in a return on common equity well below the return required by the financial markets for companies with a level of risk similar to that of HECO.

Q. Why is it important for HECO to maintain its financial integrity?

A. As Ms. Sekimura states in HELCO T-19, if HECO does not maintain its financial integrity, investors will invest their money elsewhere which will have negative implications for HECO's customers because it will reduce the demand for the Company's securities and increase the Company's cost of capital. In adverse market conditions, it may be difficult to attract capital.

In other words, if HECO is unable to provide acceptable returns, HECO will be viewed as a riskier investment in the eyes of investors. This could result in credit rating downgrades which would increase the cost for the Company to acquire debt financing. It would also increase the return on common equity required by investors and create downward pressure on the value of the Company's equity. This increase in the cost of capital would eventually have to be reflected in the rates the Company charges to its customers. Thus, it is imperative from a customer standpoint for HECO to maintain its financial integrity.

BACKGROUND

Q. When did HECO file its Notice of Intent?

A. HECO filed its Notice of Intent on September 22, 2006 and the Commission assigned Docket No. 2006-0386 to this proceeding.

Q. When did HECO file the completed application and direct testimonies, exhibits, and workpapers?

A. HECO filed the completed application, and HECO's direct testimonies, exhibits, and workpapers on December 22, 2006. In accordance with the Commission's Rules of Practice and Procedure, Title 6, Chapter 61, of the Hawaii Administrative

Rules, the Company served copies on the Consumer Advocate and the Mayor of the City and County of Honolulu. The application, together with the written testimonies, exhibits, and workpapers, satisfy the completed application requirements of the Commission's Rules of Practice and Procedure.

Q. Please briefly identify the exhibits attached to the application.

A. The application itself is marked as HECO-101.

HECO-102 is an unaudited balance sheet as of September 30, 2006, and an unaudited income statement and statement of retained earnings for the nine months ending September 30, 2006.

HECO-103 describes the details of HECO's outstanding issues of cumulative preferred stock, QUIDS Hybrid Securities, and long-term debt.

HECO-104 is a copy of HEI's latest proxy statement dated April 6, 2006, which was sent to stockholders.

HECO-105 is HECO's present rate schedules.

HECO-106 is HECO's proposed rate schedules.

HECO-107 is HECO's present Table of Contents and Rule 4.

HECO-108 is HECO's proposed Table of Contents and Rule 4.

HECO-109 is HECO's present Rule 7.

HECO-110 is HECO' proposed Rule 7.

HECO-111 shows HECO's proposed rate increase over present rates in total and by rate classes, in terms of dollars and by percentage for test year 2007.

HECO-112 shows HECO's proposed rate increase over current effective rates in total and by rate classes, in terms of dollars and by percentage for test year 2007.

HECO-113 is a summary of HECO's estimated earnings on its average rate base at present rates for the normalized 2007 test year.

HECO-114 is a summary of HECO's estimated earnings on its average rate base at current effective rates for the normalized 2007 test year.

Q. What justification has HECO submitted to support this request for rate relief?

A. In addition to the application, a total of 23 witnesses, including myself, have submitted 23 written testimonies with supporting exhibits and workpapers, which detail and support the reasons and need for rate relief. The witnesses, including myself, and the subject matters of their testimonies are as follows:

Witness Number	Witness	Subject
T-1	Robert A. Alm	Introductory Statement
T-2	George Willoughby	Electric Sales and Customer Forecasts
T-3	Peter C. Young	Electric Sales Revenues at Present Rates and at Proposed Rates Other Operating Revenues
T-4	Ross H. Sakuda	Capacity Situation, Fuel Expense, Fuel Related Expense, Generation Efficiency, Fuel Inventory
T-5	Daniel S. W. Ching	Purchased Power Expense
T-6	Dan V. Giovanni	Production O&M Expenses, Production Inventory
T-7	Robert K. S. Young	Transmission and Distribution System, T&D Operations and Maintenance Expense, T&D Materials Inventory
T-8	Darren S. Yamamoto	Customer Accounts Expense, Customer Deposit, Interest on Customer Deposits, Revenue Lag Days

T-9	Alan K.C. Hee	Customer Service Expense, Demand-Side Management Program Expense, Integrated Resource Planning Expense, Energy Cost Adjustment Clause
T-10	Patsy H. Nanbu	A&G Operations and Maintenance Expense, Accounting for Computer Software Development Costs, Unamortized Gain on Sale, Abandoned Projects, Accounting for Pensions and Postretirement Benefits Other than Pensions
T-11	Russell R. Harris	A&G Expense-Insurance
T-12	Julie K. Price	A&G Expense-Employee Benefits
T-13	Bruce Tamashiro	Miscellaneous Administrative and General Expenses, Depreciation Expense and Accumulated Depreciation, Miscellaneous Other Operating Revenues
T-14	Faye Chiogioji	Employee Count
T-15	Lon K. Okada	Taxes Other than Income Taxes, Income Tax Expense, Unamortized Net SFAS 109 Regulatory Asset, Unamortized Investment Tax Credits, Accumulated Deferred Income Taxes, Recent Tax Developments
T-16	Ken T. Morikami	Plant Additions, Underground Cost-Sharing, Property Held for Future Use, Contributions in Aid of Construction, and Customer Advances
T-17	Gayle T. Ohashi	Rate Base
T-18	Roger A. Morin, Ph.D	Rate of Return on Common Equity
T-19	Tayne S. Y. Sekimura	Rate of Return on Rate Base
T-20	Peter C. Young	Cost of Service and Rate Design
T-21	Jeff D. Makholm, Ph.D	Energy Cost Adjustment Clause

T-22	Eugene T. Meehan	Fuel Hedging Overview
T-23	William A. Bonnet	Results of Operations, including Revenue Requirements, Rate Increase Implementation, and Summary

Mr. Lon Okada is an employee of Hawaiian Electric Industries, Inc. ("HEI"). Dr. Roger Morin is a Professor of Finance at the College of Business, Georgia State University. Ms. Tayne S. Y. Sekimura is the Financial Vice President for HECO, HELCO and MECO. Dr. Jeff D. Makholm is a Senior Vice President at National Economic Research Associates, Inc. ("NERA"). Mr. Eugene T. Meehan is a Senior Vice President at NERA. All other witnesses are HECO employees.

POLICY MATTERS

Q. What are some of the policy matters the Commission should consider in determining the reasonableness of HECO's requests in this proceeding?

A. There are five policy areas that I will discuss in this section:

1) HECO's strategy for the preparation of testimony
2) The revenue increase allocation
3) The need for an Energy Cost Adjustment Clause
4) Pension/OPEB accounting
5) Amortization periods between rate cases

Strategy for Preparing Testimony

Q. How were the rate case estimates prepared?

A. The witnesses who are testifying on O&M expenses were asked to:

1) begin with HECO's 2007 O&M Expense Budget, as revised to update numbers and correct errors, where appropriate,

2) accept certain common assumptions reflected in the budget system,
3) simplify and limit issues by eliminating items that were litigated and not included in prior HELCO, HECO, and MECO ratemaking proceedings, to the extent practicable, and
4) also where appropriate, normalize the adjusted O&M Expense Budget amounts for ratemaking purposes; i.e., make adjustments to the adjusted O&M Expense Budget amounts to better represent "normal", ongoing Company operations for the period during which the proposed rates will be in effect.

The non-O&M witnesses were also requested to simplify and limit issues, to adjust their 2007 estimates, and to normalize their test year 2007 estimates, where appropriate.

Q. How did HECO estimate its revenue requirements for the 2007 test year?

A. Generally, the revenue requirements are based on HECO's August 2006 Sales Forecast, its 2007 O&M Expense Budget, estimated increases in rate base based on the expected completion dates for capital projects, a rate of return on rate base of 8.92%, and normalization adjustments necessary to better reflect operating conditions during the period when the rates as a result of this case will be in effect. Normalized test year revenues, expenses, rate base, rate of return, and results of operations are addressed in the testimonies and exhibits that follow.

Q. When were the revenue requirement inputs established?

A. The Company generally fixed most of the inputs to its revenue requirements calculation in October 2006. However, individual adjustments and corrections were made to certain items in November 2006.

Q. What are the common assumptions reflected in the budget system?

A. The common assumptions are as follows.

1) In accordance with the Company's negotiated labor agreement with the International Brotherhood of Electrical Workers, Local 1260, bargaining unit wages reflect increases for bargaining unit employees are 1.5% on May 1, 2005, and 1.5% on November 1, 2005, 1.5% on May 1, 2006 and 3% on Novmeber 1, 2006. The percentage increases are applied to bargaining unit wage rates as of November 1, 2002.
2) Merit employee salaries increase by 3.5% effective May 1, 2005, and increase by 0.25% effective September 1, 2005.
3) Base nonlabor estimates on information available for the specific item. Where none is available, assume a 2.5% general inflation factor for 2007. A listing of O&M expenses derived with the use of a general inflation factor is presented in HECO T-10. Additional discussion of the assumptions is also covered by Ms. Patsy Nanbu in HECO T-10.

Q. With respect to items that were eliminated from the test year in order to simplify and limit issues, does HECO intend to forgo recovery of the costs of these items in future rate cases?

A. No. HECO's position continues to be that these are appropriate costs of doing business as a regulated utility, and must be recovered through rates if HECO is to be afforded the full opportunity to earn a fair return. Therefore, HECO does not waive its right to seek recovery of these costs in future rate cases.

Q. What is an example of costs that were eliminated from the test year in order to simplify and limit issues?

A. Examples of items for which HECO is not seeking cost recovery in this proceeding are non-qualified pension expenses, performance incentive compensation for employees and executives, Hawaiian Electric Industries

Retirement System's ("HEIRS") 401(k) administration expense, and the expenses related to the annual service awards and Executive Life Insurance.

Q. What else has HECO done to simplify its presentation?

A. HECO has provided all of its Rate Case Reports (reports that have replaced the former FIS reports) for O&M expenses in one place (rather than in separate parts divided among each witness' exhibits and workpapers), as HECO-WP-101. This provides the entire "picture" of HECO's 2007 O&M expense budget. In addition, the Rate Case Reports are presented in nine different formats to provide additional detail with which to evaluate the reasonableness of HECO's O&M expenses. Included with the reports are detailed listings of the various codes used in the Rate Case Reports.

HECO also has made a concerted effort to inform the Commission and the Consumer Advocate of adjustments that should be made for errors that HECO has discovered in the course of finalizing its Application or for later information that arose since the finalization of the revenue requirements. These adjustments are identified in the testimonies, and will be made at the next available opportunity.

Q. In this proceeding, has HECO incorporated commitments it has made to the Consumer Advocate in past rate cases?

A. Yes. In past proceedings, HECO (and HELCO and MECO) have made several commitments to the Consumer Advocate in order to facilitate future ratemaking proceedings. The significant ones are to provide in future rate case direct testimonies:

1) a variance analysis on O&M differences by activity from prior period of amount of +/- 10% and $200,000, and
2) a listing of O&M expenses that were prepared using a general inflation factor.

Q. Has HECO provided these items in this proceeding?

A. Yes. Each O&M witness provides a variance analysis of the difference between actual 2005 and budget 2007 expenses by activity and code block.

Revenue Increase Allocation

Q. How is the requested revenue increase being allocated to the various rate schedules?

A. The Company is allocating the requested revenue increase as an equal percentage increase to each rate schedule.

Q. Why has HECO departed from the revenue increase allocation proposed in HECO's rebuttal testimonies in HECO's last rate case, Docket No. 04-0113?

A. Considering the relatively high electric bills for residential customers due to the current fuel prices, HECO is proposing to allocate the revenue increase to all rate schedules equally to share the burden among all ratepayers. This is consistent with the Company's original rate design proposals in Docket No. 04-0113. In its original application, the Company proposed an equal revenue allocation to all rate schedules because it was applying for a $98.6 million or 9.9% increase. In its rebuttal testimony (HECO RT-22) in the same proceeding, the Company reasoned that since the rebuttal proposed increase in revenues was significantly lower than the proposed increase in direct testimony, it was reasonable for HECO to propose a revenue increase allocation that more closely aligned class revenues and class costs.

Q. Is HECO proposing any new rate designs or rate schedules in this proceeding?

A. Yes. The more significant proposals are listed below:

- Inclining Rate Block Structure for Residential Customers – This proposal applies to Schedule R and is similar to the structure HELCO proposed in its 2006 rate case (Docket No. 05-0315. It establishes three tiers, one for the first 350 kWh used in the billing period, one for the next 850 kWh used in the billing period, or kWh usage between 300 kWh and 1,200 kWh, and a third tier for kWh usage above 1,200 kWh per billing period. Each tier has a different non-fuel energy charge per kWh, with the first 350 kWh having the lowest proposed non-fuel energy charge and kWh usage over 1,200 kWh having the highest proposed non-fuel energy charge. The merits on an inclining block rate design include mitigation of rate impact on the smallest users of the system, pricing signals that encourage conservation, and assignment of a greater share of the cost increase to the larger users. Approximately 90% of all kWh will be billed at either the first or second tier rate.

- Optional Time-of-Use ("TOU") Rates – HECO proposed optional TOU rates for residential and commercial customers in Docket No. 04-0113. The residential offering provides TOU rate adjustments to Schedule R to encourage customers to manage their energy usage. The commercial offering provides differential TOU rates for priority peak, mid-peak and off-peak periods.
- Standby Service Rates – HECO filed these rates on August 28, 2006 in response to Decision and Order No. 22248, issued January 27, 2006 in the distributed generation proceeding (Docket No. 03-0371).

Energy Cost Adjustment Clause

Q. What is an energy cost adjustment clause or ECAC?

A. The ECAC is an automatic adjustment provision in the utility's rate schedules that allows the utility to automatically increase or decrease rates or charges to customers to reflect changes in the Company's energy costs of fuel, DG energy and purchased energy above or below the levels included in the base charges, without a rate proceeding. The purpose of ECAC is (1) to address price changes in the Company's cost of fuel and purchased energy and (2) to accommodate changes to the generation, DG and purchased energy mix percentages, without the need for a rate case.

Q. Are there any requirements for the recovery of fuel costs through the ECAC?

A. Yes. All costs that pass through the ECAC must result from fuel oil and purchased energy contracts and/or agreements that have been approved by the Commission. In this manner, the Commission exercises its oversight of the costs passed through the ECAC.

Q. Why does the Company need an ECAC?

A. Hawaii is fueled by oil for jet planes, for cars and for power. This system is in transition to move away from oil but in the meantime it is a cost which both dominates our cost structure and is beyond our control. Having those costs covered, without profit, is a matter of fundamental fairness.

The Company needs the ECAC because fuel costs are a large portion of its expenses and because fuel price levels are largely beyond the Company's control. In the test year, fuel and purchased energy expenses make up over 72% of total O&M expenses. This makes the Company's financial condition susceptible to changes in fuel prices. The ECAC benefits the Company and its shareholders by (1) limiting the swings in cash flow and earnings, (2) reducing the cost of capital, (3) improving the Company's ability to earn a fair return on investor capital, and, (4) providing a more timely recovery of fuel and purchased energy costs.

Q. How does the ECAC benefit customers?

A. The ECAC benefits customers by (1) reducing the Company's financial risk and lowering the cost of capital, with the resulting savings being passed on to customers through lower base rates in rate proceedings, and (2) passing through to customers the savings incurred when fuel prices fall below the prices embedded in base rates (to the same extent that they incur additional costs when fuel prices are above the embedded fuel prices). Between January 1984 and September 2004 HECO's ECAC returned more than $273 million to its customers (see Docket No. 04-0113, HECO T-10, page 69).

Q. What is the efficiency factor in the ECAC?

A. This efficiency factor is a measure of how efficiently HECO expects to convert the fuel burned in its generating units into a kWh of sales during the test year. It is expressed in million btus per kWh. If the Company converts fuel into kWh more efficiently than this factor, it will get to keep the savings. But if the Company converts fuel into kWh less efficiently than this factor it will not be able to recover the additional cost from customers. In effect, the efficiency factor acts as a standard which the Company must meet to avoid under-recovery of its fuel expense and provides an incentive for the Company to operate its units as efficiently as possible.

Q. How do investors feel about the ECAC?

A. The ECAC serves to reimburse HECO for prudently-incurred energy costs in a manner that minimizes the negative financial effects caused by regulatory lag. As Dr. Roger Morin, HECO's expert witness on the cost of common equity, explains in HECO T-18, consideration of energy costs in a manner that lowers uncertainty and risk "represents the mainstream position on this issue across the United States. Accordingly, the financial community relies on the presence of energy cost recovery mechanisms to protect investors from the variability of fuel and purchased power costs that can have a substantial impact on the credit profile of a utility, even when prudently managed."

As Dr. Morin also states, "it is my understanding" that bond rating agencies would place considerably more weight on the Company's purchased power contracts as debt equivalents in the absence of ECAC, thus weakening the Company's financial integrity. The ECAC mitigates a portion of the risk and uncertainty related to the day-to-day management of a regulated utility's operations. Conversely, the absence of such protection would be factored into the Company's credit profile as a negative element, which in turn would raise its cost of capital.

Dr. Morin adds that the "approval of energy cost recovery mechanisms by regulatory commissions is widespread in the utility business. Approval of fuel adjustment clauses, purchased water adjustment clauses, and purchased gas adjustment clauses has become widespread. All else remaining constant, such clauses reduce investment risk on an absolute basis and constitute sound regulatory policy."

Dr. Morin concludes that, in the absence of the Commission renewal of the ECAC requested by HECO in this proceeding, HECO's financial condition would deteriorate, its credit ratings would likely be under review for possible downgrade, and its customers would be at risk of having to pay higher rates due to access to capital becoming more expensive for HECO. This situation would have a substantial effect on HECO and its customers because of the magnitude of the energy cost component in its cost of service.

Q. Does the ECAC discourage the use of renewable energy?

A. No. There is no indication that the ECAC discourages the use of renewable energy.

1. HECO and its sister utilities are already moving aggressively on renewable activities. They already have significant renewables on their systems (HPOWER, HC&S, PGV, HRD, KWP) and new projects are on the way, especially in the area of wind (Apollo). As the Consumer Advocate indicated in its Statements of Position filed on November 8, 2004 in Docket Nos. 04-0128 and 04-0129, HECO's "use of the ECAC to address the changing price of fuel does not appear to have diminished its effort in research and utilization of renewable energy."
2. The current ECAC allows the Companies to bring on new as-available renewable purchase power agreements without rate proceedings, including those with prices that are de-linked from the price of oil. Thus, a major potential disincentive to the Companies has been removed, because they can immediately pass on the costs of renewable projects. Firm renewable projects can be added without a rate case due to the availability of the firm capacity surcharge for nonfossil fuel producers, plus the ECAC.
3. Instead of changing the ECAC to change how the Companies view oil, and to encourage them to seek more renewables, it makes sense to look at mechanisms that directly incentivize the Companies to engage in renewable activities, which is exactly what the Commission is doing in the Renewable Portfolio Standard ("RPS") workshops, without causing major harm to the financial health of the Company. Docket No. 04-0113, Tr. (9/16/05) at 48.

Q. In the last HECO rate case, what position did the other parties take on the ECAC?

A. In Docket No. 04-0113, the parties agreed that the ECAC should be continued. With respect to continuation of the ECAC, the Consumer Advocate stated that: "Fuel price volatility in international fuel markets and HECO's dependence upon such markets makes ECAC continuation important to the Company and its ability to timely recover fluctuating costs thereby minimizing earnings volatility and the risk of reduced access to capital markets on reasonable terms." (See Docket No. 04-0113, CA-T-1, page 35, CA-T-3, page 60, lines 4-8. The Department of Defense ("DOD") did not explicitly state a position on the continuation of the ECAC, but based its derivation of ECA Revenues on the CA's estimates, as shown in DOD-126.)

The Consumer Advocate also indicated in its Statements of Position filed on November 8, 2004 in Docket Nos. 04-0128 and 04-0129 that (1) the 10-year extension of the contracts is reasonable; (2) use of the ECAC to protect against significant changes in the prices of fuel benefits both the Company and its customers; (3) HECO's "use of the ECAC to address the changing price of fuel does not appear to have diminished its effort in research and utilization of renewable energy." The Consumer Advocate concluded that continued use of the ECAC by the Company is reasonable at this time.

Continued use of an ECAC is the most reasonable means of fairly compensating HECO for its fuel and purchased energy expense without unreasonably penalizing HECO or its customers.

<u>Act 162</u>

Q. Please describe the recent state legislation that affects the ECAC.

A. On June 2, 2006, the Governor of Hawaii signed into law Act 162, Session Laws of Hawaii 2006, which states "any automatic fuel rate adjustment clause requested by a public utility in an application filed with the commission shall be designed, as determined in the commission's discretion, to:

(1) Fairly share the risk of fuel cost changes between the public utility and its customers;

(2) Provide the public utility with sufficient incentive to reasonably manage or lower it fuel costs and encourage greater use of renewable energy;

(3) Allow the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as through fuel hedging contracts;

(4) Preserve, to the extent reasonably possible, the public utility's financial integrity; and

(5) Minimize, to the extent reasonably possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs."

Q. Please summarize the testimonies of HECO's expert witnesses on the ECAC and Act 162.

A. Jeff D. Makholm, a Senior Vice President at National Economic Research Associates, Inc. ("NERA"), provides testimony in HECO T-21 explaining the role of fuel adjustment clauses ("FACs") in utility ratemaking in the United States, and addressing the compliance of HECO's current power cost recovery mechanism, the Energy Cost Adjustment Clause ("ECAC"), with Act 162. Mr. Makholm concludes that (1) FACs are a standard and longstanding part of US utility ratemaking, (2) HECO's ECAC is a well-designed FAC and benefits HECO and its ratepayers, and (3) HECO's ECAC complies with the statutory requirements of Act 162.

Eugene T. Meehan, who also is a Senior Vice President at NERA, provides a summary in HECO T-22 of the type of fuel price hedging that potentially could be performed by HECO in the marketplace and an assessment of the potential impacts of fuel price hedging on HECO, its customers and the regulatory ratemaking process. His conclusions with respect to fuel price hedging include:

(1) Hedging of oil by HECO would not be expected to reduce fuel and purchased power costs and in fact would be expected to increase the level of such costs,

(2) The liquidity of standard financial hedging products with a term of over a year is limited, and while HECO could partially hedge against oil price risk for periods of just over a year into the future, there would be considerable costs to doing so,

(3) It would not be reasonable for HECO to take the position of a principal and speculate in the oil market with shareholders assuming the risk of oil derivative gains and losses, and

(4) Even if rate smoothing is a desired goal, there may be more effective means of meeting the goal, and there is no compelling reason for HECO to use fuel price hedging as the means to achieving the objective of increased rate stability.

Ms. Tayne Sekimura in HECO T-19 and Mr. Alan Hee in HECO T-9 also address from a Company perspective how HECO's current ECAC mechanism complies with the requirements of Act 162.

Q. What is HECO's position on whether the current ECAC is designed according to the criteria specified in Act 162?

A. HECO's position is that the design of the current ECAC is reasonable and satisfies the Act 162 criteria.

Pension/OPEB Accounting

Q. Please provide a high level overview of the pension and post-retirement benefits other than pensions (also known as other post-employment benefits or "OPEB") accounting issues affecting this proceeding.

A. Ms. Patsy Nanbu in HECO T-10, Ms. Tayne Sekimura in HECO T-19 and Ms. Julie Price in HECO T-12 address the pension/OPEB accounting issues in detail. I will focus on one in particular. The accounting for pensions and OPEBs is subject to the Statement of Financial Accounting Standards ("SFAS") No. 87 and No. 106, respectively. For pensions, a prepaid pension asset is recorded when cumulative contributions to the pension fund exceed the cumulative pension expenses that the Company has incurred over time. For example, in the 2005 test year, HECO's prepaid pension asset, net of tax benefits, was approximately $50 million. In September 2006, the Financial Accounting Standards Board issued SFAS No. 158 which modified the accounting rules for pensions and OPEBs. In simple terms, if the fair value of the pension assets is less than the projected benefit obligation, the shortfall gets booked as a liability and the prepaid pension asset gets reversed out and these values less tax impacts get booked as a charge against equity called accumulated other comprehensive income ("AOCI"). The impact of SFAS No. 158 on OPEBs is similar.

Q. What is the impact of this treatment?

A. Having to take a charge against equity would artificially distort the Company's financial ratios. It would artificially reduce the cost of capital by inflating the debt ratio. Further, the reversing out of the prepaid pension asset would reduce rate base. If not corrected in the ratemaking process, these impacts would create a shortfall in recovery and could jeopardize the Company's credit ratings in the financial markets. Credit rating downgrades would impact ratepayers by increasing the cost of capital and ultimately increase rates that customer must pay.

Q. How does the Company propose to address this issue.

A. In this proceeding, for both pensions and OPEBs, the Company proposes to include in rate base, for ratemaking purposes, a regulatory asset (in the amount equivalent to what would be charged to AOCI) and the associated liabilities and deferred taxes. The net impact to rate base would be exactly the same as what the prepaid asset amount would be if there was no requirement to charge AOCI. Further, the Company proposes not to recognize the AOCI in the calculation of the cost of capital for ratemaking purposes.

Amortization Period – Period Between Rate Cases

Q. What is an amortization period?

A. An amortization period is the period over which deferred expenses are amortized.

Q. What is the basis for selecting the amortization period?

A. For some expenses it is based on the period during which the deferred expenses are expected to provide benefits. Other deferred expenses, such as regulatory commission (i.e., rate case) expenses are amortized over the estimated period between rate cases. The Company has estimated this period to be three years.

Q. What is the basis for the three years?

A. It is a normal time period between rate cases. The time period between Docket No. 04-0113 (HECO's 2005 test year rate case) and this rate case was approximately two years. Going forward, the Company contemplates that it may file for a 2010 test year rate case, the year following the in-service date of the new generating unit at Campbell Industrial Park. This would be three years from this 2007 test year rate case. In times of financial need, it is possible that the Company will file for a rate case earlier. However, to be conservative, the Company has chosen to use a period of three years to represent the time between rate cases.

SUMMARY

Q. Please summarize your testimony.

A. HECO's total requested increase in revenues is $99,556,000, or 7.1%, over revenues at current effective rates (which include revenues from the interim rate increase surcharge) for the normalized 2007 test year (using August 1, 2006 fuel prices). If the interim rate increase surcharges are excluded from the Company's revenues (i.e., revenues at "present" rates), HECO's total requested increase in revenues is $151,505,000 for the normalized 2007 test year (using August 1, 2006 fuel prices).

The need for rate relief is supported by the testimonies and exhibits of 23 different witnesses who have submitted a total of 23 different written testimonies, with supporting exhibits and workpapers. To facilitate a timely decision in this rate case proceeding, HECO has limited the number of issues by using, in most instances, the methodologies adopted by the Commission in past ratemaking proceedings.

Q. Does this conclude your testimony?

A. Yes, it does.

HAWAIIAN ELECTRIC COMPANY, INC.

ROBERT A. ALM

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. (HECO) 900 Richards Street Honolulu, HI 96813	
Position:	Senior Vice President Public Affairs	
Years of Service:	5	
Education:	University of Hawaii at Manoa BA with Distinction in Political Science (1973)	
	University of Iowa, College of Law Juris Doctor with Distinction (1975)	
Previous Positions:	1999-2001	First Hawaiian Bank Executive Vice President & Manager Financial Management Group
	1996-1998	First Hawaiian Bank Senior Vice President & Manager Financial Management Group
	1994-1996	First Hawaiian Bank Senior Vice President & Deputy Manager Financial Management Group
	1993-1994	First Hawaiian Bank Vice President & Trust Officer Trust and Investments Division
	1987-1993	State of Hawaii, Department of Commerce and Consumer Affairs Director

1984-1986	State of Hawaii, Department of Commerce and Consumer Affairs Deputy Director
1982-1984	State of Hawaii, Department of Commerce and Consumer Affairs Senior Hearings Officer
1980-1982	Office of Senator Daniel K. Inouye in Washington, D.C. Deputy Administrative Assistant
1979-1980	Office of Senator Daniel K. Inouye in Washington, D.C. Legislative Assistant
1977-1979	University of Hawaii at Manoa Legal Research Associate Pacific Urban Studies & Planning Program
1977	State Senator Stanley Hara Administrative Assistant
1976-1979	Private Practice

Professional Qualifications:

Court Admissions:	Supreme Court of Hawaii (1976) United States District Court of the District of Hawaii (1976) United States Supreme Court (1981)
Memberships:	American Bar Association Hawaii State Bar Association

Honors:

Freedom of Information Award, Society of Professional Journalists (1989)

Hawaii Public Administration Award, American Society for Public Administration, Hawaii Chapter (1992)

Honorary Ali'i, Royal Order of Kamehameha I (1993)

Outstanding Volunteer Fund Raiser Award 2000, National Society of Fund Raising Executives (NSFRE) (2000)

Volunteer of the Year Award 2000, Alexis de Tocqueville Society of Honolulu (2000)

Community Service:

Hawaii Community Foundation – Board of Governors, Past Chair

Helping Hands Hawaii – Board of Directors, Chair

Hawaii Public Television Foundation – Board of Directors, Treasurer

Boys and Girls Club of Hawaii – Board of Directors, Past President; Board of Advisors

Hawaii Institute for Public Affairs (HIPA) – Board of Directors

Bishop Museum – Board of Directors

Community Links Hawaii – Board of Directors

Family Independence Initiative – Board of Directors

The Friends of Iolani Palace – Board of Directors

Social Science Association – Member

Sutter Health Pacific – Board of Directors

Hawaii Nature Center – Board of Directors

Straub Foundation – Board of Directors

Disciplinary Board of the Hawaii Supreme Court – Hearing Committee Member

Judicial Performance Committee – Member

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

------------In the Matter of the Application of------------	)	
	)	
HAWAIIAN ELECTRIC COMPANY, INC.	)	Docket No. 2006-0386
	)	
For Approval of Rate Increases and Revised Rate Schedules and Rules	)	
	)	

APPLICATION

and

CERTIFICATE OF SERVICE

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Attorneys for
Hawaiian Electric Company, Inc.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

-------------In the Matter of the Application of------------	)	
	)	
HAWAIIAN ELECTRIC COMPANY, INC.	)	Docket No. 2006-0386
	)	
For Approval of Rate Increases and Revised Rate Schedules and Rules	)	
	)	

APPLICATION

TO THE HONORABLE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII:

I

This Application is filed by HAWAIIAN ELECTRIC COMPANY, INC. ("Applicant" or "HECO") for approval of a general rate increase and revised rate schedules and rules. The amount of the increase in revenues requested is estimated to be $99,556,000, or 7.1%, over revenues at current effective rates (i.e., rates that are currently in effect for customers). Revenues at current effective rates include revenues from the the interim rate increase approved by the Commission in Interim Decision and Order No. 22050 in HECO's 2005 test year rate case, Docket No. 04-0113. If revenues from the interim rate increase are excluded, the requested relief over the resulting revenues (i.e., revenues at present rates) is estimated to be $151,505,000.

The requested increase is based on estimated total revenue requirements of $1,501,782,000 for the normalized 2007 test year (based on August 2006 fuel oil and purchased energy prices, and an 8.92% rate of return on HECO's average rate base).

The revenue requirements exclude incremental demand-side management ("DSM") costs that HECO currently recovers through the DSM component ("DSM surcharge") of the Integrated Resource Planning ("IRP") Cost Recovery Provision. HECO has excluded DSM surcharge revenues and the associated costs from the 2006 test year because Docket No. 05-0069 (the Energy Efficiency proceeding) is presently in progress and is addressing a number of policy issues with respect to DSM programs in the state, including on the island of Oahu. The issues include what the cost recovery mechanism for DSM programs should be (e.g., whether the costs should be recovered through base rates or a separate surcharge). Because of this, HECO has excluded from its 2007 test year revenue requirements the incremental DSM costs currently recovered through the DSM surcharge. Because the DSM costs recovered through the surcharge are excluded, the DSM surcharge revenues are also removed from the case.

HECO requests that the general rate increase and the revisions to its rate schedules and rules be granted in two steps:

1. Interim Increase – an Interim Increase equal to increase in rates to which the Commission believes HECO is "probably entitled" based on the evidentiary record before it, in accordance with Section 269-16(d) of the Hawaii Revised Statues ("H.R.S."). HECO will determine the amount that it is requesting in the Interim Increase at the the close of the evidentiary hearing, based on the evidence before the Commission.

2. Final Increase – a General Rate Increase when the Commission issues its final decision and order to provide for the amount of the total requested revenue increase not included in the Interim Rate Increase.

Applicant requests that the rate design changes requested in this Application be implemented when the Final Increase is implemented. Applicant proposes to allocate the increase in revenues as an equal percentage increase to all rate schedules.

Applicant further requests that the interim increase implemented prior to the final step be structured as surcharges for the various classes based on a percentage of the customer's base charges (i.e., exclusive of Energy Cost Adjustment charges and other surcharges).

As shown in HECO-2301, the requested revenue increase of $99,556,000 over current effective rates represents a 7.1% increase over revenues at HECO's current effective rates for the normalized 2007 test year (based on August 2006 fuel oil and purchased energy prices and a rate of return on rate base of 8.92%). As shown in HECO-2302, the amount of the increase over revenues based on present rates, which exclude revenues from the interim surcharge, is $151,505,000, or 11.2%, for the normalized 2007 test year (based on August 2006 fuel oil and purchased energy prices and a rate of return on rate base of 8.92%). As is the case with revenues at current effective rates and revenues at present rates, revenues at proposed rates exclude DSM surcharge revenues and the DSM costs recovered through the surcharge have been removed from the 2007 test year revenue requirement.

II

HECO files this Application pursuant to the Rules of Practice and Procedure before the Public Utilities Commission, Title 6, Chapter 61, H.A.R. ("Rules of Practice and Procedure"). The Company seeks approval by the Commission of the proposed rate increase and revised rate schedules under the provisions of Section 269-16, H.R.S. Pursuant to Section 6-61-87(11) of the Rules of Practice and Procedure, HECO files and makes a part hereof written direct testimonies, exhibits and workpapers supporting this Application and showing justification for the requested increase.

III

HECO, whose executive office is located at 900 Richards Street, Honolulu, Hawaii, is a corporation duly organized under laws of the Kingdom of Hawaii on or about October 13, 1891, and is now existing under and by virtue of the laws of the State of Hawaii.

HECO is an operating public utility engaged in the production, purchase, transmission, distribution, and sale of electricity on the island of Oahu, State of Hawaii. Since July 1, 1983, HECO has been a wholly-owned subsidiary of Hawaiian Electric Industries, Inc. ("HEI"). A general description of HECO's property and equipment is contained in the written direct testimonies, exhibits and workpapers filed herewith and made a part hereof.

IV

Correspondence and communications in regard to this Application should be addressed to:

William A. Bonnet
Vice President, Government and Community Affairs
Hawaiian Electric Company, Inc.
P.O. Box 2750
Honolulu, Hawaii 96840-0001

Copies of such correspondence and communications should be sent to:

Dean K. Matsuura
Director, Regulatory Affairs
Hawaiian Electric Company, Inc.
P. O. Box 2750
Honolulu, Hawaii 96840-0001

and

Thomas W. Williams, Jr., Esq.
Peter Y. Kikuta, Esq.
Goodsill Anderson Quinn & Stifel
1800 Alii Place
1099 Alakea Street
Honolulu, Hawaii 96813

V

The authorized capital stock of HECO consists of 50,000,000 shares of $6 2/3 par value Common Stock (total authorized par value of $333,500,000), and 5,000,000 shares of $20 par value Cumulative Preferred Stock and 5,000,000 shares of $100 par value Cumulative Preferred Stock (total authorized par value of $600,000,000), or a total authorized par value of $933,500,000 for Common Stock and Cumulative Preferred Stock.

As of September 30, 2006, HECO had outstanding 12,805,843 shares of Common Stock of the par value of $6 2/3 per share, having a total par value of $85,387,140. A summary of the dividends paid on HECO's Common Stock for the five-year period 2001-2005 and the common stock balance at the end of each of those years is as follows:

Year	Dividends Paid	Common Stock Balance
2005	$50,895,000	$85,387,140
2004	11,613,000	85,387,140
2003	57,719,000	85,387,140
2002	44,143,000	85,387,140
2001	36,309,000	85,387,140

As of September 30, 2006, HECO had outstanding 1,114,657 shares of Cumulative Preferred Stock of the par value of $20 per share, having a total par value of $22,293,140. Details concerning such cumulative Preferred Stock are on file with the Commission under various docket numbers as set forth in HECO-103 (which is attached hereto) and are incorporated herein by reference.

A summary of the dividends accrued on HECO's Preferred Stock for the five-year period 2001-2005 and the preferred stock balance at the end of each of those years is as follows:

Year	Dividends Paid	Preferred Stock Balance
2005	$1,079,907	$22,293,140
2004	1,079,907	22,293,140
2003	1,079,907	22,293,140
2002	1,079,907	22,293,140
2001	1,079,907	22,293,140

As of September 30, 2006, HECO had outstanding $31,546,400 in Junior Subordinated Deferrable Interest Debentures ("QUIDS") hybrid securities. Details concerning the QUIDs are on file with the Commission under various dockets as set forth in HECO-103 and are incorporated herein by reference.

As of September 30, 2006, HECO had outstanding $451,580,000 in obligations to the State of Hawaii for the repayment of Special Purpose Revenue Bonds. Details are on file with the Commission under various docket numbers as set forth in HECO-103 and are incorporated herein by reference. As of September 30, 2006, HECO had no outstanding borrowings from its parent, HEI, or from Hawaii Electric Light Company, Inc. ("HELCO") and Maui Electric Company, Limited ("MECO"), but had outstanding $145,079,872 of short-term borrowings from non-affiliates.

During 2005, HECO accrued $2,050,516 in interest on QUIDs, $25,260,946 in interest on Special Purpose Revenue Bonds, $356,343 on borrowings from HEI and $316,042 on borrowings from MECO. An estimate of the savings realized by HECO's customers by virtue of using Special Purpose Revenue Bonds is shown in HECO-1917 and is incorporated herein by reference.

VI

HECO's audited financial statements for the year ended December 31, 2005 (audited by KPMG LLP) are included in HECO's and HEI's Securities and Exchange Commission ("SEC") Form 8-K dated March 7, 2006, which was routinely filed with the Commission on March 8, 2006, and are incorporated herein by reference.

HECO's unaudited balance sheet as of September 30, 2006, and unaudited income statement and statement of retained earnings for the nine months ended September 30, 2006, are attached hereto as HECO-102.

A general description of HECO's property and equipment are provided in the written direct testimonies and exhibits filed herewith. The original cost of HECO's property and equipment and the applicable depreciation reserve are shown in the September 30, 2006 balance sheet, as well as in the written direct testimonies and exhibits filed herewith.

HEI's 2005 Summary Report to Shareholders, including Appendix A and its SEC Form 10-K report for the year ended December 31, 2005, were routinely filed with the Commission on April 13, 2006, and April 10, 2006, respectively, and are incorporated herein by reference. HEI's latest Proxy Statement (dated April 5, 2006) is attached hereto as HECO-104.

VII

HECO's current effective rates are the result of its existing "base" rates, plus the interim rate increase approved in HECO's pending 2006 test year rate case, Docket No.

04-0113. HECO's existing base rates are the result of the Commission's Final Decision and Order ("D&O") No. 14412 issued December 11, 1995, in Docket No. 7766, which utilized a 1995 test year, and D&O No. 20292 issued July 1, 2003 and Order No. 20310 issued July 9, 2003, in Docket No. 03-0126, which implemented a temporary rate reduction made possible as a result of a capacity charge reduction due to the amendment of HECO's power purchase agreement with AES Hawaii, Inc. The impact of the capacity charge reduction was included in HECO's revenue requirements for the 2005 test year in Docket No. 04-0113, and the temporary rate reduction will be discontinued when new rates are set in that rate case. In addition, the current effective rates include the surcharges on Sheet No. 50.2 of HECO's Tariff resulting from the interim rate increase approved by the Commission in Interim Decision and Order No. 22050, issued September 27, 2005, in Docket No. 04-0113. As of the date of this filing, the final decision and order for Docket No. 04-0113 is pending. Upon issuance of the final decision and order in that proceeding, HECO will terminate the interim rate increase surcharges and implement revised rates in accordance with the Commission's decision and order.

HECO's current rate schedules are set forth in HECO-105, which is attached hereto.

HECO-106 sets forth HECO's proposed rate schedules. The proposed revisions to HECO's rate schedules, including revisions to existing rate schedules and discontinuance of Rider EV-R and Rider EV-C, and the addition of Schedules TOU-R, TOU-C and SS, are described in HECO T-20, and the exhibits and workpapers thereto, which are incorporated herein by reference.

HECO-107 sets forth HECO's present Table of Contents and Rule 4.

HECO-108 sets forth HECO's proposed Table of Contents and proposed Rule 4 (which reflects the discontinuance of Rule 4.D.).

HECO-109 sets forth HECO's present Rule 7.

HECO-110 sets forth HECO's proposed Rule 7, which, among other things, changes the Returned Checks Charge to a Returned Payment Charge and increases the current charge from the $7.50 to $22.00 per returned check or returned payment; increases the Field Collection Charge from $15 to $20 per field collection call and modifies its application such that the customer will be charged the Field Collection Charge even when a field call does not result in successful collection of monies; and increases the Service Establishment Charge from $15 to $20 and increases the additional charge for the same day service or for service outside of the normal business hours from the current $10.00 to $25.00, as more completely described in HECO T-20.

On July 27, 2006, in accordance with Decision and Order No. 22248 ("D&O 22248"), issued January 27, 2006 in the distributed generation ("DG") proceeding (Docket No. 03-0371), HECO filed proposed modifications to its Tariff Rule No. 14.H. governing the interconnection of DG facilities operating in parallel with the Company's electric system. In D&O 22248, among other things, the Commission required the utilities to establish reliability and safety requirements for DG, establish a nondiscriminatory interconnection policy that entitles DG systems to interconnect to the utility's distribution system and to develop a standardized interconnection agreement.

D&O 22248 also required the utilities to establish standby rates for standby and backup power services that customer-generators may want on an as-needed basis to replace or supplement power from their DG facility. On August 28, 2006, HECO filed its proposed standby service rates. Decisions on the proposed modifications to Rule No. 14.H. and the standby service rates are pending.

The proposed rate increases by rate classes for the normalized 2007 test year are shown in HECO-112. This exhibit shows revenues at current effective rates, and the total increase requested in terms of dollars and by percentage. As shown on HECO-112, the proposed percentage increase to the different classes of service is the same. The proposed increase reflects the average proposed increase for each schedule of service. The increase experienced by a particular customer will depend on the customer's schedule of service, and other factors, such as the customer's energy use and the customer's billing demand (where applicable).

The Commission will investigate the reasonableness of the proposed revenue increase and rate schedule changes. The total revenue increase will not exceed the $151,505,000 over revenues at present rates requested by the application, but the rates and charges to be finally approved by the Commission after its investigation may be higher or lower than the proposed rates and charges for the various schedules of service.

The proposed rate increases over present rates by rate classes for the normalized 2007 test year are shown in HECO-111.

A summary of HECO's estimated earnings on its average rate base at present rates for the normalized 2007 test year is shown in HECO-113. A summary of HECO's estimated earnings on its average rate base at current effective rates for the normalized 2007 test year is shown in HECO-114. The estimated results of operations at present rates, current effective rates and proposed rates, which are described in written direct testimony HECO T-23 (Results of Operations, including Revenue Requirements, Rate Increase Implementation and Summary), have been prepared on a consistent basis reflecting normalized conditions, and are shown in HECO-2301 and HECO-2302, which are incorporated herein by reference.

The recorded results of operations for calendar year 2005 were filed with the Commission on February 24, 2006 and are incorporated herein by reference. The latest publicly available recorded results of operations for the 12 months ending September 30, 2006 were filed with the Commission on October 30, 2006 and are incorporated herein by reference.

Significant projected changes since December 31, 2005 in plant-in-service, revenues and expenses for the test period are discussed in the written direct testimonies and reflected in the supporting exhibits and workpapers, which are incorporated herein by reference.

The methods which HECO has elected to employ in computing deferred taxes, investment tax credits, and depreciation deductions for determining federal income tax payments, and whether HECO has used the same methods in calculating federal income taxes for the test period, are shown in written direct testimony HECO T-15, and the exhibits and workpapers thereto, which are incorporated herein by reference.

The requested increase reflects and passes through to HECO's customers only increased costs to HECO for the services and commodities furnished to it, as described in the written direct testimonies and exhibits, which are incorporated herein by reference.

VIII

Pursuant to Section 6-61-85 of the Rules of Practice and Procedure, on September 22, 2006, HECO filed a Notice of Intent to file a general rate increase application, at which time the rate case was assigned Docket No. 2006-0386. The reasons for the requested increase are set forth in the written direct testimonies, exhibits, and workpapers filed herewith, and are summarized below and in written direct testimonies HECO T-1 (Introductory Statement) and HECO T-23 (Results of Operations, including Revenue Requirements, Rate Increase Implementation and Summary).

HECO has filed this request for a general rate increase due to investment in additional plant and equipment, additional operating and maintenance costs to maintain the Company's system, and increasing costs for labor (including wage increases pursuant to HECO's bargaining unit contract), materials, contract services, depreciation, and other operating expenses. Without further rate relief in this proceeding, it is estimated that, at current rates, HECO's rate of return on its average rate base is estimated to be 4.36% for the normalized 2007 test year, as compared to the 9.16% authorized by the Commission in Docket No. 7766 for test year 1995, and the 8.92% justified in this docket. At present rates (i.e., if revenues from the interim increase in Docket No. 04-0113 are not considered), HECO's rate of return on its average rate base is estimated to be 1.98% for the normalized 2007 test year.

WHEREFORE, HECO prays:

1. That the required public hearing and evidentiary hearing be held on this application;

2. That the Commission establish a procedural schedule with the intent to make every effort to complete its deliberations in order to render a decision such that an increase in rates is effective as soon as practicable;

3. That the Commission approve HECO's requested revenue increase of $151,505,000 over present rates (or $99,556,000 over current effective rates) for the normalized 2007 test year (based on August 2006 fuel oil and purchased energy prices and a rate of return on rate base of 8.92%), and its revised rate schedules and rules;

4. That the Commission approve an Interim Increase to which the Commission, based on the evidentiary record before it, believes HECO is probably entitled, to be effective as soon as practicable, pursuant to Section 269-16(d), H.R.S.;

5. That the Commission approve a Final Increase (which would incorporate the Interim Increase), such that the combined impact of the Interim and Final Increases yields the requested revenue increase of $151,505,000 over present rates (or $99,556,000 over current effective rates) for the normalized 2007 test year (based on August 2006 fuel oil and purchased energy prices and a rate of return on rate base of 8.92%);

6. That the Commission grant HECO such other and further relief as may be just and equitable in the premises.

DATED: Honolulu, Hawaii, December 22, 2006.

HAWAIIAN ELECTRIC COMPANY, INC.

By ______________________________
William A. Bonnet
Vice President
Government and Community Affairs

VERIFICATION

STATE OF HAWAII)
) ss.
CITY AND COUNTY OF HONOLULU)

WILLIAM A. BONNET, being first duly sworn, on oath, deposes and says: That he is the Vice President, Government and Community Affairs of Hawaiian Electric Company, Inc., the within-named applicant; that he makes this verification for and on behalf of said applicant and is authorized so to do; that he has read the foregoing Application, knows the content thereof, and that the same are true.

WILLIAM A. BONNET

Subscribed and sworn to before me
this 22th day of December, 2006.

HOPE M. ONAGA
NOTARY
PUBLIC
STATE OF HAWAII

Hope M. Onaga
Notary Public, State of Hawaii

My commission expires: 7/18/2008

CERTIFICATE OF SERVICE

I hereby certify that on December 22, 2006, I served one copy each of the foregoing completed Application, including written direct testimonies, exhibits and workpapers, together with this Certificate of Service, by hand delivery or carrier to the following at the following addresses:

Division of Consumer Advocacy
Department of Commerce and Consumer Affairs
333 Merchant Street, Room 326
Honolulu, Hawaii 96813

Mr. Michael L. Brosch
Utilitech, Inc.
740 North West Blue Parkway, Suite 204
Lee's Summit, Missouri 64086

Mr. Joseph A. Herz
Sawvel & Associates, Inc.
100 East Main Cross Street, Suite 300
Findlay, Ohio 45840

Pursuant to an agreement with the Consumer Advocate, three double-sided copies of the completed Application, including written direct testimonies, exhibits, and workpapers together with this Certificate of Service will be hand delivered on December 26, 2006 at the Division of Consumer Advocacy's address.

One copy of the completed Application, including written direct testimonies, exhibits and workpapers together with this Certificate of Service was served by hand delivery on December 22, 2006 at the following address:

The Honorable Muliufi Hannemann
Mayor, City and County of Honolulu
Honolulu Hale
530 South King Street
Honolulu, Hawaii 96813

DATED: Honolulu, Hawaii, December 22, 2006.

HAWAIIAN ELECTRIC COMPANY, INC.

Lyndon Haack

Hawaiian Electric Company, Inc.
BALANCE SHEET
(Unaudited)
As of September 30, 2006

UTILITY PLANT AT COST :	
In Service :	
Land	$ 25,697,536
Plant and Equipment	2,391,629,777
Utility Plant in Service	2,417,327,313
Property Held for Future Use	598,735
Construction Work in Progress	82,945,186
Less Accumulated Provision for Depreciation	(938,647,372)
Net Utility Plant	1,562,223,862
Other Property:	
Non-Utility Property	6,452,752
Less Accumulated Provision for Depreciation	(1,132,021)
Net Other Property	5,320,731
Investment in wholly-owned subsidiaries	397,573,677
CURRENT ASSETS :	
Cash	1,945,420
Notes Receivable from Associated Companies	61,650,000
Customer Accounts Receivable	94,301,163
Less Allowance for Uncollectible Accounts	(304,027)
Net Customer Accounts Receivable	93,997,136
Accrued Unbilled Revenues, net	67,237,498
Other Accounts Receivable, net	4,485,554
Fuel Oil Stock, at Average Cost	68,618,247
Construction & Operating Materials & Supplies, at Average Cost	14,729,044
Prepaid Pension Benefit Cost	71,832,911
Other	8,184,650
Total Current Assets	392,680,460
OTHER ASSETS	
Regulatory Assets	81,168,149
Unamortized Debt Expense	9,459,596
Other	14,982,364
Total Other Assets	105,610,109
TOTAL ASSETS	$ 2,463,408,839

Hawaiian Electric Company, Inc.
BALANCE SHEET
(Unaudited)
As of September 30, 2006

CAPITALIZATION :	
Common Stock Equity	
Common Stock @ $6 2/3 Par Value	$ 85,387,140
Premium on Capital Stock, net of Capital Stock Expense	299,186,413
Retained Earnings	687,244,737
Total Common Stock Equity	1,071,818,290
Cumulative Preferred Stock of $20 Par Value	22,293,140
Total Stockholders' Equity	1,094,111,430
QUIDS	31,546,400
Long-Term Debt	
Revenue Bonds, net of discount, and Less Funds on Deposit with Trustee	449,666,579
Total Capitalization	1,575,324,409
CURRENT LIABILITIES	
Borrowings from non-affiliates	145,079,872
Accounts Payable	74,237,945
Payable To Associated Companies	296,007
Customer Deposits	6,078,395
Customer Advances	976,918
Taxes Accrued	104,660,020
Interest and Preferred Dividends Payable	10,180,122
Other	18,374,021
Total Current Liabilities	359,883,300
DEFERRED CREDITS	
Deferred Income Taxes	155,421,848
Unamortized Tax Credits	32,378,046
Regulatory Liabilities	160,807,573
Other	20,327,091
Total Deferred Credits	368,934,558
CONTRIBUTIONS IN AID OF CONSTRUCTION	159,266,572
TOTAL CAPITALIZATION & LIABILITIES	$ 2,463,408,839

Hawaiian Electric Company, Inc.
STATEMENT OF INCOME
(Unaudited)
For the Nine Months Ended September 30, 2006

OPERATING REVENUES	
Electric Revenues	$ 1,031,569,127
Other	2,913,978
Total Operating Revenues	1,034,483,105
OPERATING EXPENSES	
Production	
Fuel Oil	397,360,028
Purchased Power	268,018,893
Other Production	18,488,030
Transmission and Distribution Operations	9,790,587
Maintenance	39,880,147
Customer Accounts & Customer Service	19,416,936
Administrative and General	45,058,154
Depreciation	56,096,505
Taxes, Other Than Income Taxes	95,464,460
Tax Credits, Deferred, Net	1,804,351
Income Taxes	23,568,994
Total Operating Expenses	974,947,085
OPERATING INCOME	59,536,020
OTHER INCOME AND DEDUCTIONS	
Allowance for Equity Funds Used During Construction	3,001,958
Equity in Earnings of Subsidiaries	21,408,033
Other	3,788,381
Total Other Income & Deductions	28,198,372
INTEREST CHARGES	
Interest on Long-Term Debt	20,224,863
Amortization of Net Bond Premium & Expense	1,031,538
Other Interest Charges	5,071,851
Allowance for Debt Funds Used During Construction	(1,343,650)
Total Interest Charges	24,984,602
NET INCOME	62,749,790
Preferred Stock Dividends	809,930
NET INCOME FOR COMMON STOCK	$ 61,939,860

Hawaiian Electric Company, Inc.
STATEMENT OF RETAINED EARNINGS
(Unaudited)
For the Nine Months Ended September 30, 2006

Retained Earnings, Beginning of Period	$	654,685,877
Net Income for Common Stock		61,939,860
Common Stock Dividends		(29,381,000)
Retained Earnings, End of Period	$	687,244,737

Hawaiian Electric Company, Inc.

DETAILS OF OUTSTANDING ISSUES OF
PREFERRED STOCK, HYBRID SECURITIES
AND OTHER LONG-TERM DEBT
FOR INCORPORATION BY REFERENCE
As of September 30, 2006

Year Issued	Description	Total Par Value	Docket No. and Date	Commission Decision & Order and Date
Preferred Stock				
1945	Series C, 4 1/4% 150,000 shares	$ 3,000,000	888 7/11/1945	75-482 7/21/1945
1948	Series D, 5% 50,000 shares	1,000,000	993 3/17/1948	98-589 6/24/1948
1950	Series E, 5% 150,000 shares	3,000,000	1027 3/4/1949	107-625 5/9/1949
1960	Series H, 5 1/4% 250,000 shares	5,000,000	1414 5/27/1960	1012 7/21/1960
1961	Series I, 5% 89,657 shares	1,793,140	1460 6/21/1961	1067 7/21/1961
1962	Series J, 4 3/4% 250,000 shares	5,000,000	1496 3/21/1962	1100 4/17/1962
1964	Series K, 4.65% 175,000 shares	3,500,000	1546 4/30/1963	1203 5/16/1963
TOTAL OUTSTANDING 9/30/06		$ 22,293,140		

Hawaiian Electric Company, Inc.

DETAILS OF OUTSTANDING ISSUES OF
PREFERRED STOCK, HYBRID SECURITIES
AND OTHER LONG-TERM DEBT
FOR INCORPORATION BY REFERENCE
As of September 30, 2006

Year Issued	Description	Issue Amount	Docket No. and Date	Commission Decision & Order and Date
Long-Term Debt				
State of Hawaii - Special Purpose Revenue Bonds				
1993	5.45% Series 1993 due 2023	$ 50,000,000	7624 / 6797 2/26/1993	12651 10/6/1993
1996	6.20% Series 1996A due 2026	48,000,000	95-0096 4/28/1995	14396 - 11/28/95 14517 - 2/12/96
1996	5 7/8 % Series 1996B due 2026	14,000,000	95-0096 4/28/1995	PUC approval 10/10/1996
1997	5.65% Series 1997A due 2027	50,000,000	95-0096 / 96-0381 4/28/95 & 9/30/96	PUC approval 9/30/1997
1998	4.95% Refunding Series 1998A due 2012	42,580,000	97-0351 9/29/1997	16145 1/5/1998
1999	5.75% Refunding Series 1999B due 2018	30,000,000	99-0060 3/12/1999	17057 6/29/1999
1999	6.20% Series 1999C due 2029	35,000,000	99-0120 5/17/1999	17253 9/27/1999
1999	6.15% Refunding Series 1999D due 2020	16,000,000	99-0060 3/12/1999	17057 6/29/1999
2000	5.70% Refunding Series 2000 due 2020	46,000,000	00-0120 4/14/2000	18151 10/20/2000
2002	5.10% Series 2002A due 2032	40,000,000	99-0120 5/17/2002	19525 8/15/2002
2003	5.00% Refunding Series 2003B due 2022	40,000,000	03-0045 2/21/2003	20120 4/14/2003
2005	4.80% Refunding Series 2005A due 2025	40,000,000	04-0303 10/15/2004	21497 12/17/2004
TOTAL OUTSTANDING 9/30/06		$ 451,580,000		

Hawaiian Electric Company, Inc.

DETAILS OF OUTSTANDING ISSUES OF
PREFERRED STOCK, HYBRID SECURITIES
AND OTHER LONG-TERM DEBT
FOR INCORPORATION BY REFERENCE
As of September 30, 2006

Year Issued	Description	Issue Amount	Docket No. and Date	Commission Decision & Order and Date
Hybrid Security				
2004	6.50% Junior Subordinated Deferrable Interest Debentures, Series 2004 (2004 QUIPS) due 2034	$ 31,546,400	03-0409 12/8/2003	20803 2/13/2004 Amended by 20812 2/24/2004
TOTAL OUTSTANDING 9/30/06		$ 31,546,400		

HAWAIIAN ELECTRIC INDUSTRIES, INC. • PO BOX 730 • HONOLULU, HI 96808-0730

HEI

Robert F. Clarke
Chairman, President and
Chief Executive Officer

April 5, 2006

Dear Fellow Shareholder:

On behalf of the Board of Directors, it is once again my pleasure to invite you to attend the Annual Meeting of Shareholders of Hawaiian Electric Industries, Inc. (HEI). The meeting will be held on the Company's premises in Room 805 on the eighth floor of the American Savings Bank Tower in Honolulu, Hawaii on May 2, 2006, at 9:30 a.m. A map showing the location of the meeting site appears on page 39 of the Proxy Statement.

The accompanying Notice of Annual Meeting of Shareholders and Proxy Statement describe the items of business to be conducted during the meeting. In addition, we will review significant events of 2005 and their impact on you and your Company. Corporate officers will be available before and after the meeting to talk with you and answer any questions you may have.

As a shareholder of HEI, it is important that your views be represented. Please help us obtain the quorum needed to conduct business at the meeting by promptly voting your shares.

After holding various positions with HEI for 19 years, I will be retiring in May. The Board has elected Constance Lau to succeed me as President and CEO and has named Jeffrey Watanabe as nonexecutive Chairman of the Board. I join Connie, Jeff, and the management team of HEI in expressing our appreciation for your confidence and support. I look forward to seeing you at the Annual Meeting in Honolulu.

Sincerely,

Robert F. Clarke

Hawaiian Electric Industries
900 Richards Street
Honolulu, Hawaii 96813

HEI

NOTICE OF ANNUAL MEETING

Date and time	Tuesday, May 2, 2006, at 9:30 a.m.
Place	American Savings Bank Tower, 1001 Bishop Street, 8th floor, Room 805, Honolulu, Hawaii 96813.
Items of Business	1. Elect four Class I directors. 2. Elect KPMG LLP as the Company's independent registered public accounting firm. 3. Approve amending Article Fourth of the Restated Articles of Incorporation to increase the number of authorized common shares to 200,000,000. 4. Approve the 1990 Nonemployee Director Stock Plan, as amended and restated. 5. Approve amending Article Sixth of the Restated Articles of Incorporation to modify provisions related to the independent registered public accounting firm. 6. Transact any other business properly brought before the meeting.
Record Date	February 23, 2006
Annual Report	The 2005 Annual Report to Shareholders (Appendix A) and Summary Report to Shareholders, which are not a part of the proxy solicitation materials, have been mailed along with this Notice and accompanying Proxy Statement.
Proxy Voting	Shareholders of record may appoint proxies and vote their shares in one of three ways: • Via Internet pursuant to the instructions on the proxy card; • Calling the toll-free number on the proxy card; or • Signing, dating, and mailing the proxy card in the prepaid envelope provided. Shareholders whose shares are held by a bank, broker, or other financial intermediary (street name) should follow the voting instruction card included by the intermediary. Any proxy may be revoked in the manner described in the accompanying Proxy Statement.
Attendance at Meeting	If your shares are registered in street name, please bring a letter from your bank or broker or provide other evidence of your beneficial ownership if you plan to attend the Annual Meeting.

By Order of the Board of Directors

April 5, 2006

Patricia U. Wong
Vice President-Administration and Secretary

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Proxy Statement

Hawaiian Electric Industries, Inc. is soliciting proxies for the Annual Meeting of Shareholders scheduled for May 2, 2006. The mailing address of the principal executive offices of the Company is P.O. Box 730, Honolulu, Hawaii 96808-0730.

The approximate mailing date for this Proxy Statement, form of proxy, and annual and summary reports to shareholders for the fiscal year ended December 31, 2005, is April 5, 2006. The annual report and summary report are not considered proxy soliciting materials.

About the Meeting

Who can attend the meeting?

Attendance will be limited to:

- shareholders of record;
- beneficial owners of HEI Common Stock ("Common Stock") having evidence of ownership and entitled to vote at the meeting;
- authorized representatives of absent shareholders; and
- invited guests of management.

If you own shares of Common Stock in the name of a bank, brokerage firm or other holder of record, you must show proof of ownership. This may be in the form of a letter from the holder of record or a recent statement from the bank or broker showing ownership of Common Stock.

Any person claiming to be an authorized representative of a shareholder must produce written evidence of the authorization.

What are shareholders being asked to vote on?

- Election of four Class I directors for a three-year term expiring at the 2009 Annual Meeting of Shareholders.
- Election of KPMG LLP as the Company's independent registered public accounting firm.
- Approval to amend Article Fourth of the Restated Articles of Incorporation to increase the number of authorized common shares to 200,000,000.
- Approval of the 1990 Nonemployee Director Stock Plan, as amended and restated.
- Approval to amend Section (b) of Article Sixth of the Restated Articles of Incorporation to modify provisions related to the independent registered public accounting firm.

Voting Procedures

Who is eligible to vote?

Only shareholders of record at the close of business on February 23, 2006 (the record date) are entitled to vote.

How many shares are outstanding and entitled to vote?

On February 23, 2006, 81,051,976 shares of Common Stock were outstanding. Each shareholder is entitled to one vote for each share held. Under the By-Laws of the Company, shareholders do not have cumulative voting rights in the election of directors.

What constitutes a quorum?

A quorum is needed to conduct business at the Annual Meeting. A majority of the shares entitled to vote at the meeting constitutes a quorum. Abstentions and broker nonvotes will be counted in the number of shares present, in person or by proxy, for purposes of determining a quorum. A broker nonvote occurs when a broker does not have discretionary voting power to vote on a specific matter (such as nonroutine proposals) and has not received voting instructions from the beneficial owner.

How do shareholders vote?

Whether or not you plan to attend the Annual Meeting, please take the time to vote. You may vote by mail, telephone, or on-line via the Internet. The telephone and Internet procedures are designed to authenticate and confirm that your voting instructions are followed. You do not need to return your proxy if you vote by telephone or via the Internet.

- BY MAIL: Please mark your vote and sign, date, and promptly return the proxy in the enclosed postage-paid envelope. If you return the signed proxy but do not mark the boxes showing how you wish to vote, your votes will be cast following the recommendations of management on all proposals.
- BY TELEPHONE: Please call the toll-free telephone number on the proxy (1-888-693-8683). Once connected, you will be prompted to record and confirm your vote. Telephone voting is available 24 hours a day, through Monday, May 1, 2006, 11:59 p.m. (EDT).
- BY INTERNET: You may vote on-line by using the following Internet address: http://www.cesvote.com. Specific instructions will be available allowing you to record and confirm your vote. Internet voting is available 24 hours a day, through Monday, May 1, 2006, 11:59 p.m. (EDT).
- IN PERSON: You may vote your shares by attending the Annual Meeting and voting in person. If you wish to give your proxy to someone other than the individuals listed on the enclosed proxy, cross out all three names and insert the name of another person to vote your shares at the meeting.

How do shareholders vote if their shares are held in street name?

If your shares are held in "street name" (that is, through a broker, trustee or other holder of record), you will receive a proxy card from your broker seeking instruction as to how your shares should be voted. If no instructions are given, your broker or nominee may vote your shares at its discretion on your behalf on routine matters (such as the election of directors and the independent registered public accounting firm) under New York Stock Exchange rules.

You may not vote shares held in "street name" at the Annual Meeting unless you obtain a legal proxy from your broker or holder of record.

How do shareholders vote if their shares are held in the Dividend Reinvestment and Stock Purchase Plan (DRIP) and/or the 401(k) Hawaiian Electric Industries Retirement Savings Plan (HEIRS)?

If you own shares held in DRIP and HEIRS (including shares previously received under the Tax Reduction Act Stock Ownership Plan (TRASOP)), the respective plan trustees will vote the shares of stock held in these Plans according to your directions. For both DRIP and HEIRS, the respective trustees will vote all the shares of Common Stock for which they receive no voting instructions in the same proportion as they vote shares for which they receive instruction.

Can shareholders change their vote?

If you execute and return a proxy, you may revoke it at any time before the Annual Meeting in one of three ways:

- submit a properly signed proxy with a later date or vote again at a later time by telephone or Internet;
- notify the Secretary of the Company in writing; or
- vote in person at the Annual Meeting (if your shares are registered directly on the Company's books or, if your shares are held in "street name", you have a legal proxy from your broker or holder of record).

How many votes are required?

If a quorum is present at the Annual Meeting, then:

- directors shall be elected by a plurality of the votes cast in the election;
- the Company's independent registered public accounting firm shall be elected if more votes are cast in favor of election than against election;
- Articles Fourth and Sixth of the Articles of Incorporation shall be amended if no less than two-thirds of the shares entitled to vote are cast in favor of the amendment; and
- the 1990 Nonemployee Director Stock Plan, as amended and restated shall be approved if a majority of the votes cast are in favor of the amendments and the total vote cast on the proposal represents more than 50% of all shares entitled to vote.

Abstentions and broker nonvotes will count in establishing a quorum, but will not otherwise affect the outcome of the election of directors or the Company's independent registered public accounting firm. Abstentions and broker nonvotes, if any, will have the same effect as voting against the amendments to the Articles of Incorporation. Abstentions and broker nonvotes will not affect the outcome of the proposal to approve the 1990 Nonemployee Director Stock Plan, as amended and restated unless they cause the total votes cast to be less than 50% of the shares entitled to vote.

Who will count the votes and are the votes confidential?

Corporate Election Services will act as tabulator for broker and bank proxies as well as the proxies of the other shareholders of record. Your identity and vote will not be disclosed to persons other than those acting as tabulators except as follows:

- as required by law;
- to verify the validity of proxies and the results of the voting in the case of a contested proxy solicitation; or
- when you write a comment on the proxy form.

Proposals You May Vote On

1. Election of Class I Directors

The Board of Directors currently consists of 12 directors divided into three classes with staggered terms so that one class of directors must be elected at each Annual Meeting.

This year, the four Class I nominees being proposed for election at this Annual Meeting are:

- Shirley J. Daniel
- Constance H. Lau
- A. Maurice Myers
- James K. Scott

Robert F. Clarke, a Class I director, has announced his retirement from the Company and his service as a director will end at the 2006 Annual Meeting of Shareholders. Constance H. Lau is being proposed for election to the Board of Directors as a Class I director, replacing Mr. Clarke. She will succeed Mr. Clarke, as President and Chief Executive Officer of the Company at the Annual Meeting of Shareholders on May 2, 2006. Ms. Lau was previously a director of HEI from June 2001 to December 2004.

Each nominee, except Ms. Lau, is currently a member of the Board of Directors and has consented to serve for the new term expiring at the 2009 Annual Meeting. If a nominee is unable to stand for election, the proxy holders listed in the proxy may vote in their discretion for a suitable substitute.

YOUR BOARD RECOMMENDS THAT YOU VOTE FOR EACH OF THE NOMINEES FOR CLASS I DIRECTORS.

Detailed information on each nominee and Class II and III directors is provided on pages 9 to 11.

2. Election of Independent Registered Public Accounting Firm

KPMG LLP, an independent registered public accounting firm, has been the auditor of the Company since 1981. The Audit Committee selected KPMG LLP as its independent registered public accounting firm for 2006. The Board of Directors, upon the recommendation of its Audit Committee, recommends the election of KPMG LLP as the independent registered public accounting firm of the Company for fiscal year 2006 and thereafter until its successor is elected. Representatives of KPMG LLP will be present at the Annual Meeting and will be given the opportunity to make a statement and to respond to appropriate questions.

YOUR BOARD RECOMMENDS THAT YOU VOTE FOR KPMG LLP AS INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM OF THE COMPANY.

3. Amend the Restated Articles of Incorporation to Increase Authorized Shares of Common Stock

On January 31, 2006, the Company's Board of Directors recommended, pursuant to Section 414-283 of the Hawaii Business Corporation Act, that the shareholders approve at the Annual Meeting an amendment to Article Fourth of the Company's Restated Articles of Incorporation to increase the authorized number of shares of the Company's Common Stock, without par value, from 100,000,000 shares to 200,000,000 shares. If the proposed amendment is adopted, the total number of shares of all classes of stock which the Company is authorized to issue would be 210,000,000. The text of the proposed amendment is set forth in Appendix B to this Proxy Statement.

Reasons for Approval of the Proposed Increase in Authorized Common Shares

On June 10, 2004, the Company effected a two-for-one stock split, which increased the number of issued shares to 80,373,804. As of December 31, 2005, 80,983,326 shares of Common Stock were issued (of which 80,983,326 were outstanding and zero were held as treasury shares of the Company) leaving a balance of only 19,016,674 authorized but unissued shares of Common Stock available for issuance without further action by the shareholders. As of December 31, 2005, none of the Company's 10,000,000 shares of Preferred Stock, without par value, have been issued.

Although the Company's management currently has no plan or intention to take any of the following actions, the Board of Directors believes that it is necessary, and in the best interests of the Company, to have additional shares of Common Stock available for future stock splits or stock dividends, financings, acquisitions and other general corporate purposes. The Board considers this amendment advisable to provide the Company's management with greater flexibility to pursue transactions in which an issuance of Common Stock might be appropriate or desirable without the expense and delay of calling and holding a special shareholders' meeting for such a purpose at a later date. Aside from the issuance of Common Stock pursuant to employee stock options and the nonemployee director stock plan, the Company has not entered into any agreements, commitments or plans with respect to the sale or issuance of additional shares of Common Stock.

The increase in the authorized number of shares of Common Stock and the subsequent issuance of such shares could be used by the Board to delay or make more difficult a change of control of the Company. The proposed amendment is not prompted by any specific effort or takeover threat and management of the Company is not currently aware of any efforts to obtain control of the Company.

If the proposed amendment is approved by the shareholders, the Board may issue such additional shares without further action of, or authorization by, the shareholders, except as may be required by applicable law. The additional shares, when issued, will have the same rights and privileges as the shares of Common Stock currently outstanding. Shareholders have no preemptive rights to subscribe for or purchase any additional shares of Common Stock, except as may be agreed from time to time by the Board.

YOUR BOARD RECOMMENDS THAT YOU VOTE FOR THE AMENDMENT TO THE RESTATED ARTICLES OF INCORPORATION TO INCREASE THE NUMBER OF AUTHORIZED SHARES OF COMMON STOCK FROM 100,000,000 TO 200,000,000.

4. Amend the 1990 Nonemployee Director Stock Plan

The 1990 Nonemployee Director Stock Plan, as previously amended ("the Plan"), provides nonemployee directors with incentives to improve the Company's performance by increasing the level of stock owned by nonemployee directors to reinforce their role in enhancing shareholder value and to provide an additional means of attracting and retaining nonemployee directors.

As further described below, 200,000 shares of Company Common Stock (as adjusted for the Company's 2004 stock split) had been reserved for issuance under the Plan (176,722 shares of which have been issued as of the date hereof). The Board of Directors has amended the Plan, subject to your approval of this proposal, to reserve an additional 100,000 shares of Common Stock for issuance.

Attached as Appendix C to this proxy statement is a copy of the Plan as it would be amended and restated upon approval of the proposed amendment. The following summary of the Plan is qualified in its entirety by reference to the full text of the Plan, which is incorporated herein by reference.

YOUR BOARD RECOMMENDS THAT YOU VOTE FOR THE APPROVAL OF THE AMENDMENTS TO THE 1990 NONEMPLOYEE DIRECTOR STOCK PLAN.

Summary of Plan Terms

The Plan was originally adopted by the Company in 1990. It was subsequently amended in certain respects and, in 2002, was amended to incorporate provisions formerly memorialized in the Company's 1999 Nonemployee Company Director Stock Grant (the "1999 Plan"), which was thereupon superseded. The Plan has been amended in certain respects since 2002.

The plan is administered in the discretion of the Company's Nominating and Corporate Governance Committee or such other committee as may be appointed from time to time by the Company's Board of Directors (the "Committee"). The Plan provides benefits to nonemployee directors of the Company ("Nonemployee Company Directors") and nonemployee directors of Company subsidiaries ("Nonemployee Participating Company Directors") whose participation in the Plan has been approved by the Company's Board of Directors (a "Participating Company"). Currently, 11 HEI and 9 American Savings Bank, F.S.B. ("ASB") and Hawaiian Electric Company, Inc. ("HECO") directors participate in the Plan. ASB and HECO are subsidiaries of the Company.

Under the terms of the Plan: (i) each Nonemployee Company Director who serves in that capacity immediately following the date of an Annual Meeting of Shareholders of the Company receives a grant of Common Stock (a "Stock Payment") equal to one thousand four hundred (1,400) shares of Common Stock (two thousand (2,000) shares in the case of the first Stock Payment to a Nonemployee Company Director); and (ii) each nonemployee director of Company subsidiaries who serves in that capacity immediately following the date of an Annual Meeting of Shareholders receives a Stock Payment equal to one thousand (1,000) shares of Common Stock. Each individual who, during any calendar year, becomes a Nonemployee Company Director or Nonemployee Participating Company Director for the first time, other than at the Annual Meeting of Shareholders (whether by election or appointment as a director of the Company or a Participating Company), receives a Stock Payment equal to two thousand (2,000) shares of Common Stock (in the case of the Company) or one thousand (1,000) shares of Common Stock (in the case of a Participating Company). The dollar value of such Stock Payments will vary with changes in the fair market value of Company Common Stock. Such Stock Payments are paid by the Company as soon as practicable following the date the director is first elected or appointed to the Board of Directors of the Company or the Board of Directors of a Participating Company, as the case may be.

Once granted, the shares of Common Stock are not subject to forfeiture.

Before its amendment as described in this proposal, the Plan provided that the maximum number of shares of Company Common Stock that may be issued under the Plan, when taken together with any shares ever granted under the 1999 Plan, is 200,000 (as adjusted for the Company's 2004 stock split). As noted above, the proposed amendment would increase that amount by 100,000 shares to 300,000 shares (subject to appropriate adjustments upon changes in capitalization, such as a stock split).

The Board of Directors of the Company in its discretion may amend, suspend or terminate the Plan at any time. However, no such amendment will, without approval of the shareholders of the Company, change the class of persons eligible to receive Stock Payments under the Plan or otherwise modify the requirements as to eligibility for participation in the Plan, or increase the number of shares of Common Stock which may be issued under the Plan. Moreover, no amendment, suspension or termination of the Plan will, without the consent of any affected Nonemployee Company Director or Nonemployee Participating Company Director, alter, terminate, impair, or adversely affect any right or obligations under any Stock Payment previously granted under the Plan unless such amendment, suspension or termination is required by applicable law. Notwithstanding the foregoing, the Board of Directors of the Company may, without further action by the shareholders of the Company, amend the Plan or modify Stock Payments under the Plan in response to changes in securities or other laws, or rules, regulations or regulatory interpretations thereof, applicable to the Plan, or to comply with stock exchange rules or requirements.

Unless terminated earlier by the Board of Directors of the Company, the Plan will expire on April 27, 2010.

5. Amend the Restated Articles of Incorporation to modify provisions related to the independent registered public accounting firm.

On March 6, 2006, the Audit Committee of the Company's Board of Directors, which is comprised of independent directors, recommended, and on March 7, 2006, pursuant to Section 414-283 of the Hawaii Business Corporation Act, the Company's Board of Directors recommended, that the shareholders approve at the Annual Meeting an amendment to Section (b) of Article Sixth of the Company's Restated Articles of Incorporation to provide for the authority of the Audit Committee over the appointment, removal, compensation and oversight of the Company's independent registered public accounting firm; to provide for shareholder ratification, rather than election, of the appointment of the independent registered public accounting firm; to eliminate certain historical language; and make certain other changes in that provision. The text of the proposed amendment is set forth in Appendix D to this Proxy Statement.

Reasons for Approval of the Proposed Amendment

Currently the Company's Restated Articles of Incorporation provide that the Company's auditor shall be elected by the shareholders and serve until a successor is elected, but do not reflect the important role that the Company's Audit Committee plays in the auditor retention process. The proposed amendment to the Restated Articles of Incorporation would address this issue by embodying in the Company's Restated Articles of Incorporation one of the hallmarks of good corporate governance contained in the Sarbanes-Oxley Act of 2002, namely that the Audit Committee shall be responsible for the appointment, compensation and oversight of the independent registered public accounting firm. The Audit Committee and the Board believe that elevating this requirement into the Company's fundamental organizational document underscores their commitment to this central principle of good corporate governance.

More particularly, by requiring that the shareholders elect the auditor, the existing provision constrains the ability of the Audit Committee to remove and replace the Company's independent registered public accounting firm at any time other than when recommending an independent registered public accounting firm to the shareholders in connection with the Company's annual meeting of shareholders, because changing the auditor at other times of the year would require a special meeting of shareholders to effect the change. The need to remove or replace the independent registered public accounting firm can arise, however, at any time throughout the year, such as when the Audit Committee determines that it is in the best interest of the Company and its shareholders that the independent registered public accounting firm be removed or replaced or when the existing independent registered public accounting firm resigns. The delay occasioned in calling a special meeting of shareholders could impair the Audit Committee's ability to respond effectively in such circumstances.

The proposed amendments avoid the potential issues present in the existing provision by empowering the Audit Committee to appoint and remove the independent registered public accounting firm in these circumstances. In addition, the Audit Committee believes that enhancing the Audit Committee's authority over appointment and removal of the independent registered public accounting firm will increase the independent registered public accounting firm's accountability to the Audit Committee, because the independent registered public accounting firm will know that retention decisions can be made without the added delay and uncertainty of a shareholder meeting. The proposed revisions would require that any such appointment be subject to later ratification by the shareholders, thereby ensuring that shareholders would retain a voice in the independent registered public accounting firm retention process.

The other changes to Section (b) of Article Sixth of the Restated Articles of Incorporation are designed to specify that the stockholders ratify not elect the independent registered public accounting firm, to eliminate certain historical language, and to clarify that the independent auditor shall be an independent registered public accounting firm.

THE AUDIT COMMITTEE AND THE BOARD OF DIRECTORS RECOMMEND THAT YOU VOTE FOR THE AMENDMENT TO THE RESTATED ARTICLES OF INCORPORATION TO MODIFY PROVISIONS RELATING TO THE INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM.

Nominees for Class I directors whose terms expire at the 2009 Annual Meeting

Shirley J. Daniel, Ph.D., C.P.A.
Age 52
Director Since 2002

Professor of Accountancy, College of Business Administration, University of Hawaii-Manoa since 1986.

Director of American Savings Bank, F.S.B., Pacific Asian Management Institute, and University of Hawaii Center for International Business Education and Research. Henry A. Walker, Jr. Distinguished Professor of Business Enterprise, College of Business Administration, University of Hawaii-Manoa. Managing director of Pacific Asian Center for Entrepreneurship and E-Business.

Constance H. Lau
Age 53

President, chief executive officer and director of American Savings Bank, F.S.B. since June 2001. Chief operating officer and senior executive vice president of American Savings Bank, F.S.B. from December 1999 to June 2001.

Director of Hawaiian Electric Industries Charitable Foundation, Maunalani Foundation, Consuelo Zobel Alger Foundation, and Alexander & Baldwin, Inc. Trustee, Punahou School and Kamehameha Schools. President, Hawaii Bankers Association.

A. Maurice Myers
Age 65
Director Since 1991

Chairman, president and chief executive officer of Waste Management, Inc. (environmental services), Houston, Texas from November 1999 to November 2004; now retired.

Director of Hawaiian Electric Co., Inc. and Tesoro Petroleum. Member, Oceanic CableVision Advisory Board. Chairman of the Board, Emeritus, Keep America Beautiful Inc.

James K. Scott, Ed.D.
Age 54
Director Since 1995

President of Punahou School.

Director of Hawaiian Electric Company, Inc., Pacific and Asian Affairs Council, Hawaii Public Television, and Hawaii Association of Independent Schools. President, Secondary School Admission Test Board. Member, Hawaiian Educational Council and Young Presidents Organization. Trustee, Blood Bank of Hawaii.

Continuing Class II directors whose terms expire at the 2007 Annual Meeting

Diane J. Plotts
Age 70
Director Since 1987

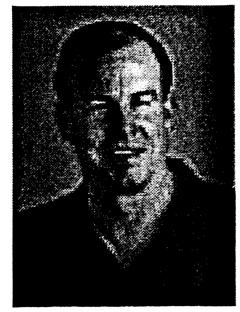
Business advisor since 2000.
Director of Hawaiian Electric Company, Inc. and American Savings Bank, F.S.B. Trustee, Kamehameha Schools.

Kelvin H. Taketa
Age 51
Director Since 1993

President and chief executive officer of the Hawaii Community Foundation.
Director of Hawaiian Electric Company, Inc., Grove Farm Company, Inc., and Civic Ventures. President and director of Sunrise Capital, Inc.

Jeffrey N. Watanabe
Age 63
Director Since 1987

Senior partner in the law firm of Watanabe Ing & Komeiji LLP.
Director of Hawaiian Electric Company, Inc., American Savings Bank, F.S.B., Alexander and Baldwin, Inc., Cellular Bioengineering, Inc., First Insurance Company of Hawaii, Grace Pacific Corporation, LOEA Corporation, Matson Navigation Company, Inc., Oahu Publications, Inc., Tissue Genesis, Inc., and Trex Enterprises Corporation. Trustee, Sesame Workshop, The Nature Conservancy of Hawaii and Hawaii Community Foundation. Chair, The Consuelo Zobel Alger Foundation.



Thomas B. Fargo
Age 57
Director Since 2005

Chairman, LOEA Corporation and SAGO Systems since April 2005 (high technology companies). President, Trex Enterprises Corporation (research and development for defense and homeland security). Commander, U.S. Pacific Command from May 2002 to February 2005. Commander-in-Chief of the Pacific Fleet from October 1999 to May 2002.
Director of Hawaiian Electric Company, Inc., Hawaiian Holdings, Inc. and Japan-America Society of Hawaii. Member, board of governors of Iolani School. Trustee, Hawaii Pacific University.

Continuing Class III directors whose terms expire at the 2008 Annual Meeting

Don E. Carroll
Age 64
Director Since 1996

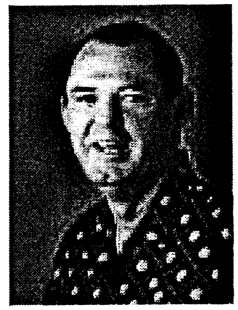
Chairman of Oceanic Cablevision from February 2001 to April 2005; now retired. Vice president of Time Warner Cable from 1985 to April 2005.

Director of American Savings Bank, F.S.B., Pacific Guardian Life, Island Insurance, American Red Cross-Hawaii Chapter, Executive Board of the Boy Scouts of America-Aloha Council, The 200 Club Advisory Board, and Hawaii Nature Center. Chairman, Broadband Interactive Television Board. Member, Oceanic CableVision Advisory Board and Finance Committee, Aloha United Way.

Victor Hao Li, S.J.D.
Age 64
Director Since 1988

Co-chairman, Asia Pacific Consulting Group. President, Li Xing Foundation. Chairman, Shanghai Li Xing School.

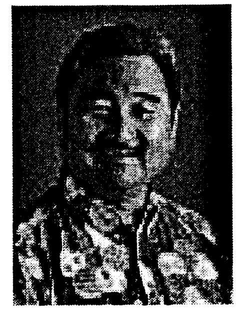
Director of American Saving Bank, F.S.B. Trustee, Japan-America Institute of Management Science.



Bill D. Mills
Age 54
Director Since 1988

Chairman of The Mills Group.

Director, Grace Pacific Corporation and Hawaii Public Television. Trustee, Hawaii Pacific University, St. Andrew's Priory, and The Nature Conservancy of Hawaii. Member, board of governors, Iolani School.



Barry K. Taniguchi
Age 58
Director Since 2004

President and chief executive officer of KTA Super Stores.

Director of Hawaiian Electric Company, Inc., American Savings Bank, F.S.B. and Hawaii Island Economic Development Board. Trustee, Hawaii Community Foundation, Public Schools of Hawaii Foundation, Tax Foundation of Hawaii, Hawaii Food Industry Association, and Lyman House Memorial Museum. Chairman, board of governors of Hawaii Employers Council.

Corporate Governance

What are the Company's governance policies and guidelines?

In 2005, the Board of Directors and management continued to review and monitor corporate governance trends and best practices to comply with the New York Stock Exchange ("NYSE") Listed Company Manual relating to corporate governance and Securities and Exchange Commission regulations. As part of an annual review, the HEI Corporate Governance Guidelines, Revised Code of Conduct (which includes the code of ethics for the HEI chief executive officer, financial vice president and controller), charters for the Audit, Compensation, Executive, and Nominating and Corporate Governance Committees were reviewed and revised as appropriate by the HEI Board of Directors. These documents, as well as HEI's Insider Trading Policy, may be found on the Company's website at www.hei.com and are available in print to any shareholder who requests them.

How does the Board select nominees for the Board?

The Nominating and Corporate Governance Committee considers candidates for Board membership suggested by its members and other Board members, as well as management and shareholders. The Committee may retain a third-party search firm to help identify candidates from time to time.

Among the qualifications considered in the Committee's assessment of a proposed candidate are knowledge, experience, skills, expertise, diversity, personal and professional integrity, character, business judgment, time availability in light of other commitments, dedication, and absence of conflicts of interest. The Committee believes that the Board should reflect a diversity of experience, gender, ethnicity, and age. The Committee also considers other relevant factors as it deems appropriate including, but not limited to, current composition of the Board, balance of independent and nonindependent directors, and need for financial expertise.

Once potential candidates are identified, the Committee may review publicly available information to assess whether the candidate should be considered further. If the Committee determines that the candidate warrants further consideration, the Chairman or another member of the Committee will contact the person, and if the person indicates a willingness to be considered for service on the Board, the candidate will be asked to provide information such as accomplishments and qualifications and one or more interviews may be conducted. The Committee members may contact one or more references provided by the candidate or other members of the business community who may have greater first hand knowledge of the candidate's qualifications and accomplishments. The evaluation process does not vary based on whether or not a candidate is recommended by a shareholder.

How can shareholders communicate with the directors?

Shareholders and all interested parties may contact (1) any member of the Board, including the Lead Director (nonemployee Chairman of the Board effective May 2, 2006) and an employee director or (2) just the nonemployee directors as a group, by mail. To communicate with the Board of Directors, any individual director or any group of directors, correspondence should be addressed to the Board of Directors or any such individual or group by either name or title. All such correspondence should be sent in care of the Corporate Secretary, Hawaiian Electric Industries, Inc., P. O. Box 730, Honolulu, HI 96808-0730. The mail will be forwarded, unopened, to the named individual director or, in the case of a group, to the Lead Director or the Chairman of the Board, effective May 2, 2006.

How does the Board evaluate itself?

Since 1996, the Board of Directors has followed an annual process of evaluating the operations and effectiveness of the Board as a whole as well as self-evaluations by individual directors up for election. In reviewing the Board as a whole, directors evaluate and comment on board structure, Board meetings (content, conduct, mechanics), Board responsibilities, performance of directors and relationship between the Board and management. Directors who are nominees for reelection evaluate their own individual meeting preparation, participation in Board meetings, contributions to the group, knowledge of the issues and concerns of the Company and understanding of the role of the Board in the governance of the Company. The Board and self-evaluation forms are submitted to the Nominating and Corporate Governance Committee for its review, after which the Committee recommends to the Board any procedures and practices to be adopted to improve the operations of the Board. The Chairman of the Nominating and Corporate Governance Committee may meet with individual directors to discuss their performance, as appropriate.

As required by the NYSE corporate governance listing standards, the Audit, Compensation and Nominating and Corporate Governance Committees developed a process for self-evaluation whereby committee members reviewed and evaluated their respective committee charters and committee meetings (content, conduct, and mechanics). The Audit Committee also reviewed and evaluated its duties and responsibilities, relationship with management and internal and external auditors, and the qualifications of its members.

Who are the independent directors of the Board?

For a director to be considered independent, the board must affirmatively determine that the director does not have any direct or indirect material relationship with the Company. The Board has established categorical standards to assist it in determining director independence. In addition to applying the standards, which are listed below, the Board considers all relevant facts and circumstances in making a determination of independence.

- A director who is an employee, or whose immediate family member is an executive officer, of the company is not "independent" until three years after the end of such employment relationship.

- A director who receives, or whose immediate family member receives, more than $100,000 per year in direct compensation from the Company, other than director and committee fees and pension or other forms of deferred compensation for prior service (provided such compensation is not contingent in any way on continued service), is not independent until three years after he or she ceases to receive more than $100,000 per year in such compensation.

- A director who is affiliated with or employed by, or whose immediate family member is affiliated with or employed in a professional capacity by, a present or former internal or external auditor of the company is not "independent" until three years after the end of the affiliation or the employment or auditing relationship.

- A director who is employed, or whose immediate family member is employed, as an executive officer of another company where any of the Company's present executives serve on that other company's compensation committee is not "independent" until three years after the end of such service or the employment relationship.

- A director who is an executive officer or an employee, or whose immediate family member is an executive officer, of a company that makes payments to, or receives payments from, the Company for property or services in an amount which, in any single fiscal year, exceeds the greater of $1 million or 2% of such other company's consolidated gross revenues, is not "independent" until three years after falling below such threshold.
- A director or any member of the director's immediate family who serves as an officer, director or trustee of a charitable organization that receives from the Company or its charitable foundation contributions which, in any fiscal year, exceed the greater of $1 million or 2% of such charitable organization's total annual charitable receipts is not "independent" until three years after falling below such threshold.

In its annual review of director independence, the board affirmatively determined that all directors of the Company are independent with the exception of Robert F. Clarke, an employee director.

In addition, the Board also determined that the Company did not make contributions to any tax exempt organization in which an independent director serves as an executive officer that exceeded the greater of $1 million, or 2% of such tax exempt organization's consolidated gross revenues.

What other Board practices does the Company have?

The nonemployee directors meet regularly in executive sessions without management. In 2005, these sessions were chaired by the Lead Director, Bill D. Mills. Beginning in May 2006 these sessions will be chaired by Jeffrey N. Watanabe, who has been named Chairman of the Board, effective at the Annual Meeting.

Information, material related to issues to be considered at a Board or Committee meeting, and other material important to the directors' understanding of the business are distributed, to the extent practical, to the directors in advance of the meeting to allow for careful review prior to the meeting.

Board of Directors

How often did the Board of Directors meet in 2005?

In 2005, there were six regular meetings of the Board of Directors. All directors attended at least 75% of the combined total meetings of the Board and Board committees on which they served (during the periods they served).

Did all directors attend last year's Annual Meeting?

All the members of the Board of Directors attended the 2005 Annual Meeting of Shareholders. The Company has a policy of encouraging the directors to attend each year's Annual Meeting of Shareholders.

How are directors compensated?

Only nonemployee directors are compensated for their service as directors. Director compensation beginning on April 1, 2005 is as follows:

Stock Grant

- A one-time grant of 2,000 shares of Common Stock to new directors.
- 1,400 shares of Common Stock are granted annually to directors for the purpose of further aligning directors' and shareholders' interests in improving stockholder value.

Fiscal Year Board Retainer commencing April 1 each year (no meeting fees are paid)

- $32,500 paid in quarterly installments.
- Additional annual fees are paid in quarterly installments to directors as follows:

Lead Director	$10,000
Audit Committee Chair	15,000
Compensation Committee Chair	5,000
Nominating and Corporate Governance Chair	5,000
Audit Committee Member	5,000

Subsidiary Board Fees

- Nonemployee directors of HEI who serve on the Board of Directors of Hawaiian Electric Company, Inc. ("HECO") or American Savings Bank, F.S.B. ("ASB") receive a fiscal year retainer of $20,000 for each such Board position.
- Diane J. Plotts, who serves as chair of the ASB Audit Committee, and Barry K. Taniguchi, who serves as chair of the HECO Audit Committee, receive an additional $10,000 annual fee for chairing each Audit Committee. An additional annual fee of $4,000 is paid to Don E. Carroll and Jeffrey N. Watanabe for serving on the ASB Audit Committee and to Thomas B. Fargo and Diane J. Plotts for serving on the HECO Audit Committee.

Do nonemployee directors receive a retirement benefit?

At the meeting of the Board of Directors on December 17, 1996, the Board voted to terminate the Nonemployee Director Retirement Plan, which had been approved by the shareholders on April 17, 1990. Pursuant to the terms of the termination, the right of previously retired directors to receive benefits continues in accordance with the terms of the Plan as in effect at termination, and the present value of the accrued benefit of directors age 55 or younger or with 5 years of service or less as of April 22, 1997 has been paid out. The retirement benefit for all other directors who had been participating in the Plan (Mr. Myers and Ms. Plotts) was frozen as of December 31, 1996, and will be paid according to the terms of the Plan as in effect at termination. Accordingly, upon their retirement from service as a director, Mr. Myers and Ms. Plotts will each receive an annual payment of $15,000 (their annual retainer in effect at December 31, 1996) for a period equal to the number of years of their active service through December 31, 1996 (7 years for Mr. Myers and 10 years for Ms. Plotts).

Committees of the Board

What committees has the Board established and how often did they meet?

The Board of Directors has four standing committees: Audit, Compensation, Executive, and Nominating and Corporate Governance. The names of the current committee members are shown on the table below. In addition, the table below also shows the number of meetings held in 2005.

Name	Audit	Compensation	Executive	Nominating and Corporate Governance
Don E. Carroll		X		
Robert F. Clarke*			X	
Shirley J. Daniel	X			
Thomas B. Fargo	X			
Victor Hao Li		X		
Bill D. Mills		X**	X**	X
A. Maurice Myers		X		
Diane J. Plotts	X**	X	X	
James K. Scott	X***			X***
Kelvin H. Taketa				X**
Barry K. Taniguchi	X			
Jeffrey N. Watanabe				X
Number of Meetings in 2005	8	3	0	1

* Employee director
** Committee chair
*** Effective March 7, 2006

What are the primary functions of each of the four committees?

- Audit Committee

The Audit Committee operates and acts under a written charter, which was adopted and approved by the HEI Board of Directors. The Committee provides independent and objective oversight of the Company's (1) financial reporting processes, (2) audits of the financial statements, including appointment, compensation and oversight of the external auditor, (3) internal controls, and (4) risk assessment and risk management policies set by management. The Committee also reviews and approves related party transactions and reviews and resolves complaints from any employee regarding accounting, internal controls or auditing matters. All members of the Committee are independent directors as independence for audit committee members is defined in the listing standards of the NYSE and none of them are members of audit committees of other publicly traded companies. See pages 35 and 36 for the Audit Committee Report.

- Compensation Committee

The Compensation Committee operates and acts under a written charter, which was adopted and approved by the HEI Board of Directors. The Committee oversees the Company's compensation and employee benefit plans and its incentive compensation and equity based plans. All members of the Committee are independent directors as defined in the listing standards of the NYSE. The Compensation Committee meets in executive session to set the compensation level of the Chief Executive Officer ("CEO") after receiving input on the CEO's performance from all the nonemployee directors meeting in executive session. The Committee then sets the compensation level of the CEO. See pages 28 to 33 for the Compensation Committee Report on Executive Compensation.

- Executive Committee

The Executive Committee operates and acts under a written charter, which was adopted and approved by the HEI Board of Directors, and is authorized to act on matters brought before it when a meeting of the full Board is impractical. It may also consider any other matter concerning the Company that may arise from time to time. The Committee is comprised of the Lead Director, the CEO and one other independent director. Beginning in May 2006, the Committee will be comprised of the Chairman of the Board, the CEO and one other independent director.

- Nominating and Corporate Governance Committee

The Nominating and Corporate Governance Committee operates and acts under a written charter, which was adopted and approved by the HEI Board of Directors. All members of the Committee are independent directors as defined in the listing standards of the NYSE. Its functions include (1) reviewing the background and qualifications of potential nominees for the board of directors of HEI and its subsidiary companies presented by shareholders, directors and management, (2) recommending to the Board the slate of nominees to be submitted to the shareholders for election at the next Annual Meeting, (3) advising the Board with respect to matters of Board composition and procedures, (4) overseeing the annual evaluation of the Board, (5) reviewing nonemployee director compensation and (6) overseeing corporate governance matters generally.

See the section on Corporate Governance for a discussion concerning the involvement of this Committee on matters relating to corporate governance.

Stock Ownership Information

How much stock do the Company's directors and executive officers own?

The following table shows how many shares of Common Stock were owned as of February 23, 2006 by each director, Named Executive Officer (as listed in the Summary Compensation Table on page 20) and by all directors and executive officers as a group.

Amount of Common Stock and Nature of Beneficial Ownership

Name of Individual or Group	Sole Voting or Investment Power	Shared Voting or Investment Power(1)	Other Beneficial Ownership(2)	Stock Options/ Stock Appreciation Rights(3)	Total
Nonemployee directors					
Don E. Carroll	10,985				10,985
Shirley J. Daniel	6,659				6,659
Thomas B. Fargo	3,519				3,519
Victor Hao Li	1,026	11,204	917		13,147
Bill D. Mills	22,700		10		22,710
A. Maurice Myers	26,016	3,689			29,705
Diane J. Plotts	11,380				11,380
James K. Scott	12,275				12,275
Kelvin H. Taketa	10,021				10,021
Barry K. Taniguchi		11,255			11,255
Jeffrey N. Watanabe	14,875		4		14,879
Employee director and Named Executive Officer					
Robert F. Clarke	42,082	53,746	4,056	205,364	305,248
Other Named Executive Officers					
Constance H. Lau	55,391		7,656	267,576	330,623
T. Michael May	42,379			151,454	193,833
Patricia U. Wong	3,921			1,161	5,082
Eric K. Yeaman	14,352			18,175	32,527
All directors and executive officers as a group (19 persons)	304,676	68,690	23,847	733,099	1,130,312(4)

(1) Shares registered in name of the individual and spouse.

(2) Shares owned by spouse, children or other relatives sharing the home of the director or officer in which the director or officer disclaims personal interest.

(3) Stock options/stock appreciation rights, including accompanying dividend equivalent shares, exercisable within 60 days after February 23, 2006 (record date), under the 1987 Stock Option and Incentive Plan.

(4) As of March 1, 2006, the directors and executive officers of HEI as a group beneficially owned 1.4% of outstanding Common Stock and no director or officer owned more than 0.4% of such stock.

Does the Company have stock ownership guidelines for directors and officers?

In 2003, the Board adopted stock ownership guidelines for HEI officers and directors. Each officer and director named in the guidelines, which went into effect on January 1, 2004, has five years to achieve the level of stock ownership set forth in the guidelines. The targets are as follows: 1) President and CEO of the Company — 2.5 times base salary, 2) executive officers of the Company and subsidiary operating company presidents — 1.5 times base salary, and 3) members of the Board of Directors of the Company — 5 times annual cash payouts. Stock ownership will be measured on January 1 of each year based on the average price of stock for the previous calendar year. The directors and officers have until January 1, 2009 to meet the current guidelines, except for Mr. Taniguchi, Admiral Fargo, and Ms. Wong who have until January 1, 2010 to meet the guidelines.

Does anyone own more than 5% of the Company's stock?

No person is known to the Company to be the beneficial owner of more than 5% of outstanding Common Stock.

Were Section 16(a) beneficial ownership reporting forms filed with the SEC?

Based on a review of forms filed by its reporting persons during the last fiscal year, the Company believes that they complied with the reporting requirements of Section 16(a) of the Securities Exchange Act of 1934.

Executive Compensation

Summary Compensation Table

The following summary compensation table shows the annual and long-term compensation of the chief executive officer and the four other most highly compensated executive officers of the Company and its subsidiaries serving during 2005 (collectively referred to as the "Named Executive Officers").

SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Annual Compensation			Long-Term Compensation			All Other Compensation(8) ($)
					Awards(4)		Payouts	
		Salary ($)	Bonus(2) ($)	Other Annual Compensation(3) ($)	Restricted Stock Award(5) ($)	Securities Underlying Options/SARs(6) (#)	LTIP Payouts(7) ($)	
Robert F. Clarke	2005	747,000	830,008	-0-	-0-	150,000	-0-	20,870
Chairman, President & CEO	2004	713,000	1,022,000	7,349	-0-	135,000	420,000	17,463
	2003	681,000	610,107	-0-	-0-	100,000	548,463	14,898
Constance H. Lau	2005	562,000	678,818	-0-	-0-	50,000	437,772	N/A
President & CEO, American	2004	538,000	751,400	-0-	-0-	50,000	388,260	N/A
Savings Bank, F.S.B.	2003	517,000	579,177	-0-	-0-	50,000	228,260	N/A
T. Michael May	2005	553,000	-0-	-0-	-0-	50,000	-0-	10,311
President & CEO, Hawaiian	2004	533,000	345,678	-0-	-0-	50,000	126,000	9,300
Electric Company, Inc.	2003	513,000	294,012	-0-	-0-	50,000	154,368	8,208
Eric K. Yeaman(1)	2005	364,000	216,944	-0-	-0-	30,000	-0-	1,187
Financial Vice President,	2004	348,000	377,658	-0-	-0-	30,000	116,800	1,114
Treasurer and Chief Financial Officer	2003	293,000	174,172	-0-	206,450	20,000	71,556	911
Patricia U. Wong(9)	2005	231,000	154,613	-0-	-0-	24,000	-0-	1,514
Vice President —	2004	163,000	23,979	-0-	-0-	-0-	NA	993
Administration and Corporate Secretary	2003	154,000	34,606	-0-	-0-	4,000	NA	867

NA Not Applicable (not a participant in the plan).

(1) Eric K. Yeaman became Financial Vice President, Treasurer and Chief Financial Officer effective January 15, 2003.

(2) The Named Executive Officers are eligible for an incentive award under the Company's annual Executive Incentive Compensation Plan ("EICP"). EICP bonus payouts are reflected as compensation for the year earned. Also includes special award in 2004 of $60,000 for Mr. Yeaman.

(3) Amount attributable to the reimbursement of taxes payable on the Company's payment of country club initiation fees.

(4) All awards and per share amounts prior to June 10, 2004 adjusted for 2 for 1 stock split in 2004.

(5) On August 11, 2003, 10,000 shares of restricted stock were granted to Mr. Yeaman. On the date of the grant, the closing price of HEI Common Stock was $20.65 on the New York Stock Exchange. Quarterly dividends on the 10,000 shares of restricted stock are paid to Mr. Yeaman. The 10,000 shares of restricted stock become unrestricted on August 11, 2006. On December 31, 2005, the restricted stock value was $259,000 based on the closing price of HEI Common Stock of $25.90 on the New York Stock Exchange.

(6) Options and stock appreciation rights (SARs) granted earn dividend equivalents as further described below under the headings "Stock Appreciation Rights Grants in Last Fiscal Year" and "Aggregated SAR/Option Exercises and Fiscal Year-End SAR/Option Values."

(7) Long-Term Incentive Plan ("LTIP") payouts are determined in the first quarter of each year for the three-year cycle ending on December 31 of the previous calendar year.

(8) Represents amounts attributable each year by the Company for certain preretirement death benefits provided to the Named Executive Officers, except Ms. Lau. See the Compensation Committee Report on page 33 under the heading "Other Compensation Plans" for a discussion of the preretirement death benefits.

(9) Patricia U. Wong became Vice President — Administration and Corporate Secretary effective April 26, 2005. In 2004 and 2003 she was HECO, Vice President of Corporate Excellence.

Stock Appreciation Rights Grants in Last Fiscal Year

The following table presents information on the SARs which were granted to the five Named Executive Officers during 2005 (on April 7, 2005). The practice of granting stock options, which include dividend equivalent shares, was followed each year from 1987 to 2003. The practice of granting SARs, which include dividend equivalent shares, has been followed each year since 2004.

STOCK APPRECIATION RIGHTS GRANTS IN LAST FISCAL YEAR

Name	Number of Securities Underlying SARs Granted(1) (#)	Percent of Total SARs Granted to Employees in Fiscal Year	Exercise Price ($/share)	Expiration Date	Grant Date Present Value(2) ($)
Robert F. Clarke	150,000	27%	$26.18	April 7, 2015	$873,000
Constance H. Lau	50,000	9	26.18	April 7, 2015	291,000
T. Michael May	50,000	9	26.18	April 7, 2015	291,000
Eric K. Yeaman	30,000	5	26.18	April 7, 2015	174,600
Patricia U. Wong	24,000	4	26.18	April 7, 2015	139,680

(1) These SARs vest at the end of four years (cliff vesting). Additional dividend equivalent shares are granted at no additional cost to the recipient throughout the four-year vesting period. Dividend

equivalents are computed, as of each dividend record date, both with respect to the number of shares under the SARs and with respect to the number of dividend equivalent shares previously credited to the Named Executive Officer and not issued during the period prior to the dividend record date. Accelerated vesting is provided in the event of a change-in-control or upon retirement.

(2) Based on a Binomial Option Pricing Model, which is a variation of the Black-Scholes Option Pricing Model calculated by the HEI Compensation Committee's independent compensation consulting firm. The Binomial Value is $5.82 per share. The following assumptions were used in the model: Stock Price: $26.18; Term: 10 years; Expected life: 4.5 years; Volatility: 18.1%; Risk-Free Interest Rate: 4.1%; and Dividend Yield: 5.9%. The following were the valuation results: Binomial SARs Value: $2.83; Dividend Credit Value: $2.99; and Total Value: $5.82.

In calculating the grant date present values set forth in the table, the volatility and dividend yield were based on the daily closing stock prices and dividends for the four and a half year period preceding the grant date. The risk-free interest rate was fixed on the date of grant at the rate of return on a stripped U.S. Treasury bill with a term to maturity approximately equal to the SARs expected life. Dividend equivalents are payable in the form of stock on the SARs for a period of four years. The value of the dividend equivalents was determined on the basis of the dividend yield, using the daily closing stock prices and dividends for the four and a half year period preceding the grant date. The use of different assumptions can produce significantly different estimates of the present value of SARs. Consequently, the grant date present value set forth in the table is only theoretical and may not accurately represent present value. The actual value, if any, a recipient will realize will depend on the excess of the market value of the HEI Common Stock over the exercise price on the date the SAR is exercised, plus the value of the dividend equivalents.

In December 2005, to accommodate changes to the tax rules imposed by the new Section 409A of the Internal Revenue Code of 1986, as amended (Section 409A), the Company modified the provisions for paying dividend equivalents on shares underlying nonqualified stock options and SARs that were vested on December 31, 2004, and the Company similarly modified provisions for paying dividend equivalents on dividends declared after 2004. Before modification, dividend equivalents were paid when and to the extent that the employee exercised the nonqualified stock option/SARs. In order to comply with Section 409A, any vested dividend equivalent subject to the modification will be paid not later than 2½ months after the year in which the underlying dividend equivalent is declared (without regard to whether the underlying nonqualified stock option/SAR is exercised). The amount of such dividend equivalent payment generally is reduced if, as of December 31 for the year the payment is made, the per share exercise price of the underlying nonqualified stock option/SAR exceeds the fair market value per share of the underlying common stock.

The Section 409A modification increased the fair value of the 2005 SARs by $0.12 per underlying share (at modification date).

Aggregated SAR/Option Exercises and Fiscal Year-End SAR/Option Values

The following table shows the stock options, including dividend equivalents, exercised by the Named Executive Officers in 2005. Also shown is the number of securities underlying unexercised SARs/options and the value of unexercised in the money SARs/options, including dividend equivalents, at the end of 2005. HEI granted dividend equivalents to all Named Executive Officers as part of the SAR or stock option grants.

Dividend equivalents permit a participant who exercises a SAR or stock option to obtain, at no additional cost, the amount of dividends declared between the grant and the exercise of the SAR or option during the vesting period, except for dividend equivalents modified for Section 409A, which do not require exercise and will be paid as described above. Dividend equivalents are computed as of each dividend record date throughout the four-year vesting period both with respect to the number of shares under the SAR or option and the number of dividend equivalent shares previously credited to the Named Executive Officer, which have not been exercised/issued during the period prior to the dividend record date.

AGGREGATED SAR/OPTION EXERCISES IN LAST FISCAL YEAR AND FISCAL YEAR-END SAR/OPTION VALUES

Name	Shares Acquired On Exercise (#)	Dividend Equivalents Acquired On Exercise (#)	Value Realized On Options ($)	Value Realized On Dividend Equivalents ($)	Number of Securities Underlying Unexercised SARs/ Options (Including Dividend Equivalents) at Fiscal Year-End Exercisable/ Unexercisable (#)	Value of Unexercised In the Money SARs/ Options (Including Dividend Equivalents) at Fiscal Year-End(1) Exercisable/ Unexercisable ($)
Robert F. Clarke . . .	100,000	24,909	653,200	625,625	185,186/353,155	1,267,645/1,018,697
Constance H. Lau .	10,000	3,150	60,750	83,708	253,927/136,421	2,736,970/ 465,307
T. Michael May . . .	—	—	—	—	137,805/136,421	1,200,255/ 465,307
Eric K. Yeaman . . .	—	—	—	—	19,626/ 67,000	108,274/ 159,540
Patricia U. Wong . .	6,000	1,293	42,820	33,391	—/ 27,162	—/ 34,191

(1) All grants were in the money (where the SAR/option price is less than the closing price on December 31, 2005) except the 2004 SAR grant at $26.02 and the 2005 SAR grant at $26.18. Values based on the closing price of $25.90 per share on the New York Stock Exchange on December 31, 2005. The 2004 and 2005 SAR grants were included in the table because the related dividend equivalents provided value exceeding the exercise price.

Long-Term Incentive Plan (LTIP) Awards

The table on page 25 lists the LTIP awards made to the Named Executive Officers during 2005. The table shows potential payments that are tied to performance over a three-year period (2005-2007) relating to two separate HEI goals for all the Named Executive Officers except Mr. May (who has a third goal in addition to the two HEI goals listed immediately below) and Ms. Lau (who has four separate goals that are unique to her).

The two separate HEI goals are (1) return on average common equity for HEI (weighted 60%), and (2) total return to HEI shareholders (weighted 40%). The weighting of each goal applies to all the Named Executive Officers except Mr. May and Ms. Lau. The Company's performance for the return on average common equity goal is based on an internal goal. The Company's performance for the total return to shareholders goal is measured against the Edison Electric Institute ("EEI") Index of Investor-Owned Electric Companies ("Peer Group") for the three-year period ending December 31, 2007. This is the same Peer Group used for the Shareholder Performance Graph shown on page 34. However, the performance of the LTIP Peer Group is calculated on a noncapitalized weighted basis whereas the Shareholder Performance Graph Peer Group is calculated on a capitalized weighted basis. The LTIP uses a noncapitalized weighted basis so as not to give a disproportionate emphasis to the larger companies in the Peer Group. For Mr. May, the two goals set forth above are (1) return on average common equity (weighted 30%), and (2) total return to shareholders (weighted 20%). Mr. May's third goal (weighted 50%) is based on a prorated percent of allowed return on average common equity for Hawaiian Electric Company, Inc. and subsidiaries ("consolidated HECO") for the same three-year LTIP cycle. Ms. Lau's four goals for the 2005-2007 LTIP cycle are (1) return on average common equity for American Savings Bank F.S.B. ("ASB") (weighted 40%), (2) ASB net income (weighted 40%), (3) ASB fee income (weighted 10%) and (4) ASB efficiency ratio (weighted 10%).

The threshold for minimum awards under the 2005-2007 LTIP with respect to the return on average common equity goal for the Company is 10.54%. The threshold minimum award with respect to the total return to shareholders goal will be earned if the Company's performance is at the 30th percentile of the Peer Group. Mr. May's threshold minimum for his third goal, which must be achieved in at least two out of three years during the LTIP cycle, is a prorated percent of allowed return on average common equity for consolidated HECO of 90%. Ms. Lau's threshold minimums for her four ASB goals are: (1) a return on average common equity of 10.49%, (2) achieve at least two out of three years during the LTIP cycle average net income of $62 million, (3) achieve in at least two out of three years during the LTIP cycle average fee income of $45.45 million and (4) achieve at the end of the third year efficiency ratio of 59.62%.

Maximum awards with respect to the Company's return on average common equity goal will be earned if the Company's return on average common equity is 11.75%. Maximum awards with respect to the Company's total return to shareholders will be earned if the Company's performance is measured at the 70th percentile of the Peer Group. For Mr. May, the maximum award on his third goal will be earned if the prorated percent of allowed return on average common equity for consolidated HECO equals 100%. For Ms. Lau, the maximum award for her four ASB goals will be earned based on: (1) a return on average common equity of 13.04%, (2) average net income of $77 million, (3) average fee income of $52.27 million and (4) efficiency ratio of 55.15%, which must be achieved at the end of the third year. Earned awards are distributed in the form of 60% cash and 40% Common Stock with the maximum award level for each Named Executive Officer ranging from 120% to 160% of the midpoint of the officer's salary grade range at the end of the three-year performance period.

LONG-TERM INCENTIVE PLAN — AWARDS IN LAST FISCAL YEAR

Name	Three-Year Performance Cycle Ending Date	Estimated Future Payouts: Minimum Threshold(1) ($)	Target ($)	Maximum ($)
Robert F. Clarke(2)	12/31/07	$301,600	$603,200	$1,206,400
Constance H. Lau	12/31/07	233,250	466,500	933,000
T. Michael May	12/31/07	211,875	423,750	847,500
Eric K. Yeaman	12/31/07	117,900	235,800	471,600
Patricia U. Wong	12/31/07	97,200	194,400	388,800

(1) Assumes meeting minimum threshold on all goals; however, if only one goal (weighted 40%) is met, the minimum threshold estimated future payout would be: Mr. Clarke — $120,640; Mr. Yeaman — $47,160; and Ms. Wong — $38,880. For Mr. May, if only one goal (weighted 20%) is met, the minimum threshold estimated future payout would be $42,375. For Ms. Lau, if only one goal (weighted 10%) is met, the minimum threshold estimated future payout would be $23,325. There is no LTIP payout unless the minimum threshold is met on at least one of the goals.

(2) If there is a payout under the 2005-2007 LTIP, Mr. Clarke will only be eligible to receive a pro-rated award since he will have been an active employee for 17 months of the 36-month period.

Equity Compensation Plan Information

Information as of December 31, 2005 about HEI Common Stock that may be issued upon the exercise of awards granted under all of the Company's equity compensation plans was as follows:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights(1)	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column(a))(2)
Equity compensation plans approved by shareholders	1,153,235	$22.92	4,305,181
Equity compensation plans not approved by shareholders	—	—	—
Total	1,153,235	$22.92	4,305,181

(1) Includes 929,000 of outstanding stock option and 187,209 of dividend equivalent shares accrued as of December 31, 2005 for such options. Also includes the 47,957 of dividend equivalent rights accrued as of December 31, 2005 for SARs, net of the 10,931 of outstanding converted SARs which are not in the money (i.e., the market price of common share as of December 31, 2005 is higher than the grant price).

(2) This represents the number of shares remaining available as of December 31, 2005, including 4,281,903 under the 1987 Stock Option and Incentive Plan of HEI as amended and restated effective April 20, 2004 and 23,278 under the HEI Nonemployee Director Plan. All of the shares remaining available for issuance under the HEI Nonemployee Director Plan may be issued in the form of unrestricted Common Stock. Of the shares remaining available for issuance under the 1987 Stock Option and Incentive Plan of HEI, as amended and restated effective April 20, 2004, 422,000 shares may be issued in the form of restricted stock, stock payments, or stock-settled restricted stock units (i.e., other than in the form of options, warrants or rights).

Pension Plans

All regular employees (including the Named Executive Officers) are covered by noncontributory, qualified defined benefit pension plans. The plans provide retirement benefits at normal retirement (age 65), reduced early retirement benefits and death benefits. The Named Executive Officers except Ms. Lau participate in the Retirement Plan for Employees of HEI and Participating Subsidiaries ("HEI Plan"). Ms. Lau participated in the HEI Plan while employed by HECO and HEI and is currently a participant in the American Savings Bank Retirement Plan ("ASB Plan"). Mr. Clarke and Mr. May also participate in the HEI Supplemental Executive Retirement Plan ("HEI SERP") and Ms. Lau also participates in the ASB Supplemental Retirement, Disability, and Death Benefit Plan ("ASB SERP") (see pages 27 and 28).

In December 2005 Mr. Yeaman was added as a participant to the HEI SERP effective April 1, 2006 or such later date when the plan is formally amended to comply with the requirements of IRC Section 409A.

Some of the Named Executive Officers are affected by Internal Revenue Code ("IRC") limitations on qualified plan benefits. They are, therefore, also covered under the HEI Excess Benefit Plan ("Excess Plan") and the HEI Excess Pay Supplemental Executive Retirement Plan ("Excess Pay SERP"), which are noncontributory, nonqualified plans.

The following table shows estimated annual pension benefits payable at retirement under the HEI Plan, Excess Plan and Excess Pay SERP based on base salary that is covered under the three plans and years of service with the Company and other participating subsidiaries.

PENSION PLAN TABLE

	Years of Service						
Remuneration	5	10	15	20	25	30	35
$250,000	25,500	51,000	76,500	102,000	127,500	153,000	167,500
300,000	30,600	61,200	91,800	122,400	153,000	183,600	201,000
350,000	35,700	71,400	107,100	142,800	178,500	214,200	234,500
400,000	40,800	81,600	122,400	163,200	204,000	244,800	268,000
450,000	45,900	91,800	137,700	183,600	229,500	275,400	301,500
500,000	51,000	102,000	153,000	204,000	255,000	306,000	335,000
550,000	56,100	112,200	168,300	224,400	280,500	336,600	368,500
600,000	61,200	122,400	183,600	244,800	306,000	367,200	402,000
650,000	66,300	132,600	198,900	265,200	331,500	397,800	435,500
700,000	71,400	142,800	214,200	285,600	357,000	428,400	469,000
750,000	76,500	153,000	229,500	306,000	382,500	459,000	502,500
800,000	81,600	163,200	244,800	326,400	408,000	489,600	536,000

The HEI Plan provides a monthly retirement pension for life. Benefits are determined by multiplying years of credited service and 2.04% (not to exceed 67%) times the participant's Final Average Compensation (average base salary as shown for the Named Executive Officers in the Summary Compensation Table for any consecutive 36 months out of the last 10 years that produces the highest monthly average) without any offset for social security. As of December 31, 2005, the Named Executive Officers had the following number of years of credited service under the HEI Plan: Mr. Clarke, 18 years; Mr. May, 13 years; Ms. Lau, 15 years; Mr. Yeaman, 3 years; and Ms. Wong, 15 years.

Benefits under the ASB Plan are determined by multiplying years of credited service (not to exceed 35 years) and 1.5% times the participant's Final Average Compensation (average compensation as shown for Ms. Lau in the Summary Compensation Table for the highest five of the last ten years of credited service) without any offset for social security. As of December 31, 2005, Ms. Lau had six years of credited service under the ASB Plan.

Section 415 of the IRC limits the retirement benefit that a participant can receive from qualified retirement plans such as the HEI Plan and ASB Plan. The limit for 2005 was $170,000 ($175,000 for 2006) per year at age 65. The Company adopted the Excess Plan to provide benefits that cannot be paid from the qualified plans due to this maximum limit, based on the same formula as the qualified plans.

IRC Section 401(a)(17) limits a participant's compensation that can be recognized under qualified retirement plans. The limit on the maximum compensation for 2005 under IRC Section 401(a)(17) was $210,000 ($220,000 for 2006). The Company adopted the Excess Pay SERP to provide benefits that cannot be paid from the qualified plans due to the maximum compensation limit under IRC Section 401(a)(17), based on the same formula as the qualified plans.

The Company also maintains two supplemental executive retirement plans ("HEI SERP" and "ASB SERP") for certain executive officers. Mr. Clarke and Mr. May participate in the HEI SERP and Ms. Lau participates in the ASB SERP. Mr. Yeaman will participate in the HEI SERP effective the later of April 1, 2006 or the date the plan is amended for IRC Section 409A. Benefits under the HEI SERP and ASB SERP are in addition to qualified retirement benefits payable from the HEI Plan, the ASB Plan and Social Security.

Under the HEI SERP, the executive is eligible to receive, at age 60, a benefit of up to 60% (depending on years of credited service) of the participant's average compensation, which includes amounts received under the annual EICP in the highest three out of the last five years of service. The benefit payable under the HEI SERP is reduced by the participant's primary Social Security benefit and the benefit payable from the HEI Plan, but in no event is it less than the benefit that would be payable under the HEI Plan before any IRC Sections 415 and 401(a)(17) reductions. The HEI SERP provides for reduced early retirement benefits at age 50 with 15 years of service or age 55 with five years of service, and survivor benefits in the form of an annuity in the event of the participant's death after becoming eligible for early retirement. Based on Mr. Clarke's announced retirement date of May 31, 2006, the overall total retirement benefits payable to Mr. Clarke in the form of a straight life annuity at age 63 is $603,011, based on his current compensation level ($92,608 from the HEI Plan, $510,403 from the HEI SERP, and no amount owing from the Excess Pay SERP or the Excess Plan). The overall benefits payable to Mr. May in the form of a straight life annuity projected to age 65 is $288,226, based on his current compensation level ($86,137 from the HEI Plan, $65,288 attributed to the HEI SERP, $136,801 calculated under the Excess Pay SERP and no amount owing from the Excess Plan).

The ASB SERP provides a benefit at age 65 of up to 60% (depending upon years of service) of the participant's average compensation (including 50% of the amounts received under the annual EICP) in the highest five consecutive years out of the last ten years of service, reduced by the participant's primary Social Security benefit and the benefit payable from the ASB and HEI Plans, but in no event is it less than the benefit that would be payable under the ASB Plan before any IRC Sections 415 and 401(a)(17) reductions. The ASB SERP also provides for termination and survivor benefits in certain circumstances. The overall total retirement benefits payable to Ms. Lau in the form of a straight life annuity projected to age 65 is $530,573, based on her current compensation level

($54,600 from the ASB Plan, $64,974 from the HEI Plan, $410,999 calculated under the HEI Excess Pay SERP and no amounts owing under the Excess Plan or the ASB SERP).

Change-in-Control Agreements

Since 1989, the Company has entered into change-in-control agreements with certain executives, including the Named Executive Officers listed in the Summary Compensation Table, to encourage and ensure their continued attention and dedication to the performance of their assigned duties without distraction in the event of potentially disruptive circumstances arising from a change-in-control of the Company.

Each agreement provides that benefits, compensation and position responsibility of these officers will remain at existing levels for a period of two years following a "change-in-control," unless the "Expiration Date" of the agreement has occurred. A "Change-in-Control" is defined to include a change-in-control required to be reported under the proxy rules in effect on the date of the agreements, the acquisition by a person (as defined under the Securities Exchange Act of 1934) of 25% or more of the voting securities of the Company, or specified changes in the composition of the Board of Directors of the Company following a merger, tender offer or certain other corporate transactions. "Expiration Date" is defined as the earliest to occur of the following:

(1) two years after a change-in-control;

(2) termination of the executive's employment by the Company for "Cause" (as defined in the agreement) or by the executive other than for "Good Reason" (as defined in the agreement);

(3) retirement; or

(4) termination of the agreement by the Company's Board of Directors, or termination of the executive's employment prior to a change-in-control.

If the employment of one of these executives is terminated after a change-in-control and prior to the expiration date, the Company is obligated to provide a lump sum severance equal to 2.99 times the executive's average W-2 earnings for the last five years (or such lesser period that the executive has been employed by the Company), subject to certain limitations. In the event of a change-in-control, all outstanding stock options/SARs would be accelerated and become immediately exercisable.

Compensation Committee Report on Executive Compensation

Introduction

The Compensation Committee of the Board, which is composed entirely of nonemployee, independent directors, makes decisions on executive compensation. The full Board ratifies decisions by the Committee.

The Committee has retained the services of an independent compensation consulting firm to assist the Committee in executive compensation matters.

Executive Compensation Philosophy

The Committee applies the following principles for the executive compensation program:

- maintains a compensation program that is fair in a competitive marketplace;
- provides compensation opportunities that relate pay with the Company's annual and long-term performance goals which support growth in shareholder value;
- recognizes and rewards individual initiative and achievements; and

- allows the Company to attract, retain, and motivate qualified executives who are critical to the Company's success.

The Committee believes that stock ownership by management is beneficial in aligning management's and shareholders' interests in improving shareholder value. It therefore uses stock options/SARs and stock payouts in the compensation program for the executive officers with a goal of increasing their stock ownership over time. In September 2003, the Board approved mandatory stock ownership guidelines for the Named Executive Officers and the Board.

Executive Compensation Program

The Company's executive compensation program includes:

- base salary;
- potential for an annual bonus based on overall Company financial and operational performance as well as individual performance; and
- the opportunity to earn long-term cash and stock-based incentives which are intended to encourage the achievement of superior results over time and to align executive officer and shareholder interests.

The second and third elements constitute the "at-risk" portion of the compensation program and are designed to link the interests of the executive with those of the shareholders. This means that total compensation for each executive may change significantly from year to year depending on the short- and long-term performance of the Company and its subsidiaries.

Base Salary

The Committee reviews salaries for executive officers in April of each year in consultation with the Committee's independent compensation consultant. The consultant examines the position and responsibilities of each officer at HEI and its subsidiaries against similar positions in similar organizations. Base salary references in those surveys represent the fiftieth percentile or midpoint of pay practices found in similar organizations.

Salaries for executive officers of the various HEI companies are based on competitive references drawn from compensation surveys and are weighted as follows:

- holding company — other electric utilities (25%), other financial institutions (25%), and general industry (50%)
- electric utilities — other electric utilities (100%)
- financial institution — other financial institutions (100%)

Based on the information from these surveys, the consultant recommends a salary range for each executive officer position. As noted, the midpoint of the range approximates the fiftieth percentile of the survey data and the range has a spread of plus and minus 20% around this midpoint.

Mr. Clarke's base salary is determined through the Committee and the Board's overall evaluation of his performance during the preceding year. This evaluation is subjective in nature and takes into account all aspects of his responsibilities at the discretion of the Committee. Based on the survey data provided by the consultant, the resulting salary range recommendation, and the Committee and the Board's overall evaluation of Mr. Clarke's performance during 2004, Mr. Clarke's base salary was increased from an annual rate of $725,000 to an annual rate of $757,600, effective May 1, 2005. The other Named Executive Officers also received salary increases ranging from 3.0% to 5.1%, based on Mr. Clarke's recommendation and the Committee's approval.

In May 2006, Mr. Clarke will retire after 19 years of service to HEI from his current position as Chairman, President and Chief Executive Officer of HEI. Ms. Lau will succeed Mr. Clarke on May 2, 2006, as HEI President and Chief Executive Officer, as well as Chairman of HECO. Ms. Lau will also retain her position as President and Chief Executive Officer of ASB and will add the title of Chairman of ASB's board. She will also be nominated to be elected a director of HEI. The Committee will determine what changes in compensation are appropriate in light of these changed responsibilities.

Annual Executive Incentive Compensation Plan

Under the Executive Incentive Compensation Plan ("EICP"), annual incentive awards are granted upon the achievement of financial and nonfinancial performance measures established by the Committee in the early part of each calendar year. The measures are stated in terms of minimum, target and maximum goals. These measures, which may differ for individual Named Executive Officers, may include:

- earnings per share;
- company (subsidiary) net income;
- total return to shareholders measured against the Edison Electric Institute (EEI) Index of Investor-Owned Electric Companies (Peer Group) for the same period;
- company specific financial, operational and strategic goals; and
- individual officer's performance.

In February 2006, the Committee established the 2006 Executive Incentive Compensation Plan (EICP) financial and other operational measures for the Named Executive Officers. Mr. Clarke, who has announced his retirement effective May 31, 2006 will not have the requisite service to participate in the 2006 EICP. Mr. Yeaman has an earnings per share goal (weighted 50%), a total return to shareholders goal (weighted 25%) and one operational goal (weighted 25%). Ms. Wong has an earnings per share goal (weighted 50%), a total return to shareholders goal (weighted 25%) and one operational goal (weighted 25%). Mr. May has a consolidated utility net income goal (weighted 45%), a consolidated utility capital expenditures goal (weighted 10%) and five utility operational goals (weighted a total of 45%). Ms. Lau has an ASB net income goal (weighted 35%), an ASB return on assets goal (weighted 35%) and one operational goal (weighted 30%).

The EICP has a minimum financial performance threshold linked to earnings per share or net income (based on whether the measurement is at the Company or subsidiary level) which must be achieved before a bonus can be considered. The current minimum, target and maximum award level ranges differ for each of the Named Executive Officers and are based on a November 2005 competitive assessment undertaken by the Committee's independent compensation consultant which looked at EICP award level opportunities from a cross-section of all industries, including some of the electric companies included in the Shareholder Performance Graph.

The prospective awards under the EICP for each of the Named Executive Officers currently range from 22.5% to 42.5%, from 45% to 85%, and from 90% to 170%, for the minimum, target, and maximum awards, respectively, of the midpoint of the executive salary grade ranges at the end of the year, but in any event in any individual case not in excess of $2 million. Potential payouts if all goals are met at the target level are currently estimated as follows: Ms. Lau, $394,550; Mr. May, $330,600; Mr. Yeaman, $191,500 and Ms. Wong, $130,500.

Under the 2005 EICP, Mr. Clarke received a payout of $830,008 in February 2006. This resulted from achievement of (1) the earnings per share goal (weighted 60%) near the maximum level, (2) one individual operational goal (weighted 10%) at maximum level, (3) one individual operational goal (weighted 5%) at maximum level, and one individual operational goal at minimum level (weighted 5%). The total return to shareholders goal (weighted 15%) and another operational goal (weighted 5%) were not achieved. The EICP award for Mr. Clarke was exclusively based on the foregoing measures. No further adjustment was made by the Committee. The other Named Executive Officers, except for Mr. May, who did not achieve the minimum earnings threshold, also received EICP payouts under the 2005 EICP, as noted in the Summary Compensation Table of the Executive Compensation section of this Proxy Statement.

Long-Term Incentive Plan

The Company provides a long-term incentive plan ("LTIP") that is linked to the long-term financial performance of the Company. All awards under the LTIP are paid 60% in cash and 40% in HEI Common Stock. The LTIP goals are based on achieving financial criteria established by the Committee for a three-year period. A new three-year performance period starts each year.

In February and March 2006, the Committee established the financial measures for the 2006-2008 cycle for the Named Executive Officers at HEI. Mr. Clarke, who has announced his retirement effective May 31, 2006 will not have the requisite service to participate in the 2006-2008 LTIP. There are two goals for Mr. Yeaman and Ms. Wong: (1) HEI return on average common equity (ROACE) goal (weighted 60%) based 50% on HECO's ROACE goal and 50% on ASB's ROACE goal and (2) HEI's total return to shareholders goal (weighted 40%).

Mr. May has three LTIP goals: (1) HECO consolidated ROACE goal (weighted 40%), based on HECO's percentile position measured against a utility peer group of the EEI Index of Investor-Owned Electric Companies, (2) HECO consolidated net income goal (weighted 40%) and (3) HEI's total return to shareholders (weighted 20%). Ms. Lau also has three LTIP goals: (1) ASB's ROACE (weighted 40%) based on an internal budget measurement, (2) ASB's net income (weighted 40%), and (3) HEI's total return to shareholders (weighted 20%).

The achievement of each of the goals for the Named Executive Officers is expressed in terms of minimum, target and maximum levels. The LTIP award levels for each of the Named Executive Officers are established by the Committee based on recommendations from the Committee's independent compensation consultant. The current minimum, target and maximum award level ranges differ for each of the Named Executive Officers and were based on a November 2005 competitive assessment undertaken by the Committee's independent compensation consultant which reviewed LTIP award level opportunities from a cross-section of all industries, including some of the electric companies included in the Shareholder Performance Graph.

The prospective awards under the LTIP for each of the Named Executive Officers currently range from 30% to 65%, from 60% to 130%, and from 120% to 260%, for the minimum, target, and maximum awards, respectively, of the midpoint of the executive salary grade ranges projected to the end of the performance period, but in any event not in any individual case in excess of $2.5 million. Potential payouts if all goals are met at the target level are currently estimated as follows: Ms. Lau, $510,400; Mr. May, $463,200; Mr. Yeaman, $241,200, and Ms. Wong, $183,000.

For the three-year cycle ending December 31, 2005, only Ms. Lau received an LTIP award between the target and maximum level for all three ASB goals of ROACE, net income, and fee income. Mr. Clarke, Mr. May, Mr. Yeaman and Ms. Wong received no payout on the ROACE or total shareholder return goals. Mr. May received no LTIP award for his third goal, consolidated utility ROACE as a percent of allowed return.

Stock Incentives

The Committee may grant nonqualified stock options, incentive stock options, restricted stock, stock appreciation rights, and dividend equivalents under the 1987 Stock Option and Incentive Plan (SOIP) of Hawaiian Electric Industries, Inc. (as amended, restated and approved by the shareholders on April 20, 2004). Prior to 2004, nonqualified stock options with dividend equivalents were issued to the Named Executive Officers under the Plan. In 2004 and 2005, the Committee granted Stock Appreciation Rights (SARs) with SARs dividend equivalents to the Named Executive Officers.

The number of SARs grants for each of the Named Executive Officers was based on a September 2003 competitive assessment undertaken by the Committee's independent compensation consultant. The assessment reviewed grants from a cross-section of all industries, including some of the electric companies included in the Shareholder Performance Graph. Based on this assessment, the consultant recommended a range of stock option grants for each of the Named Executive Officers. This range took into account the fact that a portion of the officer's long-term incentive opportunity is delivered through participation in the LTIP. In granting stock options or SARs, the Committee takes into consideration the amount and value of current options and SARs outstanding. The grants are intended to retain the officers, motivate them to improve long-term stock performance and to increase their ownership position in the Company over time. Stock options and SARs were granted at average fair market value which is based on the average of the daily high and low sales prices of HEI Common Stock on the New York Stock Exchange during the calendar month immediately preceding the date of grant. Stock options and SARs issued before 2005 vest in equal installments over a four-year period. The 2005 SARs award was granted with a four-year cliff vesting.

In 2005, the Compensation Committee granted Mr. Clarke a SARs award of 150,000 shares of HEI Common Stock (reflecting the Company's 2004 stock split) plus SARs dividend equivalents, with an exercise price of $26.18 per share. The award was based on the compensation consultant's recommendation and the independent evaluation of an appropriate award level by the Committee. In this evaluation, the Committee took into account prior grants to Mr. Clarke and an overall subjective evaluation of his job performance. The other Named Executive Officers also received the following SARs awards of HEI Common Stock plus SARs dividend equivalents in 2005: Ms. Lau 50,000 shares; Mr. May 50,000 shares; Mr. Yeaman, 30,000 shares; and Ms. Wong 24,000 shares.

In December 2005, to accommodate changes to the tax rules imposed by the new Section 409A of the Internal Revenue Code of 1986, as amended (Section 409A), the Company modified the provisions for paying dividend equivalents on shares underlying nonqualified stock options and SARs that were vested on December 31, 2004, and the Company similarly modified provisions for paying dividend equivalents on dividends declared after 2004. Before modification, dividend equivalents were paid when and to the extent that the employee exercised the nonqualified stock options/SARs. In order to comply with Section 409A, any vested dividend equivalent subject to the modification will be paid not later than 2½ months after the year in which the underlying dividend equivalent is declared (without regard to whether the underlying nonqualified stock option/SAR is exercised). The amount of such dividend equivalent payment generally is reduced if, as of December 31 for the year the payment is made, the per share exercise price of the underlying nonqualified stock option/SAR exceeds the fair market value per share of the underlying common stock.

As a result of this change for Section 409A, a total of 61,482 dividend equivalent shares were paid out to SOIP participants in February 2006 for the stock option grants of 2001-2003 and SARs grants of

2004 and 2005. The gross amount of 69,737 dividend equivalent shares subject to 409A was reduced by 8,255 shares because the exercise price of the SARs grants of 2004 and 2005 exceeded the value of the underlying common stock at December 31, 2005. The Named Executive Officers received the following dividend equivalent shares: Mr. Clarke 19,487 shares, Ms. Lau 9,049 shares; Mr. May 9,049 shares; Mr. Yeaman, 1,583 shares; and Ms. Wong -0- shares.

In December 2002, the Company elected to adopt the fair value based method of accounting for its stock options, as prescribed by Statement of Financial Accounting Standards (SFAS) No. 123, "Accounting for Stock-Based Compensation," as amended. In January 2006 the company adopted SFAS No. 123 (Revised 2004).

Other Compensation Plans

The Named Executive Officers participate in certain broad-based employee benefit plans and executive retirement and death benefits adopted by the Company. Other than the HEI Retirement Savings Plan (which qualifies under Section 401(k) of the Internal Revenue Code of 1986, as amended (IRC)), which offers the HEI Common Stock as one of the investment options, benefits under these other plans are not tied to Company performance.

The Company provides additional retirement benefits which are discussed on pages 26 to 28 for the Named Executive Officers and certain other employees. To provide for the event of death during active employment, the Company also provides all the Named Executive Officers (except Ms. Lau) and certain other employees Flex plan credits to purchase $50,000 term life insurance plus an amount equal to two times the employee's salary on an after-tax basis at the date of death, paid by the Company to the employee's beneficiary. If the employee dies after retirement, this benefit is reduced to $20,000 term life insurance plus an amount equal to one times the employee's salary at retirement, also on an after-tax basis. For Ms. Lau, ASB provides Flex plan credits to purchase term life insurance equal to one and one-half times her salary at the date of death in the event of death during active employment. If Ms. Lau dies after retirement, the Company provides a payout to her beneficiary in an amount equal to one times her salary at the date of her retirement on an after-tax basis.

Finally, the Committee reviewed the provisions of Section 162(m) of the IRC, relating to the $1 million deduction cap for executive salaries, and believes that no compensation for the five highest paid Named Executive Officers will be governed by this regulation except for Mr. Clarke and Ms. Lau. Compensation alternatives to comply with IRC Section 162(m) were approved by the shareholders at the 2003 Annual Meeting. The Committee will take Section 162(m) into account as one of the factors it considers in establishing executive compensation and will award deductible compensation to the extent consistent with its overall compensation policy. However, the Committee may determine to award compensation in excess of Section 162(m) deduction limits as it deems appropriate.

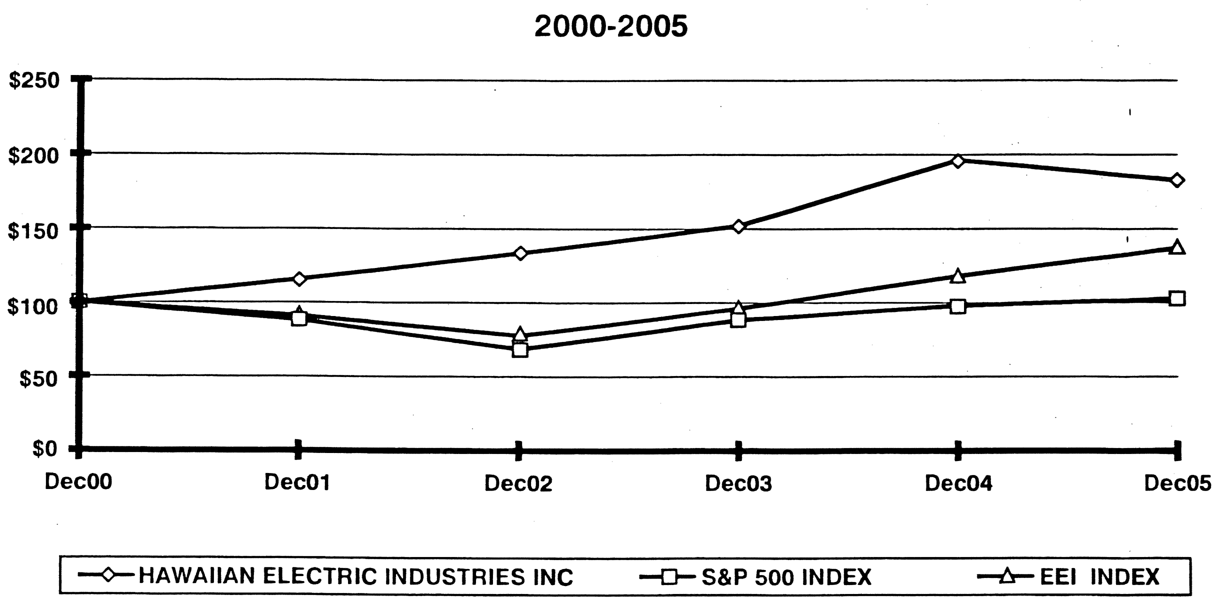
**SUBMITTED BY THE
COMPENSATION COMMITTEE
OF THE HEI BOARD OF DIRECTORS**

**Bill D. Mills, Chair
Don E. Carroll
Victor H. Li
A. Maurice Myers
Diane J. Plotts**

Shareholder Performance Graph

The graph below compares the cumulative total shareholder return on HEI Common Stock against the cumulative total return of companies listed on Standard & Poor's ("S&P") 500 Stock Index and the EEI Peer Group (65 companies were included in the Peer Group in 2005). The companies comprising the EEI Peer Group serve over 90% of the customers of the investor-owned electric utility industry. The graph is based on the market price of common stock for all companies at December 31 each year and assumes that $100 was invested on December 31, 2000 in HEI Common Stock and the common stock of all companies and that dividends were reinvested for all companies.

Comparison of Five-Year Cumulative Total Return
Among Hawaiian Electric Industries, Inc.,
S&P 500 Index, and EEI Peer Group



Audit Committee Report

The Audit Committee is responsible for providing independent, objective oversight of HEI's accounting functions and internal controls. It operates and acts under a written charter, which was adopted and approved by the Committee and the HEI Board of Directors. A copy of the Audit Committee Charter is attached to this Proxy Statement as Appendix E and may also be viewed on the Company's website. The Board has determined that the four directors of the Audit Committee meet the independence and other qualification requirements of the New York Stock Exchange Listed Company Manual and applicable securities laws. Ms. Plotts, Dr. Daniel and Mr. Taniguchi have been determined by the Board of Directors to be the "audit committee financial experts" on the Audit Committee. In addition, the Committee has standby arrangements with its own independent legal counsel and accounting advisors.

The Audit Committee oversees the Company's financial process on behalf of the Board of Directors. Management has the primary responsibility for the Company's consolidated financial statements and reporting process, including the systems of internal control. The independent registered public accounting firm has the responsibility for the independent audit of the consolidated financial statements and expressing an opinion on the conformity of those audited consolidated financial statements with U. S. generally accepted accounting principles.

In connection with these responsibilities, the Audit Committee held five regular and three special meetings in 2005. In these meetings with management and KPMG LLP, HEI's independent registered public accounting firm, the Committee's review and discussion included the audited consolidated financial statements, audit plan, and quality/adequacy of internal controls. The Committee believes that management maintains effective systems of internal control that result in fairly presented consolidated financial statements. Discussions with KPMG LLP included the matters required by Statement on Auditing Standards No. 61 (Codification of Statements on Auditing Standards §380), which incorporates information regarding the scope and results of the audit.

Independent Registered Public Accounting Firm's Independence

KPMG LLP provided the Committee with written disclosures and a letter regarding its independence from management as required by Independence Standards Board Standard No. I (Independence Discussions with Audit Committee). Based on its review of the disclosure statements and discussions with KPMG LLP, the Audit Committee satisfied itself as to the independence of the external auditor.

Auditors' Fees

The following table sets forth the fees paid or payable to KPMG LLP relating to the audit of the 2005 consolidated financial statements and fees for other professional services billed in 2005 with comparative amounts for 2004:

	2005		2004	
	Fees	**%**	**Fees**	**%**
Audit fees (principally consisted of fees associated with the audit of the consolidated financial statements and internal control over financial reporting (SOX 404), quarterly reviews, issuances of letters to underwriters, accounting consultations on matters reflected in the financial statements, statutory audits, review of registration statements, and issuance of consents)	2,171,000	96.0	$2,615,000	96.8
Audit-related fees (principally consisted of fees associated with the audit of the financial statements of certain employee benefit plans)	51,000	2.2	47,000	1.7
Tax fees (tax compliance services with respect to Federal and State taxes):				
American Savings Bank	25,000	1.1	25,000	0.9
Other	15,000	.7	15,000	0.6
All other fees (advisement on Sarbanes-Oxley Act of 2002)	0	0	0	0
	2,262,000	100.0	$2,702,000	100.0

The Audit Committee approved and adopted preapproval policies and procedures for nonaudit services proposed to be performed by the Company's independent auditor. The policies and procedures were implemented in 2002. Departmental requests for nonaudit services are reviewed by senior management and, once approved, are forwarded to the Chair of the Audit Committee for preapproval. The Audit Committee is asked to ratify the Chair's preapproval at its next scheduled meeting. In addition, the Audit Committee reviewed the professional fees billed by KPMG LLP and determined that the provision of nonaudit services was compatible with the maintenance of the auditors' independence. In addition, the Audit Committee, pursuant to the terms of its charter, approves all audit services to be performed by the independent auditor.

Based on its discussions with management and KPMG LLP and review of their representations, the Audit Committee recommended to the Board of Directors that the audited consolidated financial statements be included in HEI's 2005 Annual Report on Form 10-K.

SUBMITTED BY THE
AUDIT COMMITTEE
OF THE HEI BOARD OF DIRECTORS

Diane J. Plotts, Chair
Shirley J. Daniel
Thomas B. Fargo
James K. Scott (effective March 7, 2006)
Barry K. Taniguchi

Indebtedness of Management

Did the Company or any subsidiary provide loans to directors or executive officers?

American Savings Bank, F.S.B. ("ASB"), a subsidiary of the Company, offers preferential employee rate loans to its directors and executive officers, as allowed by the amended Federal Reserve Act.

Six ASB directors listed below who are also directors of HEI, whose aggregate indebtedness to ASB exceeded $60,000 at any time during 2005, received preferential rate loans as shown below.

Name	Largest Loan Amount Outstanding During 2005	Loan Amount Outstanding on 1/31/06	Type of Transaction	Average Interest Rate Charged(1)
Robert F. Clarke	$ 871,824	$ 826,845	First Mortgage	3.000%
Shirley J. Daniel	1,500,000	1,489,122	First Mortgage	4.000%
Constance H. Lau	842,136	818,676	First Mortgage	2.625%
Constance H. Lau	42,328	39,150	Second Mortgage	3.125%
Constance H. Lau	1,760	640	Credit Card	12.00%
Victor H. Li	357,218	349,129	First Mortgage	3.000%
Victor H. Li	1,841	0	Preferred Credit Line	12.00%
Diane J. Plotts	458,227	445,612	First Mortgage	2.265%
Jeffrey N. Watanabe	573,353	555,169	First Mortgage	3.750%

(1) The first mortgage rate is based on ASB's policy for employees and directors using a formula of .50% premium above the cost of funds or .50% premium above the Applicable Federal Rate established by the Internal Revenue Service, whichever is greater. The second mortgage rate uses the same formula with a premium of 1.0%. The interest rates for the employee Preferred Credit Line and credit card are set and reviewed annually by ASB's Management Committee, which is comprised of senior officers of the bank.

The Board of Directors approved a recommendation of the Nominating and Corporate Governance Committee that effective June 30, 2006, new preferential rate loans not be extended to any nonemployee directors of ASB, including directors who are also directors of HEI.

ASB made other loans, established lines of credit and issued credit cards to directors and executive officers of the Company, and to members of their immediate families. These loans and extensions of credit were made in the ordinary course of business, were made on substantially the same terms, including interest rates and collateral, as those prevailing at the time for comparable transactions with other persons, and did not involve more than the normal risk of collectibility or present other unfavorable features.

Transactions with Directors and Executive Officers

Did the Company enter into any transactions with directors or executive officers?

Director Jeffrey Watanabe is a partner in the law firm of Watanabe Ing and Komeiji LLP which performed legal services for the Company and certain of its subsidiaries during 2005.

Other Information

How is the solicitation to be made and what is its cost?

The Company pays all expenses of the proxy solicitation. Georgeson Shareholder Communications Inc. has been hired to assist in the distribution of proxy materials and solicitation of votes for $5,500 plus reasonable out-of-pocket expenses. In addition, the Company will reimburse brokerage firms and other custodians, nominees, and fiduciaries for their expenses to forward proxy and solicitation material to shareholders.

What is the deadline for submitting a proposal for next year's Annual Meeting?

Shareholders who want to have a proposal included in the Proxy Statement and form of proxy for the 2007 Annual Meeting of Shareholders must notify the Secretary of the Company in writing. The proposal must be received by December 6, 2006.

How can business matters be brought before the Annual Meeting and how will they be voted?

Shareholders who want to properly present business before the Annual Meeting must give notice to the Secretary of the Company no later than 60 days nor earlier than 90 days prior to the anniversary date of the preceding year's annual meeting. To be timely in the year 2007, notice must be received by the Secretary of the Company no later than March 3, 2007 nor earlier than February 1, 2007. The notice must be in writing and state the reason and brief description of the business, the name and address of the shareholder, number of shares of Common Stock owned by the shareholder, and any material interest of the shareholder in such business, and include a representation that the shareholder will present the business before the meeting in person or by proxy.

How can shareholders make recommendations for director nominees?

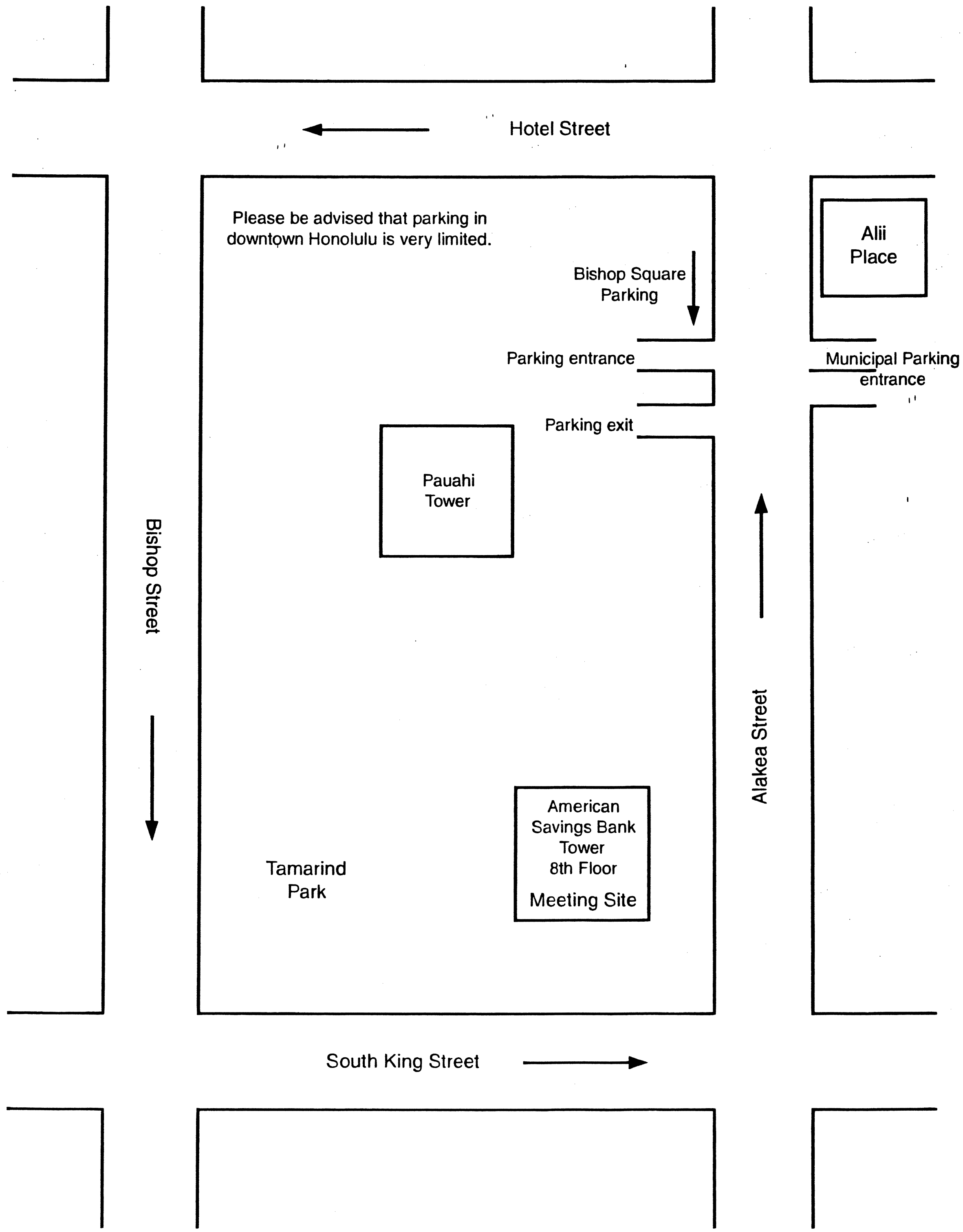
You can recommend any person as a director of HEI to the Nominating and Corporate Governance Committee by writing to the Committee in care of the Secretary, Hawaiian Electric Industries, Inc., P. O. Box 730, Honolulu, Hawaii 96808-0730. Recommendations must be received by December 6, 2006 for consideration by the Committee for the 2007 Annual Meeting of Shareholders. The recommendation must include the nominee's qualifications to be a director of the Company and other relevant biographical information and confirmation of the nominee's consent to serve. In addition, a shareholder nominating any person for election to the board at the annual meeting must provide notice no later than March 3, 2007 nor earlier than February 1, 2007. The notice must be in writing and provide the information required to be disclosed in any filing made in connection with solicitations of proxies for the election of directors pursuant to Section 14 of the Securities Exchange Act of 1934, as amended and the rules and regulations promulgated thereunder. The nomination must be accompanied by a written confirmation of the nominee's consent to serve.

If other business is properly brought before the Annual Meeting, or at any adjournment, the persons named on the enclosed proxy will vote your stock in accordance with their best judgment. The Company knows of no other business to be presented at the 2006 Annual Meeting.

Please vote your proxy as soon as possible to make certain that your shares will be counted at the meeting.

Patricia U. Wong
Vice President-Administration and Secretary

April 5, 2006


Hotel Street
Please be advised that parking in downtown Honolulu is very limited.
Bishop Square Parking
Alii Place
Parking entrance
Municipal Parking entrance
Parking exit
Pauahi Tower
Bishop Street
Alakea Street
American Savings Bank Tower 8th Floor
Meeting Site
Tamarind Park
South King Street

Appendix B

AMENDMENT TO ARTICLE FOURTH OF THE RESTATED ARTICLES OF INCORPORATION OF HAWAIIAN ELECTRIC INDUSTRIES, INC.

Amendment to Increase the Authorized Shares of Common Stock

Article Fourth is amended so that the first paragraph thereof shall read in its entirety of the Restated Articles of Incorporation of the Corporation as follows:

Fourth: The amount of the capital stock of the corporation shall be two hundred million (200,000,000) shares of Common Stock without par value and ten million (10,000,000) shares of Preferred Stock without par value.

Appendix C

HAWAIIAN ELECTRIC INDUSTRIES, INC.
1990 Nonemployee Director Stock Plan
As Amended and Restated: May 2, 2006

1. Purposes of the Plan

The purposes of this Hawaiian Electric Industries, Inc. 1990 Nonemployee Director Stock Plan are to provide participating directors with additional incentives to improve the Company's performance by increasing the level of stock owned by such nonemployee directors to reinforce the participating directors' role in enhancing shareholder value, and to provide an additional means of attracting and retaining such nonemployee directors through the issuance of Common Stock under the Plan as compensation to Nonemployee Directors. As amended and restated herein, this Plan incorporates all amendments effective on or before May 2, 2006, including provisions formerly memorialized in the Hawaiian Electric Industries, Inc. 1999 Nonemployee Company Director Stock Grant Plan, which is hereby superceded.

2. Definitions

When used herein, the following terms shall have the respective meanings set forth below:

(a) "Annual Retainer" means the annual fee payable to all Nonemployee Company Directors and Nonemployee Participating Company Directors as provided in Section 6 below (exclusive of any expense reimbursements).

(b) "Annual Meeting of Shareholders" means the annual meeting of shareholders of the Company, or any Participating Company, at which directors of the Company or the Participating Company, as the case may be, are elected.

(c) "Board" means the Board of Directors of the Company.

(d) "Committee" means the Nominating and Corporate Governance Committee of the Board or such other committee appointed from time to time by the Board to administer the Plan in accordance with Section 4(a) hereof.

(e) "Common Stock" means the common stock, without par value, of the Company.

(f) "Company" means Hawaiian Electric Industries, Inc., a Hawaii corporation, and any successor corporation.

(g) "Employee" means any officer or employee of the Company or any of its direct or indirect subsidiaries or affiliates (whether or not such subsidiary or affiliate participates in the Plan).

(h) "Nonemployee Company Director" means any person who is elected or appointed to the Board of Directors of the Company and who is not an employee.

(i) "Nonemployee Participating Company Director" means any person who is elected or appointed to the Board of Directors of any one or more Participating Companies and who is not an Employee.

(j) "Participating Company" means any direct or indirect subsidiary or affiliate of the Company whose participation in the Plan has been approved by the Board.

(k) "Plan" means the Company's 1990 Nonemployee Director Stock Plan, as amended and restated as set forth herein, as it may be further amended from time to time.

(l) "Stock Payment" means the grant of shares of Common Stock to Nonemployee Company Directors or Nonemployee Participating Company Directors for services rendered as a director of the Company or a Participating Company, as provided in Section 7 hereof.

3. Shares of Common Stock Subject to the Plan

Subject to adjustment as provided in Section 9 below, the maximum aggregate number of shares of Common Stock that may be issued under the Plan, when taken together with any shares ever granted under the provisions of the Hawaiian Electric Industries, Inc. 1999 Nonemployee Company Director Stock Grant Plan, is 300,000 shares. The Common Stock to be issued under the Plan will be made available from authorized but unissued shares of Common Stock, and the Company shall set aside and reserve for issuance under the Plan said number of shares.

4. Administration of the Plan

(a) The Plan will be administered by the Committee, which will consist of three or more Nonemployee Company Directors. Members of the Committee need not be members of the Board. The Company shall pay all costs of administration of the Plan.

(b) Subject to the express provisions of the Plan, the Committee has and may exercise such powers and authority of the Board as may be necessary or appropriate for the Committee to carry out its functions under the Plan. Without limiting the generality of the foregoing, the Committee shall have full power and authority (i) to determine all questions of fact that may arise under the Plan, (ii) to interpret the Plan and to make all other determinations necessary or advisable for the administration of the Plan, and (iii) to prescribe, amend, and rescind rules and regulations relating to the Plan, including, without limitation, any rules which the Committee determines are necessary or appropriate to ensure that the Company, each Participating Company and the Plan will be able to comply with all applicable provisions of any federal, state or local law, including securities laws and laws relating to the withholding of tax. All interpretations, determinations, and actions by the Committee will be final, conclusive, and binding upon all parties. Any action of the Committee with respect to the administration of the Plan shall be taken pursuant to a majority vote at a meeting of the Committee (at which members may participate by telephone) or by the unanimous written consent of its members.

(c) Neither the Company, nor any Participating Company, nor any representatives, employees or agents of the Company or any Participating Company, nor any member of the Board or the Committee or any designee thereof will be liable for any damages resulting from any action or determination made by the Board or the Committee with respect to the Plan or any transaction arising under the Plan or any omission in connection with the Plan in the absence of willful misconduct or gross negligence.

5. Participation in the Plan

(a) All Nonemployee Company Directors and Nonemployee Participating Company Directors shall participate in the applicable provisions of the Plan, subject to the conditions and limitations of the Plan, so long as they remain eligible to participate in the Plan.

(b) Nonemployee Company Directors and Nonemployee Participating Company Directors shall be eligible for Annual Retainers pursuant to the terms of Section 6 of the Plan and for Stock Payments pursuant to the terms of Section 7 of the Plan.

6. Determination of Nonemployee Directors' Annual Retainers

The Committee shall meet annually to determine the Annual Retainer for all Nonemployee Directors, subject to approval by the Board. Unless there are material changes in the duties of a Nonemployee Company Director or a Nonemployee Participating Company Director during the course of any calendar year, the Annual Retainer shall not be determined more than once each calendar year. The Annual Retainer shall be paid to each Nonemployee Company Director and each Nonemployee Participating Company Director by the respective company for which the person serves as a director. The Annual Retainer shall be paid at such times and in such manner as may be determined by the Board or the Committee.

7. Determination of Nonemployee Directors' Stock Payments

(a) Each Nonemployee Company Director who serves in that capacity immediately following the date of the Annual Meeting of Shareholders of the Company shall receive, in addition to the Annual Retainer payable to such Nonemployee Company Director, a Stock Payment equal to one thousand four hundred (1,400) shares of Common Stock for serving as a Nonemployee Company Director (two thousand (2,000) shares in the case of the first Stock Payment to a Nonemployee Company Director pursuant to this sentence). Each Nonemployee Participating Company Director (who is not also a director of the Company) who serves in that capacity immediately following the date of the Annual Meeting of Stockholders of one or more Participating Companies shall receive, in addition to the Annual Retainer payable to such Nonemployee Participating Company Director, a Stock Payment equal to one thousand (1,000) shares of Common Stock for serving as a Nonemployee Participating Company Director. Each Director who during any calendar year becomes a Nonemployee Company Director or Nonemployee Participating Company Director for the first time, other than at the Annual Meeting of Shareholders (whether by election or appointment as a director of the Company or a Participating Company), shall receive, in addition to any Annual Retainer payable, a Stock Payment equal to two thousand (2,000) shares of Common Stock (in the case of the Company) or one thousand (1,000) shares of Common Stock (in the case of a Participating Company), for serving as a Nonemployee Company Director or Nonemployee Participating Company Director, as the case may be. Such Stock Payments shall be paid by the Company as soon as practicable following the date such director is first elected or appointed to the Board of Directors of the Company or the Board of Directors of a Participating Company, as the case may be.

(b) No Nonemployee Company Director or Nonemployee Participating Company Director shall be required to forfeit or otherwise return to the Company any shares of Common Stock issued to him or her as a Stock Payment pursuant to the Plan notwithstanding any change in status of such director which renders him or her ineligible to continue as a participant in the Plan.

8. Shareholder Rights

(a) Nonemployee Company Directors and Nonemployee Participating Company Directors shall not be deemed for any purpose to be or have rights as shareholders of the Company with respect to any shares of Common Stock except as and when such shares are issued and then only from the date of issuance therefore. No adjustment shall be made for dividends or distributions or other rights for which the record date precedes the date of such issuance.

(b) Subject to the provisions of Section 8(a) above, Nonemployee Company Directors and Nonemployee Participating Company Directors will have all rights of a shareholder with respect to

Common Stock issued, including the right to vote the shares and receive all dividends and other distributions paid or made with respect thereto.

9. Adjustment for Changes in Capitalization

If the outstanding shares of Common Stock of the Company are increased, decreased, or exchanged for a different number or kind of shares or other securities, or if additional shares or new or different shares or other securities are distributed with respect to such shares of Common Stock or other securities, through merger, consolidation, sale of all or substantially all of the property of the Company, reorganization, recapitalization, reclassification, stock dividend, stock split, reverse stock split, combination of shares, rights offering, distribution of assets or other distribution with respect to such shares of Common Stock or other securities or other change in the corporate structure or shares of Common Stock, the maximum number of shares and/or the kind of shares that may be issued under the Plan may be appropriately adjusted by the Committee. Any determination by the Committee as to any such adjustment will be final, binding, and conclusive. The maximum number of shares issuable under the Plan as a result of any such adjustment shall be rounded up to the nearest whole share.

10. Continuation of Director or Other Status

Nothing in the Plan or in any instrument executed pursuant to the Plan or any action taken pursuant to the Plan shall be construed as creating or constituting evidence of any agreement or understanding, express or implied, that the Company or any other Participating Company, as the case may be, will retain a Nonemployee Company Director or Nonemployee Participating Company Director as a director or in any other capacity for any period of time or at a particular retainer or other rate of compensation, as conferring upon any director any legal or other right to continue as a director or in any other capacity, or as limiting, interfering with or otherwise affecting the right of the Company or a Participating Company to terminate a director in his or her capacity as a director or otherwise at any time for any reason, with or without cause, and without regard to the effect that such termination might have upon him or her as a participant under the Plan.

11. Compliance with Government Regulations

Neither the Plan nor the Company shall be obligated to issue any shares of Common Stock pursuant to the Plan at any time unless and until all applicable requirements imposed by any federal and state securities and other laws, rules, and regulations, by any regulatory agencies or by any stock exchanges upon which the Common Stock may be listed have been fully met. As a condition precedent to any issuance of shares of Common Stock and delivery of notice of share ownership evidencing such shares pursuant to the Plan, the Board or the Committee may require a Nonemployee Company Director or Nonemployee Participating Company Director to take any such action and to make any such covenants, agreements and representations as the Board or the Committee, as the case may be, in its discretion deems necessary or advisable to ensure compliance with such requirements. The Company shall in no event be obligated to register the shares of Common Stock issued or issuable under the Plan pursuant to the Securities Act of 1933, as now or hereafter amended, or to qualify or register such shares under any securities laws of any state upon their issuance under the Plan or at any time thereafter, or to take any other action in order to cause the issuance and delivery of such shares under the Plan or any subsequent offer, sale or other transfer of such shares to comply with any such law, regulation or requirement. Nonemployee Company Directors and Nonemployee Participating Company Directors are responsible for complying with all applicable federal and state securities and other laws, rules and regulations in connection with any offer, sale or other transfer of the shares of Common Stock issued under the Plan or any interest therein including, without limitation, compliance with the registration requirements of the Securities Act of 1933, as amended (unless an exemption therefrom is available), or with the provisions of Rule 144 promulgated thereunder, if available, or any successor provisions.

12. Nontransferability of Rights

No Nonemployee Company Director or Nonemployee Participating Company Director shall have the right to assign the right to receive any Stock Payment or any other right or interest under the Plan, contingent or otherwise, or to cause or permit any encumbrance, pledge or charge of any nature to be imposed on any such payment (prior to the issuance of notice of share ownership evidencing such Stock Payment) or any such right or interest.

13. Amendment and Termination of Plan

(a) The Board will have the power in its discretion, to amend, suspend or terminate the Plan at any time. No such amendment will, without approval of the shareholders of the Company:

(i) Change the class of persons eligible to receive Stock Payments under the Plan or otherwise modify the requirements as to eligibility for participation in the Plan; or

(ii) Increase the number of shares of Common Stock which may be issued under the Plan (except for adjustments as provided in Section 9 hereof).

(b) No amendment, suspension or termination of the Plan will, without the consent of the Nonemployee Company Director or Nonemployee Participating Company Director, alter, terminate, impair, or adversely affect any right or obligations under any Stock Payment previously granted under the Plan to such Participant, unless such amendment, suspension or termination is required by applicable law.

(c) Notwithstanding the foregoing, the Board may, without further action by the shareholders of the Company, amend the Plan or modify Stock Payments under the Plan (i) in response to changes in securities or other laws, or rules, regulations or regulatory interpretations thereof, applicable to the Plan, or (ii) to comply with stock exchange rules or requirements.

14. Governing Law

The laws of the State of Hawaii shall govern and control the interpretation and application of the terms of the Plan.

15. Effective Date and Duration of the Plan

The Plan, as amended and restated herein, will become effective as of May 2, 2006. Unless previously terminated by the Board, the Plan will terminate on April 27, 2010.

Appendix D

AMENDMENT TO ARTICLE SIXTH, SECTION (b) OF THE RESTATED ARTICLES OF INCORPORATION OF HAWAIIAN ELECTRIC INDUSTRIES, INC.

Amendment to Modify Provisions Related to the Independent Registered Public Accounting Firm

Article Sixth of the Restated Articles of Incorporation of the Corporation is amended so that Section (b) thereof shall read in its entirety as follows:

> There shall be an audit committee of the board of directors which shall be responsible for the appointment, removal, compensation and oversight of the corporation's registered public accounting firm. The audit committee shall ask the stockholders of the corporation to ratify such appointment at the annual meeting of stockholders. An independent registered public accounting firm appointed by the audit committee shall serve until a successor is elected or such independent registered public accounting firm's earlier resignation or removal by the audit committee of the board of directors following a determination that it is in the best interest of the corporation and its stockholders that the independent registered public accounting firm be so removed. Upon such resignation or removal the audit committee of the board of directors shall appoint a new independent registered public accounting firm. An independent registered public accounting firm so appointed shall be recommended for ratification at the next annual or special meeting of the stockholders of the corporation, unless such independent registered public accounting firm shall earlier resign or be replaced.

x x x x x

The text of Section (b) of Article Sixth prior to the amendment is as follows:

> (b) The stockholders of the corporation shall elect an auditor at the annual meeting of stockholders who shall not be an officer of the corporation and shall serve until a successor is elected. The auditor may be an individual, partnership or corporation. The initial auditor of the corporation to serve until the first annual meeting of stockholders shall be Peat, Marwick, Mitchell & Co.

Appendix E

CHARTER OF THE AUDIT COMMITTEE OF THE BOARD OF DIRECTORS OF HAWAIIAN ELECTRIC INDUSTRIES, INC. ADOPTED SEPTEMBER 17, 2002 (AS AMENDED DECEMBER 13, 2005)

Purpose

There shall be a committee of the board of directors (the "Board") of Hawaiian Electric Industries, Inc. ("HEI" or the "Company") to be known as the audit committee (the "Committee"). The Committee shall assist the Board in fulfilling its oversight responsibilities. The Committee's primary duties and responsibilities are to:

- Comply with all applicable laws and regulations and rules of the Securities and Exchange Commission ("SEC") and New York Stock Exchange ("NYSE") and Sarbanes Oxley Act of 2002 (the "Act").
- Monitor the quality and integrity of the Company's financial statements, financial reporting process and systems of internal controls regarding risk management, finance, accounting, and legal and regulatory compliance.
- Monitor the independence and qualifications of the Company's registered public accounting firm engaged for the purpose of preparing or issuing an audit report for inclusion in the Company's Annual Report on Form 10-K (referred to herein as the "independent auditors"); further, monitor the performance of the independent auditors and the Company's internal auditing function.
- Provide an avenue of communication among the independent auditors, management, the Company's internal auditing function and the Board.
- Issue the report pursuant to Item 306 of Regulation S-K of the SEC that is required to be included in the Company's annual proxy statement.

Membership

The Committee shall be composed of directors who are independent of the management of the Company and are free of any relationship that, in the opinion of the Board, might interfere with their exercise of independent judgment as a committee member.

The Committee will consist of a minimum of three members who shall be appointed annually by the Board. New members will be proposed by the nominating and corporate governance committee for approval and appointment by the Board. Vacancies on the Committee shall be filled by majority vote of the Board at the next meeting of the Board following the occurrence of the vacancy. No member of the Committee shall be removed except by majority vote of the Board. Each member of the Committee shall be qualified to serve thereon under the requirements of the NYSE and any additional requirements that the Board deems appropriate.

A chairperson of the Committee shall be appointed by the Board. The Committee shall meet no less than four times a year. The chairperson of the Committee or a majority of the members of the Committee may also call a special meeting of the Committee. The Committee, in its discretion, may ask members of management or others to attend its meetings (or portions thereof) and to provide pertinent information as necessary. A majority of the members of the Committee present in person or by means of a conference telephone or other communications equipment by means of which all persons participating in the meeting can hear each other shall constitute a quorum.

Responsibilities

The Committee shall provide assistance to the Board in fulfilling its responsibility to the shareholders, potential shareholders, and investment community relating to risk management, corporate accounting, reporting practices of the Company, and the quality and integrity of the financial reports of the Company. In so doing it is the responsibility of the Committee to maintain free and open means of communication among the independent auditors, those responsible for the internal auditing function, management of the Company and the Board.

In carrying out these responsibilities, the Committee will:

1. Have sole authority (subject to shareholder ratification, if applicable) to retain and terminate the independent auditors who will audit the books of the Company and its subsidiaries (with the input, if the Committee so desires, of Company management and, as appropriate, management and boards of directors of the Company's subsidiaries). The independent auditors are ultimately accountable to the Committee.

2. Have sole authority to approve the independent auditors' fee arrangements and other terms of service, and to approve all non-audit engagements of the independent auditors permitted by the Act, including the fees therefore and the terms of service (in each case, with the input, if the Committee so desires, of Company management and, as appropriate, management and boards of directors of the Company's subsidiaries). Approvals of all audit and, as provided in the Act and the SEC rules and regulations promulgated thereunder, all permitted non-audit services will be made in advance of the provision of such services. The Committee may delegate the preapproval of audit and permitted non-audit services to one or more of its members, provided that such members shall report any such approvals to the full committee.

3. At least annually, obtain and review a report by the independent auditors describing:

   (a) The independent auditors' internal quality-control procedures;

   (b) Any material issues raised by the most recent internal quality-control review, or peer review, of the independent auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the independent auditors, and any steps taken to address any such issues; and

   (c) All relationships between the independent auditors and the Company (in order to assess the independence of the independent auditors).

4. Evaluate the qualifications, independence and performance of the Company's independent auditors and in its sole discretion (subject, if applicable, to shareholder ratification), make decisions regarding the replacement or termination of the independent auditors when circumstances warrant. In making its evaluation, the Committee will consult with management. The Committee will present its conclusions with respect to the independent auditor to the full Board.

5. Meet with the independent auditors, those responsible for the internal auditing function, and management of the Company to review the scope of the proposed audit for the current year and the audit procedures to be utilized, monitor such plan's progress and results during the year, and, at the conclusion thereof, review such audit including any comments or recommendations of the independent auditors.

6. Review with the independent auditors, those responsible for the internal auditing function, and Company management the adequacy and effectiveness of the risk, financial, accounting and internal controls of the Company as well as of the disclosure controls and procedures of the Company, and elicit any recommendations that they may have for the improvement of such internal and disclosure control procedures or particular areas where new or more detailed controls or procedures are desirable. Particular emphasis will be given to the adequacy of such internal controls to expose any payments, transactions or procedures which might be deemed illegal or otherwise improper and the adequacy of disclosure controls to identify on a timely basis material information that should be disclosed to current and prospective investors. Further, the Committee will periodically review the Company's Corporate Code of Conduct. The Committee will also periodically discuss the Company's major financial risk exposures and steps management has taken to monitor and control such exposures.

7. Review periodically the Company's administrative, operational and auditing internal controls and evaluate whether the Company is operating in accordance with its prescribed policies, procedures and the Company's Corporate Code of Conduct with the chief executive officer and chief financial officer and independent auditors.

8. Regularly review the responsibilities, budget, staffing and performance of the internal audit function of the Company. The Company's Director of Enterprise Risk shall assist the Committee, at the Committee's direction, in the coordination with any outsourced internal audit services. Any third party provider that provides the Company's internal auditing function shall not also function as the Company's independent outside auditor. The Committee shall annually review and approve the internal audit plan and discuss any changes in the scope of the audit plan. The Committee shall review the results of the internal audit process with management and those responsible for the internal audit function, including significant findings, management's responses thereto, and the status of corrective actions or implementation of recommendations.

9. Discuss with management, the Company's independent auditors, and, if appropriate, those responsible for the internal audit function, the following information which is required to be reported by the independent auditor:

   a. Major issues regarding the accounting principles and financial statement presentations, including any significant changes in the Company's selection or application of accounting principles, and major issues as to the adequacy of the Company's internal controls and any special audit steps adopted in light of material control deficiencies.

   b. The effect of regulatory and accounting initiatives, as well as off-balance sheet structures, on the financial statements of the Company.

10. Receive and discuss periodic reports from the independent auditors, those responsible for the internal audit function, and management on significant accounting or financial reporting developments that may have a bearing on the Company in order to assess the impact on the Company.

11. Receive and review (1) pension audits of the HEI Retirement Plan, American Savings Bank, F.S.B. Retirement Plan, Postretirement Welfare Benefits Plan for Employees of Hawaiian Electric Company, Inc. ("HECO") and Participating Employees and (2) HEI Retirement Savings ("HEIRS") (401-K) Plan audits.

12. Meet to discuss the disclosures and quarterly financial statements contained in the quarterly reports of HEI and HECO on SEC Form 10-Q, including the Company's specific disclosures under "Management's Discussion and Analysis of Financial Condition and Results of Operations," with management and with the independent auditors to determine that the independent auditors concur with the disclosure and content of the financial statements presented to the shareholders. Any material changes in accounting principles or accounting for new significant items will be reviewed.

13. Prior to the release of the annual report to shareholders and the reports of HEI and HECO on SEC Form 10-K, discuss disclosures and the financial statements to be contained therein, including the Company's disclosures under "Management's Discussion and Analysis of Financial Condition and Results of Operations," with management and with the independent auditors to determine that the independent auditors concur with the disclosure and content of the financial statements to be presented to the shareholders. Any material changes in accounting principles or accounting for significant new items will be reviewed.

14. Meet to discuss periodically the Company's earnings press releases (especially the use of "pro forma" or "adjusted" information not prepared in compliance with generally accepted accounting principles), as well as financial information and earnings guidance (if any) provided by the Company to analysts and rating agencies. This responsibility may be discharged generally (i.e., the Committee may discuss the types of information to be disclosed and the types of presentation to be made), and does not require that each earnings release or each provision of financial information and earnings guidance (if any) be discussed in advance.

15. Meet separately, periodically, with management, those responsible for the internal auditing function, and with independent auditors.

16. At all of its meetings make sufficient opportunity available for the independent auditors to meet with the members of the Committee without members of management present. The Committee must regularly review with the independent auditors any difficulties the auditor encountered in the course of the audit work, including any restrictions on the scope of the independent auditors' activities or on access to requested information, and any significant disagreements with management.

17. Attempt to resolve all disagreements between the Company's independent auditors and management regarding financial reporting.

18. With respect to the hiring by the Company of current or former employees of the Company's independent auditors or any third party responsible for the internal auditing function, it is the policy of the Company that the hiring of any such current or former employee of the independent auditors must be approved in advance by the Committee, and that no current or former employee of the independent auditor or third party responsible for the internal auditing function who, within one year prior to the initiation of the audit, participated in any capacity in the Company's audit shall be hired in a financial reporting oversight role, as defined in Rule 2-01 of Regulation S-X under the Securities and Exchange Act of 1934.

19. Minutes of all meetings of the Committee shall be submitted to the Board of the Company for ratification. The Committee shall further report regularly to the full Board and will review with the full Board any issues that arise with respect to the quality or integrity of the Company's financial statements, the Company's compliance with legal or regulatory requirements, the performance and independence of the Company's independent auditors, the performance of those responsible for the internal auditing function, and other matters of importance to the full Board.

20. Issue the report pursuant to Item 306 of Regulation S-K of the SEC that is required to be included in the Company's annual proxy statement addressing the Committee's review of the Company's financial statements, certain communications with management and with the independent auditors, the Committee's recommendation as to whether the financial statements should be included in the Company's annual report on Form 10-K.

21. Review the Company's policies relating to the ethical handling of conflicts of interest and review past or proposed transactions between the Company and members of management. The Committee shall consider the results of any review of these policies and procedures by the Company's independent auditors or those responsible for the internal auditing function. The Company's Director of Enterprise Risk shall coordinate the review of the CEO expense accounts with those responsible for the internal auditing function, who shall report their findings to the Chair of the Committee.

22. At least annually, review the Company's Corporate Code of Conduct and the Company's program to monitor compliance with the Company's Corporate Code of Conduct, and meet periodically with HEI's Compliance Officer to discuss compliance with the Corporate Code of Conduct.

23. Maintain procedures, as set forth in Annex A hereto, for the receipt, retention and treatment of complaints received by the Company regarding financial statement disclosures, accounting, internal accounting controls or auditing matters, and the confidential, anonymous submission by employees of the Company of concerns regarding financial statement disclosures, accounting, internal accounting controls or auditing matters.

24. Cause to be made an investigation into any appropriate matter brought to its attention within the scopes of its duties, with the power to retain outside counsel for this purpose if, in its judgment, that is appropriate.

25. The Committee shall, on an annual basis, evaluate the scope of this Charter and the Committee's performance thereunder. The Committee shall deliver to the Board a report setting forth the results of its evaluation, including any recommended amendments to this Charter and any recommended changes to the Company's or the Board's policies or procedures. The Committee shall address all matters that the Committee considers relevant to its performance.

26. Obtain advice and assistance from outside legal, accounting or other advisors, as appropriate in the course of fulfilling its duties without the necessity of seeking Board approval, the cost of such advisors to be borne by the Company.

27. Perform such additional activities, and consider such other matters, within the scope of its responsibilities, as the Committee or the Board deems necessary or appropriate.

In carrying out its responsibilities, the policies and procedures of the Committee should remain flexible in order that it can best react to changing conditions and assure the directors and shareholders that the corporate accounting and reporting practices of the Company are in accordance with all requirements and are of the highest quality.

* * *

While the Committee has the duties and responsibilities set forth in this Charter, the Committee is not responsible for preparing or certifying the financial statements, for planning or conducting the audit or for determining whether the Company's financial statements are complete and accurate and are in accordance with generally accepted accounting principles.

In fulfilling their responsibilities hereunder, it is recognized that members of the Committee are not full-time employees of the Company, it is not the duty or responsibility of the Committee or its members to conduct "field work" or other types of auditing or accounting reviews or procedures or to set auditor independence standards, and each member of the Committee shall be entitled to rely on (i) the integrity of those persons and organizations within and outside the Company from which it receives information and (ii) the accuracy of the financial and other information provided to the Committee, in either instance absent actual knowledge to the contrary.

Nothing contained in this charter is intended to create, or should be construed as creating, any responsibility or liability of the members of the Committee, except to the extent otherwise provided under the applicable state and federal laws or the listing requirements of the NYSE which shall continue to set the legal standard for the conduct of the members of the Committee.

* * *

Annex A

Procedures for the Submission of Complaints or Concerns Regarding Financial Statement Disclosures, Accounting, Internal Accounting Controls or Auditing Matters

1. Employees may submit any concerns or complaints regarding financial statement disclosures, accounting, internal accounting controls or auditing matters to their respective controller, chief financial officer, president, compliance officer or the Hawaiian Electric Company ("HECO") General Counsel, any of whom must promptly notify the HEI Compliance Officer designated in the Corporate Code of Conduct. ***The Company is committed to the policy that no one will be subject to retaliation because of a good faith report of a concern or complaint regarding financial statement disclosures, accounting, internal accounting controls or auditing matters or any suspected violation of Company policy or the law.***

2. Non-employees may communicate concerns and complaints regarding financial statement disclosures, accounting, internal accounting controls or auditing matters to HEI's Compliance Officer by regular mail at the following address: HEI Compliance Officer, P.O. Box 730, Honolulu, Hawaii 96808-0730.

3. The Company shall forward to the Audit Committee of the Board of Directors any complaints that it has received regarding financial statement disclosures, accounting, internal accounting controls or auditing matters.

4. Any employee of the Company may submit, on a confidential, anonymous basis if the employee so desires, any concerns regarding financial statement disclosures, accounting, internal accounting controls or auditing matters by setting forth such concerns in writing and forwarding them in a sealed envelope to the Chair of the Audit Committee, in care of the HEI Corporate Secretary, such envelope to be labeled with a legend such as: "To be opened by the Audit Committee only." If an employee would like to discuss any matter with the Audit Committee, the employee should indicate this in the submission and include a telephone number at which he or she might be contacted if the Audit Committee deems it appropriate. Any such envelopes received by the HEI Corporate Secretary shall be forwarded promptly to the Chair of the Audit Committee. Upon receipt of any complaint or concern with respect to HECO or American Savings Bank, F.S.B. ("ASB"), the Chair of the Audit Committee shall promptly forward a copy of the complaint or concern to the chair of the audit committee of HECO or ASB, as appropriate. The Company will maintain the confidentiality of such reports to the extent reasonably possible.

5. The Company informs employees of their obligation to report and the procedures by which to report concerns regarding financial statement disclosures, accounting, internal accounting controls or auditing matters in the Corporate Code of Conduct, which is distributed to all employees and is available on the Company's Internet website, and in this Annex to the Charter, which is available on the Company's Internet website.

6. At each of its meetings, including any special meeting called by the Chair of the Audit Committee following the receipt of any information pursuant to this Annex, the Audit Committee shall review and consider any such complaints or concerns that it has received and take any action that it deems appropriate in order to respond thereto, *provided*, *however*, that the Chair of the Audit Committee will consult with the chair of the audit committee of HECO or ASB, as appropriate,

before any decision is made with respect to the handling of a complaint or concern involving either of those companies.

7. The Audit Committee shall retain any such complaints or concerns for a period of no less than 7 years.

8. This Annex A shall appear on the Company's website as part of this Charter.

Superseding Revised Sheet No. 50
Effective June 1, 2006

REVISED SHEET No. 50
Effective July 1, 2006

RATE SCHEDULES

The following listed sheets contain all rates in effect on and after the date indicated thereon subject to the Rules and Regulations of the Company applicable thereto:

Sheet	Schedule	Date Effective	Character of Service
50.1	Rate Adjustment	July 1, 2006	All Schedules Except Schedule Q
50.2	Interim Rate Increase	September 28, 2005	All Schedules Except Schedule Q
51	"R"	January 1, 1997	Residential Service
51A	"R"	September 1, 1992	Residential Service
52	"G"	January 1, 1997	General Service Non-Demand
53	"G"	September 1, 1992	General Service Non-Demand
54	"J"	January 1, 1997	General Service Demand
54A	"J"	January 1, 1996	General Service Demand
54B	"J"	September 1, 1992	General Service Demand
55	"H"	January 1, 1997	Commercial Cooking, Heating, Air Conditioning & Refrigeration Service
56	"H"	September 1, 1992	Commercial Cooking, Heating, Air Conditioning & Refrigeration Service
57	"PS"	June 1, 2001	Large Power Secondary Voltage Service
58	"PS"	June 1, 2001	Large Power Secondary Voltage Service
58A	"PS"	June 1, 2001	Large Power Secondary Voltage Service
58B	"PP"	June 1, 2001	Large Power Primary Voltage Service
58C	"PP"	June 1, 2001	Large Power Primary Voltage Service
58D	"PP"	June 1, 2001	Large Power Primary Voltage Service
58E	"PT"	June 1, 2001	Large Power Transmission Voltage Service
58F	"PT"	June 1, 2001	Large Power Transmission Voltage Service
58G	"PT"	June 1, 2001	Large Power Transmission Voltage Service

Superseding Revised Sheet No. 50A
Effective September 1, 2000

REVISED SHEET NO. 50A
Effective June 1, 2001

RATE SCHEDULES (continued)

Sheet	Schedule	Date Effective	Character of Service
59	"F"	January 1, 1997	Public Street Lighting, Highway Lighting, & Park & Playground Floodlighting
60	"F"	September 1, 1992	Public Street Lighting, Highway Lighting, & Park & Playground Floodlighting
61	"U"	January 1, 1995	Time-of-Use Service
61A	"U"	January 1, 1995	Time-of-Use Service
61B	"U"	January 1, 1996	Time-of-Use Service
62	"E"	June 1, 1996	Electric Service for Employees
63	Energy Cost Adjustment Clause	January 1, 1996	All Schedules Except Schedule Q
63A	Energy Cost Adjustment Clause	January 1, 1996	All Schedules Except Schedule Q
64	Rider "I"	January 1, 1986	Interruptible Contract Service
65	Rider "M"	February 1, 1998	Off-Peak and Curtailable Service
65A	Rider "M"	February 1, 1998	Off-Peak and Curtailable Service
65B	Rider "M"	February 1, 1998	Off-Peak and Curtailable Service
65C	Rider "M"	February 1, 1998	Off-Peak and Curtailable Service
65D	Rider "M"	February 1, 1998	Off-Peak and Curtailable Service
(PAGE 66 - NOT ASSIGNED)			
67	Rider "T"	January 1, 1995	Time-of-Day Service
67A	Rider "T"	January 1, 1995	Time-of-Day Service

Superseding Revised Sheet No. 50B
Effective November 1, 2006

REVISED SHEET NO. 50B
Effective December 1, 2006

RATE SCHEDULES (continued)

Sheet	Schedule	Date Effective	Character of Service
68	IRP Cost Recovery Provision	December 1, 2006	All Schedules Except Schedule Q
68A	IRP Cost Recovery Provision	December 1, 2006	All Schedules Except Schedule Q
		(PAGES 69 - 80 NOT ASSIGNED)	
81	"Q"	January 1, 1996	Purchases From Qualifying Facilities -100 kW or Less
81A	"Q"	January 1, 1996	Purchases From Qualifying Facilities -100 kW or Less
82	Green Pricing Program Provision	January 1, 1999	Green Pricing
82A	Green Pricing Program Provision	January 1, 1999	Green Pricing
83	Rider EV-R	July 6, 1998	Residential Electric Vehicle Charging Service
83A	Rider EV-R	July 6, 1998	Residential Electric Vehicle Charging Service

Superseding Sheet No. 50C
Effective January 1, 2004

REVISED SHEET NO. 50C
Effective May 13, 2006

RATE SCHEDULES (continued)

Sheet	Schedule	Date Effective	Character of Service
84	Rider EV-C	July 6, 1998	Commercial Electric Vehicle Charging Service
84A	Rider EV-C	July 6, 1998	Commercial Electric Vehicle Charging Service

(SHEETS NO. 85 - 89 NOT ASSIGNED)

SHEET NO. 50.1
Effective July 1, 2006
to June 30, 2007

RATE ADJUSTMENT

Supplement To

Schedule R	- Residential Service
Schedule E	- Electric Service For Employees
Schedule G	- General Service Non-Demand
Schedule J	- General Service Demand
Schedule H	- Commercial Cooking, Heating, Air Conditioning & Refrigeration Service
Schedule PS	- Large Power Secondary Voltage Service
Schedule PP	- Large Power Primary Voltage Service
Schedule PT	- Large Power Transmission Voltage Service
Schedule F	- Public Street Lighting, Highway Lighting, & Park & Playground Floodlighting
Schedule U	- Time-of-Use Service

All terms and provisions of Schedules "R", "E", "G", "J", "H", "PS", "PP", "PT", "F", and "U" are applicable except that the total base rate charges for each billing period shall be decreased by the Rate Adjustment approved by the Public Utilities Commission. The total base rate charges for each billing period include all base rate schedule charges, and base rate adjustments, and exclude the Energy Cost Adjustment, the IRP Cost Recovery Adjustment, Residential DSM Adjustment, and Commercial and Industrial DSM Adjustment.

Rate Adjustment:....................... -0.391 percent

The Rate Adjustment is based on passing through to customers the estimated reduction in capacity payments to AES Hawaii and related revenue taxes totaling $3,187,140 annually pursuant to Amendment No. 2 to the Purchase Power Agreement between AES Hawaii and HECO. The percentage is based on the forecast base revenues for the period July 1, 2006 through June 30, 2007. The percentage will be adjusted annually effective July 1 of each year to reflect a revised forecast of base revenues for the next 12 month period.

RECONCILIATION ADJUSTMENT:

In order to reconcile any differences that may occur between the amount passed through to customers and the estimated reduction in the capacity payments and related revenue taxes, the recorded amount for the Rate Adjustment will be compared with the $3,187,140 estimated reduction in capacity payments and related revenue taxes on a quarterly basis. If there is a variance between the recorded amount for the Rate Adjustment and the refunded amount, a reconciliation adjustment, lagged by two months and effective for three months, will be made to the above Rate Adjustment.

HAWAIIAN ELECTRIC COMPANY, INC.

Transmittal Letter dated June 30, 2006.

INTERIM RATE INCREASE

Supplement To

Schedule R	- Residential Service
Schedule E	- Electric Service For Employees
Schedule G	- General Service Non-Demand
Schedule J	- General Service Demand
Schedule H	- Commercial Cooking, Heating, Air Conditioning & Refrigeration Service
Schedule PS	- Large Power Secondary Voltage Service
Schedule PP	- Large Power Primary Voltage Service
Schedule PT	- Large Power Transmission Voltage Service
Schedule F	- Public Street Lighting, Highway Lighting, & Park & Playground Floodlighting
Schedule U	- Time-of-Use Service
Schedule TOU-R	- Residential Time-of-Use Service Pilot Program

All terms and provisions of Schedules "R", "E", "G", "J", "H", "PS", "PP", "PT", "F", "U", and "TOU-R" are applicable except that the total base rate charges for each billing period shall be increased by the following Interim Rate Increase approved by the Public Utilities Commission. The total base rate charges for the current billing period shall include all base rate schedule charges, and base rate adjustments, excluding the Energy Cost Adjustment, the IRP Cost Recovery Adjustment, Residential DSM Adjustment, Commercial and Industrial DSM Adjustment, and Rate Adjustment.

INTERIM RATE INCREASE:

Schedule R/E/TOU-R........................	6.60 percent
Schedule G................................	5.97 percent
Schedule J/U..............................	6.40 percent
Schedule H................................	6.68 percent
Schedule PS...............................	7.65 percent
Schedule PP...............................	7.04 percent
Schedule PT...............................	0.00 percent
Schedule F................................	9.33 percent

The above Interim Rate Increase is based on the interim increase of $53,235,400 approved by the Public Utilities Commission in its Interim Decision & Order No. 22050 in Docket No. 04-0113. The revenues collected through this Interim Rate Increase are subject refund with interest in accordance with the Public Utilities Commission's Interim Decision & Order No. 22050.

Superseding Revised Sheet No. 51
Effective January 1, 1996

REVISED SHEET NO. 51
Effective January 1, 1997

SCHEDULE "R"

Residential Service

Availability:

Applicable to residential lighting, heating, cooking, air conditioning and power in a single family dwelling unit metered and billed separately by the Company. This schedule does not apply where a residence and business are combined.

Service will be delivered at secondary voltages as specified by the Company.

Rate:

CUSTOMER CHARGE:

Single Phase Service - per month	$7.00
Three Phase Service - per month	$15.00

NON-FUEL ENERGY CHARGE (To be added to Customer Charge)

All kwhr per month - per kwhr	7.7814 cents

BASE FUEL/ENERGY CHARGE (To be added to Customer Charge and Non-Fuel Energy Charge)

All kwhr per month - per kwhr	3.5140 cents

Minimum Charge:

The minimum monthly charge shall be $16.00.

Apartment House Collection Arrangement:

Any apartment owner having three or more apartments at one location, each apartment being separately metered and billed on the above rate, may elect to accept a discount of ten percent (10%) of the amount of the bills rendered for each apartment, but not to exceed $5.00 per month for each apartment, upon entering into the following collection agreement with the Company under the following terms and conditions:

1) All accounts shall be kept in the name of the apartment house owner who shall assume the responsibility for the prompt payment of all bills.

SCHEDULE "R" (continued)

2) All accounts shall remain active at all times and, though vacant, shall be subject to the minimum charge. Individual apartments cannot be added or deleted from this agreement more often than once in twelve months.

3) The Company will render individual bills for each apartment on a regular billing period basis and will also furnish a statement showing gross and net billings.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy Charges.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy Charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 52
Effective January 1, 1996

REVISED SHEET NO. 52
Effective January 1, 1997

SCHEDULE "G"

General Service Non-Demand

Availability:

Applicable to general light and/or power loads less than or equal to 5000 kwh per month, and less than or equal to 25 kilowatts, and supplied through a single meter.

If a customer's usage exceeds 5000 kwh per month or in the opinion of the Company exceeds 25 kw of demand three times in a twelve-month period, a demand meter will be installed and the customer's billing will be transferred to Schedule "J" beginning with the next convenient billing period.

Service will be delivered at secondary voltages as specified by the Company, except that where the nature or location of the customer's load makes delivery at secondary voltage impractical, the Company may, at its option, deliver the service at a nominal primary voltage as specified by the Company. Service supplied at primary voltage shall be subject to the special terms and conditions set forth below.

Rate:

CUSTOMER CHARGE:

Single phase service - per month	$20.00
Three phase service - per month	$45.00

ENERGY CHARGE: (To be added to Customer Charge)

All kwhr per month - per kwhr	11.1570 cents

Minimum Charge:

Single phase service - per month	$25.00
Three phase service - per month	$45.00

Primary Supply Voltage Service:

Where, at the option of the Company, service is delivered and metered at the primary supply line voltage, the above energy charges will be decreased by 1.9%. When customers' transformers are adjacent to the delivery point, the Company may permit the customer to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customers' transformers, the above energy charge will be decreased by 0.7%.

Superseding Revised Sheet No. 53
Effective October 25, 1991

REVISED SHEET NO. 53
Effective September 1, 1992

Schedule "G" (continued)

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy Charges.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy Charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 54
Effective January 1, 1996

REVISED SHEET NO. 54
Effective January 1, 1997

SCHEDULE "J"

General Service Demand

Availability:

Applicable to general light and/or power loads which exceed 5000 kilowatthours per month three times within a twelve-month period, or 25 kilowatts, and supplied through a single meter.

Rate:

CUSTOMER CHARGE:

Single phase service - per month	$35.00
Three phase service - per month	$60.00

DEMAND CHARGE - (To be added to Customer Charge)

All kw of billing demand - per kw per month $5.75

ENERGY CHARGE: (To be added to Customer and Demand Charges)

First	200	kwhr/month/kw of billing demand - per kwhr	8.6900 cents
Next	200	kwhr/month/kw of billing demand - per kwhr	7.5419 cents
All over	400	kwhr/month/kw of billing demand - per kwhr	6.5130 cents

Minimum Charge:

The minimum monthly charge shall be the sum of the Customer and the Demand Charges. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand, but not less than $143.75 per month. The kilowatts of demand for the minimum charge calculation each month shall be the highest of the maximum demand for the month, the greatest maximum demand of the preceding eleven months or 25 kw.

Determination of Demand:

The maximum demand for each month shall be the maximum average load in kw during any fifteen-minute period as indicated by a demand meter. The billing demand for each month shall be the maximum demand for such month but not less than 75% of the greatest maximum demand for the preceding eleven months nor less than 25 kw.

Superseding Revised Sheet No. 54A
Effective September 1, 1992

REVISED SHEET NO. 54A
Effective January 1, 1996

SCHEDULE "J" (continued)

Power Factor:

For customers with maximum measured demands in excess of 200 kilowatts per month one time within a twelve-month period, the following power factor adjustment will apply to the energy and demand charges.

For each 1% the average power factor is above or below 85%, the energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%. The power factor will be computed to the nearest whole percent.

In no case, however, shall the power factor be taken as more than 100% for the purpose of computing the adjustment.

The average monthly power factor will be determined from the readings of a Kwh meter and a Kvarh meter. The Kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

This Power Factor Clause became effective on January 17, 1993, when installation of the KVARH meters on qualified customers was completed.

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	3.3%
Distribution voltage supplied without further transformation	1.9%

Metering will normally be at the delivery voltage. When customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 2.4% and 0.7%, respectively.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy Charges.

Superseding Sheet No. 54B
Effective October 25, 1991

REVISED SHEET NO. 54B
Effective September 1, 1992

SCHEDULE "J" (continued)

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy Charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SCHEDULE "H"

Commercial Cooking, Heating
Air Conditioning and Refrigeration Service

Availability:

Applicable to commercial cooking, heating (including heat pump waterheaters), air conditioning and refrigeration service. This schedule applies only where the voltage supplied by the Company is less than 600 volts.

Rate:

CUSTOMER CHARGE:

Single phase service - per month	$20.00
Three phase service - per month	$45.00

DEMAND CHARGE: (To be added to Customer Charge)

$9.00 per kw per month of required kw load, but in no case less than $9.00 per month.

ENERGY CHARGE: (To be added to Customer and Demand Charges)

All kwhr per month - per kwhr	7.7422 cents

Minimum Charge:

The minimum monthly charge shall be the sum of Customer and Demand Charges.

Determination of Required kw load:

The required kw load for billing purposes shall be:

A. The sum of:

1) The total connected motor load;
2) 50% of the connected heating load, exclusive of cooking and all-electric resistance and heat pump waterheating; and
3) the connected all-electric waterheating load in excess of one-sixth kilowatt per gallon of storage capacity; or

Superseding Revised Sheet No. 56
Effective October 25, 1991

REVISED SHEET NO. 56
Effective September 1, 1992

SCHEDULE "H" (continued)

B. When the load is 25 KW or more the demand may be determined by measured demand. The maximum demand for each month shall be the maximum average load during any fifteen-minute period as indicated by a demand meter. The demand for each month shall be the maximum demand for such month, the highest demand in the preceding eleven months, or 25 KW, whichever is highest. Measured demand service under this schedule will be referred to as Schedule "K" service. The Schedule K service will be closed to new customers after August 31, 1992.

The required kw load will be determined to the nearest one-tenth kw.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy Charges.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy Charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Term of Contract:

Not less than one year.

Superseding Revised Sheet No. 57
Effective January 1, 1997

REVISED SHEET NO. 57
Effective June 1, 2001

SCHEDULE PS

LARGE POWER SECONDARY VOLTAGE SERVICE

AVAILABILITY:

Applicable to large light and/or power service supplied and metered at a single voltage and delivery point. Service under this Schedule shall be delivered at a secondary voltage specified by the Company.

RATES:

CUSTOMER CHARGE - $ per customer per month:	$320.00/month
DEMAND CHARGE - $ per kW of billing demand:	
First 500 kW of billing demand - per kW	$10.00/kW
Next 1000 kW of billing demand - per kW	$9.50/kW
Over 1500 kW of billing demand - per kW	$8.50/kW
ENERGY CHARGE - ¢ per kWh:	
First 200 kWh/month/kW of billing demand - per kWh	7.2087 ¢/kWh
Next 200 kWh/month/kW of billing demand - per kWh	6.4104 ¢/kWh
Over 400 kWh/month/kW of billing demand - per kWh	6.1010 ¢/kWh

NETWORK SERVICE ADJUSTMENT:

Because of the inherent operating conditions in the downtown area supplied from the Company's underground network system, the Company will deliver and meter the service to customers in this area at 120/208Y or 277/480Y volts. The demand and energy charges will be increased by 0.9%.

Superseding Revised Sheet No. 58
Effective October 25, 1991

REVISED SHEET NO. 58
Effective June 1, 2001

SCHEDULE PS - Continued

MINIMUM CHARGE:

The minimum monthly charge shall be the sum of the Customer and Demand charges. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall be the highest of the maximum demand for the month, the greatest maximum demand for the preceding eleven months, or the minimum billing demand specified below, rounded to one-tenth kW.

DETERMINATION OF DEMAND:

The maximum demand for each month shall be the maximum average load in kW during any fifteen-minute period as indicated by a demand meter. The billing demand for each month shall be the highest of the maximum demand for such month, or the mean of maximum demand for the current month and the greatest maximum demand for the preceding eleven (11) months, whichever is the higher, but not less than the minimum billing demand specified below, rounded to one-tenth kW:

Minimum Billing Demand:

Power Service Only	150 kW (Closed to new Customers after January 1, 1986)
Power & Lighting Service	300 kW

Power Factor:

The above demand and energy charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed above, shall be decreased or increased, respectively, by 0.10%. The power factor will be computed to the nearest whole percent.

Schedule PS - Continued

Power Factor - cont.

In no case, however, shall the power factor be taken as more than 100% for the purpose of computing the adjustment.

The average monthly power factor will be determined from the readings of a kWh and Kvarh meter. The Kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, Energy, and Network Service charges, and Power Factor.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, Energy, and Network Service charges, Power Factor, and energy cost adjustment.

TERM OF CONTRACT:

Not less than one year.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

SCHEDULE PP

LARGE POWER PRIMARY VOLTAGE SERVICE

AVAILABILITY:

Applicable to large light and/or power service supplied and metered at a single voltage and delivery point. Service under this Schedule shall be delivered at a primary voltage specified by the Company.

RATES:

CUSTOMER CHARGE - $ per customer per month:	$320.00/month
DEMAND CHARGE - $ per kW of billing demand:	
First 500 kW of billing demand - per kW	$9.81/kW
Next 1000 kW of billing demand - per kW	$9.32/kW
Over 1500 kW of billing demand - per kW	$8.34/kW
ENERGY CHARGE - ¢ per kWh:	
First 200 kWh/month/kW of billing demand - per kWh	7.0715 ¢/kWh
Next 200 kWh/month/kW of billing demand - per kWh	6.2884 ¢/kWh
Over 400 kWh/month/kW of billing demand - per kWh	5.9849 ¢/kWh

SECONDARY METERING ADJUSTMENT FOR SERVICE AT PRIMARY VOLTAGE:

Metering will normally be at the delivery point. For services delivered at primary voltage and metered on the secondary side of the customer's transformers which are adjacent to the delivery point, and where the metering point is approved by the Company, a secondary metering adjustment of 0.1081 ¢/kWh shall be added to the above energy charge.

SCHEDULE PP - Continued

MINIMUM CHARGE:

The minimum monthly charge shall be the sum of the Customer and Demand charges. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall be the highest of the maximum demand for the month, the greatest maximum demand for the preceding eleven months, or the minimum billing demand specified below, rounded to one-tenth kW.

DETERMINATION OF DEMAND:

The maximum demand for each month shall be the maximum average load in kW during any fifteen-minute period as indicated by a demand meter. The billing demand for each month shall be the highest of the maximum demand for such month, or the mean of maximum demand for the current month and the greatest maximum demand for the preceding eleven (11) months, whichever is the higher, but not less than the minimum billing demand specified below, rounded to one-tenth kW:

Minimum Billing Demand:

Power Service Only	150 kW (Closed to new Customers After January 1, 1986)
Power & Lighting Service	300 kW

Power Factor:

The above demand and energy charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed above, shall be decreased or increased, respectively, by 0.10%. The power factor will be computed to the nearest whole percent. In no case, however, shall the power factor be taken as more than 100% for the purpose of computing the adjustment.

Schedule PP - Continued

Power Factor - cont.

The average monthly power factor will be determined from the readings of a kWh and Kvarh meter. The Kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges, Secondary Metering Adjustment, and Power Factor.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, Secondary Metering Adjustment, Power Factor, and energy cost adjustment.

TERM OF CONTRACT:

Not less than one year.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

SCHEDULE PT

LARGE POWER TRANSMISSION VOLTAGE SERVICE

AVAILABILITY:

Applicable to large light and/or power service supplied and metered at a single voltage and delivery point. Service under this Schedule shall be delivered at transmission voltage specified by the Company.

RATES:

CUSTOMER CHARGE - $ per customer per month:	$320.00/month
DEMAND CHARGE - $ per kW of billing demand:	
First 500 kW of billing demand - per kW	$9.67/kW
Next 1000 kW of billing demand - per kW	$9.19/kW
Over 1500 kW of billing demand - per kW	$8.22/kW
ENERGY CHARGE - ¢ per kWh:	
First 200 kWh/month/kW of billing demand - per kWh	6.9708 ¢/kWh
Next 200 kWh/month/kW of billing demand - per kWh	6.1989 ¢/kWh
Over 400 kWh/month/kW of billing demand - per kWh	5.8997 ¢/kWh

SECONDARY METERING ADJUSTMENT FOR SERVICE AT TRANSMISSION VOLTAGE:

Metering will normally be at the delivery point. For services delivered at transmission voltage and metered on the secondary side of the customer's transformers which are adjacent to the delivery point, and where the metering point is approved by the Company, a secondary metering adjustment of 0.0865 ¢/kWh shall be added to the above energy charge.

SCHEDULE PT - Continued

MINIMUM CHARGE:

The minimum monthly charge shall be the sum of the Customer and Demand charges. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall be the highest of the maximum demand for the month, the greatest maximum demand for the preceding eleven months, or the minimum billing demand specified below, rounded to one-tenth kW.

DETERMINATION OF DEMAND:

The maximum demand for each month shall be the maximum average load in kW during any fifteen-minute period as indicated by a demand meter. The billing demand for each month shall be the highest of the maximum demand for such month, or the mean of maximum demand for the current month and the greatest maximum demand for the preceding eleven (11) months, whichever is the higher, but not less than the minimum billing demand specified below, rounded to one-tenth kW:

Minimum Billing Demand:

Power Service Only	150 kW (Closed to new Customers after January 1, 1986)
Power & Lighting Service	300 kW

Power Factor:

The above demand and energy charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed above, shall be decreased or increased, respectively, by 0.10%. The power factor will be computed to the nearest whole percent. In no case, however, shall the power factor be taken as more than 100% for the purpose of computing the adjustment.

Schedule PT - Continued

Power Factor - cont.

The average monthly power factor will be determined from the readings of a kWh meter and Kvarh meter. The Kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges, Secondary Metering Adjustment, and Power Factor.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, Secondary Metering Adjustment, Power Factor, and energy cost adjustment.

TERM OF CONTRACT:

Not less than one year.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 59
Effective January 1, 1996

REVISED SHEET NO. 59
Effective January 1, 1997

SCHEDULE "F"

Public Street Lighting, Highway Lighting and
Park and Playground Floodlighting

Availability:

Applicable only to public street and highway lighting, and public outdoor park and playground floodlighting service where the customer owns, maintains and operates the lighting fixtures and interconnecting circuits and conversion equipment. This rate is applicable to gaseous discharge lighting (Mercury Vapor) provided the regulator is corrected to power factor equivalent to the addition of one (1) KVAR of capacitors for each kw of name plate rating of the regulator. Under this schedule energy shall be supplied and metered at a nominal voltage of 2400 volts or more, as specified by the Company, except as set forth below under Special Terms and Conditions.

Rate:

First	150 kwhr/month/kw of billing demand - per kwhr	12.7049 cents
All over	150 kwhr/month/kw of billing demand - per kwhr	8.7309 cents

Minimum Charge:

$35.00 per month for each point of delivery.

Determination of Demand:

The maximum demand for each month shall be the maximum average load in kw during any fifteen-minute period as indicated by a demand meter. The billing demand for each month shall be the maximum demand for such month but not less than 50% of the greatest maximum demand for the preceding eleven months.

Optional Secondary Metering for Street and Highway Lighting:

The street and highway lighting customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the monthly bill will be increased by 2%.

Special Terms and Conditions:

Multiple street lighting lamps may be individually served unmetered at secondary voltage along public streets and highways when, (1) in an overhead area, secondary voltage is available on the lamp pole or (2), in an underground area, secondary voltage is available along the public street. The total connected lamp

Superseding Revised Sheet No. 60
Effective October 25, 1991

REVISED SHEET NO. 60
Effective September 1, 1992

SCHEDULE "F" (continued)

load per connection point shall not exceed 2 KW. A one-year contract is required for service under this provision and each such contract will remain in effect from year to year thereafter unless, after the first year, terminated by 30 days notice in writing. Each contract will constitute a point of delivery. The monthly billing demand will be the connected lamp load expressed in kilowatts times 1.05 to the nearest one-tenth kilowatt, and the monthly billing kilowatt-hours will be 340 times the billing demand. The customer will provide a switching device for each lamp to limit the annual burning time to not more than 4100 hours.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy Charges.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy Charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Sheet No. 61
Effective September 1, 1992

REVISED SHEET NO. 61
Effective January 1, 1995

SCHEDULE U

TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads which exceed 300 kilowatts per month and supplied and metered at a single voltage and delivery point. This Schedule cannot be used in conjunction with load management Riders "M", "T", and "I".

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods shall be as follows:

On-Peak Period: 7:00 a.m. - 9:00 p.m., daily
Off-Peak Period: 9:00 p.m. - 7:00 a.m., daily

RATE:

CUSTOMER CHARGE - per month $215.00

DEMAND CHARGE - (To be added to Customer Charge)

All On-Peak Kw of billing demand - per Kw $17.00

ENERGY CHARGE - (To be added to Customer and Demand Charges)

All On-Peak Kwhr per month	- per Kwhr	7.823 cents
All Off-Peak Kwhr per month	- per Kwhr	3.000 cents

Minimum Charge:

The monthly minimum charge shall be the sum of the Customer and the Demand Charges. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of billing demand for the minimum charge calculation for each month shall be the highest of the maximum on-peak demand for such month but not less than 300 kw.

Superseding Sheet No. 61A
Effective October 25, 1991

REVISED SHEET NO. 61A
Effective January 1, 1995

Schedule "U" (Continued)

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's energy consumption and kw load during the time-of-day rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The on-peak kilowatts of billing demand for each month shall be the maximum on-peak demand for such month but not less than 300 kilowatts.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%

The average monthly power factor will be determined from the readings of a Kwh meter and kVarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kVarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Special Terms and Conditions:

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation 3.3%
Distribution voltage supplied without further transformation 1.9%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 2.4% and 0.7%, respectively.

Schedule "U" (Continued)

Because of the inherent operating conditions in the downtown area supplied from the Company's underground network system the Company will deliver and meter service to customers in this area at 120/208Y or 277/480Y volts (See Rule 2). The demand and energy charges will be increased 0.9%.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy Charges.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy Charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

TERM OF CONTRACT:

Not less than five years.

Superseding Revised Sheet No. 62
Effective August 21, 1972

REVISED SHEET NO. 62
Effective June 1, 1996

SCHEDULE "E"

Electric Service for Employees

Availability:

Applicable to all regular full-time Company employees, Company retirees, members of the Company Board of Directors, and retirees of Hawaii Electric Light Company, Inc. and Maui Electric Company, Ltd. who retired on or after January 1, 1996 and who are served by Hawaiian Electric Company, Inc. This schedule is applicable to the above customers' residential electric service in a single family dwelling unit metered and billed separately by the Company, subject to the Special Terms and Conditions specified below. This schedule does not apply where a residence and business are combined.

Rate:

The rates applicable to service under this schedule shall be two-thirds (2/3) of the current effective Schedule R rates - Residential Service, for usage up to 825 kwh per month. Energy usage above 825 kwh shall be charged the full Schedule R energy rates.

Special Terms and Conditions:

1. "Regular full-time Company employee" is defined as an employee who has successfully completed any required probationary requirements, is hired for an indefinite period, and who works no less than 40 hours per week.

2. This schedule is applicable only to primary residences.

3. Availability of this schedule terminates six months after death of eligible employee, retiree, or member of the Board of Directors.

Rules and Regulations:

Service supplied under this schedule shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 63
Effective January 1, 1995

REVISED SHEET NO. 63
Effective January 1, 1996

ENERGY COST ADJUSTMENT CLAUSE

Applicable To

Schedule "R" - Residential Service
Schedule "E" - Electric Service For Employees
Schedule "G" - General Service - Non-Demand
Schedule "J" - General Service - Demand
Schedule "H" - Commercial Cooking, Heating, Air Conditioning and Refrigeration Service
Schedule "P" - Large Power Service
Schedule "F" - Public Street Lighting, Highway Lighting and Park and Playground Floodlighting
Schedule "U" - Time-of-Use Service

All terms and provisions of Schedules "R", "E", "G", "J", "H", "P", "F" and "U" are applicable, except that the Energy Cost Adjustment described below will be added to the customer bills.

All base rate schedule discounts, surcharges, and all other adjustments will not apply to the energy cost adjustment.

Energy Cost Adjustment Clause:

This Energy Cost Adjustment Clause shall include the following:

FUEL AND PURCHASED ENERGY - The above rates are based on a cost of fuel for Company generation of 287.83 cents per million Btu for fuel delivered in its service tanks and a cost for purchased energy of 3.005 cents per kilowatthour. Company-generated energy from non-fuel sources shall be considered as zero fuel cost in the determination of the composite fuel cost. When the Company-generated net energy cost is more or less than 287.83 cents per million Btu, and/or the purchased energy cost is more or less than 3.005 cents per kilowatthour, a corresponding adjustment (Energy Cost Adjustment Factor) to the energy charges shall be made. This adjustment shall be comprised of a Company Generation Component and a Purchased Energy Component.

The Company Generation Component shall be the difference in current generation cost and base generation cost, adjusted for additional revenue taxes. The current generation cost shall be determined by the current fuel cost in cents per million Btu, multiplied by a generation conversion factor of 0.011170 million Btu per kilowatthour, weighted by the proportion of current Company generation to total system net energy in kilowatthours. The base generation cost is the base fuel cost of 287.83 cents per million Btu multiplied by a generation conversion factor

Energy Cost Adjustment Clause (Continued)

of 0.011170 million Btu per kilowatthour, weighted by the proportion of the 1995 test year generation to total system energy in kilowatthours.

The Purchased Energy Component shall be the difference between (1) the current purchased energy cost weighted by the proportion of current purchased energy to total system net energy, and (2) the base purchased energy cost of 3.005 cents per kilowatthour weighted by the proportion of the 1995 test year purchased energy to total system net energy, adjusted to the sales delivery level and for additional revenue taxes. The Energy Cost Adjustment Factor shall be the sum of the Generation Component and the Purchased Energy Component.

The revenue tax requirement shall be calculated using current rates of the Franchise Tax, Public Service Company Tax, and Public Utility Commission fee.

The Energy Cost Adjustment shall be effective on the date of cost change. When a cost change occurs during a customer's billing period, the Energy Cost Adjustment will be prorated for the number of days each cost was in effect.

This Energy Cost Adjustment Clause is consistent with the terms of the Company's operations and purchased energy contracts and may be revised to reflect any revisions or changes in operations and the purchased energy contracts, subject to approval by the Commission.

Reconciliation Adjustment:

In order to reconcile any differences that may occur between recorded and forecasted Energy Cost Adjustment Clause revenues, the year-to-date recorded revenue from the Energy Cost Adjustment Clause will be compared with the year-to-date revenue expected from the Energy Cost Adjustment Clause on a quarterly basis. If there is a variance between the recorded Energy Cost Adjustment Clause revenue and the expected Energy Cost Adjustment Clause revenue, an adjustment, lagged by two months, shall be made to the Energy Cost Adjustment Clause to reconcile the revenue variance over the sales estimated for the subsequent quarter.

Superseding Sheet No. 64
Effective July 15, 1981

REVISED SHEET NO. 64
Effective January 1, 1986

RIDER "I"

Interruptible Contract Service

Availability:

This Rider is applicable to service supplied and metered at a single voltage and delivery point where 500 kw or greater is subject to disconnection by the utility under the terms and conditions as set forth in the contract agreement.

Rates:

Reduction in demand charge as set forth in a contract between the customer and the utility and approved by the Public Utilities Commission.

Term of Contract:

Not less than five years.

Superseding Revised Sheet No. 65
Effective January 1, 1996

REVISED SHEET NO. 65
Effective February 1, 1998

RIDER "M"

Off-Peak and Curtailable Service

AVAILABILITY:

This Rider is available to customers served under rate Schedule "J" or "P", whose maximum measured demands prior to any load modifications effected under this rider, exceed 100 and 300 kilowatts, respectively. This Rider cannot be used in conjunction with Rider T, Rider I and Schedule U.

RATES:

A. Basic Rates

The rate(s) for service under this Rider shall be as specified under the regular Schedule "J" or "P", whichever is applicable, except that the Minimum Charge and the determination of billing demand used in the calculation of demand and energy charges shall be as defined below, subject to the requirements under the Determination of Demand provision of the applicable rate schedule.

The customer shall select Option A - Off-Peak Service or Option B - Curtailable Service:

OPTION A - OFF-PEAK SERVICE:

1) Any demand occurring during the off-peak period shall not be considered in determining the billing kW demand for each month, but shall be used in determining the excess off-peak charge. Only the maximum kW demand occurring during the on-peak period shall be used in the determination of the billing kW demand for the calculation of the demand charge, energy charge and minimum charge as specified in the regular Schedule J or P.

2) An excess Off-Peak Charge of $2.00 per kilowatt shall be added to the regular rate schedule charges for each kilowatt that the maximum off-peak demand exceeds the maximum demand during of the on-peak period.

RIDER "M" (continued)

3) For calculation of the excess off-peak charge for each month, the maximum off-peak demand and maximum demand during the on-peak period shall be the highest measured demands during the respective periods for such month.

4) The time-of-use rating period shall be defined as follows:

On-Peak Period: 7 a.m. - 9 p.m. Fourteen hours, Daily

Off-Peak Period: 9 p.m. - 7 a.m. Ten hours, Daily

5) The monthly minimum charge shall be the sum of the customer charge, demand charge, Excess Off-Peak Charge, and Time-of-Day Metering Charge specified below.

OPTION B - CURTAILABLE SERVICE:

1) A customer who chooses curtailable service shall curtail his/her kW demand during the Company's curtailment hours, and shall indicate the load that he/she is willing to curtail. This curtailable load must be load that is normally operated during the Company's curtailment hours and must be at least 50 and 150 horsepower for motor loads under Schedules "J" and "P" respectively, or 50 and 150 kilowatts for other than motor loads.

2) The Company may install a meter, in accordance with Rule 14, to measure the customer's curtailable load prior to the start of curtailable service under this Rider.

3) For billing purposes, the curtailed kW demand shall be determined monthly as the difference between the maximum kW demands outside of the curtailment hours and the maximum kW

RIDER "M" (Continued)

demand during the curtailment hours measured for each month, but not to exceed the curtailable kW load specified in the customer's Rider M contract.

4) The customer shall choose one of the curtailment periods specified below. The billing demand under this curtailable service option shall be the normal billing demand under Schedule "J" or "P" reduced by:

Option 1) 75% of the curtailed kilowatt demand if the curtailment period is fixed throughout the year from 5 p.m. to 9 p.m., Monday through Friday; or

Option 2) 40% of the curtailed kilowatt demand if the curtailment period is two (2) consecutive hours as specified by the Company.

5) The monthly minimum charge shall be the sum of the customer charge, demand charge, and the Time-of-Day Metering Charge specified below.

Where the Company specifies the curtailment period, the Company shall give the customer at least 30 days notice prior to changing the curtailment period.

B. TIME-OF-DAY METERING CHARGE:

The Company shall install a time-of-use meter to measure the customer's maximum kW load during the time-of-day rating periods and curtailment periods.

An additional time-of-day metering charge of $10.00 per month shall be assessed to cover the additional cost of installing, operating, and maintaining a time-of-use meter.

Superseding Sheet No. 65C
Effective January 1, 1995

REVISED SHEET NO. 65C
Effective February 1, 1998

RIDER "M" (continued)

C. TERMS OF CONTRACT:

1. The initial term of contract shall be at least 3 years. Thereafter, the contract shall continue from year-to-year until terminated by either party by a 30-day written notice.

2. A customer applying for service under this Rider shall sign a standard Rider M contract form with the Company.

3. The customer shall be allowed to take service under this Rider for a six-month trial period without penalty for termination within this period.

4. If the contract is terminated after the first six-months trial period, but before the first three-year period which begins from the start date of the customer's service under this Rider, the customer shall be assessed a termination charge equal to the last six months discount received under this Rider.

5. The customer may request a change of Rider options (Option A - Off-Peak Service or Option B - Curtailable Service) or curtailment hours (Options 1 or 2 under Curtailable Service) by providing a 30-day written notice to the Company. The change will become effective after the next regular meter reading following the receipt of such written notice by the Company, provided however, the Company may not be required to make such change until 12 months of service has been rendered after the last change, unless a new or revised Rider has been authorized, or unless a customer's operating conditions have altered so as to warrant such change.

6. If under the curtailable service option the customer fails to curtail his maximum demand during the curtailment period three times within a twelve-month period, the Company may terminate the Rider M contract by a 30-day written notice to the customer. If service under this Rider

RIDER "M" (continued)

is terminated due to the customer's failure to curtail his demand as provided in the contract, the customer shall be assessed a termination charge equal to the last six months discount received under this Rider.

7. Service supplied under this Rider shall be subject to the Rules and Regulations of the Company.

Superseding Sheet No. 67
Effective October 25, 1991

REVISED SHEET NO. 67
Effective January 1, 1995

RIDER T
TIME-OF-DAY RIDER

AVAILABILITY:

This rider is available to customers on rate Schedule J or P but cannot be used in conjunction with the load management Rider M, Rider I or Schedule U.

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods under this Rider shall be as follows:

On-Peak Period:	7:00 a.m. - 9:00 p.m., Daily
Off-Peak Period:	9:00 p.m. - 7:00 a.m., Daily

RATE:

The rate(s) for service under this Rider including the Customer Charge, Energy Charge, and Demand Charge shall be as specified in the regular rate Schedule J or P, except that the following charges shall be added:

TIME-OF-DAY METERING CHARGE - per month $10.00

TIME-OF-DAY ENERGY CHARGE ADJUSTMENTS:

On-Peak Energy Surcharge	- all on-peak kwh	+2.00 cents/kwh
Off-Peak Energy Credit	- all off-peak kwh	-3.00 cents/kwh

MINIMUM CHARGE:

The Minimum Charge shall be as specified under the regular rate schedule except that it shall include the Time-of-Day Metering Charge. In addition, the monthly average energy charge computed from the regular energy charge and the above Time-of-Day energy charge adjustments including the energy cost adjustment, cannot be lower than the off-peak avoided energy cost at the metering point.

DETERMINATION OF DEMAND:

The Determination of Demand shall be as specified in the regular rate schedule, except that only the on-peak Kw demand shall be used in the determination of the kilowatts of billing demand for the Demand Charge, the regular Energy Charge and the Minimum Charge calculations.

Superseding Sheet No. 67A
Effective October 25, 1991

REVISED SHEET NO. 67A
Effective January 1, 1995

Rider T (Continued)

VOLTAGE SERVICE AND POWER FACTOR ADJUSTMENTS:

The voltage service and power factor adjustments shall be as specified in the regular rate schedule.

MEASUREMENT OF TIME-OF-DAY ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's energy consumption and maximum kw demand during the time-of-day rating periods.

TERMS OF AGREEMENT:

A customer applying for service under this Rider shall sign a standard Rider T contract form with the Company. Service under this Rider shall not be less than five years. The customer may terminate service under this Rider during the first six months without penalty. If the customer terminates service after the first six months but before the end of the first five-year period which begins from the start date of the customer's service under this Rider, the customer shall be charged a termination fee equal to the amount of the last six months of discount received under this Rider.

Superseding Revised Sheet No. 68
Effective November 1, 2006

REVISED SHEET NO. 68
Effective December 1, 2006

INTEGRATED RESOURCE PLANNING
COST RECOVERY PROVISION

Supplement To

Schedule R - Residential Service
Schedule E - Electric Service For Employees
Schedule G - General Service Non-Demand
Schedule J - General Service Demand
Schedule H - Commercial Cooking, Heating, Air Conditioning, and Refrigeration Service
Schedule PS - Large Power Secondary Voltage Service
Schedule PP - Large Power Primary Voltage Service
Schedule PT - Large Power Transmission Voltage Service
Schedule F - Public Street Lighting, Highway Lighting and Park and Playground Floodlighting
Schedule U - Time of Use Service

All terms and provisions of Schedules R, E, G, J, H, PS, PP, PT, F,and U, are applicable except that the total base rate charges for each billing period shall be increased by the following Integrated Resource Planning (IRP) Cost Recovery Adjustment, Residential Demand-Side Management (DSM) Adjustment, and Commercial and Industrial Demand-Side Management (DSM) Adjustment:

A: INTEGRATED RESOURCE PLANNING COST RECOVERY ADJUSTMENT:

All Rate Schedules ....0.000 percent

The total base rate charges for all rate schedules shall be increased by the above Integrated Resource Planning Cost Recovery Adjustment, which is based on the recovery of the ____ IRP Planning Costs as approved by the Public Utilities Commission.

The total base rate charges for the current billing period shall include all base rate schedule charges, discounts, surcharges, or base rate adjustments, excluding the Energy Cost Adjustment, Residential DSM Adjustment, and Commercial and Industrial DSM Adjustment and temporary Rate Adjustment.

B: Residential Demand-Side Management (DSM) Adjustment:

Schedule R - per kwh ....0.3578 ¢/kWh

The total residential monthly bill shall include the above Residential DSM adjustment applied to all kWh per month. The above Residential DSM adjustment is based on recovering $7,946,973 for the 2006 residential program cost and revenue taxes, lost revenue margins through May 25, 2006, shareholder incentives through May 25, 2006 and revenue taxes, and the reconciliation of the 2005 program cost recovery including reconciled lost revenue margins and revenue taxes, for which recovery has been approved by the Public Utilities Commission.

Superseding Revised Sheet No. 68A
Effective November 1, 2006

REVISED SHEET NO. 68A
Effective December 1, 2006

Integrated Resource Planning Cost Recovery Provision - Continued

C: Commercial and Industrial Demand-Side Management (DSM) Adjustment:

Schedules G, J, H, PS, PP, PT, U - per kWh ....0.2044 ¢/kWh

The total monthly bill for Schedules G, J, H, PS, PP, PT, and U customers shall include the above Commercial and Industrial DSM adjustment applied to all kWh per month. The above adjustment is based on recovering $11,826,246 for the 2006 C&I program costs and revenue taxes, lost revenue margins through May 25, 2006, shareholder incentives through May 25, 2006 and revenue taxes, and the reconciliation of the 2005 program cost recovery including reconciled lost revenue margins and revenue taxes, for which recovery has been approved by the Public Utilities Commission.

RECONCILIATION ADJUSTMENT: (To be added to Integrated Resource Planning Cost Recovery Adjustment, Residential DSM Adjustment, and Commercial and Industrial DSM Adjustment):

In order to reconcile any differences that may occur between the above costs to be recovered and the revenues received from the above adjustments, recorded revenues will be compared with the above costs. The Integrated Resource Planning Cost Recovery Adjustment, Residential DSM Adjustment, and the Commercial and Industrial DSM Adjustment will be reconciled annually. If there is a variance between the recorded revenues from the adjustments and the costs to be recovered, a reconciliation adjustment, lagged by two months, will be made to the above adjustments.

Superseding Revised Sheet No. 81
Effective January 1, 1995

REVISED SHEET NO. 81
Effective January 1, 1996

SCHEDULE "Q"

Purchases From Qualifying Facilities - 100 KW or Less

Availability:

This schedule is available to customers with cogeneration and/or small power production facilities which qualify under the Commission's Rules, Chapter 74 of Title 6, Subchapter 2 with a design capacity of 100 kilowatts or less. Such qualifying facilities (QF's) shall be designed to operate properly in parallel with the Company's system without adversely affecting the operations of its customers and without presenting safety hazards to the Company's or other customer's personnel. The customer shall comply with the Company's requirements for customer generation interconnected with the utility system.

Energy delivered to the customer by the Company will be metered separately from the energy delivered by the customer to the Company.

Rate for Energy Delivered to the Company by Customer

The Company will pay for energy as follows:

All kwh per month - per kwhr	3.67 cents

Metering Charge:

There is a monthly charge to the customer for metering, billing and administration of the interconnection for purchase power as follows:

Single phase service - per month	$ 5.00
Three phase service - per month	$10.00

Energy Delivered to the Customer by the Company:

Energy delivered to the customer shall be billed on an applicable Company rate schedule.

System Compatibility:

The customer must deliver electric power at 60 hertz and the same phase and voltage as the customer receives service from the Company.

Superseding Revised Sheet No. 81A
Effective January 1, 1995

REVISED SHEET NO. 81A
Effective January 1, 1996

SCHEDULE "Q" (continued)

Interconnection Facilities:

The customer shall furnish, install, operate and maintain facilities such as relays, switches, synchronizing equipment, monitoring equipment and control and protective devices designated by the Company as suitable for parallel operation with the Company system. Such facilities shall be accessible at all times to authorized Company personnel. All designs should be approved by the Company prior to installation.

If additional Company facilities are required or the existing facilities must be modified to accept the QF's deliveries, the QF shall make a contribution for the cost of such additional facilities.

Contract:

The Company shall require a contract specifying technical and operating aspects of parallel generation.

Energy Cost Adjustment Clause:

The above rate for energy delivered to the Company by the Customer is based on a cost of fuel for Company generation of 287.83 cents per million Btu for fuel delivered in its service tanks. Effective the first day of January, April, July, and October an Adjustment shall be made to reflect the Company-generated fuel cost on file with the Commission and shall be effective for the following three months.

The Adjustment shall be the sum of the time-weighted on-peak adjustment (14 hours of 24 hours) and off-peak adjustment (10 hours of 24 hours). On-peak and off-peak adjustments shall be determined by the amount of the Company-generated fuel cost increase or decrease (in terms of cents per million Btu) from the base of 287.83 cents per million Btu multiplied by an on-peak heat rate of 13,382 Btu per net kilowatthour and an off-peak heat rate of 9,929 Btu per net kilowatthour.

This Energy Cost Adjustment Clause is consistent with the terms of the Company's operations and may be revised to reflect any revisions or changes in operations, subject to approval by the Commission.

Superseding Sheet No. 82
Effective October 23, 1996

REVISED SHEET NO. 82
Effective January 1, 1999

GREEN PRICING PROGRAM PROVISION

AVAILABILITY:

Available to all residents/non-residents of the Island of Oahu who wish to make voluntary contributions for the development of renewable energy resources on Oahu.

GREEN PRICING PROGRAM:

The objective of the Green Pricing Program is to encourage the development of Hawaii's renewable energy resources. The participant's voluntary contributions under the Green Pricing Program Provision are used to develop renewable energy facilities.

The Company's Sun Power for Schools Pilot Program is a pilot project under which photovoltaic systems are installed on selected public schools on the Island of Oahu. The participating school will own the photovoltaic facility and use the energy produced by the system at no cost. Contributions received from the participants in this Green Pricing Program Provision are used to help fund this pilot program.

Other renewable energy projects may be developed in the future as part of the Company's Green Pricing Program, depending on the availability of contributions received from this Green Pricing Program Provision.

VOLUNTARY PARTICIPATION:

1. Participation in the Green Pricing Program through the Green Pricing Program Provision, is voluntary and may be terminated by the participant at any time.

2. Any resident/non-resident of the Island of Oahu may contribute to the Green Pricing Program through the Green Pricing Program Provision by completing a standard program sign-up form which indicates the participant's mailing address, electric service account number (if participant is currently a HECO customer), and the contribution payment option desired. The Green Pricing Program Provision contribution payment options are listed below.

GREEN PRICING PROGRAM PROVISION (Continued)

3. A participant may terminate his/her voluntary contribution to the Green Pricing Program at any time by submitting a written or telephonic request to the Company to terminate participation in the Green Pricing Program Provision.

CONTRIBUTION PAYMENT OPTIONS:

A participant will specify the amount of his/her voluntary contribution (in whole dollars) and shall elect one of the following payment options:

Option 1: Monthly Contribution - the participant will be billed monthly based on the participant's specified dollar contribution amount.

Option 2: One Time Contribution - the participant will be billed one time for one lump sum contribution.

TERMS AND CONDITIONS:

1. Payments received by the Company shall be applied first to the participant's outstanding electric service bill balance, if any, and the remainder shall be applied to the participant's contribution to the Green Pricing Program under the Green Pricing Program Provision.

2. Electric Service will not be terminated if the participant fails to make contribution payments under the Green Pricing Program Provision.

3. The Company may terminate a participant's participation in the Green Pricing Program Provision, if the participant fails to make contribution payments for two (2) consecutive months.

4. The Company's late payment charge shall not apply to the participant's voluntary contributions under the Green Pricing Program Provision.

SHEET NO. 83
Effective July 6, 1998

RIDER EV-R

RESIDENTIAL ELECTRIC VEHICLE CHARGING SERVICE

AVAILABILITY:

This Rider is applicable to electric charging service of electric vehicles in a residential dwelling unit. Electric vehicle charging service under this Rider shall be separately metered from residential power service served under Schedule R or Schedule E, and shall be supplied at a secondary voltage as specified by the Company.

RATES:

TIME-OF-USE METERING CHARGE - per month	$4.00
TIME-OF-USE ENERGY CHARGE:	
On-Peak Energy Charge - per on-peak Kwh	11.2954 ¢/kwh
Off-Peak Energy Charge - per off-peak Kwh	5.0556 ¢/kwh

MINIMUM CHARGE:

The Minimum Charge shall be the Time-of-Use Metering Charge.

DETERMINATION OF TIME-OF-USE ENERGY USAGE:

The Company shall install time-of-use metering equipment to measure the customer's electric vehicle charging kilowatthour usage by time-of-day rating periods defined below.

TIME-OF-USE RATING PERIODS:

The Time-of-Day rating periods under this Rider shall be as follows:

On-Peak Period:	7:00 a.m. - 9:00 p.m., Monday-Friday
Off-Peak Period:	9:00 p.m. - 7:00 a.m., Daily
	7:00 a.m. - 9:00 p.m., Saturday-Sunday

RIDER EV-R (continued)

ENERGY COST ADJUSTMENT CLAUSE:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Time-of-Use Metering Charge and Energy Charge.

INTEGRATED RESOURCE PLANNING COST RECOVERY PROVISION:

The Integrated Resource Planning Cost Recovery Provision shall be added to the Time-of-Use Metering Charge, Time-of-Use Energy Charge, and Energy Cost Adjustment.

RULES AND REGULATIONS:

Service supplied under this Rider shall be subject to the Rules and Regulations of the Company.

RIDER EV-C

COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

AVAILABILITY:

This Rider is applicable to commercial electric charging service of electric vehicles. Electric vehicle charging service shall be separately metered from other power service served under the applicable rate schedule for general power service. Service under this Rider will be supplied through a single meter at a secondary voltage as specified by the Company.

If a customer's electric vehicle charging load is less than or equal to 5000 kwh per month, and less than 25 kw, the Time-of-Use Energy Charge for Non-Demand Service shall apply.

If a customer's electric vehicle charging load exceeds 5000 kwh per month or in the opinion of the Company, equals or exceeds 25 kw of demand three times in a twelve-month period, a time-of-use demand meter will be installed and the Time-of-Use Energy Charge and the On-Peak Demand Charge for Demand Service shall apply.

RATES:

TIME-OF-USE METERING CHARGE - per month $10.00

Non-Demand Service:
TIME-OF-USE ENERGY CHARGE - (To be added to Time-of-Use Metering Charge)

On-Peak Energy Charge - per on-peak Kwh	11.1570 ¢/kwh
Off-Peak Energy Charge - per off-peak Kwh	5.3085 ¢/kwh

Demand Service:
TIME-OF-USE ENERGY CHARGE - (To be added to Time-of-Use Metering Charge)

On-Peak Energy Charge - per on-peak Kwh	8.6900 ¢/kwh
Off-Peak Energy Charge - per off-peak Kwh	5.3085 ¢/kwh

ON-PEAK DEMAND CHARGE - (To be added to Time-of-Use Metering and Time-of-Use Energy Charges)

All On-Peak billing demand - per kw per month $5.75

RIDER EV-C (continued)

MINIMUM CHARGE:

Non-Demand Service: Time-of-Use Metering Charge.

Demand Service: Sum of Time-of-Use Metering Charge and On-Peak Demand Charge.

DETERMINATION OF TIME-OF-USE ENERGY USAGE:

The Company shall install time-of-use metering equipment to measure the customer's electric vehicle charging kilowatt demand and kilowatthour usage by time-of-day rating periods defined below. The on-peak billing kw per month shall be the maximum on-peak demand for such month but not less than 25 kw. The maximum on-peak demand for each month shall be the maximum average on-peak load in kw during any fifteen-minute period as indicated by a time-of-use meter.

TIME-OF-USE RATING PERIODS:

The Time-of-Day rating periods under this Rider shall be as follows:

On-Peak Period:	7:00 a.m. - 9:00 p.m., Monday-Friday
Off-Peak Period:	9:00 p.m. - 7:00 a.m., Daily
	7:00 a.m. - 9:00 p.m., Saturday-Sunday

ENERGY COST ADJUSTMENT CLAUSE:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Time-of-Use Metering Charge, Energy Charge, and On-Peak Demand Charge.

INTEGRATED RESOURCE PLANNING COST RECOVERY PROVISION:

The Integrated Resource Planning Cost Recovery Provision shall be added to the Time-of-Use Metering Charge, Time-of-Use Energy Charge, On-Peak Demand Charge, and Energy Cost Adjustment.

RULES AND REGULATIONS:

Service supplied under this Rider shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 50
Effective July 1, 2006

REVISED SHEET NO. 50
Effective

RATE SCHEDULES

The following listed sheets contain all rates in effect on and after the date indicated thereon subject to the Rules and Regulations of the Company applicable thereto:

Superseding Revised Sheet No. 50A
Effective June 1, 2001

REVISED SHEET NO. 50A
Effective

RATE SCHEDULES - (continued)

Sheet	Schedule	Date Effective	Character of Service
59	F		Public Street Lighting, Highway Lighting, & Park & Playground Floodlighting
60	F		Public Street Lighting, Highway Lighting, & Park & Playground Floodlighting
61	U		Time-of-Use Service
61A	U		Time-of-Use Service
61B	U		Time-of-Use Service
62	E		Electric Service for Employees
63	Energy Cost Adjustment Clause		All Schedules Except Schedule Q
63A	Energy Cost Adjustment Clause		All Schedules Except Schedule Q
63B	Energy Cost Adjustment Clause		All Schedules Except Schedule Q
64	Rider I		Interruptible Contract Service
65	Rider M		Off-Peak and Curtailable Service
65A	Rider M		Off-Peak and Curtailable Service
65B	Rider M		Off-Peak and Curtailable Service
65C	Rider M		Off-Peak and Curtailable Service
65D	Rider M		Off-Peak and Curtailable Service

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Superseding Sheet No. 50B
Effective December 1, 2006

REVISED SHEET NO. 50B
Effective

RATE SCHEDULES (continued)

Sheet	Schedule	Date Effective	Character of Service
67	Rider T		Time-of-Day Service
67A	Rider T		Time-of-Day Service
67B	Rider T		Time-of-Day Service
68	IRP Cost Recovery Provision		All Schedules Except Schedule Q
68A	IRP Cost Recovery Provision		All Schedules Except Schedule Q
69	SS		Standby Service
69A	SS		Standby Service
69B	SS		Standby Service
69C	SS		Standby Service
69D	SS		Standby Service
69E	SS		Standby Service
69F	SS		Standby Service
69G	SS		Standby Service
69H	SS		Standby Service
(PAGES 70-80 - NOT ASSIGNED)			
81	Q		Purchases From Qualifying Facilities -100 kW or Less
81A	Q		Purchases From Qualifying Facilities -100 kW or Less
81B	Q		Purchases From Qualifying Facilities -100 kW or Less
82	Green Pricing Program Provision		Green Pricing
82A	Green Pricing Program Provision		Green Pricing
83	Schedule TOU-C		Commercial Time-of-Use Service
84	Schedule TOU-C		Commercial Time-of-Use Service
85	Schedule TOU-C		Commercial Time-of-Use Service
85A	Schedule TOU-C		Commercial Time-of-Use Service

Superseding Sheet No. 50C
Effective May 13, 2006

REVISED SHEET NO. 50C
Effective

RATE SCHEDULES (continued)

Sheet	Schedule	Date Effective	Character of Service
86	Schedule TOU-R		Residential Time-of-Use Service
87	Schedule TOU-R		Residential Time-of-Use Service
88	Schedule TOU-R		Residential Time-of-Use Service
89	DSM Reconciliation Clause		All Schedules Except Schedule F and Schedule Q

Superseding Revised Sheet No. 51
Effective January 1, 1997

REVISED SHEET NO. 51
Effective

SCHEDULE R

Residential Service

Availability:

Applicable to residential lighting, heating, cooking, air conditioning and power in a single family dwelling unit metered and billed separately by the Company. This Schedule does not apply where a residence and business are combined.

Service will be delivered at secondary voltages as specified by the Company.

Rate:

CUSTOMER CHARGE:

Single-Phase Service - per month	\$8.00/month
Three-Phase Service - per month	\$17.00/month

NON-FUEL ENERGY CHARGE (To be added to Customer Charge)

First 350 kWhr per month - per kWhr	8.8981 ¢/kWhr
Next 850 kWh per month - per kWhr	10.1951 ¢/kWhr
All kWhr over 1,200 kWhr per month - per kWhr	11.0878 ¢/kWhr

BASE FUEL ENERGY CHARGE (To be added to Customer Charge and Non-Fuel Energy Charge)

All kWhr per month - per kWhr	10.8940 ¢/kWhr

Minimum Charge:

Single-Phase Service - per month	\$17.00/month
Three-Phase Service - per month	\$22.00/month

Apartment House Collection Arrangement:

Any apartment owner having three or more apartments at one location, each apartment being separately metered and billed on the above rate, may elect to accept a discount of ten percent (10%) of the amount of the total bills rendered for each apartment for each billing period, but not to exceed \$5.00 per month for each apartment, upon entering into the following collection agreement with the Company under the following terms and conditions:

Superseding Revised Sheet No. 51A
Effective September 1, 1992

REVISED SHEET NO. 51A
Effective

SCHEDULE R - (continued)

1) All accounts shall be kept in the name of the apartment house owner who shall assume the responsibility for the prompt payment of all bills.

2) All accounts shall remain active at all times and, though vacant, shall be subject to the minimum charge. Individual apartments cannot be added or deleted from this agreement more often than once in twelve months.

3) The Company will render individual bills for each apartment on a regular billing period basis and will also furnish a statement showing gross and net billings.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer and Energy Charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 52
Effective January 1, 1997

REVISED SHEET NO. 52
Effective

SCHEDULE G

General Service Non-Demand

Availability:

Applicable to general light and/or power loads less than or equal to 5000 kilowatt hours per month, and less than or equal to 25 kilowatts, and supplied through a single meter.

If a customer's usage exceeds 5000 kilowatt hours per month or in the opinion of the Company exceeds 25 kilowatt of demand three times in a twelve-month period, a demand meter will be installed and the customer's billing will be transferred to Schedule "J" beginning with the next convenient billing period

Service will be delivered at secondary voltages as specified by the Company, except where the nature or location of the customer's load makes delivery at secondary voltage impractical, the Company may, at its option, deliver the service at a nominal primary voltage as specified by the Company. Service supplied at primary voltage shall be subject to the special terms and conditions set forth below.

Rate:

CUSTOMER CHARGE:

Single-Phase Service - per month	$30.00/month
Three-Phase Service - per month	$55.00/month

ENERGY CHARGE: (To be added to Customer Charge)

All kWhr per month - per kWhr	19.9393 ¢/kWhr

Minimum Charge:

Single-Phase Service - per month	$30.00/month
Three-Phase Service - per month	$55.00/month

Primary Supply Voltage Service:

Where, at the option of the Company, service is delivered and metered at the primary supply line voltage, the above energy charges will be decreased by 2.1%. When customers' transformers are adjacent to the delivery point, the Company may permit the customer to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customers' transformers, the above energy charge will be decreased by 0.5%.

SCHEDULE G - (continued)

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer and Energy Charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 54
Effective January 1, 1997

REVISED SHEET NO. 54
Effective

SCHEDULE J

General Service Demand

Availability:

Applicable to general light and/or power loads which exceed 5000 kilowatt hours per month three times within a twelve-month period, or 25 kilowatts but less than 300 kilowatts per month, and supplied through a single meter.

Rate:

CUSTOMER CHARGE:

Single-Phase Service - per month	$50.00/month
Three-Phase Service - per month	$70.00/month

DEMAND CHARGE - (To be added to Customer Charge)

All kW of billing demand - per kW per month	$12.00/kW

ENERGY CHARGE: (To be added to Customer and Demand Charges)

First	200 kWhr/month/kW of billing demand - per kWhr	15.7410¢/kWhr
Next	200 kWhr/month/kW of billing demand - per kWhr	14.5929¢/kWhr
All over	400 kWhr/month/kW of billing demand - per kWhr	13.5639¢/kWhr

Minimum Charge:

The minimum monthly charge shall be the sum of the Customer and the Demand Charges. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand, but not less than $350.00 per month. The kilowatts of demand for the minimum charge calculation each month shall be the highest of the maximum demand for the month, the greatest maximum demand of the preceding eleven months or 25 kW.

Determination of Demand:

The maximum demand for each month shall be the maximum average load in kW during any fifteen-minute period as indicated by a demand meter. The billing demand for each month shall be the highest of the maximum demand for such month, or the mean of maximum demand for the

Superseding Revised Sheet No. 54A
Effective January 1, 1996

REVISED SHEET NO. 54A
Effective

SCHEDULE J - (continued)

Determination of Demand - Continued

current month and the greatest maximum demand for the preceding eleven (11) months, whichever is the higher, but not less than 25 kW.

This Schedule is closed to new customers with kW demand equal to or greater than 300 kW after _________, 2007. Existing customers with maximum measured kW demand equal to, or greater than 300 kW per month may continue to receive service under this Schedule until the customer transfers to another applicable rate schedule.

Power Factor:

The above demand and energy charges are based upon an average monthly power factor of 85%. For customers with maximum measured demands in excess of 200 kilowatts per month for one time within a twelve-month period, the following power factor adjustment will apply for all succeeding billing periods.

For each 1% the average power factor is above or below 85%, the energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%. The power factor will be computed to the nearest whole percent.

In no case, however, shall the power factor be taken as more than 100% for the purpose of computing the adjustment.

The average monthly power factor will be determined from the readings of a kWh meter and a Kvarh meter. The Kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Superseding Revised Sheet No. 54B
Effective September 1, 1992

REVISED SHEET NO. 54B
Effective

SCHEDULE "J" (continued)

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	2.9%
Distribution voltage supplied without further transformation	2.1%

Metering will normally be at the delivery voltage. When customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 2.4% and 0.5%, respectively.

NETWORK SERVICE ADJUSTMENT:

Because of the inherent operating conditions in the downtown area supplied from the Company's underground network system, the Company will deliver and meter the service to customers in this area at 120/208Y or 277/480Y volts. The demand and energy charges will be increased by 0.9%.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy Charges, Supply Voltage Delivery Adjustment, Power Factor Adjustment, and Network Service Adjustment.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy Charges, Supply Voltage Delivery Adjustment, Power Factor Adjustment, Network Service Adjustment, and energy cost adjustment.

SCHEDULE J - (continued)

Term of Contract:

Not less than five years beginning from the service start date. If service is terminated before the end of the initial contract term, the customer shall be charged a termination fee equal to the total connection costs incurred by the Company to serve the customer less customer advance and/or contribution paid by the customer.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 55
Effective January 1, 1997

REVISED SHEET NO. 55
Effective

SCHEDULE "H"

Commercial Cooking, Heating
Air Conditioning and Refrigeration Service

Availability:

Applicable to commercial cooking, heating (including heat pump waterheaters), air conditioning and refrigeration service. This schedule applies only where the voltage supplied by the Company is less than 600 volts. This schedule is closed to new customers after ________, 2007.

Rate:

CUSTOMER CHARGE:

Single-Phase Service - per month	$25.00
Three-Phase Service - per month	$60.00

DEMAND CHARGE: (To be added to Customer Charge)

$10.00 per kw per month of required kw load, but in no case less than $10.00 per month.

ENERGY CHARGE: (To be added to Customer and Demand Charges)

All kWhr per month - per kWhr	16.5324 ¢/kWhr

Minimum Charge:

The minimum monthly charge shall be the sum of Customer and Demand Charges.

Determination of Required kw load:

The required kw load for billing purposes shall be:

A. The sum of:

1) The total connected motor load;
2) 50% of the connected heating load, exclusive of cooking and all-electric resistance and heat pump waterheating; and
3) the connected all-electric waterheating load in excess of one-sixth kilowatt per gallon of storage capacity; or

Superseding Revised Sheet No. 56
Effective September 1, 1992

REVISED SHEET NO. 56
Effective

SCHEDULE "H" (continued)

B. When the load is 25 KW or more the demand may be determined by measured demand. The maximum demand for each month shall be the maximum average load during any fifteen-minute period as indicated by a demand meter. The demand for each month shall be the maximum demand for such month, the highest demand in the preceding eleven months, or 25 KW, whichever is highest. Measured demand service under this schedule will be referred to as Schedule "K" service. The Schedule K service will be closed to new customers after August 31, 1992.

The required kw load will be determined to the nearest one-tenth kw.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy Charges.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy Charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Term of Contract:

Not less than one year.

Superseding Revised Sheet No. 57
Effective June 1, 2001

REVISED SHEET NO. 57
Effective

SCHEDULE PS

LARGE POWER SECONDARY VOLTAGE SERVICE

AVAILABILITY:

Applicable to large light and/or power loads equal or greater than 300 kilowatts, supplied and metered at a single voltage and delivery point. Service under this Schedule shall be delivered at a secondary voltage specified by the Company.

RATES:

CUSTOMER CHARGE - $ per customer per month	$350.00/month
DEMAND CHARGE - $ per kW of billing demand:	
First 500 kW of billing demand - per kW	$20.00/kW
Next 1000 kW of billing demand - per kW	$19.50/kW
Over 1500 kW of billing demand - per kW	$18.50/kW
ENERGY CHARGE - ¢ per kWh:	
First 200 kWh/month/kW of billing demand - per kWhr	14.1560¢/kWhr
Next 200 kWh/month/kW of billing demand - per kWhr	13.3577¢/kWhr
Over 400 kWh/month/kW of billing demand - per kWhr	13.0485¢/kWhr

NETWORK SERVICE ADJUSTMENT:

Because of the inherent operating conditions in the downtown area supplied from the Company's underground network system, the Company will deliver and meter the service to customers in this area at 120/208Y or 277/480Y volts. The demand and energy charges will be increased by 0.9%.

SCHEDULE PS - (continued)

MINIMUM CHARGE:

The minimum monthly charge shall be the sum of the Customer and Demand charges. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall be the highest of the maximum demand for the month, the greatest maximum demand for the preceding eleven months, or 300 kW.

DETERMINATION OF DEMAND:

The maximum demand for each month shall be the maximum average load in kW during any fifteen-minute period as indicated by a demand meter. The billing demand for each month shall be the highest of the maximum demand for such month, or the mean of maximum demand for the current month and the greatest maximum demand for the preceding eleven (11) months, whichever is the higher, but not less than 300 kW.

This Schedule is closed to new customers with kW demand less than 300 kW after _______, 2007. Existing customers with maximum measured demand less than 300 kW per month may continue to receive service under this Schedule until the customer transfers to another applicable rate schedule.

Power Factor:

The above demand and energy charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed above, shall be decreased or increased, respectively, by 0.10%. The power factor will be computed to the nearest whole percent.

Superseding Revised Sheet No. 58A
Effective June 1, 2001

REVISED SHEET NO. 58A
Effective

Schedule PS - (continued)

Power Factor - continued

In no case, however, shall the power factor be taken as more than 100% for the purpose of computing the adjustment.

The average monthly power factor will be determined from the readings of a kWhr and Kvarh meter. The Kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges, Network Service adjustment, and Power Factor adjustment.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, Network Service adjustment, Power Factor adjustment, and energy cost adjustment.

TERM OF CONTRACT:

Not less than five years beginning from the service start date. If service is terminated before the end of the contract term, the customer shall be charge a termination fee equal to the total connection costs incurred by the Company to serve the customer less customer advance and/or contribution paid by the customer.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

Superseding SHEET NO. 58B
Effective June 1, 2001

REVISED SHEET NO. 58B
Effective

SCHEDULE PP

LARGE POWER PRIMARY VOLTAGE SERVICE

AVAILABILITY:

Applicable to large light and/or power loads equal or greater than 300 kilowatts, supplied and metered at a single voltage and delivery point. Service under this Schedule shall be delivered at a primary voltage specified by the Company.

RATES:

CUSTOMER CHARGE - $ per customer per month	$400.00/month
DEMAND CHARGE - $ per kW of billing demand:	
First 500 kW of billing demand - per kW	$18.50/kW
Next 1000 kW of billing demand - per kW	$18.00/kW
Over 1500 kW of billing demand - per kW	$17.00/kW
Billing Credit	
For Customers directly served from a Distribution substation, per billing kW	- $1.75/kW
ENERGY CHARGE - ¢ per kWh:	
First 200 kWh/month/kW of billing demand - per kWhr	14.5773¢/kWhr
Next 200 kWh/month/kW of billing demand - per kWhr	13.7944¢/kWhr
Over 400 kWh/month/kW of billing demand - per kWhr	13.4907¢/kWhr

SECONDARY METERING ADJUSTMENT FOR SERVICE AT PRIMARY VOLTAGE:

Metering will normally be at the delivery point. For services delivered at primary voltage and metered on the secondary side of the customer's transformers which are adjacent to the delivery point, and where the metering point is approved by the Company, a secondary metering adjustment of 0.2825 ¢/kWhr shall be added to the above energy charge.

SCHEDULE PP - (continued)

MINIMUM CHARGE:

The minimum monthly charge shall be the sum of the Customer and Demand charges. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall be the highest of the maximum demand for the month, the greatest maximum demand for the preceding eleven months, or 300 kW.

DETERMINATION OF DEMAND:

The maximum demand for each month shall be the maximum average load in kW during any fifteen-minute period as indicated by a demand meter. The billing demand for each month shall be the highest of the maximum demand for such month, or the mean of maximum demand for the current month and the greatest maximum demand for the preceding eleven (11) months, whichever is the higher, but not less 300 kW.

This Schedule is closed to new customers with kW demand less than 300 kW after ________, 2007. Existing customers with maximum measured demands less than 300 kW per month may continue to receive service under this Schedule until the customer transfers to another applicable rate schedule.

Power Factor:

The above demand and energy charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed above, shall be decreased or increased, respectively, by 0.10%. The power factor will be computed to the nearest whole percent. In no case, however, shall the power factor be taken as more than 100% for the purpose of computing the adjustment.

The average monthly power factor will be determined from the readings of a kWhr and Kvarh meter. The Kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Superseding SHEET NO. 58D
Effective June 1, 2001

REVISED SHEET NO. 58D
Effective

Schedule PP - (continued)

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges, Secondary Metering adjustment, and Power Factor adjustment.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, Secondary Metering Adjustment, Power Factor, and energy cost adjustment.

TERM OF CONTRACT:

Not less than five years beginning from the service start date. If service is terminated before the end of the contract term, the customer shall be charge a termination fee equal to the total connection costs incurred by the Company to serve the customer less customer advance and/or contribution paid by the customer.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

Superseding SHEET NO. 58E
Effective June 1, 2001

REVISED SHEET NO. 58E
Effective

SCHEDULE PT

LARGE POWER TRANSMISSION VOLTAGE SERVICE

AVAILABILITY:

Applicable to large light and/or power loads equal or greater than 300 kilowatts, supplied and metered at a single voltage and delivery point. Service under this Schedule shall be delivered at transmission voltage specified by the Company.

RATES:

CUSTOMER CHARGE - $ per customer per month $400.00/month

DEMAND CHARGE - $ per kW of billing demand:

First 500 kW of billing demand - per kW	$16.25/kW
Next 1000 kW of billing demand - per kW	$15.75/kW
Over 1500 kW of billing demand - per kW	$14.75/kW

ENERGY CHARGE - ¢ per kWh:

First 200 kWh/month/kW of billing demand - per kWhr	14.3519 ¢/kWhr
Next 200 kWh/month/kW of billing demand - per kWhr	13.5799 ¢/kWhr
Over 400 kWh/month/kW of billing demand - per kWhr	13.2809 ¢/kWhr

SECONDARY METERING ADJUSTMENT FOR SERVICE AT TRANSMISSION VOLTAGE:

Metering will normally be at the delivery point. For services delivered at transmission voltage and metered on the secondary side of the customer's transformers which are adjacent to the delivery point, and where the metering point is approved by the Company, the above demand and energy charges shall be increased by 0.5%.

Superseding SHEET NO. 58F
Effective June 1, 2001

REVISED SHEET NO. 58F
Effective

SCHEDULE PT - (continued)

MINIMUM CHARGE:

The minimum monthly charge shall be the sum of the Customer and Demand charges. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall be the highest of the maximum demand for the month, the greatest maximum demand for the preceding eleven months, or 300 kW.

DETERMINATION OF DEMAND:

The maximum demand for each month shall be the maximum average load in kW during any fifteen-minute period as indicated by a demand meter. The billing demand for each month shall be the highest of the maximum demand for such month, or the mean of maximum demand for the current month and the greatest maximum demand for the preceding eleven (11) months, whichever is the higher, but not less than 300 kW.

This Schedule is closed to new customers with kW demand less than 300 kW after _______, 2007. Existing customers with maximum measured demand less than 300 kW per month may continue to receive service under this Schedule until the customer transfers to another applicable rate schedule.

Power Factor:

The above demand and energy charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed above, shall be decreased or increased, respectively, by 0.10%. The power factor will be computed to the nearest whole percent. In no case, however, shall the power factor be taken as more than 100% for the purpose of computing the adjustment.

The average monthly power factor will be determined from the readings of a kWhr meter and Kvarh meter. The Kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Schedule PT – (continued)

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges, Secondary Metering adjustment, and Power Factor adjustment.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, Secondary Metering adjustment, Power Factor adjustment, and energy cost adjustment.

TERM OF CONTRACT:

Not less than five years beginning from the service start date. If service is terminated before the end of the contract term, the customer shall be charge a termination fee equal to the total connection costs incurred by the Company to serve the customer less the customer advance and/or contribution paid by the customer.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 59
Effective January 1, 1997

REVISED SHEET NO. 59
Effective

SCHEDULE F

Public Street Lighting, Highway Lighting and
Park and Playground Floodlighting

Availability:

Applicable only to public street and highway lighting, and public outdoor park and playground floodlighting service where the customer owns, maintains and operates the lighting fixtures and interconnecting circuits and conversion equipment. This rate is applicable to gaseous discharge lighting (Mercury Vapor) provided the regulator is corrected to power factor equivalent to the addition of one (1) KVAR of capacitors for each kW of name plate rating of the regulator. Under this schedule energy shall be supplied and metered at a nominal voltage of 2400 volts or more, as specified by the Company, except as set forth below under Special Terms and Conditions.

Rate:

CUSTOMER CHARGE:

$20.00 per month for each point of delivery.

ENERGY CHARGE - ¢ per kWh:

First	150 kWhr/month/kW of billing demand - per kWhr	22.0105 ¢/kWhr
All over	150 kWhr/month/kW of billing demand - per kWhr	18.0368 ¢/kWhr

Minimum Charge:

$35.00 per month for each point of delivery.

Determination of Demand:

The maximum demand for each month shall be the maximum average load in kW during any fifteen-minute period as indicated by a demand meter. The billing demand for each month shall be the maximum demand for such month but not less than 50% of the greatest maximum demand for the preceding eleven months.

Optional Secondary Metering for Street and Highway Lighting:

The street and highway lighting customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the energy charge will be increased by 1.5%.

Superseding Revised Sheet No. 60
Effective September 1, 1992

REVISED SHEET NO. 60
Effective

SCHEDULE F - (continued)

Special Terms and Conditions:

Multiple street lighting lamps may be individually served unmetered at secondary voltage along public streets and highways when, (1) in an overhead area, secondary voltage is available on the lamp pole or (2), in an underground area, secondary voltage is available along the public street. The total connected lamp load per connection point shall not exceed 2 KW. A one-year contract is required for service under this provision and each such contract will remain in effect from year to year thereafter unless, after the first year, terminated by 30 days notice in writing. Each contract will constitute a point of delivery. The monthly billing demand will be the connected lamp load expressed in kilowatts times 1.02 to the nearest one-tenth kilowatt, and the monthly billing kilowatt-hours will be 340 times the billing demand. The customer will provide a switching device for each lamp to limit the annual burning time to not more than 4100 hours.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer and Energy Charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Sheet No. 61
Effective January 1, 1995

REVISED SHEET NO. 61
Effective

SCHEDULE U

TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads equal to or greater than 300 kilowatts per month and supplied and metered at a single voltage and delivery point. This Schedule cannot be used in conjunction with load management Riders M, T, and I.

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods shall be as follows:

On-Peak Period: 7:00 a.m. - 9:00 p.m., daily
Priority Peak Period: 5:00 p.m. - 9:00 p.m., Monday through Friday
Mid-Peak Period: All On-Peak hours outside of Priority Peak hours
Off-Peak Period: 9:00 p.m. - 7:00 a.m., daily

RATE:

CUSTOMER CHARGE - per month	$350.00/month

DEMAND CHARGE - (To be added to Customer Charge)

Priority Peak - per kW of billing demand	$22.50/kW
Mid-Peak - per kW of billing demand	$19.50/kW

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE - (To be added to Customer and Demand Charges)

All On-Peak kWhr per month	- per kWhr	15.6596 ¢/kWhr
All Off-Peak kWhr per month	- per kWhr	12.0000 ¢/kWhr

SCHEDULE U - (continued)

Minimum Charge:

The monthly minimum charge shall be the sum of the Customer and the Demand Charges. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of billing demand for the minimum charge calculation for each month shall be the highest of the maximum on-peak demands for such month but not less than 300 kW.

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-day rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The on-peak kilowatts of billing demand for each month shall be the maximum on-peak demand for such month but not less than 300 kilowatts.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Special Terms and Conditions:

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	2.9%
Distribution voltage supplied without further transformation	2.1%

SCHEDULE U - (continued)

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 2.4% and 0.5%, respectively.

Because of the inherent operating conditions in the downtown area supplied from the Company's underground network system the Company will deliver and meter service to customers in this area at 120/208Y or 277/480Y volts (See Rule 2). The demand and energy charges will be increased 0.9%.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges, Service Voltage adjustment, Network Service adjustment, and Power Factor adjustment.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, Service Voltage adjustment, Network Service adjustment, Power Factor adjustment, and Energy Cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

TERM OF CONTRACT:

Not less than five years beginning from the service start date. If service is terminated before the end of the contract term, the customer shall be charge the total connection costs incurred by the Company to serve the customer less any customer advance and/or contribution paid by the customer.

Superseding Revised Sheet No. 62
Effective August 21, 1972

REVISED SHEET NO. 62
Effective

SCHEDULE E

Electric Service for Employees

Availability:

Applicable to all regular full-time Company employees, Company retirees, members of the Company Board of Directors, and retirees of Hawaii Electric Light Company, Inc. and Maui Electric Company, Ltd. who retired on or after January 1, 1996 and who are served by Hawaiian Electric Company, Inc. This schedule is applicable to the above customers' residential electric service in a single family dwelling unit metered and billed separately by the Company, subject to the Special Terms and Conditions specified below. This schedule does not apply where a residence and business are combined.

Rate:

The rates applicable to service under this schedule shall be two-thirds (2/3) of the current effective Schedule R rates - Residential Service, for usage up to 825 kwh per month. Energy usage above 825 kwh shall be charged the full Schedule R energy rates.

Special Terms and Conditions:

1. "Regular full-time Company employee" is defined as an employee who has successfully completed any required probationary requirements, is hired for an indefinite period, and who works no less than 40 hours per week.

2. This schedule is applicable only to primary residences.

3. Availability of this schedule terminates six months after death of eligible employee, retiree, or member of the Board of Directors.

Rules and Regulations:

Service supplied under this schedule shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 63
Effective January 1, 1996

REVISED SHEET NO. 63
Effective

ENERGY COST ADJUSTMENT CLAUSE

Applicable To

Schedule R	-	Residential Service
Schedule E	-	Electric Service for Employees
Schedule G	-	General Service - Non-Demand
Schedule J	-	General Service - Demand
Schedule H	-	Commercial Cooking, Heating, Air Conditioning and Refrigeration Service
Schedule PS	-	Large Power Secondary Voltage Service
Schedule PP	-	Large Power Primary Voltage Service
Schedule PT	-	Large Power Transmission Voltage Service
Schedule F	-	Public Street Lighting, Highway Lighting and Park and Playground Floodlighting
Schedule U	-	Time-of-Use Service
Schedule TOU-R	-	Residential Time-of-Use Service
Schedule TOU-C	-	Commercial Time-of-Use Service

All terms and provisions of Schedules R, E, G, J, H, PS, PP, PT, F, U, TOU-R, and TOU-C are applicable, except that the Energy Cost Adjustment described below will be added to the customer bills.

All base rate schedule discounts, surcharges, and all other adjustments will not apply to the energy cost adjustment.

Energy Cost Adjustment Clause:

This Energy Cost Adjustment Clause shall include the following:

FUEL AND PURCHASED ENERGY - The above rates are based on a company-owned central station and other generation cost (exclusive of company-owned distributed generation (DG)) of 1,059.86 cents per million BTU for fuel delivered in its service tanks, a purchased energy composite cost of 6.772 cents per kilowatthour, and a company-owned DG energy composite cost of 5.072 cents per kilowatt hour for fuel delivered to the fuel tank at the site used for the company-owned DG. Company-generated energy from non-fuel sources shall be considered as zero fuel cost in the determination of the composite fuel cost.

When the Company-generated Composite Cost of Generation is more or less than 1,059.86 cents per million BTU, and/or the Purchased Energy Cost is more or less than 6.772 cents per kilowatthour, and/or the company-owned DG Energy Composite Cost is more or less than 5.072 cents per kilowatt hour, a corresponding adjustment (Energy Cost Adjustment Factor) to the energy charges shall be made

Superseding Revised Sheet No. 63A
Effective January 1, 1996

REVISED SHEET NO. 63A
Effective

Energy Cost Adjustment Clause - (continued)

This adjustment shall be comprised of a Company Composite Central Station with Other Generation Component, a Purchased Energy Component, and a DG Energy Generation Component.

The Company Composite Central Station with Other Generation Component shall be the difference between the current Weighted Composite Central Station + Other Generation Cost and the Weighted Base Central Station + Other Generation Cost, adjusted for additional revenue taxes. The current Weighted Composite Central Station + Other Generation Cost shall be determined by the current Composite Cost of Generation in cents per million BTU weighted by the proportion of current company-owned central station + other generation to total system net energy, multiplied by the 2007 test-year efficiency factors of 0.011139 million BTU per kilowatthour for low sulfur fuel oil (LSFO), 0.032003 million BTU per kilowatthour for diesel fuel, and 0.011225 million BTU per kilowatthour for other company generation sources, weighted by the current proportion of generation produced by each generation source to the total company-owned generation.

The Weighted Base Central Station + Other Generation Cost is the Base Central Station + Other Generation Cost of 1,059.86 cents per million BTU weighted by the 2007 Test Year proportion of company-owned central station + other generation to total system net energy, multiplied by the 2007 Test year efficiency factor of 0.011225 million BTU per kilowatthour.

The Purchased Energy Component shall be the difference between (1) the current Composite Cost of Purchased Energy weighted by the proportion of current purchased energy to the total system net energy, and (2) the Base Purchased Energy Composite Cost of 6.772 cents per kilowatthour weighted by the 2007 Test Year proportion of the purchased energy to total system net energy, adjusted to the sales delivery level and for additional revenue taxes.

The Distributed Generation Energy Component shall be the difference between (1) the current Composite Cost of DG Energy weighted by the proportion of current DG energy to total system net energy, and (2) the Base DG Energy Composite Cost of 5.072 cents per kilowatthour weighted by the proportion of the 2007 Test Year DG energy to total system net energy, adjusted to the sales delivery level and for additional revenue taxes.

The Energy Cost Adjustment Factor shall be the sum of the Central Station with Other Generation Component, the Purchased Energy Component and the DG Energy Generation Component.

Energy Cost Adjustment Clause - (continued)

The revenue tax requirement shall be calculated using current rates of the Franchise Tax, Public Service Company Tax, and Public Utility Commission Fee.

The Adjustment shall be effective on the date of cost change. When a cost change occurs during a customer's billing period, the Adjustment will be prorated for the number of days each cost was in effect.

This Energy Cost Adjustment Clause is consistent with the terms of the Company's operations, purchased energy contracts, and DG contracts, and may be revised to reflect any revisions or changes in operations, purchased energy contracts, and is subject to approval by the Commission.

Reconciliation Adjustment:

In order to reconcile any differences that may occur between recorded and forecasted Energy Cost Adjustment Clause revenues, the year-to-date recorded revenue from the Energy Cost Adjustment Clause will be compared with the year-to-date revenue expected from the Energy Cost Adjustment Clause on a quarterly basis. If there is a variance between the recorded Energy Cost Adjustment Clause revenue and the expected Energy Cost Adjustment revenue, an adjustment, lagged by two months, shall be made to the Energy Cost Adjustment Clause to reconcile the revenue variance over the sales estimated for the subsequent quarter.

Superseding Sheet No. 64
Effective January 1, 1986

REVISED SHEET NO. 64
Effective

RIDER I

Interruptible Contract Service

Availability:

This Rider is applicable to service supplied and metered at a single voltage and delivery point where 500 kW or greater is subject to disconnection by the utility under the terms and conditions as set forth in the contract agreement. This Rider shall be closed to new customers after ________, 2007.

Rates:

Reduction in demand charge as set forth in a contract between the customer and the utility and approved by the Public Utilities Commission.

Term of Contract:

Not less than five years.

Superseding Revised Sheet No. 65
Effective February 1, 1998

REVISED SHEET NO. 65
Effective

RIDER M

Off-Peak and Curtailable Service

AVAILABILITY:

This Rider is available to customers served under rate Schedule J, PS, PP, or PT, whose maximum measured demands prior to any load modifications effected under this rider, exceed 100 and 300 kilowatts, respectively. This Rider cannot be used in conjunction with Rider T, Rider I, Schedule U, and Schedule TOU-C.

RATES:

A. Basic Rates

The rate(s) for service under this Rider shall be as specified under the regular Schedule J, PS, PP, or PT whichever is applicable, except that the Minimum Charge and the determination of billing demand used in the calculation of demand and energy charges shall be as defined below, subject to the requirements under the Determination of Demand provision of the applicable rate schedule.

The customer shall select Option A - Off-Peak Service or Option B - Curtailable Service:

OPTION A - OFF-PEAK SERVICE:

1) Any demand occurring during the off-peak period shall not be considered in determining the billing kW demand for each month, but shall be used in determining the excess off-peak charge. Only the maximum kW demand occurring during the on-peak period shall be used in the determination of the billing kW demand for the calculation of the demand charge, energy charge and minimum charge as specified in the regular Schedule J, PS, PP, or PT.

2) An excess Off-Peak Charge of $2.00 per kilowatt shall be added to the regular rate schedule charges for each kilowatt that the maximum off-peak demand exceeds the maximum demand during of the on-peak period.

RIDER M - (continued)

OPTION A - continued:

3) For calculation of the excess off-peak charge for each month, the maximum off-peak demand and maximum demand during the on-peak period shall be the highest measured demands during the respective periods for such month.

4) The time-of-use rating period shall be defined as follows:

On-Peak Period: 7 a.m. - 9 p.m. Fourteen hours, Daily

Off-Peak Period: 9 p.m. - 7 a.m. Ten hours, Daily

5) The monthly minimum charge shall be the sum of the customer charge, demand charge, Excess Off-Peak Charge, and Time-of-Day Metering Charge specified below.

OPTION B - CURTAILABLE SERVICE:

1) A customer who chooses curtailable service shall curtail his/her kW demand during the Company's curtailment hours, and shall indicate the load that he/she is willing to curtail. This curtailable load must be load that is normally operated during the Company's curtailment hours and must be at least 50 horsepower for motor loads served under Schedule J, and 150 horsepower for motor loads served under Schedule PS, PP, and PT, or 50 and 150 kilowatts for other than motor loads, respectively.

2) The Company may install a meter, in accordance with Rule 14, to measure the customer's curtailable load prior to the start of curtailable service under this Rider.

3) For billing purposes, the curtailed kW demand shall be determined monthly as the difference between the maximum kW demands outside of the curtailment hours and the maximum kW.

RIDER M - (continued)

OPTION B - continued:

demand during the curtailment hours measured for each month, but not to exceed the curtailable kW load specified in the customer's Rider M contract.

4) The customer shall choose one of the curtailment periods specified below. The billing demand under this curtailable service option shall be the normal billing demand under Schedule J, PS, PP, or PT reduced by:

Option 1) 75% of the curtailed kilowatt demand if the curtailment period is fixed throughout the year from 5 p.m. to 9 p.m., Monday through Friday; or

Option 2) 40% of the curtailed kilowatt demand if the curtailment period is two (2) consecutive hours as specified by the Company.

5) The monthly minimum charge shall be the sum of the customer charge, demand charge, and the Time-of-Day Metering Charge specified below.

Where the Company specifies the curtailment period, the Company shall give the customer at least 30 days notice prior to changing the curtailment period.

B. TIME-OF-DAY METERING CHARGE:

The Company shall install a time-of-use meter to measure the customer's maximum kW load during the time-of-day rating periods and curtailment periods.

An additional time-of-day metering charge of $10.00 per month shall be assessed to cover the additional cost of installing, operating, and maintaining a time-of-use meter.

Superseding Revised Sheet No. 65C
Effective February 1, 1998

REVISED SHEET NO. 65C
Effective

RIDER M - (continued)

C. TERMS OF CONTRACT:

1. The initial term of contract shall be at least 5 years. Thereafter, the contract shall continue from year-to-year until terminated by either party by a 30-day written notice.

2. A customer applying for service under this Rider shall sign a standard Rider M contract form with the Company.

3. The customer shall be allowed to take service under this Rider for a six-month trial period without penalty for termination within this period.

4. If the contract is terminated after the first six-months trial period, but before the first five-year period which begins from the start date of the customer's service under this Rider, the customer shall be assessed a termination charge equal to the last six months discount received under this Rider.

5. The customer may request a change of Rider options (Option A - Off-Peak Service or Option B - Curtailable Service) or curtailment hours (Options 1 or 2 under Curtailable Service) by providing a 30-day written notice to the Company. The change will become effective after the next regular meter reading following the receipt of such written notice by the Company, provided however, the Company may not be required to make such change until 12 months of service has been rendered after the last change, unless a new or revised Rider has been authorized, or unless a customer's operating conditions have altered so as to warrant such change.

6. If under the curtailable service option the customer fails to curtail his maximum demand during the curtailment period three times within a twelve-month period, the Company may terminate the Rider M contract by a 30-day written notice to the customer. If service under this Rider

Superseding Sheet No. 65D
Effective February 1, 1998

Revised SHEET NO. 65D
Effective

RIDER M - (continued)

C. TERMS OF CONTRACT - continued:

is terminated due to the customer's failure to curtail his demand as provided in the contract, the customer shall be assessed a termination charge equal to the last six months discount received under this Rider.

7. Service supplied under this Rider shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 67
Effective January 1, 1995

REVISED SHEET NO. 67
Effective

RIDER T
TIME-OF-DAY RIDER

AVAILABILITY:

This rider is available to customers on rate Schedule J, PS, PP, or PT but cannot be used in conjunction with the load management Rider M, Rider I, Schedule U, and Schedule TOU-C.

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods under this Rider shall be as follows:

On-Peak Period:	7:00 a.m. - 9:00 p.m., Daily
Off-Peak Period:	9:00 p.m. - 7:00 a.m., Daily

RATE:

The rate(s) for service under this Rider including the Customer Charge, Energy Charge, and Demand Charge shall be as specified in the regular rate Schedule J, PS, PP, or PT except that the following charges shall be added:

TIME-OF-DAY METERING CHARGE - per month	$10.00

TIME-OF-DAY ENERGY CHARGE ADJUSTMENTS:

On-Peak Energy Surcharge	- all on-peak kwh	+2.00 cents/kwh
Off-Peak Energy Credit	- all off-peak kwh	-3.00 cents/kwh

MINIMUM CHARGE:

The Minimum Charge shall be as specified under the regular rate schedule except that it shall include the Time-of-Day Metering Charge. In addition, the monthly average energy charge computed from the regular energy charge and the above Time-of-Day energy charge adjustments including the energy cost adjustment, cannot be lower than the off-peak avoided energy cost at the metering point.

DETERMINATION OF DEMAND:

The Determination of Demand shall be as specified in the regular rate schedule, except that only the on-peak Kw demand shall be used in the determination of the kilowatts of billing demand for the Demand Charge, the regular Energy Charge and the Minimum Charge calculations.

Superseding Revised Sheet No. 67A
Effective January 1, 1995

REVISED SHEET NO. 67A
Effective

Rider T (Continued)

VOLTAGE SERVICE AND POWER FACTOR ADJUSTMENTS:

The voltage service and power factor adjustments shall be as specified in the regular rate schedule.

MEASUREMENT OF TIME-OF-DAY ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's energy consumption and maximum kW demand during the time-of-day rating periods.

TERMS OF AGREEMENT:

A customer applying for service under this Rider shall sign a standard Rider T contract form with the Company. Service under this Rider shall not be less than five years. The customer may terminate service under this Rider during the first six months without penalty. If the customer terminates service after the first six months but before the end of the first five-year period which begins from the start date of the customer's service under this Rider, the customer shall be charged a termination fee equal to the amount of the last six months of discount received under this Rider.

A customer may perform emergency maintenance on his equipment or load served under this rider during the on-peak period and the customer's maximum demand during that time will not be considered in the determination of the billing kW demand under the following conditions:

a. The conditions under which the customer may perform emergency maintenance on his equipment or load during on-peak period will be defined in the customer's contract.

b. The customer may perform such emergency maintenance during on-peak period only when approved by HECO, and will operate only for the duration approved by HECO. Such HECO approval shall be by phone, or by e-mail, or in writing to the customer.

c. The customer must notify HECO as far in advance as possible, but not less than 1 hour before performing such emergency maintenance on his equipment or load during the on-peak period. Such notice shall be by phone, by e-mail, or in writing. HECO may approve the customer's request on the basis of available

Rider T - (continued)

capacity. Service to the customer under this condition may be interrupted at any time when HECO's system conditions dictate the necessity to interrupt service, or when in HECO's sole judgment the system may be impaired or the startup of another unit would be uneconomic.

d. The customer's request to operate its load during the on-peak period under this condition cannot exceed four (4) times within a 12-month period.

Superseding Revised Sheet No. 68
Effective December 1, 2006

REVISED SHEET NO. 68
Effective

INTEGRATED RESOURCE PLANNING
COST RECOVERY PROVISION

Supplement To

Schedule R	-	Residential Service
Schedule E	-	Electric Service For Employees
Schedule G	-	General Service Non-Demand
Schedule J	-	General Service Demand
Schedule H	-	Commercial Cooking, Heating, Air Conditioning and Refrigeration Service
Schedule PS	-	Large Power Secondary Voltage Service
Schedule PP	-	Large Power Primary Voltage Service
Schedule PT	-	Large Power Transmission Voltage Service
Schedule F	-	Public Street Lighting, Highway Lighting and Park and Playground Floodlighting
Schedule U	-	Time of Use Service
Schedule TOU-R	-	Residential Time-of-Use Service
Schedule TOU-C	-	Commercial Time-of-Use Service

All terms and provisions of Schedules R, E, G, J, H, PS, PP, PT, F, U, TOU-R, and TOU-C are applicable except that the total base rate charges for each billing period shall be increased by the following Integrated Resource Planning (IRP) Cost Recovery Adjustment, Residential Demand Side Management (DSM) Adjustment, and Commercial and Industrial Demand Side Management (DSM) Adjustment:

A: INTEGRATED RESOURCE PLANNING COST RECOVERY ADJUSTMENT:

All Rate Schedules .... 0.000 percent

The total base rate charges for all rate schedules shall be increased by the above Integrated Resource Planning Cost Recovery Adjustment, which is based on the recovery of the ____ IRP Planning Costs and the reconciliation of ____ IRP Planning Costs, including interest and taxes, of $_____, as approved by the Public Utilities Commission.

The total base rate charges for the current billing period shall include all base rate schedule charges, discounts, surcharges, or base rate adjustments, excluding the Energy Cost Adjustment, Residential DSM Adjustment, and Commercial and Industrial DSM Adjustment and temporary Rate Adjustment.

B: Residential Demand-Side Management (DSM) Adjustment:

Schedules R and TOU-R - per kWhr .... _____¢/kWhr

Superseding Revised Sheet No. 68A
Effective December 1, 2006

REVISED SHEET NO. 68A
Effective

Integrated Resource Planning Cost Recovery Provision - (continued)

The total residential monthly bill shall include the above Residential DSM adjustment applied to all kWh per month. The above Residential DSM adjustment is based on recovering $__________ for the 200_ residential program costs and lost revenue margins, the reconciliation of the 200_ program cost recovery including lost revenue margins and revenue taxes, and the 200_ shareholder incentives, for which recovery has been approved by the Commission.

C: Commercial and Industrial Demand-Side Management (DSM) Adjustment:

Schedules G, J, H, PS, PP, PT, U, TOU-C - per kWh _____¢/kWhr

The total monthly bill for Schedules G, J, H, PS, PP, PT, U, and TOU-C customers shall include the above Commercial and Industrial DSM adjustment applied to all kWh per month. The above adjustment is based on recovering $___________ for the 200_ program costs and lost revenue margins, the reconciliation of the 200_ C&I program costs including the lost revenue margins and revenue taxes, and the 200_ shareholders incentives, for which recovery has been approved by the Public Utilities Commission.

RECONCILIATION ADJUSTMENT: (To be added to Integrated Resource Planning Cost Recovery Adjustment, Residential DSM Adjustment, and Commercial and Industrial DSM Adjustment):

In order to reconcile any differences that may occur between the above costs to be recovered and the revenues received from the above adjustments, recorded revenues will be compared with the above costs. The Integrated Resource Planning Cost Recovery Adjustment, Residential DSM Adjustment, and the Commercial and Industrial DSM Adjustment will be reconciled annually. If there is a variance between the recorded revenues from the adjustments and the costs to be recovered, a reconciliation adjustment, lagged by two months, will be made to the above adjustments.

REVISED SHEET NO. 69
Effective

SCHEDULE SS

STANDBY SERVICE

APPLICABILITY:

Applicable to standby service to customers with alternate regular source(s) of energy other than electricity from the Company (non-utility power source(s)). Service under this Schedule shall be at least 25 kW, supplied and metered at a single voltage and delivery point as specified by the Company.

Standby service is the power service that the Company is obligated to stand ready to supply when the customer's non-utility power source(s) is unavailable for service. Standby service refers to power service that the Company provides during both unscheduled outages (Backup Service) and Scheduled Maintenance Periods.

Supplemental Service is the power service supplied by the Company in addition to the customer's electric power requirements normally obtained from its non-utility power source(s). The Company will serve the customer's supplemental service under the applicable regular commercial rate schedule.

Rates:

The rates, terms, and conditions of the applicable regular commercial rate schedule shall apply except that the Billing kW under the applicable commercial rate schedule shall be adjusted as described below, the Standby Demand Charge and Standby Energy Charge shall be added to the customer's bill, and the Minimum Charge provisions of this Schedule shall supersede the Minimum Charge provisions in the applicable regular commercial rate schedule.

Standby Demand Charge:

The Standby Demand Charge for each month shall be the sum of the Reservation Demand Charge and the Daily Demand Charge.

SCHEDULE SS - Continued

Standby Demand Charge: continued

RESERVATION DEMAND CHARGE

$10.08 per Contract Standby kW, for customers served on Schedule J for Supplemental Service.
$12.47 per Contract Standby kW, for customers served on Schedule PS for Supplemental Service.
$10.89 per Contract Standby kW, for customers served on Schedule PP for Supplemental Service.
$8.55 per Contract Standby kW, for customers served on Schedule PT for Supplemental Service.

The Contract Standby kW shall be the greater of (1) the Contract Standby kW specified in the customer's Standby Service Contract form or (2) the maximum load served by the Customer's generation equipment in the current or previous 11 billing months, less the kW amount specified in the customer's Standby Service Contract form that would not have to be served by the Company in the event of an outage of the customer's generation equipment. The Contract Standby kW shall also include, in addition to the customer's normal operating level of its generation equipment, an equivalent kW for electrical power that would be required to replace thermal energy that is not supplied by the customer's generation equipment.

DAILY DEMAND CHARGE

$0.38 per Standby Billing kW per day, for customers served on Schedule J for Supplemental Service.
$0.47 per Standby Billing kW per day, for customers served on Schedule PS for Supplemental Service.
$0.45 per Standby Billing kW per day, for customers served on Schedule PP for Supplemental Service.
$0.46 per Standby Billing kW per day, for customers served on Schedule PT for Supplemental Service.

Backup Demand during a 15 minute interval is the lesser of (1) the Contract Standby kW minus the customer's load served by the customer's generation equipment, but not less than zero, or (2) the load served by the Company's generation equipment in that same time interval as the customer's own generation load. The Standby Billing kW each day is the maximum Backup Demand during the 24-hour day. The daily demand charge shall be the sum of the calculated demand charges for each day of the billing period. For the purpose of calculating the Backup Demand only, the Contract Standby kW will exclude any amounts that represent equivalent kW for electrical power that would be required to replace thermal energy that is not supplied by the customer's generation equipment.

The Daily Demand Charge will be waived during days of Scheduled Maintenance.

SCHEDULE SS - Continued

STANDBY ENERGY CHARGE

Standby Energy kWh is the sum of 15 minute interval Backup Demands (including periods of Scheduled Maintenance) during the month divided by four.

$0.098 per Standby Energy kWh, for customers served on Schedule J for Supplemental Service.
$0.104 per Standby Energy kWh, for customers served on Schedule PS for Supplemental Service.
$0.102 per Standby Energy kWh, for customers served on Schedule PP for Supplemental Service.
$0.096 per Standby Energy kWh, for customers served on Schedule PT for Supplemental Service.

SUPPLEMENTAL SERVICE DEMAND CHARGE

The Billing kW for Supplemental Service shall be as follows:

The Billing kW shall be calculated as described in the applicable regular commercial rate schedule, based on the meter readings of the service provided by the Company's generation equipment, except that the calculated billing kW shall be reduced by the sum of the Standby billing kW for each day of the billing period divided by the total number of days in the billing period. This adjusted Billing kW shall be the kW basis for billing the supplemental service demand and energy charges.

SUPPLEMENTAL SERVICE ENERGY CHARGE

Supplemental Service Energy kWh shall be based on the meter readings of the service provided by the Company's generation equipment and shall be the total kWh provided minus the Standby Energy kWh. Supplemental Service Energy shall be billed at the rates shown on the appropriate regular commercial rate schedule, based on the adjusted billing kW described above.

SUPPLY VOLTAGE ADJUSTMENT

The Supply Voltage Adjustment in the applicable regular commercial rate schedule shall apply to the Standby Demand Charge and the Standby Energy Charge.

SCHEDULE SS - Continued

MINIMUM CHARGE

The monthly minimum charge shall be the sum of the Minimum Charge under the applicable regular commercial rate schedule and the Standby Demand Charge. The Minimum Charge under the applicable regular commercial rate schedule shall be based on the maximum kW provided by the Company's generation equipment in the current or 11 previous billing months less the Contract Standby kW. Where the Company determines that the installed capacity of the customer's non-utility power source(s) exceeds the customer's total kW requirement as determined by the Company, the monthly minimum charge shall be the sum of the Customer Charge under the applicable regular commercial rate schedule and the Standby Demand Charge.

TERMS AND CONDITIONS:

1. This tariff shall apply when a customer regularly obtains power service from a source(s) other than the Company, and obtains supplemental service from the Company when its non-utility power source(s) capability is less than its total power requirements; and/or requires standby service from the Company.

2. This tariff shall not apply
   a. to non-utility power sources used exclusively by a customer for emergency service; or
   b. to non-utility power sources that would be used exclusively by a customer for emergency service but for an agreement between the customer and the Company to use the non-utility power sources to reduce utility system load and/or provide capacity to the utility system; or
   c. to non-utility power sources that are at least fifty percent fueled by non fossil fuel energy, calculated on an annual fuel energy input basis; or
   d. to non-utility power sources that produce electricity for sale to the Company under a purchased power agreement that is approved by the Commission, unless otherwise specified in the purchase power agreement; or

SCHEDULE SS - Continued

Terms and Conditions: continued

e. to non-utility power sources that are operated for the benefit of customers who have an interruptible service contract (Rider I) or curtailable service contract (Rider M, option B) with the utility; or

f. to non-utility power sources covered under an agreement for net energy metering with the Company under Rule No. 18.

3. The connection and operation of the customer's non-utility power source(s) in parallel with the Company's system will be permitted when the customer is served under this Schedule and in accordance with the terms of a contract with the Company for parallel interconnection, as described in the Company's Rule No. 14.

4. Customers receiving service under this Schedule shall sign a Standby Service Contract with the Company, which shall specify the Contract Standby kW for standby service required from the Company, and the Scheduled Maintenance Service, if any, elected by the customer.

5. The Contract Standby kW normally will not be less than the lesser of (1) the Total Capacity of the customer's non-utility power source(s), or (2) the highest customer kW Load for the twelve months preceding commencement of service under this Schedule, or execution date of the Standby Service Contract, whichever is earlier. The customer must notify the Company of any changes in its non-utility power source(s) that may affect its Contract Standby kW specified in the Standby Service Contract. The Company may, from time to time, verify the customer's Contract Standby kW specified in the Standby Service Contract. Where the Company determines that the Contract Standby kW requires adjustment, the Company shall inform the customer in writing 60 days before such change becomes effective.

6. The maximum instantaneous demand may be limited by contract. When the capacity of the service connection is limited to conform to the Contract Standby kW, the customer shall provide, install and maintain at its expense, and the Company shall control, any circuit breaker and other equipment necessary to limit the service connection to the Contract Standby kW.

SCHEDULE SS - Continued

Terms and Conditions: continued

7. The Company shall not be liable for any consequential damages caused by, or resulting from any limitation of kW capacity supplied to the customer under this Schedule.

8. Scheduled Maintenance Service under this rate schedule shall be for power service during the Scheduled Maintenance Periods of the customer's non-utility power source(s). A customer shall specify in the Standby Service Contract whether it is taking Standard Scheduled Maintenance Service, Off-peak Scheduled Maintenance Service, or both.

   For Standard Scheduled Maintenance Service, maintenance for a customer's non-utility power source is subject to the following terms and conditions:

   a. A non-utility power source cannot be down for Standard Scheduled Maintenance Service more than 2 times during the calendar year.

   b. The customer shall specify its initial Scheduled Maintenance Periods (to be taken during the first calendar year or partial calendar year in which it takes Scheduled Maintenance Service), subject to review and approval by the Company, in the Standby Service Contract. Prior to July 1 of each year, the customer shall submit in writing to the Company any changes to the Scheduled Maintenance Periods for the following calendar year. Where the Company indicates within 60 days that any such changes are not acceptable to the Company based on operating, technical or other similar reasons, the Company and the customer will work together to determine the changes to the Scheduled Maintenance Periods that are reasonable and acceptable to both parties.

   c. Either the Company or the customer may request one change in the start date and/or duration of any scheduled outage by written request (specifying the reason for such request, and the proposed start date and/or duration of the scheduled outage) made at least thirty days before the scheduled start of such outage. The Company and the customer will make reasonable efforts to accommodate such requests (by written responses given within one week of receiving such requests).

SCHEDULE SS - Continued

Terms and Conditions: continued

For Off-peak Scheduled Maintenance Service, a customer may elect Scheduled Maintenance periods that occur only during the Company's off-peak period, subject to the following conditions:

a. A power source can be maintained during off-peak hours only with two-week prior notice to the Company. Notice can be given either by phone, fax, or e-mail, and must include the meter number for the power source(s) to be maintained and the expected additional kW demand to be provided by the Company during the Scheduled Maintenance Service period(s). Off-peak hours are 9 p.m. - 7 a.m., daily.

b. Maintenance on the same power source can be scheduled no more than twice within a four-week period. The customer must call the Company in advance of shutting off and/or starting up its power source that will be maintained under this provision.

c. The Standby Service Contract must specify the non-utility power source(s) and meter numbers of the sources to be maintained during off-peak hours under the above terms.

The total of the Scheduled Maintenance Periods arranged under Standard Scheduled Maintenance Service and Off-peak Scheduled Maintenance Service shall not exceed 3 weeks per non-utility power source within a calendar year.

9. The customer's non-utility power source(s) shall be metered with a meter or recorder capable of interval metering, unless the Company deems such metering to be impractical for engineering or operating reasons. If the customer's non-utility power source(s) cannot be metered by the Company, then the customer's Standby Billing kW per day shall be equal to the Contract Standby kW, and the customer shall not be eligible for Scheduled Maintenance Service. If the customer has more than one non-utility power source, and elects scheduled maintenance service for only one of its non-utility power sources at a time, then each of the customer's non-utility power sources shall be separately metered.

SCHEDULE SS - Continued

Terms and Conditions: continued

10. The Company shall install, own, operate, maintain, and read meters on the customer's non-utility power source(s) for billing purposes. The customer shall be responsible for any cost associated with metering its non-utility power source(s), including the total installed cost of the meters. All meters shall be installed at some convenient place approved by the Company upon the customer's premises, and shall be so placed as to be accessible at all times for inspection, reading, and testing.

    When the Company performs maintenance work on the meters on the customer's non-utility power source(s), the Company shall bill the customer for the total cost associated with such maintenance including labor and material costs, and shall add this amount to the customer's electric bill for the period. The Company shall provide the customer with the breakdown of such maintenance costs such as the labor cost, materials and supplies, taxes, and any other cost incurred.

    The customer shall, at its expense, furnish, install and maintain in accordance with the Company's requirements all associated equipment such as all conductors, service switches, fuses, meter sockets, meter and instrument transformer housing and mountings, switchboard meter test buses, meter panels, and similar devices, required for service connection and meter installations on customer's premises. The customer shall at its expense, provide a dedicated telephone line to connect the meter(s) to the Company's communication system.

11. The term of contract under this Schedule is at least one (1) year, and the contract shall remain in effect from month-to-month thereafter, unless terminated by either party upon thirty 30) days prior written notice to the other party. Early termination by the customer shall incur a fee equal to the sum of the last six months' Reservation Demand charges.

12. Service supplied under this Schedule shall be subject to the Rules and Regulations of the Company.

REVISED SHEET NO. 69H
Effective

Standby Service Contract Form

This Contract covers Standby Service provided by HAWAIIAN ELECTRIC COMPANY, INC. (HECO) to:

Customer: ____________________ Account Number: ____________________

Service Address: ____

Under this Contract, the electric service provided by HECO to the customer's service location shall be served on rate Schedule SS and Schedule ______. All terms of Schedule _____ shall apply, except as further specified in Schedule SS and in this Contract.

The customer elects the following Scheduled Maintenance Service:

_______ Standard Scheduled Maintenance Service

_______ Off-peak Scheduled Maintenance Service

Contract Standby kW ________ (1)

Installed kW Capacity of Each Non-Utility Power Source ________ (2)

Total Number of Non-Utility Power Sources _________ (3)

Standard Scheduled Maintenance Periods & Non-Utility Power Sources to be maintained:

Standard Scheduled Maintenance Periods & Non-Utility Power Sources to be maintained: ____

____

____

This Contract shall become effective at the beginning of the first regular billing cycle following ______________ (date) or the first billing period after the installation of the required meters for service under Schedule ________ and Schedule SS, whichever occurs later.

The parallel interconnection of the customer's non-utility power sources with the Company's system shall be permitted in accordance with the terms and conditions specified in a contract for parallel interconnection.

Term of Contract shall be at least one year, and shall continue thereafter month-to-month until terminated by either party upon thirty (30) days prior written notice to the other party. This Contract may be terminated at any time by mutual agreement of the Company and the customer.

Authorized Customer Signature | HECO Representative

____
Company

____ ____
Name Date | Name Date

____ ____
Title | Title Date

Superseding Revised Sheet No. 81
Effective January 1, 1996

REVISED SHEET NO. 81
Effective

SCHEDULE Q

Purchases From Qualifying Facilities - 100 KW or Less

Availability:

This schedule is available to customers with cogeneration and/or small power production facilities which qualify under the Commission's Rules, Chapter 74 of Title 6, Subchapter 2 with a design capacity of 100 kilowatts or less. Such qualifying facilities (QF's) shall be designed to operate properly in parallel with the Company's system without adversely affecting the operations of its customers and without presenting safety hazards to the Company's or other customer's personnel. The customer shall comply with the Company's requirements for customer generation interconnected with the utility system.

Energy delivered to the customer by the Company will be metered separately from the energy delivered by the customer to the Company.

Rate for Energy Delivered to the Company by Customer

The Company will pay for energy as follows:

All kwh per month - per kwhr	12.94 ¢/kWhr

Energy Delivered to the Customer by the Company:

Energy delivered to the customer shall be billed under the Company's applicable rate schedule.

Service Charge:

A service charge of $20.00 per month shall be added to the customer's total electric bill for the energy delivered to the customer for the billing and administration of the purchase power.

If a customer is only selling power to the Company under this Schedule, and is not receiving electric power service from the Company under any of the Company's applicable rate schedule, the customer shall be billed the customer charge under Schedule J to cover the metering, meter reading, billing and administration of the purchase power. In this situation, the above Service Charge will not apply.

Superseding Revised Sheet No. 81A
Effective January 1, 1996

REVISED SHEET NO. 81A
Effective

SCHEDULE Q - (continued)

System Compatibility:

The customer must deliver electric power at 60 hertz and the same phase and voltage as the customer receives service from the Company.

Interconnection Facilities:

The customer shall furnish, install, operate and maintain facilities such as relays, switches, synchronizing equipment, monitoring equipment and control and protective devices designated by the Company as suitable for parallel operation with the Company system. Such facilities shall be accessible at all times to authorized Company personnel. All designs should be approved by the Company prior to installation.

If additional Company facilities are required or the existing facilities must be modified to accept the QF's deliveries, the QF shall make a contribution for the cost of such additional facilities.

Contract:

The Company shall require a contract specifying technical and operating aspects of parallel generation.

Energy Cost Adjustment Clause:

The above rate for energy delivered to the Company by the Customer is based on a composite cost of fuel for Company generation and Company Distributed Generation (DG) of 1,063.14 cents per million Btu for fuel delivered in its service tanks. Effective the first day of January, April, July, and October an Adjustment shall be made to reflect the composite cost of Company-generated and Company DG-generated fuel cost on file with the Commission and shall be effective for the following three months.

The Adjustment shall be the sum of the time-weighted on-peak adjustment (14 hours of 24 hours) and off-peak adjustment (10 hours of 24 hours). On-peak and off-peak adjustments shall be determined by the amount of the composite cost of Company-generated and Company DG-generated fuel cost increase or decrease (in terms of cents per million Btu) from the base of 1,063.14 cents per million Btu multiplied by an on-peak heat rate of 13,382 Btu per net kilowatthour and

SCHEDULE Q - (continued)

and an off-peak heat rate of 9,929 Btu per net kilowatthour.

This Energy Cost Adjustment Clause is consistent with the terms of the Company's operations and may be revised to reflect any revisions or changes in operations, subject to approval by the Commission.

Superseding Sheet No. 82
Effective October 23, 1996

REVISED SHEET NO. 82
Effective

GREEN PRICING PROGRAM PROVISION

AVAILABILITY:

Available to all residents/non-residents of the Island of Oahu who wish to make voluntary contributions for the development of renewable energy resources on Oahu.

GREEN PRICING PROGRAM:

The objective of the Green Pricing Program is to encourage the development of Hawaii's renewable energy resources. The participant's voluntary contributions under the Green Pricing Program Provision are used to develop renewable energy facilities.

The Company's Sun Power for Schools Pilot Program is a pilot project under which photovoltaic systems are installed on selected public schools on the Island of Oahu. The participating school will own the photovoltaic facility and use the energy produced by the system at no cost. Contributions received from the participants in this Green Pricing Program Provision are used to help fund this pilot program.

Other renewable energy projects may be developed in the future as part of the Company's Green Pricing Program, depending on the availability of contributions received from this Green Pricing Program Provision.

VOLUNTARY PARTICIPATION:

1. Participation in the Green Pricing Program through the Green Pricing Program Provision, is voluntary and may be terminated by the participant at any time.

2. Any resident/non-resident of the Island of Oahu may contribute to the Green Pricing Program through the Green Pricing Program Provision by completing a standard program sign-up form which indicates the participant's mailing address, electric service account number (if participant is currently a HECO customer), and the contribution payment option desired. The Green Pricing Program Provision contribution payment options are listed below.

Superseding Sheet No. 82A
Effective October 23, 1996

REVISED SHEET NO. 82A
Effective

GREEN PRICING PROGRAM PROVISION (Continued)

3. A participant may terminate his/her voluntary contribution to the Green Pricing Program at any time by submitting a written or telephonic request to the Company to terminate participation in the Green Pricing Program Provision.

CONTRIBUTION PAYMENT OPTIONS:

A participant will specify the amount of his/her voluntary contribution (in whole dollars) and shall elect one of the following payment options:

Option 1: Monthly Contribution - the participant will be billed monthly based on the participant's specified dollar contribution amount.

Option 2: One Time Contribution - the participant will be billed one time for one lump sum contribution.

TERMS AND CONDITIONS:

1. Payments received by the Company shall be applied first to the participant's outstanding electric service bill balance, if any, and the remainder shall be applied to the participant's contribution to the Green Pricing Program under the Green Pricing Program Provision.

2. Electric Service will not be terminated if the participant fails to make contribution payments under the Green Pricing Program Provision.

3. The Company may terminate a participant's participation in the Green Pricing Program Provision, if the participant fails to make contribution payments for two (2) consecutive months.

4. The Company's late payment charge shall not apply to the participant's voluntary contributions under the Green Pricing Program Provision.

SHEET NO. 83
Effective

SCHEDULE TOU-C

COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads less than 300 kilowatts per month and supplied and metered at a single voltage and delivery point. This Schedule cannot be used in conjunction with load management Riders M, T, and I.

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods shall be as follows:

Priority Peak:	5:00 p.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

RATE:

<u>NON-DEMAND SERVICE:</u>
Applicable to general light and/or power loads less than or equal to 5000 kWhr per month, and less than 25 kW, and supplied and metered at single voltage and delivery point.

CUSTOMER CHARGE:

Single-Phase Service - per month	\$30.00/month
Three-Phase Service - per month	\$55.00/month

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period - per kWhr	24.9393 ¢/kWhr
Mid-Peak Period - per kWhr	21.9393 ¢/kWhr
Off-Peak Period - per kWhr	14.9393 ¢/kWhr

MINIMUM CHARGE:

Single-Phase Service - per month	\$30.00/month
Three-Phase Service - per month	\$55.00/month

SCHEDULE TOU-C - continued

DEMAND SERVICE:

Applicable to general light and/or power loads greater than 5000 kWhr per month, or equal to or greater than 25 kW but less than 300 kW, and supplied and metered at single voltage and delivery point.

CUSTOMER CHARGE:

Single-Phase Service - per month	\$50.00/month
Three-Phase Service - per month	\$70.00/month

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period - per kWhr	20.1766 ¢/kWhr
Mid-Peak Period - per kWhr	17.1766 ¢/kWhr
Off-Peak Period - per kWhr	12.0000 ¢/kWhr

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak - per kW of billing demand	\$19.50/kW
Mid-Peak - per kW of billing demand	\$12.00/kW

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 25 kW.

SCHEDULE TOU-C - (continued)

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-day rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 25 kW.

Power Factor: (Applicable to Demand Service)

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery: (Applicable To Demand Service)

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	-2.9%
Distribution voltage supplied without further transformation	-2.1%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 2.4% and 0.5%, respectively.

SHEET NO. 85A
Effective

SCHEDULE TOU-C - (continued)

Supply Voltage Delivery - continued:

Because of the inherent operating conditions in the downtown area supplied from the Company's underground network system the Company will deliver and meter service to customers in this area at 120/208Y or 277/480Y volts (See Rule 2). The demand and energy charges will be increased 0.9%.

Energy Cost Adjustment Clause: (For Non-Demand and Demand Service)

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges, Service Voltage adjustment, Network Service adjustment, and Power Factor adjustment.

Integrated Resource Planning Surcharge: (For Non-Demand and Demand Service)

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, Service Voltage adjustment, Network Service adjustment, Power Factor adjustment, and energy cost adjustment.

Rules and Regulations: (For Non-Demand and Demand Service)

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

TERM OF CONTRACT: (For Non-Demand and Demand Service)

Not less than five years beginning from the service start date. If service is terminated before the end of the contract term, the customer shall be charge the total connection costs incurred by the Company to serve the customer less any customer advance and/or contribution paid by the customer.

Superseding Sheet No. 86
Effective May 12, 2003

REVISED SHEET NO. 86
Effective

SCHEDULE TOU-R

RESIDENTIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to residential power service metered and billed separately by the Company. This Schedule does not apply where a residence and business are combined. Service under this Schedule will be delivered at secondary voltage specified by the Company.

This Schedule is limited to 1,000 residential customers on a first come first serve basis until the new Customer Information System is implemented.

RATES:

CUSTOMER CHARGE - $ per customer per month:	
Single-Phase Service - per month	$ 9.50/month
Three-Phase Service - per month	$17.50/month
ENERGY CHARGES - ¢ per kWh:	
<u>BASE CHARGES</u> - ¢ per kWh:	
First 350 kWh per month - per kWhr	19.7921 ¢/kWhr
Next 850 kWh per month - per kWhr	21.0891 ¢/kWhr
All kWhr over 1,200 kWh per month - per kWhr	21.9818 ¢/kWhr
<u>TIME-OF-USE CHARGES</u> - ¢ per kWh:	
Priority Peak Period - per kWhr	5.0 ¢/kWhr
Mid-Peak Period - per kWhr	2.0 ¢/kWhr
Off-Peak Period - per kWhr	-3.5 ¢/kWhr
MINIMUM CHARGE:	
Single-Phase Service - per month	$17.50/month
Three-Phase Service - per month	$22.50/month

Superseding Sheet No. 87
Effective May 12, 2003

REVISED SHEET NO. 87
Effective

SCHEDULE TOU-R - (continued)

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods under this Schedule shall be defined as follows:

Priority Peak:	5:00 p.m.-9:00 p.m.,	Monday-Friday
Mid-Peak	7:00 a.m.-5:00 p.m.,	Monday-Friday
	5:00 p.m.-9:00 p.m.,	Saturday-Sunday, Holidays
Off-Peak	7:00 a.m.-5:00 p.m.,	Saturday-Sunday, Holidays
	9:00 p.m.-7:00 a.m.,	Daily

Holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWh energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1. The Company may meter the customer's energy usage pattern for one to three months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.
2. The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

3. The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

Superseding Sheet No. 88
Effective May 12, 2003

REVISED SHEET NO. 88
Effective

Schedule TOU-R - (continued)

TERMS AND CONDITIONS - continued:

4. A customer may terminate service under this rate Schedule and return to the regular Schedule R at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

ENERGY COST ADJUSTMENT CLAUSE:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

INTEGRATED RESOURCE PLANNING COST RECOVERY PROVISION:

The Integrated Resource Planning Surcharge shall be added to the Customer and Energy Charges, and energy cost adjustment.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

SHEET NO. 89
Effective

DSM RECONCILIATION CLAUSE

Applicable To

Schedule R	-	Residential Service
Schedule E	-	Electric Service for Employees
Schedule G	-	General Service - Non-Demand
Schedule J	-	General Service - Demand
Schedule H	-	Commercial Cooking, Heating, Air Conditioning and Refrigeration Service
Schedule PS	-	Large Power Secondary Voltage Service
Schedule PP	-	Large Power Primary Voltage Service
Schedule PT	-	Large Power Transmission Voltage Service
Schedule U	-	Time-of-Use Service
Schedule TOU-R	-	Residential Time-of-Use Service
Schedule TOU-C	-	Commercial Time-of-Use Service

All terms and provisions of Schedules R, E, G, J, H, PS, PP, PT, U, TOU-R, and TOU-C are applicable except that the total base rate charges for each billing period shall be increased by the following DSM Reconciliation Adjustment:

DSM RECONCILIATION ADJUSTMENT:
Schedules R, E, G, J, H, PS, PP, PT, U TOU-R, and TOU-C . . . . ________ ¢ / kWhr

The total monthly bill shall include the above DSM Reconciliation Adjustment applied to all kWhr per month. The above DSM Reconciliation Adjustment is based on recovering any differences that may occur between:

- The dollar amount of DSM program customer incentives actually paid during the previous calendar year and $________ the amount of customer incentives included in base rates, and
- The actual annualized kWhr (at the customer level) reduced due to measures installed and actions taken during the previous calendar year through the DSM programs in such year and ____________kWh (at the customer level), times ____¢/kWhr, representing the difference in the DSM Utility Incentive.

The sum of the two differences above, the DSM Reconciliation balance, divided by the projected total kWh sales for the applicable rate schedules over the period of recovery, plus applicable revenue taxes, shall equal the DSM Reconciliation Adjustment.

The DSM Reconciliation Adjustment will be calculated annually and the amount recovered over the subsequent 12 months, or shorter if the amount is small. The actual dollar amount recovered through the DSM Reconciliation Clause will not be reconciled.

HAWAIIAN ELECTRIC COMPANY, INC.

HAWAIIAN ELECTRIC COMPANY, INC.

Superseding Revised Sheet No. 2
Effective June 6, 2003

REVISED SHEET NO. 2
Effective June 17, 2005

TABLE OF CONTENTS

RULES

HAWAIIAN ELECTRIC COMPANY, INC.

REVISED SHEET NO. 12
Effective: October 28, 1966

REISSUED
JUNE 1, 1988

RULE NO. 4

Service Contracts

A. SERVICE CONTRACTS REQUIRED

Service contracts will be required as a condition precedent to service when:

1. Required by a rate schedule; or
2. A line extension advance is required under Rule No. 13; or
3. Temporary service is installed under Rule No. 12.

B. LARGE LOADS

A service contract may be required of a customer who has a large load requiring the Company to make a substantial investment in facilities to serve him. Such contract may include termination charges, a guaranteed minimum charge or a minimum demand higher than specified in the rate schedule.

C. COMMISSION APPROVAL

Form contracts for service other than regular utility service provided under the provisions of the tariffs contained in these rules, are contained in these rules and are authorized by the Public Utilities Commission. Special contracts for service other than that provided under the tariffs or attached form contracts must be authorized by the Public Utilities Commission prior to the effective date of said contract.

Each contract for service will contain a statement that it shall at all times be subject to changes or modifications by the Public Utilities Commission as said Commission may from time to time direct in the exercise of its jurisdiction.

P.U.C. Order
No. 1849

Issued By
Herbert Heinrich
Vice President

Cancels Sheet No. 11
Effective: Dec. 14, 1961

RULE 4 - Continued

D. FORM CONTRACT FOR CUSTOMER RETENTION

The attached form contract for customer retention may be used by the Company with customers who have demonstrated to the satisfaction of the Company that it has a realistic competitive alternative, and must have provided the Company with information sufficient for the Company to analyze the customer's intent, capability and economic incentive to self-generate or otherwise purchase energy from a non-Company source.

The energy rates provided by the standard form contract for customer retention will be based on energy rates that do not include subsidies of other classes of customers, based on the test year results adopted by the Commission in the Company's last rate case.

Contracts shall become effective when executed by the Company and the customer. The Company shall not recover any reduction of revenues resulting from a form contract for customer retention between the time the form contract goes into effect until the Company's next general rate case. The appropriate ratemaking treatment will be determined in the Company's future general rate case proceedings using traditional ratemaking principles.

STANDARD FORM CONTRACT
FOR CUSTOMER RETENTION

This Contract covers electric service provided by HAWAIIAN ELECTRIC COMPANY, INC. (HECO) to:

Customer: ______________________________

Account Number: ______________________________

Service Address: ______________________________

Applicable rates, charges and rules

1. Under this Contract, service will be provided by HECO to Customer on Rate Schedule ____, and in accordance with other applicable provisions of HECO's tariff, as the same may be modified from time to time. The terms and conditions of such rate schedule and tariff shall apply, except to the extent provided in Attachment 1 (Customer Retention Rate) to this Contract.

Term

2. This Contract shall be effective upon execution by both parties (the Execution Date) and shall continue in effect for a term of three (3) years beginning on the first day of the month following filing with the Public Utilities Commission of the State of Hawaii (Commission) of the Contract (the Customer Retention Rate Effective Date), unless terminated in accordance with the provisions of this Contract; provided that the Customer Retention Rate shall not be effective until the Customer Retention Rate Effective Date.

3. This Contract may be terminated by mutual agreement of the parties, in writing.

Customer Retention

4. Customer agrees and acknowledges that the purposes of this Contract include (i) allowing HECO to retain load that would otherwise be lost if Customer implemented a Self-Generation option, (ii) maintaining revenues from Customer at a level higher than HECO's incremental cost to serve Customer, which benefits HECO's other customers, and (iii) allowing HECO to reduce uncertainty regarding large customer loads when planning its generation supply system, and its transmission and distribution systems.

5. If, during the term of this Contract, Customer's load is reduced as a result of the implementation by or on behalf of customer of a Self-Generation option, then HECO may terminate this Contract upon thirty (30) days written notice to customer. In the event of such termination, Customer shall be obligated to refund to HECO the difference between Customer's bills if calculated without the Load Retention Rate discount and the amounts actually billed to Customer, for the entire period between Load Retention Rate Effective Date and the effective date of such termination.

6. The payment of the refund to HECO shall be due and owing on the tenth (10th) day following the effective date of termination.

7. Self-Generation includes the generation of all or a portion of Customer's electrical requirements (i) by self-generation (generally, generation owned, leased, operated or used by Customer, which is located on-site, or in the vicinity of Customer, or the output of which can be delivered to Customer without the use of HECO's transmission or distribution system), (ii) by an electrical supplier other than HECO, or (iii) by obtaining energy for a commercial or industrial process or purpose previously powered by HECO-supplied electricity.

Customer Information

8. Information regarding Customer and Customer's energy usage is provided in Attachment 2.

9. Customer represents and warrants that the information set forth in Attachment 3 (Customer's Self-Generation Option(s)) is true and correct. The following Customer Self-Generation information must be provided in Attachment 3, except to the extent waived by the Company:

(i) a description of Customer's Self-Generation option(s), including, but not limited to, its size and fuel source;

(ii) detailed documentation of Customer's actual Self-Generation costs and evaluation of these costs. This evaluation should include a verifiable analysis of the Self-Generation option with the assumptions used over the life of the option. The cost evaluation also should include a comparison of the cost of the Self-Generation option to the Load Retention Rate;

(iii) an evaluation of the reasonable feasibility of Customer's ability to obtain all required permits for Self-Generation; and

(iv) an evaluation of the reasonableness of Customer's Self-Generation option in terms of the need for back-up power, the need for infrastructure, air emissions and water discharge permitting, and land use approvals; and

(v) information that demonstrates the extent to which the Load Retention Rate will encourage the customer to continue or improve existing load patterns that produce significant system benefit (i.e., time-of-use operations, peak shaving, standby generation).

10. Customer agrees to provide HECO with a recent energy assessment, conducted or adequately updated within the last two years, including a statement as to whether recommendations have been implemented or if prior action has already been taken to reduce peak usage and/or improve efficiency. The purpose of the assessment is to identify potential energy efficiency improvements; it will provide reliable cost and benefit information on electric energy efficiency improvements with reasonable paybacks. The energy assessment must be reasonably satisfactory to HECO, and shall meet the specifications in Attachment 4, except to the extent waived in writing by HECO.

Confidentiality

11. HECO shall retain as confidential all information and data furnished to it by Customer that relates to Customer's Self-Generation option, which are designated in writing by Customer as confidential at the time of transmission and are obtained or acquired by the HECO in connection with this Contract, and shall not disclose such information to any third party, except as necessary to obtain approval of this Contract.

12. However, nothing herein is meant to prevent nor shall be interpreted as preventing HECO from disclosing and/or using said information or data (i) when the information or data is actually known to HECO before being obtained or derived from Customer, or (ii) when information or data is generally available to the public without HECO's fault at any time before or after it is acquired from Customer, or (iii) where the information or data is obtained or acquired in good faith at any time by HECO from a third party who has the same in good faith and who is not under any obligation to Customer in respect thereof; or (iv) where a written release is obtained by HECO from Customer.

13. HECO will mark any part of the application for approval of the Contract it deems should not be subject to public disclosure as "confidential information." Unredacted copies of documents containing information so marked shall be withheld from public disclosure unless disclosure is ordered by the Commission. Copies of documents redacted to exclude confidential information shall be filed and placed in the public file. By Commission order or agreement with the applicant, other participants may be provided unredacted copies of documents containing confidential information but shall not disclose confidential information to any person unless permitted to do so by the Commission order.

Commission Jurisdiction

14. This contract for service shall at all times be subject to changes or modifications by the Commission as said Commission may from time to time direct in the exercise of its jurisdiction.

Authorizing Customer Signature:	HECO Representative(s):
Signature	Signature
Name	Name
Title Date	Title Date
	Signature
	Name
	Title Date

ATTACHMENT 1

CUSTOMER RETENTION RATE

Energy rates for Schedule P:

First 200 kwh/mo/kw of billing demand	7.2087 cents/kwh
Next 200 kwh/mo/kw of billing demand	6.4104 cents/kwh
All over 400 kwh/mo/kw of billing demand	6.1010 cents/kwh

Percentage discount: 2.77 % *

Customer Retention Rates for this contract:

First 200 kwh/mo/kw of billing demand	7.0090 cents/kwh
Next 200 kwh/mo/kw of billing demand	6.2328 cents/kwh
All over 400 kwh/mo/kw of billing demand	5.9320 cents/kwh

---

*Calculation of the % discount:

Schedule P	$000	Docket No. 7766 Letter dated 12/21/99
1) Return on rate base @ 10.54% ROR	= $ 24,748.8	Exhibit 6, Page 22
2) Rate base at proposed rates for Schedule P	= $234,898.5	Exhibit 6, Page 22
3) Return on rate base @ 9.16% ROR	= $ 21,516.7	line 2 x 0.0916
4) Reduction in return from 10.54% to 9.16%	= $ 3,232.1	line 1 – line 3
5) Operating income divisor	= 0.5569	Exhibit 6, Page 22 (1,474.5 ÷ 2,647.9)
6) Revenue impact	= $ 5,803.7	line 4 ÷ line 5
7) Revenues from energy charges	= $209,707.2	Exhibit 8, Page 76
8) % discount (to 2 decimal places)	= 2.77 %	line 6 ÷ line 7

ATTACHMENT 1 (continued)

CUSTOMER RETENTION RATE

Energy rates for Schedule J:

First 200 kwh/mo/kw of billing demand	8.6900 cents/kwh
Next 200 kwh/mo/kw of billing demand	7.5419 cents/kwh
All over 400 kwh/mo/kw of billing demand	6.5130 cents/kwh

Percentage discount: 11.27 % *

Customer Retention Rates for this contract:

First 200 kwh/mo/kw of billing demand	7.7106 cents/kwh
Next 200 kwh/mo/kw of billing demand	6.6919 cents/kwh
All over 400 kwh/mo/kw of billing demand	5.7790 cents/kwh

---

*Calculation of the % discount:

Schedule J	$000	Docket No. 7766 Letter dated 12/21/99
1) Return on rate base @ 14.35% ROR	= $ 18,384.4	Exhibit 6, Page 22
2) Rate base at proposed rates for Schedule J	= $128,086.1	Exhibit 6, Page 22
3) Return on rate base @ 9.16% ROR	= $ 11,732.7	line 2 x 0.0916
4) Reduction in return from 14.35% to 9.16%	= $ 66,51.7	line 1 – line 3
5) Operating income divisor	= 0.5558	Exhibit 6, Page 22 (740.2 ÷ 1,331.7)
6) Revenue impact	= $ 11,967.8	line 4 ÷ line 5
7) Revenues from energy charges	= $106,228.6	Exhibit 8, Page 15
8) % discount (to 2 decimal places)	= 11.27 %	line 6 ÷ line 7

ATTACHMENT 2

CUSTOMER INFORMATION

Customer Information

a. ______________________________
(Customer's full and correct name)

b. ______________________________
____
____
____
(Customer's business address)

c. ______________________________
(Customer's telephone number)

____
(Customer's fax number)

d. ______________________________
____
____
(Customer's account number(s))

e. ______________________________
____
____
____
____
(Agent's name, business address and numbers, if applicable)

Site and Business Description

____
____
____
____
____
____

Energy Usage (for each meter)

(a) Load ____ (Ave. last yr.) ____ Peak (last 12 mos.)
(b) Energy ____ (last 1 yr.) ____ (last 2 yrs.)
(c) Time of use – a description of when and how the existing Customer uses electricity and what benefits or detriments this use has on existing system operation.

____

____

____

(d) Future use – a statement indicating the potential for future Customer load growth once served on the proposed tariff.

____

____

____

(e) Revenues $_________ (last 1 year) $_________ (last 2 years)

(f) Currently applicable rate schedules and riders

____

____

____

____

(g) Billing determinants (past 12 mos.)

____

____

____

____

(h) Billing determinants (projected 12 mos. with Load Retention Rate)

____

____

____

____

ATTACHMENT 3

CUSTOMER'S SELF-GENERATION OPTION(S)

(Customer provided information to be attached to executed contract.)

ATTACHMENT 4

ENERGY AUDIT SPECIFICATIONS

General Description

The assessment must be an evaluation of the facilities' systems to identify opportunities for energy efficiency improvements which will result in a more efficient use of electricity. Areas to be analyzed must include, but are not limited to, electrical consumption in manufacturing processes (if applicable) and in building systems.

Specifications

1. The assessment must be performed by a Professional Engineer licensed to practice in the State of Hawaii. It is expected that at least one member of the assessment team will have a minimum of two years of experience in identifying and analyzing energy efficiency opportunities associated with the energy systems outlined in items a-f of specification 4.

2. The assessment must reflect the current operation of Customer's facility. Existing assessments may be updated to meet this requirement. Existing equipment surveys and architectural drawings may be used to meet this requirement. However, the assessment must comply with all requirements of the specification. Assessments not meeting these requirements should be returned by the utility to Customer for revision at Customer's expense.

3. The analysis must include an evaluation of electrical energy consumed by systems within the customer's facility. The analysis should also include a review of existing conditions, equipment load characteristics, and age of equipment (when the actual age of the equipment is unknown an estimated age range must be supplied). The analysis may use engineering estimates in lieu of monitoring or load simulations.

4. Areas that must be analyzed include:
   a. Lighting Systems.
   b. Electric Motors and Drive Systems.
   c. Mechanical systems, including heating, water heating, ventilating, refrigeration, and air conditioning.
   d. Heat recovery opportunities.
   e. Any other suitable technologies that increase electrical efficiency.
   f. Operation and maintenance procedures pertaining to electric motors, drive systems, lighting, mechanical systems, and electrical processes.

5. The assessment report must include at a minimum, except to the extent waived by the Company:
   a. Table of Contents
   b. Introduction stating the purpose of the assessment.
   c. An executive summary stating the conclusions and recommendations of the assessment.
   d. An action plan for Customer to implement the recommendations.
   e. A summary of building characteristics (applicable for portion of building where space is electrically cooled) describing the architectural, mechanical, and electrical components including identification of problems.
   f. An analysis of electric energy consumed by systems within Customer's facility. The report will also include a review of existing conditions, equipment load characteristics, and age of equipment (when the actual age of equipment is unknown an estimated age range must be supplied).
   g. A methodology section explaining the approaches taken and assumptions used to examine and analyze the building or systems.
   h. A prioritized list of all electrical energy conservation measures analyzed including a description of the present condition, the proposed measure, energy savings estimate, cost estimate, and simple payback.

Transmittal Letter No. 99-01 dated April 1, 1999
Docket No. 99-0106, Order No. 16965 dated April 30, 1999

i. A description of each energy conservation measure identified including interaction of measures.

j. Identification of other benefits, if any, related to the measure such as reduced maintenance, improved safety, productivity gains, or reduced waste.

k. A brief description of the assessmentor's educational and professional background and a statement attesting to the accuracy and completeness of the assessment findings followed by the assessmentor's Professional Engineer license information (state, number, and date received) and signature.

Superseding REVISED SHEET NO. 2
Effective June 6, 2003

REVISED SHEET NO. 2
Effective

TABLE OF CONTENTS

RULES

Superseding REVISED SHEET NO. 12
Effective: October 28, 1966

REVISED SHEET NO. 12
Effective:

RULE NO. 4

Service Contracts

A. SERVICE CONTRACTS REQUIRED

Service contracts will be required as a condition precedent to service when:

1. Required by a rate schedule; or

2. A line extension advance is required under Rule No. 13; or

3. Temporary service is installed under Rule No. 12.

B. LARGE LOADS

A service contract may be required of a customer who has a large load requiring the Company to make a substantial investment in facilities to serve him. Such contract may include termination charges, a guaranteed minimum charge or a minimum demand higher than specified in the rate schedule.

C. COMMISSION APPROVAL

Form contracts for service other than regular utility service provided under the provisions of the tariffs contained in these rules, are contained in these rules and are authorized by the Public Utilities Commission. Special contracts for service other than that provided under the tariffs or attached form contracts must be authorized by the Public Utilities Commission prior to the effective date of said contract.

Each contract for service will contain a statement that it shall at all times be subject to changes or modifications by the Public Utilities Commission as said Commission may from time to time direct in the exercise of its jurisdiction.

HAWAIIAN ELECTRIC COMPANY, INC.

REVISED SHEET NO. 15
Effective: October 28, 1966

RULE NO. 7

Discontinuance and Restoration of Service

A. REASONS FOR DENYING SERVICE

The Company may refuse or discontinue service for any of the reasons listed below:

1. Without notice in the event of a condition determined by the Company to be hazardous. The Company shall have the right to refuse service to any applicant and to refuse or discontinue service to any customer whose wire, appliances, apparatus, or other equipment, or use thereof shall be determined by the Company to be unsafe or in violation of applicable laws, ordinances, rules or regulations of any public authority, or if any condition exists upon the applicant's or customer's premises shall be determined by the Company to endanger the Company's service facilities;

The Company does not assume any duty of inspecting or repairing any applicant's or customer's wire, appliances, apparatus, or other equipment or any part thereof and assumes no liability therefor;

2. Without notice in the event of customer use of equipment in such a manner as to adversely affect the Company's equipment or the Company's service to others;

3. Without notice in the event of tampering with the equipment furnished and owned by the Company;

4. Without notice in the event of unauthorized use or use in violation of applicable laws, ordinances, rules, or regulations of any public authority;

5. For violation of and/or non-compliance with the Company's tariff or rules on file with and approved by the Commission. The Company may discontinue service to a customer if after written notice of such non-compliance the customer fails to comply within 5 days after date of presentation of such notice or within such other period of time after date of presentation of such notice as may be specified in such notice;

6. For failure of the customer to fulfill his contractual obligations for service and/or facilities subject to regulation by the Commission;

7. For failure of the customer to permit the Company reasonable access to its equipment;

8. For non-payment of bill provided that the Company has made a reasonable attempt to effect collection and has given the customer written notice that he has at least 5 days, excluding Sundays and holidays, in which to make settlement on his account or have his service denied;

9. If, for an applicant's convenience, the Company should provide service before credit is established or should continue service to a customer when credit has not been re-established in accordance with Rule No. 5 and he fails to establish or re-establish his credit within 5 days after date of presentation of written notice to do so or within such other period of time after date of presentation of such notice as may be specified in such notice, the Company may discontinue service;

10. For failure of the customer to furnish such service equipment, permits,

RULE NO. 7 (Continued)

Discontinuance and Restoration of Service

certificates, and/or rights-of-way, as shall have been specified by the Company as a condition to obtaining service, or in the event such equipment or permission are withdrawn or terminated; or

II. Fraud against the Company:

Unless otherwise stated, the customer shall be allowed a reasonable time in which to comply with the rule before service is discontinued. No service shall be discontinued on the day preceding or day or days on which the Company's business office is closed unless provisions are made for payment or reconnection on days when the Company's business offices are closed, except as provided in Rules 7A1 and 7A2.

B. CUSTOMER'S REQUEST FOR SERVICE DISCONTINUANCE

When a customer desires to terminate his responsibility for service, he shall give the Company not less than 2 days notice and state the date on which he wishes the termination to become effective. A customer may be held responsible for all service furnished at the premises until 2 days after receipt of such notice by the Company or until the date of termination specified in the notice, whichever date is later.

C. RETURNED CHECKS CHARGE

Payment by check for any service covered herein which is returned by the financial institution on which it is issued will result in a fee to the customer of $7.50 per returned check.

D. FIELD COLLECTION CHARGE

The Company shall require payment of $15.00 for a field call to the customer's service location necessitated by the customer's nonpayment of bills when such field call results in a successful collection of monies.

E. SERVICE ESTABLISHMENT CHARGE

The Company shall require payment of $15.00 for each establishment, supersedure, or re-establishment of electric service to any customer. This service establishment charge is in addition to the charges

RULE No. 7 (Continued)

calculated in accordance with the applicable rate schedule and will be required each time an account is opened, including a turn on, a reconnection of electric service, or a change of customer which requires a meter reading.

When a customer requests same day service or that electric service be turned on or reconnected outside of regular business hours, an additional charge of $10.00 will be assessed.

Superseding REVISED SHEET NO. 15
Effective: October 28, 1996

REVISED SHEET NO. 15
Effective:

RULE NO. 7

Discontinuance and Restoration of Service

A. REASONS FOR DENYING SERVICE

The Company may refuse or discontinue service for any of the reasons listed below:

1. Without notice in the event of a condition determined by the Company to be hazardous. The Company shall have the right to refuse service to any applicant and to refuse or discontinue service to any customer whose wire, appliances, apparatus, or other equipment, or use thereof shall be determined by the Company to be unsafe or in violation of applicable laws, ordinances, rules or regulations of any public authority, or if any condition exists upon the applicant's or customer's premises shall be determined by the Company to endanger the Company's service facilities;

   The Company does not assume any duty of inspecting or repairing any applicant's or customer's wire, appliances, apparatus, or other equipment or any part thereof and assumes no liability therefor;

2. Without notice in the event of customer use of equipment in such a manner as to adversely affect the Company's equipment or the Company's service to others;

3. Without notice in the event of tampering with the equipment furnished and owned by the Company;

4. Without notice in the event of unauthorized use or use in violation of applicable laws, ordinances, rules, or regulations of any public authority;

5. For violation of and/or non-compliance with the Company's tariff or rules on file with and approved by the Commission. The Company may discontinue service to a customer if after written notice of such non-compliance the customer fails to comply within 5 days after date of presentation of such notice or within such other period of time after date of presentation of such notice as may be specified in such notice;

Superseding REVISED SHEET NO. 16
Effective January 1, 1995

REVISED SHEET NO. 16
Effective:

RULE NO. 7 (Continued)

Discontinuance and Restoration of Service

6. For failure of the customer to fulfill his contractual obligations for service and/or facilities subject to regulation by the Commission;

7. For failure of the customer to permit the Company reasonable access to its equipment;

8. For non-payment of bill provided that the Company has made a reasonable attempt to effect collection and has given the customer written notice that he has at least 5 days, excluding Sundays and holidays, in which to make settlement on his account or have his service denied;

9. If, for an applicant's convenience, the Company should provide service before credit is established or should continue service to a customer when credit has not been re-established in accordance with Rule No. 5 and he fails to establish or re-establish his credit within 5 days after date of presentation of written notice to do so or within such other period of time after date of presentation of such notice as may be specified in such notice, the Company may discontinue service;

10. For failure of the customer to furnish such service equipment permits, certificates, and/or rights-of-way, as shall have been specified by the Company as a condition to obtaining service, or in the event such equipment or permission are withdrawn or terminated; or

II. Fraud against the Company:

Unless otherwise stated, the customer shall be allowed a reasonable time in which to comply with the rule before service is discontinued. No service shall be discontinued on the day preceding or day or days on which the Company's business office is closed unless provisions are made for payment or reconnection on days when the Company's business offices are closed, except as provided in Rules 7A1 and 7A2.

Superseding SHEET NO. 16A
Effective January 1, 1995

REVISED SHEET NO. 16A
Effective:

RULE NO. 7 (Continued)

B. CUSTOMER'S REQUEST FOR SERVICE DISCONTINUANCE

When a customer desires to terminate his responsibility for service, he shall give the Company not less than 2 days notice and state the date on which he wishes the termination to become effective. A customer may be held responsible for all service furnished at the premises until 2 days after receipt of such notice by the Company or until the date of termination specified in the notice, whichever date is later.

C. RETURNED PAYMENT CHARGE

Payment by check or any electronic payment form such as payment by credit card, debit card, or any form of automatic bill payment for any service covered herein which is returned by the financial institution on which it is issued will result in a fee to the customer of $22.00 per returned check or returned payment.

D. FIELD COLLECTION CHARGE

The Company shall require payment of $20.00 for a field call to the customer's service location necessitated by the customer's nonpayment of bills. This charge will be added to the customer's bill.

E. SERVICE ESTALBISHMENT CHARGE

The Company shall require payment of $20.00 for each establishment, supersedure, or re-establishment of electric service to any customer. This service establishment charge is in addition the charges calculated in accordance with the applicable rate schedule and will be required each time an account is opened, including a turn on, a reconnection of electric service, or a change of customer which requires a meter reading.

When a customer requests same day service or that electric service be turned on or reconnected outside of regular business hours, an additional charge of $25.00 will be assessed.

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2007

SUMMARY OF REVENUES AT PRESENT AND PROPOSED RATES

Rate Class	At Present Rates ($000s)	At Proposed Rates ($000s)	PROPOSED INCREASE Amount ($000s)	PROPOSED INCREASE Percent (%)
Schedule R	$415,723.4	$463,564.9	$47,841.5	11.51%
Schedule G	$77,691.4	$86,424.7	$8,733.3	11.24%
Schedule J	$358,924.9	$398,587.8	$39,662.9	11.05%
Schedule H	$7,077.7	$7,873.7	$796.0	11.25%
Schedule PS	$135,059.5	$150,691.1	$15,631.6	11.57%
Schedule PP	$319,103.4	$354,407.5	$35,304.1	11.06%
Schedule PT	$26,047.3	$27,887.5	$1,840.2	7.06%
Schedule F	$6,751.4	$7,628.8	$877.4	13.00%
Total Sales Revenue	$1,346,379.0	$1,497,066.0	$150,687.0	11.19%
Other Operating Revenues	$3,898.0	$4,716.0	$818.0	20.99%
Total Revenues	$1,350,277.0	$1,501,782.0	$151,505.0	11.22%

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2007

SUMMARY OF REVENUES AT CURRENT EFFECTIVE AND PROPOSED RATES

Rate Class	At Current Effective Rates ($000s)	At Proposed Rates ($000s)	PROPOSED INCREASE Amount ($000s)	PROPOSED INCREASE Percent (%)
Schedule R	$432,975.6	$463,564.9	$30,589.3	7.06%
Schedule G	$80,721.8	$86,424.7	$5,702.9	7.06%
Schedule J	$372,286.2	$398,587.8	$26,301.6	7.06%
Schedule H	$7,354.1	$7,873.7	$519.6	7.07%
Schedule PS	$140,747.4	$150,691.1	$9,943.7	7.06%
Schedule PP	$331,021.2	$354,407.5	$23,386.3	7.06%
Schedule PT	$26,047.3	$27,887.5	$1,840.2	7.06%
Schedule F	$7,125.4	$7,628.8	$503.4	7.06%
Total Sales Revenue	$1,398,279.0	$1,497,066.0	$98,787.0	7.06%
Other Operating Revenues	$3,947.0	$4,716.0	$769.0	19.48%
Total Revenues	$1,402,226.0	$1,501,782.0	$99,556.0	7.10%

Hawaiian Electric Company, Inc.
Base Case - Test Year 2007
Results of Operations
($ Thousands)

	Present Rates
Electric Sales Revenue	1,346,379
Other Operating Revenue	3,391
Gain on Sale of Land	507
TOTAL OPERATING REVENUES	1,350,277
Fuel	542,961
Purchased Power	386,108
Production	68,222
Transmission	10,491
Distribution	24,722
Customer Accounts	12,020
Allowance for Uncoll. Accounts	1,358
Customer Service	7,176
Administration & General	72,007
Gen Excise Tax Rate Incr Adj	320
Operation and Maintenance	1,125,385
Depreciation & Amortization	79,736
Amortization of State ITC	(1,321)
Taxes Other Than Income	126,151
Interest on Customer Deposits	375
Income Taxes	(4,107)
TOTAL OPERATING EXPENSES	1,326,219
OPERATING INCOME	24,058
AVERAGE RATE BASE	1,216,188
RATE OF RETURN ON AVERAGE RATE BASE	1.98%

Hawaiian Electric Company, Inc.
With IRP Cost Recovery Provision
Test Year 2007
Results of Operations
($ Thousands)

	Current Effective Rates
Electric Sales Revenue	1,398,279
Other Operating Revenue	3,440
Gain on Sale of Land	507
TOTAL OPERATING REVENUES	1,402,226
Fuel	542,961
Purchased Power	386,108
Production	68,222
Transmission	10,491
Distribution	24,722
Customer Accounts	12,020
Allowance for Uncoll. Accounts	1,411
Customer Service	7,176
Administration & General	72,007
Gen Excise Tax Rate Incr Adj	320
Operation and Maintenance	1,125,438
Depreciation & Amortization	79,736
Amortization of State ITC	(1,321)
Taxes Other Than Income	130,761
Interest on Customer Deposits	375
Income Taxes	14,292
TOTAL OPERATING EXPENSES	1,349,281
OPERATING INCOME	52,945
AVERAGE RATE BASE	1,215,544
RATE OF RETURN ON AVERAGE RATE BASE	4.36%

TESTIMONY OF
GEORGE WILLOUGHBY

DIRECTOR
FORECASTS & RESEARCH DIVISION, CUSTOMER SOLUTIONS
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Electricity Sales and Customer Forecasts

INTRODUCTION

Q. Please state your name and business address.

A. My name is George Willoughby and my business address is 220 South King Street, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am employed by Hawaiian Electric Company, Inc. ("HECO" or "Company") as the Director of the Forecasts and Research Division.

Q. What is your educational background and professional experience?

A. My experience and educational background are shown in HECO-200.

Q. What is the scope of your testimony in this proceeding?

A. I will discuss HECO's forecast of electricity sales in gigawatt-hours ("GWh") and average number of customers in test year 2007.

TEST YEAR SALES AND CUSTOMERS

Q. What are the test year 2007 estimates for the items in your area of responsibility?

A. The test year 2007 estimates for my area of responsibility are shown in HECO-201 and are summarized below:

	Test year 2007	units
Test Year Electricity Sales	7,720.8	GWh
Average Monthly Number of Customers	295,620	

Q. What are HECO's rate schedules?

A. For forecasting purposes, HECO has six primary rate schedules including:

1) Schedule R – Residential Service (includes Schedule E – Electrical Service

for Employees),

2) Schedule G – General Service–Non Demand,

3) Schedule J – General Service–Demand (includes Schedule U – Time of Use Service),

4) Schedule H – Commercial Cooking, Heating, Air Conditioning & Refrigeration Service,

5) Schedule P – Large Power Service (includes Schedules PP, PS, and PT), and

6) Schedule F – Street Lighting Service.

Electricity sold under these rate schedules is the primary source of revenue to HECO.

Q. Of what significance are the sales and customer forecasts in the rate case?

A. The sales and customer estimates identify the anticipated level of electricity consumption by our customers in the test year. Revenues at current and proposed rates are derived from the estimates of electricity sales and customers. The estimate of sales is also used in the derivation of test year fuel and purchased power expense estimates.

Q. Was the sales forecast prepared solely for the purpose of this proceeding?

A. No. HECO normally prepares an annual sales forecast with quarterly updates for financial and resource planning purposes. The August 2006 sales forecast is used as the basis for this rate proceeding because it reflects current sales and economic information.

Q. How does a sales update differ from a sales forecast?

A. A sales <u>forecast</u> is an annual undertaking of the entire forecast process including comprehensive review of the sales data, forecast methods, and results. The annual sales forecast also incorporates a detailed economic forecast prepared for HECO by the University of Hawaii Economic Research Organization ("UHERO"). A sales forecast is only undertaken once a year because the scope is so encompassing and considerable amounts of utility resources are required. The August 2006 sales and peak forecast is HECO's 2006 annual forecast.

Occasionally, HECO undertakes an even more comprehensive forecast for use in the Integrated Resources Plan ("IRP") process. In addition to the normal annual forecast process, the forecast used in an IRP undergoes public review throughout the forecast process, requiring a large time commitment from public participants.

Quarterly sales updates focus on changes, if any, from the most recent sales forecast or update. The primary focus is on changes in the economic outlook, year-to-date sales performance, and the magnitude and timing for large new projects. The methods used to project sales typically remain the same as those used to develop the previous annual forecast.

Q. What are the major topics of discussion in your testimony on 2007 sales and customers?

A. To support the test year estimates of sales and customers, I will:

1) describe the forecasting process,
2) present the economic outlook for 2007,
3) describe the forecast methods used in the derivation of the sales and customers forecasts,
4) discuss the derivation and reasonableness of 2007 sales forecasts for residential and commercial rate schedules, and
5) discuss the accuracy of previous forecasts.

Forecasting Process for the August 2006 Sales Forecast

Q. How did HECO develop its August 2006 sales forecast?

A. The August 2006 sales forecasting process started in January of 2006 and continued through August 2006, when the final forecast was approved by HECO's executive staff.

From February through April of 2006, HECO undertook an extensive review of its short-term sales forecasting methods. This review was part of the Company's ongoing efforts to continuously improve forecast processes and procedures. Particular attention was directed towards the short-term sales forecasting process partially because recorded sales were beginning to deviate from previously forecasted levels. In May of 2005, HECO sales were forecasted to increase 0.9% over 2004 by year-end. However, actual year-end 2005 recorded sales were 0.1% below 2004 levels. In February of 2006, sales were already 0.5% below February 2005 YTD levels, and 3.9% below the May 2005 forecasted levels.

HECO retained the consulting services of two noted utility industry economic consulting firms to assist in the review of methods and approaches to short-term sales forecasting. Over the course of several months, Energy and Environmental Economics ("E3") of San Francisco, California, and Charles Rivers Associates ("CRA") of Berkeley, California, participated in an active and open exchange of ideas and methods with personnel from HECO's Forecasts and Research Division.

HECO subsequently incorporated methods and approaches suggested by E3 and CRA and scrutinized and reviewed by HECO management to develop the August 2006 forecast. The most notable result of this review was HECO's decision to use short term econometric and time series models based on monthly data for short term forecasting purposes. I will describe the specific forecasting models that were developed later in my testimony.

Q. Who was responsible for collecting the data, identifying and executing the models, and developing the final forecast?

A. HECO's Forecasts and Research Division was responsible for this work.

Q. Was the August 2006 forecast reviewed at any other steps in the process?

A. Yes, it was. The draft forecast was subject to two levels of internal review within the Company. The first level of review was the Forecast Working Group ("FWG"), made up of mid-level HECO employees, whose task it is to evaluate the forecast from a technical standpoint and to recommend if the forecast should be forwarded to Executive Committee for the second level of internal review. The Executive Committee is comprised of HECO's executive staff.

In addition, the methods used to develop the August 2006 forecast were submitted to an informal technical review group that included several noted local economists. The purpose of this review was to examine the forecasting models and methodology on their technical merits.

Q. Was the forecast adopted by the Executive Committee?

A. Yes. The forecast was adopted by the Executive Committee for HECO's planning purposes on August 31, 2006.

<u>Economic Outlook</u>

Q. What is the economic outlook that underlies the sales and customer estimates for 2007?

A. Hawaii's economy in 2006 is performing to expectations for continued growth, although somewhat more slowly than 2005's banner year. Tourism, despite some early weakness, looks to recover in the second half of the year, and the construction industry continues to be strong.

Although slowing after sustained growth the last few years, the outlook for the local economy remains positive with continued growth in tourist arrivals, combined with persistent strength in the construction and real estate industries and robust military spending. While inflation and the slowing economy may constrain job and personal income growth relative to recent performance, the outlook for 2007 is still optimistic.

Q. Please describe the outlook for tourism.

A. The tourism sector continues to expand, although off the pace of 2005 when record visitor arrivals levels were set. A stable U.S. economy supported by continued job and income growth should maintain domestic arrivals, provided high oil prices and rising interest rates do not rapidly dampen economic growth. The Japan economy is projected to see growth in 2006 – 2007, and could support international visitor arrivals. However, international arrivals were disappointing in 2006, and the continuing weakness in Japanese visitor arrivals could be a potential problem. While the domestic market has largely compensated for these declines, the declining arrivals remain a serious concern. Although Oahu visitor arrivals growth slowed in 2006, the tourism industry should continue to contribute to economic growth.

Q. What is the outlook for the construction sector?

A. The local housing market appears to be cooling after rapid expansion in recent years with a lower volume of home sales, but home prices have not shown any move toward significant decline. Various residential and commercial construction projects already announced should continue to maintain the construction industry for several years. Increased activity in Pacific Rim countries is likely to reinforce the need for a strong military presence in Hawaii and funding for military construction projects is expected to continue for several years.

UHERO indicated in its September 29, 2006 construction forecast that the Hawai'i construction cycle is at a turning point with a gradual slowing of the construction sector projected over the next few years. The residential housing market, which drove much of the recent expansion, is expected to soften with rising prices and slowing demand. While nonresidential construction is expected to remain somewhat stronger, the overall outlook is for gradual slowing.

Home prices more than doubled in Hawai'i since the late-1990's and UHERO projects that home prices have largely peaked for the current investment cycle. UHERO expects that real construction activity will decline slightly over the next several years after peaking in 2006 - 2007. Construction costs have increased rapidly in the last two years, driven by spikes in the price of energy, metals, and building materials. Growth in nominal contracting receipts will be stronger this year than previously expected, but half of the increase is a reflection of higher construction costs.

UHERO expects nonresidential construction will continue at comparatively high levels for the next several years, although real permit values are expected to peak this year. Tight supplies of industrial and warehouse space continues to provide a strong basis for new commercial space construction, and retail development is likely to remain healthy with Nordstrom, Target, Whole Foods and other national brands entering the local market. Existing hotel room conversions to condominiums, timeshares, and other fractional ownership forms of resort area property may sustain construction activity in resort areas. Higher land prices and construction costs have likely dampened office market expansion.

UHERO notes, however, that the current construction expansion has been marked by little public infrastructure spending, raising concerns that public infrastructure may fall short of what is needed to support ongoing private development.

Q. What are the potential risks to the economic outlook?

A. While the economic outlook remains optimistic, the local economy appears to be slowing after several years of robust growth. There are several potential hurdles that may lead to erosion of the economic outlook.

If interest rates continue to rise, this may further contribute to lower demand for housing, as well as constrain growth in consumer spending. The impact of Federal Reserve interest rate actions may slow U.S. economic growth and dampen domestic travel.

The tourism industry is always vulnerable to disease outbreaks or acts of terrorism. Travel costs driven higher by fuel surcharges in airfares and high hotel occupancy rates could also limit Hawaii's desirability as a travel destination.

Higher costs may also dampen economic activity. According to UHERO's 3rd quarter 2006 economic outlook update, inflation is a real threat with Honolulu consumer price inflation topping the nation in the first half of 2006. Crude oil prices recently hit record high levels not seen in recent years, exceeding $78 per barrel in July. While oil prices have eased recently, members of the Organization of Petroleum Exporting Countries ("OPEC") have discussed trimming quotas to maintain prices. Rising prices are diminishing local residents' purchasing power and limiting real personal income growth. High prices could also affect commercial customers' spending as companies and government entities struggle to stay within limited budgets with rising electricity prices and transportation costs. High construction labor and materials costs may also restrict housing and commercial construction activity.

In general, the local economic outlook for 2007 remains optimistic but growth is expected to continue at a slower rate than in recent years.

Q. How does the economic outlook affect HECO's sales forecast?

A. The economic outlook is considered when projecting estimates of sales and customers, both directly through economic variables incorporated into econometric models, and indirectly through qualitative expectations for growth.

Forecasting Methods

Q. In general, how were the estimates of 2007 sales derived?

A. The 2007 sales were derived in the following manner:

1) The bases for 2007 sales are the residential (Schedule R), total commercial (sum of Schedules G, J, H, and P), and street lighting (Schedule F) sales estimates, not reduced by demand-side management ("DSM") program impacts. Each sector was forecasted using the methods described below.
2) Updated estimates of DSM and net energy metering ("NEM") impacts were subtracted from the allocated rate schedule sales estimates.

Q. What methods of analysis were used to develop the 2007 sales forecasts?

A. The estimate of residential sales in 2007 was based on an econometric analysis. A model was developed to estimate the residential use per customer and expanded to total Schedule R sales using the 2007 customer forecast. The estimate of total commercial sales was also based on an econometric analysis. Descriptions of these methods are provided later in this section.

Q. What method of analysis was used to develop the 2007 customer forecasts?

A. The 2007 customer forecast was based on time series analysis and large customer analysis by rate schedule.

Q. What is econometric analysis?

A. Econometric analysis relies on econometric models, which relate sales or customers' use of electricity to macroeconomic and other variables such as temperature, humidity, and electricity price. Econometric models may also incorporate time series parameters such as lagged dependent variables or an autoregressive term. The quantification of the impact of changes in the economic and other variables on use is the strength of these models.

Q. What is the general form of the equation, which makes up the econometric model?

A. The econometric model is specified in the following form:

$$Y = A + [B \times R] + [C \times S]$$

Where, the independent (explanatory) variables, R and S, represent economic or other variables to which the dependent variable, Y, use per customer or sales, is related.

Q. How was the residential econometric equation developed?

A. To specify the residential econometric equation, recorded monthly use per residential customer in kilowatt-hours ("kWh"), weather, economic and other data were collected for the period January 1997 through June 2006. The recorded use per customer data was adjusted by adding back the kWh impacts of DSM program measures verified and installed through June 2006. HECO then evaluated numerous hypothetical relationships between use per customer and explanatory variables from this database. The residential use per customer econometric equation is discussed in further detail later in my testimony.

Q. How was the commercial econometric equation developed?

A. For the commercial sales econometric equation, recorded monthly sales in kilowatt-hours, weather, economic and other data were also collected for the period January 1997 through June 2006. The recorded sales data was adjusted by adding back DSM kWh impacts verified and installed through June 2006. HECO then evaluated numerous hypothetical relationships between total commercial sales and explanatory variables from this database. The commercial sales econometric equation is discussed in further detail later in my testimony.

Q. How were the econometric equations evaluated?

A. The evaluation of the hypothetical relationships was performed using a proprietary software package, EViews. EViews is a linear regression package, which provides quick analysis and statistical testing of econometric models. Many hypothetical relationships were considered, tested, and rejected until econometric equations for residential use per customer and commercial kWh sales were identified for use in HECO's sales projections.

Q. How does HECO treat weather in its short-term econometric analyses of sales?

A. As mentioned above, HECO included weather as explanatory variables in the econometric models. Several weather variables were examined in testing various hypothetical models; including average wet bulb and dry bulb temperatures, heat index, and rainfall.

Q. Is this how HECO has treated weather impacts in estimating sales in previous forecasts?

A. No, this method represents a departure from the way HECO has treated weather in past forecasts. In the past, HECO would attempt to remove the effects of weather from historical sales before estimating an econometric model. HECO would develop independent time series models relating cooling degree days ("CDD") to kWh sales, and then adjust historical sales for the difference in the historical CDD to the CDD average over the historical period.

The current method treats historical weather as an independent variable that can be used to explain observed changes in use per customer or commercial sales. For 2007, average weather is assumed, since it is difficult to assume that the weather over the forecast period will resemble the current year or that the weather will be either warmer or cooler or dryer or more humid than average. In the econometric models used to forecast 2007, wet bulb temperature and cooling degree days (CDD) were identified as the variables with best explanatory powers. The forecast assumes average wet bulb temperature and CDD derived from monthly averages for 1997 – 2003 and 1976 – 2003, respectively.

Q. Why was the data period 1997 through 2006 chosen for the development of the econometric equation?

A. This period was chosen because of the availability of weather data. HECO does not have monthly data reported by the National Oceanic and Atmospheric Administration ("NOAA") on several of the weather variables prior to January 1997, most notably, average monthly wet bulb temperature. June 2006 represents the last month of data that was available at the time the forecast models were developed.

Q. Why is average weather only calculated through 2003?

A. Several data periods were considered in developing the weather variables. Honolulu weather appeared to experience weather in 2004 - 2006 anomalous relative to previous years, especially for wet bulb temperature (see HECO-WP-202 for historical weather variables and comparison graphs). Wet bulb temperature in 2004 was much higher (two standard deviations from the annual 1997 – 2005 mean) than other years during 1997 – 2006. In addition, when comparing the average wet bulb temperature over various periods, including 1997 – 2003, 1997 – 2005, and 1997 – YTD 2006, see HECO-WP-202 page 2, the difference in the monthly average values is not large. Until a longer data period is available for the wet bulb temperature, it appeared to be more reasonable to use the 1997 – 2003 average. To be consistent, the average for CDD was also calculated only through 2003.

Q. What was the general method used to specify the econometric equations?

A. HECO used a "general-to-specific" method to specify the econometric equations. In this procedure, the initial model includes all possible combinations of the variables, including lagged values if the relationship seems reasonable (e.g., is the electricity price in the previous month likely to impact the current month's electricity use?). Statistical tests were then used to eliminate variables that did not appear to have a statistically significant relationship to the dependent variable. The resultant equations were then subjected to tests using several criteria.

Q. What criteria were used to select the final econometric equation?

A. There were several criteria used to evaluate the numerous equations developed. First and foremost, the equation had to make sense in the real world, i.e., there had to be a reasonable basis for believing that the electricity sales were, in fact, related to the independent variables included in the equation.

Second, the direction of the relationship had to be plausible. For instance, positive economic growth should lead to higher electricity sales all else being equal. Therefore, the coefficient associated with the economic variable had to be positive. On the other hand, higher electricity prices should lead to lower sales, all else being equal. Therefore, the coefficient associated with electricity price had to be negative.

Finally, various statistical measures produced in the EViews reports (shown in HECO-WP-203, pages 2 – 5 and HECO-WP-206, pages 2 – 5) were examined for each equation developed. In addition, the independent variable coefficients were tested to be sure that they were significantly different from zero.

Q. How are the results of the forecast model applied?

A. The growth rates from the econometric model results were applied to actual 2005 residential use and commercial sales to forecast 2006 and 2007 use and sales (as shown in HECO-WP-203, page 8 and HECO-WP-206, page 8). Adjustments are also made to the sales forecast to reflect customer-specific project impacts, NEM impacts, and DSM kWh impacts.

Q. What are customer-specific impacts on the forecast?

A. Customer-specific impacts on the forecast are primarily from large construction projects that are deemed to not be captured in the historical data and therefore are not reflected in the historical relationship between sales and the explanatory variables. An example of this might be the construction of a desalination plant or the recent out-of-trend increase in the number of new luxury condominiums. Other impacts might include non-DSM energy conservation or the installation of a customer-owned co-generation unit.

Q. How are the forecasts for new large construction projects developed?

A. New large construction projects are identified and their approximate timetables are established using various sources, some public and others internal to HECO, such as news publications, Marketing Services Division contacts, and HECO service requests. Expected electricity sales from these new projects are estimated using information from the same sources mentioned above, as well as from sales data for existing customers that have similar characteristics, and/or by using engineering estimates. Engineering estimates include estimates of sales or demand provided by the customer, or from indices for a type of business such as average sales per square foot, or per employee, etc.

Q. How are other customer-specific project impacts identified and quantified?

A. Similar to large construction projects, various internal and external sources are used. If the impact to the customer is known through Marketing Services contacts, the customer's historical data is used to quantify the impact of the project. At other times, data is less available and estimated impacts from similar types of projects or changes in historical trends are used to estimate the project impact.

Q. How are rate schedule sales determined from the estimate of total commercial sales?

A. Time series and econometric models using rate schedule historical sales data were evaluated with variables similar to the total commercial sales equation. The proportion of each rate schedule's forecasts for similar equation specifications to the sum of all rate schedules' forecasts was used to allocate the total commercial sales forecast to rate schedules. Several different allocations based on different econometric equations and time series models (e.g., linear, exponential, etc.) were evaluated and the allocation that seemed the most reasonable relative to historical sales trends was selected.

The impact of large known customer projects was subtracted from the forecast prior to allocating the sales to rate schedules. Once the allocation factor has been applied, the projected sales for new large customers are added back to the appropriate rate schedule – normally either Schedule J or P. Further adjustments are made to the allocated sales to account for anticipated customer rate schedule transfers and other reasons. The result is a sales estimate by rate schedule in which the results from the econometric analysis is increased by the results of the estimate of sales to new large construction projects.

Q. What utility DSM programs are included in the 2007 sales estimates?

A. The 2007 sales estimates are adjusted for the future impact of HECO's DSM programs ("future DSM") as described by Mr. Hee in HECO T-9. The estimate of future DSM includes savings from DSM measures installed in 2006 and 2007. The impact of DSM measures installed prior to 2006 ("acquired DSM") is already included in the sales estimates.

Q. What is the impact of including future DSM in the 2007 sales estimate?

A. The inclusion of future DSM reduces electricity.

<u>2007 Sales Estimates by Rate Schedule</u>

Q. How were the estimated 2007 sales and number of customers by rate schedule derived?

A. The estimated residential and commercial 2007 sales and number of customers were derived using the methods described earlier in my testimony, and are further discussed in this section.

Q. What are the 2007 estimates for <u>Schedule R – Residential Service</u> sales and number of customers?

A. The 2007 estimate for Schedule R sales is 2,128.9 GWh and the projected number of customers is 261,302, as shown in HECO-201. The sales projected for this schedule represent a decrease of 1.1% in 2006 below recorded 2005, and a 0.5% increase in 2007 over expected 2006 sales of 2,118.4 GWh. Residential customers are projected to grow by 1.1% and 0.9% in 2006 and 2007, respectively, as shown in HECO-WP-201, page 33.

Q. How was this sales estimate developed?

A. The 2007 estimate for Schedule R was derived by multiplying the projection of use per customer times the estimated number of customers. Future DSM impacts were then applied to the result.

Q. How was the 2007 estimate of use per customer derived?

A. The 2007 estimate of residential use per customers is based on an econometric model developed by HECO. The dependent and independent variables and forecast assumptions for the independent variables used in the econometric equation are shown in HECO-202.

Q. What is the specific form of the residential econometric model for use per customer?

A. The specification for the residential use per customer econometric equation is shown in HECO-203. The econometric model describes residential electricity use per customer as a function of temperature, humidity, electricity price, some month-to-month seasonal factors, a time trend, and lagged dependent variable terms. In the short-term, both temperature (CDD) and humidity as measured by the wet bulb temperature were found to have a relationship with residential use per customer. Recent (since 2005), large increases in residential electricity prices was also found to have a relationship with residential use per customer. The time trend was included to represent the underlying growth trend in the residential use per customer. The lagged dependent variables (similar in function to an autoregressive parameter) strengthen the statistical robustness of the model, as do the dummy variables for specific months.

Q. What is the estimated growth in use per customer for the 2007?

A. The annual average use per customer is expected to decrease 2.2% in 2006 below recorded 2005, and another 0.4% in 2007 below 2006 to 8,147 kWh per year (see HECO-204 and HECO-WP-201, page 33).

Q. What assumptions were used to derive the Schedule R use per customer projection?

A. The assumptions and sources for the independent variables used to derive the Schedule R use per customer projections are shown in HECO-202.

Q. How was the 2007 estimate of the number of customers developed?

A. The number of residential customers was derived using an additive linear trend time series model. Historical residential customer data from January 1980 through April 2006 was adjusted to remove the impact of the Kukui Gardens conversion to Schedule R beginning in 2005 and the addition of customers from 215 N. King Street condominium beginning in January 2006. These customers were added back later to the time series model forecast. The Kukui Gardens and 215 N. King Street condominium impacts were removed because they are not part of the normal trend. Kukui Gardens was the conversion of one large master metered commercial customer to about 850 individual Schedule R customers. 215 N. King Street is a new condominium with about 240 individually metered units. (Note: most of the new condominiums currently under construction are master metered customers and are included as single customers in the commercial rate schedules.)

Q. What is the 2007 estimate for Schedule R number of customers?

A. The estimated 2007 average number of customers is 261,302, an increase of 0.9% or 2,338 over the 2006 average estimate of 258,964. The historical and projected residential customer increases are shown in HECO-204.

Q. What is the resulting 2007 sales estimate for Schedule R?

A. As discussed earlier, the Schedule R use per customer is 8,147 kWh per year and the number of customers is 261,302. Multiplying the two together results in a 2007 Schedule R sales estimate of 2,128.9 GWh, including future DSM, as shown in HECO-204.

Q. Why are the 2007 Schedule R estimates reasonable?

A. The Schedule R 2007 estimates are reasonable because they are consistent with the economic outlook for Oahu and with recent historical trends.

The active housing market on Oahu and continuing demand for homes is likely to continue to support growth in the average number of residential customers at recent historical levels. The average rate of customer growth is expected to continue to remain near historical levels in 2007, although not as strong as the growth was in 2006, which benefited from the conversion of Kukui Gardens and the addition of 215 N. King Street customers. The customer growth of about 0.9% is similar to the growth rates seen in recent years, as shown in HECO-204.

Residential use per customer has softened since 2005, due in part to higher electricity prices and cooler, less humid than average weather in 2005 and 2006. Slower growth rates in residential sales are driven by sluggish residential use per customer, which is projected to continue to decline. The decline in use slows after 2006, but continues to be consistently lower for 2007 – 2011 than in recent years. The main driver of this decline in use is the assumed higher electricity prices. Oil prices are expected to stabilize somewhat, but are not expected to weaken significantly over the forecast horizon. Climbing interest rates, historically high housing prices, and slower projected growth in personal income are likely to further erode customers' disposable income. HECO's residential appliance survey indicated that air conditioning saturation climbed 17 percentage points, from 41% to 58% between surveys taken in 2000 and 2004. Penetration of air conditioning in the residential market is expected to continue to grow in the forecast horizon, but at a slower pace. For 2007, HECO assumes a return to average weather, which contributes to higher use per customer, offset by decreased use due to electricity prices that are somewhat higher than 2005 and year-to-date 2006 average prices.

Projected 2006 residential sales of 2,118.4 GWh are 1.1% below recorded 2005. This is reasonable relative to the year-to-date November 2006 residential sales decline of 0.4% below recorded sales for the same period in 2005 (see HECO-212). Schedule R 2007 sales are projected to be 0.5% above estimated 2006 sales. The Schedule R sales increase is reasonable relative to recent sales trends as shown in HECO-204 and the expectation of continued growth in the residential market, offset somewhat by the expected slowing in the local economy in 2007, particularly the impact of inflation on personal income growth and rising mortgage rates.

Q. What are the 2007 estimates for total commercial sales?

A. The 2007 estimate for commercial sales is 5,554.1 GWh as shown in HECO-201. The sales projected for this sector are expected to decrease by 0.8% in 2006 below recorded 2005, and then grow 1.1% in 2007 over 2006, as shown in HECO-205.

Q. How was the commercial sales estimate developed?

A. The 2007 estimate for commercial was derived from the results of an econometric equation plus customer-specific project impacts. Future DSM impacts were then applied to the result.

Q. How was the 2007 estimate of commercial sales derived?

A. The 2007 estimate of commercial sales is based on an econometric model developed by HECO. The dependent and independent variables and forecast assumptions for the independent variables used in the econometric equation are shown in HECO-202.

Q. What is the specific form of the econometric model for commercial rate classes?

A. The specification for the commercial sales econometric equation is shown in HECO-206. The econometric model describes commercial sales as a function of temperature, humidity, non-agricultural job count ("non-ag jobs"), some month-to-month seasonal factors, and lagged dependent variable terms. In the short-term, both temperature (CDD) and humidity as measured by the wet bulb temperature were found to have a relationship with commercial sales. Non-ag jobs have often been used by HECO in forecast efforts because of the strong relationship this economic variable appears to have with commercial sales. The lagged dependent variables strengthen the statistical robustness of the model, as do the dummy variables for specific months.

Q. What assumptions were used to derive the commercial sales projection?

A. The assumptions and sources for the independent variables used to derive the commercial sales forecast are shown in HECO-202.

Q. How was the 2007 estimate of the number of customers developed?

A. The number of commercial customers was derived at a rate schedule level using time series models. Schedules P and F were based on 1980 – 2005 data, and Schedules G, J, and H were derived from 1986 – 2005 data. In all commercial rate schedules except H, the growth rates from additive linear trend time series models were used in deriving the customer forecast. For Schedule H, which has a history of decreasing sales and customers, 1.25 times the growth rate from an exponential, multiplicative (Winters) trend model was used. All time series model results examined for Schedule H resulted in too precipitous a decline in customers to use the raw model growth rates.

Q. For 2007, how are the forecasts of sales for individual commercial rate schedules developed?

A. As discussed earlier, a rate schedule allocation factor is applied to the total commercial sales estimates. The rate schedule allocation factors used to derive 2007 estimates were based on projected sales by rate schedule from exponential smoothing, additive trend time series models (HECO-WP-207). Once the allocation factor has been applied, the projected sales for new large customers are added back to the appropriate rate schedule – normally either Schedule J or P. Further adjustments are made to the allocated sales to account for anticipated customer rate schedule transfers and other reasons. The result is a sales estimate by rate schedule.

Q. What are the 2007 estimates for <u>Schedule G – General Service (Non-demand)</u> sales and number of customers?

A. The 2007 sales estimate for Schedule G is 371.8 GWh and the estimated average number of customers is 26,032, as shown in HECO-207. The Schedule G sales are projected to decrease 1.7% in 2006 below recorded 2005, and then increase 2.3% in 2007 over estimated 2006 sales of 363.4 GWh. Customers are projected to grow by 0.8% and 1.1% in 2006 and 2007, respectively.

Q. What are the 2007 estimates for <u>Schedule J – General Service (Demand)</u> sales and number of customers?

A. The 2007 sales estimate is 2,068.8 GWh and the estimated average number of customers is 6,745, as shown in HECO-208. The sales in this schedule are projected to increase slightly in 2006 over recorded 2005 sales, and then increase 2.3% in 2007 over 2006. Customers are projected to grow by 1.5% and 1.7% in 2006 and 2007, respectively.

Q. What are the 2007 estimates for Schedule H – Commercial Cooking, Air Conditioning, Heating and Refrigeration Service sales and number of customers?

A. The 2007 sales estimate is 40.5 GWh and the estimated average number of customers is 746, as shown in HECO-209. The sales projected for Schedule H represents a decrease of 12.9% in 2006 below recorded 2005 sales, and a decrease of 11.6% in 2007 below 2006. Customers are projected to decrease by 11.4% and 9.6% in 2006 and 2007, respectively.

Q. What are the 2007 estimates of sales and number of customers for Schedule P – Large Power Service?

A. The 2007 estimate of sales is 3,073.0 GWh, and the estimated average number of customers is 358, as shown in HECO-210. The sales projected for Schedule P represents a decrease of 1.1% in 2006 below recorded 2005 sales, and an increase of 0.3% in 2007 above 2006. Customers are projected to remain flat in 2006, and then grow by 0.6% in 2007.

Q. What are the 2007 estimates of sales and number of customers for Schedule F – Street Lighting?

A. The 2007 sales estimate is 37.8 GWh, and the estimated 2007 average number of customers is 437, as shown in HECO-211. The sales projected for Schedule F are expected to remain the same as 2005 recorded sales over the 2006 – 2007 time period. Customers are projected to increase 3.6% and 2.1% in 2006 and 2007, respectively.

Q. Why are the 2007 estimates for the commercial sector reasonable?

A. The commercial sector 2007 estimates are reasonable because they are consistent with the economic outlook for Oahu and with recent historical trends.

The tourism and construction industries remain strong, although economic growth is expected to begin slowing in 2006 and 2007. The cooler, less humid than average weather in 2005 and 2006 appeared to have dampened commercial sector sales. For 2007, HECO assumes a return to average weather, which should contribute to higher sales. High prices could also affect sales to commercial customers. While commercial customers have less flexibility in responding to higher electricity prices, many customers, including the military, may have made energy conservation efforts a higher priority in order to stay within limited operating budgets. Companies and government entities appear to have begun to institute energy conservation efforts such as turning off lights and air conditioning when facilities are not occupied. High construction labor and materials costs may also restrict housing and commercial construction activity.

Projected 2006 commercial sales of 5,494.0 GWh are 0.8% below recorded 2005. This is reasonable relative to the year-to-date November 2006 commercial sales decline of 0.3% below recorded sales for the same period in 2005 (see HECO-212). Commercial 2007 sales are projected to be 1.1% above estimated 2006 sales. The commercial sales increase is reasonable relative to recent sales trends as shown in HECO-205 and the expectation of continued growth in military spending and construction, offset somewhat by the expected slowing in the local economy in 2007, particularly the impact of inflation on business spending and a slowdown in the growth of non-ag jobs.

<u>Sales Forecast Accuracy</u>

Q. How accurate have past sales forecasts been?

A. The variances, shown in HECO-213, between the forecasts developed in 2003 and 2004 and weather normalized 2005 sales reflect the conditions which characterized HECO's outlook during those years. HECO had experienced relatively strong total recorded sales growth for several years beginning in 2000, average 2% growth per year. In particular, residential sales saw an average of 3.2% increase per year between 2000 and 2004, a combination of strong use per customer and steady average number of customer growth. Residential sales exceeded previous sales forecasts as interest rates fell and mortgage re-financings and income tax relief resulted in higher disposable income. Low interest rates also encouraged activity in the housing market.

Commercial sales during 2000 – 2004 also saw moderate growth averaging 1.2% per year. Expectations were that the local economy would continue to accelerate during 2005 with a rebound in the tourism industry (particularly travelers from Japan), continued strength in construction, and new military spending. Sales in the commercial sector were expected to continue to see moderate growth.

Based on this optimistic outlook, the most recent full year 2005 forecasts shown in HECO-213 were expecting to see about 2% growth in 2005 above 2004. Instead, 2005 recorded sales were 0.1% below recorded 2004 as cooler, less humid weather and high electricity prices driven by high oil prices dampened electricity use. On average, the forecasts shown in HECO-213 were 3.0% above weather normalized actual.

SUMMARY

Q. Please summarize your testimony on the test year 2007 sales and customers forecasts.

A. HECO uses a comprehensive set of forecasting methods that are evaluated through a rigorous forecasting process to develop its sales and customers forecasts. The sales estimate for test year 2007 is from an annual sales forecast that was developed through a comprehensive process involving expert and internal review. The 2007 forecasts of sales of 7,720.8 GWh and 295,620 customers are reasonable for ratemaking purposes because they reflect the economic outlook for Oahu, the inclusion of estimated large construction projects, and recent historical trends.

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaiian Electric Company, Inc.

George A. Willoughby

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Other Testimony:	Docket No. 05-0145 – Sales and Peak Forecasts

Hawaiian Electric Company, Inc.

TEST YEAR 2007 SALES AND CUSTOMERS

Rate Schedule	2007 Test Year Annual Sales (GWh) *	2007 Test Year Average Monthly Number of Customers
R	2,128.9	261,302
G	371.8	26,032
J	2,068.8	6,745
H	40.5	746
P	3,073.0	358
F	37.8	437
Total	7,720.8	295,620
Commercial *	5,554.1	33,881

* Excluding Schedule F

Reference: HECO-WP-201, HECO-WP-207

Hawaiian Electric Co., Inc.

FORECAST ASSUMPTIONS

	2005	2006	**2007**	Forecast Assumption
Explanatory Variables				
Cooling Degree Days (CDD)	4970	4575	**4727**	1976 - 2003 Average by Month
Wet Bulb Temperature	69.9	69.4	**69.8**	1997 - 2003 Average by Month
Residential Electricity Price				
Nominal (¢/kWh)	17.577	20.965	**21.535**	Test Year 2007
Real (¢/kWh) *	13.812	15.864	**15.803**	Assuming base year 1992
CPI-U Honolulu	197.5	205.1	**211.5**	3/06 UHERO Forecast (1982-84)
LSFO (nominal $/BBL)	50.579	63.63	**66.18**	2/26/06 Fuel Price Forecast (High Scenario)
Non-Farm Jobs (Honolulu)	443.3	454.5	**459.7**	"UHERO County Economic Forecast: Slowing Evident in County Economies," June 26, 2006
Dependent Variables				
Residential Use Per Customer				(Recorded monthly residential kWh with installed DSM added back) ÷ monthly residential customers Jan 1997 - Jun 2006
Commercial Sales				Recorded monthly kWh sales with installed DSM added back Jan 1997 - Jun 2006

* 1992$ real price (1992 CPI-U=155.2)

Reference: HECO-WP-202

Hawaiian Electric Co., Inc.

RESIDENTIAL USE PER CUSTOMER FORECAST MODEL

Short Term (2006 - 2007) Model
Monthly Data

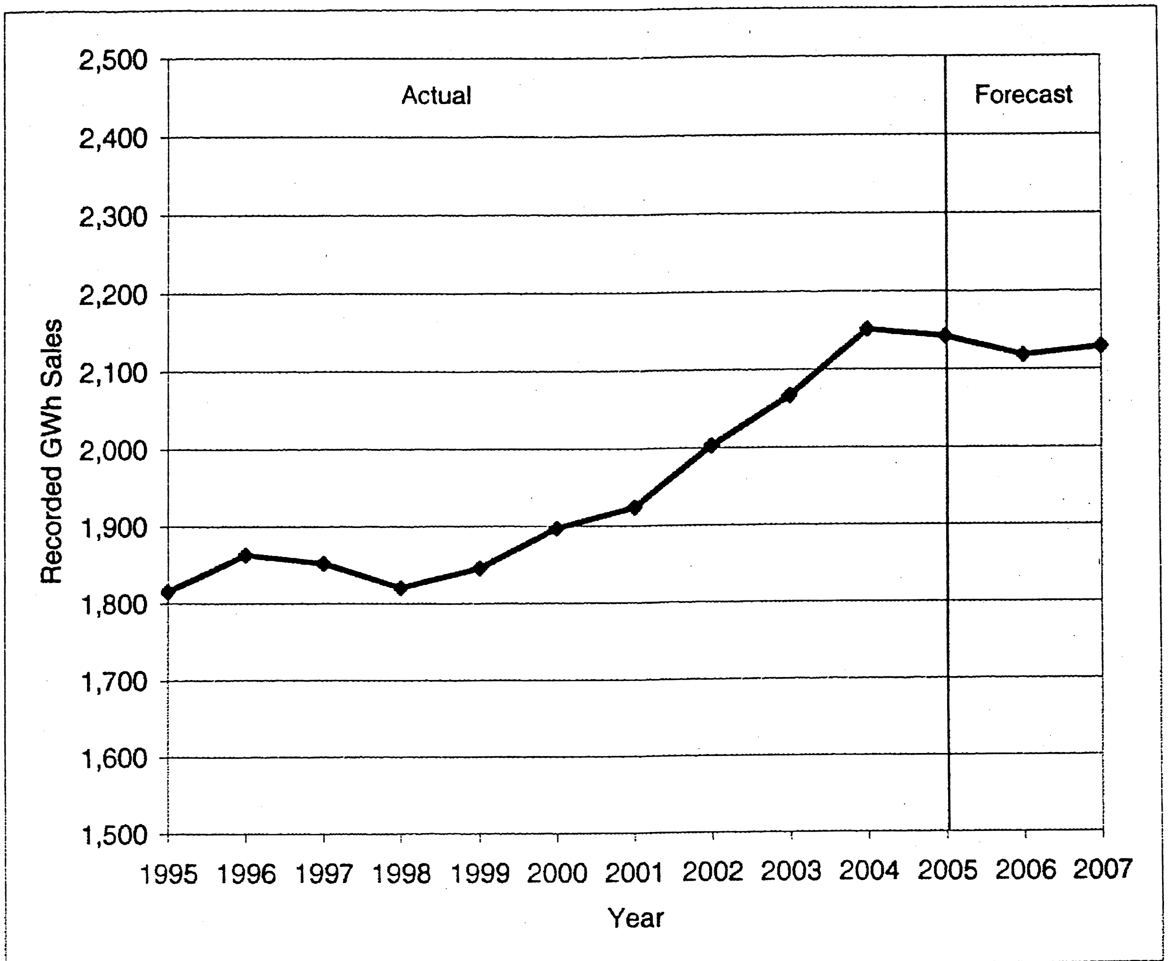
Dependent Variable

- Residential Recorded kWh per Customer (Use per Customer)

Explanatory Variables

- CDD (1976 – 2003 Average)
- Wet Bulb (1997 – 2003 Average)
- Electricity Price (1992$)
- Lag (1, 2, 3 ,12) Dep Variables
- Time Trend
- Month (1, 10) Dummy Variables

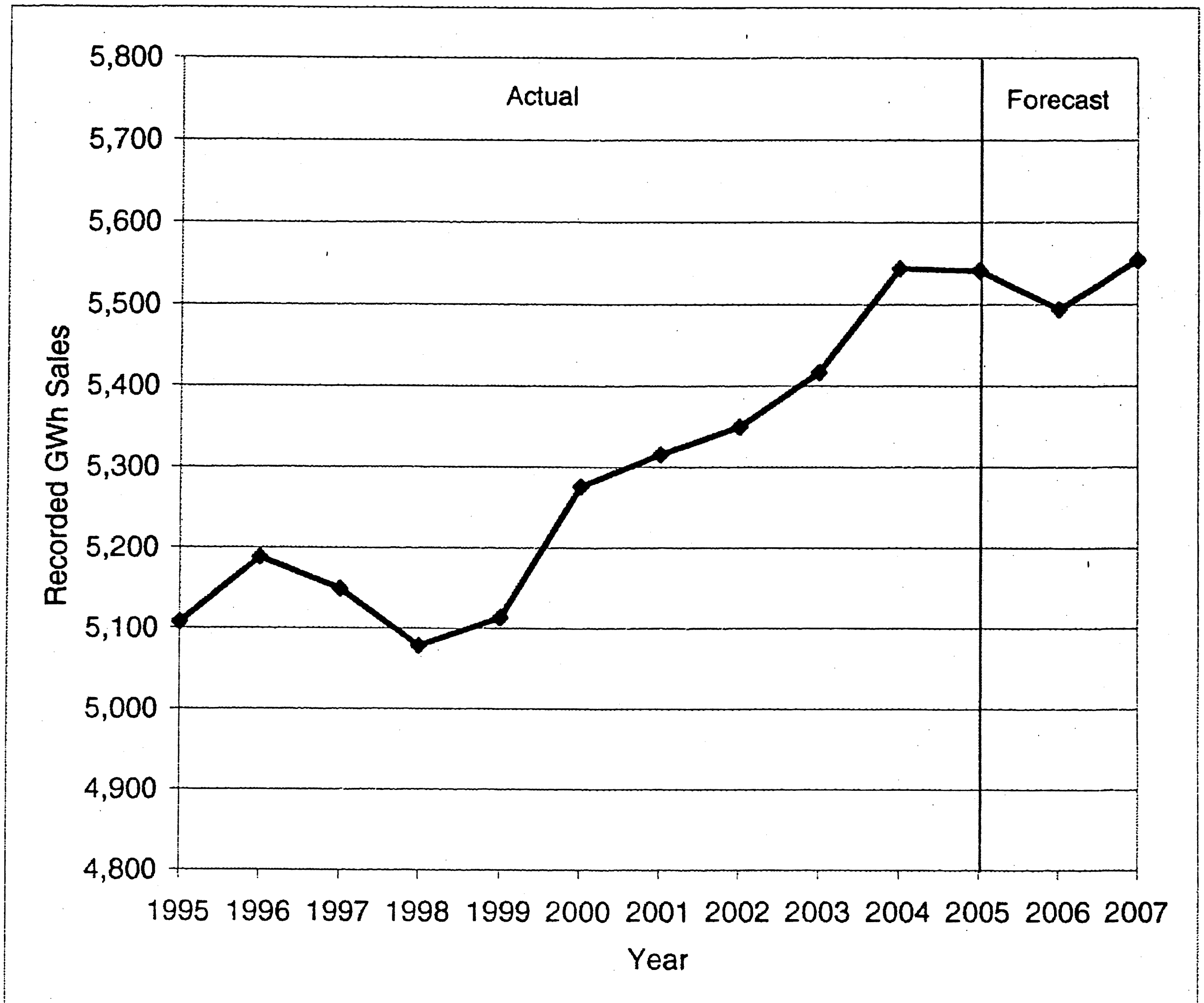
Hawaiian Electric Company, Inc.
SCHEDULE R - RESIDENTIAL SERVICE



	Year	Recorded GWh Sales *	Customers	Use/Customer
Recorded	1995	1,815.7	234,832	7,732
	1996	1,863.4	236,849	7,867
	1997	1,852.2	238,269	7,774
	1998	1,820.8	239,487	7,603
	1999	1,846.0	241,167	7,654
	2000	1,897.7	243,511	7,793
	2001	1,924.4	246,226	7,816
	2002	2,002.7	248,765	8,051
	2003	2,066.5	251,248	8,225
	2004	2,151.3	253,670	8,481
	2005	2,142.5	256,269	8,360
Forecast	2006	2,118.4	258,964	8,180
	2007	2,128.9	261,302	8,147

* 1995-2005 are recorded sales. 2006-2007 are forecasted sales assuming average weather.

Hawaiian Electric Company, Inc.
TOTAL COMMERCIAL



	Year	Recorded GWh Sales *	Customers
Recorded	1995	5,107.4	33,053
	1996	5,188.0	33,093
	1997	5,149.2	32,782
	1998	5,078.7	32,469
	1999	5,113.4	32,447
	2000	5,276.2	32,526
	2001	5,315.9	32,890
	2002	5,349.9	32,724
	2003	5,416.5	32,890
	2004	5,543.9	33,180
	2005	5,541.0	33,356
Forecast	2006	5,494.0	33,560
	2007	5,554.1	33,881

* 1995-2005 are recorded sales. 2006-2007 are forecasted sales assuming average weather.

Hawaiian Electric Co., Inc.

COMMERCIAL SALES FORECAST MODEL

Short Term (2006 - 2007) Model
Monthly Data

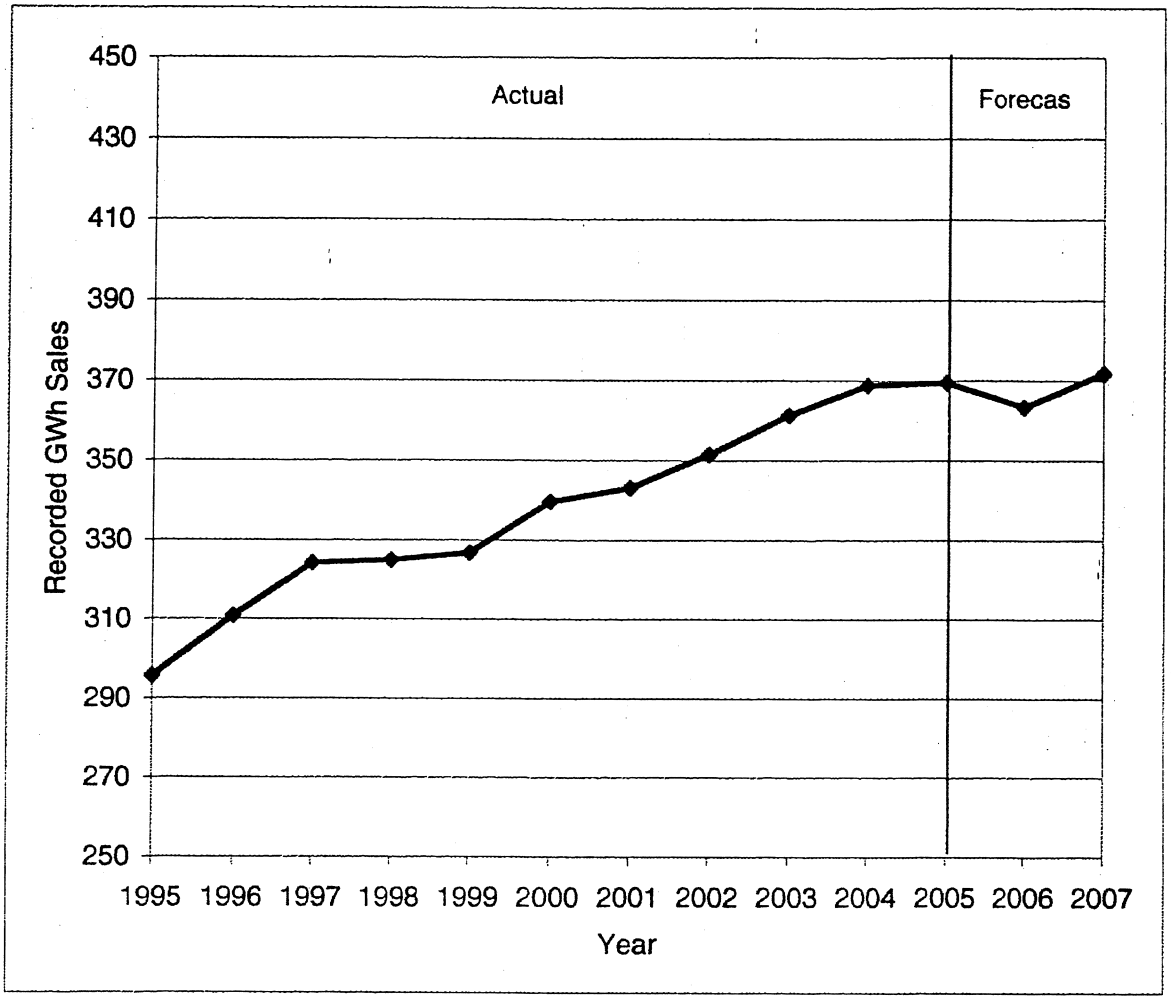
Dependent Variable

- Commercial Recorded kWh Sales

Explanatory Variables

- CDD (1976 – 2003 Average)
- Wet Bulb (1997 – 2003 Average)
- Non-Ag Jobs
- Lag (1, 2, 3 ,12) Dep Variables
- Month (1, 10) Dummy Variables

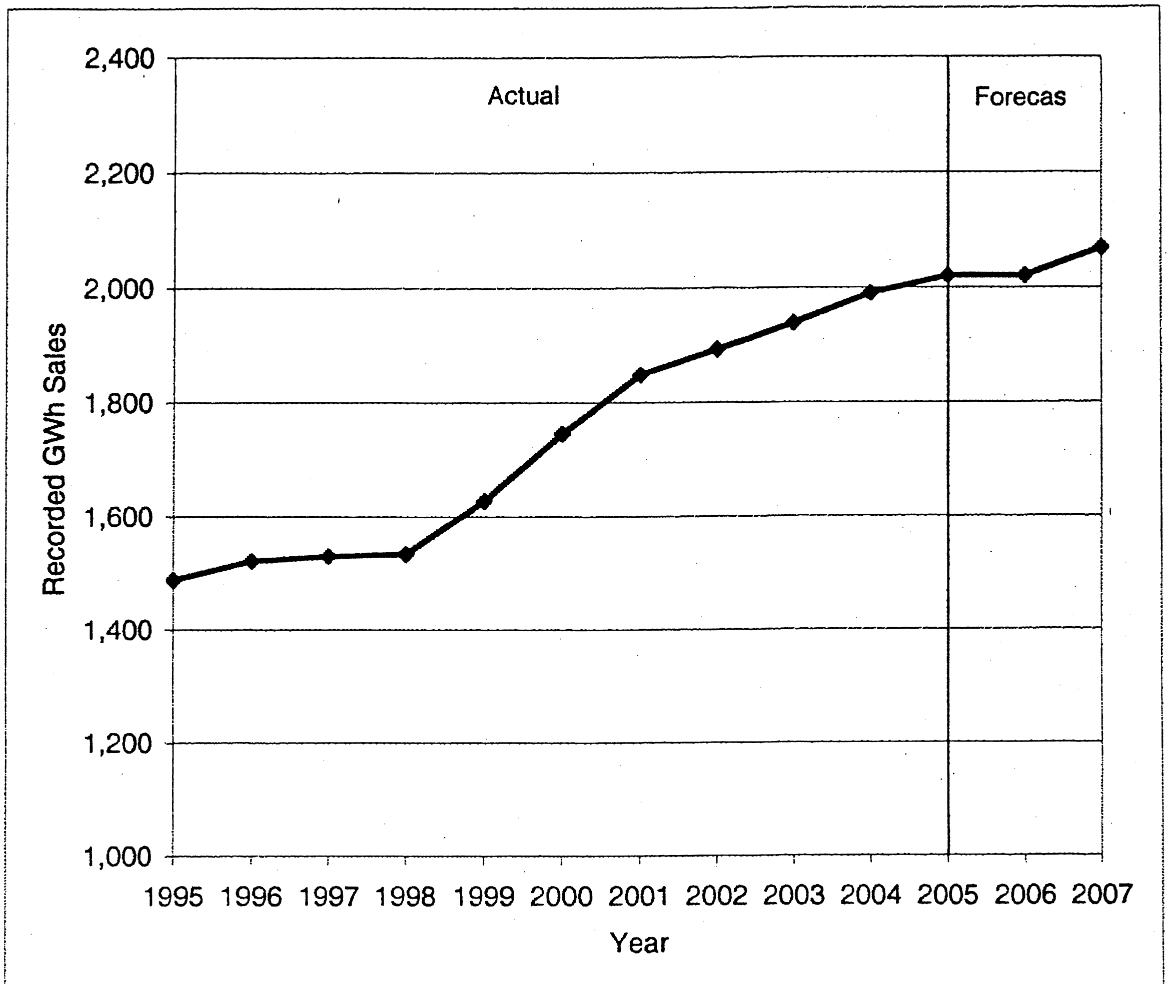
Hawaiian Electric Company, Inc.
SCHEDULE G - GENERAL SERVICE



	Year	Recorded GWh Sales *	Customers
Recorded	1995	295.7	22,793
	1996	310.8	23,075
	1997	324.2	23,176
	1998	325.0	23,181
	1999	326.8	23,274
	2000	339.7	23,605
	2001	343.2	24,507
	2002	351.5	24,710
	2003	361.4	24,952
	2004	368.8	25,245
	2005	369.5	25,533
Forecast	2006	363.4	25,744
	2007	371.8	26,032

* 1995-2005 are recorded sales. 2006-2007 are forecasted sales assuming average weather.

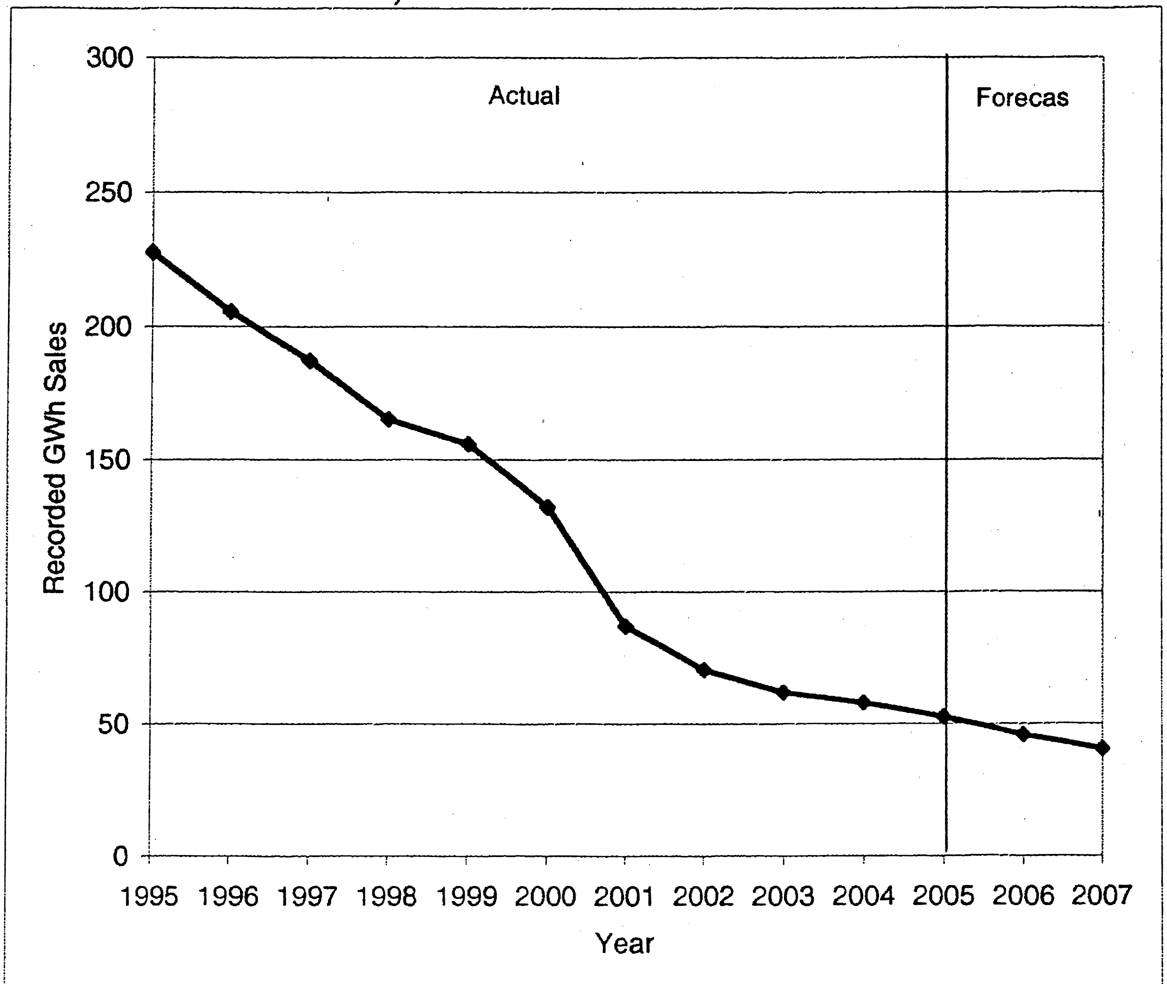
Hawaiian Electric Company, Inc.
SCHEDULE J - GENERAL SERVICE DEMAND



	Year	Recorded GWh Sales *	Customers
Recorded	1995	1,487.9	5,410
	1996	1,521.4	5,501
	1997	1,529.5	5,311
	1998	1,533.4	5,274
	1999	1,627.3	5,450
	2000	1,745.8	5,681
	2001	1,849.3	6,147
	2002	1,893.2	6,275
	2003	1,938.8	6,390
	2004	1,990.4	6,498
	2005	2,020.5	6,536
Forecast	2006	2,021.3	6,635
	2007	2,068.8	6,745

* 1995-2005 are recorded sales. 2006-2007 are forecasted sales assuming average weather.

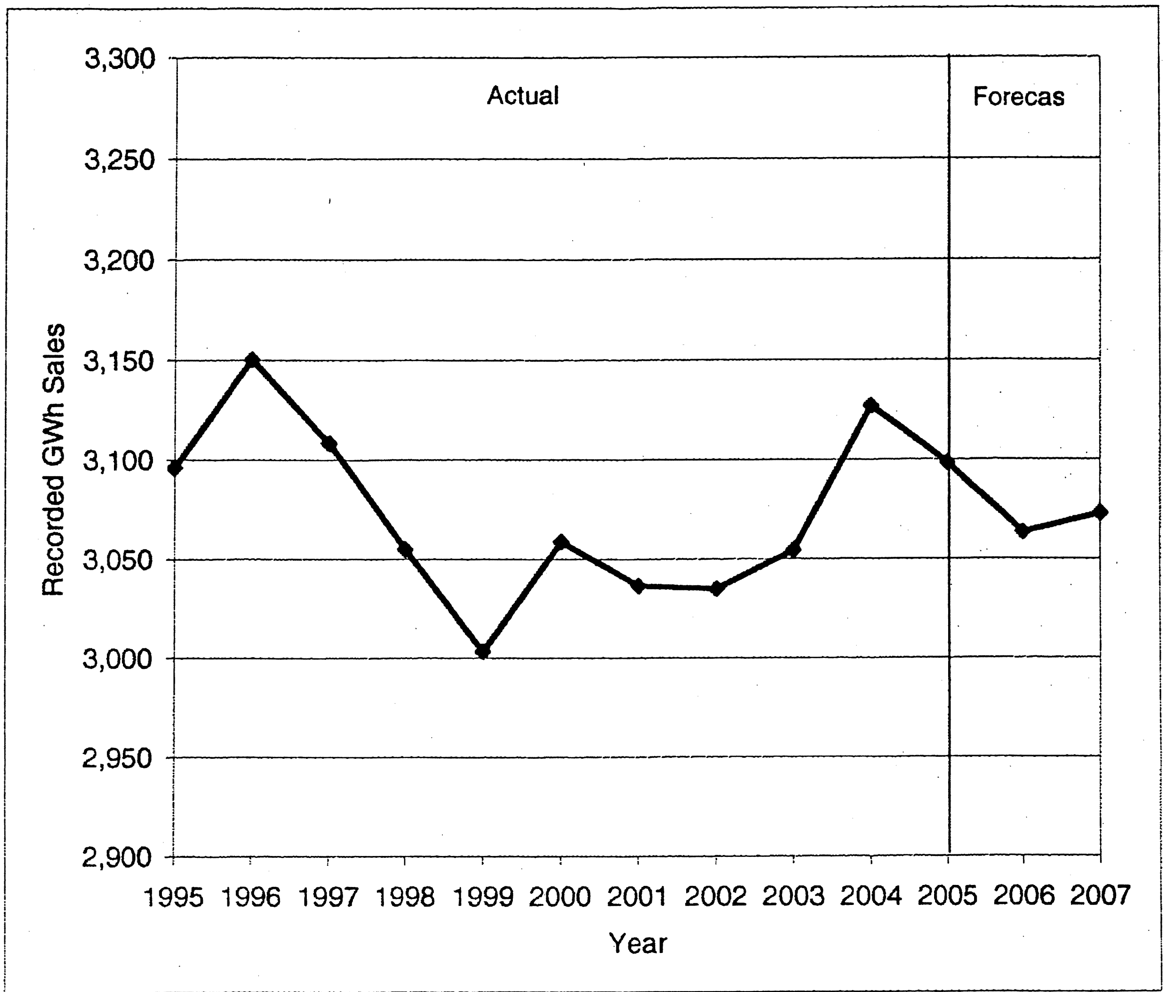
Hawaiian Electric Company, Inc.
SCHEDULE H - COMMERCIAL COOKING, AIR CONDITIONING, HEATING, AND REFRIGERATION SERVICE



	Year	Recorded GWh Sales *	Customers
Recorded	1995	227.8	4,456
	1996	205.6	4,125
	1997	187.2	3,906
	1998	165.2	3,626
	1999	155.9	3,354
	2000	132.1	2,879
	2001	87.1	1,880
	2002	70.3	1,384
	2003	61.9	1,194
	2004	57.9	1,083
	2005	52.6	931
Forecast	2006	45.8	825
	2007	40.5	746

* 1995-2005 are recorded sales. 2006-2007 are forecasted sales assuming average weather.

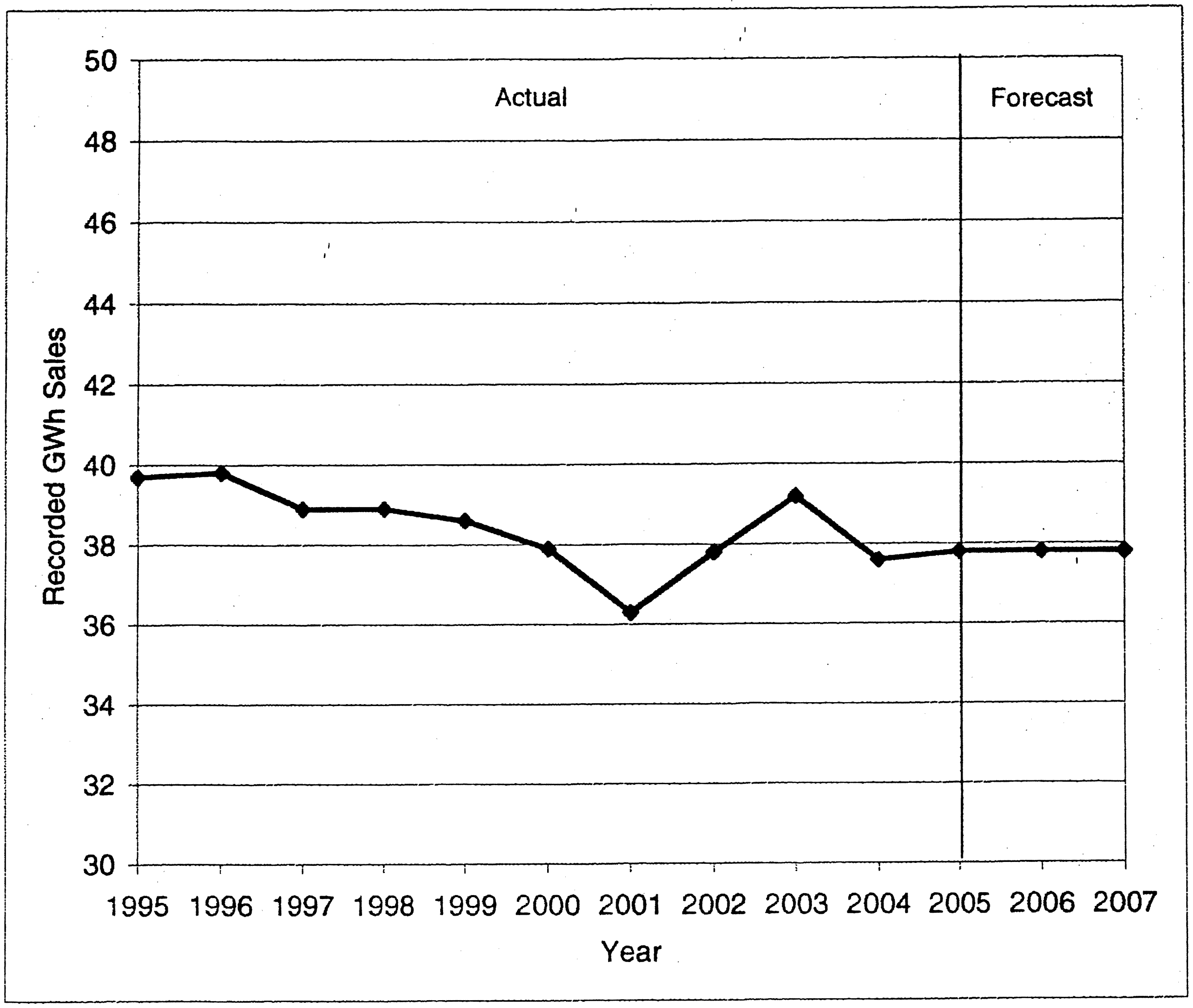
Hawaiian Electric Company, Inc.
SCHEDULE P - LARGE POWER SERVICE



	Year	Recorded GWh Sales *	Customers
Recorded	1995	3,096.1	393
	1996	3,150.2	392
	1997	3,108.3	389
	1998	3,055.0	388
	1999	3,003.4	369
	2000	3,058.6	361
	2001	3,036.4	356
	2002	3,034.9	355
	2003	3,054.3	354
	2004	3,126.8	354
	2005	3,098.4	356
Forecast	2006	3,063.5	356
	2007	3,073.0	358

* 1995-2005 are recorded sales. 2006-2007 are forecasted sales assuming average weather.

Hawaiian Electric Company, Inc.
SCHEDULE F - STREET LIGHTING



	Year	Recorded GWh Sales *	Customers
Recorded	1995	39.7	340
	1996	39.8	352
	1997	38.9	359
	1998	38.9	359
	1999	38.6	353
	2000	37.9	356
	2001	36.3	366
	2002	37.8	382
	2003	39.2	392
	2004	37.6	407
	2005	37.8	413
Forecast	2006	37.8	428
	2007	37.8	437

* 1995-2005 are recorded sales. 2006-2007 are forecasted sales assuming average weather.

Hawaiian Electric Company, Inc.

COMPARISON OF 2006 VS. 2005
NOVEMBER YEAR-TO-DATE
Recorded GWh Sales

Schedule	Nov YTD 2006	Nov YTD 2005	Diff	% Diff
R	1,953.5	1,960.8	-7.3	-0.4%
G	337.2	338.6	-1.4	-0.4%
J	1,867.2	1,853.5	13.7	0.7%
H	43.2	48.5	-5.3	-10.8%
P	2,817.4	2,838.7	-21.3	-0.7%
F	34.2	34.4	-0.2	-0.6%
Total	7,052.7	7,074.5	-21.7	-0.3%
Commercial *	5,065.0	5,079.3	-14.3	-0.3%

Legend:
- R Residential Service
- G General Service Non-Demand
- J General Service Demand
- H Commercial Cooking, Heating, Air Conditioning & Refrigeration
- P Large Power Service
- F Public Street, Highway, Park & Playground Lighting

* Not including Schedule F

Note: Totals may differ due to rounding.

Hawaiian Electric Company, Inc.

COMPARISON OF 2005 SALES TO FORECAST

Rate Schedule	2005 Recorded	Weather Normalized 2005 *	October 2003 Forecast			February 2004 Forecast			June 2004 Update		
			2005 Forecast	Wx Norm - Fcst Diff		2005 Forecast	Wx Norm - Fcst Diff		2005 Forecast	Wx Norm - Fcst Diff	
				GWh	%		GWh	%		GWh	%
R	2,142.5	2,136.5	2,130.8	5.7	0.3%	2,160.2	-23.7	-1.1%	2,145.7	-9.2	-0.4%
G	369.5	366.2	389.6	-23.4	-6.0%	383.5	-17.3	-4.5%	377.1	-10.9	-2.9%
J	2,020.5	2,003.3	2,091.4	-88.1	-4.2%	2,057.1	-53.8	-2.6%	2,016.9	-13.6	-0.7%
H	52.6	52.1	53.8	-1.7	-3.2%	55.3	-3.2	-5.8%	53.4	-1.3	-2.4%
P	3,098.4	3,072.3	3,241.5	-169.2	-5.2%	3,220.1	-147.8	-4.6%	3,209.4	-137.1	-4.3%
F	37.8	37.8	38.7	-0.9	-2.3%	40.3	-2.5	-6.2%	40.3	-2.5	-6.2%
Total	7,721.3	7,668.2	7,945.8	-277.6	-3.5%	7,916.5	-248.3	-3.1%	7,842.8	-174.6	-2.2%

* Weather adjustment = 241.3 MWh per cooling degree day difference from 1976 - 2005 average.
Forecasts prior to 2006 were developed using weather normalized sales.

HECO-213
DOCKET NO. 2006-0386
PAGE 1 OF 1

HECO T-3
DOCKET NO. 2006-0386

TESTIMONY OF
PETER C. YOUNG

DIRECTOR, PRICING DIVISION
ENERGY SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Electric Revenues and Other Operating Revenues

INTRODUCTION

Q. Please state your name and business address.

A. My name is Peter C. Young and my business address is 220 South King Street, Suite 1201, Honolulu, Hawaii, 96813.

Q. By whom are you employed and in what capacity?

A. I am employed by the Hawaiian Electric Company, Inc. as the Director of the Pricing Division of the Energy Services Department. My experience and background are listed in HECO-300.

Q. What is your area of responsibility in this proceeding?

A. My testimony in HECO T-3 will cover the estimates of electric revenues at present rates, at current effective rates, and at proposed rates for the 2007 test year. I also sponsor the cost of service and rate design testimony in HECO T-20.

Q. What is the difference between revenue estimates at present rates and revenue estimates at current effective rates?

A. Revenue estimates at present rates are based on rates effective January 01, 1997 (Schedules: R, G, H, J, and F) and June 01, 2001 (Schedules: PS, PP, and PT) respectively, plus revenues from the Energy Cost Adjustment Factor (ECAF), and Rate Adjustment. Revenue estimates at current effective rates are based on the revenue estimates at present rates plus the Interim Rate Increase effective September 28, 2005 as approved in Interim Decision and Order No. 22050 in Docket No. 04-0113.

Q. Will the other operating revenues be addressed by other Company witnesses?

A. Yes. The following witnesses will address the test year 2007 estimates for other operating revenues:

1) Mr. Darren Yamamoto (HECO T-8) will address non-sales electric utility

charges and

2) Mr. Bruce Tamashiro (HECO T-13) will address the miscellaneous other operating revenues.

ESTIMATES OF TEST-YEAR REVENUES

Q. What are the estimated electric sales revenues at present, at current effective, and at proposed rates for the 2007 test year?

A. The estimated revenues at present rates, at current effective, and at proposed rates for the 2007 test year are $1,346,379,000, $1,398,279,000 and $1,497,066,000, respectively. The estimated revenue at proposed rates represents an increase of $150,687,000 or 11.19% over the estimated revenue at present rates. Compared to current effective rates, revenue at proposed rates represents an increase of $98,787,000 or 7.06%. A summary of the revenue estimates for the 2007 test year at present rates, current effective rates, and proposed rates, by rate class is shown in HECO-301.

Q. What are the estimated other operating revenues at present and at proposed rates for the 2007 test year?

A. The estimated other operating revenues at present rates and at proposed rates for the 2007 test year are $3,897,000 and $4,716,000, respectively.

DERIVATION OF ELECTRIC SALES REVENUES

Q. What are included in the estimates of electric sales revenue for each rate class?

A. The estimates of the electric sales revenues for each rate class include the revenues from the base electric charges as well as the revenues from the Rate Adjustment, and Energy Cost Adjustment Clause. Electric sales revenues at current effective rates also include revenues from the interim rate increase approved in Interim Decision and Order No. 22050 in Docket 04-0113. The base electric charges are comprised of the customer, demand, energy and minimum charges, the power factor adjustment, service voltage adjustment, and other adjustments as provided in each rate and rate rider schedule.

A summary of the determination of the 2007 test year electric sales revenues for each rate schedule at present rates, and at current effective rates is provided in HECO-WP-301. A summary of the determination of the 2007 test year electric sales revenues for each rate schedule at proposed rates is provided in HECO-WP-2016 and is discussed in my HECO T-20 testimony.

Q. How are the revenues from the base charges for each rate class determined?

A. The determination of the electric sales revenues for each class is based on the same method used in previous dockets by the Company. It is based on the following data:

1) 2007 test year sales forecasts for each rate class;
2) 2007 test year forecasts of number of customers for each rate class;
3) recorded billing loads by subgroups and rate blocks within each rate class; and
4) 2007 test year forecasts of rate rider adjustments.

The revenues from base electric charges are derived by simulating the billing procedure for each rate class using the following steps:

1) The 2007 test year forecasts of sales and number of customers are allocated into subgroups and rate blocks within each rate class, based on recorded billing data. The allocation of the 2007 test year sales by rate blocks, as in Schedule J's energy rate blocks and in Schedule PS's

demand rate and energy rate blocks, is based on the Ogive method, using recorded billing data for the 12-month period from January 2005 to December 2005.

2) The sales and number of customers allocated to each subgroup and rate block are multiplied by the corresponding unit charges, and then summed to derive the base electric sales revenues for each rate class.

3) For customers who are on rate riders (such as Rider M, Rider T, Rider I), electric sales revenues are calculated for each customer at their regular class rates and at their rate rider rates. The differences are included as rider adjustments to the base electric revenues of their respective rate classes.

Q. Are there any changes to the method of determining the base revenues for test year 2007?

A. Yes. The determination of billing demand for Schedule J is proposed to be changed, as I discuss in HECO T-20. The estimate of Schedule J revenues at proposed rates includes adjustments to the estimates of billed kWb to reflect the proposed change. This change in Schedule J billing demand was proposed in HECO's test year 2005 rate case in Docket 04-0113.

Q. How were these adjustments to Schedule J's billing demand calculated?

A. Schedule J customer actual monthly billing data for the year 2005 were re-calculated to derive the adjusted kWb based on the proposed determination of Schedule J kWb. The percentage increase in kWb between the adjusted kWb based on the proposed determination of Schedule kWb and the actual monthly kWb for 2005 was calculated. The test year forecast Schedule J billing kWb at proposed rates was calculated by applying this percentage increase in kWb to the test year Schedule J billing kWb at present rates. These calculations are illustrated in HECO-WP-2016.

Q. Are there any additional changes to the method of determining the base revenues for test year 2007?

A. Yes, HECO is proposing to modify the flat rate energy charge of Schedule R, residential service; to a tiered, inclining block rate design to lessen the rate impact on low usage customers and to encourage energy conservation. This rate design modification is discussed further in my HECO T-20 testimony.

Q. What customers are reflected in the rate rider adjustments?

A. The rate rider adjustments include estimates of rider adjustments from existing rider customers only. Existing rider customers have rate rider adjustments, including Rider M, Rider T, Rider I, and Schedule U, on Schedules J, PS and PP.

Q. What is the Rate Adjustment?

A. The Rate Adjustment is a rate reduction as a result of Decision and Order No. 20292 issued July 1, 2003 and Order No. 20310 issued July 9, 2003, which approved the amendment of HECO's power purchase agreement with AES Hawaii, Inc. in Docket No. 03-0126.

Q. How is the estimate of revenues from the Rate Adjustment determined?

A. The estimate of revenues from the Rate Adjustment is derived by multiplying the base electric sales revenues by the Rate Adjustment percentage factor. The Rate Adjustment percentage factor at present rates and currently effective rates is -0.406% as shown in HECO-303. The Rate Adjustment percentage factor at proposed rates is 0.000%.

Q. How is the Rate Adjustment percentage factor determined?

A. The Rate Adjustment percentage factor at present rates is estimated by taking the estimated adjustment to the AES capacity payment, plus associated revenue taxes, and dividing by the estimated base electric sales revenues for test year 2007. The Rate Adjustment percentage factor at proposed rates is zero because the Company reflects the adjustment in its 2007 test year estimate of capacity payments to AES, as discussed by Mr. Ching in HECO T-5.

Q. How is the estimate of revenues from the Energy Cost Adjustment Clause determined?

A. The estimate of revenues from the Energy Cost Adjustment Clause is derived by multiplying the 2007 test year sales by the Energy Cost Adjustment Factor. The Energy Cost Adjustment Factor at present rates and current effective rates is 7.299 cents per kWh and 0.000 cents per kWh at proposed rates, as discussed by Mr. Hee in HECO T-9.

DERIVATION OF OTHER OPERATING REVENUES

Q. What is included in "Other Operating Revenues"?

A. Included in Other Operating Revenues are revenues from non-sales electric utility charges and miscellaneous revenue items as discussed by Mr. Darren Yamamoto (HECO T-8) and Mr. Bruce Tamashiro (HECO T-13), respectively.

A summary of the 2007 test year other operating revenues at present and proposed is provided in HECO-302.

SUMMARY

Q. Please summarize your testimony.

A. HECO's estimates of electric revenues at present rates, current effective rates, and proposed rates for the 2007 test year are $1,346,379,000 $1,398,279,000, and

$1,497,066,000, respectively, which represents a proposed increase of $150,687,000 or 11.19% over revenues at present rates; and $98,787,000 or 7.06% over current effective rates.

The determination of the 2007 test year electric revenues is based on the same methodology used and approved by the Commission in previous dockets.

HECO's estimates of other operating revenues at present rates and proposed rates for the 2007 test year are $3,897,000 and $4,716,000 respectively. HECO's total operating revenues at present rates and proposed rates for the 2007 test year are $1,350,276,000 and $1,501,782,000, respectively. Refer to HECO-302.

Q. Does this conclude your testimony?

A. Yes, this concludes my direct testimony.

PETER C. YOUNG

BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	Hawaiian Electric Company P.O. Box 2750 Honolulu, Hawaii 96840
CURRENT POSITION:	Director, Pricing Division, Energy Services Department
YEARS OF SERVICE:	18 Years
OTHER EXPERIENCE:	Financial Analyst, Pacific Resources, Inc. Corporate Analyst, Pentagram, Inc.
EDUCATION:	MBA (Finance), University of Washington BA (Economics, Political Science), Claremont McKenna College, Claremont, CA
OTHER TESTIMONY:	Docket No. 05-0146 – Residential Rate Reduction Program; Revenue Requirements and Customer Impact (HECO) Docket No. 05-0145 – Revenue Requirements and Customer Impact (HECO) Docket No. 04-0113 - Electric Sales Revenue; Cost of Service and Rate Design (HECO) Docket No. 99-0207 - Electric Sales Revenue; Cost of Service and Rate Design (HELCO) Docket No. 97-0346 - Electric Sales Revenue; Cost of Service and Rate Design (MECO) Docket No. 7766 - Rate Base (HECO) Docket No. 7764 - Rate Base (HELCO) Docket No. 7700 - Rate Base (HECO)

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2007

SUMMARY OF REVENUES AT PRESENT AND PROPOSED RATES

Rate Class	At Present Rates ($000s)	At Proposed Rates ($000s)	PROPOSED INCREASE Amount ($000s)	PROPOSED INCREASE Percent (%)
Schedule R	$415,723.4	$463,564.9	$47,841.5	11.51%
Schedule G	$77,691.4	$86,424.7	$8,733.3	11.24%
Schedule J	$358,924.9	$398,587.8	$39,662.9	11.05%
Schedule H	$7,077.7	$7,873.7	$796.0	11.25%
Schedule PS	$135,059.5	$150,691.1	$15,631.6	11.57%
Schedule PP	$319,103.4	$354,407.5	$35,304.1	11.06%
Schedule PT	$26,047.3	$27,887.5	$1,840.2	7.06%
Schedule F	$6,751.4	$7,628.8	$877.4	13.00%
Total Sales Revenue	$1,346,379.0	$1,497,066.0	$150,687.0	11.19%

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2007

SUMMARY OF REVENUES AT CURRENT EFFECTIVE AND PROPOSED RATES

Rate Class	At Current Effective Rates ($000s)	At Proposed Rates ($000s)	PROPOSED INCREASE Amount ($000s)	Percent (%)
Schedule R	$432,975.6	$463,564.9	$30,589.3	7.06%
Schedule G	$80,721.8	$86,424.7	$5,702.9	7.06%
Schedule J	$372,286.2	$398,587.8	$26,301.6	7.06%
Schedule H	$7,354.1	$7,873.7	$519.6	7.07%
Schedule PS	$140,747.4	$150,691.1	$9,943.7	7.06%
Schedule PP	$331,021.2	$354,407.5	$23,386.3	7.06%
Schedule PT	$26,047.3	$27,887.5	$1,840.2	7.06%
Schedule F	$7,125.4	$7,628.8	$503.4	7.06%
Total Sales Revenue	$1,398,279.0	$1,497,066.0	$98,787.0	7.06%

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386
2007 TEST YEAR

TOTAL OPERATING REVENUES
SUMMARY

($ Thousands)

	At Present Rates	At Proposed Rates	Proposed Increase	% Increase
Electric Sales Revenues	$1,346,379	$1,497,066	$150,687	11.19%
Other Operating Revenues				
Non-Sales Electric Utility Charges	2,202	3,021	819	
Misc. Other Operating Revenues	1,695	1,695	0	
Subtotal	3,897	4,716	819	21.02%
Total Operating Revenues	**$1,350,276**	**$1,501,782**	**$151,506**	**11.22%**

Source: HECO-301, HECO-807 and HECO-1312.

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386
2007 TEST YEAR

DERIVATION OF RATE ADJUSTMENT
FOR CALCULATION OF ELECTRIC REVENUES
AT PRESENT RATES

L1	AES Hawaii Capacity Payment Adjustment	-$2,904,000
L2	Revenue Tax Factor	1.0975
L3 = L1 * L2	Amount to be Refunded to Customers	-$3,187,140
L4	Base Electric Revenues @ Present Rates, TY2007	$785,969,800
L5 = L3 ÷ L4	Rate Adjustment @ Present Rates, TY 2007	-0.406%